Industry4Redispatch (I4RD)[1]

Deliverable 3.1

Current and new business models of industrial customers as grid service providers and their associated incentives

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1 Introduction

The flagship project **Industry4Redispatch (I4RD)** is designed as a key project within the model region NEFI – New Energy for Industry. I4RD will be the first NEFI project that develops innovative solutions enabling (i) the provision of flexibility from the demand and supply-side at distribution network level for redispatch and (ii) the demonstration of an online, predictive and holistic control concept for industrial energy supply systems, which optimizes a company's market participation while ensuring its energy supply. With this approach, the expected results will enable participation of industry in redispatch and help to boost technological development within the NEFI community, especially by contributing to the central NEFI-innovation fields through *digitalization and flexibilization of the industry.*

In recent years, a growing need for redispatch in Austria and Germany, was observed. This growing need for redispatch is largely caused by the integration of renewable generation and continuing integration of the european electricity markets, which exacerbate existing grid congestions caused by a lag of critical transmission projects and it is likely to increase in the future. The costs for redispatch for Austria have been rapidly increasing from 23 M€ in 2015 to 117 M€ in 2018.

Redispatch, i.e. the shift of generation and demand of electrical energy to decrease the loading of a network element, is a necessary measure for congestion management at the transmission system level in order to maintain n-1 secure operation. Currently, in most cases, flexibility from generation units is utilized for redispatch. If new units at the distribution level are introduced, it must be ensured that critical operation conditions in the distribution grid must not occur by such industrial redispatch measures. The increase in renewable generation and an increase of concurrency factors caused by smart devices is not limited to the transmission level and could also cause congestions on the distribution level. Consequently, it can be expected that in the future, congestions are going to be managed by redispatch even on distribution levels. However, the regulatory framework as well as incentives are currently not attracting industrial customers to participate in redispatch. In addition, the available capability to shift power is small compared to current redispatch needs.

At the same time, the producing industry faces challenges such as achieving energy efficiency targets and adapting to the changing energy market. The current situation shows that a highly dynamic industrial plant operation is often not possible due to a lack of algorithms combining industrial process optimization with automated participation algorithms in the congestion management. In addition, investments in plant flexibility is currently mostly unprofitable as a result of low incentives.

The primary goal of I4RD is to enable flexibility provision from the demand and supply-side at distribution network level for redispatch. The project will assess all necessary technical, regulatory, economic and organisational requirements for the implementation of redispatch, as well as the necessary interaction between TSO (Transmission System Operator) and DSOs (Distribution Grid Operators). I4RD is the first project in Austria bringing all relevant stakeholders together to provide a general solution through the automation and optimization of the industry, setting up a coordination process between the TSO and the DSOs, developing a novel redispatch module based on standardized requirements and demonstrating the value of the new approach through the proof-of-concept. In this way, I4RD will integrate untapped flexibility from industrial customers for the redispatch provision while observing DSO requirements.

The redispatch module, as illustrated in Figure 1, is envisaged as a process specification and software implementation that incorporates different functionalities and interfaces which facilitates the interaction between the TSOs, DSOs and industrial customers for the provision of redispatch.

The redispatch module therefore enables:

- the participation of (aggregated) industrial customers – that are located in the distribution grid – to support congestion management/redispatch and
- automated finding of the optimal flexibility operation for both DSOs and the TSO.

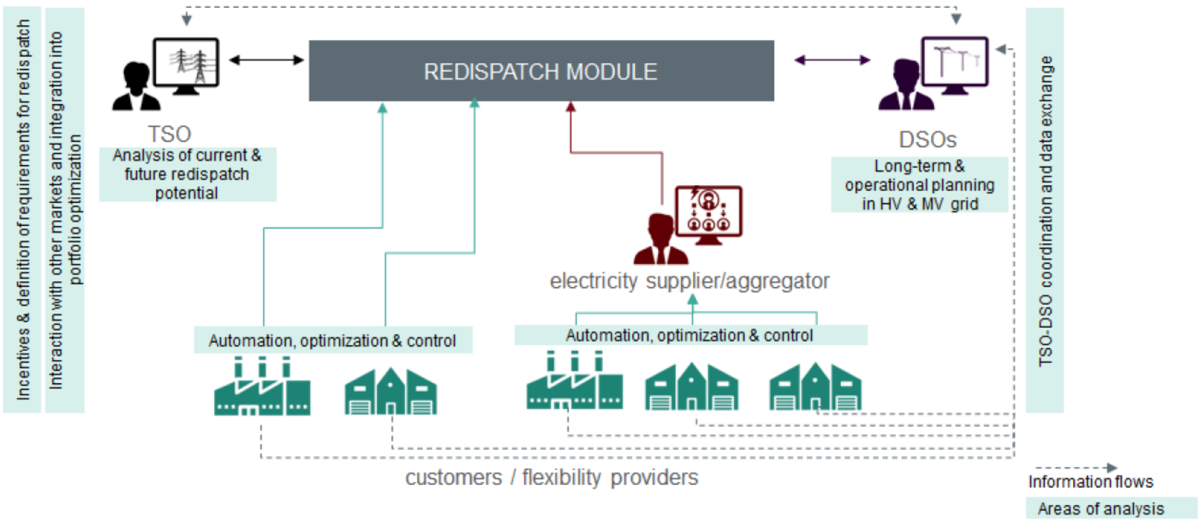

Figure 1: Overview of the project architecture, stakeholders and main research areas

Expected results and findings: I4RD will develop redispatch service and processes and related tools for the exchange of technical restrictions between the DSOs and the TSO. In addition, I4RD will set up industrial demonstrators/virtual power plants (VPPs) at distribution system level to efficiently address industrial customers with control systems with different levels of maturity and lay the groundwork for the future engagement of different industrial sectors and flexibility volumes. A cost-benefit analysis determines the distribution of costs and benefits among the stakeholder groups. A scalability analysis for TSO-DSO interaction identifies the impact on the distribution system caused by large-scale demand and supply-side management for redispatch in the transmission system and required information flows between TSO and DSO. Finally, a guideline is provided including a step-by-step tutorial for transforming a conventional existing industrial energy supply system into a more flexible, more decarbonized, optimally operated one as well as the guidelines for the TSO-DSO coordination process.

The objectives of this deliverable include:

- displaying the state-of the art of market participation at spot-and balancing markets, redispatch provision, as well as international and national initiatives for redispatch procurement
- defining project use cases based on stakeholder needs
- defining technical and economical KPIs for the comparison of all Use Cases

This deliverable covers project Tasks 3.1 (Analysis of stakeholder needs, high-level use cases & KPIs) and parts of Task 3.3. Together with Task 3.2 (Analysis and definition of redispatch requirements), this Task (3.1) will facilitate the preliminary identification of suitable use cases as input for relevant business models which will be used as an input for WP 7.

The current status-quo and trends of existing markets are analysed in Section 2. Section 3 describes redispatch in general and provides a specific snapshot for Austria and Germany. Concepts of international projects or initiatives concerning redispatch, their needs and expectations are analysed qualitatively in Section 4. In course of the project, six different Use Cases were identified with the help of a joint workshop series with all stakeholder groups involved. The Use Cases are described in Section 6 as well as in more detail in the annex of the document.

Table 1 provides an overview of the Use Cases that will be considered within the project, the specific section where the Use Cases and the relevant thematically related sections are described. High-level project KPIs are defined and discussed in Section 7, and a conclusion and outlook are drawn in Section 8.

Table 1 Use Cases developed within the project and related sections

ID	Use Case	Section	Thematic related sections	Focus	Description
1	**Reference**	**5.2**	2.3, 5	Reference	The historical baseline to compare the other markets/Use Cases to.
2	**Spot markets**	**5.3**	2.1	Markets	The identification of the value of flexibility on the traditional spot markets for the participating industrial customers.
3	**Spot- and balancing**	**5.4**	2.2	Markets	The identification of the value of flexibility on the traditional spot markets and selected balancing markets for the participating industrial customers.
4	**TSO Redispatch + Spot markets**	**5.5**	3	TSO	The added value of redispatch for the industrial customers and the value of the participation for the TSO. The Use Case helps to define all necessary processes for the participation of industrial customers at redispatch.
5	**DSO Redispatch + Spot markets**	**5.6**	4	DSO	Reference Use Case to compare Use Case 6 with the focus on the DSO with only the DSOs using the flexibility.
6	**DSO-TSO Redispatch+ Spot markets**	**7.7**	3,4	TSO-DSO Interactio n	This Use Case serves to analyse the TSO-DSO interaction.

The Use Cases are designed to be implemented in a step-by-step procedure. Therefore, Use Case 1 should be understood as the reference Use Case that constitutes the baseline case. Use Cases 2 and 3 provide the gradual transition towards the Use Cases 4-6 which form the backbone Use Cases of this project.

2 Status-quo & trends: Existing markets for flexibility

The continental european power grid is operated at a frequency of 50Hz, which means that supply needs to coincide with demand at any point in time. As a consequence of the fact that electric energy can only be stored to a very limited extent, electricity markets need to be well organised in order to maintain this frequency at a constant equilibrium.

In electricity markets, participants are required to bid/ask for electricity in for a certain future time period subject to a certain lead time. Basically, the market offers two different lead times

- Day-ahead market: lead time of 36 to 12h before delivery
- Intraday market: lead time of 24h to 5mins before delivery

In the following, the functioning of markets in different lead times is described.

2.1 Spot markets

2.1.1 Day-Ahead spot market

The Day-Ahead (DA) market enables trading of electricity with a lead time of around one day before physical delivery. The market participants can submit their bids and offers based on most recent generation and demand forecasts for their respective generation fleet or demand units.

The Day-Ahead energy exchange is conducted on the two main power exchanges: EPEX Spot, located in Paris and Energy Exchange Austria (EXAA), located in Vienna. The minimum tradable energy volume is 0.1 MWh and the minimum price increment is 0.01 €/MWh.

The products on **EPEX Spot** are traded via a blind auction, which takes place every day all year round. Results are published as soon as possible from 12:50 for all Day-Ahead coupled markets. The order book opens 45 days before the auction start and closes one day before energy delivery at 12:00. The contracts are traded in form of single hour, quarter hour and block products. The price limit is between -500 and +3000 €/MWh [1].

EXAA offers two auctions: a national auction conducted at 10:15 CET and multi-regional coupling auction at 12:00 CET. The auction at 10:15 is conducted on workdays, except specified public holidays. The noon auction is conducted on all weekdays of a calendar year. Single hours, quarter hours, block products[2] and spread products[3] are tradable on EXAA. Exchange trading[4] hours for the 10:15 auction are divided into the following phases: pre-trading phase, auction phase and post-trading phase. In the pre-trading phase it is possible to change or delete orders from 08:00 CET until ~10:10 CET on the auction day, as well as from 12 noon CET until 16:00 CET on the seven exchange trading days preceding the delivery day. In the auction phase matching of orders is executed from 10:00 until 10:30 CET. The post-trading (until 10:40) phase allows access to the surplus volumes. Pre-trading phase for the noon auction begins at 8:00 and lasts until 16:00 CET on 30 weekdays preceding the delivery day. Auction phase is from 12:00 noon to latest 12:42 CET. Since 2019, EXAA offers physical location spreads that enable virtual coupling of Austrian and German markets. The traders can bid additionally block, full hour and quarter hour products. The minimal tradable volume is 0.01 MW [2].

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[2] Block products: “fill-or-kill” – execution of the entire block or cancellation

[3] Spread products: In this case, the spread is understood as the price in the Bidding Zone Austria minus the price in the Bidding Zone Germany. The execution of the spread order results in a sell volume in the selected bidding zone that corresponds to the same buy volume in the respective other bidding zone.

[4] Exchange trading hours constitute the period, during which orders may be entered and exchange trades may be executed on an exchange trading day.

Most of the trading volume on the Day-Ahead market is exchanged via EPEX Spot. [3] Although the price structure on EXAA and EPEX is similar, the prices for the same product are slightly different. The possible reason for that is the different auctions schedule and lack of trading on the weekends on the EXAA platform. In addition, the EXAA auction at 10:15 is constrained with respect to its regional scope and therefore exhibits a different order book which obviously results in different clearing prices. It is worth mentioning that the 12:00 Day-Ahead auction connects all market places. It is irrelevant through which Nominated Electricity Market Operator (NEMO) the bid is submitted (i.e EXAA, EPEX or Nordpool), it will be included into the same market coupling process.

Table 2: Day-Ahead auctions schedule and available products [1] [4]

Power Exchanges		Products	Gate opening time (GOT)	Gate closure time (GCT)
EXAA	Auction at 10:15	Single hours Quarter hours Spread products Blocks	D-7/pre-trading phase 8:00	D-1/10:12
	Auction at 12:00		D-30/pre-trading phase 8:00	D-1/12:00
EPEX Spot (Auction at 12:00)		Single hours Blocks Combined hours	D-45	D-1/12:00

Besides that, electricity can also be traded via non-standardized Over-The-Counter (OTC) platforms. The OTC trading is based on bilateral agreements between the trading partners and is often carried out with the involvement of intermediaries such as brokers. The general problem regarding OTC trading is the lack of transparency. The information about price and volume development can be obtained exclusively by conducting a survey among the market participants.

In general, it is worth mentioning that the Day-Ahead market is characterised by strong cross-border interconnection and market coupling between day ahead auctions. For example, the Austrian Transmission grid is well connected through physical links with the Czech Republic, Germany, Hungary, Italy, Slovenia and Switzerland and EXAA, EPEX Spot and Nord Pool are integrated in the Single Day Ahead Coupling. Currently, there is no interconnection with Slovakia. Traditionally, flows to/from Germany play a significant role for price setting in the Austrian market. In general, Austria is a net-importer as well as a transit country for electricity. Typically, power flows from Northern countries such as Germany and the Czech Republic towards Hungary, Slovenia or Italy.

Currently, two main market coupling initiatives can be identified: the Multi-Regional Coupling (MRC) and the 4M Market Coupling. The interim coupling project aims to operationally merge these two projects, by introducing Net Transmission Capacity (NTC) on the connecting borders in a first step. The interim coupling project was successfully launched in June 2021. It is an important step to extend SDAC, foreseen by Regulation 2015/1222 (Guideline on Capacity Allocation and Congestion Management (CACM)). In a further step, these borders are planned to be integrated into the Core Capacity Calculation Region (Core CCR). In January 2022, some tests were finished successfully. The project partners confirmed that the go-live date of flow based market coupling will be 20th April 2022 [5] [6] [7].

2.1.2 Intraday spot market

The Intraday (ID) market is conducted after the Day-Ahead market. It allows the market participants to react to schedule deviations or to manage unforeseen events, for example, power plant outages. The volume of products sold on the intraday market have increased in the past years, due to the growing share of renewables, variable production and variable loads. Active consumers can bid directly on this market (directly or via aggregators). This allows for the possibility to gain more short-term flexibility and additional revenue. The European power exchange EPEX Spot acts as the NEMO for the

Austrian control area and enables its market participants to trade intraday products across bidding zones via the European Cross-Border Intraday (XBID) Solution. The price determination is carried out via continuous trading or auctions. The products available for the Austrian market are quarter hours, single hours and user-defined blocks. Generally, prices for the same products differ on the intraday and Day-Ahead markets, for example the price difference for single hour products on the Day-Ahead and intraday markets. While single hour products on the intraday market are procured via continuous trading and the price is determined based on the "Pay-as-bid" principle, the single hour product on the Day-Ahead market is procured on the auction, based on the market clearing price.

The continuous market offers 15/30/60 minute products with a lead time of up to 5 minutes before delivery for intra-zonal delivery and up to 60 minutes for cross-border delivery. The trading opening is one day prior to physical delivery at 15:00 CET. The market participants enter their orders into the system. The buy and sell orders are constantly compared. Once the two orders match, the trade is executed. Minimum and maximum price differences must be chosen between -3000 €/MWh and 3000 €/MWh. The minimum tradable volume is 0.01 MW. And the minimum price change 0.1 €/MWh [1].

In October 2020, EPEX Spot introduced new local auctions for quarter hour products in Austria, Belgium and the Netherlands. The quarter hour products are traded via a blind auction that takes place once a day all year round. The order book opens 45 days in advance and closes at 15:00 CET. The minimum volume and price increment are 0.1 MW and 0.1 €/MW. The price floor and cap are between -3000 €/MWh and 3000 €/MWh [2].

Table 3: The auctions schedule and products available on the intraday market for APG

Type	Products	Gate Opening Time (GOT)	Gate Closure Time (GCT)
Continuous	15/30/60 minutes	D-1 15:00 CET	t-5' intra-zonal t-60' cross-zonal
Auction	15 minutes	Daily D-1 15:00 CET	

2.1.3 Historical Day-Ahead market price development

Figure 2 illustrates the monthly development of the Day-Ahead market in Austria for the timeframe of 2015-2021.

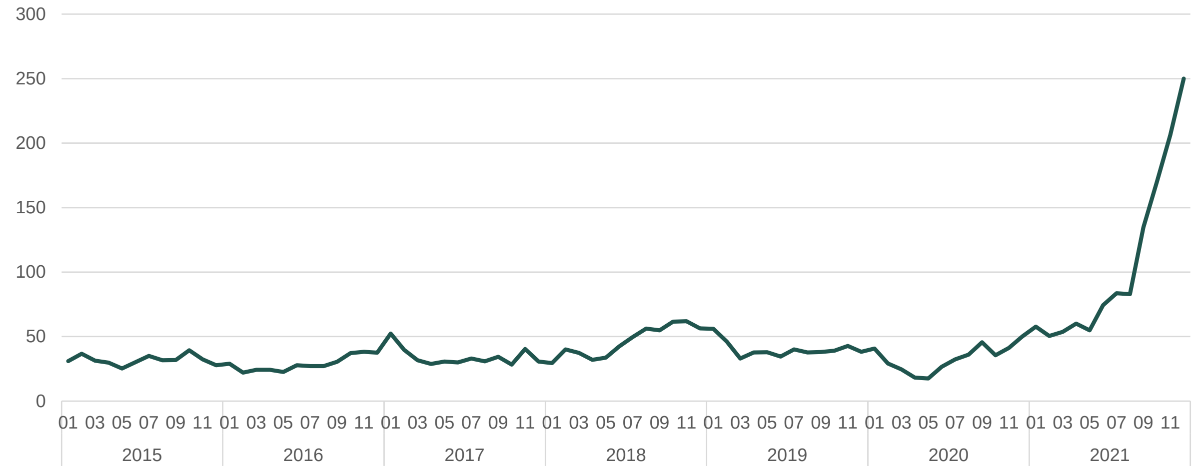


Figure 2: Monthly Day-Ahead market prices in Austria [Entso-e Transparency Platform]

It can be seen that prices mostly range between 20 and 50 €/MWh for most of the time. Notable price spikes can be identified in 2017 and 2018, for example. In early 2017, where dry weather conditions, combined with low nuclear availability in France and extreme cold weather across Europe caused the prices to spike. In 2018, a similar picture as in 2017 was observable with even a higher median hourly wholesale price and comparable price spikes as the year before. In 2019, the median hourly wholesale price has toned down a bit compared to 2018, while the price variability remained intact. Prices continued sinking further in 2020 with the economic down following the Covid-19 pandemic.

The price development on the Austrian wholesale electricity market in 2020 is characterized by low demand due to reduction in social and economic activity caused by anti-pandemic measures. At the beginning of the year 2020, a relatively low price level of around 40 €/MWh could be observed as a result of a relatively mild winter and low fuel prices. In February and March, prices started to drop below 30 €/MWh. Together with the high share of intermittent renewable electricity generation and changing demand profiles as a result of the COVID19 lockdown measures, this led to strong price volatility and an overall low electricity price level around 20-30 €/MWh, constituting a significant reduction compared to the year 2019. In April and May, prices were down by around 50% compared to the year 2019. As a result, significant price drops on the Day-Ahead market and several hours of negative price occurred (see Figure 4). On average, European Day-Ahead electricity prices decreased by 26% in 2020 compared to the year 2019 (see Figure 3).

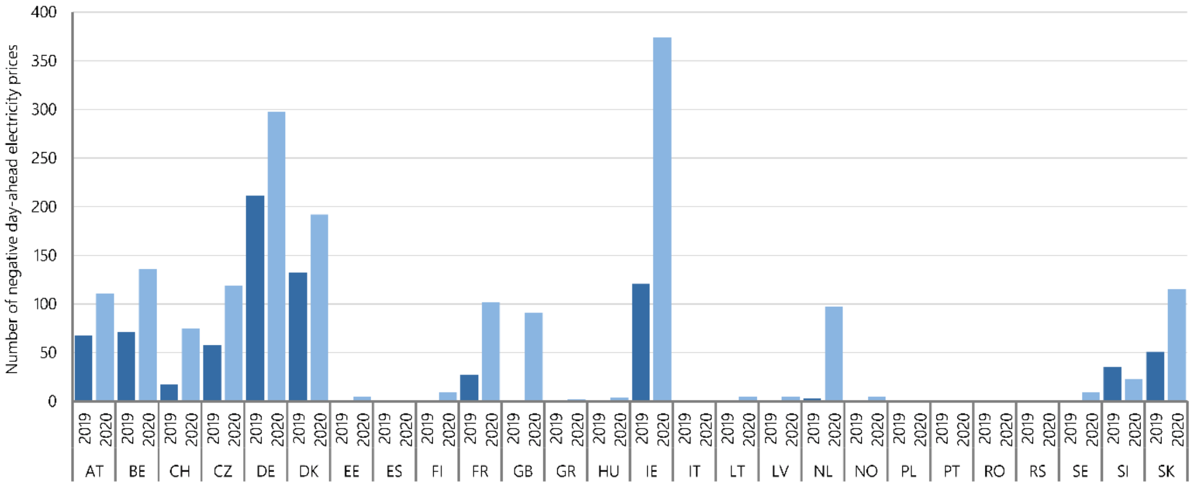


Figure 3 Number of hours with negative prices in European countries [9]

In general, when it comes to the impact of renewables on the wholesale market price, a rapid increase in renewable generation capacity has decreased market prices over the last few years. In times of high wind and/or solar electricity production in combination with low consumption, low and even negative prices can be observed. Negative prices are mainly the result of a lack of flexibility in the whole electricity system. As the system cannot integrate all the renewable capacity that is produced, the extra supply lowers the prices. Figure 4 illustrates the number of negative prices by comparing the years 2019 and and 2020 across different markets. Negative prices set incentives for market actors and consumers, in particular, to invest in more flexible production capacities [10].

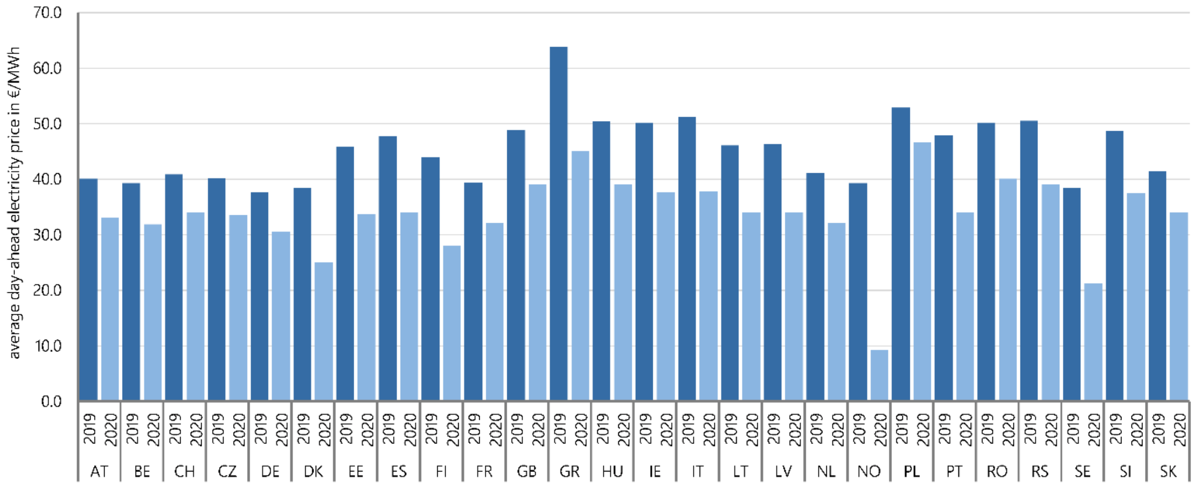


Figure 4: Average Day-Ahead electricity prices in Europe in 2020 [9]

It can be seen that Austrian wholesale electricity prices have already been declining before the Covid-19 crisis due to the weather-related low demand and declining fuel prices. The reduction of economic activity due to the lockdowns in the second quarter in 2020 not only led to the low electricity demand but also changed the structure of the load profile. As a result, price volatility increased significantly. However, after easing the lockdown measures, the market situation stabilized during summer. In September, the prices reached again a level of 50 €/MWh, mainly caused by rising costs for fuel and carbon emissions. Further lockdowns in November caused a further demand-shock, however, the impact was smaller compared to the first lockdown [8].

Since Q3 2020, wholesale electricity prices are hitting record values. This can be linked to higher natural gas, coal and emission allowance prices combined with recovering demand. The wholesale electricity price index increased by 54% in Q1 2021 in comparison to the same period in 2020. In Q2 2020, wholesale prices for commodities and electricity reached their lowest level in France, Germany, Spain and the United Kingdom. However, during Q1 2021, prices recovered quickly and the demand rebound caused gas and EU-ETS prices to increase by 171% and 95%, respectively, compared to the same period in 2020. Due to the warmer winter in 2020 in Nordics, electricity demand for heating was low which slowed the recovery of wholesale electricity prices.

Energy commodity prices hit record high levels across Europe. Gas prices in October 2021 are 400% higher than in January 2021 and electricity prices increased by 200%. Power prices are typically linked to the gas price through price setting of gas-fired power plants. Since electricity is hard to store, gas price fluctuations will be directly translated as electricity price volatility. There are many factors that led to these price levels. However, the main factor is the increase in the price of natural gas, which is related to many factors. First of all, the price spike can be related to a demand increase in Asia, particularly in China. Second, adverse weather events have led to supply constraints. Liquefied Natural Gas (LNG) has become a commonly traded commodity across the globe which has led to energy prices being strongly linked. As LNG acts as a substitute for many commodities, higher coal prices in Australia or Asia lead to a rising LNG demand as a substitute for coal. Therefore, increasing coal prices in one region can lead to increasing prices for another commodity elsewhere. [11]

The main driver of the high electricity prices in Europe is the global gas price surge as well as increasing prices for EU-ETS certificates. Rapid economic recovery after lockdown end and unusually cold winter combined with tight supply increased the demand. North-East Asian and South American LNG demand has grown significantly. This put pressure on global prices and left less gas available for import into Europe.

Global gas prices are the main driver of energy price increases, however, some secondary factors also contributed in Europe:

- The increase in coal and carbon prices (which can be also linked to extreme gas prices. When the gas prices are high, the production switches to coal and becomes more emission intensive. Hence, the demand for EU-ETS certificates also increases);
- high demand (driven by the economic recovery) and unusually cold winter and hot summer;
- low renewable generation (e.g. lower wind generation and hydro impacted by drought);
- lower domestic gas production (-10% YoY)
- gas supply constraints due to maintenance (maintenance works in Norway) and less investment in new production.

Although it was expected that the higher price would attract more pipeline supplies, the aggregated gas pipeline imports remained steady.

The price developments explained so far relate to the results of the Day-Ahead market coupling auction, which is held daily at 12:00 CET and enables cross-border trade. In addition to this, the EXAA offers a national Day-Ahead auction at 10:15. Due to the time difference, there is a so-called "time spread" in the trades, meaning that the same product from two auctions can have different prices. The average time spread in 2020 amounted to 6 cents/MWh, meaning that the electricity prices at the 10:15 auction were on average lower than the comparable prices of the market coupling auction at 12:00. Despite the average price difference during the year being very moderate, earlier auctions were characterised by less liquidity and higher forecast uncertainty.

To give an overview regarding Day-Ahead market liquidity, the churn factor across European countries is illustrated in Figure 5 for the period from 2015 to 2019. The churn factor represents the relationship between a commodity trading volume and the volume consumed in a given period. By this metric, the higher the churn factor, the higher is the market liquidity. It can be observed that European Day-Ahead markets are characterised by different levels of liquidity, depending on the market structure and design. For example, in the Single Energy Market of Ireland[5] and in Greece, the churn factor broadly equals one. This means that the commodity from the producer goes directly to the consumer (direct contract between the producer and consumer). Markets, where energy is mostly sourced through bilateral contracts or specific national arrangements are characterized by a low churn factor, for example, France, whose energy sector is dominated by state-owned Électricité de France. Moreover, it shows that the year-on-year changes in DA market liquidity are in general modest.

One can conclude that mature DA markets are liquid for the largest part of Europe. Relatively young markets such as Croatia and Bulgaria exhibit generally low liquidity but strong growth rates with year-on-year increases of 154% and 36%, respectively in 2019) [12].

[5] Wholesale market for the island of Ireland, replaced by I-SEM in 2018

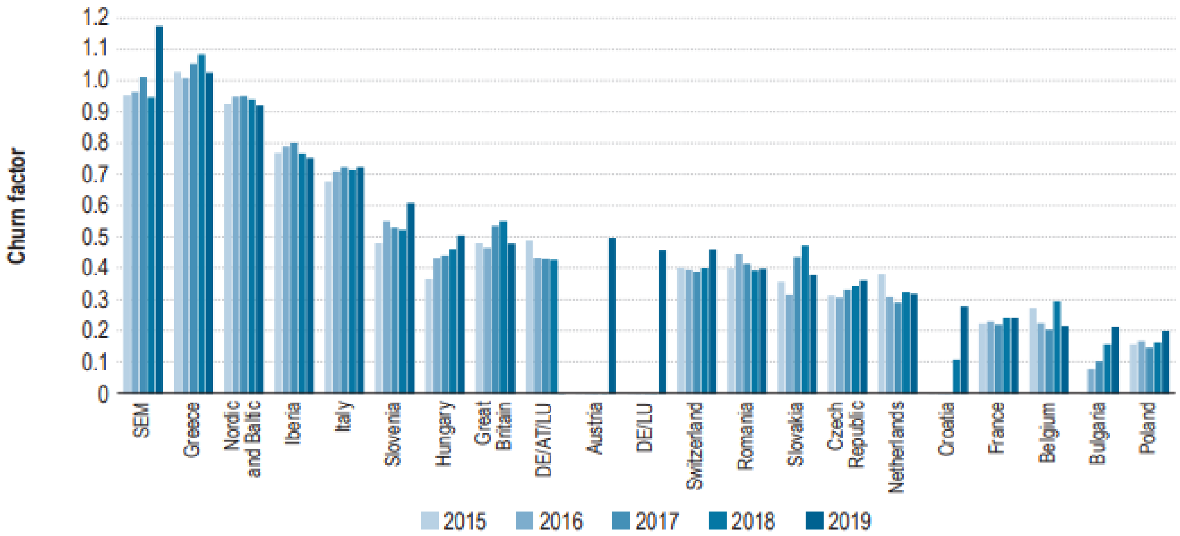


Figure 5: Day-Ahead market liquidity in European Countries [2015-2019] [12]

2.1.4 Historical Intraday market price development

Compared to the Day-Ahead market, the traded volume on the Intraday market is rather low. Figure 6 compares the traded volumes of the 12:00 DA auction, the 10:15 DA auction and the Intraday market. It is obvious that the 12:00 DA auction conducted on EPEX Spot dominates the market place.

In general, the Intraday market has gained in volume during 2020. While local 10:15 DA auction has suffered from a 9.5% reduction in volume during 2020 compared to 2019, the Intraday market volume has increased by 26.9% to 3.7 TWh. The year 2020 had already started with a trading record of 409 GWh for the intraday market, reflecting a relatively low availability of wind and solar PV generation, resulting in strong necessities for short-term trading. In light of higher future needs for flexibility and volatile generation patterns, a further shift in favour of intraday trading is likely [8].

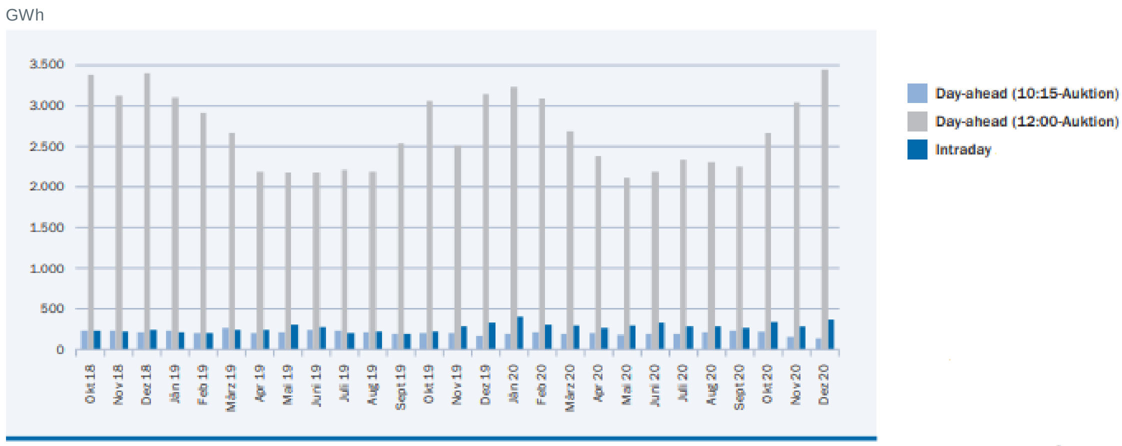


Figure 6: Austrian Day-Ahead and Intraday (continuous) traded volumes [09.10.2018-12.12.2020] [8]

In general, Intraday market liquidity is showing an upward trend in the past years. Figure 7 shows annual intraday market churn factors in major European markets between 2017 and 2019. It is evident that the Iberian, German/Luxembourgish, Italian and British markets exhibit the highest intraday market liquidity, followed by Austria. The increase is largely related to the go-live of SIDC's (Single Intraday Coupling's) first wave on 12/13 June 2018 across 15 countries. As it can be seen from Figure 8, the share of cross-border traded volumes is growing every year. With the expansion of SIDC this trend will continue. More information about SIDC and related projects are further discussed in [12].

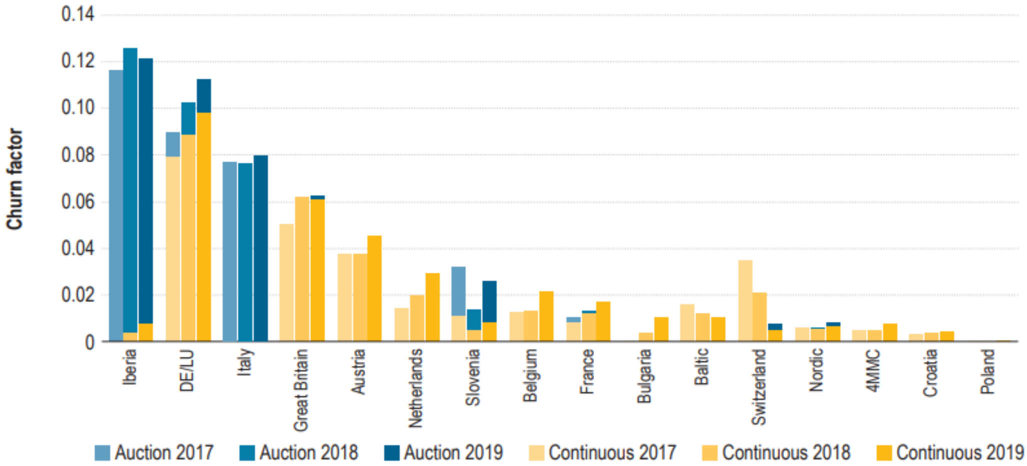


Figure 7: Annual intraday churn factors in major European markets [12]

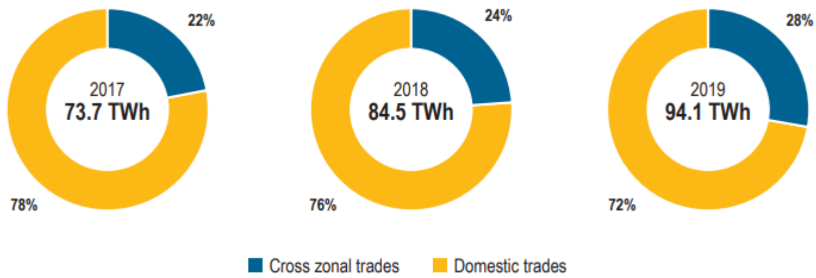


Figure 8: Share of ID-traded volumes intra-zonal vs. cross-zonal in European countries [12]

Figure 9 illustrates average intraday market prices (EPEX Spot) in Germany in 2020. The German intraday market was highly volatile, which could be linked to a lack of flexibility, less and less conventional capacity, the nuclear exit and coal exit strategies. Lack of flexibility also led to the occurrence of one intraday trade at a price of 4,000 €/MWh in September 2020.

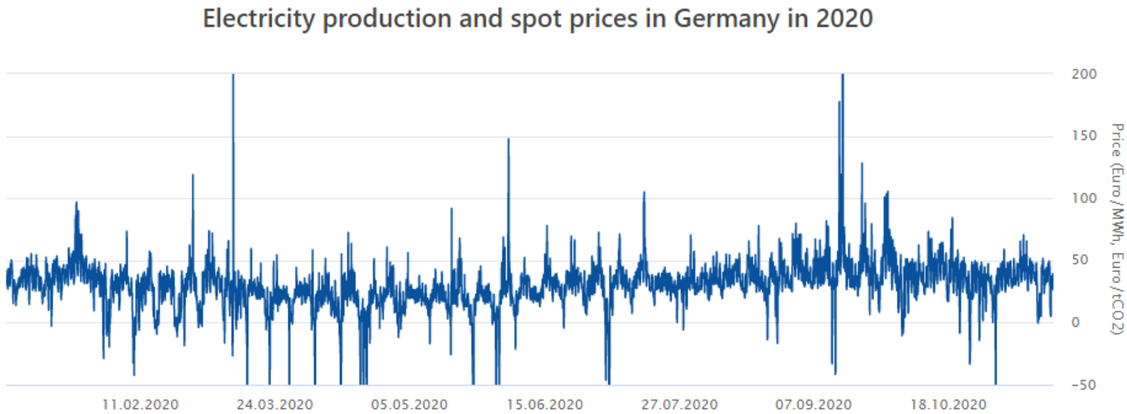


Figure 9: Intraday continuous average index price hourly product EPEX spot [13]

Single Intraday Coupling (SIDC) uses a common IT system for continuous cross-border capacity allocation across Europe, 27 countries with 33 TSOs and 15 NEMOs are participating in the project. So far, 29 bidding zones were integrated [14]. The integration of new borders/bidding zones into SIDC is executed though the Local Implementation Projects (LIPs), organized by Nominated Electricity Market

Operators (NEMO) and TSOs. Figure 10 shows borders already integrated into the SIDC and planned go-lives. Currently, two go-lives were conducted resulting in the integration of 22 countries. The 3rd go-live happened in Q3 2021.

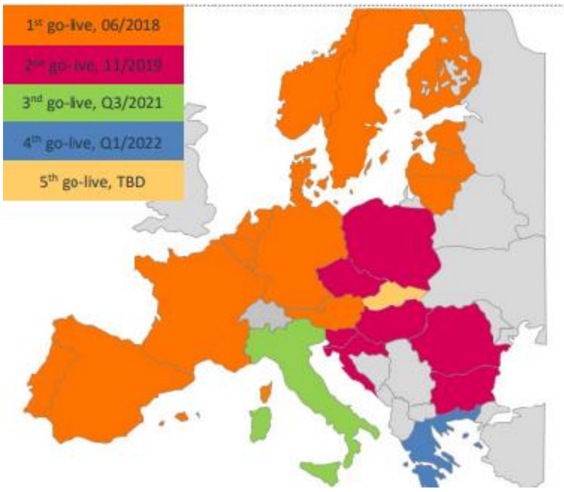


Figure 10: Countries integrated in SIDC Source: APG Webinar

2.1.5 Future electricity price scenarios

The EU Reference Scenario is one of the European Commission's key analysis tools in the areas of energy, transport and climate action. It allows policy-makers to analyse the long-term economic, energy, climate and transport outlook based on the policy framework in place in 2020. According to the authors, the reference scenario is not a prediction, but a simulated model-based future overview, based on certain framework conditions, assumptions, current political situation and historical trends. [15]

Assumptions for the EU Reference scenario

There are many possible scenarios for future price developments. In the EU Reference Scenario, the authors assume that future technologies will improve their efficiency and optimize their costs, however possible innovative breakthroughs are not considered. In addition, it considers the EU policy, stating that there will be more RES implemented before 2030. However, it is assumed that no further measures will be undertaken between 2030 and 2050.

The target set of the National Energy and Climate Plans (NECP)[6] to achieve 32.5% energy efficiency is not accomplished in the Reference Scenario, due to the lack of collective ambition and insufficient efforts proposed by member states. It is assumed that a shift to flow-based capacity allocation happened and market couplings perfectly operate across all participating countries. The EU target model was successfully implemented from 2025, which means higher Net Transport Capacity (NTC) levels and better coordination between the TSOs reduces balancing costs. Assuming that the balancing of RES was conducted in a cost efficient and cooperative way, this would help to avoid high investments in peaking power plants, like gas turbines. It is also assumed that the grid infrastructure was improved

[6] 10- year national energy and climate plan introduced under the Regulation on the governance of the energy union and climate action (EU/2018/1999)

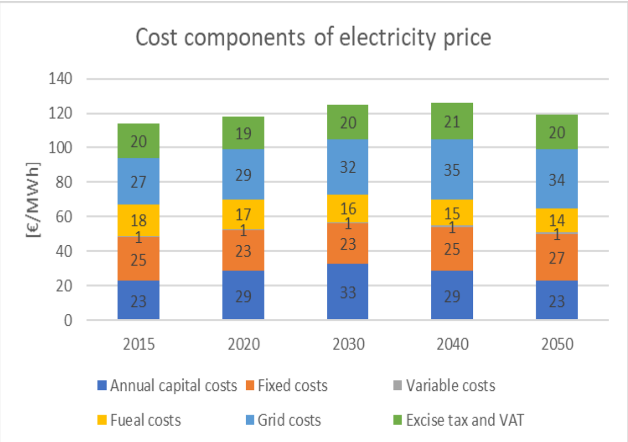
according to the Ten Years Network Development Plan (TYNDP) of ENTSO-E and the integration of renewables is enhanced.

PRIMES: Simulating energy system costs from an end-user perspective

To simulate future electricity prices, the PRIMES energy system model was deployed. PRIMES Energy system model is a large-scale applied energy system model that provides detailed projections of energy demand, supply, prices, and investment. It covers the entire energy system and also emissions from combustion and industrial processes. The PRIMES model and the official infrastructure development plans from ENTSOE, ENTSOG and the TEN-T networks for transport are considered in PRIMES and its sub-models as well. PRIMES combines behavioural modelling, following a micro-economic foundation, with engineering aspects. It covers all energy sectors and markets. The model includes political instruments, standards and targets of each sector and also for the entire energy system. PRIMES comprises multiple policy objectives, such as GHG emissions reduction, energy efficiency and RES targets. It fully simulates the existing EU Emission Trading System (ETS) and European internal markets for electricity and gaseous fuels.

Development of electricity prices

The results of PRIMES model simulation can be seen in Figure 11. According to the simulation results, average electricity prices across European countries are expected to grow modestly. This can be linked to the grid expansions, infrastructure developments and application of carbon taxes. A small increase in capital costs by 2030 can be observed. Due to the deployment of more efficient appliances and equipment, which have higher capital costs and lower fuel expenditures the capital costs increase. After 2030, capital costs of RES decrease. The reasons for that are learning effects and decreasing technology costs. Between 2015 and 2030, the fuel prices increase sharply while after 2030 it can be seen that the prices remain more stable, due to the gradual reduction of the number of combustion power plants in operation. Modest price growth for services and households in the medium term is expected. Industrial prices remain stable or decrease over time (industry maintains base-load profile and is charged for a fraction of grid costs). Tax application mainly has an impact on prices for households and services (see Figure 12).



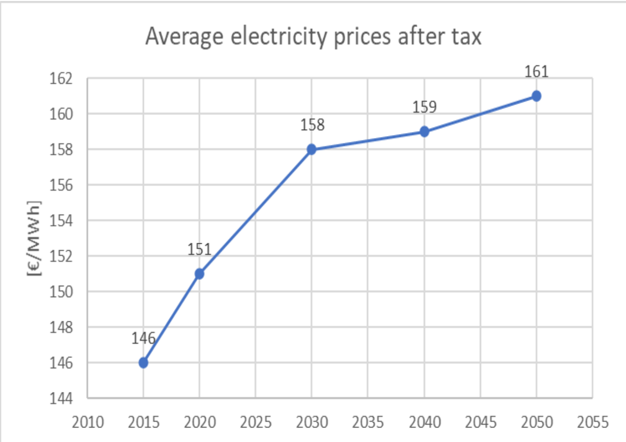


Figure 11: Cost components of electricity price and average electricity prices in EU until 2050 [16]

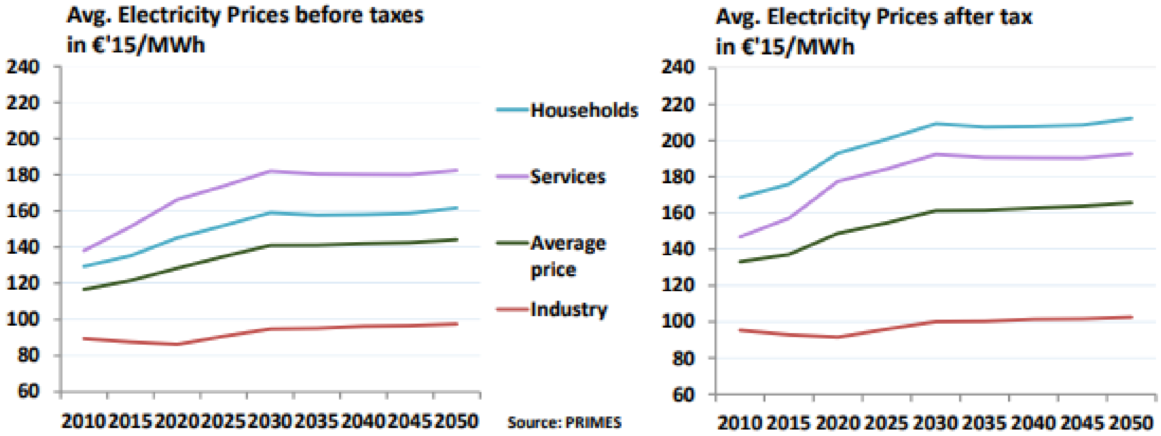


Figure 12: Average EU electricity prices before and after taxes [2015-2050] [16]

2.2 Balancing markets

Balancing reserves are used by the TSOs to ensure the secure and stable operation of the power system through the permanent balancing of generation and demand within the control area. If the control area's net position (sum of generation and load including import and export) deviates from its scheduled net position, the so-called Balancing Service Providers (BSP) either adapt their generation or their consumption. In case of an energy deficit, positive balancing energy is activated (increased power plant generation or reduced withdrawal through controllable consumers). The TSO is responsible for the procurement of balancing power and, if needed, for the activation of balancing energy.

2.2.1 Balancing types

It can be distinguished between the following products for balancing reserves, which are procured in daily auctions: Frequency containment reserve (FCR), Automated Frequency Restoration Reserve (aFRR) and Manual Frequency Restoration Reserve (mFRR).

Frequency Containment Reserve (FCR) is used for immediate grid stabilisiation as a result of imbalances. In continental Europe, a primary control reserve of +/-3,000 MW is constantly available. Each control area contributes a share, depending on a distribution key which is based on yearly generation/consumption. The FCR for Austria in 2022 is +/-73 MW. The FCR must be activated within 30 seconds and available at a full capacity for at least 30 minutes. For the procurement of FCR capacity, Austria is part of an international cooperation together with Belgium, Switzerland, Germany, Netherlands and France. Bids and offers received by the TSOs are ordered by means of a common merit order list in order to cover the FCR demand in the most cost-efficient way.

Automated Frequency Restoration Reserve (aFRR) is used to relieve FCR and restore frequency and power exchange to neighboring TSOs to the set values. The activation of aFRR is undertaken automatically based on the aFRR merit order (energy prices). The providers have to follow the activation signal with a full activation time (FAT) of 5 minutes.

Manual Frequency Restoration Reserve (mFRR) is activated if the imbalance within the control zone persists and aFRR keeps being activated or if the imbalance cannot be covered by aFRR alone. The activation is carried out using an electronic signal via a tool called AutoMOT (Automated Merit Order Tool). AutoMOT ensures that mFRR is activated according to the merit order of energy prices. It must be available at a full capacity within 12,5 minutes (AT).

2.2.2 EU cooperations

The Commission Regulation (EU) 2017/2195 of 23 November 2017 establishing a Guideline on Electricity Balancing (EB GL) aims to integrate European balancing markets in order to enhance the efficiency of the European balancing system and security supply. Based on the EB regulation, TSOs are required to implement four platforms (PICASSO, MARI, TERRE, IGCC).

The **Platform for the International Coordination of Automated Frequency Restoration and Stable System Operation (PICASSO)** is the implementation project approved by all TSOs through the ENTSO-E Market Committee. The main objective of PICASSO is to establish a common European platform for optimizing the activation of aFRR (see Article 21 of the EB GL). Germany and Austria decided to implement this concept before the go-live of PICASSO (DE-AT-cooperation). The existing PICASSO members and observers are marked in Figure 13. The planned go-live for DE/AT is Q4 2021 [14].

The platform for common procurement of mFRR will be implemented within the **Manually Activated Reserves Initiative (MARI)**. The primary objective of MARI is the optimisation of the mFRR activation and has to be implemented by all EU-TSOs. On 24th July 2019, the implementation framework for the mFRR platform proposal was referred to ACER. On 24 January 2020, the proposal was adopted, and ACER established the deadline for its implementation 30 months following the decision (i.e. July 2022). Certain operational regions have decided to implement mFRR platform before its go-live (for example Germany and Austria). The AT/DE MARI go-live is planned for Q1 2022. Germany and Austria decided to implement a similar concept before the go-live of MARI (Project GAMMA), from which many conclusions for the design of MARI were drawn.

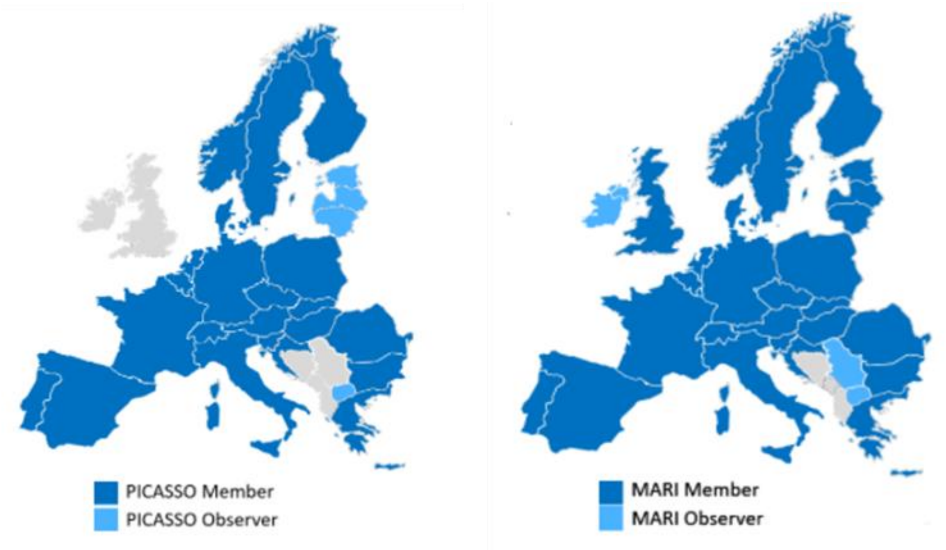


Figure 13: PICASSO and MARI members

Trans European Replacement Reserves Exchange (TERRE) is another European implementation project. It was designed to enable exchange of the replacement reserves (RR) in line with the EB Regulation. The exchange of reserve activation from generators, storage, and demand response between TSOs can be conducted via a common RR platform. If FCR and FRR were activated and the imbalance persisted or additional system imbalances occurred after their activation, the TSOs can use RR in order to restore the required level of FCR and FRR. Unlike FCR and FRR, not all TSOs in the EU use RR products. Eight members are in the process of implementing this platform. These are: Czech Republic, Spain, Switzerland, France, Italy, Portugal and Great Britain. In January 2020, the first TSO (ČEPS a.s.) and in March 2020 Red Eléctrica de España S.A.U joined the RR platform. The remaining TSOs will join within Q3 and Q4 2020, except Polskie Sieci Elektroenergetyczne S.A., which will join in January 2022. Six members remain in the role of observers[7]: Bulgaria, Hungary, Romania, Germany, Norway and Sweden [14].

[7] TERRE observers follow the internal development of the RR platform but do not have any input into its operation.

APG is an operational member of the **International Grid Control Cooperation** (IGCC)[8] and the future imbalance netting platform for RG CE[9] (see Article 22 of the EB regulation). Imbalance netting is used to avoid simultaneous activation of aFRR in opposite directions. The process involves the TSOs and two or more load frequency control areas (LFC). IGCC is a platform, that carries out imbalance netting of aFRR.

A common market for the procurement and exchange of FCR is operated together with the German, Belgian, Dutch, French and Swiss TSOs. It is organized as a TSO–TSO model[10]. In 2016, APG and German TSOs established a joint aFRR activation, which is the early adoption of the requirements of the EB Regulation concerning the exchange of balancing energy. Since December 2019, this cooperation includes mFRR. Thus, APG and the German TSOs already activate all FRR energy based on a common merit order, provided sufficient cross-border capacity is available. In February 2020, APG and the German TSOs extended their cooperation and established a common procurement of aFRR balancing capacity [17].

2.2.3 Procurement of balancing products

Since 2012, balancing reserve products are mostly[11] procured by TSOs in a market-based manner, via regular auctions. The technical entities (*Ger. Technische Einheit, TE*), respectively the pools of technical entities of potential providers of balancing capacity must fulfill prequalification (*Ger. Präqulifizierung, PQ*) requirements separately for each control reserve type, in order to meet the technical criteria to provide a balancing reserve. The conditions for the provision of balancing capacity and balancing energy are specified in TSO-BSP framework agreements, in the relevant market rules and in the Austrian requirements for prequalification. Fossil power plants and pump storage have been used as classic balancing service providers (BSP) in the past. In recent years, various technologies, for instance, battery storage systems, industrial plants with controllable loads/generators (as for example electric furnaces in Iron and Steel production) and power-to-heat units have also become more significant in their role as TEs. Aggregators with small TE can act as BSPs as long as the minimum bid size can be reached with the required availability of 1 MW bid size. [18].

In November 2020, the separate balancing energy auction for automated frequency restoration reserve (aFRR) and manual frequency restoration reserve (mFRR) products was introduced (*Ger. Regelarbeitsmarkt RAM*). While balancing capacity and balancing energy were previously traded in a single auction, balancing energy can now be traded in a separate auction up to one hour before product delivery without prior participation in the capacity auction. The trading procedure for FCR remains unchanged. The implementation of the balancing energy market was required by the EU

[8] IGCC includes 24 members TSOs – AT (APG), BE (Elia), BG (ESO), CH (Swissgrid), CZ (CEPS), DE (50Hz, Amprion, TenneT DE, TransnetBW), DK (Energinet), EL (ADMIE), ES (REE), FR (RTE), HR (HOPS), HU (MAVIR) IT (Terna), LU (CREOS), NL (TenneT NL), PL (PSE), PT (REN), RO (Transelectrica), RS (EMS), SI (ELES), and SK (SEPS). In addition, three TSOs are observers to IGCC: BA (NOS BiH), ME (CGES) and MK (MEPSO). Source: https://www.entsoe.eu/network_codes/eb/imbalance-netting/

[9] RG CE: Regional Group Continental Europe

[10] According to Article 2(21) of the Commission Regulation (EU) 2017/2195 of 23 November 2017 establishing a guideline on electricity balancing, 'TSO-TSO model' is a model for the exchange of balancing services where the Balancing Service Provider (BSP) provides balancing services to its connecting TSO, which then provides these balancing services to the requesting TSO.

[11] In Austria, the TSO APG is procuring balancing reserve products.

commission in terms of the EB Regulation, to create more efficient competition and better market chances for flexible and renewable energy generators.

On the balancing capacity auction for aFRR and mFRR, six 4-hours products are traded. The BSPs submit two bids: the capacity bid [MW] and the capacity price bid [€/MW]. After the closure of the bidding period, APG creates a merit order list (MOL), based on the capacity prices. The accepted bids are rewarded the capacity price, according to the „pay-as-bid" principle and can further participate in the balancing energy auction [19]. In the case of two or more bids with the same price, the bid will be chosen randomly.

The capacity balancing auction is followed by the balancing energy auction, which defines in which order the reserved balancing capacity is activated. Here, the participants can adjust prices submitted in the previous auction or offer other prequalified capacities independently from the capacity auction. APG creates again the merit order list, based on the submitted bids from both auctions and remunerates successful bids according to their activation and the "pay-as-bid" principle [19]. Previously, participation in the balancing capacity auction was obligatory for the Balance Service Providers (BSP). Current market design allows all prequalified participants to bid directly into the market by submitting the so-called "free bids"[12]. In the case of activation of the balancing energy, the participants with free bids are remunerated by balancing energy price. However, they will not receive remuneration for the balancing capacity [18].

On the local auction for FCR, six 4-hour product blocks are traded. The product contains positive and negative balancing capacity to the same extent (symmetrical bids). Separate offers for positive or negative FCR capacity are therefore not possible. The minimum bid is +/- 1 MW. Additional offers can be submitted in whole MW steps, but no more than up to the prequalified capacity. A maximum bid size of +/- 25 MW applies to indivisible bids. The GOT for the FCR tendering procedure is 14 days ahead at 11:00 and the GCT one day prior to physical delivery at 8:00. After closure of the bidding period, the bids are ranked according to price - the cheapest bids first - until the required total capacity is reached. If one or more bids have the same price, the earlier received time stamp counts. Once the tender volume has been reached, APG has the right to reduce the last bid to 1 MW in order to meet the required total capacity. Balancing Service Providers are remunerated according to "pay-as-cleared" principle for the bids that have been accepted. There is no energy activation price for FCR. An overview of the activation time, the bid size and the procured volume is provided in Table 4.

Additionally, to the launch of the balancing energy market, continuous further development will take place until the common European platforms are fully implemented in 2021/2022. The transition to the European common platforms will also be accompanied by significant changes for aFRR and mFRR:

- in the product granularity (15 minutes instead of 4 hours),
- the pricing principle (marginal price (pay-as-cleared) procedure instead pay-as-bid for balancing energy),
- the gate closure time (GCT) for the balancing energy trading closer to real-time (t-25min).

As the gate closure time of the balancing energy (energy bids only) was postponed from Day-Ahead to one hour prior to physical delivery (can be further reduced in future), this results in nearly real-time pricing. [18] The main objective of the introduction of the "energy-only tender" was to increase the competition in the balancing energy market.

[12] Bids without a designated capacity price

Table 4: Balancing energy market auction information [19] [20] [21]

	FCR	aFRR	mFRR
Activation	Full activation within 30 sec	Full activation within 5 min	Full activation within 12,5 min
Current products	Six 4-hour blocks	Six 4-hour blocks, positive and negative	Six 4-hour blocks, positive and negative
Products MARI/PICASSO	-	15 min products, positive and negative	15 min products, positive and negative
Min. bid size	+/-1 MW	1 MW	1 MW
Total daily provision (AT)	+/-73 MW (2022)	+/-200 MW	+280 MW/-195 MW
GOT/GCT	D-14 11:00/D-1 8:00	Capacity: D-7 10:00/D-1 09:00 Energy: H-1	Capacity: D-7 10:00/D-1 10:00 Energy: H-1
GCT MARI/PICASSO		25 min before product delivery	25 min before product delivery

Figure 14 shows the development of the energy volume used in the Austrian APG-control area for imbalance compensation (so-called delta control area): the annual activated aFRR and mFRR, the avoided aFRR through the international cooperation activations and the unintentional energy exchange with the neighbouring control zones. It can be observed that after a significant increase in balancing energy demand in the APG control area between 2010 and 2017, the balancing energy demand has started to decrease in recent years.

At the same time, the activated volumes of aFRR and mFRR have not changed, because the increasing demand for balancing energy is fully covered through the imbalance netting with other control areas. In total, 600 GWh of aFRR and mFRR (positive and negative energy) were activated in 2019 in Austria, which corresponds to less than 1% of the total annual Austrian electricity consumption. The expansion of international cooperation in the procurements of balancing capacity and balancing energy not only reduced balancing energy activation needs but also the resulting total costs (see Figure 15). The total balancing energy costs in 2019 amounted to around 50 Mio. €, which is almost a quarter of the costs spent for balancing energy in 2014 (200 Mio. €). In 2020, balancing costs decreased even further. However, in 2021, balancing costs started to increase again as a consequence of a generally higher price level on the commodity and Day-Ahead markets [18].

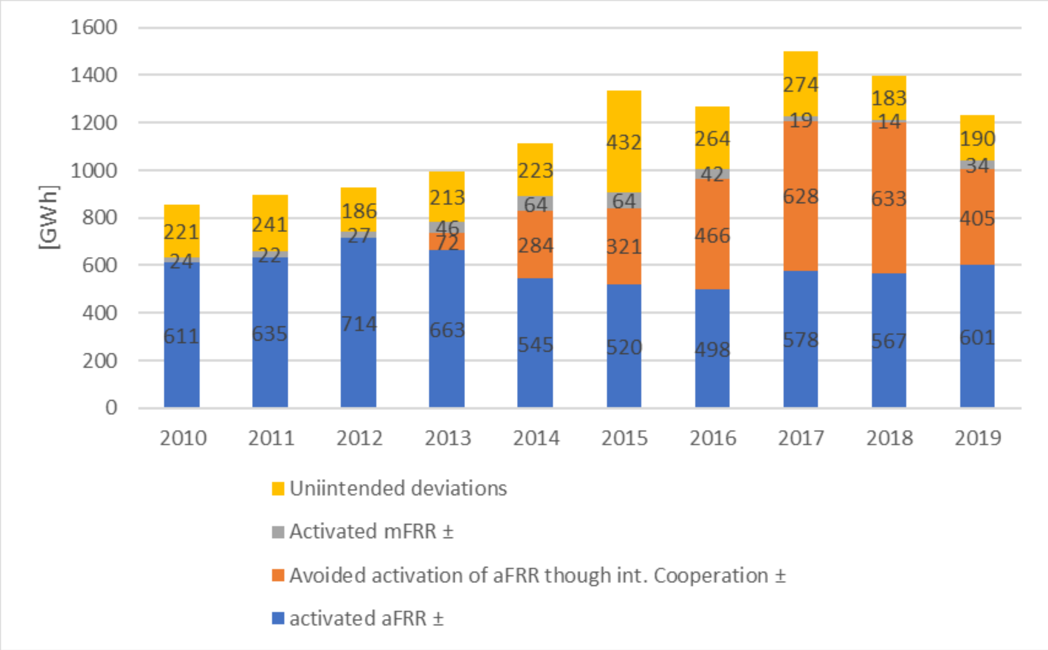


Figure 14: Annual balancing energy volumes in APG control zone [18]

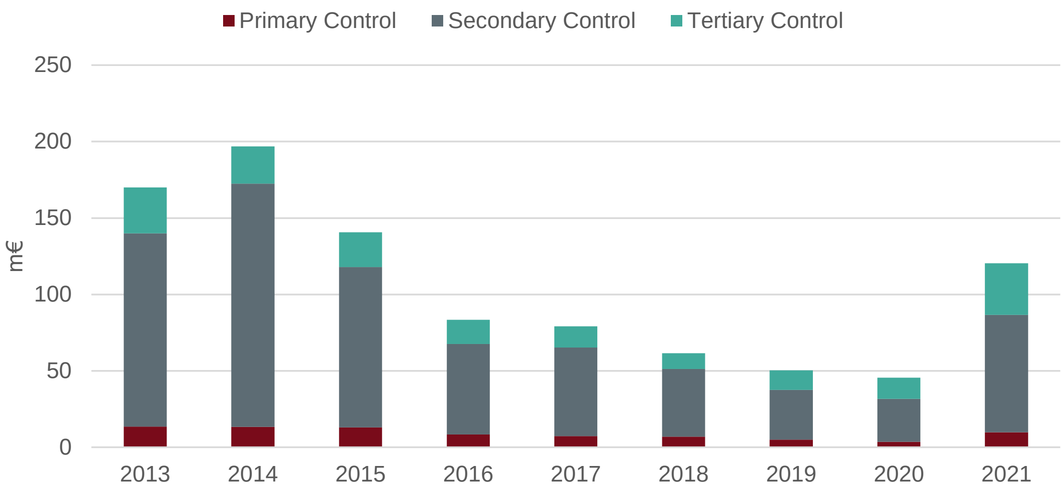


Figure 15: Annual costs on the Austrian balancing market [APG Balancing Statistics]

2.3 Imbalance settlement

2.3.1 Balancing responsible parties

In the energy industry, schedules are the chronological sequence or timetable of the planned generation or consumption of a power plant/consumer or an entire balancing responsible party. A balancing responsible party (BRP) is a virtual group, that comprises of a number of suppliers and consumers (Section 7 ElWOG). Within this group supply (procurement schedules and injection) and demand (delivery schedules and withdrawals) should be balanced. BRPs are an important concept within the power sector that facilitate the organisation of the production/consumption schedules, such that they can be followed in the best possible way and disincentivise deviations from the schedule.

BRPs are a rather virtual concept, which means that consumers/generators within one BRP do not share a common point of injection within the grid. But they are rather used to net the production/consumption and their deviations within each other in order to ensure transparent settlement and administration. In Austria, BRPs are required to report their schedules on a daily basis, typically in the morning of the day before delivery. Control areas can include any number of BRPs that trade with each other. Generally, schedule submission can be divided into internal (within control area) and external (cross-border) schedules.

2.3.2 Imbalance settlement

The imbalance settlement is a financial settlement mechanism for balancing responsible parties to be charged or paid for their deviations from their schedule (=imbalances). Imbalance settlement is designed to reflect the real-time value of energy by considering both balancing, and wholesale market prices in imbalance settlement prices.

The BRP is financially liable for its imbalances and is required to submit the resulting internal and external schedules of the BRP to the LFC Area/Block Operator at the latest by 14:30 Day-Ahead. In addition, any generation units connected at or above the 110kV voltage level or above a generation capacity of 25 MW and any generation units deemed necessary by the Control Area Manager, must also submit their individual generation and availability schedules to the CAO before 14:30 Day Ahead. [20]

BRPs are provided incentives to be in balance generally; hence the imbalance prices reflect the real-time imbalance situation. Financial neutrality is assured based on national legislation and complemented with the introduction of an additional settlement mechanism (see below). The main characteristic for the imbalance price calculation is the Imbalance Settlement Period (ISP), which defines the frequency of the determination. Based on the EB Regulation and the recast of the Electricity Market Regulation[13], the ISP was harmonized in 2021 to 15 min, where BRPs must calculate their imbalances [14], but this did not change the ISP as it has been 15 min before.

Imbalance settlement price calculation

Until the end of 2018, the imbalance costs were quarter-hourly imbalance prices were determined, using the so-called "Funnel formula" (*Ger. Trichterformel*). This model was changed in 1.1.2019 and further adapted with 1.7.2021. The current model consists of **three elements: price of activated balancing energy/avoided activation, market prices (Intraday or Day-Ahead) and the scarcity element** [18]:

- The **volume-weighted average balancing prices** and volumes of activated aFRR/mFRR balancing energy are submitted to the Austrian BRP Coordinator APCS (Austrian Power Clearance and Settlement) by the Control Area Manager. If balancing energy was not activated within a quarter hour interval, the price of avoided energy activation is charged, which is the lowest price for activated positive and the highest price for activated negative energy in the local MOL for aFRR product depending on the sign of the Delta of the Control Area [21]. If within a quarter hour interval only positive or negative energy was activated, the balancing energy price component is calculated based on the activated positive or negative energy. In case both positive and negative energy were activated, the price is determined according to the sign of the Delta of the Control Zone [21].
- The article 44 of EB Regulation states that the imbalances must be charged at a price reflecting the real-time value of energy. To fulfill this requirement, the second element of the imbalance settlement price model contains a **reference to the market prices**. This element is supposed to ensure that the imbalance settlement prices are less profitable from the perspective of the BRPs, compared to the market prices, in order to exclude the speculations against the

[13] Regulation (EU) 2019/943 of the European Parliament and of the Council of 5 June 2019

imbalance settlement prices. The market price indexes are provided by Nominated Electricity Market Operators (NEMO) in the Austrian market area. The $ID_3$15-MIN[14] and/or $ID_3$60-MIN are used to derive a reference price. In order to avoid wrong price signals from insufficiently liquid markets, the average volume-weighted Day-Ahead price P_{DA} will be included when traded volumes on the intraday market fall below the threshold. To avoid large jumps near extremely low level of the Delta of the Control Area, a linear ramp was introduced [21].

- The third element of the imbalance settlement is the so-called "scarcity element". The aim of the scarcity element is to prevent the Balancing Responsible Parties from the behaviour that might cause a system destabilization and to encourage its avoidance. The scarcity element is used to penalize extremely high imbalances [22]. The scarcity price consists of basic market price index (not "ramped") and a polynomial function of the third grade. The polynomial function is applied from a certain area of the Delta of the Control Area, the so-called "dead band" (available aFRR $\pm$200 MW for Austria). The area of scarcity element application is limited by the dead band and a capping capacity (see Figure 16) [21].

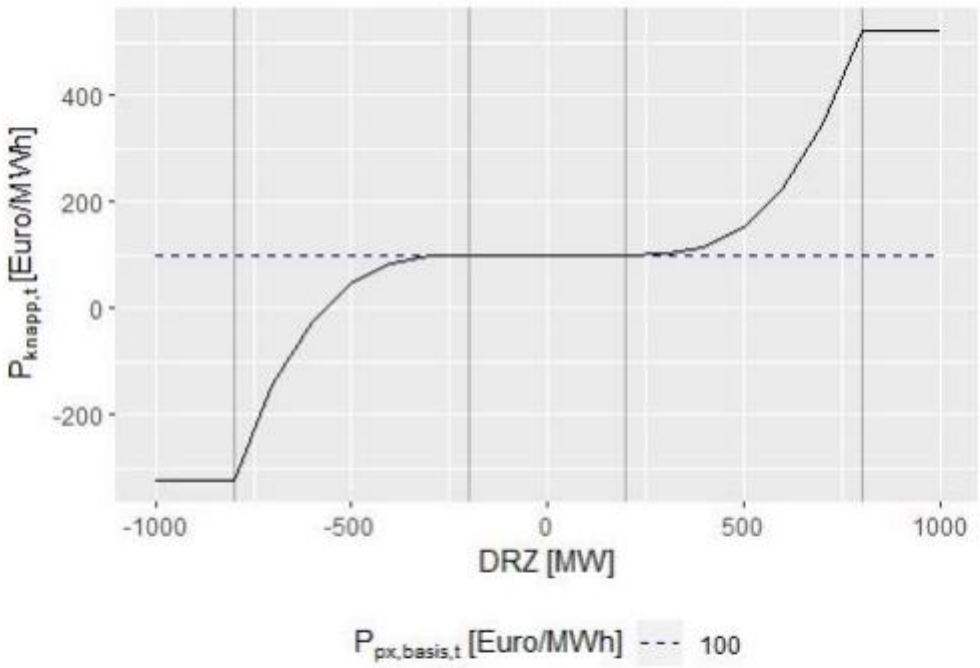


Figure 16: Scarcity Element [21]

2.4 Balancing energy vs. imbalance settlement

The focus of the imbalance settlement mechanism described in Section 2.3.2 is an administrative or economic one. The target of the imbalance settlement scheme is to allocate deviations from the schedules to the causing BRPs and implicitly individual market participants. Through the imbalance settlement mechanism, it is ensured that system-beneficial behaviour is incentivised. Put differently, the mechanism is designed to incentivise market participants to keep forecast errors and deviations from the schedule to a minimum.

[14] ID3 15-min is the volume-weighted average of the price of all trades taking place in a 3 hour time window before start of delivery.

Section 2.2 described the functioning of the balancing markets, which are instruments used by the TSOs to balance electricity generation and consumption in a physical way. For system security, it is necessary to keep deviations of frequency from 50Hz to a minimum. aFRR and mFRR is used to restore system frequency and energy exchanges to the respective set values. It is clear that balancing energy is costly. In this respect, the imbalance settlement regime is the mechanism that not only ensures that deviations are kept to a minimum but is also used to allocate the relevant costs from the balancing market to in a 'polluter-pays principle'.

Therefore, the imbalance settlement regime can be understood as the administrative/economic counterpart of the balancing market that ensures – together with FCR - the actual physical system stability. Together with the DA and ID markets, the imbalance settlement mechanism ensures system-compatible behaviour from market participants. For example, in case the system is *short* (and units on the balancing market are required to *deliver* energy), market participants are typically incentivised through an imbalance price that is strictly *above* the DA price. It reflects the physical situation that energy is costly at this very moment. Conversely, when the system is long (and units on the balancing market are required to *reduce/consume* energy), the imbalance price is typically well below the DA price and even negative in extreme cases. This reflects the physical situation that energy is available in abundance and any additional feed-in is therefore detrimental to the system.

3 Redispatch

Congestion management measures are undertaken to provide network security. This means that all elements in the power grid are kept within their operational voltage and current limits. For transmission system operators, network elements must also be kept in an n-1 secure state, i.e. all remaining network elements must be within operational limits after failure or tripping of a single network element. Network elements with projected flows above these limits are said to be congested. Congestions can occur as a result of different influencing factors, such as topological changes in adjacent power grids, changes in demand patterns, additional power flows resulting from international trade and the increased integration of renewable energy sources.

To tackle congestions the following measures are used: non-costly remedial actions (phase-shifting transformers, special switching states, ...), redispatch and countertrading[15]. This report mainly focuses on redispatch measures in Austria and Germany.

Redispatch as well as balancing services are fundamental ancillary services in electric power systems. Redispatch can be defined as a planned deviation from a previously set generation or consumption schedule in order to relieve congestion. In practice, this means that in the most simple case a power plant located before the congestion reduces its production (redispatch downwards) and a power plant located after the congestion point increases its production (redispatch upwards) [23]. The initial, usually market-based, planning of conventional power plant generation is called dispatch. To conduct redispatch the TSOs must intervene in the originally planned schedule. As redispatch usually targets a specific network element, the geographical location is crucial for these measures: the closer the provider is located to the congestion point, the better is the effectiveness of the undertaken measures. There are, in theory, many possible redispatch service providers in the meshed European network, but

[15] A remedial action between two TSOs to alleviate congestions by utilising the energy market and thus without specific geographical location.

if they are located far from the congestion point, they become less effective. This limits the available redispatch service providers for TSOs [23]. This geographical aspect is very important for further work in this project.

Generally, it can be distinguished between preventive redispatch (relocating the feed-in in advance in order to avoid the congestion) and curative redispatch (measures, aimed to quickly keep elements within their operational limits immediately after an element has already failed) [24] [23].

3.1 Redispatch across Europe

Procedures for redispatch measures are provided by the Capacity Allocation and Congestion Management Guideline (CACM GL), the System Operations Guideline as well as Regulation 2019/943/EU (2019). This regulation sets the basis for redispatch measures within the European Union. For example, Regulation 2019/943/EU (2019) states that redispatch measures should ideally be procured in a marketbased way, open to all types of generation and needs to be financially compensated.

However, redispatch as a form of congestion management in general is implemented in different ways across Europe. [25] In particular, regulatory design for redispatch measures differ significantly with regards to market-based or regulatory approaches. While Germany takes a regulated approach, more market-based approaches can be found within Europe as well, for example in the Netherlands or in the nordic regions, where advanced platforms like GOPACS [26] or NODES [27] are used. Some countries have integrated redispatch procurement into the balancing market, for instance Belgium [28] and France [23]. A lot of other countries are currently in discussions how to implement the european regulatory, such as Ireland [29] or Greece [30]. A cost-based approach might not consider the economic incentives for market participants adequately, since marginal costs need to be determined on an individual basis [31], a market based approach on the other hand might encourage inc-dec gaming [25]. A detailed comparison of countries will be analysed in the further course of the project.

3.2 Redispatch in Austria

In Austria, congestions are mainly caused by a delay of vital transmission projects in combination with current developments in the European electricity market. Figure 17 illustrates the number of days where redispatch was required in Austria within the timeframe of 2013 to 2021. It is evident that the number of interventions has steeply increased since 2013, reached its highest number in 2017 and has remained high since then.

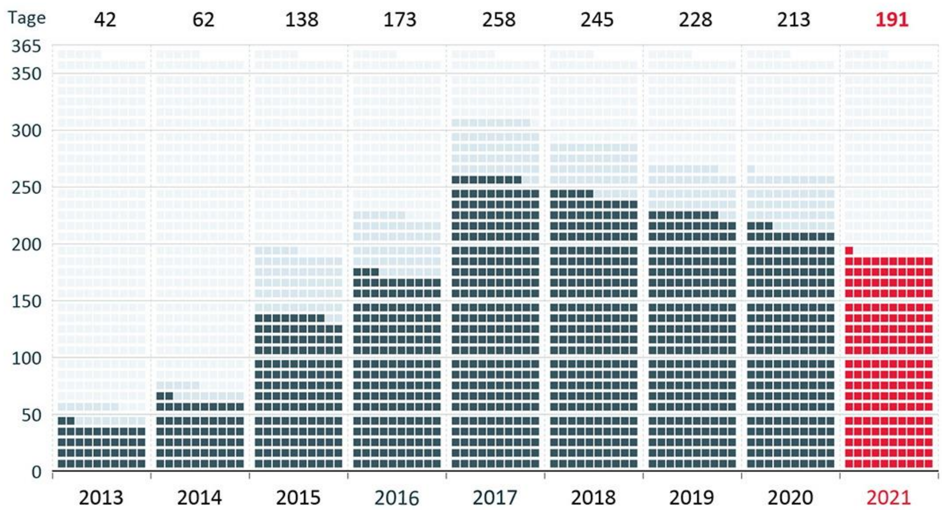


Figure 17: Number of days requiring redispatch [32]

Austria lies in the centre of Europe and as a result, congestions have been influenced by recent trends such as increased international trade and the increased integration of renewable energy sources across

Europe. These trends are expected to continue as in the near future, more RES will be integrated, to comply with the targets defined in the Austrian Climate and Energy Strategy, Mission 2030, but also in other European Nations. Cross-border electricity trading is also likely to keep increasing following the implementation of minimum trading capacity targets required in the EU Regulation 2019/943.

3.2.1 Legal framework

The redispatch services in Austria are regulated by the ElWOG 2010, which grants the TSO the right to require any producer to change their infeed and specifies that the TSO shall enter into contracts with producers and consumers of electricity to govern the provision of redispatch. As previously stated, the provision of redispatch is highly influenced by the location and direction of the congestion and is based on these requirements, mainly provided by conventional thermal or hydro-power plants. However, the required type of measure is highly dependent on the nature of the problem. Hydro and gas-fired power plants are characterised by different technical features, therefore, their dispatch depends on the relevant problem that is to be solved. In addition, there is an option to act on the demand side via reducing industry demand.

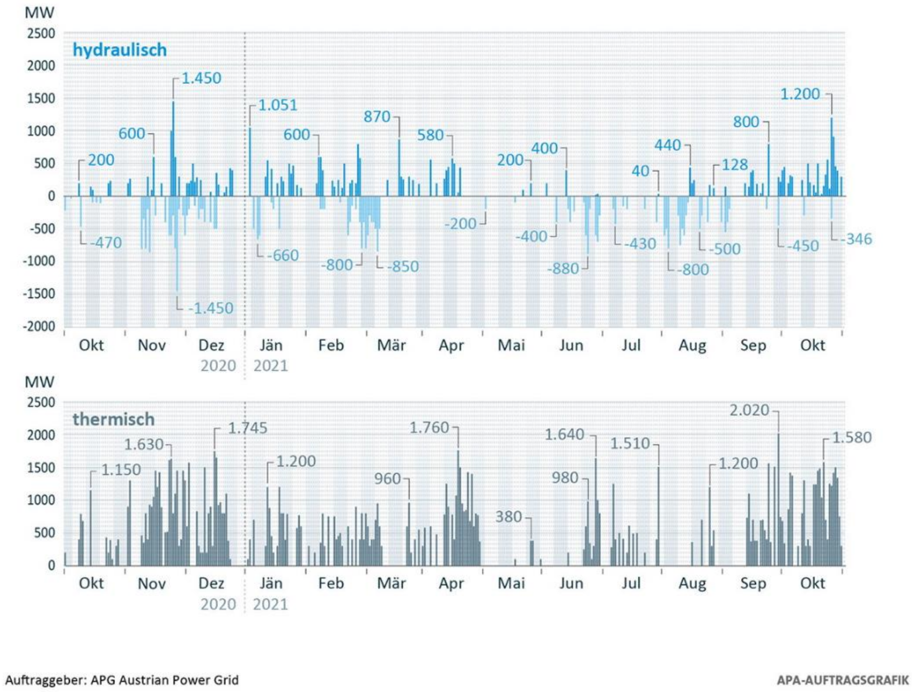


Figure 18: Redispatch measures per plant type

Based on Article 23(2) EIWOG, the TSO is responsible for the identification of congestions in the transmission network and also has to undertake measures to prevent or manage them. In Austria, redispatch services are procured separately from other ancillary services. APG concludes contracts with individual generation units or loads, based on which these units are committing to increase or decrease output when requested by APG. Changes in power production/consumption schedules are remunerated based on the submitted costs and economical disadvantages, which must be justified.

The regulatory framework for redispatch and DSO-TSO interaction within the EU and Austria will be described in detail in Deliverable 3.2. The following list provides a short overview of the duties of the TSO as well as producers:

As per ElWOG 2010

The Control Area Manager (CAM) is legally obliged to

- Ensure frequency control and control zone balance
- Identification of congestions in the transmission network
- The implementation of measures to remove and overcome bottlenecks in the transmission grid
- Compensate providers for economic disadvantages and costs

As per Electricity Market Code Chapter 3 (SoMA3)

- Power plants are required to provide day-ahead production schedules if they are either connected to the 110kV level or higher, have a generation capacity greater than25 MW or are deemed relevant for grid security calculation by the CAM

As per the System Operations (SO) Guideline

- Costs for any measures need to be disclosed ex-ante
- Producers are obliged to follow instructions of the CAM

<u>Calculation of power flows in interconnected transmission system operation:</u>

Generation and consumption in the power grid must be balanced at all times. Therefore, this balance must apply to the sum of all countries and boundary injections of the synchronous zone. From schedules and load forecasts, the vertical load of the sub-networks in Austria can be determined, whereby the aggregation level of vertical loads, 220 kV or 110 kV, depends on data availability. In turn, the sum of all generation and loads in Austria results in the exchange with other countries in Europe.

This information combined with the physical restrictions of the electrical grid results in a model for the Austrian control area. This model does not include the effect of international flows resulting from the net positions of other control areas and is called an Internal Grid Model (IGM). In a final step, all IGMs of the synchronous zone are merged into a Common Grid Model (CGM). Any control areas not explicitly covered by the CGM are substituted by appropriate boundary injections which model the exchange with adjacent regions. Finally, from this CGM a power flow calculation can be performed to determine the power flows in the transmission grid. Based on these power flow calculations, congestion forecasts can be made at different times.

3.2.2 Timing of events for redispatch planning and activation:

Redispatch measures can be undertaken in day-ahead, intraday or real-time timeframes. After receiving load/generation schedules from the balancing responsible parties (BRP) (14:30 D-1) and building Europe-wide datasets, the TSO conducts load flow calculations. In the situations, where the TSO expects a congestion all potential providers of redispatch are considered and the best solution to the congestion is calculated. A redispatch request is then sent to the selected redispatch parties, which in turn confirm this request and adjust their schedules accordingly. On the day of delivery, further dispatch adjustments can be undertaken if required by a change in forecasts, intraday trading or other unforeseen events.

On the transmission grid, redispatch measures are typically conducted from two sides of a critical network element. Load on the critical network element is relieved in a way that generation is ramped up on one side of the network element and ramped down on the other side. In this respect, redispatch on the transmission grid can be understood as 'neutral' in a way that redispatch does not trigger the use of any balancing energy.

As laid out in the previous paragraph, determining the power flows in an interconnected transmission system is not the work of a single TSO but depends on the cooperation with the other TSOs in the synchronous zone. So-called Market Coupling is used, where available cross-border capacities are taken into account implicitly by Power Exchanges when determining the market results. In this way, market participants do not individually receive allocations of cross-border capacity, they just bid for the electricity on the Exchange. [35]

The aim is to maximize social welfare, avoid artificial splitting of the markets and send the most relevant price signal for investment in cross-border transmission capacities. The efficiency of Market Coupling is furthermore proven by an increasing price convergence between market areas. [35] An important role in carrying out market-coupling play the so-called NEMOs (Nominated Electricity Market Operators). These are entities designated by the competent authority to perform tasks related to single day-ahead or single intraday market coupling. In other words, NEMOs are the organisations mandated to run the day-ahead and intraday integrated electricity markets in the EU. Namely, NEMOs operating in Austria are the electricity exchanges EXXA, EPEX and Nordpool. [36] NEMOs receive the information about cross boarder transmission capacities as outcomes of the capacity calculations of so-called Regional Security Coordinators (RSCs). RSCs are owned by the TSOs and act as service providers to TSOs. RSCs can develop their services as much as is needed to make grids more efficient. [37] When the market results are not available on time, the necessary data has to be generated and optimally aligned in order to obtain a consistent picture of the forecast situation. For this purpose, the RSCs generate forecasts for the net position of each bidding zone, i.e. the balances of all import and export transactions, which are then included in the capacity calculation. [37] A coordinated capacity calculation is carried out for a geographical area, which is called a capacity calculation region. Sixteen TSOs follow the decision of the Agency for the Cooperation of Energy Regulators (ACER) to combine the existing regional initiatives of former Central Eastern Europe (Germany, Luxembourg, Austria, Poland, the Czech Republic, Slovakia, Hungary, Romania, Slovenia and Croatia) and Central Western Europe (France, Germany and the Benelux countries) to the enlarged European Core region (Decision 06/2016 of November 17, 2016). [38] The countries within the Core region are located in the heart of Europe which is why the Core CCR Project has substantial importance for the future European market integration [39]. CORE (see Figure 19) is one of ten CCRs within Europe. [40]

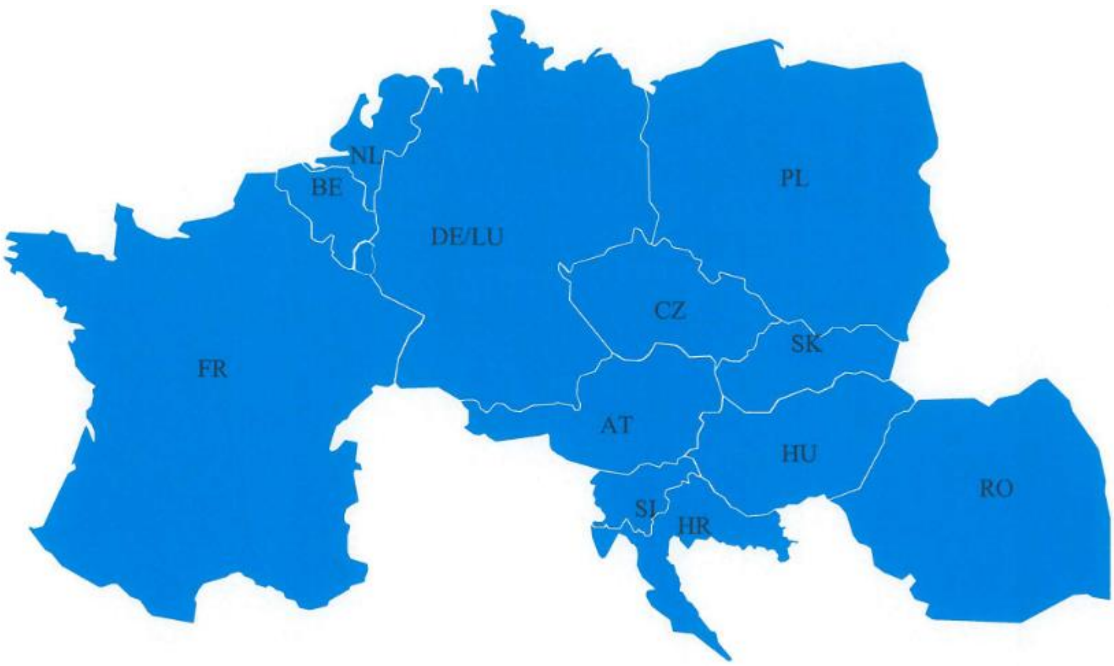


Figure 19 Map of members of the capacity calculation region CORE [40]

RSCs do not only provide forecasts for transmission capacity calculations but intervene from one year ahead to one hour before dispatch. They run calculations and make recommendations forTSOs . [37] In the CORE region the two different RSCs CORESO and TSCNET are operating, as indicated in Figure 20 considering the members of the Core Region in Figure 19.

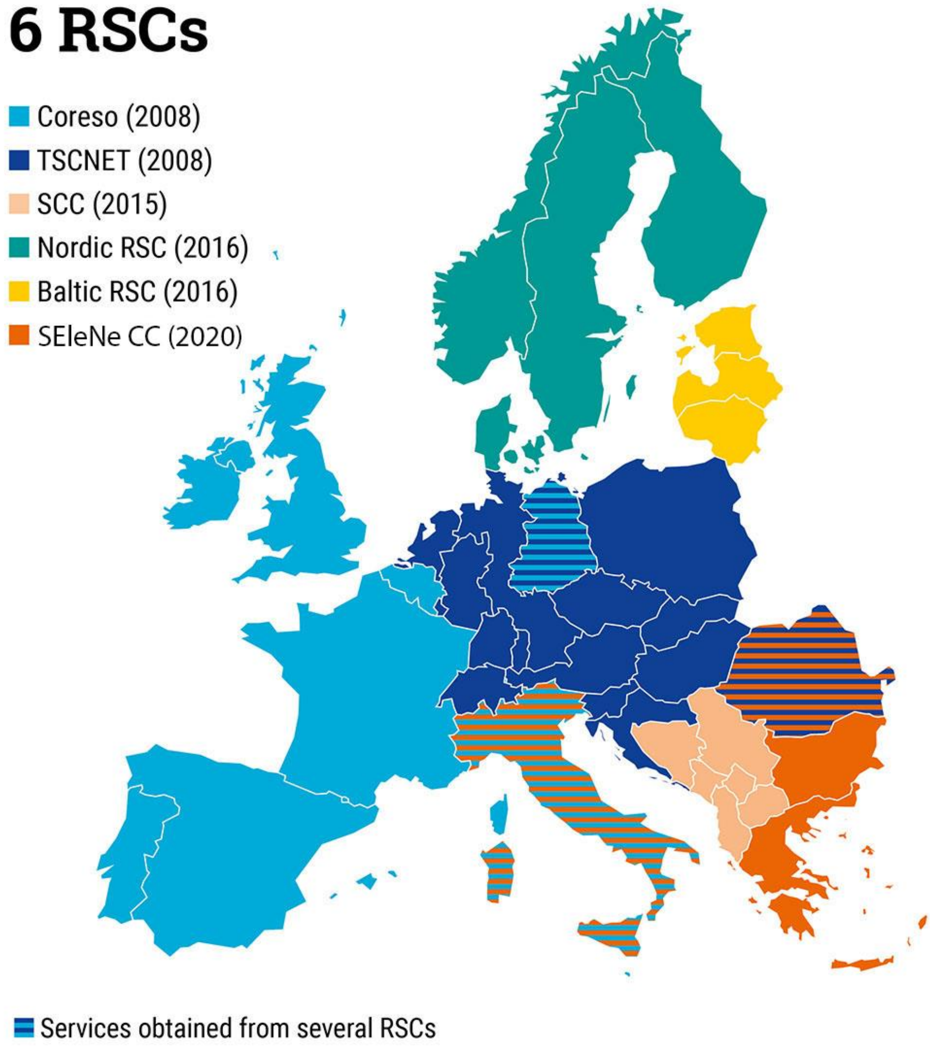


Figure 20 The six different regional security coordinators (RSCs) which are operating in different regions in Europe [37]

The establishment of a common grid model (CGM) is the basis for every single evaluation of transmission system security. The European CGM is tailored to the requirements of the most important services of an RSC and consists of detailed input and forecast data of generation, consumption and network connectivity for all TSOs. The data is provided by the TSOs in the form of their individual network models (IGMs) and other specific information. The RSC must check the quality of the IGMs and integrate them into the CGM in accordance with predefined rules. The legal basis for the CGM is provided by the Network Guidelines (EU) 2015/1222 and 2017/1487, which are described in the CGM Methodology. [41]

Besides the establishment of a common grid model and the already mentioned capacity calculation, RSCs must carry out three other services, according to the multilateral agreement that ENTSO-E members have all signed. These will not be described in further detail but shall be mentioned for the sake of completeness. They are namely the Security analysis, the Outage Coordination and the Adequacy Forecast. RSCs must respond to regulators due to the fact that they are service providers of nationally regulated TSOs. Since 2016 they must increase reporting on their work. [37]

The so called regional operational security coordination (ROSC) Methodology is developed in accordance with Article 76 of the SO Regulation and for organisation of regional operational security coordination in accordance with Article 77 of the SO Regulation. It covers the year-ahead, day-ahead and intraday regional operational security coordination within the Core CCR. It introduces the remedial action optimisation (RAO). The aim of this optimisation is to minimise the incurred costs as well as to ensure the remedial actions are applied effectively to address operational security violations. It also ensures the conditions for maintaining the operational security throughout the Union by specifying the provisions and process for the coordination of operational security within Core CCR as well as with neighbouring CCRs systems in accordance with Article 4(1)(d) of the SO Regulation. [42]

While some tasks in power system operation such as monitoring and switching operations are performed in real-time, avoiding congestions in the transmission grid requires some tasks with lead times starting from 30 minutes up to 8 hours or more e.g. if the start of a thermal power plant is required. To manage the various requirements, power flow calculations are performed in different TSO/RSC Processes. Table 5 gives an overview of different processes used to calculate power flows and redispatch demand.

Table 5: Timing of network security calculation and redispatch planning for TSO

<u>Overview of Timing of network security calculations and redispatch planning</u>

- **<u>D-2 Capacity Calculation – common, together with RSC</u>**
  - Used to provide Cross-Border transmission capacities to NEMOs
  - Theoretical consideration of RD potentials
  - Usually no requests for redispatch
- **<u>Day Ahead Congestion Forecast – common, together with RSC</u>**
  - Performed after Day-Ahead market coupling
  - Calculation of congestions for the next day
  - Planning of Redispatch
  - Requests for necessary Redispatch
- **<u>Intraday Congestion Forecast – common, together with RSC</u>**
  - Control of network security according to Day-Ahead planning
  - Response to forecast deviations, and requests for redispatch with shorter lead time possible
- **<u>Real-Time calculations/SCADA - local</u>**
  - Monitoring of the system state
  - Instruction of additional measures
  - Fault management

➔ Requests for Redispatch from approx. 18:00 Day-Ahead until 1-2 hours before delivery

A more detailed timeline for the Day-Ahead and intraday planning and activation horizon is shown below.

Day-Ahead Timeline in Austria

- Approx. 14:30 Update of power plant schedules as well as load and res forecasts
- Approx. 16:00 Creation of APG grid model (IGM) and merge to European grid model
- Approx. 18:00 Merge of Common Grid Model
- Approx. 18:30 Calculation of load flow and grid congestion
- **Approx: 20:00 – 24:00 (as soon as CGM and results of load flow calculations are available) Selecting and coordinating the optimal remedial actions (redispatch)**
- From 0:00 Monitoring in real time - change to ID and RT process

Intraday, rolling horizon timeline

- Schedule messages and forecasts
- Creation of APG grid model (IGM) and merge to European grid model
- Merge of Common Grid Model (CGM)
- Calculation of load flow and grid congestion
- **If necessary: Selecting and coordinating the optimal remedial actions (redispatch)**
- Monitoring in real-time

3.3 Redispatch in Germany

Due to the increased expansion of wind power plants in Northern Germany, combined with an increasing electricity deficit related to conventional power plant shutdowns and the high demand for electricity from large industrial consumers in the South and the slow progress in network expansion, congestions appear in the German transmission and distribution networks. While only around 5 TWh were "redispatched" in 2013, the total volume increased by a factor of 4 by 2017 to around 20 TWh, as illustrated in Figure 21. Previously, the participation in redispatch was only mandatory for conventional power plants and storages with a capacity greater than 10 MW.

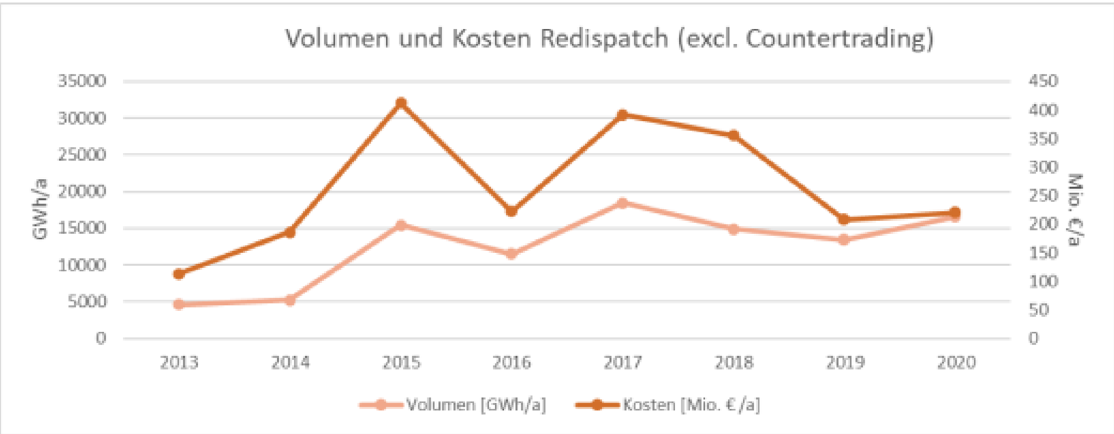


Figure 21: Volumes and costs of redispatch measures in Germany 2013-2020 [43]

Redispatch measures can further be classified as current and voltage related. The current-related redispatch serves to avoid or eliminate short-term overloads in network components and the voltage-related redispatch is aimed to maintain the voltage in an affected network area through the additional provision of reactive power. The majority of the measures undertaken in Germany were current-related (see Figure 22). It can be concluded that network congestions are the most common reason to use the redispatch measures in Germany [43].

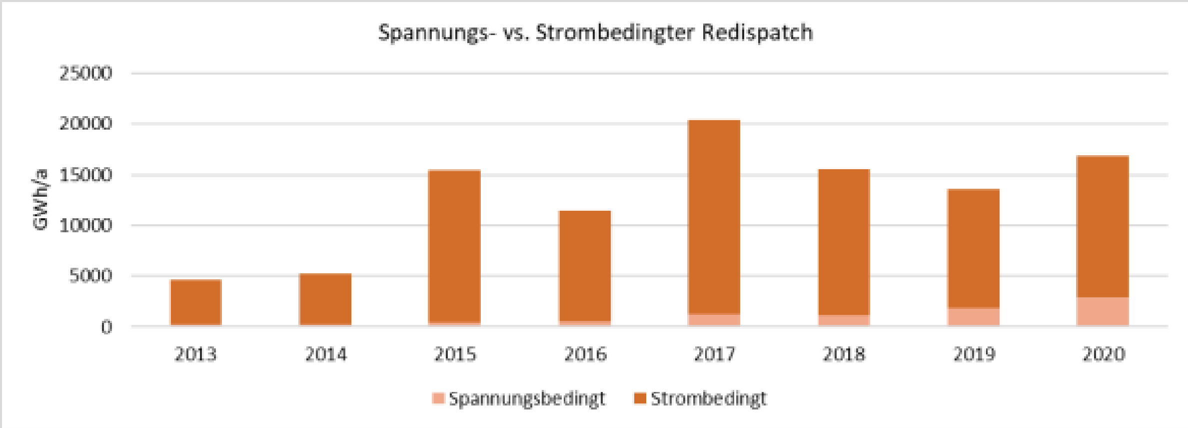


Figure 22: Commonly used redispatch measure types in Germany 2013-2020 [43]

With the amendment of the EnWG and the integration of the changes to the "Network Expansion Acceleration Act" (NABEG 2.0), there are new requirements for grid congestion management foreseen. Therefore, from October 2021, the new regulation on the extended redispatch process (Redispatch 2.0) obliges not only the TSOs but also the distribution system operators (DSOs) to participate in congestion management and to ensure system stability in Germany. Generators with a capacity over 100 kW (as well as plants larger than 30 kW that can be remotely controlled by a grid operator at any time) will be also obliged to participate [44]. With this new regulation, the potential for utilisable redispatch capacity enlarges significantly. By lowering the threshold value from 10 MW to 100 kW, the number of plants participating in the regulated redispatch increases strongly.

As in the past, redispatch will primarily involve conventional plants. Renewable energy plants are only requested when the possibilities of conventional plants are exhausted or when their utilization to relieve a congestion is cheaper by a factor of 10 or by a factor of 5 in the case of CHP [45].

In practice there have been some delays in the implementation of the Redispatch 2.0 processes, therefore a transitional solution for balancing processes in the new redispatch regime has been established. The management of the supplier's balancing responsible party (BRP) , taking into account the balancing of the Redispatch 2.0 measures by the instructing network operator, will continue to be carried out by the balancing responsible party of the supplier of the affected plants within the framework of the transitional solution. [46] For this purpose, the supplier receives a compensation in the form of a financial compensation by the connection network operator, who would be responsible for the settlement in the first place. The implementation of the processes for basic data delivery and activation is expressly not suspended as part of the transitional solution. The obligation to press ahead with the implementation of the Redispatch 2.0 processes in accordance with the statutory and regulatory requirements continues to exist. By March 1, 2022 at the latest, operational readiness must be ensured by all process participants. [47]

In the context of introducing Redispatch 2.0., the **Connect+ platform** [48] (named RAIDA) has been developed for the exchange of information between dispatchers and network operators. It was established as a service to transfer information between the actors from the Redispatch 2.0 process. Connect+ offers a so-called Single Point of Contact (SPoC) for all actors involved in this process, which means that the required data is transferred to a central location. This eliminates the need for cost-intensive and error-prone interfaces in all directions. Only one interface is required between Connect+ and the system used by the respective actor. In addition, data packets can be sent to several actors at the same time. This significantly simplifies the manageability of the "Redispatch 2.0" process.

DA/RE [49] is a digital platform solution for the coordination of redispatch/congestion management actions of the network security initiative BW. It is an IT platform that ensures network security at all levels. It creates transparency about flexibilities of the market participants in the grid and coordinates their use between the grid operators (also see section 5.2.1).

As of 1st October 2021, measures for congestion management are specified in EnWG §13[16], replacing the previous definitions with regards to the framework of feed-in-management (EinsMan) regulated by the Erneuerbaren Energie Gesetz (EEG) and Kraft-Wärme-Kopplungs-Gesetz (KWKG). According to §13 EnWG, the TSO is required to maintain reliable supply and remediate any dangers or disturbances by use of the following measures:

- network-related measures
- market-related instruments, balancing energy, interruptible loads, countertrading or redispatch/curtailment of generation units larger than 100 kW, as defined in §13a
- additional reserves, especially grid reserves as defined in §13d or capacity reserve as defined in §13 e

In case of the redispatch of active power generation or consumption the set of measures with the lowest expected cost is to be activated. For this calculation EnWG §13 1a – 1c sets rules how the expected calculatory cost for Renewable Energy Sources, CHP and grid reserve must be assumed.

As per §13a, the BRP of the plant affected by redispatch is entitled to BRP-neutral-compensation for the measure against the TSO who requested the adjustment. In case of a renewable plant, the TSO shall carry out the adjustment with the BRP via which the TSO carries out the marketing. In this way, no balancing reserve is required to be activated. In case the power of a generation unit is curtailed as per §13a, the generation unit is eligible for full compensation for the reduced amount of energy. The financial compensation is appropriate if the operator of the installation neither is financially better nor worse off than he would have been without the measure. For example, a renewable producer within the market premium will be compensated for the lost market premium. [50]

4 Flexibility from the DSO's perspective

4.1 Introduction and overview

Due to the increased changes in the electrical energy landscape, as a result of the increased integration of RES as well as the integration of generation at distribution level, there is a paradigm shift in the way that electricity is generated, transmitted and distributed. Generation units have transitioned from those which were centralised and controllable to those which are distributed and non-controllable. Loads, on the other hand, from transitioned from fixed and non-controllable are now able to be controlled and time shifted. Power flows within the power system are no longer unidirectional but have transitioned to become bidirectional. Furthermore, consumers have continuously increased their active participation and thus have subsequently transitioned towards becoming prosumers. They are able to provide various services to DSOs by participating in various demand side management (DSM) activities.

The increasing penetration of distributed energy resources, general electrification (e.g. heat pumps, electric mobility) and the emergence of new market players – such as prosumers, aggregators and active consumers have led to increased complexity and unpredictability within the power system which results in the various challenges for the DSOs when ensuring the safe and reliable operation of

[16] §13 was amended through Article 2 G. 16.07.2021 BGBl. I S. 3026. Changes came into effect as of 1/10/2021. For a proper comparison please see https://www.buzer.de/gesetz/2151/al0-53072.htm

the network. The results of these influencing factors may cause network congestion and voltage violations. At the transmission level, these networks can be managed through re-dispatch techniques, while on the distribution level, congestion management is currently achieved mainly through planned reinforcements or upgrades of the network components [51] that are mainly financed by the customers and defined in the grid connection contracts. Thus, the redispatch can be seen as a service that, per se, benefits customers and not the DSO i.e. buyers of this service are customers and not the DSO. DSOs would like to offer their customers an alternative to grid reinforcement and upgrades in their connection requests in the possibility to either dynamically adjust their consumption power or to take part in a redispatch market. DSO should act as a neutral market facilitator. The Austrian renewable energies act changed this traditional environment somewhat in the manner that the DSOs will be obliged to carry a larger share in costs for grid expansion due to the connection of renewables to the grid. This could, in the medium to long term, make the use of flexibility services interesting also to the DSOs.

4.2 Flexibility services for DSO

The DSO has the responsibility to ensure the safe, secure and reliable operation of the electrical network. Therefore, for DSOs, the use of flexibility is primarily related to achieving these objectives based on a technical perspective according to local, regional or national usage. This is in contrast to market players who primarily perceive the use of flexibility from an economic perspective [52]. The use of flexibility can assist the DSO in a wide range of activities which enable the successful planning and operation of the distribution network. According to the Article 32 of the Electricity Market Directive of the EU Commission, the DSO should be allowed and should be incentivized to procure flexibility services in their areas in order to improve efficiencies in the operation and development of the distribution system.

From the perspective of the DSO, the procurement of flexibility services is primarily used for:

Congestion management

Due to the increased penetration of DER and new loads, the DSO will be required to maximize the DER hosting capacity in order to successfully integrate them within the network. Thus, improved network capacity planning and congestion management effort will be required (both short and long term) in order to maintain a high level of security and quality of supply [53] [52]. Therefore, the use of flexibilities from distributed generation and consumers can be used by customers/-DSOs to solve local network congestion (very close to real time) and help optimize network operation in a cost-effective way [53] [52]. In doing so, it is possible to reduce or defer network reinforcement requirements for a certain duration (alongside network planning) until it becomes more cost effective than flexibility utilization [52] [54].

Voltage control/reactive power management

Voltage control is vital consideration for DSOs due to the increased integration of distributed generations within the distribution network. This increase in active power injection, particularly in meshed grids, results in voltage profile variations across the network which may result in voltage violations. Since the DSO is obliged to conform with network codes (EN 50160) to ensure the safe and secure operation of the network, the coordination of these distributed generation can be used to the advantage of the DSO for voltage control, grid support and network loss management [53] [52] [54]. These aspects serve the DSO by reducing the requirement for additional network reinforcements [55].

Grid capacity management

In [55], the use of load flexibility was used to ensure the optimized operational performance of assets within the DSO network. This was achieved through the reduction of peak loads, even distribution of loads and extending the component lifetime. Furthermore, this service was mentioned to be able to reduce network losses since the electricity can be generated closer to where it is required [54]. Additionally, the optimization of network planning can be achieved through the contraction of flexibility in order to defer network investments [53]. Through careful coordination between the TSO and DSO, the balance between availability and market liquidity can be achieved [53], in particular the DSO is required to fulfill Articles 32(1) and 32(3) of the Electricity Directive.

Although the use of flexibility can be exploited by DSOs to plan and operate their network in a cost efficient way and allow for the reduction or deferral of grid reinforcement requirements, it should not be seen as the primary solution. Rather, the use of flexibility should be seen as a complementary resource to traditional operation and planning measures [51].

4.3 Impact of market-based flexibility on the DSO grid

Market based solutions allow for the activation of explicit flexibilities which are able to change the direction of power flows in a system and can be used by DSOs when performing congestion management. These services can be traded in various marketplaces which are relevant to the DSO and include Day-Ahead, Intraday, Balancing market or congestion management markets [56].

The use of market-based solutions can have a wide range of advantages which are cost-effective, innovative and can provide adequate competition when locally available [51]. The use of market mechanism can be particularly useful since they allow many players (provided they are available) to participate by providing the most efficient solution to the DSO [51].

Some of the notable challenges for DSOs when it comes to market-based solutions are the concept of liquidity and firmness of bids [51]. Therefore, it is necessary to ensure that the minimum requirements are clearly defined (product definition) and that there is an adequate number of active participants which provide the flexibility (i.e., liquidity) [51]. It is important to ensure the liquidity of the market In [55] in order to increase competition, which results in lower prices and increased cost benefits to the community [51]. Therefore, from the perspective of the DSOs, all flexibilities should be seen as equally viable for activating if they are able to provide a feasible solution for congestion management or other operational related problems [51]. In this regard, the DSO should act as a neutral market facilitator for new emerging market-based services [52]. Furthermore, measures should be in place to ensure that the market players are unable to participate in “gaming” in which the players deliberately create peaks to sell their services for higher prices to the network operator who is then obliged to accept [44]

Due to the nature of the flexibility market, it should be noted that flexibilities can also be activated by other market participants for their own incentives. In such cases, it is imperative to ensure that such activations do not lead to congestions in the DSO network. However, it is important to establish how the market participants will interact within the market and to assess what the impact of the flexibility activation will have on the DSO network. It is essential to ensure that the activation of a flexibility does not negatively impact the safe and secure operation of the network.

Furthermore, the activation of the same flexibilities may be required simultaneously by different market participants. Therefore, the need for adequate coordination amongst all parties is a necessity in order to mitigate the impact on TSO/ DSO networks. The concept of a single marketplace for flexibility, which allows for the procurement of flexibility by both TSO and DSO, is recommended [57] [58]. The advantage of such a single marketplace includes [58]:

- ensuring liquidity
- building a level playing field for different service providers
- allowing the coordination of different market processes such as balancing and congestion management
- allows TSOs and DSOs to access all bids and to mutually coordinate activations
- flexibility providers can participate in all processes collecting the maximum value for their flexibility

In the Austrian context, an assessment of the impact of market-based flexibility on distribution grids was conducted in [59]. The review of three projects showed that the coincidence factor of flexible devices will play a major role in future grid congestion scenarios, especially when participating in the market. In the case of generation units, Austrian DSOs do not expect to see high levels of congestion due to market participation, however, in theory, household PV may pose a risk to the distribution network in cases where there is interruption of peak shaving due to market participation [59]. However, currently, this is not the case in Austria since these planning methods are not in use.

The participation of industry customers within the market is also not expected to cause congestion within DSO networks. With high coincidence factors, weaker networks may be subject to increased congestion. However, as mentioned in [59], these are only evident in exceptional cases. On the other hand, when considering the market participation of households, the synchronous activation of heat pumps or simultaneous charging or electric vehicles is expected to cause congestion when considering high penetration in future scenarios. Although congestions are unlikely to occur through the use of reduce tariff options and optimised charging solutions, these congestions can be mitigated [59].

4.4 Impact of grid connection requirements

Due to the robust nature and design of current electrical systems, the activation of flexibilities in the DSO network is unlikely to cause major congestion in the electrical network. When connecting the DER, DSOs typically perform a worst-case load flow calculation based on a high feed in-low-load/ low feed-in-high-load scenarios in order to assess the impact on the network [59] and approves the connection accordingly. This is to ensure that under normal operation, the network is able to accommodate the maximum injected power generated by the DER at times of low consumption at all times throughout the year and vice versa [52]. In doing so, network conditions are assessed such as the evaluation of loading and voltage levels in order to ensure that network components are within their operating limits. In general, the connection of the flexibility is dependent on the location of the point of connection which determines the network characteristics at the point of connection. In general, the network capacity is mainly limited by [51]:

- the maximum load on a distribution asset or parts of an asset (depending on the number of connections and the simultaneity of loads) and the respective current in points of the network/of the network components.
- the voltage-range limitations or impacts on existing connections (i.e., in terms of local generation); and
- security and safety margins to operate the distribution or transmission system close to or in real time after gate closure

Accordingly, the current European regulatory framework encourages a prioritisation toward the integration of RES through guaranteed network access [51]. Network operators are therefore required to consider the associated challenges of flexibility services for both short- and long-term planning and operation in order to allow for a more efficient system.

In order to incorporate these flexibilities, DSOs may also be interested in the various characteristic of flexibilities connected to their network, which may be active on the flexibility market. Therefore, product specifications or attributes need to be clearly identified. A list of possible attributes is identified in [53]. A more detailed product definition will be developed with WP5.

5 Status quo and trends: TSO-DSO interaction for joint capacity management

This section provides a brief overview of the national and European status of implementation of the regulations concerning DSO-TSO interaction, which have been defined and/or proposed by various European regulations as well as position papers by ENTSO-E and ACER. Network codes, like the System Operations Guideline, define the possibility of DSOs to prohibit or limit TSO-activated flexibility from distributed connected pre-qualified units. On the other hand, Regulation 2019/944/EU(2019) on common rules for the internal market for electricity enhances the usage of distributed flexibility, as described in article 32 (Incentives for the use of flexibility in distribution networks) and article 13 (Aggregation contract). [60] Improved coordination between DSOs and TSOs is therefore required, as it has been already stated in ACER's European Energy Regulation: A Bridge to 2025, published in April

2014. [61] Furthermore, ENTSO-E and the European associations representing electricity DSOs, provide a joint assessment of the regulatory gaps and furthermore a roadmap, that requires addressing to facilitate the participation of DERs in "flexibility services". [62] Although this analysis shows that regulatory gaps in the current EU framework exist, it has been also stated that in the current EU regulatory framework, some implementation choices are deliberately left to NRAs and Member States to be able to consider existing local contexts and can still benefit from testing different approaches and from collecting best practices before defining common rules for the sake of harmonisation. ENTSO-E, therefore, believes that it would be more efficient to await the effects of the national implementation of the Electricity Directive by all Member States before considering an additional NC. Section 5.1 describes the current status of developments concerning DSO-TSO interaction within Austria, Section 5.2. provides an overview of the two projects DA/RE (GER) and GOPACS (NL), which are examples for a non-market-based and a market-based redispatch approach. Table 6 gives an overview of other international research projects and initiatives.

International research projects	International initiatives
SmartNet	Connect+
CoordiNet project	DA/RE
FLECH-iPower	Enera
FlexGrid	CINELDI
INTEGRID	GOPACS-IDCONS
INTERRFACE	NODES
EU-SYSFLEX	SINTEG

Table 6 Overview of projects and initiatives concerning DSO-TSO coordination which will be described in detail in section 5.2.

5.1 Status national projects

The organisation „Oesterreichs Energie" represents the interests of the Austrian electricity stakeholders, .i.e its 140 Members, including nine regional energy utilities, large scale energy utility Verbund, smaller municipal utilities as well as DSOs and the TSOs. It represents the jointly developed stakeholder interests to politics, administration and to the public. In light of recent developments and the need to coordinate the efforts regarding the use of distributed flexibilities in Austria the project System Operation 2.0 *(Ger.: "Systemführung 2.0")* was started to develop the principles of coordinated flexibility use by the TSO and DSOs in Austria. This project is organised in three expert groups. Expert group one is "Market roles and processes" *(Ger.: "Marktrollen und Prozesse")*, expert group two is "Cascaded network management and active distribution network management*" (Ger.: "Kaskadierte Netzführung und aktive Verteilernetzführung")* and expert group three is named *"Data&Technology"*. These three expert groups are tasked with setting the common guidelines for the use of flexibilities for the distribution grid and the consideration of the distribution grid when flexibilities are activated by the transmission grid operator. The discussions and current developments in these expert groups will be strongly considered during the project in order for the developments on this topic in Austria to be harmonized.

5.2 Status international projects

This section presents an overview of TSO/DSO coordination procedures currently observed in EU initiatives and projects, and the related services and different market structures presented in these projects. In this section, two European research projects or initiatives are presented.

5.2.1 Connect+ and DA/RE -Redispatch 2.0 in BDEW

The German grid expansion Act **NABEG [63]** (Ger.: Netzausbaugesetz) defines the regulatory framework for Redispatch 2.0 in Germany and obliges all grid operators to select the most cost efficient redispatch-actions in their own grid and in all underlying grids. All production and storage units above 100kW including renewable and combined heat and power (CHP) plants must be considered within this scheme. It also requires coordination between all grid operators whose grids are affected by the redispatch activation and that the system operators must inform the operators of the plants of the planning and execution of redispatch activation. The balancing and accounting of the stakeholders in the context of redispatch provision has to be done by the grid operators. For this purpose, all DSOs have to act as a balance responsible party.

To enable an exchange of information between dispatchers and network operators and simplify the manageability of the "Redispatch 2.0" process, the **Connect+ platform** [48] has been developed. It was established as a service to transfer information between the actors from the Redispatch 2.0 process. It offers a so-called Single Point of Contact (SPoC) for all actors involved in this process, which means that the required data is transferred to a central location. This eliminates the need for cost-intensive and error-prone interfaces in all directions. Only one interface is required between Connect+ and the system used by the respective actor.

To enable the communication and coordination of redispatch/congestion management actions, the digital platform solution **DA/RE** [49] has been developed in the course of the network security initiative BW(Baden-Württemberg). The IT platform ensures network security at all levels. Furthermore, it allows for the transparency of market participant's flexibilities and coordinates their use between the grid operators, while aiming to reduce the overall costs of activated redispatch.

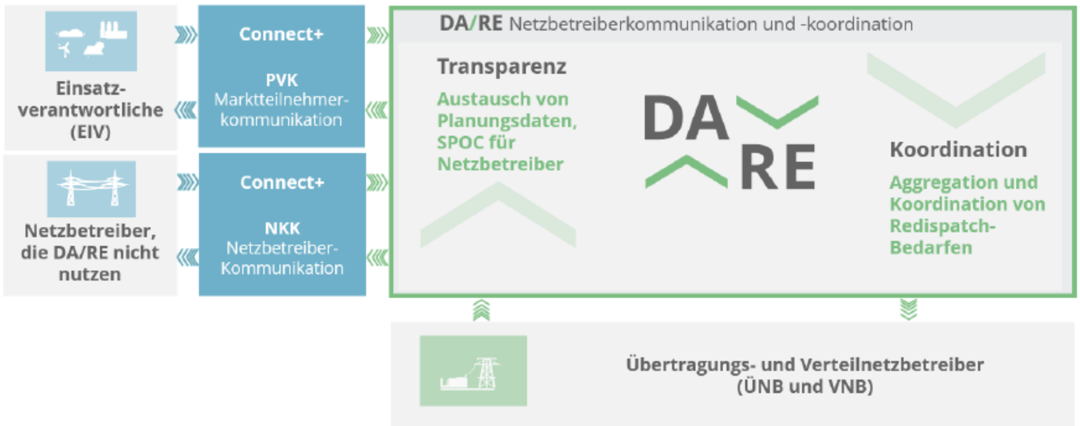


Figure* 23 Responsibilities and links between the involved stakeholders and the DA/RE platform. *[49]

DA/RE offers various functions for data exchange (see Figure 23). The direct exchange of relevant redispatch 2.0 data between DA/RE and network operators is possible, as well as the indirect exchange via Connect+ with the EIV (ger. "Einsatzverantwortlicher" = party, that is responsible for the control of the redispatch providing unit) and grid operators which are not using DA/RE. Besides the data exchange module, DA/RE also offers a coordination mechanism, where redispatch needs are aggregated and the activation of redispatch amounts is optimized and coordinated. The coordination module has been developed to handle two main Use Cases, which can occur within the grid when activating redispatch by TSOs and/or DSOs:

- Avoidance of a congestion in the distribution network due to a redispatch activation of the TSO
- Utilization of synergy potentials through avoidance of unnecessary simultaneous activations (by DSO and another DSO/TSO) by merging the redispatch needs and thus reducing the total amount of redispatch volume

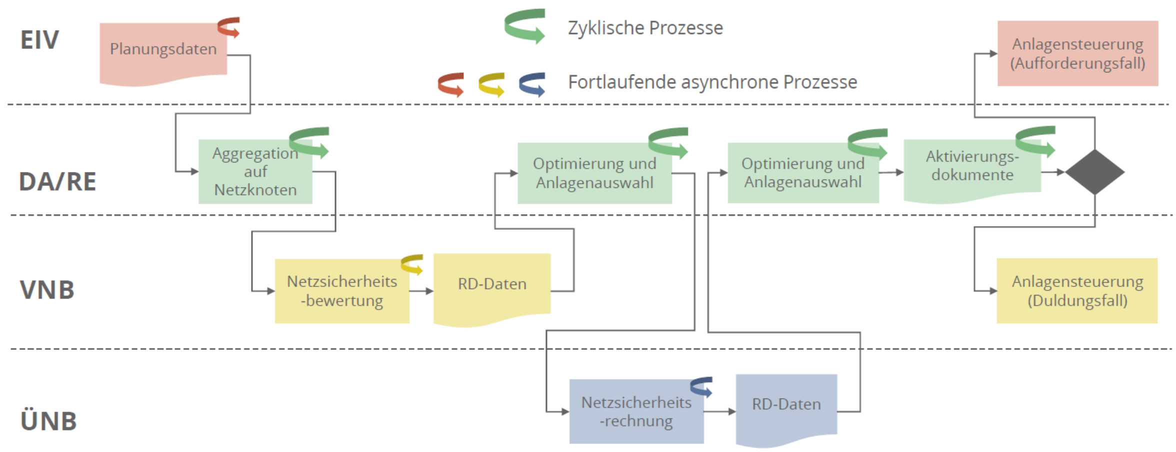


Figure* 24 Sequence of events within the DA/RE process *[49]

Figure 24 indicates the sequence of events of the processes performed within the DA/RE platform. First, the planning data (Ger.: Planungsdaten), which consists essentially of the schedules of all relevant plants, are aggregated on the DA/RE platform for all grid nodes. These aggregated schedules are sent to the DSOs, who perform a grid security calculation and determine free capacities and/or redispatch demand for relevant grid nodes which is then provided to the DA/RE platform (an example can be seen in Figure 25). The DSOs and TSOs are additionally providing simplified grid models of their own grids to DA/RE. The platform then performs an optimization calculation, which selects the most cost-efficient plants to be activated. The results are sent to the TSO, who then calculates their redispatch demand/free capacities. In another additional optimization execution, the final selection of redispatch units is re-evaluated and established. This is followed by the creation and distribution of activation documents either to the DSOs and/or to the EIVs. In this way, the platform enables coordination of redispatch requirements and potentials across voltage levels and reduces the coordination effort between the players.

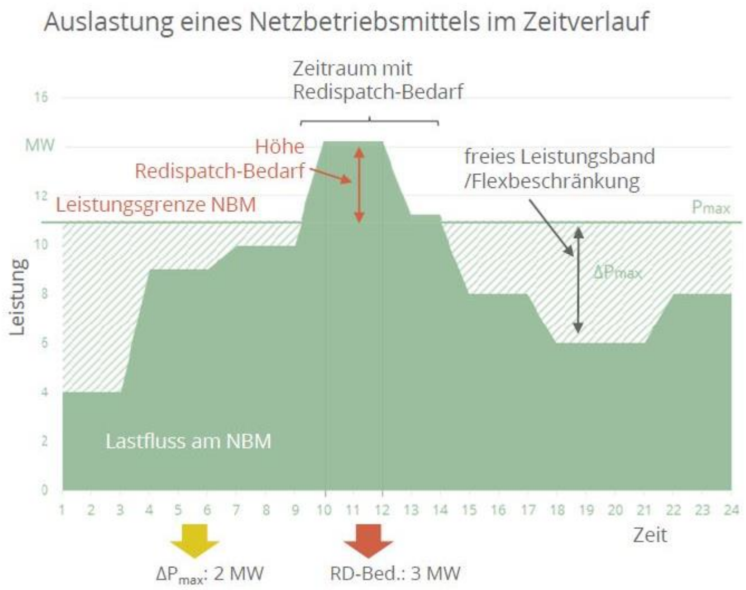


Figure* 25 Example for a profile for redispatch demand (red arrow) and free capacities (black arrow) which is sent by the DSOs/TSOs to the platform DA/RE *[49]

The following lists provide a summary of the information requirements which must be provided by the respective network operators to the platform and which tasks are performed by DA/RE:

Responsibility of network operators to provide:

- **Data import and export:**
    - Import of planning data (i.e. aggregated schedules of the underlying flexible units at relevant grid nodes) and plant basic data (*Ger.: Stammdaten*, contains information regarding the flexible units, i.e. contact data, grid connection point, balancing zone or market role)
    - Enrichment of plant basic data, provision of network model data, Time series management (creation of time series documents)
    - Export planning and enriched plant basic data (including planning data for plants in the forecast model, RD requirements, flexibility constraints)
- Forecast generation for plants in the "forecast model" (*Ger.: Prognosemodell*)
- Grid security evaluation
- Possible activation of redispatch units
- Balancing and billing

Tasks performed by DA/RE

- **DSO data exchange:** Single point of contact for the exchange of plant basic and planning data between DA/RE network operators as well as to the planning data distribution concept and network operator coordination concept of Connect+
- **Aggregation:** Aggregation of planning data of individual plants at network interconnection points
- **Coordinated plant selection:** Selection of most cost-effective plants to meet redispatch demands (alleviation of a congestion), taking into account all redispatch potentials, redispatch demands and flexibility constraints of the different grid operators as well as the effective impact on the network
- **Request / instruction of redispatch activation:** Preparation of activation documents for EIV/ANB (Ger.: Anschlussnetzbetreiber, engl: Connection network operator) as well as notification documents for grid operators, suppliers and balancing responsible parties.
- **Participation in DA/RE balancing:** Balancing management and management of a joint DA/RE-redispatch balancing responsible party for procurement of the balancing flexibilities/units by incurring the schedule registration

Forecast/accounting models in the Redispatch 2.0 process:

There are two different forecast/accounting models available for the potential redispatch providing plants, which are dependent on the forecast quality of the planning data. The assignment to the different models is coordinated and mutually agreed between the plant operator/EIV and the grid operator:

- The **planned value model** *(Ger.: "Planwertmodell")* is possible for non-fluctuating but also fluctuating producers (large wind or solar parks, mostly >1MW), for which forecasts are available and an ex-ante schedule can be provided. Plants >10MW are obliged to contribute/ participate to the planned value model, all plants below 10MW can choose whether they want to participate in the planned value or the forecast model.
- The **forecast model** *(Ger.: "Prognosemodell")* is available for all resources <10MW who cannot provide an ex-ante schedule by themselves. Non-fluctuating (small conventional CHPs for instance) and fluctuating producers (whose fluctuations are caused by fluctuating primary energy) can be assigned to this model.

Depending on the assigned model, there are further three different billing methods available:

- **"Spitzabrechnung":** The potential production without curtailment either comes from the ex-ante schedule (which is provided by the plants in the planned value model) or in case of the forecast model comes from measured weather data of the production unit (this is not possible for conventional producers in the forecast model).

- **“Spitzabrechnung light”:** The potential production without curtailment comes from reference measured values or weather data for this location (this is only possible for renewables in the forecast model).
- **“Pauschalabrechnung”:** The value before the last quarter hour before the redispatch activation is taken for accounting. Additional correction factors can be considered, for example, for the change of the sun position during the day (this is only possible within the forecast model).

Lessons learned for I4RD:

DA/RE is a working showcase project for a non-market based coordinated redispatch activation between DSO-TSO, including smaller producers >100kW. Due to the geographical proximity of Germany, alongside the similarities in grid and market structure and the associated challenges of integration of renewables, the developments in Germany can provide an indication for the expected outcomes when applied within the context of Austria. Therefore, the lessons learned from the project in Table 7 are highly beneficial for developing a Redispatch/DSO-TSO concept for Austria.

Table 7 Lessons learned from the german initiative DA/RE

Concept	Relevance for I4RD
Go-live and implementation of processes	The implementation of processes for DSOs and small producers requires a significant amount of effort and time, especially when considering the data exchange for smaller plants and new tasks required by DSOs in terms of BRP-neutral billing. In particular, the coordinated transfer of responsibility for balancing from the supplier's balancing responsible party (current responsibility) of the affected system to the requesting network operator lead to significant delays. [64] This should be considered when planning the implementation and the regulatory framework of a DSO-TSO interaction in Austria.
Requirement for DSO to maintain its own balancing responsible party	In Germany, each DSO has to maintain its own balancing responsible party to enable BRP-neutral billing. In the context of Industry for Redispatch, if DSOs need to activate redispatch for their own purposes, it will be necessary to ensure the DSOs are able to do so. Currently in Austria, not every DSO requires flexibility activation within their grid, and therefore it is not required that every stakeholder needs to be part of a balancing responsible party.
Network modelling and load flow calculations	When considering the requirements for network modelling, it is necessary to consider the extent of detail to which the network needs to be modelled such that load flow calculations can be carried out within the distribution grid. From the working example in Germany, it can be assumed, that the usage of simplified grid models in a first step could provide a sufficient level of detail for redispatch calculation and the application of a grid filter for redispatch bids. These aspects will be examined in further detail in WP5.

Implementation of a central platform for redispatch coordination	All data exchange and optimisation modules are implemented at one single platform (supported by the Connect+ platform). In I4RD, UC6b is inspired by the handling of processes in DA/RE. This concerns the responsibility of the platform for optimization and bid selection, as well as the coordination process with all involved grid operators. UC6b stands in contrast to the main UC6a, where the platform serves as a bid filter, but the selection of bids is done by the system operators themselves.
Needs for improvement of optimization and bid selection	The iteration processes between the separate stakeholders in the DA/RE concept could be improved though: o Temporal shifts of the single assignments of grid restrictions by the system operators to the platform only lead to semi-optimal results. For optimal results, grid restrictions of all grid operators would have to be considered simultaneously, which requires a higher effort for coordination mechanisms. o Network calculations have to be carried out including large security margins since there are only a few iterative steps and the interdependencies of the different network calculations cannot be included sufficiently without a high number of iterative steps.

5.2.2 GOPACS-IDCONS [26]

There are two ways of redispatch procurement carried out in the Netherlands by the TSO, TenneT. The first one is the activation of redispatch "by using reserve power for other purposes" on a platform called Resin. In this case, the bids are directly submitted to TenneT where the location of the flexibility must be added in order to use the bids for congestion management. The second possibility for redispatch procurement in the Netherlands is the usage of "IDCONS" (Intrady Congestion Spreads) via "GOPACS", which is a platform operated independently from the TSO. [65] It manages congestion at all voltage levels, increasing the available flexibility for redispatch and improving DSO/TSO coordination [66].

GOPACS has been developed in order to enlarge the number of suppliers and increase competition [65], and uses flexibilities already available at the spot markets. GOPACS develops, contrary to the German initiative DA/RE, a form of market based redispatch. It evolved as a cooperation of the Dutch TSO TenneT and the Dutch DSO's Stedin, Liander, Enexis Groep and Westland Infra, and has been used in daily operations since 2019 [25]. GOPACS provides the so-called Intraday Congestion Spreads (IDCONS) product, that are essentially volume-balanced order pairs. It is not an actual market platform, no flexibility bids are processed through it but bids from other market platforms can be used. GOPACS enables all market participants via existing commercial market platforms to interact with all Dutch DSOs and TenneT in submitting bids to solve congestion in the Dutch grid. The energy trade platform ETPA [67] (only the intraday timeframe is considered for GOPACS) is the first, and at the moment only, market platform that has joined GOPACS, the integration with existing regulated market models is under development [68].

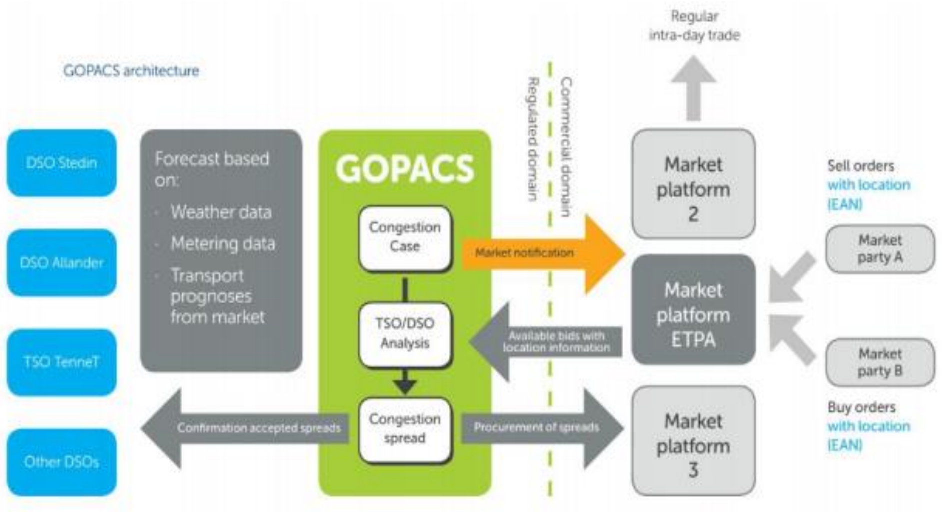


Figure 26 GOPACS architecture, with the regular intraday market, and the congestion management through GOPACS-IDCONS (congestion spread [68]).

In the first step TSO/DSOs calculate their congestions and announce congestions. Market participants from ETPA are invited to voluntarily provide bids/orders which include a delivery location to their trading platform [25]. These bids, with locational information, are assigned to the platform. Load flow calculations are carried out by the DSOs and the TSO, if the outcome of the calculations indicates congestion, they are registered on GOPACS, which adds additional constraints for the solution. GOPACS considers all available bids and tries to optimize the costs while considering, whether the bids solve the congestion or if they enhance congestion elsewhere in the grid [25]. The sum of selected order pairs (bid volumes) must always be zero. All bids outside the congested area can contribute to solving the congestion under equal competitive conditions [69]. Figure 27 shows how sell orders from market participants with a connection in the congestion area and buy orders from market participants outside the congestion area can be matched, and how the price spread is determined, that should be paid by the network operator to facilitate a trade. The TSO/DSO may then choose which IDCONS to buy in order to relieve a congestion. The market platform (not GOPACS) carries out the clearing process; therefore, the DSOs do not have to have a balancing responsible party licence [69]. GOPACS, therefore, is an intermediary between the system operators' needs and market platforms. The system operator pays the price spread between bid and ask price. Figure 27

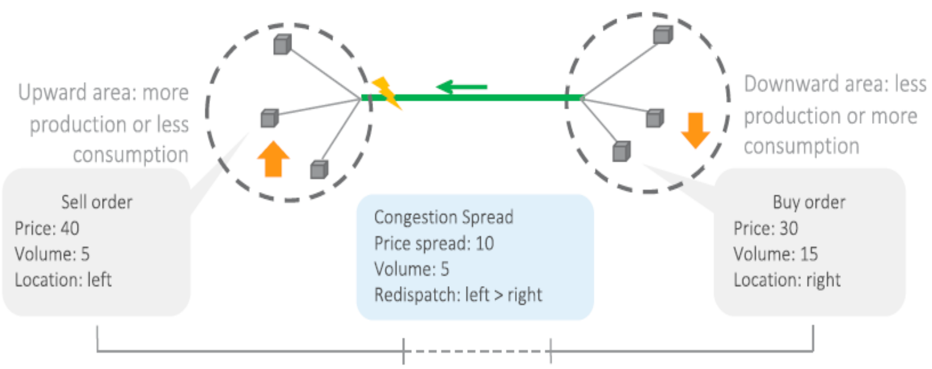


Figure 27 Schematic description of the IDCONS (intraday congestion spread) product

Lessons learned for I4RD:

GOPACS is an established showcase for a market based coordinated redispatch activation between DSO-TSO, using bids from conventional market platforms. This highly innovative market approach is interesting and depicts an alternative approach to that considered within DA/RE. Therefore, the lessons learned in Table 8 from this innovative project should also be considered when developing a Redispatch/DSO-TSO concept for Austria.

Table 8 Lessons learned from the platform GOPACS

Concept	Relevance for I4RD
Consideration of the intraday timeframe	Providing redispatch within the intraday timeframe can be challenging because the necessary capacity needs to be reserved and the plants are not able to use their assets during this time of capacity reservation. At the moment, the focus of the project I4RD lies mostly within the day-ahead timeframe, but for the intraday timeframe, alternative incentives need to be given to plants, in order to reserve capacity for redispatch.
TSO-DSO coordination	Established (tried and tested) TSO-DSO cooperation, which shows the mutual benefit for all stakeholders. TSO-DSO cooperation receiving increased attention in various countries/ projects, however, are mostly in their pilot phase. GOPACs provides an example of TSO-DSO interaction, by using regulated functions implemented via an algorithm centrally within the platform. The concept is in a slightly more mature phase and thus is relevant for I4RD since it confirms the need and added value for TSO-DSO interaction in modern future power systems.
Bids from regular market platforms	By using the bids from existing market platforms, the amount of total available bids can be increased. Most of the intraday volume is traded few hours prior to the product delivery, therefore the availability of bids may be insufficient in the day-ahead when most of the redispatch-volume is required by the TSO in Austria. This should be considered in the context of ID4R because it is essential that this minimum dispatch volume is sustained in order to satisfy the needs of the TSO.
Regular bids with added geographical information	Learnings from the GOPACS concept in NL include the idea that regular market bids suffice the standards for redispatch provision under the condition that additional geographical information is provided. This indicates that geographical information is highly valuable and should be considered as a minimum additional requirement for I4RD.
Requirement for DSO to maintain its own balancing responsible party	No BRP licence for DSOs is required in this concept. This allows for easier access to flexibilites for DSOs. Two bid volumes, each the same size yet in opposite directions, have to be matched symmetrically by the platform. However, the processing of schedules has to be done externally, for instance by the redispatch platform operator or directly via the market platforms.
Incentives through market	This concept is very beneficial for regular market participants, offering their bids. The trading effort is not higher, but with DSOs and the TSO as buyers, there is a potentially higher probability for

a flexibility to be activated. This should be considered in the context of I4RD in order to encourage increased market participation (in the long term).

6 Project Use Cases

6.1 Introduction to the project Use Cases

In the course of the project, different Use Cases (UC) have been created with the aim of comparing and combining different flexibility applications with the focus on industry units, which shall provide this flexibility. The focus of flexibility usage lies on spot- (Day-Ahead and intraday) and balancing-markets as well as redispatch. For each Use Case, KPIs have been defined which will be evaluated by simulations, surveys, or other calculation methods. The aim is to make all Use Cases comparable so that different stakeholders have an analysis of the eventual costs and benefits of each type of application.

In UC1, a baseline is created which aims to serve as a reference scenario and represent the conventional case/current situation where no active participation by the industry in considered. For this purpose, available historical data of industrial plants participating in the project is used. UC2 represents participation in the spot (Day-Ahead and/or intraday) markets. UC3a and UC3b finally combine the spot and the balancing markets. These two Use Cases, therefore, include all current marketing opportunities for flexibility. UC4 puts its focus on a flexibility market for the TSO, where bids in UC4a can be made for redispatch and in UC4b for redispatch and balancing. UC5 puts its focus on a flexibility market for the DSO, considering the intraday timeframe which is more important for the DSO. UC6 combines the applications of flexibility bids for DSOs and TSOs at the same time and puts a special focus on the necessary DSO-TSO interaction. UC6a describes a decentralized and sequential approach for the selection of redispatch, whereas in UC6b the selection of redispatch bids happens in a centralized way through common optimization. A more detailed description of the processes and exchanged information for each Use Case can be found in the Annex in the form of UC templates.

It is also worth mentioning that in the following, an ‘aggregator’ is to be understood as a general actor representing any kind of flexibility provider towards the redispatch platform. This does not strictly require that units are actually aggregated.

Table 9: Overview about Use Cases and their focus for Industry/Aggregator/DSO/TSO

ID	Use Case	Markets/Services	Focus	Description	Priority	Industry	Aggregator	DSOs	TSO
1	Reference		Reference	The historical baseline to compare the other markets/Use Cases to.	*Baseline*	For comparison of revenues	Comparison of revenues	Schedule of industry	Schedule of industry
2	Spot markets	Day-Ahead/ Intraday	Markets	The identification of the value of flexibility on the traditional spot markets for the participating industrial consumer.	High for industry	Revenues Comparison with UC4	Revenues Comparison with UC4	Changed schedule as input for network simulations	Changed schedule as input for network simulations
3	Spot- and balancing	Day-Ahead, aFRR, Intraday	Markets	The identification of the value of flexibility on the traditional spot markets and selected balancing markets for the participating industrial consumer.	Relevant for industry, not high priority for this project	Revenues Comparison with UC4	Revenues Comparison with UC4	Changed schedule as input for network simulations	Changed schedule as input for network simulations
4	TSO RD + Spot markets	Day-Ahead + Redispatch	TSO RD	This UC helps to define all necessary processes for the participation of industrial customers at redispatch. The added value of redispatch for the industrial customers and the value of the participation for the TSO can be derived.	Very high for industry and TSO	Characteristics of redispatch; additional requirements for control	Revenues & additional requirements for control	-	Characteristics of redispatch & comparison with UC6
5	DSO RD+ Spot markets	Day-Ahead + Congestion management	DSO RD	Reference Use Case to compare Use Case 6 with the focus on the DSO with only the DSOs using the flexibility.	Reference for DSO process	Requirements	Additional requirements for control	Comparison with UC6	-

6	DSO-TSO RD + Spot markets	Day-Ahead + Intraday + Redispatch (DSO-TSO)	TSO-DSO Interactio n	This Use Case serves to analyse the TSO-DSO interaction.	Very high for TSO/DSOs	Characteristics of redispatch; additional requirements for control	Additional requirements for control	TSO-DSO interaction	TSO-DSO interaction

6.2 UC1 Reference

Measurement values of historical consumption are evaluated at the historic Day-Ahead spot price and fuel prices. All taxes and grid costs are considered according to the real location of the plants. The interaction between the aggregator and the market is not considered in the Use Case itself at all. Furthermore, this interaction happens D-1 and is therefore, strictly speaking, not part of the actual Use Case. It is assumed that the aggregator is able to purchase the power required by the industrial unit at every timestep at the corresponding clearing price. The industrial unit therefore does not have to announce any schedules before the consumption, it neither participates in spot or balancing markets nor does it provide bids for redispatch. The Aggregator supplies the industrial unit with energy and allocates the corresponding costs in accordance with the clearing price (compare Figure 28) This can be assumed as the status quo, although the aggregator will in reality add some additional fee for uncertainties. However, this uncertainty fee would be necessary for each Use Case and will not be considered in the further Use Cases UC2-UC6 . The revenues, derived in further Use Cases, will be the overall revenues for industry and aggregator and must be split in a meaningful way.

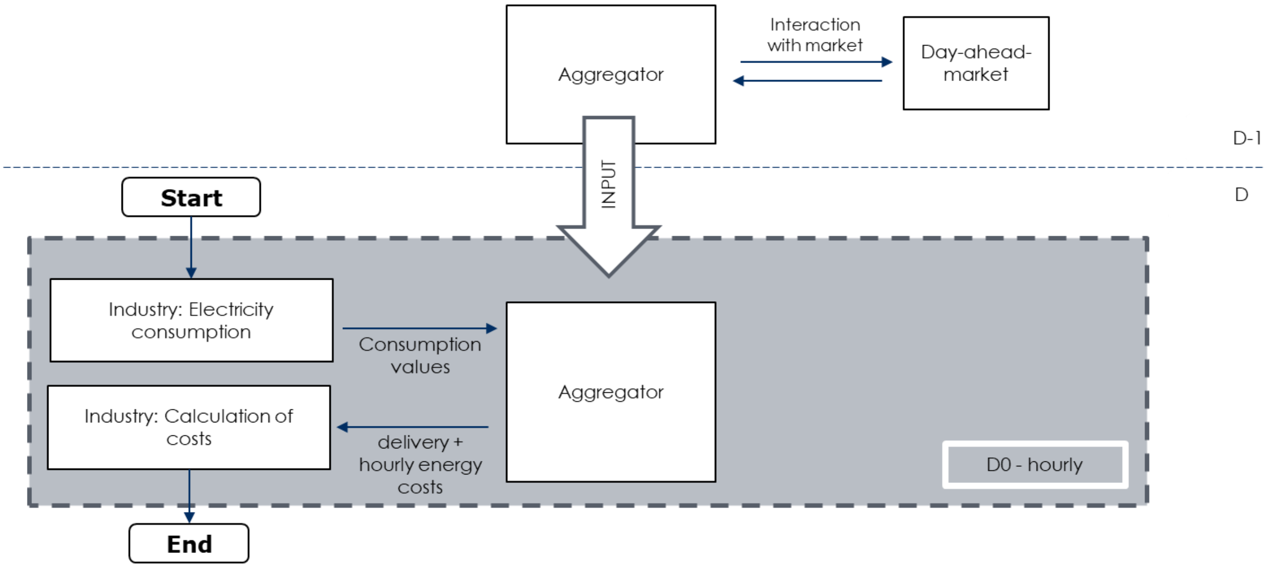


Figure 28 UC1: Flow-chart showing sequence of the reference Use Case

6.3 UC2 Spot market (Market UC)

6.3.1 UC2a Day-Ahead Spot market

This Use-Case showcases the advantages of using increased flexibility to optimize energy production/consumption in the conventional electricity markets. The Day-Ahead spot market allows consumers to purchase electricity for the following day. In general, prices for electricity can vary substantially from hour to hour. In this scenario, the flexibility is used to shift load from high-price to low-price timeslots. When the consumer/industry unit can provide optimized schedules, to which it is committed to a certain extent, the aggregator has an enhanced forecast quality and is able to reduce costs when trading at the markets. The avoided costs can be partly passed on to the consumer. An optimization algorithm will be developed in the project for the corresponding industry units in order to create suitable Day-Ahead-schedules, which will be exchanged with the aggregator (see Figure 29), who is then interacting with the market. The aggregator is also responsible to forward all necessary information of the market result (which is already available at D-1 in the afternoon), so that the industry unit is able to adapt their schedules accordingly.

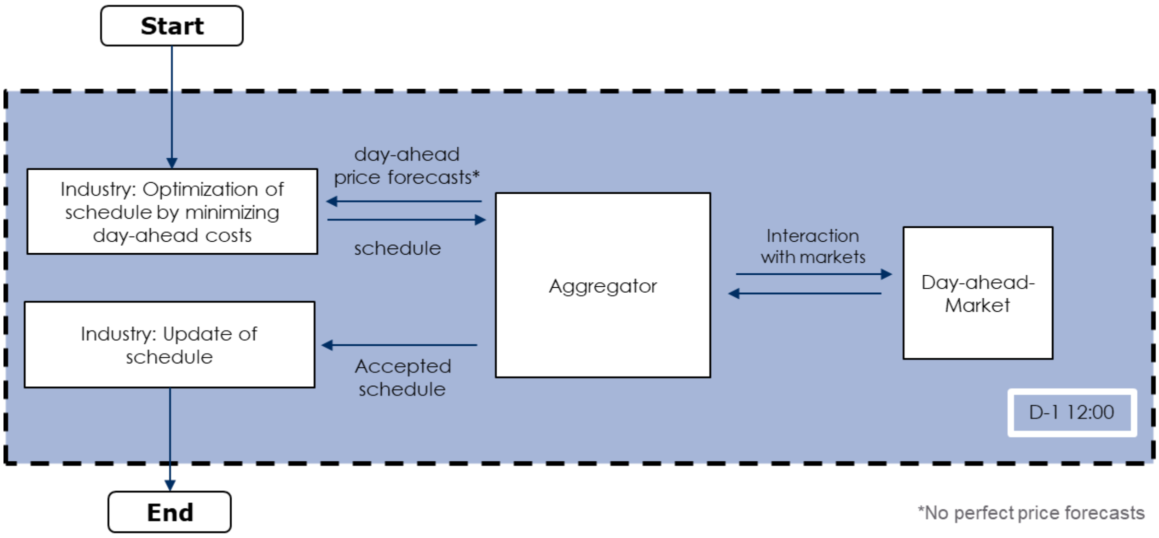


Figure 29 UC2a: Flow-chart showing Day-Ahead Use Case

6.3.2 UC2b Day-Ahead and Intraday spot market

In Use Case 2b, the available flexibility is not only used to trade at the Day-Ahead-market, but also on the intraday-market, where the participation is possible until shortly before product delivery. The participation in the intraday-market is for the industry unit very similar to the participation at the Day-Ahead market, with the exception, that the already traded electricity amounts have to be considered within each new optimization process and calculations have to take place with a higher frequency during the day. The markets are different, as the intraday market has a pay-as-bid scheme, while at the Day-Ahead-market settles in marginal pricing. The fundamental scheme of interaction between stakeholders is very similar to UC2a, as can be seen in Figure 30. However, it is still open whether the process regarding the ID-price-forecasts starts on the side of the aggregator or on the side of the industry. The iteration takes time which means that ID-price-forecasts might be outdated when transferred back from the aggregator to the industry. Another option would be to submit bids from the industry to the aggregator, who seeks – depending on market liquidity – to place corresponding orders on the ID market.

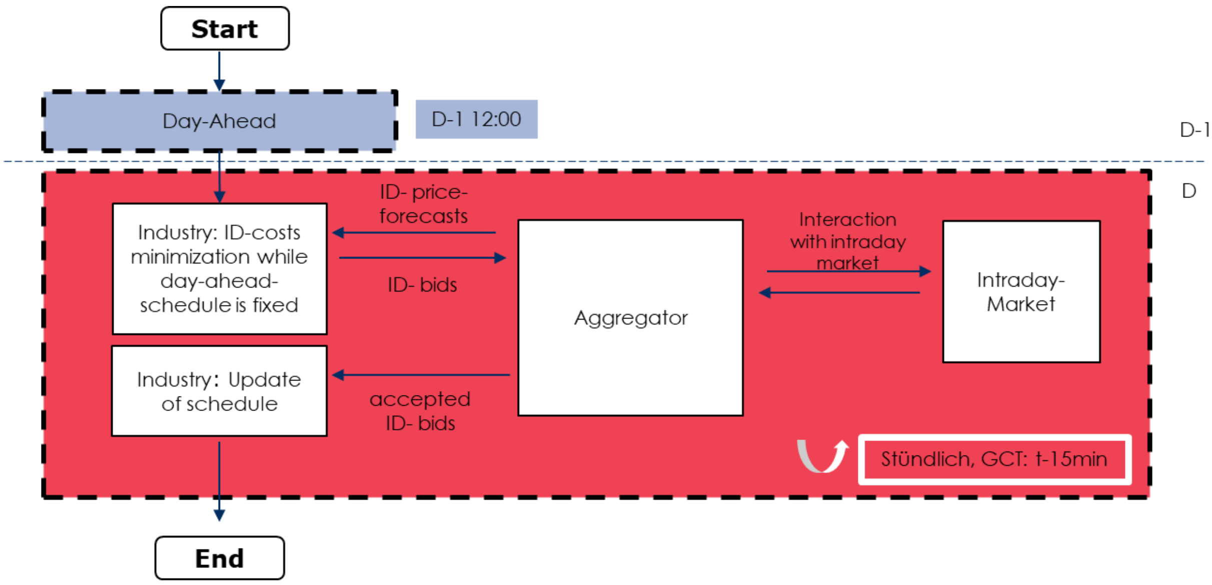


Figure 30 UC2b: Flow-chart showing Day-Ahead + Intraday Use Case

6.4 UC3 Spot & balancing market (Market UC)

UC3 combines the spot markets from UC2 with the aFRR balancing market. The aFRR balancing market consists of the balancing capacity market which takes place in the Day-Ahead timeframe and the intraday rolling balancing energy market. A plant gets remunerated for reserving capacities (Balancing capacity market) and in case of activation for the delivered amounts of energy. With this new, split scheme, it is also possible to only participate in the balancing energy market, which enables renewables and not perfectly plannable producers/consumers to also provide balancing energy. The optimization tool, which will be developed in the course of the project for planning consumption schedules for the industry unit, has to consider the balancing bids, which have to be able to be fully activated in case of an activation. This bid information is given to the aggregator which uses them to trade on the market and forwards the market results to the industry unit operator. As for Day-Ahead and intraday spotmarket, the events for the participation of stakeholders in the balancing capacity market and balancing energy market are very similar to each other (compare Figure 31 and Figure 32).

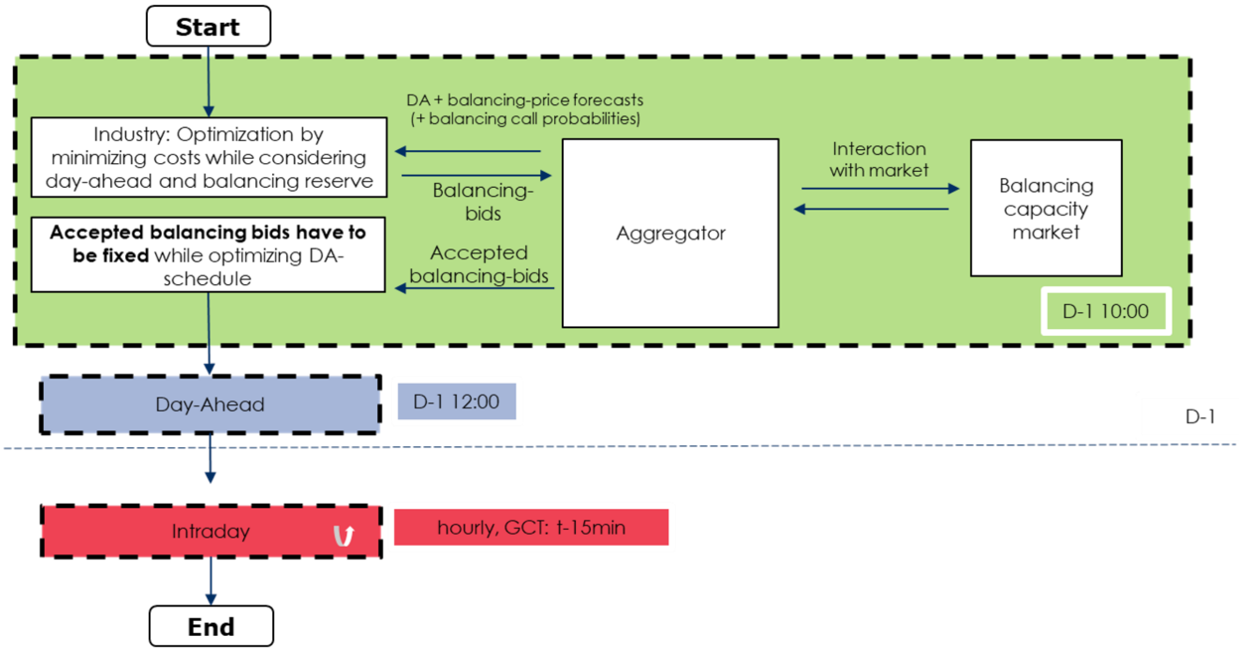


Figure 31 UC3a (1/2): Flow-chart showing balancing capacity trading

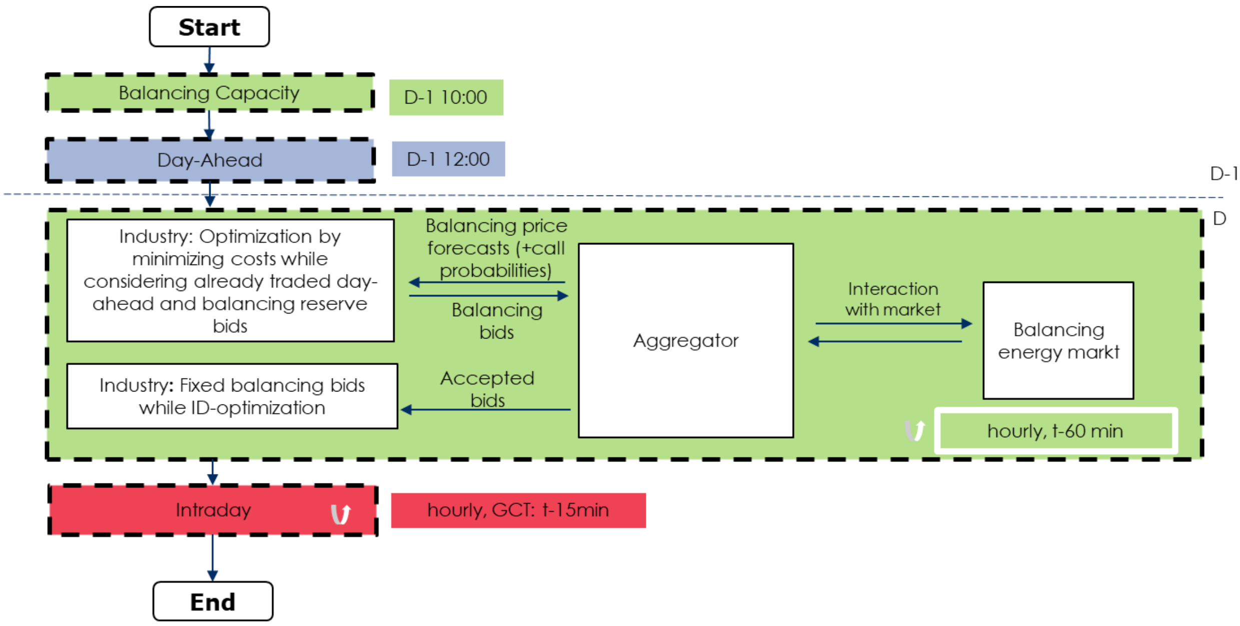


Figure 32 UC3a (2/2): Flow-chart showing balancing energy trading

6.5 UC4 TSO Redispatch

In UC4 the previous use-cases 2 and 3 are extended by the provision of redispatch. In UC4, the flexibility is used to participate in the Day-Ahead market as well as to provide redispatch bids to a redispatch platform where bids can be accessed by the TSO.

6.5.1 UC4a TSO services + participation in spot markets

In this UC, electricity is, similar to UC2a first procured on the Day-Ahead spot market, which results in a preliminary schedule for the entire next day. Compared to the Spot market UC2a, the industrial consumer now also calculates an upward/and downward shift potential (active power) and the respective costs for each timestep in order to offer them for redispatch. The bids are sent to an aggregator/FSP, who is aggregating them to larger bids depending on their geographical location and are further provided to the redispatch platform. The description of bid criteria are part of deliverable 3.3. The TSO may now select any number of bids based on grid needs and the price and location of redispatch bids offered by the flexibility providers as well as conventional power plants. If redispatch bids are selected by the TSO the energy is bought/sold to the EPM balancing responsible party (BRP) and all schedules need to be updated accordingly. This means that the flexiblity provider has to update its generation/consumption schedule and both TSO and flexibility provider have to update their commercial schedules between BRPs. Unlike the flexibility use for balancing energy no separate activation signal is needed.

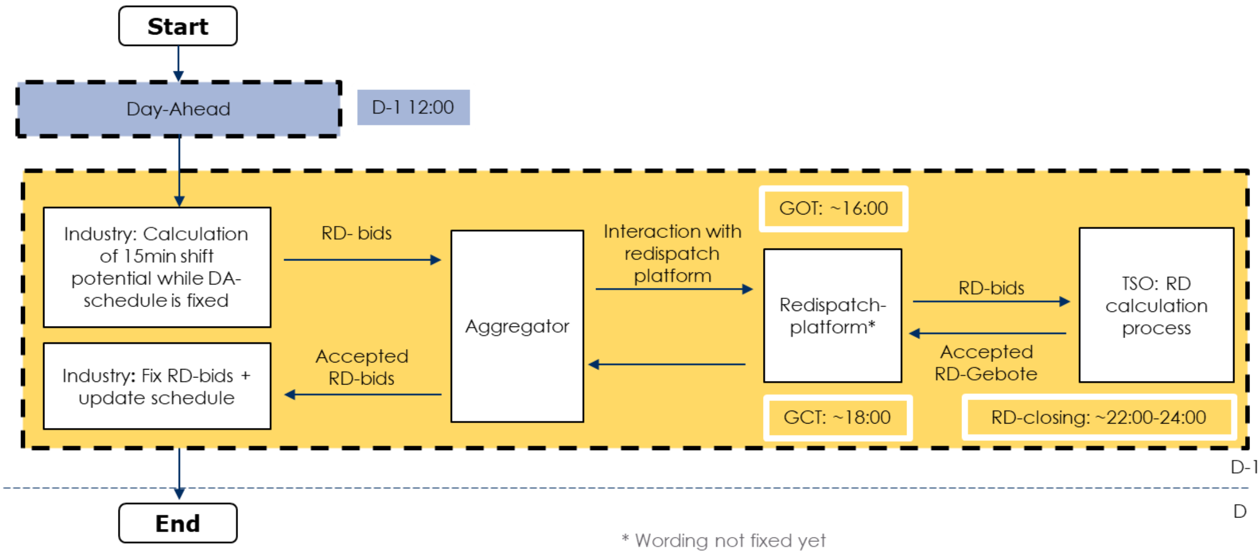


Figure 33 UC4a: Flow-chart showing TSO capacity management

6.5.2 UC4b TSO services + participation in spot markets and balancing markets

UC4b combines the above-mentioned use Cases 2a through 4a. The upward/downward shift potential can now be either used for balancing or redispatch, depending on the markets which the flexible unit is prequalified for. Before the start of the Day Ahead Market the flexibility providers decides which part of capacity to use for bids in the balancing capacity market. After the balancing capacity is allocated the flexibility participates in the day a head market while observing any constraints by balancing capacity provision. Redispatch bids, as per UC4a are created and provided to the TSO. In the course of the day, the industrial consumer with flexibility may decide to participate in the balancing energy market and in the intraday market and update its schedule and flexibility bids, provided that updates are only made in hours where no redispatch bids have yet been selected by the TSO. Redispatch is used used to target congestions in specific locations of the grid and therefore the efficiency of redispatch measures depends on reliable energy delivery by the flexibility. This requires a set of constraints between intrady markets, redispatch and balancing markets is observed. This set of constraints is also showcased in Figure 34.

1) For timesteps during which balancing capacity was allocated redispatch may not be offered in the opposite direction, as a later activation of said balancing capacity would counteract redispatch measures

2) In line with 1) after redispatch bids have been accepted and schedules adapted, flexibilities shall not offer balancing energy bids in the opposite direction of previously accepted redispatch bids in order to not counteract the redispatch measures

3) While participating in the intraday market, intraday trade shall also not be used to counteract redispatch measures and the requirements on anticipatory and catch-up effects described in deliverable 3.3. must be observed

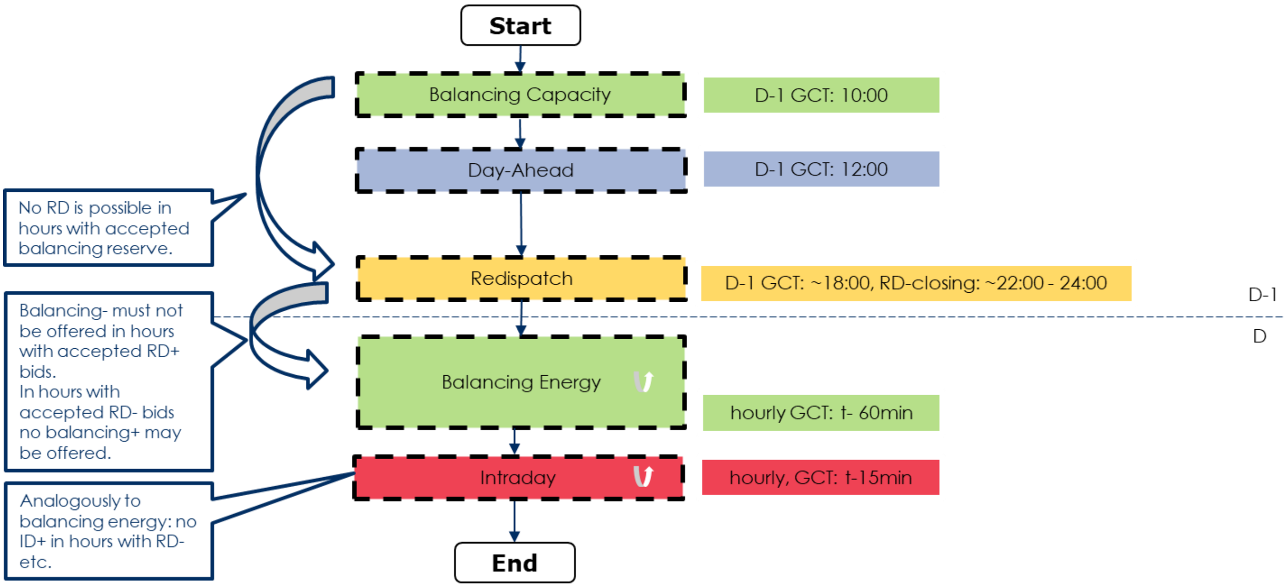


Figure 34 UC4b: Flow-chart showing TSO Redispatch combined with balancing capacity marekts, intraday market and balancing energy market.

6.6 UC5 DSO Redispatch

UC5 includes a redispatch platform similar to UC4a. However, this Use-Case is applicable to grid congestion management at DSO level. The aggregator is sending the schedules of the relevant plants to the Balancing Responsible Party, which is forwarding them to the DSOs. Based on that information and with information from the TSO, the DSO is able to calculate free capacities and redispatch needs. These are sent to the redispatch platform, which is filtering all bids and offerings such that the remaining bids are feasible for the DSOs. The DSOs are selecting the bids (the order in which the DSOs are allowed to choose will be defined in subsequent tasks) and sending a query to the platform, which is forwarded to the aggregator and then to the industrial unit. DSOs detect a majority of congestions and grid problems rather short-term during the day of delivery, therefore a possibility for intraday redispatch requests has to be available as well, as can be seen in Figure 35.

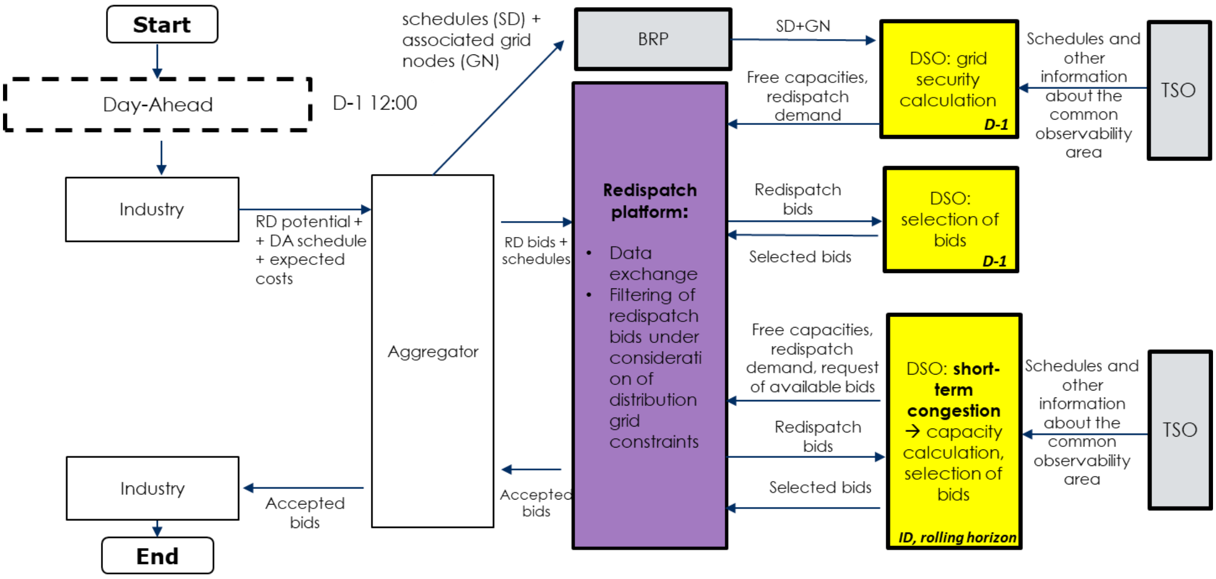


Figure 35 UC5 Flow-chart showing DSO capacity management with intraday timeframe

6.7 UC6 TSO-DSO Joint capacity management

UC6 again only considers the Day-Ahead timeframe. The redispatch bids on the platform are now available for DSOs as well as for the TSO. In order to enable the use the use of flexibility bids by both TSO and DSOs without causing n-0 or n-1 violations in the respective other TSO/DSOs grids a means to manage available transmission capacity is necessary. To facilitate this capacity calculation within the TSO and DSOs, grid(s) data is exchanged between DSOs and TSO. Further details on timings for this data exchange will be included in deliverable 3.3. The redispatch platform has to consider the capacities of all DSOs and the TSO when applying the redispatch bid filter, which combines the information on bid availability sent by the flexibility providers with the information about grid restrictions in system operator's grids, sent by TSO/DSOs. As a result only bids which do not exceed grid capacities can be selected. There will be two different Sub-UC, in UC 6a the System Operators are only providing network restrictions to the redispatch platform and the platform uses those bids to filter out any bids causing n-1/n-0 violations, TSO/DSOs subsequently choose the bids required for redispatch by themselves, in UC 6b the ideal selection of bids is not performed individually but also done by the platform.

6.7.1 UC6a DSO-TSO decentralized

Each grid operator is performing an individual capacity calculation (in their own supply areas). The data to be exchanged is grid congestions and capacities in the individual DSO supply areas and availability of flexibilities sent by the providers of flexiblity. The redispatch platform serves mainly as a data exchange platform with the additional feature to filter out bids according to restricted grid capacity by TSO/DSOs. Working out the details on how grid capacity information is to be exchanged is part of Work Package 5. The platform also contains a mechanism for the coordination of redispatch bid selection between TSO and DSOs (the details are still to be defined in subsequent tasks).

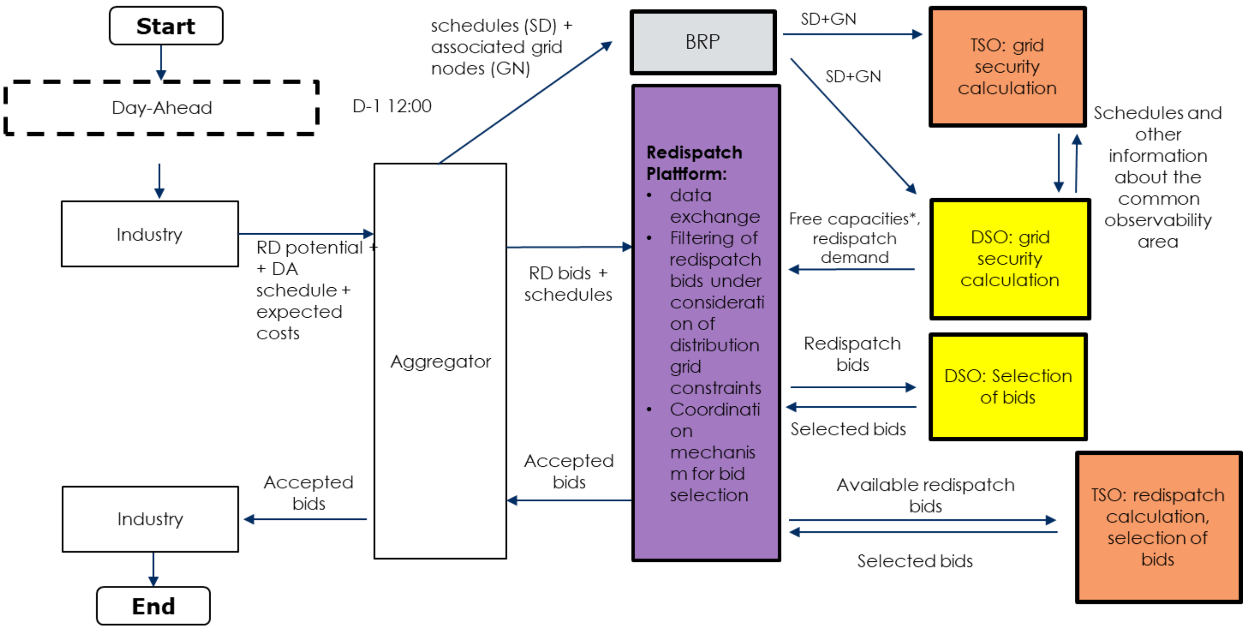


Figure 36 UC6a Flowchart showing decentralized TSO-DSO joint capacity management

6.7.2 UC6b DSO-TSO centralized

In addition to the functions in 6a, in UC6b the platform also takes over the selection of the most useful and favourable bids for the overall system. This means that a combined redispatch optimisation for TSO and DSO needs is performed. For this task, simplified grid models, representing redispatch needs, and results of capacity calculations from the DSOs/TSO have to be provided to the platform. The platform informs the grid operators of the selected bids .The grid operators then have to accept or decline the selection. (Declining the selection results in a fallback to UC6a). Afterwards, the information about the selected bids is forwarded to the aggregator and finally the bids are activated by the industry unit. (see Figure 37)

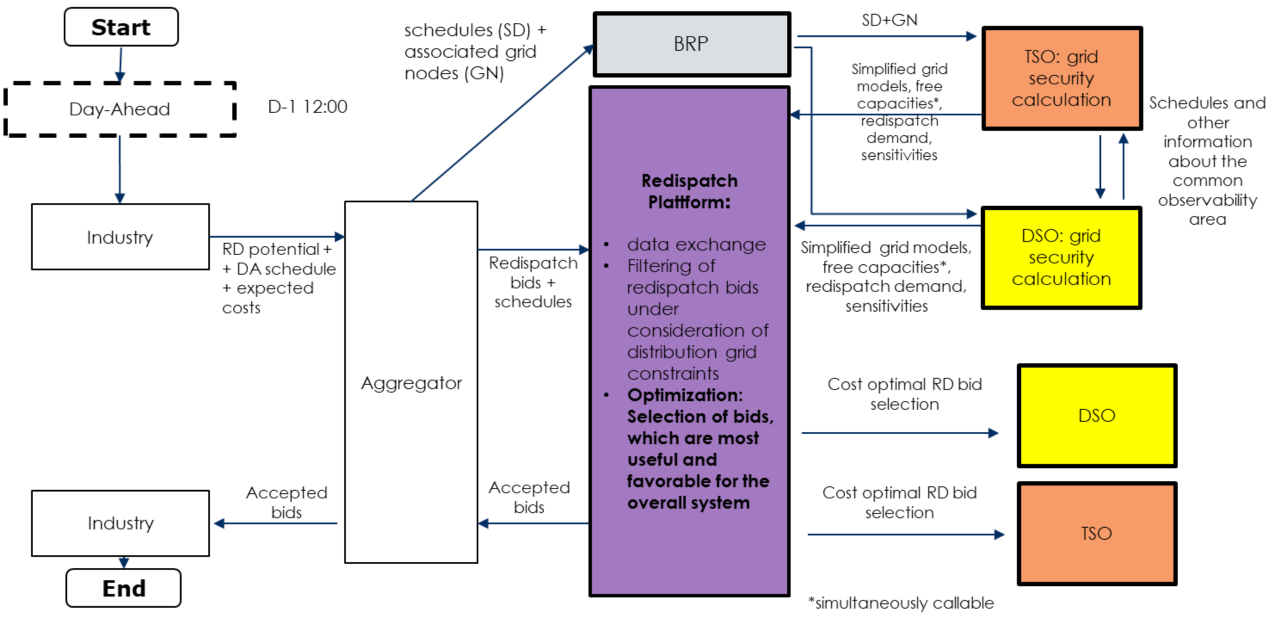


Figure 37 UC6b Flowchart showing centralized TSO-DSO joint capacity management

7 High-level project KPIs

The term key performance indicator (KPI) is used to describe general key metrics that relate to the success, performance or utilization of a company, an industry or a project. Good key performance indicators are aligned as precisely as possible with the goals and requirements of a project. They match the critical success factors and therefore, are always very specific. In general, KPIs are used to evaluate how successful certain activities are in relation to the target of a set of KPIs, such that all relevant processes for the project can be monitored and subsequently be analyzed using these key performance indicators. In the context of the project, the indicators are used to validate the implementations, and through consistent monitoring, processes and measures can be adjusted and optimized accordingly. Furthermore, the indicators are used to analyse the performance, impact and transferability of the developed solutions. KPIs can be used to evaluate which actions are successful and where there is potential for optimization and cost savings. Which key figures are suitable as key performance indicators depends on the area in question.

For detection of the impact, it is essential to determine what data can be aggregated from the project monitoring with direct effect. This is called the micro level in the project. Additionally, descriptive variables will be collected and used for explanatory reasons. On the project level, the data from the micro level will be summarized and/or upscaled to get results on the impact of the project. The macro level is based on the overarching NEFI project where the outcomes of the individual projects, like I4RD, are collected and displayed in total numbers. An outline of the different levels is given in Figure 38.

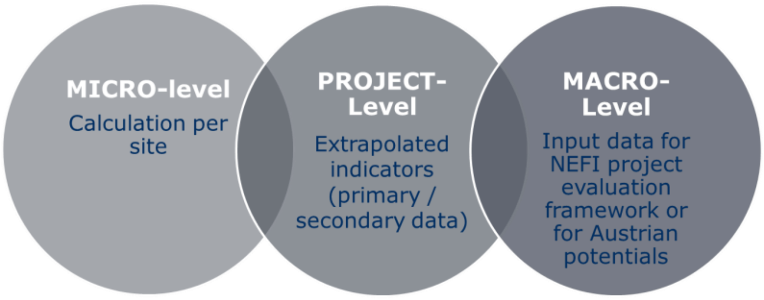


Figure 38 Levels of evaluation

There are different types of data collection that are used in order to calculate the selected indicators such as TSO estimation, surveys, demos, network simulations, industry simulations, general simulations or a combination of the above. After data collection, the next step is to specifically calculate the different indicators. Many indicators are measurable and can be determined, for example, with analysis tools, through a formula or a definition. An overview of the process of how the indicators are evaluated is given in Figure 39.

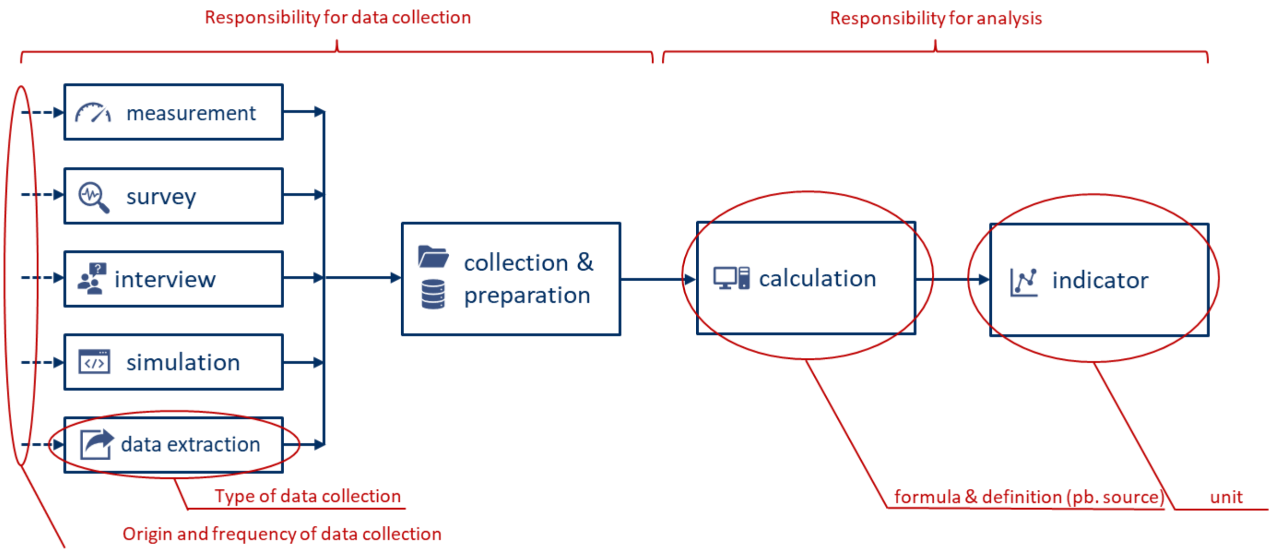


Figure 39 Structure of the KPIs

Relation of KPIs to the goals of the project

As already mentioned, it is important that performance indicators are aligned as precisely as possible with the goals and requirements of an area. Therefore, it is important to stress the connection between project goals and the defined indicators.

There are two categories of objectives in the project. First, goals concerning the flagship energy region and second, overarching goals concerning the vision of New Energy For Industry projects. These goals are summarized in Table 10.

Table 10 Overarching Goals

VORZEIGEREGION ENERGIE	NEFI NEW ENERGY FOR INDUSTRY
Technology development - development of local energy and energy-related transport technologies.	**Decarbonization of the industrial energy system**
Market development - Strengthening and development of a leading role of the Austrian market for energy and energy-related transport technologies	**Value creation through technologies 'Made in Austria'**
Acceptance - Involvement and active participation of users	**Securing production sites and jobs through user involvement**

Specific objectives relevant for the definition of the indicators are:

1. Determine the **flexibility potential for the industry** to provide redispatch in Austria based on the results from detailed simulations of at least 4 industrial sites.
2. Identify the requirements and incentives that can be created in order to enable redispatch service provision considering the **interaction with the wholesale and balancing markets**. Based on the results, define and evaluate at least 2 incentive models for redispatch taking into account the regulatory barriers and **the acceptance of industrial customers**.

3. Analyze at least 2 methods to address constraints in either TSO or DSO grid between TSO-DSO in detail in order to account for **network constraints on the distribution and transmission grid levels** and enable a more efficient joint system operation in alignment with the stakeholder group "Vertical Market Integration".
4. Develop and define related approaches, processes and tools for DSOs in order to enable operational planning for flexibility aggregation and utilization and test them at least for 1 DSO in the demonstration. Analyze the **impact on costs for at least 2 DSOs**.
5. Assess the **costs and benefits** for the relevant stakeholder groups in the project, based on results from the simulation, proof-of-concept, and analysis of interaction with electricity markets and scalability analyses for the distribution grids.

Methodology

In the project, the process of determining, calculating and working with relevant KPIs is the following:

1. The goals for a specific area have to be known and named.
2. The key figures that make it visible whether goal X has been achieved have to be defined.
3. The way of how the data for the corresponding key figures are measured has to be defined.
4. The actual values for these key figures from this data have to be calculated.
5. The relevance of the key figure has to be checked on a regular basis to determine, whether the key figure is still needed for planning and controlling the area of responsibility. If not, it is replaced.

The procedure used to create the preliminary final list of indicators for the I4RD project is shown in Figure 40. As a first step, a first draft was develped with the goal to define a common starting point. Then, this draft was used to get feedback from the project partners, which was subsequently included into the list. The resulting list of indicators was then discussed with the partners and further processed interactively. After another feedback loop the list of indicators was finalised.

Figure 40 process of creating a relevant indicators list

The generated list of indicators is a first list of indicators and it is possible that it will be further edited within the project duration. This list of indicators will result in a list of KPIs over the course of the project. Note, that the scope of the indicators can change in due course of the project.

The performance evaluation includes the assessment of indicators in the following context:

- Industry and Aggregator
- Flexibility in Austria
- DSO
- TSO
- NEFI

The further division of these five main groups into more specific subgroups is shown in Figure 41.

Figure 41 Grouping of KPIs

In order to achieve a clearer design, the following logic is used to create an identification. To start with, the letters are an indicator for the group the KPI belongs to. The first number is used to indicate the respective subgroup (see Table 11) and the second number is used for numbering the KPIs in the respective subgroup.

Table 11 Creation of ID for the KPIs

Number	Group
1	Flexibility
2	Costs and Revenues
3	Impact
4	Technical Restrictions

The visualize which KPIs are relevant for which UCs, the following color code is used:

Table 12 Color Code for visualization of relevance of KPIs for use cases

(dark blue)	output from this UC
(light blue)	no output, either input from other UC or independent of it
(green)	external input for UC

In the following subchapters, the various indicators are presented, broken down according to the already presented stakeholder groups. The structure of the tables in which the defined indicators are presented follows the following logic: The first column presents the ID of the indicator, following the logic presented above. The next six colums present the relevance of the KPIs for the different use cases. Then the title of the indicator, followed by a detailed description of the respective indicator is presented. Afterwards, the unit of the indicator and a possible formula for evaluation is defined and in the last column a first tendency of the stakeholders regarding the relevance of the respective indicator is indicated.

7.1 Industry/ Aggregator

The first group of indicators, focusing on industry and aggregators, deals with the availability of flexibilities. For the potential providers of flexibility it is important to know, how much and at what time flexibility can be offered.

Table 13 Technical indicators for flexibility potential

ID	UC1	UC2	UC3	UC4	UC5	UC6	indicator	description	unit	formula/ type of data collection	relevance
IND.1.1							max pos/neg flex per site	**maximum available positive/negative flexibility aggregated per site (usually sum)**	**[kW $\pm$]**	**survey** **$P_{pos,\ max}$** **$P_{neg,\ max}$**	**high**
IND.1.2							seasonal changes in flex	**Fluctuations that occur in the amount of flexibility provided, due to changing conditions in different seasons.**	**[%]**	**For pos and neg, respectively:** **Average daily positive flex per characteristic day per season / max posositive flex.** $\frac{\frac{\sum P_{pos}}{24}}{P_{pos,max}}$	**medium**
IND.1.3							max pos/neg flexibility per component (technology)	**maximum available positive/negative flexibility per component**	**[kW $\pm$]**	**survey** **$P_{pos,tech,max}$**	**medium**
IND.1.4							max call-off duration for pos/neg flex per comp. at max power	**maximum delivery duration of the maximum power with which positive/negative flexibility can be provided (can go up to unlimited)**	**[h $\pm$]**	**In simulation by presetting the minimum bid size to max flex and formulating the objective function according to 'max energy supply in flex'**	**high**
IND.1.5							h in a year in which redispatch (pos/neg flex)	**Total number of hours in a year in which positive/negative flexibility is offered per Component**	**[h $\pm$/year]**	Sum over all representative periods (i) of (Weight of the representative period (ω_i) * Sum of the time steps (t) in which the binary variable for pos.b_+	**high**

							is offered per comp.			/neg Flex >0 (i.e. one) multiplied by the time step length $\Delta\tau$) $\Sigma_i \left(\omega_i \cdot \Sigma_t (b_+(t) \cdot \Delta\tau)\right)$	
IND.1.6							max offered redispatch (pos/neg flex) per year per component	**maximum amount of energy that is offered for redispatch (positive/negative flexiliblity) per year**	**[kWh ±/year]**	Sum over all representative periods (i) of (Weight of representative period (ω_i)* sum of pos. (p_+) /neg flex multiplied by time step length $\Delta\tau$) $\Sigma_i \left(\omega_i \cdot \Sigma_t (p_+(p) \cdot \Delta\tau)\right)$	**medium**
IND.1.7							average energy for compensation effects per pos/neg flex supply	**In case of compensation effects (or rebound effects) for positive/negative Flex., this KPI becomes >0 and also provides information about the amount of energy that can be flexibilized**	**[kWh ±]**	From simulation: Sum over all representative periods (i) (weight of representative period (ω_i) * (sum catch-up effect per day/ number of RD provision offers n_{RD}) $\frac{\Sigma_i \left(\omega_i \cdot \Sigma_t (e_+(t) + e_-(t))\right)}{n_{RD}}$	**high**

The indicators in Table 14 have been defined to provide a solid basis of decision-making for the various industries to decide whether flexibility provision (e.g. participation in redispatch) is an option to consider.

Table 14 Economic indicators for potential flexibility provision

ID	**UC1**	**UC2**	**UC3**	**UC4**	**UC5**	**UC6**	**indicator**	**description**	**unit**	**formula/ type of data collection**	**relevance**
IND.2.1							total revenues/ energy costs per use case 2-4	**Total profit (energy costs) that can be generated annually under the conditions of the respective case study.**	**[€/year/site]**	Energy costs are summarized In simulation coupled with network simulation:	**high**

										revenues: sum over one year offered quantity*price r*call c (0 or 1) $\Sigma_i \Big(\omega_i \cdot \Sigma_t \Big(r(t) \cdot c(t) \cdot \big(e_+(t) + e_-(t)\big)\Big)\Big)$	
IND.2.2							cost reduction/ additional income per use case 2-4	**Costs or additional revenues that can be reduced or generated under the conditions of the respective case study.**	**[€/year/site]**	**same principle as indicator above**	**high**
IND.2.3							investment costs for flexibilization depending on use case 2-4	**Investment costs to be incurred for the flexibilization measures in the respective case study.**	**[€]**	**survey**	**high**
IND.2.4							additional OPEX for flexibilization	**costs such as personnel costs, ...**	**[€/year]**	**sum over representative days- flex calls * operating costs** **type and amount of operating costs for different components: from surveys**	**high**
IND.2.5							additional redispatch costs for aggregator	**Additional costs e.g. for additional ICT, personnel, ...**	**[€/year]**	**survey**	**medium**

In order to fully evaluate the additional costs per site, deviations from legal requirements resulting from RD (emission limit, missed efficiency targets) are sometimes decisive. Therefore, the evaluation of the following indicators is essential:

Table 15 Inidcators related to the environment

ID	UC1	UC2	UC3	UC4	UC5	UC6	indicator	description	unit	formula/ type of data collection	relevance

IND.3.1							change of efficiency from provision of redispatch	**It is possible that due to the provision of redispatch efficiencies change. This aspect is captured within this indicator.**	[%]	**Comparison of the following:** **1) Sum over repr. Days weight*(E_{demand}(process)/ $E_{purchase}$) without RD provision** **2) As 1) but for RD provision**	**medium**
IND.3.2							change of emissions from provision of redispatch	**Change in emissions generated by redispatch provision compared to the reference case.**	[%/year]	**As above but instead of E_{demand}/ $E_{purchase}$ here Emission factor*$E_{purchase}$**	**medium**

7.2 Flexibility in Austria

In the category 'Flexibility in Austria' the goal was to summarize the overall amount of energy that can be provided for flexibility by the different industry sectors aiming at making more precise predictions regarding suitability for redispatch deployment of the various components and technologies. The following indicators will be used for the assessment of flexibilities:

Table 16 Indicators related to flexibility

ID	UC1	UC2	UC3	UC4	UC5	UC6	indicator	description	unit	formula/ type of data collection	relevance
FLEX.1.1							total supply of redispatch per industry- peak power	**Peak Power provided for flexibility by the individual industrial sectors.**	**[MW]**	**survey** $\sum_{i=1}^{n} \begin{matrix} peak\ performance \\ provided\ for\ redispatch(i) \end{matrix}$ $\forall\ industrail\ sectors$ **i = # of TU in industrial sector**	**medium**
FLEX.1.2							total supply of redispatch per industry- energy content	**Total amount of energy provided for flexibility by the individual industrial sectors.**	**[MW]**	**survey** $\sum_{i=1}^{n} \begin{matrix} total\ capacity \\ provided\ for\ redispatch(i) \end{matrix}$ $\forall\ industrail\ sectors$ n = # of TU in industrial sector	**medium**

Another important factor concerning the provision of flexibility are the associated costs. The following indicators will be used to evaluate the impact on revenues and costs:

Table 17 Indicators related to costs

ID	UC1	UC2	UC3	UC4	UC5	UC6	indicator	description	unit	formula/ type of data collection	relevance
FLEX.2.1							Average cost per technology per bid/request per hour per MW	**Costs for a flexibility call, dependent on technology and the incentive model**	**[€/MWh]**	**survey**	**medium**
FLEX.2.2							Average cost per industry per hour per MW	**Costs for a flexibility call, dependent on industrial sector and the incentive model**	**[€/MWh]**	**survey**	**medium**

7.3 Transmission System Operator

The relevant indicators from the TSO perspective are mainly related to the actual retrieval of redispatch. For the TSO it is important to know how often, how much and for how long redispatch is used to relieve the grid, in order to be able to define adequate length of required bids and an optimal catch-up curve. Another goal is to monitore an increase in redispatch efficiency through integration of industry and, especially with regard to the goals of the project, to monitore the costs that can be saved by integrating industries in the redispatch provision. The indicators classified as relevant are summarized in Table 18.

Table 18 Relevant indicators for the TSO

ID	UC1	UC2	UC3	UC4	UC5	UC6	indicator	description	unit	formula/ type of data collection	relevance
TSO.1.1							Number of hours on which redispatch was activated	**Total number of hours in a year in which flexibility is activated**	**[h]**	**estimation TSO** $\sum_{i=1}^{8760} 1_A(i)$ $A = \{i: amount\ of\ redispatch\ \neq\ 0\}$	**medium**
TSO.1.2							Total amount of energy	**Total amount of energy required**	**[MWh/year]**	**estimation TSO**	**high**

					activated for redispatch by industry per hour per year	**annually for activation of flexibility by the industry**		$\sum_{i=1}^{8760} amount\ of\ redispatch\ provided\ by\ industry$	
TSO.1.3					Typical duration of congestion	**Average time interval a congestion lasts.**	**[h]**	**estimation TSO** $\frac{1}{n}\sum_{i=1}^{n} duration\ of\ a\ congestion(i)$ n = # congestions per year	**medium**
TSO.2.1 [17]					Cost savings for redispatch with I4RD compared to conventional redispatch	**Redispatch costs that can be saved by integrating industry through the I4RD project.**	**[€]**	**estimation TSO** $cost\ RD\ -\ cost\ I4RD$	**high**
TSO.1.4					Savings of Peak RD demand through I4RD in contrast to redispatch through conventinal power plants	**Reduced Peak RD Power that is needed less compared to conventional units**	**[MW]**	**estimation TSO** *required peak power RD – required peak power I4RD*	**n.a.**
TSO.1.5					Energy amounts of conventional redispatch that can be prevented by	**Energy amounts that can be avoided by integrating**	**[MWh/year]**	**estimation TSO** *amount of energy RD – amount of energy I4RD*	**n.a.**

[17] According to current status not to be published/only project internal KPI

							redispatch with I4RD	**industry through the I4RD project.**			
TSO.1.6							predicted n-1/n-0 violations per year	**amount of predicted events where the overloading of a component cannot be prevented by redundancies – before and after redispatch**	**[#]**	**estimation TSO** *predicted n-1 violations before remedial actions – predicted n-1 violations after remedial actions*	**n.a.**

7.4 Distribution System Operator

Together with the TSO, the DSO has the responsibility of ensuring the long term ablity of the system to meet reasonable demands and integrate more DERs on the DSO side. Therefore, it is assumed to be highly relevant for the DSOs to measure the influence of redispatch on grid stability and supply security.

For the initial evaluation, a so-called reduction factor has been identified and will be further evaluated and developed in WP 5. Its focus is on monitoring technical restrictions which have to be met at all times according to the European standards (EN50160) [70] and other Euopean technical regulations [71].

Table 19 Indicator related to technical restrictions

ID	UC1	UC2	UC3	UC4	UC5	UC6	indicator	description	unit	formula/ type of data collection	relevance
DSO.4.1							compliance with technical restrictions	**This factor is considered to have a value between 0 and 1, where 1 is used to indicate that there are no network restrictions on the distribution network, due to the activation of the flexibility, and therefore no impact on any node within the transmission grid**	**[0,1]**	**simulation in WP 5**	**high**

7.5 NEFI

The last group of indicators were summarized under the term NEFI. The I4RD project will generate valuable knowledge of flexibility solutions and optimisation and these have therefore to be set in context through upscaling. The findings should be seen as benefits and the opportunity to create the baseline for industrial development in the future. It is essential to include this perspective into the monitoring approach to analyse the overall impact of the activities on areas that are directly and indirectly affected by them. The assessment of these indicators includes the following aspects:

- Environmental impacts
- Economic impacts
- Impacts on energy technologies

The indicators summarized in Table 20, Table 21 and Table 22 will be used for the impact assessment:

Table 20 Indicators related to the environment

ID	UC1	UC2	UC3	UC4	UC5	UC6	indicator	description	unit	relevance
NEFI.1							CO2 savings	total carbon emission savings through implementation	[kg/year]	low/medium
NEFI.2							reduction CO2 emissions	relative carbon emission savings through implementation	[%]	low/medium

Table 21 Indicators related to economy

ID	UC1	UC2	UC3	UC4	UC5	UC6	indicator	description	unit	relevance
NEFI.3							cost savings due to redispatch	OPEX savings by redispatch	[€/year]	medium
NEFI.4							return on investment	ratio between the net income and capital employed	[%]	low
NEFI.5							payback period	estimation of the payback period of the developed technology	[year]	low
NEFI.6							additional funds	impact of the project on the provision of funds beyond project funding	[€]	low
NEFI.7							new contacts	number of new business contacts through project participation	[#]	low

NEFI.8							new contracts	**number of new contracts through project participation**	**[#]**	**low**
NEFI.9							job creation	**number of new jobs created through project participation**	**[#]**	**low**

Table 22 Indicators related to energy technologies

ID	**UC1**	**UC2**	**UC3**	**UC4**	**UC5**	**UC6**	**indicator**	**description**	**unit**	**relevance**
NEFI.10							total final energy use	**annual total final energy use in the corporation**	**[MWh/year]**	**low**
NEFI.11							final energy use per carrier	**specific annual final energy use divided by energy carriers**	**[MWh/year]**	**medium**
NEFI.12							on-site energy supply	**on-site energy supply divided by carrier**	**[MWh/year]**	**medium**
NEFI.13							storage capacity	**capacity of on-site storage facilities (if applicable, used for grid services, marekt services or seasonally operated)**	**[MWh]**	**medium**

8 Conclusion

Different marketing options for flexibility of industrial consumers are already available or currently emerging, which have been described in Section 2. The technically ‘easiest-to-implement’ application is to use flexibility by shifting the consumption to periods with low **spot-market prices**. This can be done on the Day-Ahead or Intraday market. Even if the consumption is not shifted, the supplier can profit from advanced predictability of their balancing responsible party, assuming that the industry unit provides consumption forecasts. On the one hand, a rapid increase in renewable generation capacity has decreased market prices over the last few years. In some cases, negative prices on wholesale markets and high volatility on intraday markets could be observed, which indicates a lack of flexibility in the grid. However, it should be noted that since 2020 Q3, a massive increase in wholesale electricity prices can be observed. This can be linked to higher natural gas and emission allowance prices combined with recovering demand after the low of the COVID-pandemic and less renewable production caused by an unfavourable climate/weather-situation.

Balancing markets provide an alternative marketing opportunity for flexibility. There are three different options (FCR, aFRR, mFRR), which mainly differ in their technical requirements for activation and their product design (symmetric/asymmetric, product length). As of 1.12.2020, the preconditions have been changed in favour of renewable producers, the participation in the balancing energy market (GCT at the moment is 1 hour before delivery) is now possible without prior participation in the balancing capacity market, which takes place day-ahead. The **imbalance settlement regime** is important to consider when for example catch-up effects[18] change the schedule of the balancing responsible parties.

The frequent occurrence of congestions in Austria is linked to a high level of interconnection and a growing share of RES. It can be observed that redispatch costs rose dramatically in the past years. At the moment, individual generation units or loads are contracted by the TSO in Austria. **Redispatch**, therefore, is not a market per se, but the plants are remunerated according to their real costs. In the future, the redispatch procurement should be extended to include flexibilities from industrial consumers and the DSOs will, therefore, play an increasingly important role, as supported by the Clean Energy Package as well. In Germany, producers above 100kW are obliged to provide information about redispatch capacities alongside their planned schedule, while in other countries there are more market-like concepts available, such as the platform GOPACS where spot-market bids are used to solve congestions. Furthermore, other projects have been reviewed in the course of the project to gain more information and consolidate various state-of-the-art concepts in order to be used as a basis for the developments in ID4R.

What can be noticed is that the planning, operation and managing of small units for congestion management via central platforms is still a challenging process. This can be shown by the fact that only two weeks before the official start date on October 1, the industry association BDEW had admitted that a punctual start of Redispatch 2.0 was impossible. Insufficient data had been exchanged for one of the largest digitization projects in the German energy market - hundreds of thousands of solar and

[18] Catch-up effects can occur, when consumption is shifted in time, for instance due to the use of storages. The possibly simultaneous occurence of storage recharging after balancing activations could cause problems within the grid due to possible consumption peaks. Furthermore, if these schedule changes are not forwarded to the supplier, unexpected imbalances can be caused.

wind plants and CHP plants above 100 kW are affected.[19] Moreover, the partcipation on demand side flexibility is currently not included in Redispatch 2.0.

Within the ID4R project, different **Use Cases** have been developed in order to compare the different flexibility applications and to develop a concept for a platform for redispatch provision. UC1 serves as a reference Use Case and should represent the status-quo for the considered industry units. UC2 and UC3 focus on the existing markets and are relevant for industry plant operators due to the possible savings or revenue when participating on these markets, as well as for grid operators due to the improved predictability of network powers flows, provided that schedules are available. UC2 shows the costs/revenues for participation in spot markets and UC3 in spot-and balancing markets. The other Use Cases focus on the system operators, which can use flexibility for congestion management. Within these Use Cases, industry units can benefit from revenues as well, but the concept of incentives and requirements for bids will have to be investigated in more detail. UC4 develops a concept for redispatch procurement for the TSO, UC5 for the DSOs, and UC6 investigates a TSO-DSO coordinated concept for redispatch provision via a platform, which is either responsible to provide bids to the DSOs/TSO depending on the grid restrictions of other DSOs (Filter is applied, UC6a) or to perform a centralized optimization for the cost-optimal selection of redispatch bids (UC6b). The most relevant Use Cases for the project will be Use Cases 4a and 6a. Use-case 4a builds the link between current TSO redispatch and future redispatch with industrial units. It is also vital to the definition of redispatch requirements in deliverable 3.3. UC6a is especially important due to the TSO-DSO interaction, while for industry and their revenues, UC4a will play an important role. All Use Cases are described in detail in the Annex. Relevant KPIs for the analysis of the project results have been developed and described. The Use Cases will be partly simulated and partly implemented within field demonstrations.

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I. UC1: Reference Use Case

Disclaimer: This use case template follows the IEC 62559-2 standard.

i. Description of the use case

a. Name of the use case

ID	*Main purpose*	*Name of Use Case*
01	Reference	Reference Use Case

b. Version management

Version Management			
Version No.	*Date*	*Name of Author(s)*	*Changes*
1	27.10.2021	Sophie Knöttner	First Version of Template
2	30.10.2021	Sophie Knöttner	Figure input and description of workflow, insert into deliverable
3	28.03.2022	All	Final and by partners reviewed Version

c. Scope and objectives of use case

Scope and Objectives of Use Case	
Scope	This is a hypothetical UC to derive a comparison benchmark (total costs) for a conventional (historical) operation and thus demand profil without valorization of flexiblity. In further, optimization based UCs (2-4) also total costs are derived but in contrast to UC 1 the flexibility of industrial actors is valorized on different markets and plattforms. With this UC a baseline for better comparability shall be ensured. To determine a cost benchmark without the necessity of sharing energy supply contract details between industrial consumers and energy supply companies / aggregators in this UC historical consumption profiles are assumed to be covered with historical DA electricity prices and average fuel prices. Within the calculation workflow only multiplication and summation of time series data is performed.
Objective(s)	Derive a cost benchmark for energy demand fulfillment with DA electricity costs without “flexibility valorization” and without detailed information about contract details of industrial consumers and energy supply companies/aggreagtors.
Related use case(s)	The methodology of this UC is not further elaborated but the result (total costs) is used to compare other UCs, where flexibility is valorized.

d. Narrative of use case

Narrative of Use Case
Description

Flexibility Unit Perspective: The energy demand profile for both electricity and fuels has to be fulfilled. **Aggregator Perspective:** The energy demand for all customers is forecasted on the day before the delivery and the corresponding amount is bought on the DA market. It is assumed that this FC covers the actual demand profiles perfectly. Thus, DA energy costs are directly transferred to the industrial units without any further fees or price increases (e.g. caused by costs for imbalance settlement).

e. Key performance indicators (KPI)

Key performance indicators (KPIs)				
ID	***Name***	***Description***	***Unit***	***Calculation form***
IND.2.1	total revenues/ energy costs	Total profit (energy costs) that can be generated annually under the conditions of the respective case study.	For this UC only determination of total energy costs In simulation coupled with network simulation: revenues: sum over one year offered quantity*price r*call c (0 or 1) $\Sigma_i \left(\omega_i \cdot \Sigma_t \left(r(t) \cdot c(t) \cdot \left(e_+(t) + e_-(t)\right)\right)\right)$	[€/year/ site]

f. Use case conditions

Use case conditions
Assumptions
• Fulfillment of historical, mostly not optimized demand profiles • No optimization is performed • Calculation is carried out for one year as multiplication and summation • Industrial consumption has no impact on electricity price in UC • Aggregator forecasts demand of all industrial customers without previous knowledge • Aggregator covers industrial demand 100% on DA electricity demand • Further potential costs for aggregators (e.g. for imbalance settlement) are not covered by payments of the industrial consumer
Prerequisites
• Industrial demand profiles for fuels and electricity • Electricity DA price profiles (provided by aggregator) and fuel prices • Grid costs for five specific industrial sites

ii. Common Terms and Definitions

Common Terms and Definitions	
Term	**Definition**
D-1	Day before delivery
D0	Day of delivery
DA	Day-Ahead
ID	Intraday
FC	Forecast
GOT	Gate opening time
GCT	Gate closure time
RD	Redispatch
UC(s)	Use Case(s)
DSO	Distribution system operator
MRC	Multi-regional coupling

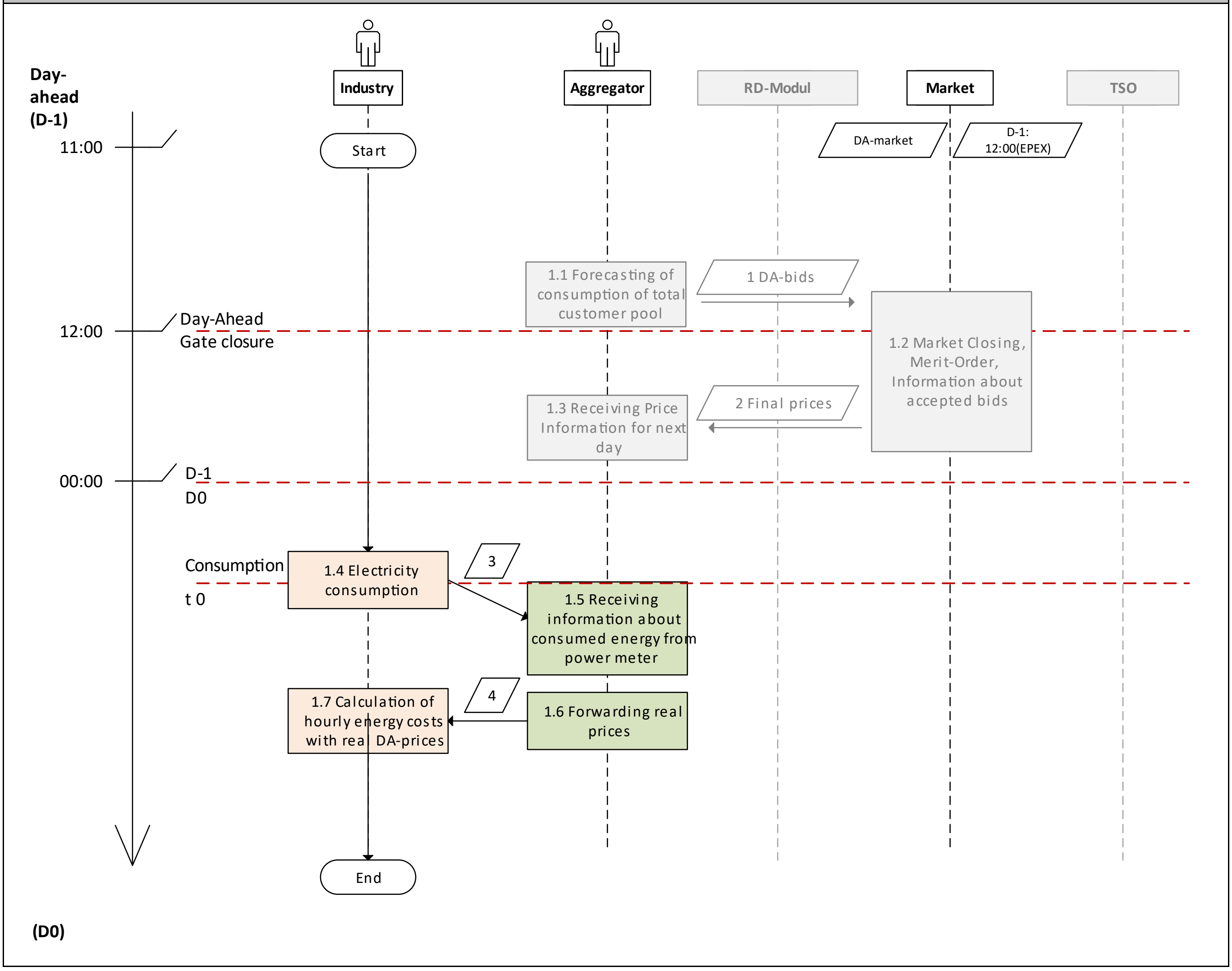
g. Actors

Actors		
Actor Name	***Actor Type***	***Actor Description***
Aggregator	Actor	Organisation offering energy services to the consumer, such as aggregation and pooling of flexibility bids but also in form of electricity delivery contracts.
Day-Ahead Market	Service	The DA market is operated through a blind auction which takes place once a day, all year round. All hours of the following day are traded in this auction. The orders are logged in by the market participants before the order book closes at 12:00. As a result of the order matching, the Power Exchange determines trades which are legally binding agreements to purchase or sell a determined quantity of electricity to a defined delivery area for the matched (or "cleared") price. There is one price, the market clearing price or MCP, that is determined for each delivery period and that applies to all buyers and sellers. The EPEX SPOT DA auction is integrated into the Multi-Regional Coupling (MRC) which encompasses the Baltics, Central Western Europe, Great Britain and the Nordics.
Intraday Market	Service	On the ID market, market participants trade continuously, 24 hours a day, with delivery on the same day. As soon as a buy- and sell-order match,

Actors		
Actor Name	***Actor Type***	***Actor Description***
		the trade is executed. Electricity can be traded up to 5 minutes before delivery and through hourly, half-hourly or quarter-hourly contracts. As this allows for a high level of flexibility, members use the ID market to make last minute adjustments and to balance their positions closer to real time.
Industrial flexibility unit	Actor	An industrial consumption or generation asset in the electrical power grid which has the capability to deviate – to some extent - from its planned schedule in order to provide redispatch. It is preconditioned that the industrial flexibility unit fulfils the necessary requirements for redispatch according to the defined list in task 3.2 and is prequalified for the provision of redispatch.
Industrial flexibility unit operator	Role	Role which links the role customer and its possibility to provide flexibilities to the redispatch provision process by the operated industrial consumption or generation asset.
Aggregator	Actor	Organisation offering energy services to the consumer, such as aggregation and pooling of flexibility bids but also in form of electricity delivery contracts.

h. Sequence diagram of use case

Sequence diagram(s) of use case



i. Step by step analysis of use case

Step No.	Event	Name of process/ activity	Description of process/ activity	Information producer (actor)	Information receiver (actor)	Information Exchanged (IDs)
1.1	Aggregator forecasts industrial energy demand and sends DA amount request	FC of consumption of total consumer pool	To supply the correct amount of electricity the aggregator forecasts the energy demand for its customers on the next day	Aggregator	Market	1
1.2	Market clearing process	Market clearing process	The clearing of the market takes place, and the market sends information back to the Aggregator, whether and at which price (clearing price) the bids have been accepted.	Market	Aggregator	2
1.3	Aggregator receives price information	Receiving price information for next day	Aggregator receives information whether and at which price (clearing price) the bids have been accepted.	Market	Aggregator	2
1.4	Industrial unit consumes energy	Electricity consumption	Energy demand is covered by electricity and further fuels	Industrial power meter	Aggregator	3
1.5	Aggregator receives information about previous consumption	Receiving information about consumed energy	Energy demand is covered by electricity and further fuels. The electricity demand is metered and the aggregator is performed after consumption about the actual amount	Industrial power meter	Aggregator	3

1.6	Aggregator provides DA price profile	Forwarding real prices	Aggregator provides DA fixed price profile after energy is supplied as requested to the industrial consumer	Aggregator	Industrial flexibility unit operator	4
1.7	Calculation of real energy costs	Calculation of hourly energy prices with real DA prices	Industrial unit calculates energy costs	Industrial flexibility unit operator		4

iii. Information exchanged

Information exchanged (ID)	***From***	***To***	***Name of information***	***Description of information exchanged***
1	Agg	Market	DA-Bids	amount and prices the aggregator wants to buy on the DA-markt to fulfill the energy demand for its customer
2	Market	Agg	Final prices	Accepted bids and prices from market clearing
3	Ind	Agg	Metered power consumption	Data collected by meter itself for power consumption
4	Agg	Ind	DA price information	Aggregator delivers actual DA prices

II. UC2A: Day-Ahead Use Case

Disclaimer: This use case template follows the IEC 62559-2 standard.

i. Description of the use case

a. Name of the use case

ID	Main purpose	Name of Use Case
02	Day-Ahead trading	Day-Ahead-Use-Case

b. Version management

Version Management			
Version No.	Date	Name of Author(s)	Changes
1	19.10.21	Regina Hemm	First Version of template
2	29.10.21	Regina Hemm	Final Version of template before review
3	28.03.2022	All	Final and by partners reviewed Version

c. Scope and objectives of use case

Scope and Objectives of Use Case	
Scope	The electricity produced or consumed by the industrial unit is traded on the DA market. The flexibility is used to shift the consumption to periods with low prices or shift the feed-in into the grid to periods with high prices. The schedule for the industrial unit is created using an optimization tool.
Objective(s)	Minimize costs when trading at the DA-spot-market.
Related use case(s)	The DA UC is part of all other UCs (3-6), except the Reference UC. A schedule always has to be calculated before calculating flexibility potentials, which are desired to be offered at balancing markets or for redispatch services. These flexibility bids will be always based on a DA schedule.

d. Narrative of use case

Narrative of Use Case
Description
Flexibility Unit Perspective: The flexibility unit can profit from cheaper energy costs, if an optimized schedule is created DA, for which the consumption is shifted to periods with low prices. The schedule is sent then to the aggregator, to trade the desired amounts at the DA-market. **Aggregator Perspective:** The aggregator profits from advanced planning security, if the schedules are known before, as well as cheaper portfolio costs if the energy consumption of the plants is optimized. **DSO/TSO Perspective:** If the schedules are made available for the TSO/DSO, they also profit from advanced planning security. Yet at the moment and therefore in this UC, TSO/DSOs are only receiving schedules from plants >10MW.

e. Key performance indicators (KPI)

Key performance indicators (KPIs)				
ID	**Name**	**Description**	**Unit**	**Calculation form**
IND.1.1	max pos/neg flex per site	maximum available positive/negative flexibility aggregated per site (usually sum)	[kW ±]	survey $P_{pos,\ max}$ $P_{neg,\ max}$
IND.1.2	seasonal changes in flex	Fluctuations that occur in the amount of flexibility provided, due to changing conditions in different seasons.	[%]	For pos and neg, respectively: Average daily positive flex per characteristic day per season / max posositive flex. $$\frac{\frac{\sum P_{pos}}{24}}{P_{pos,max}}$$
IND.1.3	max pos/neg flexibility per component (technology)	maximum available positive/negative flexibility per component	[kW ±]	survey $P_{pos,tech,max}$
IND.1.4	max call duration for pos/neg flex per comp. at max power	maximum call duration of the maximum power with which positive/negative flexibility can be provided (can go up to unlimited)	[h ±]	In simulation by presetting the minimum bid size to max flex and formulating the objective function according to 'max energy supply in flex'
IND.2.1	total revenues/ energy costs per use case 2-4	Total profit (energy costs) that can be generated annually under the conditions of the respective case study compared to UC1.	[€/year/site]	Energy costs are summarized In simulation coupled with network simulation: revenues: sum over one year offered quantity*price r*call c (0 or 1) $$\Sigma_i\left(\omega_i \cdot \Sigma_t\left(r(t) \cdot c(t) \cdot \left(e_+(t) + e_-(t)\right)\right)\right)$$
IND.2.2	cost reduction/ additional income per use case 2-4	Costs or additional revenues that can be reduced or generated under the conditions of the respective case	[€/year/site]	same principle as indicator above

		study compared to UC1.		
IND.2.3	investment costs for flexibilization depending on use case 2-4	Investment costs to be incurred for the flexibilization measures in the respective case study.	[€]	survey
IND.2.4	additional OPEX for flexibilization	costs such as personnel costs, …	[€/year]	sum over representative days- flex calls * operating costs type and amount of operating costs for different components: from surveys
IND.2.5	additional redispatch costs for aggregator	Additional costs e.g. for additional ICT, personnel, …	[€/year]	survey
IND.3.1	change of efficiency from provision of redispatch	It is possible that due to the provision of redispatch efficiencies change. This aspect is captured within this indicator.	[%]	Comparison of the following: 1) Sum over repr. Days weight*(E_{demand}(process)/ $E_{purchase}$) without RD provision 2) As 1) but for RD provision
IND.3.2	change of emissions from provision of redispatch	Change in emissions generated by redispatch provision compared to the reference case.	[%/year]	As above but instead of E_{demand}/ $E_{purchase}$ here Emission factor*$E_{purchase}$

f. Use case conditions

Use case conditions
Assumptions
• The industrial unit is able to calculate a schedule DA of the planned production/consumption • All applicable grid fees will be considered • It is assumed, that the industrial flexibility unit operator knows the consumption for the next day as a perfect FC. • The optimization tool for industrial units is also capable to reduce the maximum peak power (and therefore grid fees) within the rolling horizon optimization • As a simulation timeframe a representative period with corresponding weights (to scale up to one year) will be chosen for the market and production-situation, covering 5-10 weeks • The simulation is carried out as a rolling horizon optimization
Prerequisites

- DA-price forecasts (provided by aggregator)
- Historic consumption profiles for the simulated timeframes are used as perfect FC
- For demonstration: FC of the planned consumption of the industrial flexibilit units at least for the next day is possible
- Detailed optimization model which considers all physical constraints of the industrial flexibility unit
- Applicable grid fees for each industrial site

ii. Common Terms and Definitions

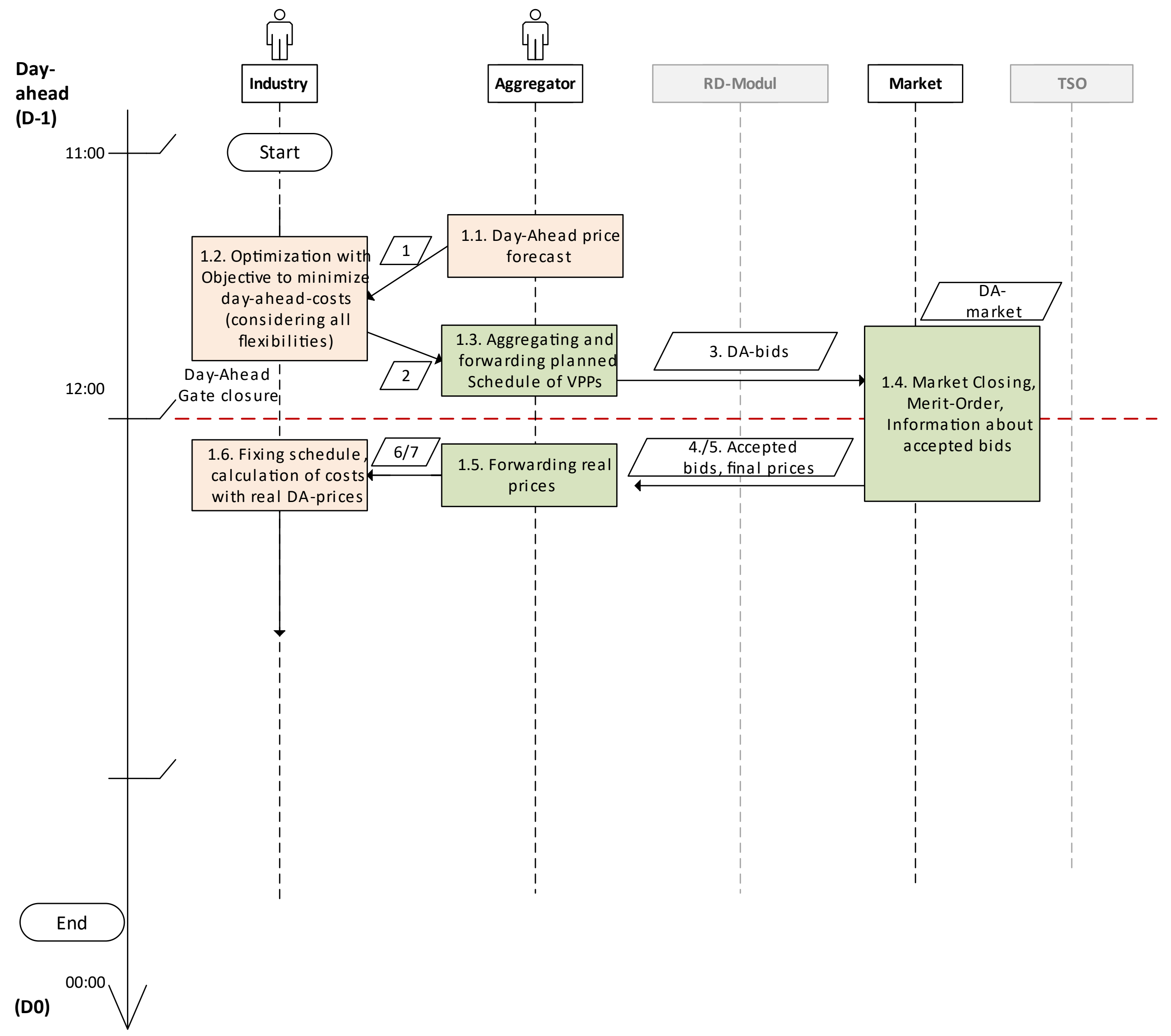
Common Terms and Definitions	
Term	**Definition**
D-1	Day before delivery
D0	Day of delivery
DA	Day-Ahead
FC	Forecast
GOT	Gate opening time
GCT	Gate closure time
RD	Redispatch
UC	Use Case
DSO	Distribution system operator
MRC	Multi-regional coupling

g. Actors

Actors		
Actor Name	***Actor Type***	***Actor Description***
Aggregator	Actor	Organisation offering energy services to the consumer, such as aggregation and pooling of flexibility bids but also in form of electricity delivery contracts.
Day-Ahead Market	Service	The DA market is operated through a blind auction which takes place once a day, all year round. All hours of the following day are traded in this auction. The orders are logged in by the market participants before the order book closes at 12:00. As a result of the order matching, the Power Exchange determines trades which are legally binding agreements to purchase or sell a determined quantity of electricity to a defined

Actors		
Actor Name	**Actor Type**	**Actor Description**
		delivery area for the matched (or "cleared") price. There is one price, the market clearing price or MCP, that is determined for each delivery period and that applies to all buyers and sellers. The EPEX SPOT DA auction is integrated into the Multi-Regional Coupling (MRC) which encompasses the Baltics, Central Western Europe, Great Britain and the Nordics.
Intraday Market	Service	On the ID market, market participants trade continuously, 24 hours a day, with delivery on the same day. As soon as a buy- and sell-order match, the trade is executed. Electricity can be traded up to 5 minutes before delivery and through hourly, half-hourly or quarter-hourly contracts. As this allows for a high level of flexibility, members use the ID market to make last minute adjustments and to balance their positions closer to real time.
Industrial flexibility unit	Actor	An industrial consumption or generation asset in the electrical power grid which has the capability to deviate – to some extent - from its planned schedule in order to provide redispatch. It is preconditioned that the industrial flexibility unit fulfils the necessary requirements for redispatch according to the defined list in task 3.2 and is prequalified for the provision of redispatch.
Industrial flexibility unit operator	Role	Role which links the role customer and its possibility to provide flexibilities to the redispatch provision process by the operated industrial consumption or generation asset.

h. Sequence diagram of use case

Sequence diagram(s) of use case


i. Step by step analysis of use case

Step No.	*Event*	*Name of process/ activity*	*Description of process/ activity*	*Information producer (actor)*	*Information receiver (actor)*	*Information Exchanged (IDs)*
1.1	Aggregator provides forecast data	Aggregator provides forecast data	The aggregator provides all the forecast data that the industrial flexibility unit operator needs for its optimization of the schedule.	Aggregator	Industrial flexibility unit operator	1
1.2.	Industrial flexibility unit operator produces optimization schedule	Optimization of DA-schedule	The industrial flexibility unit operator creates a schedule for the next day by using an optimization tool and forecasts for demand and prices.	Industrial flexibility unit operator	Aggregator	2
1.3.	Aggregator sends request for DA-amounts at markets	DA-trading	The aggregator trades the aggregated Schedules at the DA-market	Aggregator	Market	3
1.4.	Market clearing process	Market clearing process	The clearing of the market takes place, and the market sends information back to the Aggregator, whether and at which price (clearing price) the bids have been accepted.	Market	Aggregator	4,5
1.5.	Aggregator is forwarding the acception signals to the industrial flexibility	Forwarding information to industrial flexibility unit operator	The aggregator forwards the information, whether and (maybe) at which price the schedules have been accepted to the industrial flexibility unit operator.	Aggregator	Industrial flexibility unit operator	6,7

	unit operator					
1.6.	industrial flexibility unit is updating its operational schedule	Industrial flexibility unit is updating its operational schedule	The industrial flexibility unit takes the information about the accepted bids and updates its schedule.	Industrial flexibility unit		

iii. Information exchanged

Information exchanged (ID)	***From***	***To***	***Name of information***	***Description of information exchanged***
1	Agg	Ind	DA Forecast	Forecast of DA-Prices [€/MWh]
2	Ind	Agg	Operating Schedule	Timeseries of planned industrial DA-Schedule [kW]
3	Agg	Market	Required DA-Volumes	Timeseries [MW]
4	Market	Agg	Accepted DA-Volumes	Timeseries [MW]
5	Market	Agg	Real DA prices	DA-Clearing Prices [€/MWh]
6	Agg	Ind	Accepted Schedule	Timeseries of sold volumes (should be the same) [kW]
7	Agg	Ind	Optional: Real DA prices	DA-Clearing Prices [€/MWh]

III. UC 2B: Day-Ahead + Intraday Use Case

Disclaimer: This use case template follows the IEC 62559-2 standard.

i. Description of the use case

a. Name of the use case

ID	Main purpose	Name of Use Case
03	Day-Ahead and intraday trading	Day-Ahead + Intraday Use Case

b. Version management

Version Management			
Version No.	Date	Name of Author(s)	Changes
1	19.10.21	Regina Hemm	First Version of template
2	29.10.21	Regina Hemm	Final Version of template before review
3	28.03.2022	All	Final and by partners reviewed Version

c. Scope and objectives of use case

Scope and Objectives of Use Case	
Scope	The electricity which is produced or consumed by the industrial flexibility unit is traded on the DA and also on the ID market. The flexibility is used to shift the consumption to periods with low prices or shift the injection into the grid to periods with high prices. The schedule for the industrial flexibility unit s is created using an optimization tool.
Objective(s)	Minimizing costs when trading at the DA and IDspot-markets.
Related use case(s)	The DA+ID UC is also part of UCs 3 and 4b. All in all ID trading could be applied to almost all UC (except UC1), but there has to be discussed if ID-trading must be forbidden in one direction when redispatch is activated in the opposite direction at the same time.

d. Narrative of use case

Narrative of Use Case
Description
Flexibility Unit Perspective: The flexibility unit can profit from additional price fluctations ID by shifting the consumption. Not in this UC but in general, also forecast deviations can be balanced by additional ID trades. Revenue possibilities are higher with additional ID spot market participation. The desired bids are sent to the aggregator, to trade the desired amounts at the market. **Aggregator Perspective:** The aggregator profits from advanced planning security as well as cheaper portfolio costs if the energy consumption schedule of the plants is optimized.

<u>DSO/TSO Perspective:</u> If the schedules are made available for the TSO/DSO, they also profit from advanced planning security. Yet at the moment and therefore in this UC, TSO/DSOs are only receiving schedules from plants below grid level three >25MW (see SoMA).

e. Key performance indicators (KPI)

Key performance indicators (KPIs)				
ID	***Name***	***Description***	***Unit***	***Calculation form***
IND.1.1	max pos/neg flex per site	maximum available positive/negative flexibility aggregated per site (usually sum)	[kW $\pm$]	survey $P_{pos,\ max}$ $P_{neg,\ max}$
IND.1.2	seasonal changes in flex	Fluctuations that occur in the amount of flexibility provided, due to changing conditions in different seasons.	[%]	For pos and neg, respectively: Average daily positive flex per characteristic day per season / max posositive flex. $\frac{\frac{\sum P_{pos}}{24}}{P_{pos,max}}$
IND.1.3	max pos/neg flexibility per component (technology)	maximum available positive/negative flexibility per component	[kW $\pm$]	survey $P_{pos,tech,max}$
IND.1.4	max callduration for pos/neg flex per comp. at max power	maximum call duration of the maximum power with which positive/negative flexibility can be provided (can go up to unlimited)	[h $\pm$]	In simulation by presetting the minimum bid size to max flex and formulating the objective function according to 'max energy supply in flex'
IND.2.1	total revenues/ energy costs per use case 2-4	Total profit (energy costs) that can be generated annually under the conditions of the respective case study.	[€/year/site]	In simulation coupled with network simulation: revenues: sum over one year offered quantity*price r*call c (0 or 1) $\Sigma_i \left(\omega_i \cdot \Sigma_t \left(r(t) \cdot c(t) \cdot \left(e_+(t) + e_-(t)\right)\right)\right)$
IND.2.2	cost reduction/ additional	Costs or additional revenues that can be reduced or generated under	[€/year/site]	same principle as indicator above

	income per use case 2-4	the conditions of the respective case study compared to UC1.		
IND.2.3	investment costs for flexibilization depending on use case 2-4	Investment costs to be incurred for the flexibilization measures in the respective case study.	[€]	survey
IND.2.4	additional OPEX for flexibilization	costs such as personnel costs, …	[€/year]	sum over representative days- flex calls * operating costs type and amount of operating costs for different components: from surveys
IND.2.5	additional redispatch costs for aggregator	Additional costs e.g. for additional ICT, personnel, ...	[€/year]	survey
IND.3.1	change of efficiency from provision of redispatch	It is possible that due to the provision of redispatch efficiencies change. This aspect is captured within this indicator.	[%]	Comparison of the following: 1) Sum over repr. Days weight*(E_{demand}(process)/ $E_{purchase}$) without RD provision As 1) but for RD provision
IND.3.2	change of emissions from provision of redispatch	Change in emissions generated by redispatch provision compared to the reference case.	[%/year]	As above but instead of E_{demand}/ $E_{purchase}$ here Emission factor*$E_{purchase}$

f. Use case conditions

Use case conditions
Assumptions
• The industrial unit is able to calculate a schedule DA of the planned production/consumption, within the simulation there will be used perfect forecasts • In case of demonstration: The industrial unit is able to update these forecasts regularly (for ID trading), for the simulation there will be considered perfect forecasts and ID-trading is only considered for using price-spreads to gain additional revenues • All applicable grid fees will be considered • The optimization tool for the industrial flexibility unit is also capable to reduce the maximum peak power (and therefore grid fees) within the rolling horizon optimization • As a simulation timeframe a representative period with corresponding weights (to scale up to one year)will be chosen for the market and production-situation, covering 5-10 weeks • The simulation is carried out as a rolling horizon optimization

Prerequisites
• DA-price forecasts (provided by aggregator) • ID price forecasts (provided by aggregator) • Grid fees for all industry sites • Historical consumption profiles • For demonstrations: Forecast of the planned consumption (for the next day and updated ID schedules) of industrial flexibility unit is possible • Detailed optimization model which considers all physical constraints of the industrial flexibility unit

ii. Common Terms and Definitions

Common Terms and Definitions	
Term	**Definition**
D-1	Day before delivery
D0	Day of delivery
DA	Day-Ahead
ID	Intraday
FC	Forecast
GOT	Gate opening time
GCT	Gate closure time
RD	Redispatch
UC	Use Case
DSO	Distribution system operator
TSO	Transmission system operator
MRC	Multi-regional coupling

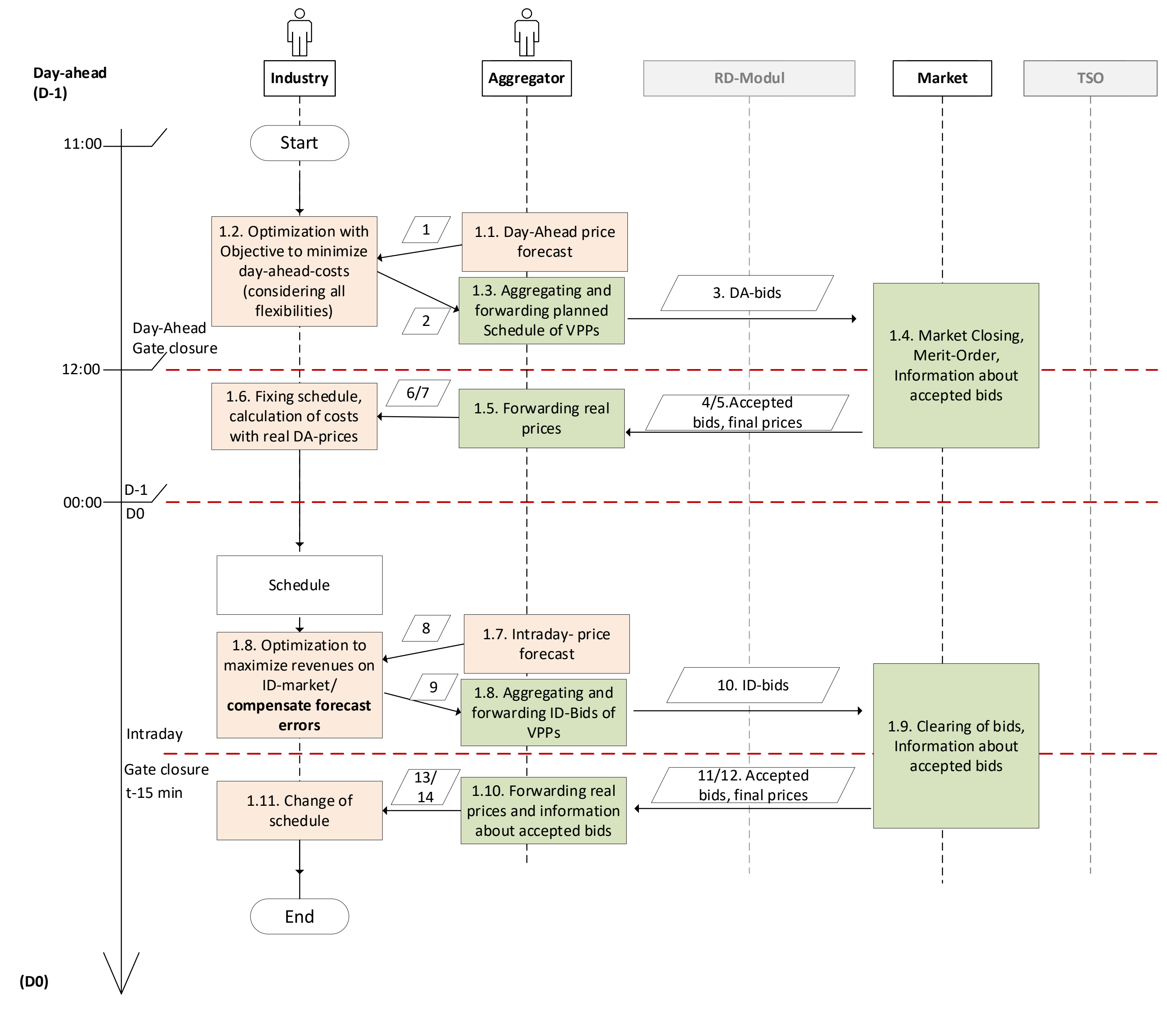
g. Actors

Actors		
Actor Name	***Actor Type***	***Actor Description***
Aggregator	Actor	Organisation offering energy services to the consumer, such as aggregation and pooling of flexibility bids but also in form of electricity delivery contracts.
Day-Ahead Market	Service	The DA market is operated through a blind auction which takes place once a day, all year round. All hours of the following day are traded in this auction. The orders are logged in by the market participants before the order book closes at 12:00. As a result of the order matching, the Power

Actors		
Actor Name	***Actor Type***	***Actor Description***
		Exchange determines trades which are legally binding agreements to purchase or sell a determined quantity of electricity to a defined delivery area for the matched (or “cleared”) price. There is one price, the market clearing price or MCP, that is determined for each delivery period and that applies to all buyers and sellers. The EPEX SPOT DA auction is integrated into the Multi-Regional Coupling (MRC) which encompasses the Baltics, Central Western Europe, Great Britain and the Nordics.
Intraday Market	Service	On the ID market, market participants trade continuously, 24 hours a day, with delivery on the same day. As soon as a buy- and sell-order match, the trade is executed. Electricity can be traded up to 5 minutes before delivery and through hourly, half-hourly or quarter-hourly contracts. As this allows for a high level of flexibility, members use the ID market to make last minute adjustments and to balance their positions closer to real time.
Industrial flexibility unit	Actor	An industrial consumption or generation asset in the electrical power grid which has the capability to deviate – to some exte–t - from its planned schedule in order to provide redispatch. It is preconditioned that the industrial flexibility unit fulfils the necessary requirements for redispatch according to the defined list in task 3.2 and is prequalified for the provision of redispatch.
Industrial flexibility unit operator	Role	Role which links the role customer and its possibility to provide flexibilities to the redispatch provision process by the operated industrial consumption or generation asset.

h. Sequence diagram of use case

Sequence diagram(s) of use case



Scenario name:						
Step No.	***Event***	***Name of process/ activity***	***Description of process/ activity***	***Information producer (actor)***	***Information receiver (actor)***	***Information Exchanged (IDs)***
1.1	Aggregator provides forecast data	Aggregator provides forecast data	The aggregator provides all the forecast data that the industrial flexibility unit operator needs for its optimization of the schedule.	Aggregator	Industry unit	1
1.2	Industrial flexibility unit operator produces optimization schedule	Optimization of DA-schedule	The industrial flexibility unit operator creates a schedule for the next day by using an optimization tool and forecasts for demand and prices.	Industrial flexibility unit operator	Aggregator	2
1.3	Aggregator sends request for DA-amounts at markets	DA-trading	The aggregator trades the aggregated Schedules at the DA-market	Aggregator	Market	3
1.4	Market clearing process	Market clearing process	The clearing of the market takes place, and the market sends information back to the Aggregator, whether and at which price (clearing price) the bids have been accepted.	Market	Aggregator	4,5
1.5	Aggregator is forwarding the acception signals to the industrial unit	Forwarding information to industrial unit	The aggregator forwards the information, whether and (maybe) at which price the schedules have been accepted to the Industrial unit.	Aggregator	Industrial flexibility unit operator	6,7
1.6	Industrial unit is updating its	Industrial unit is updating its	The industrial unit takes the information about the accepted bids and updates its schedule.	Industrial flexibility unit operator		

	operational schedule	opterational schedule				
1.7	Aggregator provides forecast data	Aggregator provides forecast data	The aggregator provides all the forecast data that the industrial flexibility unit operator needs for its optimization of the schedule.	Aggregator	Industrial flexibility unit operator	8
1.8	Industrial flexibility unit operator creates ID-optimization schedule	Optimization of ID-bid and ask energy amounts	The industrial flexibility unit operatorcreates a schedule for the next day by using an optimization tool and forecasts for demand and prices.	Industrial flexibility unit operator	Aggregator	9
1.9	Aggregator sends request for DA-amounts at markets	ID-trading	The aggregator trades the aggregated bid and ask bids at the ID-market	Aggregator	Market	10
1.10	Market clearing process	Market clearing process	The clearing of the market takes place, and the market sends information back to the Aggregator, whether and at which price (pay as bid) the bids have been accepted.	Market	Aggregator	11,12
1.11	Aggregator is forwarding the acception signals to the industrial flexibility unit	Forwarding information to industrial flexibility unit	The aggregator forwards the information, whether and (maybe) at which price the bid and ask bids have been accepted, to the industrial flexibility unit .	Aggregator	Industrial flexibility unit	13,14
1.12	Industrial flexibility unit is updating its	Industrial flexibility unit is updatin	The industrial flexibilit unit takes the information about the accepted bids and updates its schedule.	Industrial flexibility unit		

	operational schedule	g its opterational schedule				

i. Step by step analysis of use case

iii. Information exchanged

Information exchanged (ID)	***From***	***To***	***Name of information***	***Description of information exchanged***
1	Agg	Ind	DA Forecast	Forecast of DA-Prices [€/MWh]
2	Ind	Agg	Operating Schedule	Timeseries of planned Industry DA-Schedule [kW]
3	Agg	Market	Required DA-Volumes	Timeseries [MW]
4	Market	Agg	Accepted DA-Volumes	Timeseries [MW]
5	Market	Agg	Real DA prices	DA-Clearing Prices [€/MWh]
6	Agg	Ind	Accepted Schedule	Timeseries of sold volumes (should be the same) [kW]
7	Agg	Ind	Optional: Real DA prices	DA-Clearing Prices [€/MWh]
8	Agg	Ind	ID Forecast	Forecast of ID-Prices [€/MWh]
9	Ind	Agg	ID bid and ask bids	Timeseries of planned Industry ID bid and ask bids (deltaP) [kW]
10	Agg	Market	Required ID-Volumes	Timeseries [MW]
11	Market	Agg	Accepted ID-Volumes	Timeseries [MW]
12	Market	Agg	Real ID prices	ID Prices of accepted bids [€/MWh]
13	Agg	Ind	Accepted ID bid and ask bids	Timeseries of sold volumes (should be the same) [kW]
14	Agg	Ind	Optional: Real ID prices	ID Prices of accepted bids [€/MWh]

IV. UC3: Day-Ahead + Balancing + Intraday Use Case

Disclaimer: This use case template follows the IEC 62559-2 standard.

i. Description of the use case

a. Name of the use case

ID	Main purpose	Name of Use Case
04	Participation at balancing markets	Day-Ahead+Balancing+ID-Use Case

b. Version management

Version Management			
Version No.	Date	Name of Author(s)	Changes
1	19.10.21	Regina Hemm	First Version of template
2	29.10.21	Regina Hemm	Final Version of template before review
3	28.03.2022	All	Final and by partners reviewed Version

c. Scope and objectives of use case

Scope and Objectives of Use Case	
Scope	The whole produced or consumed electricity is traded on the spot markets (DA and ID) as well as balancing markets. Flexibility is used to shift the consumption to times with lower prices or shift the injection to the grid to times with higher prices. Additional, revenues can be gained for using the flexibility for the balancing reserve market. The according schedule is created with an optimization tool.
Objective(s)	Minimize costs when trading on the DA-spot- und ID market, while offering flexibility bids at balancing markets in parallel.
Related use case(s)	UC 4b combines balancing and redispatch.

d. Narrative of use case

Narrative of Use Case
Description
Flexibility Unit Perspective: The flexibility is used for purchasing electricity on the spot markets, using the variable prices, and if possible and economically feasible, some capacities are reserved for trading at the balancing market. The industrial unit calculates an operating schedule which results in a preliminary schedule for the each hour of the following day, considering DA-spot-market amounts and balancing reserve at the same time. First, the balancing capacity bids are offered at the balancing capacity market. If these bids are accepted, the respective amounts on the DA-spot market are traded at the DA-market, via the aggregator. If the bid amounts are accepted partially or rejected, the DA schedule has to be re-calculated. The industrial flexibility unit has to follow the accepted schedules based on the accepted bids and is able to trade

additional amounts in the ID timeframe at the balancing energy market or the ID market. In this case, the schedule has to be adjusted accordingly. The balancing reserves can be requested at any time and must be available to provide full power capacity within 5 minutes (aFRR). **Aggregator Perspective:** The aggregator has to pool the units to bids greater than 0,1MW for spot markets and 1MW for balancing markets. Furthermore, in case of activation, the activation signals have to be transmitted to the industrial units by the aggregator. **DSO/TSO Perspective:** The TSO sends activation signals for balancing reserve in case of frequency deviations to the aggregators.

e. Key performance indicators (KPI)

Key performance indicators (KPIs)				
ID	**Name**	**Description**	**Unit**	**Calculation form**
IND.1.3	max pos/neg flexibility per component (technology)	maximum available positive/negative flexibility per component	[kW $\pm$]	survey $P_{pos,tech,max}$
IND.2.1	total revenues/ energy costs per use case 2-4	Total profit (energy costs) that can be generated annually under the conditions of the respective case study.	[€/year/site]	Energy costs are summarized In simulation coupled with network simulation: revenues: sum over one year offered quantity*price r*call c (0 or 1) $\Sigma_i \left(\omega_i \cdot \Sigma_t \left(r(t) \cdot c(t) \cdot (e_+(t) + e_-(t)) \right) \right)$
IND.2.2	cost reduction/ additional income per use case 2-4	Costs or additional revenues that can be reduced or generated under the conditions of the respective case study.	[€/year/site]	same principle as indicator above
IND.2.3	investment costs for flexibilization depending on use case 2-4	Investment costs to be incurred for the flexibilization measures in the respective case study.	[€]	survey
IND.2.4	additional OPEX for flexibilization	costs such as personnel costs, …	[€/year]	sum over representative days-flex calls * operating costs

				type and amount of operating costs for different components: from surveys
IND.2.5	additional redispatch costs for aggregator	Additional costs e.g. for additional ICT, personnel, ...	[€/year]	survey
IND.3.1	change of efficiency from provision of redispatch	It is possible that due to the provision of redispatch efficiencies change. This aspect is captured within this indicator.	[%]	Comparison of the following: 1) Sum over repr. Days weight*(E_{demand}(process)/ $E_{purchase}$) without RD provision As 1) but for RD provision
IND.3.2	change of emissions from provision of redispatch	Change in emissions generated by redispatch provision compared to the reference case.	[%/year]	As above but instead of E_{demand}/ $E_{purchase}$ here Emission factor*$E_{purchase}$

f. Use case conditions

Use case conditions
Assumptions
• The industrial unit is able to calculate a schedule DA of the planned production/consumption and free capacities, in the simulation this will be treated as a perfect forecast. • The industrial unit is able to fulfil the prequalification process for balancing reserve. • Forecasts are available for balancing call probabilities and capacity/energy prices • The current balancing scheme is used: Balancing capacity is traded D-1 and balancing energy at the same day until 1 hour before product delivery, the product length is four hours. For the new scheme with PICASSO/MARI, the product length can be then adapted to 15-minutes time slots and balancing energy can be traded until 25 minutes before product delivery. • As a simulation timeframe a representative period with corresponding weights (to scale up to one year) will be chosen for the market and production-situation, covering 5-10 weeks. • The simulation is carried out as a rolling horizon optimization.
Prerequisites
• The industrial flexibility units are successfully prequalified for the balancing reserve provision • DA-price forecasts are available (provided by aggregator) • ID price forecasts are available (provided by aggregator) • Balancing call probabilities and correlating price forecasts are available • Forecast of the planned consumption (for the next day and updated ID schedules) of industrial units is possible • Detailed optimization model which considers all physical constraints of the industrial flexibility unit

ii. Common Terms and Definitions

Common Terms and Definitions	
Term	**Definition**
D-1	Day before delivery
D0	Day of delivery
DA	Day-Ahead
ID	Intraday
aFRR	Automatic Frequency Restoration Reserve
BRP	Balancing responsible party
FC	Forecast
GOT	Gate opening time
GCT	Gate closure time
RD	Redispatch
UC	Use Case
TSCNET	Transmission System Operator Security Cooperation Network
DSO	Distribution system operator
TSO	Transmission system operator
MRC	Multi-regional coupling

g. Actors

Actors		
Actor Name	***Actor Type***	***Actor Description***
Aggregator	Actor	Organisation offering energy services to the consumer, such as aggregation and pooling of flexibility bids but also in form of electricity delivery contracts.
Transmission System Operator (TSO)	Actor	According to the Article 2.4 of the Electricity Directive 2009/72/EC (Directive): "a natural or legal person responsible for operating, ensuring the maintenance of and, if necessary, developing the transmission system in a given area and, where applicable, its interconnections with other systems, and for ensuring the long-term ability of the system to meet reasonable demands for the transmission of electricity". Moreover, the TSO is responsible for connection of all grid users at the transmission level

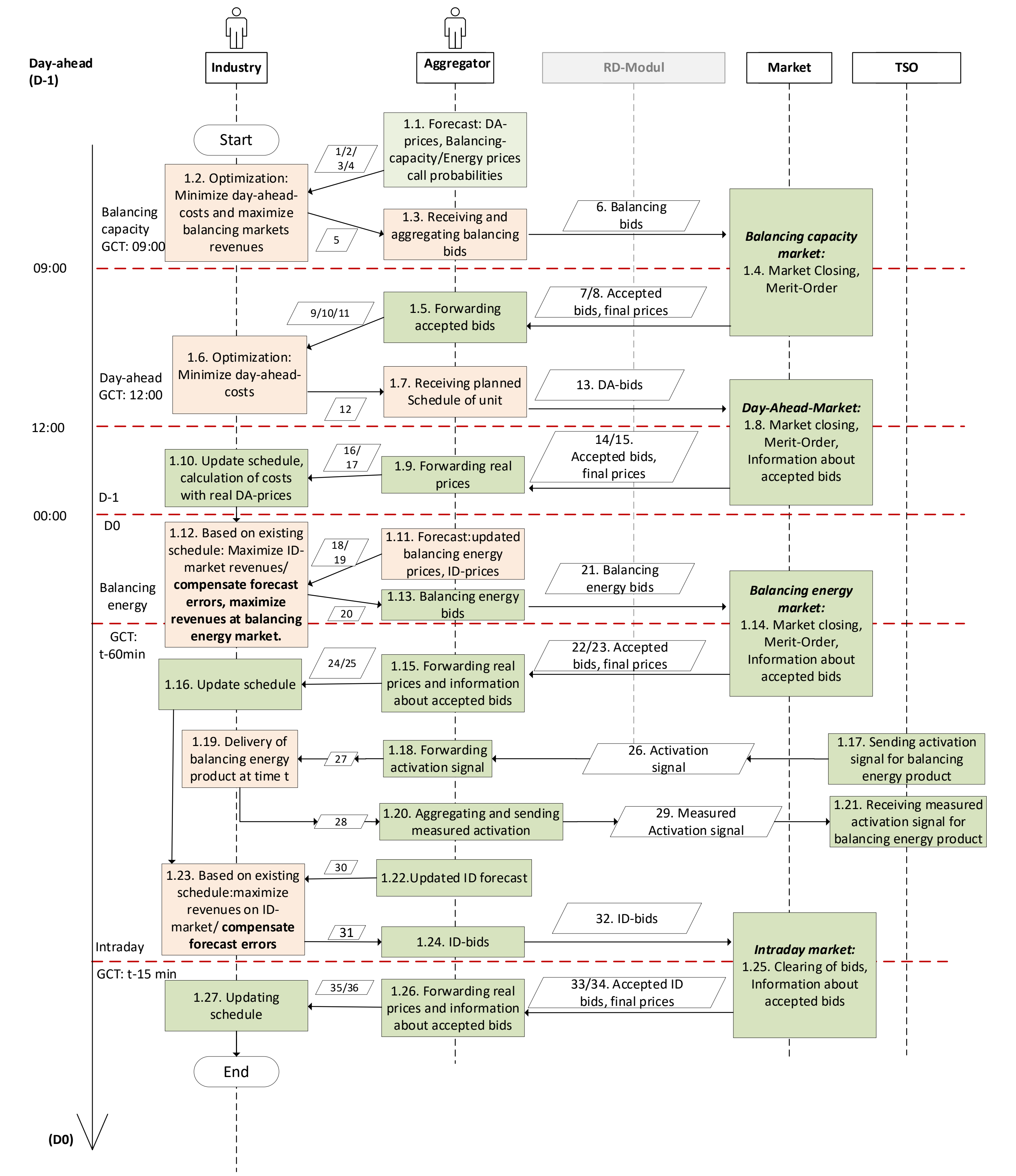
Actors		
Actor Name	**Actor Type**	**Actor Description**
		and connection of the DSOs within the TSO control area. In Austria, the TSO has also the role of the control area operator. Pursuant to section §23 (2) ElWOG 2010, the control area operator has the obligation to determine grid congestions in the transmission system; and to take measures to avoid, solve and to overcome grid congestions in transmission systems as well as to maintain security of energy supply.
TSCNET	Actor	TSCNET Services is one of Europe's leading Regional Security Coordinators (RSCs). TSCNET Services is currently entrusted with a set of mandatory services for its customers according to EU legislation: • Coordinated Security Analysis • Coordinated Capacity Calculation • Outage Planning Coordination • Short and Medium Term Adequacy forecasts • Improved Individual Grid Models and Common Grid Model
Day Ahead Market	Service	The Day Ahead market is operated through a blind auction which takes place once a day, all year round. All hours of the following day are traded in this auction. The orders are logged in by the market participants before the order book closes at 12:00. As a result of the order matching, the Power Exchange determines trades which are legally binding agreements to purchase or sell a determined quantity of electricity to a defined delivery area for the matched (or "cleared") price. There is one price, the market clearing price or MCP, that is determined for each delivery period and that applies to all buyers and sellers. The EPEX SPOT DA auction is integrated into the Multi-Regional Coupling (MRC) which encompasses the Baltics, Central Western Europe, Great Britain and the Nordics.
Intraday Market	Service	On the ID market, market participants trade continuously, 24 hours a day, with delivery on the same day. As soon as a buy- and sell-order match, the trade is executed. Electricity can be traded up to 5 minutes before delivery and through hourly, half-hourly or quarter-hourly contracts. As this allows for a high level of flexibility, members use

Actors		
Actor Name	**Actor Type**	**Actor Description**
		the ID market to make last minute adjustments and to balance their positions closer to real time.
Balancing Capacity Market	Service	'Balancing Market' means the entirety of institutional, commercial and operational arrangements that establish market-based management of balancing. Balancing capacity means a volume of reserve capacity that a balancing service provider has agreed to hold and in respect to which the balancing service provider has agreed to submit bids for a corresponding volume of balancing energy to the TSO for the duration of the contract. The flexibility provider gets remunerated for the amount of reserved capacity.
Balancing Energy Market	Service	Balancing energy means energy used by TSOs to perform balancing and provided by a balancing service provider. Every plant which has participated in the balancing capacity market also has to set a price for the balancing energy market. Moreover it is also possible to participate in this market in the ID timeframe, without prior participation at the balancing capacity market. The flexibility provider get remunerated for the balancing energy which has been activated by the TSO.
Flexibility service provider	Role	Party which offers flexibility bids on the Redispatch Platform. This role can be taken by an aggregator (in case that several industrial flexibility units are aggregated to a pool in order to aggregate flexibilities of various industrial flexibility units to one flexibility bid) or directly by an industrial flexibility unit operator (if the industrial flexibility unit is large enough to fulfil the minimal bid size).
Industrial flexibility unit	Actor	An industrial consumption or generation asset in the electrical power grid which has the capability to deviate – to some extent – from its planned schedule in order to provide redispatch. It is preconditioned that the industrial flexibility unit fulfils the necessary requirements for redispatch according to the defined list in task 3.2 and is prequalified for the provision of redispatch.
Industrial flexibility unit operator	Role	Role which links the role customer and its possibility to provide flexibilities to the redispatch provision process by the operated industrial consumption or generation asset.
Redispatch Platform	Service	Platform to which flexibility service providers send their redispatch bids. The Redispatch Platform

Actors		
Actor Name	**Actor Type**	**Actor Description**
		collects and manages these redispatch bids and forwards them to the TSO as potential remedial actions. After the redispatch calculation process, the platform forwards bid accept messages to those flexibility service providers whose redispatch bids are accepted.
Balance Responsible Party (BRP)	Actor	BRPs are responsible for maintaining supply and demand on the energy market within their own portfolio.Their tasks: • obtain day ahead consumption forecasts from all the suppliers in their balancing responsible party • send these forecasts to the clearing and settlement agent • pay the clearing and settlement agent for the imbalance settlement energy • bill the suppliers for the balancing energy required

h. Sequence diagram of use case

Sequence diagram(s) of use case



Step by step analysis of use case

Scenario name:						
Step No.	***Event***	***Name of process/ activity***	***Description of process/ activity***	***Information producer (actor)***	***Information receiver (actor)***	***Information Exchanged (IDs)***
1.1	Aggregator provides forecast data	Aggregator provides forecast data	The aggregator provides all the forecast data that the industrial flexibility unit operator needs for its optimization of the schedule.	Aggregator	Industrial flexibility unit operator	1,2,3,4
1.2	Industrial flexibility operator produces optimization schedule	Optimization of balancing bids considering DA-schedule	The industrial flexibility unit operator creates a schedule for the next day by using an optimization tool and forecasts for demand and prices.	Industrial flexibility unit operator	Aggregator	5
1.3	Aggregator sends request for balancing capacity-amounts to markets	Balancing-capacity-trading	The aggregator trades the aggregated Schedules at the balancing capacity market.	Aggregator	Market	6
1.4	Market clearing process	Market clearing process	The clearing of the balancing capacity market takes place, and the market sends information back to the Aggregator, to identify which bids, and at what price, have been accepted.	Market	Aggregator	7,8

Scenario name:						
Step No.	**Event**	**Name of process/ activity**	**Description of process/ activity**	**Information producer (actor)**	**Information receiver (actor)**	**Information Exchanged (IDs)**
1.5	Aggregator is forwarding the accepted signals to the industrial flexibility unit	Aggregator provides updated forecast data and accepted balancing bids	The aggregator forwards the information, whether and at which price the bids have been accepted to the Industrial flexibility unit as well as updated DA-forecasts.	Aggregator	Industrial flexibility unit	9,10,11
1.6	Industrial flexibility unit operator produces optimization schedule	Optimization of DA-schedule considering the already accepted balancing bids	The industrial flexibility unit operator creates a schedule for the next day by using an optimization tool and forecasts for demand and prices.	Industrial flexibility unit operator	Aggregator	12
1.7	Aggregator sends request for DA-amounts at markets	DA-trading	The aggregator trades the aggregated Schedules at the DA-market	Aggregator	Market	13
1.8	Market clearing process	Market clearing process	The clearing of the DA market takes place, and the market sends information back to the Aggregator, whether and at which price (clearing price) the bids have been accepted.	Market	Aggregator	14

Scenario name:						
Step No.	**Event**	**Name of process/ activity**	**Description of process/ activity**	**Information producer (actor)**	**Information receiver (actor)**	**Information Exchanged (IDs)**
1.9	Aggregator is forwarding the acceptation signals to the industrial flexibility unit	Forwarding information to industrial flexibility unit	The aggregator forwards the information, whether and (maybe) at which price the schedules have been accepted to the Industrial flexibility unit .	Aggregator	Industrial flexibility unit	15,16,17
1.10	Industrial flexibility unit is updating its operational schedule	Industrial flexibility unit is updating its operating schedule	The industrial flexibility unit takes the information about the accepted bids and updates its schedule.	Industrial flexibility unit		
1.11	Aggregator provides forecast data	Aggregator provides forecast data	The aggregator provides all the forecast data that the industrial flexibility unit operator needs for its optimization of the schedule.	Aggregator	Industrial flexibility unit operator	18,19
1.12	Industrial flexibility unit operator produces optimization schedule	Optimization of balancing bids considering DA-schedule, balancing capacity bids and ID prices.	The industrial flexibility unit operator creates a schedule of balancing energy bids by using an optimization tool and forecasts for demand and prices.	Industrial flexibility unit operator	Aggregator	20

Scenario name:						
Step No.	**Event**	**Name of process/ activity**	**Description of process/ activity**	**Information producer (actor)**	**Information receiver (actor)**	**Information Exchanged (IDs)**
1.13	Aggregator sends request for balancing energy - amounts to markets	Balancing-energy-trading	The aggregator trades the aggregated balancing energy bids at the balancing energy market.	Aggregator	Market	21
1.14	Market clearing process	Market clearing process	The clearing of the balancing energy market takes place, and the market sends information back to the Aggregator, whether and at which price the bids have been accepted.	Market	Aggregator	22,23
1.15	Aggregator is forwarding the acceptation signals to the industrial flexibility unit	Aggregator provides updated forecast data and accepted balancing bids	The aggregator forwards the information, whether and (maybe) at which price the bids have been accepted to the Industrial flexibility unit .	Aggregator	Industrial flexibility unit	24,25
1.16	Industrial flexibility unit is updating its operational	Industrial flexibility unit is updating its operating schedule	The industrial flexibility unit takes the information about the accepted bids and updates its schedule.	Industrial flexibility unit		

Scenario name:						
Step No.	**Event**	**Name of process/ activity**	**Description of process/ activity**	**Information producer (actor)**	**Information receiver (actor)**	**Information Exchanged (IDs)**
	schedule					
1.17	TSO sends activation signal	Sending activation signal	The TSO sends the activation signal for the balancing energy product to the aggregator.	TSO	Aggregator	26
1.18	Aggregator forwards activation signal	Forwarding of activation signal	The aggregator forwards the activation signal for the balancing energy product to the industrial flexibility unit.	Aggregator	Industrial flexibility unit	27
1.19	Industrial flexibility unit delivers balancing energy	Delivery of balancing energy	The industrial flexibility unit delivers the balancing energy product after the receiving the activation signal			
1.20	Aggregator forwards measured activation signal to TSO	Aggregation of measured activation signal	The aggregator receives the measured activation signals from the industrial flexibility units, aggregates them to forwards them to the TSO.	Industrial flexibility unit	Aggreator	28
1.21	TSO receives measured activation signal for	Receiving of activation signal	The TSO receives the measured activation signals for the balancing energy product, to use it for billing.	Aggregator	TSO	29

Scenario name:						
Step No.	**Event**	**Name of process/ activity**	**Description of process/ activity**	**Information producer (actor)**	**Information receiver (actor)**	**Information Exchanged (IDs)**
	balancing energy product					
1.22	Aggregator provides updated ID forecast data	Aggregator provides forecast data	The aggregator provides all the forecast data that the industrial flexibility unit operator needs for its optimization of the schedule.	Aggregator	Industrial flexibility unit operator	30
1.23	Industrial flexibility unit operator creates ID-optimization schedule	Optimization of ID-bid and ask energy amounts	The industrial flexibility unit operator creates a schedule for the next day by using an optimization tool and forecasts for demand and prices.	Industrial flexibility unit operator	Aggregator	31
1.24	Aggregator sends request for DA-amounts at markets	ID-trading	The aggregator trades the aggregated bid and ask bids at the ID-market	Aggregator	Market	32
1.25	Market clearing process	Market clearing process	The clearing of the ID market takes place, and the market sends information back to the Aggregator, whether and at which price (pay as bid)	Market	Aggregator	33, 34

Scenario name:						
Step No.	**Event**	**Name of process/ activity**	**Description of process/ activity**	**Information producer (actor)**	**Information receiver (actor)**	**Information Exchanged (IDs)**
			the bids have been accepted.			
1.26	Aggregator is forwarding the accepted signals to the industrial flexibility unit	Forwarding information to industrial flexibility unit	The aggregator forwards to the Industrial flexibility unit the information, which bids and at which price they have been accepted.	Aggregator	Industrial flexibility unit	35, 36
1.27	Industrial flexibility unit is updating its operational schedule	Industrial flexibility unit is updating its operating schedule	The industrial flexibility unit takes the information according to the accepted bids and updates its operating schedule.	Industrial flexibility unit		

iii. Information exchanged

Information exchanged (ID)	*From*	*To*	*Name of information*	*Description of information exchanged*
1	Agg	Ind	DA prices	Forecast of DA-Prices [€/MWh]
2	Agg	Ind	Balancing capacity prices	Forecast of Balancing Capacity-Prices [€/MWh]
3	Agg	Ind	Balancing energy prices	Forecast of Balancing Energy-Prices [€/MWh]
4	Agg	Ind	Balancing call probabilities	Balancing call probabilities
5	Ind	Agg	Balancing bids	Timeseries of balancing bids [MW]
6	Agg	Market	Balancing bids	Timeseries of balancing bids [MW]
7	Market	Agg	Accepted balancing bids	Timeseries [MW]
8	Market	Agg	Balancing prices of accepted bids	Balancing Capacity-Prices [€/MWh]
9	Agg	Ind	Accepted balancing bids	Timeseries [MW]
10	Agg	Ind	Balancing prices of accepted bids	Balancing Capacity-Prices [€/MWh]
11	Agg	Ind	updated DA Forecast	Forecast of DA-Prices [€/MWh]
12	Ind	Agg	Operating Schedule	Timeseries of planned Industry DA-Schedule [kW]
13	Agg	Market	Required DA-Volumes	Timeseries [MW]
14	Market	Agg	Accepted DA-Volumes	Timeseries [MW]
15	Market	Agg	Real DA prices	DA-Clearing Prices [€/MWh]
16	Agg	Ind	Accepted Schedule	Timeseries of sold volumes (should be the same) [kW]
17	Agg	Ind	Optional: Real DA prices	DA-Clearing Prices [€/MWh]
18	Agg	Ind	Balancing energy prices	Forecast of Balancing Energy-Prices [€/MWh]
19	Agg	Ind	ID prices	Forecast of ID-Prices [€/MWh]
20	Ind	Agg	Balancing Energy Bids	Timeseries [MW]
21	Agg	Market	Balancing Energy Bids	Timeseries [MW]
22	Market	Agg	Accepted balancing bids	Timeseries [MW]
23	Market	Agg	Balancing prices	Balancing Energy-Prices [€/MWh]
24	Agg	Ind	Accepted balancing bids	Timeseries [MW]

Information exchanged (ID)	From	To	Name of information	Description of information exchanged
25	Agg	Ind	Optional: accepted balancing prices	Timeseries [MW]
26	TSO	Agg	Activation signal	Activation signal
27	Agg	Ind	Activation signal	Activation signal
28	Ind	Agg	Measured activation signal	Measured activation signal
29	Agg	TSO	Measured activation signal	Measured activation signal
30	Agg	Ind	ID Forecast	Forecast of ID-Prices [€/MWh]
31	Ind	Agg	ID bid and ask bids	Timeseries of planned Industry ID bid and ask bids (deltaP) [kW]
32	Agg	Market	Required ID-Volumes	Timeseries [MW]
33	Market	Agg	Accepted ID-Volumes	Timeseries [MW]
34	Market	Agg	Real ID prices	ID Prices of accepted bids [€/MWh]
35	Agg	Ind	Accepted ID bid and ask bids	Timeseries of sold volumes (should be the same) [kW]
36	Agg	Ind	Optional: Real ID prices	ID Prices of accepted bids [€/MWh]

V. UC4a: Day-Ahead + Redispatch (TSO) Use Case

Disclaimer: This use case template follows the IEC 62559-2 standard.

i. Description of the use case

a. Name of the use case

ID	Main purpose	Name of Use Case
4a	Redispatch	UC4a: Day-Ahead + Redispatch (TSO) Use Case

b. Version management

Version Management			
Version No.	Date	Name of Author(s)	Changes
1	11.11.2021	Anne Glatt, Felix Hembach	First Draft
2	28.03.2022	All	Final and by partners reviewed Version

c. Scope and objectives of use case

Scope and Objectives of Use Case	
Scope	The electricity required to fulfil the needs of the industrial flexibility unit is procured on the day-ahead spot market. Optimization is used to calculate possible flexibility shifts in consumption or generation in order to provide flexibility bids to the Flexibility Platform.
Objective(s)	Minimize costs when trading at the day-ahead spot market and offering available flexibility in order to participate in redispatch.
Related use case(s)	UC 4b combines day-ahead, balancing and redispatch. UC 5 describes day-ahead and redispatch as well, but with redispatch on DSO level. UC 6a and 6b describe day-ahead and redispatch as well, but in coordination between TSO and DSO.

d. Narrative of use case

Narrative of Use Case
Description
Flex Unit Perspective: The owner of the industrial flexibility unit participates in the day-ahead spot market and uses this to fulfil his expected electricity demand. As the flexibility is utilized for the trade on the day-ahead spot market, this results in a preliminary day-ahead schedule for the entire day. In addition to the schedule, the industrial flexibility unit operator calculates a quarter-hourly upward / downward

shift potential (active power) and the respective costs. The industrial flexibility unit operator then sends these possible changes to the aggregator who makes them available to the Redispatch Platform as possible quarter-hourly flexibility bids. Bids must be simultaneously feasible (i.e. the activation of one bid may not impede the activation of another bid, until a more complex bid structure is defined and available). After the TSO has selected a number of bids (from 0 to all offered bids), based on the current demand for redispatch and the price structure of flexibility bids offered by all the other flexibility bidders, the information about which bids are selected is transmitted back to the industrial flexibility unit. This results in an adjustment of the generation/consumption schedule of the industrial flexibility unit. **TSO Perspective:** At Gate Opening Time (GOT), around 14:30, the Redispatch Platform allows for the submission of flexibility bids (redispatch bids) by industrial flexibility units. Any such bids must be submitted until Gate Closing Time (GCT), approx. 18:00 (tbd). After GCT, all available flexibility bids are considered as possible remedial actions by the TSO. Together with the conventional redispatch potential of large-scale power plants these bids are fed into the redispatch optimisation processes to determine which bids should be selected. Between 22:00 and 0:00 (tbd), the optimal solution to the redispatch problem has been calculated and the TSO sends a confirmation that their bid was selected to the operators of the selected industrial flexibility units, who need to adjust their schedules accordingly.

e. Key performance indicators (KPI)

Key performance indicators (KPIs)				
ID	**Name**	**Description**	**Unit**	**Calculation form**
IND.1.3	max pos/neg flexibility per component (technology)	maximum available positive/negative flexibility per component	[kW ±]	survey $P_{pos,tech,max}$
IND.1.5	h in a year in which redispatch (pos/neg flex) is offered per comp.	Total number of hours in a year in which positive/negative flexibility is offered per Komponent	[h ±/year]	Sum over all representative periods (i) of (Weight of the representative period (ω_i) * Sum of the time steps (t) in which the binary variable for pos.b_+ /neg Flex >0 (i.e. one) multiplied by the time step length $\Delta\tau$) $\Sigma_i\ (\omega_i \cdot \Sigma_t(b_+(t) \cdot \Delta\tau))$
IND.1.6	max offered redispatch (pos/neg flex) per year per component	maximum amount of energy that is offered for redispatch (positive/negative flexiliblity) per year	[kWh ±/year]	Sum over all representative periods (i) of (Weight of representative period (ω_i)* sum of pos. (p_+) /neg flex multiplied by time step length $\Delta\tau$) $\Sigma_i\ (\omega_i \cdot \Sigma_t(p_+(p) \cdot \Delta\tau))$

IND.1.7	average energy for compensation effects per pos/neg flex supply	In case of compensation effects (or rebound effects) for positive/negative Flex., this KPI becomes >0 and also provides information about the amount of energy that can be flexibilized	[kWh $\pm$]	From simulation: Sum over all representative periods (i) (weight of representative period (ω_i) * (sum catch-up effect per day/ number of RD provision offers n_{RD}) $$\frac{\Sigma_i\left(\omega_i \cdot \Sigma_t\left(e_+(t)+e_-(t)\right)\right)}{n_{RD}}$$
IND.2.1	total revenues/ energy costs per use case 2-4	Total profit (energy costs) that can be generated annually under the conditions of the respective case study.	[€/year/site]	Energy costs are summarized In simulation coupled with network simulation: revenues: sum over one year offered quantity*price r*call c (0 or 1) $$\Sigma_i\left(\omega_i \cdot \Sigma_t\left(r(t)\cdot c(t) \cdot \left(e_+(t)+e_-(t)\right)\right)\right)$$
IND.2.2	cost reduction/ additional income per use case 2-4	Costs or additional revenues that can be reduced or generated under the conditions of the respective case study.	[€/year/site]	same principle as indicator above
IND.2.3	investment costs for flexibilization depending on use case 2-4	Investment costs to be incurred for the flexibilization measures in the respective case study.	[€]	survey
IND.2.4	additional OPEX for flexibilization	costs such as personnel costs, …	[€/year]	sum over representative days- flex calls * operating costs type and amount of operating costs for different components: from surveys
IND.2.5	additional redispatch costs for aggregator	Additional costs e.g. for additional ICT, personnel, ...	[€/year]	survey

IND.3.1	change of efficiency from provision of redispatch	It is possible that due to the provision of redispatch efficiencies change. This aspect is captured within this indicator.	[%]	Comparison of the following: 1) Sum over repr. Days weight*(E_{demand}(process)/ $E_{purchase}$) without RD provision As 1) but for RD provision
IND.3.2	change of emissions from provision of redispatch	Change in emissions generated by redispatch provision compared to the reference case.	[%/year]	As above but instead of E_{demand}/ $E_{purchase}$ here Emission factor*$E_{purchase}$
FLEX.1.1	total supply of redispatch per industry- peak performance	Peak performance provided for flexibility by the individual industrial sectors.	[MW]	survey $\sum_{i=1}^{n} \begin{matrix} peak\ performance \\ provided\ for\ redispatch(i) \end{matrix}$ $\forall\ industrial\ sectors$ I = # of TU in industrial sector
FLEX.1.2	total supply of redispatch per industry- energy content	Total amount of energy provided for flexibility by the individual industrial sectors.	[MW]	survey $\sum_{i=1}^{n} \begin{matrix} total\ capacity \\ provided\ for\ redispatch(i) \end{matrix}$ $\forall\ industrail\ sectors$ n = # of TU in industrial sector
FLEX.2.1	Average cost per technology per call per hour per MW	Costs for a flexibility call, dependent on technology and the incentive model	[€/MWh]	survey
FLEX.2.2	Average cost per industry per call per hour per MW	Costs for a flexibility call, dependent on industrial sector and the incentive model	[€/MWh]	survey
TSO.1.1	Number of hours on which redispatch was retrieved	Total number of hours in a year in which flexibility is retrieved	[h]	estimation TSO $\sum_{i=1}^{8760} 1_A(i)$ $A = \{i: amount\ of\ redispatch\ \neq\ 0\}$

TSO.1.2	Total amount of energy called for redispatch by industry per hour per year	Total amount of energy required annually for retrieval of flexibility by the industry	[MWh/year]	estimation TSO $\sum_{i=1}^{8760} amount\ of\ redispatch\ provided\ by\ indust$
TSO.1.3	Typical duration of congestion	Average time interval a congestion lasts.	[h]	estimation TSO $\frac{1}{n}\sum_{i=1}^{n} duration\ redispatch\ retrieval(i$ n = # redispatch retrievals per year
TSO.2.1	Cost savings for redispatch with I4RD compared to conventional redispatch	Redispatch costs that can be saved by integrating industry through the I4RD project.	[€]	estimation TSO $cost\ RD - -\ cost\ I4RD$
TSO.1.4	Savings through I4RD in contrast to redispatch through conventinal power plants	Peak Power that is needed less compared to conventional redispatch using I4RD	[MW]	estimation TSO *required peak power RD – required peak Power I4RD*
TSO.1.5	Energy amounts of conventional redispatch that can be prevented by redispatch with I4RD	Energy amounts that can be avoided by integrating industry through the I4RD project.	[MWh/year]	estimation TSO *amount of energy RD – amount of energy I4RD*
TSO.1.6	predicted n-1/n-0 violations per transition point	amount of predicted events where the failure of a component cannot be prevented by redundancies	[#]	estimation TSO *predicted n-1 violations before remedial actions – predicted n-1 violations after remedial actions*

f. Use case conditions

Use case conditions
Assumptions
• The industrial flexibility unit operator is able to calculate a schedule day-ahead of planned generation/consumption + a quarter-hourly upward and downward shift potential (active power) + respective costs. This schedule is created with the help of an optimization tool with which the industrial flexibility unit is equipped. • All (for redispatch provision prequalified) industrial flexibility unit operators submit their planned schedules to the TSO. • The Redispatch Platform serves as a data exchange platform between aggregator and the transmission system operator. • Enough industrial flexibility units in a congestion area are available to aggregate a pool that is able to aggregate at least the minimum bid size (according to the definition in task 3.2). • Flexibilities are not offered at balancing markets, only for redispatch provision on TSO level. • Redispatch is only requested by the TSO (not by DSOs). • Geographic information about the pool/assets offering the bid is known (according to definition in task 3.2). • Regional security coordination of the Core capacity calculation region, i.e. the calculation of grid congestions and coordination of congestion management measures is performed as is it's state-of-the-art in 2021. • As a simulation timeframe a representative period with corresponding weights (to scale up to one year) will be chosen for the market and production-situation, covering 5-10 weeks • The simulation is carried out as a rolling horizon optimization
Prerequisites
• Industry: Day-ahead price forecasts available (provided by aggregator) • Industry: Forecast of planned consumption/generation is possible • Industry: Optimization tool for the creation of schedules is installed in industrial flexibility unit • Industry: The industrial flexibility units are successfully prequalified for the redispatch provision. • Definition of redispatch bids as per task 3.2 completed • TSO: Data exchange of flexibility bids as per task 3.2 is defined • Existence of a defined data model and communication protocols between all the involved actors, roles and services.

ii. Common Terms and Definitions

Common Terms and Definitions	
Term	**Definition**
D-1 / DA	Day before delivery / Day-ahead
ID	Intraday
aFRR	Automatic Frequency Restoration Reserve
BRP	Balancing responsible party

Common Terms and Definitions	
Term	**Definition**
FC	Forecast
GOT	Gate opening time
GCT	Gate closure time
RD	Redispatch
UC	Use Case
TSCNET	Transmission System Operator Security Cooperation Network
DSO	Distribution system operator
TSO	Transmission system operator
SO	System Operator
MRC	Multi-regional coupling
Agg	Aggregator
Ind	Industry flex unit

g. Actors

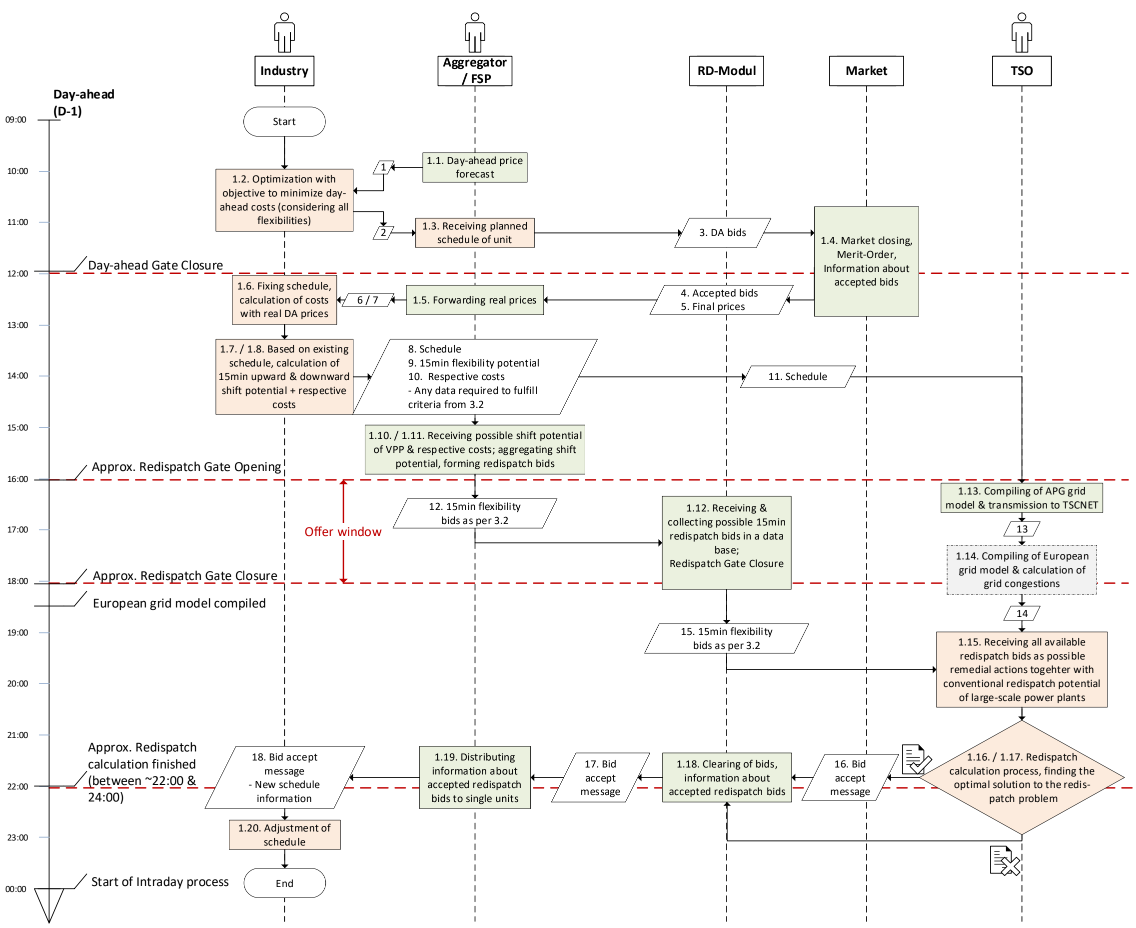
Actors		
Actor Name	***Actor Type***	***Actor Description***
Transmission System Operator (TSO)	Actor	According to the Article 2.4 of the Electricity Directive 2009/72/EC (Directive):“"a natural or legal person responsible for operating, ensuring the maintenance of and, if necessary, developing the transmission system in a given area and, where applicable, its interconnections with other systems, and for ensuring the long-term ability of the system to meet reasonable demands for the transmission of electricit”". Moreover, the TSO is responsible for connection of all grid users at the transmission level and connection of the DSOs within the TSO control area. In Austria, the TSO has also the role of the control area operator. Pursuant to section §23 (2) ElWOG 2010, the control area operator has the obligation to determine grid congestions in the transmission system; and to take measures to avoid, solve and to overcome grid congestions in transmission systems as well as to maintain security of energy supply.
TSCNET	Actor	TSCNET Services is one of Europe’s leading Regional Security Coordinators (RSCs). TSCNET Services is currently entrusted with a set of mandatory

Actors		
Actor Name	**Actor Type**	**Actor Description**
		services for its customers according to EU legislation: • Coordinated Security Analysis • Coordinated Capacity Calculation • Outage Planning Coordination • Short and Medium Term Adequacy forecasts • Improved Individual Grid Models and Common Grid Model
Aggregator / Supplier	Actor	Organisation, which facilitates the sales and purchasing of products on the different electricity markets. If an industrial flexibility unit is not sufficient in size to fulfil the requirements of a market segment or redispatch, the aggregator combines the flexibility potentials of several industrial flexibility units and uses them to build standardised bids.
Day-ahead market	Market	The Day-ahead market is operated through a blind auction which takes place once a day, all year round. All hours of the following day are traded in this auction. The orders are logged in by the market participants before the order book closes at 12:00. As a result of the order matching, the Power Exchange determines trades which are legally binding agreements to purchase or sell a determined quantity of electricity to a defined delivery area for the matched (or “cleared”) price. There is one price, the market clearing price or MCP, that is determined for each delivery period and that applies to all buyers and sellers. The EPEX SPOT Day-Ahead auction is integrated into the Multi-Regional Coupling (MRC) which encompasses the Baltics, Central Western Europe, Great Britain and the Nordics
Flexibility service provider	Role	Party which offers flexibility bids on the Redispatch Platform. This role can be taken by an aggregator (in case that several industrial flexibility units are aggregated to a pool in order to aggregate flexibilities of various industrial flexibility units to one flexibility bid) or directly by an industrial flexibility unit operator (if the industrial flexibility unit is large enough to fulfil the minimal bid size).
Industrial flexibility unit	Actor	An industrial consumption or generation asset in the electrical power grid which has the capability to deviate – to some extent–- from its planned

Actors		
Actor Name	**Actor Type**	**Actor Description**
		schedule in order to provide redispatch. It is preconditioned that the industrial flexibility unit fulfils the necessary requirements for redispatch according to the defined list in task 3.2 and is prequalified for the provision of redispatch.
Industrial flexibility unit operator	Role	Role which links the role customer and its possibility to provide flexibilities to the redispatch provision process by the operated industrial consumption or generation asset.
Redispatch Platform	Service	Platform to which flexibility service providers send their flexibility bids. The Redispatch Platform collects and manages these flexibility bids and forwards them to the requester of redispatch (TSO in this UC) as potential remedial actions. In use cases where different actors request redispatch the Redispatch Platform ensures that bids are not double-booked. After the redispatch calculation process, the platform forwards bid accept messages to those flexibility service providers whose flexibility bids are accepted.

h. Sequence diagram(s) of use case

Sequence diagram(s) of use case



i. Step by step analysis of use case

Scenario name:						
Step No.	***Event***	***Name of process/ activity***	***Description of process/ activity***	***Information producer (actor)***	***Information receiver (actor)***	***Informa-tion ex-change d (iDs)***
1.1	Aggregator provides forecast data	Aggregator provides forecast data	The aggregator provides all the forecast data that the industrial flexibility unit needs for its optimization of the schedule.	Aggregator	Industrial flexibility unit	1
1.2	Industrial flexibility unit produces optimization schedule	Optimization of day-ahead schedule	The industrial flexibility unit creates a schedule for the next day by using an optimization tool and forecasts for demand and prices.	Industrial flexibility unit	Aggregator	2
1.3	Aggregator sends request for DA amounts to market	DA trading	The aggregator attempts the necessary trades at the DA spot market to follow the optimized schedule.	Aggregator	Market	3
1.4	Market clearing process	Market clearing process	The clearing of the market takes place and the market sends the information back to the aggregator whether and at which price (clearing price) the DA bids have been accepted.	Market	Aggregator	4, 5
1.5	Aggregator is forwarding the acceptation signals to the industrial flexibility unit	Forwarding information to industrial flexibility unit	The aggregator forwards the information to the industrial flexibility unit, whether and at which price the bids have been accepted.	Aggregator	Industrial flexibility unit	6, 7
1.6	Industrial flexibility unit is generating its operational schedule	Industrial flexibility unit is generating its operational schedule	The industrial flexibility unit takes the information about the accepted DA bids to update its schedule and	Industrial flexibility unit		

Scenario name:						
Step No.	**Event**	**Name of process/ activity**	**Description of process/ activity**	**Information producer (actor)**	**Information receiver (actor)**	**Information exchanged (iDs)**
			to calculate costs with real DA prices.			
1.7	Industrial flexibility unit calculates its shift potential	Calculation of flexibility potential	Based on the existing schedule, the industrial flexibility unit calculates quarter-hourly upward & downward shift potential (active power) and the respective costs.	Industrial flexibility unit		
1.8	Industrial flexibility unit sends its flexibility potential to aggregator	Sending information of flexibility potential to aggregator	The industrial flexibility unit sends the fixed schedule, the quarter-hourly flexibility potential, respective costs and any data required to fulfil criteria defined in task 3.2. to the aggregator.	Industrial flexibility unit	Aggregator	8, 9, 10
1.9	Aggregator sends schedule	Sending schedule to TSO	The aggregator sends the schedule to the TSO	Aggregator	TSO	11
1.10	Aggregator aggregates shift potentials	Aggregation of flexibility potential	The aggregator receives the shift potential of the industrial flexibility units and the respective costs, aggregates possible shift potential and forms quarter-hourly flexibility bids out of it.			
1.11	Aggregator submits flexibility bids	Submission of flexibility bids	The aggregator submits the quarter-hourly flexibility bids to the Redispatch Platform.	Aggregator	Redispatch Platform	12
1.12	Redispatch platform collects possible flexibility bids in a data base	Collecting possible flexibility bids	From GOT, the Redispatch Platform receives and collects the possible flexibility bids in a data base until GCT.			

Scenario name:						
Step No.	Event	Name of process/ activity	Description of process/ activity	Information producer (actor)	Information receiver (actor)	Informa-tion ex-change d (iDs)
1.13	Compiling of TSO grid model & transmission to TSCNET	Compiling of TSO grid model & transmission to TSCNET	The TSO compiles the TSO grid model and transmits it to TSCNET	TSO	TSCNET	13
1.14	Compiling of European grid model & calculation of gird congestions	Compiling of European grid model & calculation of grid congestions	TSCNET compiles from all TSO grid model the European grid model. Using this common grid model the grid congestions are calculated.	TSCNET	TSO	14
1.15	TSO receives all available flexibility bids	Receiving all available flexibility bids	The TSO knows the grid congestions and receives all available flexibility bids as possible remedial actions together with the conventional redispatch potential of large-scale power plants.	Redispatch Platform	TSO	15
1.16	TSO performs the redispatch calculation process	Redispatch calculation process	The TSO performs the redispatch calculation process in order to find the optimal solution to the redispatch problem. During this step, the TSO determines which bids should be selected to relieve the congestions in the grid.			
1.17	The TSO sends the bid accept message	Forwarding bid accept message	The TSO forwards the bid accept message to the Redispatch Platform.	TSO	Redispatch Platform	16
1.18	RD clearing process	RD selection process	The RD Platform sends information back to the aggregator whether the bids have been accepted.	Redispatch Platform	Aggregator	17
1.19	Aggregator forwards bid accept message to	Distributing bid accept message to industrial flexibility units	The aggregator distributes the information about accepted bids to the	Aggregator	Industrial flexibility unit	18

Scenario name:						
Step No.	***Event***	***Name of process/ activity***	***Description of process/ activity***	***Information producer (actor)***	***Information receiver (actor)***	***Informa-tion ex-change d (iDs)***
	industrial flexibility units		single industrial flexibility units.			
1.20	Industrial flexibility unit updates its operational schedule	Industrial flexibility unit updates its operational schedule	The industrial flexibility unit takes the information according to the accepted flexibility bids and updates its operational schedule.			

iii. Information exchanged

Information exchanged (ID)	*From*	*To*	*Name of information*	*Description of information exchanged*
1	Agg	Ind	DA prices	Forecast of Day-ahead prices [€/MWh]
2	Ind	Agg	Operating schedule	Time series of planned industry DA schedule [MW] (or [kW])
3	Agg	Market	Required DA volumes	Time series [MW] (or [kW])
4	Market	Agg	Accepted DA volumes	Time series [MW] (or [kW])
5	Market	Agg	Real DA prices	Day-ahead clearing prices [€/MWh]
6	Agg	Ind	Real DA prices	Day-ahead clearing prices [€/MWh]
7	Agg	Ind	Accepted schedule	Time series of sold/purchased energy (should be the same) [kW]
8	Ind	Agg	Operating schedule	Time series of planned industry schedule [MW] (or [kW])
9	Ind	Agg	Flexibility bids	For every bid, delta P in positive or negative direction [kW]
10	Ind	Agg	Flexibility bids	For every bid, delta P in positive or negative direction [kW]
11	Agg	TSO	Operating schedule	Time series of planned industry schedule [MW] (or [kW])
12	Agg	RD Platform	Flexibility bids	List of flexibility bids as defined in task 3.2
13	TSO	TSCNET	TSO grid model	TSO grid model
14	TSCNET	TSO	European grid model	European grid model
15	RD Platform	TSO	Flexibility bids	List of all flexibility bids as defined in task 3.2
16	TSO	RD Platform	Accepted flexibility bids	List of accepted flexibility bids
17	RD Platform	Agg	Accepted flexibility bids	List of accepted flexibility bids
18	Agg	Ind	Accepted flexibility bids	Time series of change in energy consumption / production [MW] (or [kW])

VI. UC4b: Day-Ahead + Balancing + Redispatch (TSO) + Intraday Use Case

Disclaimer: This use case template follows the IEC 62559-2 standard.

i. Description of the use case

a. Name of the use case

ID	Main purpose	Name of Use Case
4b	Balancing + Redispatch	DSO+ Spot Markets

b. Version management

Version Management			
Version No.	Date	Name of Author(s)	Changes
1	11-11-2021	Anne Glatt & Felix Hembach	First draft
2	28.03.2022	All	Final and by partners reviewed Version

c. Scope and objectives of use case

Scope and Objectives of Use Case	
Scope	UC 4b combines the use of flexibility to provide redispatch (UC4a) with its alternative options to provide balancing services. The flexibility service provider first trades flexibilities on the aFRR balancing capacity market. After the additional constraints, due to balancing capacity provision are known the industrial units procures the required electricity on the day-ahead spot market. Optimization is used to calculate possible flexibility shifts in consumption or generation in order to provide redispatch and/or balancing bids to the Redispatch Platform, while observing the constraints associated with participation in both services.
Objective(s)	Minimize costs when trading on the balancing energy market and the day-ahead spot market as well as offering available flexibility in order to participate in the balancing capacity market and/or the provision of redispatch.
Related use case(s)	In UC 4b, the balancing markets of UC 3 are combined with the TSO redispatch of UC4a.

d. Narrative of use case

Narrative of Use Case
Description
Flex Unit Perspective: The owner of the industrial flexibility unit participates in the balancing capacity market and the day-ahead spot market and uses the day-ahead market to fulfil his expected electricity demand. While participating in the balancing capacity market, the operator of the industrial flexibility unit considers the expected prices on the day-ahead market. This results in secured balancing capacity

constraints which are considered as additional constraints as the flexibility demand is later utilized for the trade on the day-ahead spot market. This results in a preliminary day-ahead schedule for the entire day, considering day-ahead spot market amounts and balancing reserve at the same time. In addition to the schedule, the industrial flexibility unit operator calculates a quarter-hourly upward / downward shift potential (active power) and the respective costs. These shift potentials need to consider that redispatch can only be offered if the shift in generation / consumption does not impede, and is not impeded by the secured balancing capacity. The industrial flexibility unit operator then sends these possible changes to the aggregator who makes them available to the Redispatch Platform as possible quarter-hourly redispatch bids. Redispatch bids for the day-head timeframe are then accepted by the TSO until approx. 22:00–- 24:00. The information about which bids are selected is transmitted back to the industrial flexibility unit (via the aggregator).

This results in an adjustment of the generation / consumption schedule of the industrial flexibility unit and the flexibility unit can then start to participate in the intraday market and / or provide aFRR balancing energy bids, which are traded with a Gate-Closing Time of 60 minutes (currently) /25 minutes (MARI/PICASSO) before product delivery. Because of the locational sensitivity of redispatch, intraday trade, as well as aFRR bids must not counteract any redispatch bids which were accepted during the redispatch process. (i.e. no downward offers if they are paid for upward redispatch and vice-versa)

As described in UC 4a, all flexibility bids provided to the Redispatch Platform must be simultaneously feasible (i.e. the activation of one bid may not impede the activation of another bid, until a more complex bid structure is defined and available).

TSO Perspective:

The gate opening of the aFRR balancing capacity tender starts at 10.00 one week-ahead (GOT). At Gate Closure Time (GCT), at 9.00 D-1 the balancing capacity tender is finalized.

At GOT of redispatch, around 14:30, the Redispatch Platform allows for the submission of bids by industrial flexibility units for the provision of redispatch. Any such bids must be submitted until GCT, approx..18:00 (tbd). After the GCT, all available redispatch bids are considered as possible remedial actions by the TSO. Together with the conventional redispatch potential of large-scale power plants these bids are fed into the redispatch calculation processes to determine which bids should be selected.

Between 22:00 and 0:00 (tbd), the optimal solution to the redispatch problem has been calculated and the TSO sends a confirmation to the operators of the aggregator who forwards it to the selected industry units, that their bid was selected and that they need to adjust their schedule accordingly. If bids are accepted for redispatch, they are no longer available for the balancing energy tender.

At 9.30 D-1 (GOT), the balancing market allows for the submission of flexibility bids by industrial flexibility units for the aFRR balancing energy tender. Any such bids must be submitted until 60min before delivery time (GCT: H-60min currently/ H-25min MARI/PICASSO). While in theory this would allow the submission of balancing bids before the submission of redispatch bids, this use case assumes that balancing bids are calculated and submitted after the industrial flexibility unit has been informed about the accepted redispatch bids, as the GCT of H-60min occurs at a later time than the determination of day-ahead redispatch.

The TSO is not involved in the intraday trade of industrial flexibility units, but must receive updates in case the production or generation schedule of the industrial flexibility unit changes.

e. Key performance indicators (KPI)

Key performance indicators (KPIs)				
ID	Name	Description	Unit	Calculation form
IND.1.3	max pos/neg flexibility per component (technology)	maximum available positive/negative flexibility per component	[kW $\pm$]	survey $P_{pos,tech,max}$
IND.1.5	h in a year in which redispatch (pos/neg flex) is offered per comp.	Total number of hours in a year in which positive/negative flexibility is offered per Komponent	[h $\pm$/year]	Sum over all representative periods (i) of (Weight of the representative period (ω_i) * Sum of the time steps (t) in which the binary variable for pos.b_+ /neg Flex >0 (i.e. one) multiplied by the time step length $\Delta\tau$) $\Sigma_i \left(\omega_i \cdot \Sigma_t (b_+(t) \cdot \Delta\tau)\right)$
IND.1.6	max offered redispatch (pos/neg flex) per year per component	maximum amount of energy that is offered for redispatch (positive/negative flexiliblity) per year	[kWh $\pm$/year]	Sum over all representative periods (i) of (Weight of representative period (ω_i)* sum of pos. (p_+) /neg flex multiplied by time step length $\Delta\tau$) $\Sigma_i \left(\omega_i \cdot \Sigma_t (p_+(p) \cdot \Delta\tau)\right)$
IND.1.7	average energy for compensation effects per pos/neg flex supply	In case of compensation effects (or rebound effects) for positive/negative Flex., this KPI becomes >0 and also provides information about the amount of energy that can be flexibilized	[kWh $\pm$]	From simulation: Sum over all representative periods (i) (weight of representative period (ω_i) * (sum catch-up effect per day/ number of RD provision offers n_{RD}) $\frac{\Sigma_i \left(\omega_i \cdot \Sigma_t \left(e_+(t) + e_-(t)\right)\right)}{n_{RD}}$
IND.2.1	total revenues/ energy costs per use case 2-4	Total profit (energy costs) that can be generated annually under the conditions of the respective case study.	[€/year/site]	Energy costs are summarized In simulation coupled with network simulation: revenues: sum over one year offered quantity*price r*call c (0 or 1) $\Sigma_i \left(\omega_i \cdot \Sigma_t \left(r(t) \cdot c(t) \cdot \left(e_+(t) + e_-(t)\right)\right)\right)$

IND.2.2	cost reduction/ additional income per use case 2-4	Costs or additional revenues that can be reduced or generated under the conditions of the respective case study.	[€/year/site]	same principle as indicator above
IND.2.3	investment costs for flexibilization depending on use case 2-4	Investment costs to be incurred for the flexibilization measures in the respective case study.	[€]	survey
IND.2.4	additional OPEX for flexibilization	costs such as personnel costs, …	[€/year]	sum over representative days- flex calls * operating costs type and amount of operating costs for different components: from surveys
IND.2.5	additional redispatch costs for aggregator	Additional costs e.g. for additional ICT, personnel, ...	[€/year]	survey
IND.3.1	change of efficiency from provision of redispatch	It is possible that due to the provision of redispatch efficiencies change. This aspect is captured within this indicator.	[%]	Comparison of the following: 1) Sum over repr. Days weight*(E_{demand}(process)/ $E_{purchase}$) without RD provision As 1) but for RD provision
IND.3.2	change of emissions from provision of redispatch	Change in emissions generated by redispatch provision compared to the reference case.	[%/year]	As above but instead of E_{demand}/ $E_{purchase}$ here Emission factor*$E_{purchase}$
FLEX.1.1	total supply of redispatch per industry- peak performance	Peak performance provided for flexibility by the individual industrial sectors.	[MW]	survey $\sum_{i=1}^{n} \begin{matrix} peak\ performance \\ provided\ for\ redispatch(i) \end{matrix}$ $\forall\ industrail\ sectors$ i = # of TU in industrial sector
FLEX.1.2	total supply of	Total amount of energy provided	[MW]	survey

	redispatch per industry-energy content	for flexibility by the individual industrial sectors.		$\sum_{i=1}^{n} \text{total capacity provided for redispatch}(i)$ $\forall \text{ industrail sectors}$ n = # of TU in industrial sector
FLEX.2.1	Average cost per technology per call per hour per MW	Costs for a flexibility call, dependent on technology and the incentive model	[€/MWh]	survey
FLEX.2.2	Average cost per industry per call per hour per MW	Costs for a flexibility call, dependent on industrial sector and the incentive model	[€/MWh]	survey
TSO.1.1	Number of hours on which redispatch was retrieved	Total number of hours in a year in which flexibility is retrieved	[h]	estimation TSO $\sum_{i=1}^{8760} 1_A(i)$ $A = \{i: \text{amount of redispatch} \neq 0\}$
TSO.1.2	Total amount of energy called for redispatch by industry per hour per year	Total amount of energy required annually for retrieval of flexibility by the industry	[MWh/year]	estimation TSO $\sum_{i=1}^{8760} \text{amount of redispatch provided by indust}$
TSO.1.3	Typical duration of congestion	Average time interval a congestion lasts.	[h]	estimation TSO $\frac{1}{n}\sum_{i=1}^{n} \text{duration redispatch retrieval}(i$ n = # redispatch retrievals per year
TSO.2.1	Cost savings for redispatch with I4RD compared to conventional redispatch	Redispatch costs that can be saved by integrating industry through the I4RD project.	[€]	estimation TSO $\text{cost RD} - \text{cost I4RD}$
TSO.1.4	Savings through I4RD in contrast to redispatch	Power that is needed less compared to conventional redispatch using I4RD	[MW]	estimation TSO *required peak power RD – required peak power I4RD*

	through conventional power plants			
TSO.1.5	Energy amounts of conventional redispatch that can be prevented by redispatch with I4RD	Energy amounts that can be avoided by integrating industry through the I4RD project.	[MWh/year]	estimation TSO *amount of energy RD – amount of energy I4RD*
TSO.1.6	predicted n-1/n-0 violations per transition point	amount of predicted events where the failure of a component cannot be prevented by redundancies	[#]	estimation TSO *predicted n-1 violations before remedial actions – predicted n-1 violations after remedial actions*

f. Use case conditions

Use case conditions
Assumptions
• Participations of flexible units in the different markets and services of balancing capacity, day-ahead energy, day ahead redispatch and balancing energy. • The industrial flexibility unit operator is able to calculate a schedule day-ahead of planned generation/consumption + a quarter-hourly upward and downward shift potential (active power) + respective costs. This schedule is created with the help of an optimization tool with which the industrial flexibility unit is equipped. • All (for redispatch provision prequalified) industrial flexibility unit operators submit their planned schedules to the TSO. • The Redispatch Platform serves as a data exchange platform between aggregator and the transmission system operator. • Enough industrial flexibility units in a congestion area are available to aggregate a pool that is able to aggregate at least the minimum bid size for redispatch provision (according to the definition in task 3.2). • Redispatch is only requested by the TSO (not by DSOs). • Geographic information about the pool/assets offering the bid for redispatch is known (according to definition in task 3.2). • Regional security coordination of the Core capacity calculation region, i.e. the calculation of grid congestions and coordination of congestion management measures is performed as it's currently state-of-the-art in 2021. • The new balancing scheme (Picasso/Mari) is used: Balancing capacity is traded D-1 (until 9.00) and balancing energy from D-1 (9:30) to the day of delivery until 1 hour (currently)/25 minutes (MARI/PICASSO) before product delivery. • Forecasts are available for balancing call probabilities and capacity/energy prices. • A common platform for the submission of flexibility bids has not yet been implemented

• The operator of industrial flexibility unit participates in different markets and respect that they must not counteract the purpose of a specific market
Prerequisites
• Industry: Day-ahead price forecasts available (provided by aggregator) • Industry: Intraday-price forecasts available (provided by aggregator) • Industry: Balancing call probabilities available (provided by aggregator) • Industry: Forecast of planned consumption/generation is possible • Industry: Optimization tool for the creation of schedules is installed in industrial flexibility unit • Industry: The industrial flexibility units are successfully prequalified for the balancing reserve. • Industry: The industrial flexibility units are successfully prequalified for the redispatch provision. • Definition of redispatch bids as per task 3.2 completed • TSO: Data exchange of redispatch bids as per task 3.2 is defined • Existence of a defined data model and communication protocols between all the involved actors, roles and services. • Rolling Horizon Optimization (D-1 and hourly intraday)

ii. Common Terms and Definitions

Common Terms and Definitions	
Term	**Definition**
D-1/DA	Day before delivery/Day Ahead
D0	Day of delivery
ID	Intraday
aFRR	Automatic Frequency Restoration Reserve
BRP	Balancing responsible party
FC	Forecast
GOT	Gate opening time
GCT	Gate closure time
RD	Redispatch
UC	Use Case
TSCNET	Transmission System Operator Security Cooperation Network
DSO	Distribution system operator
TSO	Transmission system operator
SO	System Operator
MRC	Multi-regional coupling
Agg	Aggregator
Ind	Industry flex unit

g. Actors

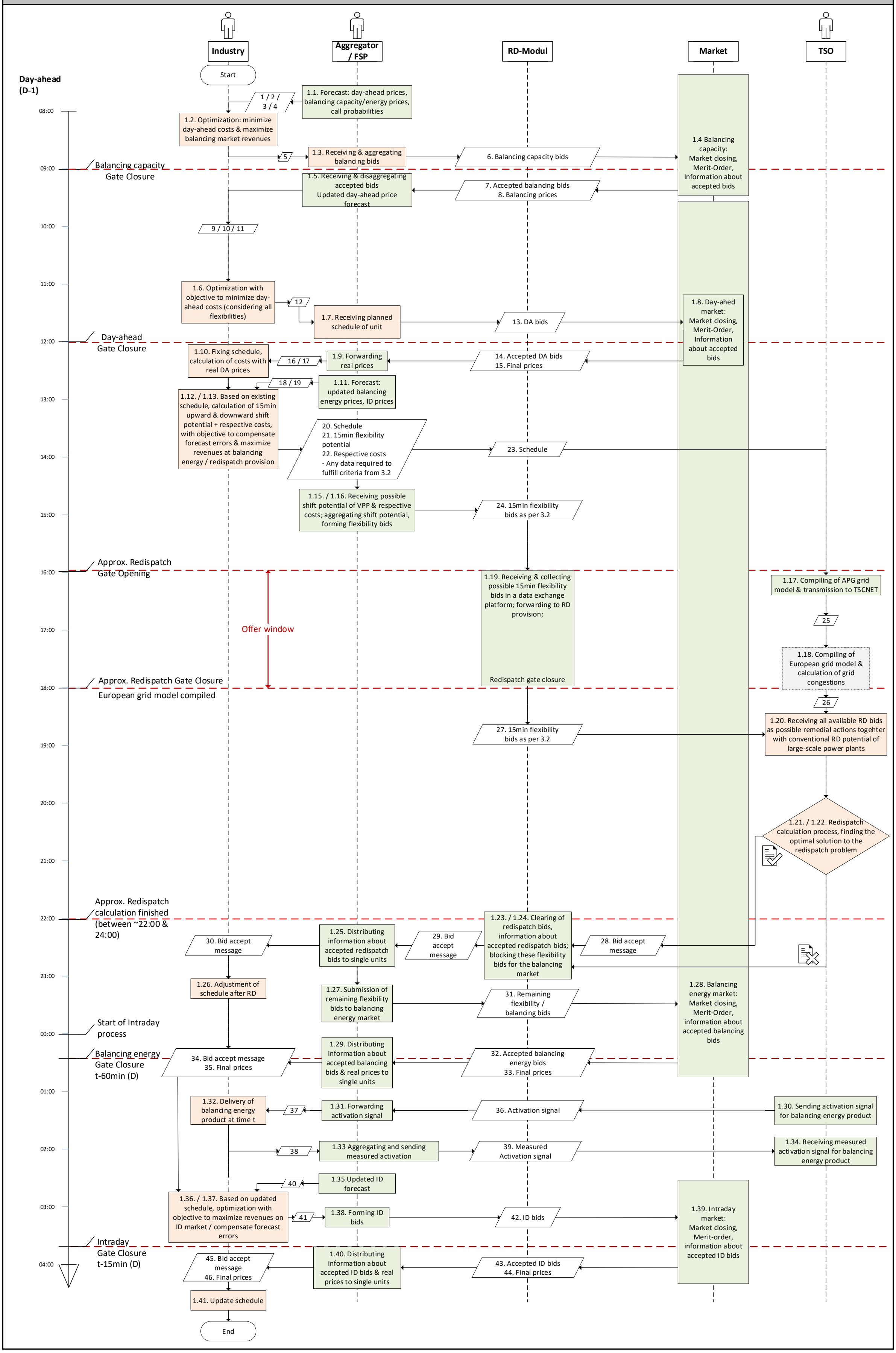
Actors		
Actor Name	**Actor Type**	**Actor Description**
Transmission System Operator (TSO)	Actor	According to the Article 2.4 of the Electricity Directive 2009/72/EC (Directive): "a natural or legal person responsible for operating, ensuring the maintenance of and, if necessary, developing the transmission system in a given area and, where applicable, its interconnections with other systems, and for ensuring the long-term ability of the system to meet reasonable demands for the transmission of electricity". Moreover, the TSO is responsible for connection of all grid users at the transmission level and connection of the DSOs within the TSO control area. In Austria, the TSO has also the role of the control area operator. Pursuant to section §23 (2) ElWOG 2010, the control area operator has the obligation to determine grid congestions in the transmission system; and to take measures to avoid, solve and to overcome grid congestions in transmission systems as well as to maintain security of energy supply.
TSCNET	Actor	TSCNET Services is one of Europe's leading Regional Security Coordinators (RSCs). TSCNET Services is currently entrusted with a set of mandatory services for its customers according to EU legislation: • Coordinated Security Analysis • Coordinated Capacity Calculation • Outage Planning Coordination • Short and Medium Term Adequacy forecasts • Improved Individual Grid Models and Common Grid Model
Aggregator / Supplier	Actor	Organisation, which facilitates the sales and purchasing of products on the different electricity markets. If an industrial flexibility unit is not sufficient in size to fulfil the requirements of a market segment or redispatch, the aggregator combines the flexibility potentials of several industrial flexibility units and uses them to build standardised bids.
Day-ahead spot market	Service	The Day-ahead market is operated through a blind auction which takes place once a day, all year round. All hours of the following day are traded in this auction. The orders are logged in by the

Actors		
Actor Name	**Actor Type**	**Actor Description**
		market participants before the order book closes at 12:00. As a result of the order matching, the Power Exchange determines trades which are legally binding agreements to purchase or sell a determined quantity of electricity to a defined delivery area for the matched (or "cleared") price. There is one price, the market clearing price or MCP, that is determined for each delivery period and that applies to all buyers and sellers. The EPEX SPOT Day-Ahead auction is integrated into the Multi-Regional Coupling (MRC) which encompasses the Baltics, Central Western Europe, Great Britain and the Nordics
Balancing capacity market	Service	'Balancing Market' means the entirety of institutional, commercial and operational arrangements that establish market-based management of balancing. Balancing capacity means a volume of reserve capacity that a balancing service provider has agreed to hold and in respect to which the balancing service provider has agreed to submit bids for a corresponding volume of balancing energy to the TSO for the duration of the contract. The flexibility provider gets remunerated for the amount of reserved capacity.
Balancing energy market	Service	Balancing energy means energy used by TSOs to perform balancing and provided by a balancing service provider. Every plant which has participated in the balancing capacity market also has to set a price for the balancing energy market. Moreover it is also possible to participate in this market in the intraday timeframe, without prior participation at the balancing capacity market. The flexibility providers get remunerated for the balancing energy which has been activated by the TSO.
Intraday market	Service	On the Intraday market, market participants trade continuously, 24 hours a day, with delivery on the same day. As soon as a buy- and sell-order match, the trade is executed. Electricity can be traded up to 5 minutes before delivery and through hourly, half-hourly or quarter-hourly contracts. As this allows for a high level of flexibility, members use the Intraday market to make last minute adjustments and to balance their positions closer to real time.
Flexibility service provider	Role	Party which offers flexibility bids on the Redispatch Platform. This role can be taken by an aggregator

Actors		
Actor Name	**Actor Type**	**Actor Description**
		(in case that several industrial flexibility units are aggregated to a pool in order to aggregate flexibilities of various industrial flexibility units to one flexibility bid) or directly by an industrial flexibility unit operator (if the industrial flexibility unit is large enough to fulfil the minimal bid size).
Industrial flexibility unit	Actor	An industrial consumption or generation asset in the electrical power grid which has the capability to deviate – to some extent - from its planned schedule in order to provide redispatch and/or balancing reserve. It is preconditioned that the industrial flexibility unit fulfils the necessary requirements for redispatch according to the defined list in task 3.2 and is prequalified for the provision of redispatch and balancing reserve.
Industrial flexibility unit operator	Role	Role which links the role customer and its possibility to provide flexibilities to the redispatch provision process by the operated industrial consumption or generation asset.
Redispatch Platform	Service	Platform to which flexibility service providers send their flexibility bids (balancing bids as well as redispatch bids). The Redispatch Platform collects and manages these flexibility bids. In case of bids considered for redispatch provision, the platform forwards them to the requestor of redispatch (TSO in this UC) as potential remedial actions. In use cases where different actors request redispatch, the Redispatch Platform ensures that bids are not double-booked. After the redispatch calculation process, the platform forwards bid accept messages to those flexibility service providers whose flexibility bids are accepted. The Redispatch Platform also manages that the same flexibility bids (prequalified for different flexibility services) are not accepted by different services at the same time. A flexibility bid accepted for redispatch provision is no longer available for the balancing energy tender.

h. Sequence diagram(s) of use case

Sequence diagram of use case



i. Step by step analysis of use case

Scenario name:						
Step No.	***Event***	***Name of process/ activity***	***Description of process/ activity***	***Information producer (actor)***	***Information receiver (actor)***	***Informa-tion ex-change d (IDs)***
1.1	Aggregator provides forecast data	Aggregator provides forecast data	The aggregator provides forecast data that the industrial flexibility unit needs for its optimization of the schedule: day-ahead prices, balancing capacity/energy prices, call probabilities.	Aggregator	Industrial flexibility unit	1,2, 3, 4
1.2	Industrial flexibility unit produces optimization schedule	Optimization of balancing bids considering day-ahead schedule	The industrial flexibility unit creates a schedule for the next day by using an optimization tool and forecasts for demand and prices.	Industrial flexibility unit	Aggregator	5
1.3	Aggregator sends request for balancing capacity amounts to markets	Balancing capacity trading	The aggregator aggregates the balancing bids and sends the request for balancing capacity amounts to the markets.	Aggregator	Market	6
1.4	Market clearing process	Market clearing process	The clearing of the balancing capacity market takes place and the market sends the information back to the aggregator whether and at which price the balancing capacity bids have been accepted.	Market	Aggregator	7, 8
1.5	Aggregator provides updated forecast data and forwards accepted balancing bids	Aggregator provides updated forecast data and forwards accepted balancing bids	The aggregator receives and disaggregates the accepted bids, and forwards the information whether and at which price the balancing bids have been accepted to the industrial flexibility unit as well as the	Aggregator	Industrial flexibility unit	9, 10, 11

Scenario name:						
Step No.	***Event***	***Name of process/ activity***	***Description of process/ activity***	***Information producer (actor)***	***Information receiver (actor)***	***Information exchanged (IDs)***
			updated day-ahead forecasts.			
1.6	Industrial flexibility unit produces optimization schedule	Optimization of day-ahead schedule	The industrial flexibility unit creates a schedule for the next day by using an optimization tool and forecasts for demand and prices.	Industrial flexibility unit	Aggregator	12
1.7	Aggregator sends request for DA amounts to market	DA trading	The aggregator attempts the necessary trades at the DA spot market to follow the optimized schedule.	Aggregator	Market	13
1.8	Market clearing process	Market clearing process	The clearing of the market takes place and the market sends the information back to the aggregator whether and at which price (clearing price) the DA bids have been accepted.	Market	Aggregator	14, 15
1.9	Aggregator is forwarding the acceptation signals to the industrial flexibility unit	Forwarding information to industrial flexibility unit	The aggregator forwards the information to the industrial flexibility unit, whether and at which price the bids have been accepted.	Aggregator	Industrial flexibility unit	16, 17
1.10	Industrial flexibility unit is generating its operational schedule	Industrial flexibility unit is generating its operational schedule	The industrial flexibility unit takes the information about the accepted DA bids to update its schedule and to calculate costs with real DA prices.	Industrial flexibility unit		
1.11	Aggregator provides updated forecast data	Provision of updated forecast data	Aggregator provides industrial flexibility unit updated forecast of balancing energy prices and ID prices	Aggregator	Industrial flexibility unit	18, 19

Scenario name:						
Step No.	**Event**	**Name of process/ activity**	**Description of process/ activity**	**Information producer (actor)**	**Information receiver (actor)**	**Information exchanged (IDs)**
1.12	Industrial flexibility unit calculates its shift potential	Calculation of flexibility potential	Based on the existing schedule, the industrial flexibility unit calculates quarter-hourly upward & downward shift potential (active power) and the respective costs, with objective to compensate forecast errors and maximize revenues on balancing energy / redispatch provision	Industrial flexibility unit		
1.13	Industrial flexibility unit sends its flexibility potential to aggregator	Sending information of flexibility potential to aggregator	The industrial flexibility unit sends the fixed schedule, the quarter-hourly flexibility potential, respective costs and any data required to fulfil criteria defined in task 3.2. to the aggregator.	Industrial flexibility unit	Aggregator	20,21, 22
1.14	Aggregator sends schedule	Sending schedule to TSO	The aggregator sends the schedule to the TSO	Aggregator	TSO	23
1.15	Aggregator aggregates shift potentials	Aggregation of flexibility potential	The aggregator receives the shift potential of the industrial flexibility units and the respective costs, aggregates possible shift potential and forms quarter-hourly flexibility bids out of it.			
1.16	Aggregator submits flexibility bids	Submission of flexibility bids	The aggregator submits the quarter-hourly flexibility bids to the Redispatch Platform.	Aggregator	Redispatch Platform	24
1.17	Compiling of TSO grid model & transmission to TSCNET	Compiling of TSO grid model & transmission to TSCNET	The TSO compiles the TSO grid model and transmits it to TSCNET	TSO	TSCNET	25

Scenario name:						
Step No.	**Event**	**Name of process/ activity**	**Description of process/ activity**	**Information producer (actor)**	**Information receiver (actor)**	**Informa-tion ex-change d (IDs)**
1.18	Compiling of European grid model & calculation of gird congestions	Compiling of European grid model & calculation of grid congestions	TSCNET compiles from all TSO grid model the European grid model. Using this common grid model, the grid congestions are calculated.	TSCNET	TSO	26
1.19	Redispatch Platform collects possible flexibility bids and forwards them	Collecting possible flexibility bids and forwarding them	The Redispatch Platform receives and collects the possible flexibility bids, activatable as redispatch and/ or as balancing energy product. After GCT of redispatch, the Redispatch Platform forwards the collected flexibility bids to the redispatch provision process, if the bidding aggregator is prequalified for the redispatch process.	Redispatch Platform	TSO or balancing energy market	27
1.20	TSO receives all available flexibility bids for redispatch	Receiving available flexibility bids for redispatch	The TSO knows the grid congestions and receives all available flexibility bids (that are prequalified for redispatch) as possible remedial actions together with the conventional redispatch potential of large-scale power plants.			
1.21	TSO performs the redispatch calculation process	Redispatch calculation process	Thereupon, the TSO performs the redispatch calculation process in order to find the optimal solution to the redispatch problem. During this step, the TSO determines which bids should be selected to			

Scenario name:						
Step No.	***Event***	***Name of process/ activity***	***Description of process/ activity***	***Information producer (actor)***	***Information receiver (actor)***	***Information exchanged (IDs)***
			relieve the congestions in the grid.			
1.22	The TSO sends the bid accept message	Forwarding bid accept message	The TSO forwards the bid accept message to the Redispatch Platform.	TSO	Redispatch Platform	28
1.23	RD clearing process	RD clearing process	The clearing of the RD process takes place. For bids whose bidders are prequalified for redispatch provision and balancing market, the Redispatch Platform updates the status of flexibility bids whether they are still available for balancing energy. Bids accepted for redispatch can't be selected anymore for the provision of balancing energy. Moreover, all balancing bids that are offered for the same product time slice by the same aggregator of an accepted redispatch bid, are deleted if they have the opposite energy direction of the accepted redispatch bid (including also the time of the catch-up effect enveloped curve defined in task 3.2).			
1.24	The Redispatch Platform sends information about accepted flexibility bids to aggregator	Sending information about accepted flexibility bids	After the clearing of the RD process, the Redispatch Platform sends information back to the aggregator whether the flexibility bids have been accepted for redispatch.	Redispatch Platform	Aggregator	29

Scenario name:						
Step No.	***Event***	***Name of process/ activity***	***Description of process/ activity***	***Information producer (actor)***	***Information receiver (actor)***	***Information exchanged (IDs)***
1.25	Aggregator forwards bid accept message to industrial flexibility units	Distributing bid accept message to industrial flexibility units	The aggregator distributes the information about accepted bids to the single industrial flexibility units.	Aggregator	Industrial flexibility unit	30
1.26	Industrial flexibility unit updates its operational schedule	Industrial flexibility unit updates its operational schedule	The industrial flexibility unit takes the information according to the accepted flexibility bids and updates its operational schedule.			
1.27	The aggregator submits remaining flexibility bids to balancing energy market	Submission of remaining flexibility bids to balancing energy market	The aggregator submits remaining bids, that are prequalified balancing energy, to the balancing energy market.	Aggregator	Balancing energy market	31
1.28	Balancing energy clearing process	Balancing energy clearing process	After GCT of the balancing energy market (t-60min), the clearing of the balancing energy tender takes place and the market sends information back to the aggregator, whether and at which price the flexibility bids have been selected.	Balancing energy market	Aggregator	32, 33
1.29	Aggregator forwards bid accept message to industrial flexibility units	Distributing bid accept message to industrial flexibility units	The aggregator distributes information about accepted bids and the prices to the single industrial flexibility units and transmits the new schedule information.	Aggregator	Industrial flexibility unit	34, 35
1.30	TSO sends activation signal	Sending activation signal	The TSO sends the activation signal for the balancing energy product to the aggregator.	TSO	Aggregator	36

Scenario name:						
Step No.	***Event***	***Name of process/ activity***	***Description of process/ activity***	***Information producer (actor)***	***Information receiver (actor)***	***Information exchanged (IDs)***
1.31	Aggregator forwards activation signal	Forwarding of activation signal	The aggregator forwards the activation signal for the balancing energy product to the industrial flexibility unit.	Aggregator	Industrial flexibility unit	37
1.32	Industrial flexibility unit delivers balancing energy	Delivery of balancing energy	The industrial flexibility unit delivers the balancing energy product after the receiving the activation signal			
1.33	Aggregator forwards measured activation signal to TSO	Aggregation of measured activation signal	The aggregator receives the measured activation signals from the industrial flexibility units, aggregates them to forwards them to the TSO.	Industrial flexibility unit	Aggreator	38
1.34	TSO receives measured activation signal for balancing energy product	Receiving of activation signal	The TSO receives the measured activation signals for the balancing energy product, to use it for billing.	Aggregator	TSO	39
1.35	Aggregator provides updated ID forecast data	Aggregator provides forecast data	The aggregator provides all the forecast data that the industrial flexibility unit needs for its optimization of the schedule.	Aggregator	Industrial flexibility unit	40
1.36	Industrial flexibility unit is updating its operational schedule	Updating its operating schedule	The industrial flexibility unit takes the information about the accepted flexibility bids and updates its schedule.			
1.37	Industrial flexibility unit creates ID optimization schedule	Optimization of intraday bid and ask energy amounts	The industrial flexibility optimizes with objective to maximize revenues on the ID market and compensate forecast errors.	Industrial flexibility unit	Aggregator	41

Scenario name:						
Step No.	***Event***	***Name of process/ activity***	***Description of process/ activity***	***Information producer (actor)***	***Information receiver (actor)***	***Information exchanged (IDs)***
1.38	Aggregator sends request for ID amounts	ID trading	The aggregator trades the aggregated bid and ask bids at the ID market.	Aggregator	ID market	42
1.39	Market clearing process	Market clearing process	The clearing of the ID market takes place, and the market sends information back to the aggregator, whether and at which price (pay as bid) the bids have been accepted.	ID market	Aggregator	43, 44
1.40	Aggregator forwards information about accepted ID bids	Forwarding information about accepted ID bids	The aggregator forwards to the industrial flexibility unit the information which ID bids and at which price they have been accepted	Aggregator	Industrial flexibility unit	45, 46
1.41	Industrial flexibility unit is updating its operational schedule	Industrial flexibility unit is updating its operating schedule	The industrial flexibility unit takes the information according to the accepted bids and updates its operating schedule.			

iii. Information exchanged

Information exchanged (ID)	*From*	*To*	*Name of information*	*Description of information exchanged*
1	Agg	Ind	DA prices	Forecast of day-ahead prices [€/MWh]
2	Agg	Ind	Balancing capacity prices	Forecast of balancing capacity prices [€/MWh]
3	Agg	Ind	Balancing energy prices	Forecast of balancing energy prices [€/MWh]
4	Agg	Ind	Balancing call probabilities	Balancing call probabilities
5	Ind	Agg	Balancing bids	Time series [MW] (or [kW])
6	Agg	Balancing capacity market	Balancing bids	Time series [MW] (or [kW])
7	Balancing capacity market	Agg	Accepted balancing bids	Time series [MW]
8	Balancing capacity market	Agg	Balancing prices of accepted bids	Balancing capacity prices [€/MWh]
9	Agg	Ind	Accepted balancing bids	Time series [MW] (or [kW])
10	Agg	Ind	Balancing prices of accepted bids	Balancing capacity prices [€/MWh]
11	Agg	Ind	Updated DA forecast	Forecast of day-ahead prices [€/MWh]
12	Ind	Agg	Operating schedule	Time series of planned industry DA schedule [MW] (or [kW])
13	Agg	DA market	Required DA volumes	Time series [MW] (or [kW])
14	DA market	Agg	Accepted DA volumes	Time series [MW] (or [kW])

Information exchanged (ID)	*From*	*To*	*Name of information*	*Description of information exchanged*
15	DA market	Agg	Real DA prices	Day-ahead clearing prices [€/MWh]
16	Agg	Ind	Real DA prices	Day-ahead clearing prices [€/MWh]
17	Agg	Ind	Accepted schedule	Time series of sold/purchased energy (should be the same) [kW]
18	Agg	Ind	Balancing energy prices	Updated forecast of balancing energy prices [€/MWh]
19	Agg	Ind	ID prices	Updated forecast of ID prices [€/MWh]
20	Ind	Agg	Operating schedule	Time series of planned industry schedule [kW]
21	Ind	Agg	Quarter-hourly flexibility potential	At the moment, we expect quarter-hourly time series of upward & downward shift potential [MWh] (or [kWh]). Details depend on further alignment between aggregator and industry
22	Ind	Agg	Flexibility potential costs	At the moment, we expect quarter-hourly time series of flexibility potential costs [€].Details depend on further alignment between aggregator and industry
23	Agg	TSO	Operating schedule	Time series of planned industry schedule [MW] (or [kW])
24	Agg	Redispatch Platform	Flexibility bids	List of flexibility bids as defined in task 3.2
25	TSO	TSCNET	TSO grid model	TSO grid model
26	TSCNET	TSO	European grid model	European grid model
27	Redispatch Platform	TSO	Flexibility bids	List of flexibility bids as defined in task 3.2
28	TSO	Redispatch Platform	Accepted flexibility bids	List of accepted flexibility bids for redispatch
29	Redispatch Platform	Agg	Accepted flexibility bids	List of accepted flexibility bids

Information exchanged (ID)	From	To	Name of information	Description of information exchanged
30	Agg	Ind	Accepted flexibility bids	Time series of change in energy consumption / production [MW] (or [kW])
31	Agg	Balancing market	Remaining flexibility / balancing bids	List of flexibility bids as defined in the balancing energy tender documents
32	Balancing energy market	Agg	Accepted balancing energy bids	Time series [MW]
33	Balancing energy market	Agg	Accepted balancing energy prices	Balancing energy prices [€/MWh]
34	Agg	Ind	Accepted balancing energy bids	Time series [MW]
35	Agg	Ind	Accepted balancing energy prices	Balancing energy prices [€/MWh]
36	TSO	Agg	Activation signal	Activation signal
37	Agg	Ind	Activation signal	Activation signal
38	Ind	Agg	Measured activation signal	Measured activation signal
39	Agg	TSO	Measured activation signal	Measured activation signal
40	Agg	Ind	ID forecast	Forecast of Intraday prices [€/MWh]
41	Ind	Agg	ID bid and ask bids	Time series of planned industry ID bid and ask bids (deltaP) [kW]
42	Agg	ID market	Required ID-Volumes	Time series [MW]
43	ID market	Agg	Accepted ID-Volumes	-Time series [MW]
44	ID market	Agg	Real ID prices	Intraday prices of accepted bids [€/MWh]

VII. UC5: DSO + Spot-Markets

Disclaimer: This use case template follows the IEC 62559-2 standard.

i. Description of the use case

a. Name of the use case

ID	Main purpose	Name of Use Case
05	DSO services + participation at spot markets	DSO + Spot markets

b. Version management

Version Management			
Version No.	Date	Name of Author(s)	Changes
1	15/09/2021	S. Henein	Initial draft
2	28.03.2022	All	Final and by partners reviewed Version

c. Scope and objectives of use case

Scope and Objectives of Use Case	
Scope	The focus of this UC is based on DSO/DSO interaction to enable a joint DSO-DSO capacity management within the energy system. The redispatch platform serves as a data exchange provider and as a filter for redispatch bids under consideration of grid restrictions from other DSOs. Industry partner perspective is similar to UC4a, where the Industry units shall be enabled to participate in spot-markets and offer their remaining flexibility as redispatch bids.
Objective(s)	• Minimize total costs for congestion management on DSO level and minimize grid losses • Ensure supply reliability/adequacy • Avoid grid congestions according to the following ranking: grid topology measures, measures defined in grid codes and grid connection contracts (e.g. Q(U), P(U), interruptible loads), grid tariff related measures (e.g. interruptible loads), limited market access, market-based flexibility – redispatch • Increase the usage of local flexibilities and the participation of more DSOs within the flexibility market
Related use case(s)	UC5 is similar to UC4a from industry perspective, but in UC5 the DSOs instead of the TSO can use the redispatch bids for congestions.

d. Narrative of use case

Narrative of Use Case
Description

Flex Unit Perspective: Electricity is purchased on the DA spot market and the flexibility is utilized for the trade on the DA spot market which results in a preliminary schedule for the entire day. In addition to the schedule the flexibility unit calculates an hourly (or possibly 15min) potential of upward/and downward shift potential (active power) and the respective costs.

Aggregator Perspective: The aggregator provides all the forecast data that the industrial flexibility unit operator needs for its optimization of the schedule.The aggregator trades the aggregated (from all participating flexibilities) schedules at the DA-market. After the market clearing process, the Aggregator receives the accepted bids and relays the infomation to the the Flex unit via the Redispatch platform.

Redispatch Platform Perspective:

Around 14:30 the redispatch platform allows the submission of redispatch bids by flexible units. Any such bids must be submitted until 18:00. After the deadline all available redispatch bids will be considered as possible remedial actions together with conventional redispatch potential of large-scale power plants and fed into the redispatch calculation processes. Bids must be simultaneously feasible (i.e. the activation of one bid may not impede the activation of another bid, until a more complex bid structure is defined and available).

The redispatch platorms serves as a data exchange tool which allows for the filtering of possible bids based on the consideration of the DSO restrictions. The available free capacity and redispatch requirements based on a capacity calculation are provided to the redispatch module.

DSO/TSO Perspective:

The DSO is performing a capacity calculation based on the short-term bottlenecks. It includes load and generation forecast as well as the available schedules of industrial flexibility units for the spot market. Interaction of active power management and reactive power management is to be considered. Further, the DSO select a number of bids (from 0 to n), based on grid needs and pricing of other flexibilities.

e. Key performance indicators (KPI)

Key performance indicators (KPIs)				
ID	***Name***	***Description***	***Unit***	***Calculation form***
IND.1.3	max pos/neg flexibility per component (technology)	maximum available positive/negative flexibility per component	[kW $\pm$]	survey $P_{pos,tech,max}$
IND.2.1	total revenues/ energy costs per use case 2-4	Total profit (energy costs) that can be generated annually under the conditions of the respective case study.	[€/year/site]	Energy costs are summarized In simulation coupled with network simulation: revenues: sum over one year offered quantity*price r*call c (0 or 1)

				$\Sigma_i\left(\omega_i \cdot \Sigma_t\left(r(t) \cdot c(t) \cdot \left(e_+(t) + e_-(t)\right)\right)\right)$
IND.2.2	cost reduction/ additional income per use case 2-4	Costs or additional revenues that can be reduced or generated under the conditions of the respective case study.	[€/year/site]	same principle as indicator above
IND.2.3	investment costs for flexibilization depending on use case 2-4	Investment costs to be incurred for the flexibilization measures in the respective case study.	[€]	survey
IND.2.4	additional OPEX for flexibilization	costs such as personnel costs, …	[€/year]	sum over representative days- flex calls * operating costs type and amount of operating costs for different components: from surveys
IND.2.5	additional redispatch costs for aggregator	Additional costs e.g. for additional ICT, personnel, ...	[€/year]	survey
IND.3.1	change of efficiency from provision of redispatch	It is possible that due to the provision of redispatch efficiencies change. This aspect is captured within this indicator.	[%]	Comparison of the following: 1) Sum over repr. Days weight*(E_{demand}(process)/ $E_{purchase}$) without RD provision As 1) but for RD provision
IND.3.2	change of emissions from provision of redispatch	Change in emissions generated by redispatch provision compared to the reference case.	[%/year]	As above but instead of E_{demand}/ $E_{purchase}$ here Emission factor*$E_{purchase}$
FLEX.1.1	total supply of redispatch per industry-peak performance	Peak performance provided for flexibility by the individual industrial sectors.	[MW]	survey $\sum_{i=1}^{n} peak\ performance\ provided\ for\ redispatch(i)\quad \forall\ industrail\ sectors$ i = # of TU in industrial sector

FLEX.1.2	total supply of redispatch per industry-energy content	Total amount of energy provided for flexibility by the individual industrial sectors.	[MW]	survey $\sum_{i=1}^{n} \substack{total\ capacity \\ provided\ for\ redispatch(i)}$ $\forall\ industrail\ sectors$ n = # of TU in industrial sector
FLEX.2.1	Average cost per technology per call per hour per MW	Costs for a flexibility call, dependent on technology and the incentive model	[€/MWh]	survey
FLEX.2.2	Average cost per industry per call per hour per MW	Costs for a flexibility call, dependent on industrial sector and the incentive model	[€/MWh]	survey

f. Use case conditions

Use case conditions
Assumptions
• The Industrial flexibility unit operator is able to calculate a schedule DA of the planned production/consumption, within the simulation there will be used perfect forecasts • In case of demonstration: The Industrial flexibility unit operator is able to update these forecasts regularly (for ID trading), for the simulation there will be considered perfect forecasts and ID-trading is only considered for using price-spreads to gain additional revenues • All applicable grid fees will be considered • The optimization tool for industry is also capable to reduce the maximum peak power (and therefore grid fees) within the rolling horizon optimization • As a simulation timeframe will be chosen - (market and production-)representative 5-10 weeks • The simulation is carried out as a rolling horizon optimization • A model of the grid is available for load flow calculations • Availability of controllable active power devices in the grid model in the form of generators • The location of flexibility units is known • Network restrictions must be considered • Hourly or quarter-hourly solution possible for simulations
Prerequisites
• DA-price forecasts (provided by aggregator) • Grid fees for all industry sites • Historical consumption profiles • For Demonstrations: Forecast of the planned consumption (for the next day and updated ID schedules) of industrial flexibility units is possible

- Detailed optimization model which considers all physical constraints of the industrial flexibility unit
- Exemplary load and generation profiles (including forecasted profiles) and characteristics are available for each bus
- Load and generation schedules between aggregators and DSOs are exchanged via the BRP and also available on the redispatch platform for the bid filter. Other needed information/data (flex need, flex-offers, including location and costs) is exchanged via the central redispatch platform.
- Coordination (and related data exchange) between all involved grid operators via Redispatch platform
- Network restrictions and redispatch limitations should be exchanged between SOs and via the central redispatch platform.

ii. Common Terms and Definitions

Common Terms and Definitions	
Term	**Definition**
D-1	Day before delivery
D0	Day of delivery
DA	Day-Ahead
ID	Intraday
aFRR	Automatic Frequency Restoration Reserve
BRP	Balancing responsible party
FC	Forecast
GOT	Gate opening time
GCT	Gate closure time
RD	Redispatch
UC	Use Case
TSCNET	Transmission System Operator Security Cooperation Network
DSO	Distribution system operator
TSO	Transmission system operator
SO	System operator, includes DSOs and TSO
MRC	Multi-regional coupling
Agg	Aggregator
Ind	Industry flex unit

g. Actors

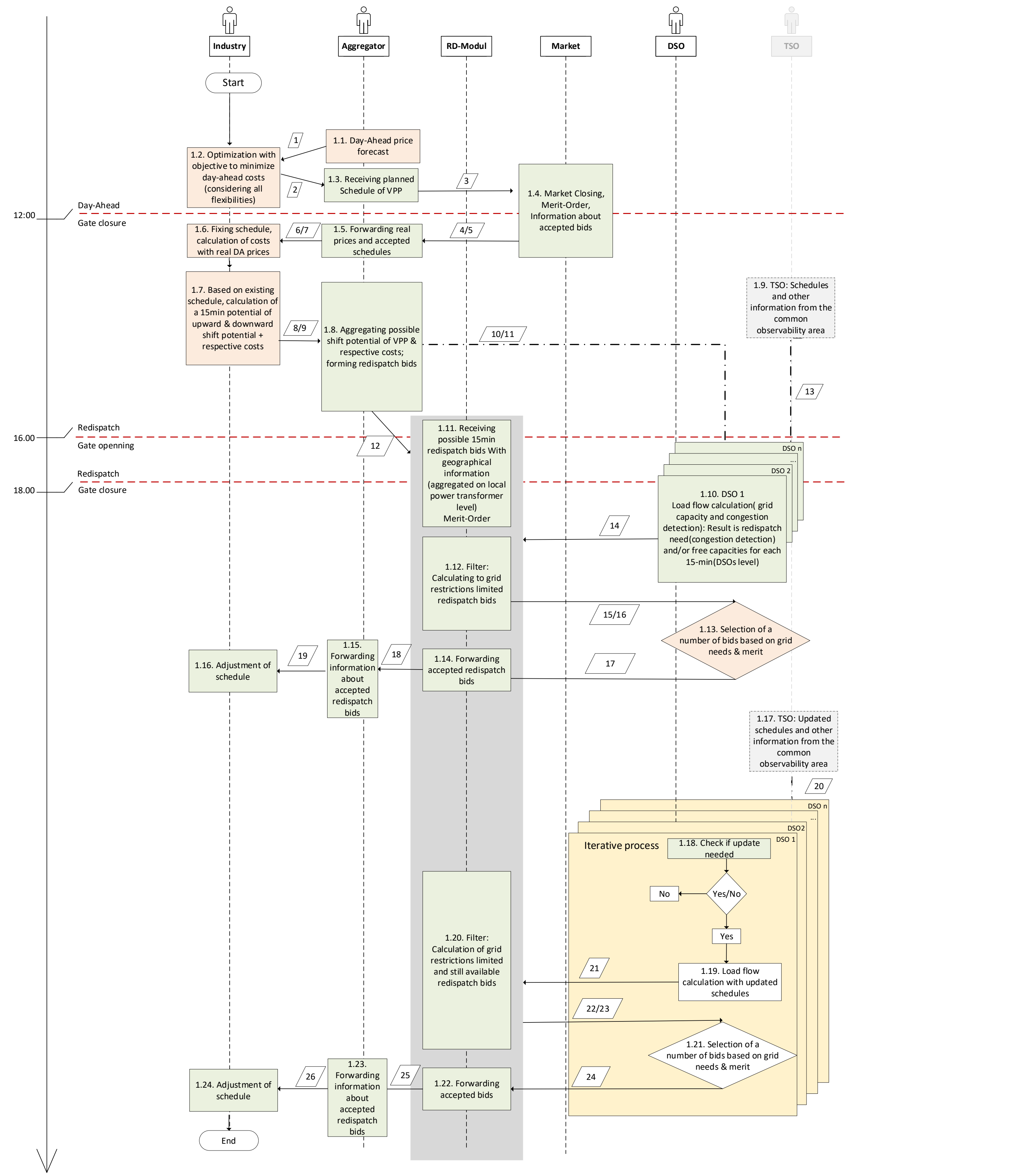
Actors		
Actor Name	***Actor Type***	***Actor Description***
Aggregator	Actor	Organisation offering energy services to the consumer, such as aggregation and pooling of flexibility bids but also in form of electricity delivery contracts.
Transmission System Operator (TSO)	Actor	According to the Article 2.4 of the Electricity Directive 2009/72/EC (Directive): "a natural or legal person responsible for operating, ensuring the maintenance of and, if necessary, developing the transmission system in a given area and, where applicable, its interconnections with other systems, and for ensuring the long-term ability of the system to meet reasonable demands for the transmission of electricity". Moreover, the TSO is responsible for connection of all grid users at the transmission level and connection of the DSOs within the TSO control area. In Austria, the TSO has also the role of the control area operator. Pursuant to section §23 (2) ElWOG 2010, the control area operator has the obligation to determine grid congestions in the transmission system; and to take measures to avoid, solve and to overcome grid congestions in transmission systems as well as to maintain security of energy supply.
TSCNET	Actor	TSCNET Services is one of Europe's leading Regional Security Coordinators (RSCs). TSCNET Services is currently entrusted with a set of mandatory services for its customers according to EU legislation: • Coordinated Security Analysis • Coordinated Capacity Calculation • Outage Planning Coordination • Short and Medium Term Adequacy forecasts • Improved Individual Grid Models and Common Grid Model
Day Ahead Market	Service	The Day Ahead market is operated through a blind auction which takes place once a day, all year round. All hours of the following day are traded in this auction. The orders are logged in by the market participants before the order book closes at 12:00. As a result of the order matching, the Power Exchange determines trades which are legally binding agreements to purchase or sell a determined quantity of electricity to a defined delivery area for the matched (or "cleared") price. There is one price, the market clearing price or

Actors		
Actor Name	**Actor Type**	**Actor Description**
		MCP, that is determined for each delivery period and that applies to all buyers and sellers. The EPEX SPOT DA auction is integrated into the Multi-Regional Coupling (MRC) which encompasses the Baltics, Central Western Europe, Great Britain and the Nordics.
Intraday Market	Service	On the ID market, market participants trade continuously, 24 hours a day, with delivery on the same day. As soon as a buy- and sell-order match, the trade is executed. Electricity can be traded up to 5 minutes before delivery and through hourly, half-hourly or quarter-hourly contracts. As this allows for a high level of flexibility, members use the ID market to make last minute adjustments and to balance their positions closer to real time.
Balancing Capacity Market	Service	'Balancing Market' means the entirety of institutional, commercial and operational arrangements that establish market-based management of balancing. Balancing capacity means a volume of reserve capacity that a balancing service provider has agreed to hold and in respect to which the balancing service provider has agreed to submit bids for a corresponding volume of balancing energy to the TSO for the duration of the contract. The flexibility provider gets remunerated for the amount of reserved capacity.
Balancing Energy Market	Service	Balancing energy means energy used by TSOs to perform balancing and provided by a balancing service provider. Every plant which has participated in the balancing capacity market also has to set a price for the balancing energy market. Moreover it is also possible to participate in this market in the ID timeframe, without prior participation at the balancing capacity market. The flexibility provider get remunerated for the balancing energy which has been activated by the TSO.
Industrial flexibility unit	Actor	An industrial consumption or generation asset in the electrical power grid which has the capability to deviate – to some extent - from its planned schedule in order to provide redispatch. It is preconditioned that the industrial flexibility unit fulfils the necessary requirements for redispatch according to the defined list in task 3.2 and is prequalified for the provision of redispatch.

Actors		
Actor Name	**Actor Type**	**Actor Description**
Industrial flexibility unit operator	Role	Role which links the role customer and its possibility to provide flexibilities to the redispatch provision process by the operated industrial consumption or generation asset.
Redispatch Platform	Service	Platform to which flexibility service providers send their redispatch bids. The Redispatch Platform collects and manages these redispatch bids and forwards them to the TSO as potential remedial actions. After the redispatch calculation process, the platform forwards bid accept messages to those flexibility service providers whose redispatch bids are accepted.
Balance Responsible Party (BRP)	Actor	BRPs are responsible for maintaining supply and demand on the energy market within their own portfolio.Their tasks: • obtain day ahead consumption forecasts from all the suppliers in their balancing responsible party • send these forecasts to the clearing and settlement agent • pay the clearing and settlement agent for the imbalance settlement energy • bill the suppliers for the balancing energy required

h. Sequence diagram(s) of use case

Sequence diagram(s) of use case



i. Step by step analysis of use case

Scenario name:						
Step No.	***Event***	***Name of process/ activity***	***Description of process/ activity***	***Information producer (actor)***	***Information receiver (actor)***	***Information Exchanged (IDs)***
1.1	Aggregator provides forecast data	Providing forecast	The aggregator provides all the forecast data that the industrial flexibility unit operator needs for its optimization of the schedule.	Aggregator	Industrial flexibility unit operator	1
1.2	Industrial flexibility unit operator produces optimization schedule	Optimization of DA-schedule	The industrial flexibility unit operator creates a schedule for the next day by using an optimization tool and forecasts for demand and prices.	Industrial flexibility unit operator	Aggregator	2
1.3	Aggregator sends request for DA-amounts at markets	DA-trading	The aggregator trades the aggregated Schedules at the DA-market	Aggregator	Market	3
1.4	Market clearing process	Market clearing process	The clearing of the market takes place, and the market sends information back to the Aggregator, whether and at which price (clearing price) the bids have been accepted.	Market	Aggregator	4,5
1.5	Aggregator is forwarding the acceptation signals to the industrial flexibility unit	Forwarding information to industrial flexibility unit	The aggregator forwards the information, whether and (maybe) at which price the schedules have been accepted to the Industrial flexibility unit .	Aggregator	Industrial flexibility unit	6,7

Scenario name:						
Step No.	***Event***	***Name of process/ activity***	***Description of process/ activity***	***Information producer (actor)***	***Information receiver (actor)***	***Information Exchanged (IDs)***
1.6	Industrial flexibility unit is updating its operational schedule	Industrial flexibility unit is updating its operational schedule	The industrial flexibility unit takes the information about the accepted bids and updates its schedule.	Industrial flexibility unit		
1.7	Redispatch potential is calculated based on the DA schedule	Calculation of redispatch potential and price	The redispatch potential for industry is calculate based on the DA schedule, considering the available industry-internal flexibility.	Industry	Aggregator	8,9
1.8	Aggregator forwards aggregated redispatch potential to the RP (redispatch platform)	Forwarding aggregated redispatch potential to the RD platform	The aggregator aggregates and links the geographical information with the redispatch bids and sends them to the redispatch platform	Aggregator	RP	12
1.9	TSO sends information about grid congestions to DSO	Information transfer from TSO to DSO(s)	The TSO is obliged to send schedules and other information from the observability area to the DSOs.	TSO	DSO	13
1.10	DSO peforms cacapcity calculations	Calculation of redispatch-need and free capacities.	The DSOs are carrying out load flow calculations, the result is the redispatch need and free capacities for each 15-min. (with safety margin)	DSO	RP	14

Scenario name:						
Step No.	**Event**	**Name of process/ activity**	**Description of process/ activity**	**Information producer (actor)**	**Information receiver (actor)**	**Information Exchanged (IDs)**
1.11	Bids are received by the redispatch platform	Schedules received by redispatch platform.	The redispatch platform is receiving the bids and processing them in the internal system.	Agg	DSO	12
1.12	Bid filtering process is applied	Redispatch platform filter is applied	Considering the grid restrictions from all DSOs, the redispatch bids are filtered, “restrained” bids won’t be able to chosen by the DSO	RP	DSO	15,16
1.13	Selection of bids	DSOs are selecting the bids needed, to solve their congestion.	The DSOs are allowed to choose bids for their redispatch use in their own grid area. The information about the chosen bids is sent to the RP. The detailed order (who is allowed to choose first) will be defined later in the project.	DSO	RP	17
1.14	Tansfer of bid acceptance information	Forwarding acceptance information	The redispatch platform is sending the accepted bids to the aggregator.	RP	Agg	18
1.15.	Forwarding information about accepted redispatch bids	Forwarding acceptance information	The aggregator sends the updated operating schedule for flexibility activation to industrial flexibility unit s	Agg	Ind	19
1.16.	Adjustment of industry schedule	Schedule update	The industrial flexibility unit receives the information about the by the DSOs accepted			

Scenario name:						
Step No.	***Event***	***Name of process/ activity***	***Description of process/ activity***	***Information producer (actor)***	***Information receiver (actor)***	***Information Exchanged (IDs)***
			bids and has to adjust their schedules accordingly.			
1.17	TSO sends information about grid congestions to DSO	Information transfer to DSO(s)	If the schedules are updated, the TSO will send new schedules and information within the common TSO-DSO observability area to the DSO.	TSO	DSO	20
1.18	DSO checks if an update in redispatch selection is required	DSO checks congestion situation	The DSO does new calculations and checks, whether there is a new congestion situation.			
1.19	DSO peforms cacapcity calculations	Calculation of redispatch-need and free capacities.	The DSOs are carrying out load flow calculations, the result is the redispatch need and/or free capacities for each 15-min. (with safety margin) which are sent with a request of available bids to the RP.	DSO	RP	21
1.20	Bid filtering process is applied	Redispatch platform filter is applied	Considering the grid restrictions from all DSOs, the redispatch bids are filtered, "restrained" bids won't be able to chosen by the DSO	RP	DSO	22,23
1.21	Selection of bids	DSOs are selecting the bids needed, to solve their congestion.	The DSOs are allowed to choose bids for their redispatch use in their own grid area. The information about the chosen bids is sent to the RP. The detailed order (who is allowed to choose first) will be	DSO	RP	24

Scenario name:						
Step No.	***Event***	***Name of process/ activity***	***Description of process/ activity***	***Information producer (actor)***	***Information receiver (actor)***	***Information Exchanged (IDs)***
			defined later in the project.			
1.22	Tansfer of bid acceptance information	Forwarding acceptance information	The redispatch platform is sending the accepted bids to the aggregator.	RP	Agg	25
1.23.	Transfor of bid acceptance information	Forwarding acceptance information	The aggregator sends the updated operating schedule for flexibility activation to industrial flexibility unit s	Agg	Ind	26
1.24	Adjustment of industry schedule	Schedule update	The industrial flexibility unit receives the information about the by the DSOs accepted bids and has to adjust their schedules accordingly.			

iii. Information exchanged

Information exchanged (ID)	***From***	***To***	***Name of information***	***Description of information exchanged***
1	Agg	Ind	DA Forecast	Forecast of DA-Prices [€/MWh]
2	Ind	Agg	Operating Schedule	Timeseries of planned Industry DA-Schedule [kW]
3	Agg	Market	Required DA-Volumes	Timeseries [MW]
4	Market	Agg	Accepted DA-Volumes	Timeseries [MW]
5	Market	Agg	Real DA prices	DA-Clearing Prices [€/MWh]
6	Agg	Ind	Accepted Schedule	Timeseries of sold volumes (should be the same) [kW]
7	Agg	Ind	Optional: Real DA prices	DA-Clearing Prices [€/MWh]
8	Ind	Agg	Redispatch bids	For every bid, ΔP in positive or negative direction [kW]

Information exchanged (ID)	*From*	*To*	*Name of information*	*Description of information exchanged*
9	Ind	Agg	Redispatch bid price	Price for activating that potential per timestep [€/MWh]
10	Agg	DSO	Schedules of single industry units	Timeseries [MW]
11	Agg	DSO	Geographical information	At which grid node is the industry unit with this schedule located
12	Agg	RP	Redispatch bids	For every bid, ΔP in positive or negative direction [kW]
13	TSO	DSO	Schedules and other information from the common observability area	Timeseries [MW]
14	DSO	RP	Capacity information (DSO)	Schedules [MW] plus free capacities in positive and negative direction [MW]
15	RP	DSO	Available Redispatch child bids	Feasible bids [MW] for each timestep
16	RP	DSO	Geographical Information of child bids	Locational information for the bids
17	DSO	RP	Selected bids	ID of selected bids
18	RP	Agg	Total selected bids	All selected bids [MW]
19	Agg	Ind	ΔP schedule change	ΔP schedule change [MW]
20	TSO	DSO	Schedules and other information from the common observability area	Timeseries [MW]
21	DSO	RP	Capacity information (DSO)	Schedules [MW] plus free capacities in positive and negative direction [MW]
22	RP	DSO	Available Redispatch child bids	Feasible bids [MW] for each timestep
23	RP	DSO	Geographical Information of child bids	Locational information for the bids
24	DSO	RP	Selected bids	ID of selected bids
25	RP	Agg	Total selected bids	All selected bids [MW]
26	Agg	Ind	ΔP schedule change	ΔP schedule change [MW]

VIII. UC 6a: DSO-TSO-decentral

Disclaimer: This use case template follows the IEC 62559-2 standard.

i. Description of the use case

a. Name of the use case

ID	Main purpose	Name of Use Case
6a	TSO + DSO services + participation in spot markets	DSO-TSO-decentral

b. Version management

Version Management			
Version No.	**Date**	**Name of Author(s)**	**Changes**
1	20.10.2021	Regina Hemm	Initial draft
2	28.03.2022	All	Final and by partners reviewed Version

c. Scope and objectives of use case

Scope and Objectives of Use Case	
Scope	The focus lies on the interaction of DSO and TSO to enable a joint TSO-DSO capacity management. The redispatch platform serves only as a data provider and filter of available bids (considering the grid restrictions of DSOs and TSO), no optimization of redispatch bids is happening on the platform. Industry partner perspective is similar to UC4a, where they shall be enabled to participate in spot-markets and offer their remaining flexibility as redispatch bids
Objective(s)	Activate potential redispatch bids in a coordinated manner between DSO and TSO. Aim is to minimize total system costs and avoid uneconomical contradicting activations of DSOs and TSOs.
Related use case(s)	UC4 and UC5 are combined, additionally the TSO-DSO interaction is introduced.

d. Narrative of use case

Narrative of Use Case
Short description
Flex Unit Perspective: Electricity is purchased on the DA spot market and the flexibility is utilized for the trade on the DA spot market which results in a preliminary schedule for the entire day. In addition to the schedule the flexibility unit calculates an hourly (or possibly 15min) potential of upward/and downward shift potential (active power) and the respective costs, which are further aggregated by the aggregator to redispatch bids.

Aggregator Perspective: The aggregator provides all the forecast data that the industrial flexibility unit operator needs for its optimization of the schedule.The aggregator trades the aggregated (from all participating flexibilities) schedules at the DA-market. After the market clearing process, the Aggregator receives the accepted bids and forwards the infomation to the the Industrial flexibility unit operator, which now calculated and provides the shift-potential for redispatch. The aggregator creates redispatch bids, which have to be simultaneously feasible (until a more complex bid structure is defined and available). **Redispatch platform Perspective:** Around 14:30 the redispatch platform allows for the submission of redispatch bids by flexibilities. Any such bids must be submitted until 18:00. The redispatch platorms serves as a data exchange tool and additionally allows the filtering of possible bids based on the consideration of the DSO grid restrictions. The available free capacity and redispatch requirements based on capacity calculations by the DSOs are provided to the redispatch module. The redispatch platform then provides all feasible bids to the DSOs/TSO. **DSO/TSO Perspective:** The DSO is performing a capacity calculation based on the short-term bottlenecks. It includes load and generation forecast as well as the available schedules of industrial flexibility unit s for the spot market. Interaction of active power management and reactive power management is to be considered. Further the DSOs first select a number of available bids (from 0 to n), based on grid needs and pricing of other flexibilities. The redispatch platform applies a filter based on the selection and the limitations of the distribution grid and provides all still available bids to the TSO. All of these redispatch bids are considered as possible remedial actions together with conventional redispatch potential of large-scale power plants and fed into the redispatch calculation processes. The ouput is again a (TSO) selection of redispatch bids.

e. Key performance indicators (KPI)

Key performance indicators (KPIs)				
ID	***Name***	***Description***	***Unit***	***Calculation form***
IND.1.3	max pos/neg flexibility per component (technology)	maximum available positive/negative flexibility per component	[kW $\pm$]	survey $P_{pos,tech,max}$
IND.2.1	total revenues/ energy costs per use case 2-4	Total profit (energy costs) that can be generated annually under the conditions of the	[€/year/site]	Energy costs are summarized In simulation coupled with network simulation: revenues: sum over one year offered quantity*price r*call c (0 or 1)

		respective case study.		$\Sigma_i \left(\omega_i \cdot \Sigma_t \left(r(t) \cdot c(t) \cdot \left(e_+(t) + e_-(t)\right)\right)\right)$
IND.2.2	cost reduction/ additional income per use case 2-4	Costs or additional revenues that can be reduced or generated under the conditions of the respective case study.	[€/year/site]	same principle as indicator above
IND.2.3	investment costs for flexibilization depending on use case 2-4	Investment costs to be incurred for the flexibilization measures in the respective case study.	[€]	survey
IND.2.4	additional OPEX for flexibilization	costs such as personnel costs, …	[€/year]	sum over representative days- flex calls * operating costs type and amount of operating costs for different components: from surveys
IND.2.5	additional redispatch costs for aggregator	Additional costs e.g. for additional ICT, personnel, ...	[€/year]	survey
IND.3.1	change of efficiency from provision of redispatch	It is possible that due to the provision of redispatch efficiencies change. This aspect is captured within this indicator.	[%]	Comparison of the following: 1) Sum over repr. Days weight*(E_{demand}(process)/ $E_{purchase}$) without RD provision As 1) but for RD provision
IND.3.2	change of emissions from provision of redispatch	Change in emissions generated by redispatch provision compared to the reference case.	[%/year]	As above but instead of E_{demand}/ $E_{purchase}$ here Emission factor*$E_{purchase}$
FLEX.1.1	total supply of redispatch per industry-	Peak performance provided for flexibility by the individual	[MW]	survey $\sum_{i=1}^{n} peak\ performance\ provided\ for\ redispatch(i)$ $\forall\ industrail\ sectors$

	peak performance	industrial sectors.		I = # of TU in industrial sector
FLEX.1.2	total supply of redispatch per industry-energy content	Total amount of energy provided for flexibility by the individual industrial sectors.	[MW]	survey $$\sum_{i=1}^{n} \begin{matrix} total\ capacity \\ provided\ for\ redispatch(i) \end{matrix}$$ $$\forall\ industrail\ sectors$$ n = # of TU in industrial sector
FLEX.2.1	Average cost per technology per call per hour per MW	Costs for a flexibility call, dependent on technology and the incentive model	[€/MWh]	survey
FLEX.2.2	Average cost per industry per call per hour per MW	Costs for a flexibility call, dependent on industrial sector and the incentive model	[€/MWh]	survey
TSO.1.1	Number of hours on which redispatch was retrieved	Total number of hours in a year in which flexibility is retrieved	[h]	estimation TSO $$\sum_{i=1}^{8760} 1_A(i)$$ $A = \{i: amount\ of\ redispatch\ \neq\ 0\}$
TSO.1.2	Total amount of energy called for redispatch by industry per hour per year	Total amount of energy required annually for retrieval of flexibility by the industry	[MWh/year]	estimation TSO $\sum_{i=1}^{8760} amount\ of\ redispatch\ provided\ by\ industr$
TSO.1.3	Typical duration of congestion	Average time interval a congestion lasts.	[h]	estimation TSO $$\frac{1}{n}\sum_{i\,=\,1}^{n} duration\ redispatch\ retrieval(i)$$ n = # redispatch retrievals per year
TSO.2.1	Cost savings for redispatch with I4RD compared to	Redispatch costs that can be saved by integrating industry through the I4RD project.	[€]	estimation TSO $$cost\ RD--cost\ I4RD$$

	conventional redispatch			
TSO.1.4	Savings through I4RD in contrast to redispatch through conventinal power plants	Power that is needed less compared to conventional redispatch using I4RD	[MW]	estimation TSO *required peak power RD – required peak power I4RD*
TSO.1.5	Energy amounts of conventional redispatch that can be prevented by redispatch with I4RD	Energy amounts that can be avoided by integrating industry through the I4RD project.	[MWh/year]	estimation TSO *amount of energy RD – amount of energy I4RD*
TSO.1.6	predicted n-1/n-0 violations per transition point	amount of predicted events where the failure of a component cannot be prevented by redundancies	[#]	estimation TSO *predicted n-1 violations before remedial actions – predicted n-1 violations after remedial actions*
DSO.4.1	compliance with technical restrictions	This factor is considered to have a value between 0 and 1, where 1 is used to indicate that there are no network restrictions on the distribution network, due to the activation of the flexibility, and therefore no impact on any node within the transmission grid	[0,1]	simulation in WP 5

f. Use case conditions

Use case conditions
Assumptions
• Industrial flexibility unit operator is able to calculate a schedule DA of planned production/consumption + free capacities + correlating prices. • DSO receives information about flex bids and is allowed to choose the ones, which are necessary for avoiding congestions in the grid area within DSO-responsibility. • The Order in which the DSOs are allowed to choose bids still has to be determined. It could be either a "everyone chooses bids in their own grid area first" or a "first come first serve" way. It should not play a role at this point, and is left open to discuss. • Platform filters the flex-bids depending on which can or cannot be activated by DSO and TSO, in order to avoid congestions. • Redispatch platform serves as a data exchange platform between aggregator and system operators • Direct ways for schedule and information exchange between DSO and TSO will be used. • Locational information for the bids is available • The exact pooling will be defined in Task 3.2., but a parent-child linking could be a preferable solution for the different bid-size-requriements of DSOs and TSOs. DSOs would mainly access child bids and the TSO would use parent-bids. • Hourly or quarter-hourly solution possible for simulations
Prerequisites
• Industry: DA-price forecasts available (provided by aggregator) • Industry: Forecast of planned production is possible • DSO: Availability of power forecast of the TSO at the common node (other DSOs not considered-otherwise, bilateral information exchange) • TSO: Availability of power forecast of the DSO at the common node • DSO: Ability to do a load flow analysis and capacity calculation/estimation to identify possible congestions • TSO: Load flow analysis based on this information • Definition of redispatch bids as per 3.2 completed • TSO: Data exchange of redispatch bids as per task 3.2 is defined • Existence of a defined data model and communication protocols between all the involved actors, roles and services.

ii. Common Terms and Definitions

D-1	Day before delivery
D0	Day of delivery
DA	Day-Ahead
ID	Intraday
aFRR	Automatic Frequency Restoration Reserve

BRP	Balancing responsible party
FC	Forecast
GOT	Gate opening time
GCT	Gate closure time
RD	Redispatch
UC	Use Case
TSCNET	Transmission System Operator Security Cooperation Network
DSO	Distribution system operator
TSO	Transmission system operator
SO	System Operator
MRC	Multi-regional coupling
Agg	Aggregator
Ind	Industry flex unit

g. Actors

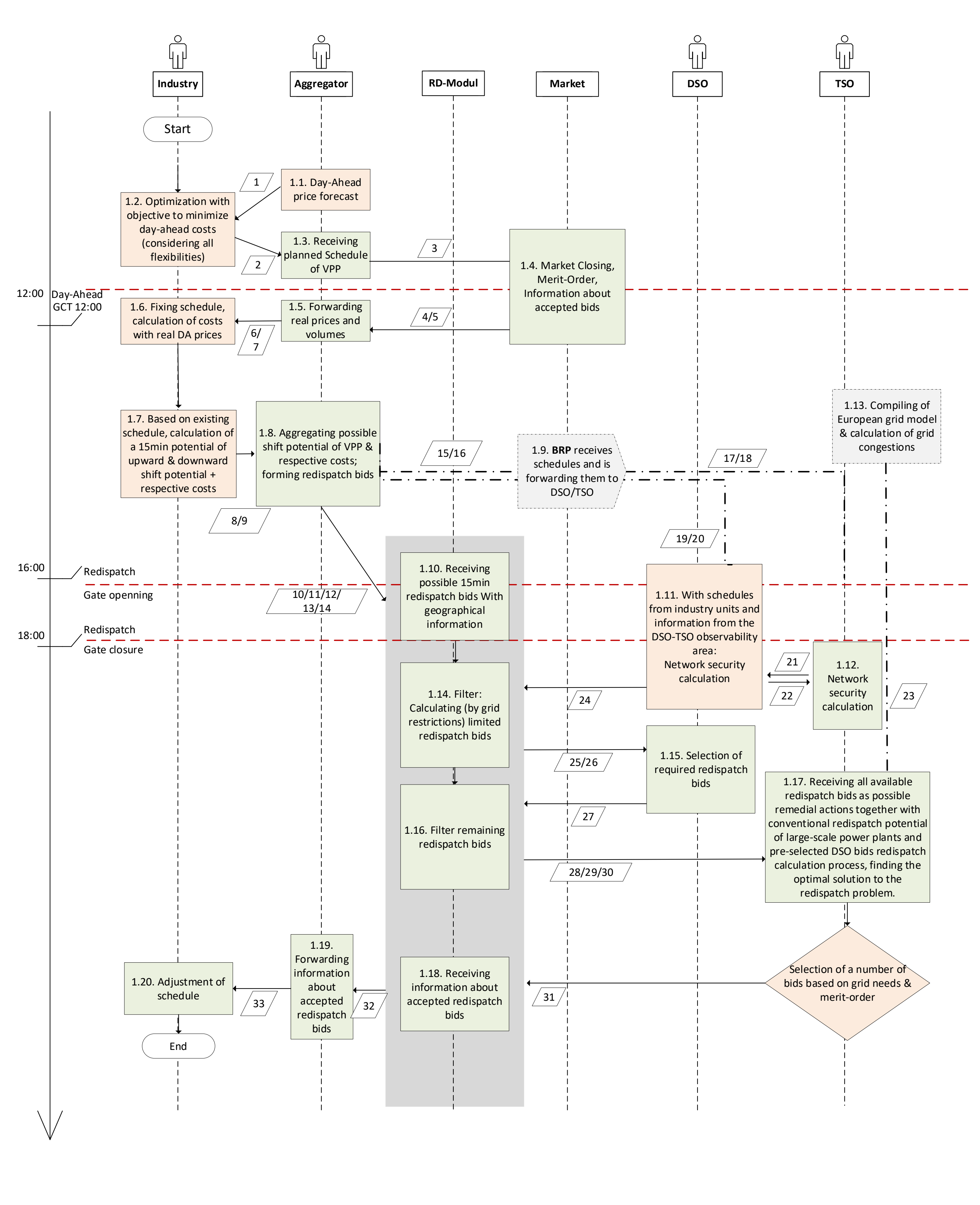
Actors		
Actor Name	***Actor Type***	***Actor Description***
Aggregator	Actor	Organisation offering energy services to the consumer, such as aggregation and pooling of flexibility bids but also in form of electricity delivery contracts.
Transmission System Operator (TSO)	Actor	According to the Article 2.4 of the Electricity Directive 2009/72/EC (Directive):“"a natural or legal person responsible for operating, ensuring the maintenance of and, if necessary, developing the transmission system in a given area and, where applicable, its interconnections with other systems, and for ensuring the long-term ability of the system to meet reasonable demands for the transmission of electricit”". Moreover, the TSO is responsible for connection of all grid users at the transmission level and connection of the DSOs within the TSO control area. In Austria, the TSO has also the role of the control area operator. Pursuant to section §23 (2) ElWOG 2010, the control area operator has the obligation to determine grid congestions in the transmission system; and to take measures to avoid, solve and to overcome grid congestions in transmission systems as well as to maintain security of energy supply.

Actors		
Actor Name	**Actor Type**	**Actor Description**
TSCNET	Actor	TSCNET Services is one of Europe's leading Regional Security Coordinators (RSCs). TSCNET Services is currently entrusted with a set of mandatory services for its customers according to EU legislation: • Coordinated Security Analysis • Coordinated Capacity Calculation • Outage Planning Coordination • Short and Medium Term Adequacy forecasts • Improved Individual Grid Models and Common Grid Model
Day Ahead Market	Service	The Day Ahead market is operated through a blind auction which takes place once a day, all year round. All hours of the following day are traded in this auction. The orders are logged in by the market participants before the order book closes at 12:00. As a result of the order matching, the Power Exchange determines trades which are legally binding agreements to purchase or sell a determined quantity of electricity to a defined delivery area for the matched (or "cleared") price. There is one price, the market clearing price or MCP, that is determined for each delivery period and that applies to all buyers and sellers. The EPEX SPOT DA auction is integrated into the Multi-Regional Coupling (MRC) which encompasses the Baltics, Central Western Europe, Great Britain and the Nordics.
Flexibility service provider	Role	Party which offers flexibility bids on the Redispatch Platform. This role can be taken by an aggregator (in case that several industrial flexibility units are aggregated to a pool in order to aggregate flexibilities of various industrial flexibility units to one flexibility bid) or directly by an industrial flexibility unit operator (if the industrial flexibility unit is large enough to fulfil the minimal bid size).
Industrial flexibility unit	Actor	An industrial consumption or generation asset in the electrical power grid which has the capability to deviate – to some extent–- from its planned schedule in order to provide redispatch. It is preconditioned that the industrial flexibility unit fulfils the necessary requirements for redispatch according to the defined list in task 3.2 and is prequalified for the provision of redispatch.

Actors		
Actor Name	**Actor Type**	**Actor Description**
Industrial flexibility unit operator	Role	Role which links the role customer and its possibility to provide flexibilities to the redispatch provision process by the operated industrial consumption or generation asset.
Redispatch Platform	Service	Platform to which flexibility service providers send their redispatch bids. The Redispatch Platform collects and manages these redispatch bids and forwards them to the TSO as potential remedial actions. After the redispatch calculation process, the platform forwards bid accept messages to those flexibility service providers whose redispatch bids are accepted.
Balance Responsible Party (BRP)	Actor	BRPs are responsible for maintaining supply and demand on the energy market within their own portfolio.Their tasks: • obtain day ahead consumption forecasts from all the suppliers in their balancing responsible party • send these forecasts to the clearing and settlement agent • pay the clearing and settlement agent for the imbalance settlement energy • bill the suppliers for the balancing energy required

h. Sequence diagram(s) of use case

Sequence diagram(s) of use case



i. Step by step analysis of use case

Scenario name:						
Step No.	***Event***	***Name of process/ activity***	***Description of process/ activity***	***Information producer (actor)***	***Information receiver (actor)***	***Information Exchanged (IDs)***
1.1	Aggregator provides forecast data	Aggregator provides forecast data	The aggregator provides all the forecast data that the industrial flexibility unit operator needs for its optimization of the schedule.	Aggregator	Industrial flexibility unit operator	1
1.2	Industrial flexibility unit operator produces optimization schedule	Optimization of DA-schedule	The industrial flexibility unit operator creates a schedule for the next day by using an optimization tool and forecasts for demand and prices.	Industrial flexibility unit operator	Aggregator	2
1.3	Aggregator sends request for DA-amounts at markets	DA-trading	The aggregator trades the aggregated Schedules at the DA-market	Aggregator	Market	3
1.4	Market clearing process	Market clearing process	The clearing of the market takes place, and the market sends information back to the Aggregator, whether and at which price (clearing price)	Market	Aggregator	4,5

Scenario name:						
Step No.	***Event***	***Name of process/ activity***	***Description of process/ activity***	***Information producer (actor)***	***Information receiver (actor)***	***Information Exchanged (IDs)***
			the bids have been accepted.			
1.5	Aggregator is forwarding the acceptation signals to the industrial flexibility unit	Forwarding information to industrial flexibility unit	The aggregator forwards the information, whether and (maybe) at which price the schedules have been accepted to the industrial flexibility unit .	Aggregator	Industrial flexibility unit	6,7
1.6	Industrial flexibility unit is updating its operational schedule	Industrial flexibility unit is updating its operational schedule	The industrial flexibility unit takes the information about the accepted bids and updates its schedule.	Industrial flexibility unit		
1.7	Redispatch potential is calculate based on the DA schedule	Calculation of Redispatch potential	Based on existing schedule, calculation of a 15min potential of upward & downward shift potential + respective costs	Industry	Aggregator	8,9
1.8	Aggregator forwards aggregated redispatch potential to the RD platform and schedules to the BRP	Forwarding aggregated redispatch potential to the RD platform and schedules to the BRP	The aggregator clusters the redispatch potential to redispatch bids and assigns a geographical information to them. Also the individual schedules are forwarded with	Aggregator	DSO/TSO	10,11,12,13, 14

Scenario name:						
Step No.	**Event**	**Name of process/ activity**	**Description of process/ activity**	**Information producer (actor)**	**Information receiver (actor)**	**Information Exchanged (IDs)**
			geo-information to the RP and to the BRP.			
1.9	Platform receives bids	Registration of redispatch bids on the RP	The redispatch platform receives the bids from all aggregators.	Agg	RP	14
1.10	Network security calculation DSO	Information transfer to RP	The DSOs are receiving the forecast schedules at the transformer stations of the TSO. The DSOs are carrying out load flow calculations, the result is the redispatch need and/or free capacities for each 15-min. (with safety margin)	DSO	RP	16,18
1.11	Network security calculation TSO	Information transfer to RP	The TSO is receiving the forecast schedules at the transformer stations of the DSO which are considered in the IGM. The IGM is then sent to TSCNET	TSO	DSO	15
1.12	Compiling of European grid model	Calculation of european	TSCNET is providing the output of the european grid model/grid	TSCNET	TSO	17

Scenario name:						
Step No.	**Event**	**Name of process/ activity**	**Description of process/ activity**	**Information producer (actor)**	**Information receiver (actor)**	**Information Exchanged (IDs)**
		redispatch demand	congestion calculation to the TSO.			
1.13	Bid filtering process is applied	Redispatch platform filter is applied	Considering the grid restrictions from all DSOs, the redispatch bids are filtered, "restrained" bids won't be able to be selected by the DSO/TSO.	RP	DSO	19,20
1.14	Selection of bids by DSO	DSOs are selecting the bids needed, to solve their congestion.	The DSOs are allowed to choose bids for their redispatch use in their own grid area. The information about the chosen bids is sent to the RP. The order in which the DSOs are allowed to choose flexibilities still has to be defined.	DSO	RP	21
1.15	Bid filtering process is applied	Redispatch platform filter is applied.	Considering the chosen bids from all DSOs, the redispatch bids are filtered, "restrained" bids won't be able to be chosen by the DSO/TSO.	RP	TSO	22,23,24

Scenario name:						
Step No.	**Event**	**Name of process/ activity**	**Description of process/ activity**	**Information producer (actor)**	**Information receiver (actor)**	**Information Exchanged (IDs)**
1.16.	Selection of bids by TSO	TSO is selecting the bids needed, to solve their congestion.	The TSO is receiving all the available redispatch bids as possible remedial actions together with conventional redispatch potential of large-scale power plants. Redispatch calculation process, finding the optimal solution to the redispatch problem. Selection of bids.	TSO	RP	25
1.17.	Transfer of accepted bid information RP-Agg	Forwarding acceptance information	The redispatch platform is sending the accepted bids to the aggregator.	RP	Agg	26
1.18.	Transfer of accepted bid information Agg-Ind	Forwarding acceptance information	The aggregator sends the updated operating schedule for flexibility activation to industrial flexibility unit s.	Agg	Ind	27
1.19.	Adjustment of schedule					

iii. Information exchanged

Information exchanged (ID)	From	To	Name of information	Description of information exchanged
1	Agg	Ind	DA Forecast	Forecast of DA-Prices [€/MWh]
2	Ind	Agg	Operating Schedule	Timeseries of planned Industry DA-Schedule [kW]
3	Agg	Market	Required DA-Volumes	Timeseries [MW]
4	Market	Agg	Accepted DA-Volumes	Timeseries [MW]
5	Market	Agg	Real DA prices	DA-Clearing Prices [€/MWh]
6	Agg	Ind	Accepted Schedule	Timeseries of sold volumes (should be the same) [kW]
7	Agg	Ind	Optional: Real DA prices	DA-Clearing Prices [€/MWh]
8	Ind	Agg	Redispatch bids	For each bid, ΔP in positive and negative direction [kW]
9	Ind	Agg	Redispatch bid price	Price for activating that potential per timestep [€/MWh]
10	Agg	TSO	DA schedules	Planned DA schedules of flexible units
11	Agg	TSO	Geographical Information for each DA schedule	Grid node where each unit is located
12	Agg	DSO	DA schedules	Planned DA schedules of flexible units [MW]
13	Agg	DSO	Geographical Information for each DA schedule	Grid node where each unit is located
14	Agg	RP	Redispatch bids defined as in Task 3.2.	For each bid ΔP in positive and negative direction + respective costs [kW]
15	TSO	DSO	Transformer Schedule (TSO) and information about the common observability area	Planned schedules at the common grid connection point (TSO) [MW]
16	DSO	TSO	Transformer Schedule (DSO) and information about the common observability area	Planned schedules at the common grid connection point (DSO) [MW]
17	TSCNET	TSO	Compiling of European grid model	European grid model
18	DSO	RP	Capacity information (DSO)	Time series of upward & downward capacities for relevant network ressources [kW]

Information exchanged (ID)	*From*	*To*	*Name of information*	*Description of information exchanged*
19	RP	DSO	Available Redispatch child bids	Feasible bids [MW] for each timestep
20	RP	DSO	Geographical Information of child bids	Locational information for the bids
21	DSO	RP	Selected bids	ID of selected bids
22	RP	TSO	Available Redispatch aggregated bids	Feasible bids [MW] for each timestep
23	RP	TSO	Already chosen bids	By DSOs activated bids [MW]
24	RP	TSO	Geographical information	Geographical information for the whole bid
25	TSO	RP	Selected aggregated bids	ID of selected bids
26	RP	Agg	Total selected bids	All selected bids [MW]
27	Agg	Ind	ΔP schedule change	ΔP schedule change [MW]

IX. UC6b: DSO-TSO-centralized

Disclaimer: This use case template follows the IEC 62559-2 standard.

i. Description of the use case

a. Name of the use case

ID	Main purpose	Name of Use Case
6b	TSO + DSO services + participations in spot markets	DSO+ TSO-centralized

b. Version management

Version Management			
Version No.	Date	Name of Author(s)	Changes
1	15.09.2021	S.Henein	Initial draft
2	27.10.2021	S.Henein	Draft
3	28.03.2022	All	Final and by partners reviewed Version

c. Scope and objectives of use case

Scope and Objectives of Use Case	
Scope	The focus of this UC is based on the interaction of DSO and TSO to enable joint TSO-DSO capacity management. The redispatch platform serves as a data exchange provider and market facilitator (creating Merit-Order-List). Optimization of the correct redispatch bid activation is also performed within the platform. Industry partner perspective is similar to UC4a, where they shall be enabled to participate in spot-markets and offer their remaining flexibility as redispatch bids.
Objective(s)	• Minimize total system costs and avoid uneconomical contradicting activations of DSOs and TSOs. • Minimize total grid losses and the related costs on DSO and TSO level • Ensure supply reliability/adequacy • Avoid grid congestions according following ranking: grid topology measures, measures defined in grid codes and grid connection contracts (e.g. Q(U), P(U), interruptible loads), grid tariff related measures (e.g. interruptible loads), limited market access, market-based flexibility–-redispatch
Related use case(s)	In UC6a DSOs and TSO are choosing the redispatch bids by themselves, in UC6b a smart optimization algorithm is taking over this task to find an overall optimal solution.

d. Narrative of use case

Narrative of Use Case
Description
Flex Unit Perspective: Electricity is purchased on the DA spot market and the flexibility is utilized for the trade on the DA spot market which results in a preliminary schedule for the entire day. In addition to the schedule the flexibility calculates an hourly (or possibly 15min) potential of upward/and downward shift potential (active power) and the respective costs, which are further aggregated by the aggregator to redispatch bids. **Aggregator Perspective:** The aggregator provides all the forecast data that the industrial flexibility unit operator needs for its optimization of the schedule.The aggregator trades the aggregated (from all participating flexibilities) schedules at the DA-market. After the market clearing process, the Aggregator receives the accepted bids and forwards the informationn to the the industrial flexibility unit operator, which now calculated and provides the shift-potential for redispatch. The aggregator creates redispatch bids, which have to be simultaneously feasible (until a more complex bid structure is defined and available). **Redispatch platform Perspective:** Around 14:30 the redispatch platform allows for the submission of redispatch bids by flexibilities. Any such bids must be submitted until 18:00. Compared to UC6a, the redispatch platorm does not only serve as a data exchange tool but also finds the cost-optimal solution for redispatch bid activation to solve grid congestions of both DSOs and the TSO. The provision of simplified grid models by the DSOs/TSO and capacity calculations with the outcome of free capacities/redispatch demand have to be continuously provided to the platform. **DSO/TSO Perspective:** The DSO is performing a capacity calculation based on the short-term bottlenecks. It includes load and generation forecast as well as the available schedules of industrial flexibility unit s for the spot market. Interaction of active power management and reactive power management is to be considered. The DSOs and TSO only have to provide their current grid status to the platform and accept the bid selection via a yet to be defined coordination process.

e. Key performance indicators (KPI)

Key performance indicators (KPIs)				
ID	***Name***	***Description***	***Unit***	***Calculation form***
IND.1.3	max pos/neg flexibility per component (technology)	maximum available positive/negativ e flexibility per component	[kW $\pm$]	survey $P_{pos,tech,max}$
IND.2.1	total revenues/ energy	Total profit (energy costs) that can be	[€/year/sit e]	Energy costs are summarized

	costs per use case 2-4	generated annually under the conditions of the respective case study.		In simulation coupled with network simulation: revenues: sum over one year offered quantity*price r*call c (0 or 1) $\Sigma_i\left(\omega_i\cdot\Sigma_t\left(r(t)\cdot c(t)\cdot\left(e_+(t)+e_-(t)\right)\right)\right)$
IND.2.2	cost reduction/ additional income per use case 2-4	Costs or additional revenues that can be reduced or generated under the conditions of the respective case study.	[€/year/site]	same principle as indicator above
IND.2.3	investment costs for flexibilization depending on use case 2-4	Investment costs to be incurred for the flexibilization measures in the respective case study.	[€]	survey
IND.2.4	additional OPEX for flexibilization	costs such as personnel costs, …	[€/year]	sum over representative days- flex calls * operating costs type and amount of operating costs for different components: from surveys
IND.2.5	additional redispatch costs for aggregator	Additional costs e.g. for additional ICT, personnel, ...	[€/year]	survey
IND.3.1	change of efficiency from provision of redispatch	It is possible that due to the provision of redispatch efficiencies change. This aspect is captured within this indicator.	[%]	Comparison of the following: 1) Sum over repr. Days weight*(E_{demand}(process)/ $E_{purchase}$) without RD provision As 1) but for RD provision
IND.3.2	change of emissions from provision of redispatch	Change in emissions generated by redispatch provision compared to the reference case.	[%/year]	As above but instead of E_{demand}/ $E_{purchase}$ here Emission factor*$E_{purchase}$

FLEX.1.1	total supply of redispatch per industry-peak performance	Peak performance provided for flexibility by the individual industrial sectors.	[MW]	survey $$\sum_{i=1}^{n} \begin{matrix} peak\ performance \\ provided\ for\ redispatch(i) \end{matrix}$$ $$\forall\ industrail\ sectors$$ i = # of TU in industrial sector
FLEX.1.2	total supply of redispatch per industry-energy content	Total amount of energy provided for flexibility by the individual industrial sectors.	[MW]	survey $$\sum_{i=1}^{n} \begin{matrix} total\ capacity \\ provided\ for\ redispatch(i) \end{matrix}$$ $$\forall\ industrail\ sectors$$ n = # of TU in industrial sector
FLEX.2.1	Average cost per technology per call per hour per MW	Costs for a flexibility call, dependent on technology and the incentive model	[€/MWh]	survey
FLEX.2.2	Average cost per industry per call per hour per MW	Costs for a flexibility call, dependent on industrial sector and the incentive model	[€/MWh]	survey
TSO.1.1	Number of hours on which redispatch was retrieved	Total number of hours in a year in which flexibility is retrieved	[h]	estimation TSO $$\sum_{i=1}^{8760} 1_A(i)$$ $A = \{i: amount\ of\ redispatch\ \neq\ 0\}$
TSO.1.2	Total amount of energy called for redispatch by industry per hour per year	Total amount of energy required annually for retrieval of flexibility by the industry	[MWh/year]	estimation TSO $\sum_{i=1}^{8760} amount\ of\ redispatch\ provided\ by\ industr$
TSO.1.3	Typical duration of congestion	Average time interval a congestion lasts.	[h]	estimation TSO $\frac{1}{n}\sum_{i\,=\,1}^{n} duration\ redispatch\ retrieval(i)$ n = # redispatch retrievals per year
TSO.2.1	Cost savings for	Redispatch costs that can	[€]	estimation TSO

	redispatch with I4RD compared to conventional redispatch	be saved by integrating industry through the I4RD project.		$cost\ RD\ -\ cost\ I4RD$
TSO.1.4	Savings through I4RD in contrast to redispatch through conventinal power plants	Power that is needed less compared to conventional redispatch using I4RD	[MW]	estimation TSO *required peak power RD – required peak power I4RD*
TSO.1.5	Energy amounts of conventional redispatch that can be prevented by redispatch with I4RD	Energy amounts that can be avoided by integrating industry through the I4RD project.	[MWh/year]	estimation TSO *amount of energy RD – amount of energy I4RD*
TSO.1.6	predicted n-1/n-0 violations per transition point	amount of predicted events where the failure of a component cannot be prevented by redundancies	[#]	estimation TSO *predicted n-1 violations before remedial actions - predicted n-1 violations after remedial actions*
DSO.4.1	compliance with technical restrictions	This factor is considered to have a value between 0 and 1, where 1 is used to indicate that there are no network restrictions on the distribution network, due to the activation of the flexibility, and therefore no impact on any node within the	[0,1]	simulation in WP 5

		transmission grid		

f. Use case conditions

Use case conditions
Assumptions
• A model of the grid is available both at TSO and DSO level • Availability of controllable active power devices in the grid model in the form of generators • The energy load and generation forecast profiles are known • The locations of RES are known • Industry: DA-price forecasts available (provided by aggregator) • Industry: Forecast of planned production is possible • load and generation forecasts can be done on DSO side at TSO common node • Load flow analysis and capacity calculation should be done on both DSO and TSO sides • Network restrictions must be considered on both sides (DSO and TSO) • Interaction with international redispatch, exact sequence and timing, emergency balancing measures are not part of this project / UC. • Hourly or quarter-hourly solution possible for simulations
Prerequisites
• Exemplary load and generation profiles (including forecasted profiles) and characteristics are available for each bus • All needed information/data (load and generation schedule, flex need, flex-offers, including location and costs) is exchanged between DSOs and TSO via the central redispatch platform. • Iterative coordination (and related data exchange) between all involved grid operators required. • Capacity calculation (central calculation over several supply areas) is done as an iterative process between system operators. • Network restrictions and redispatch limitations should be exchanged between DSOs and TSO via the central redispatch platform. • The limitation of flexibility and actual redispatch measure is defined • A simplified grid model has to be provided by all SOs.

ii. Common Terms and Definitions

Common Terms and Definitions	
Term	**Definition**
D-1	Day before delivery
D0	Day of delivery
DA	Day-Ahead
ID	Intraday
aFRR	Automatic Frequency Restoration Reserve

Common Terms and Definitions	
Term	**Definition**
BRP	Balancing responsible party
FC	Forecast
GOT	Gate opening time
GCT	Gate closure time
RD	Redispatch
UC	Use Case
TSCNET	Transmission System Operator Security Cooperation Network
DSO	Distribution system operator
TSO	Transmission system operator
SO	System Operator
MRC	Multi-regional coupling
Agg	Aggregator
Ind	Industry flex unit

g. Actors

Actors		
Actor Name	***Actor Type***	***Actor Description***
Aggregator	Actor	Organisation offering energy services to the consumer, such as aggregation and pooling of flexibility bids but also in form of electricity delivery contracts.
Day Ahead Market	Service	The Day Ahead market is operated through a blind auction which takes place once a day, all year round. All hours of the following day are traded in this auction. The orders are logged in by the market participants before the order book closes at 12:00. As a result of the order matching, the Power Exchange determines trades which are legally binding agreements to purchase or sell a determined quantity of electricity to a defined delivery area for the matched (or “cleared”) price. There is one price, the market clearing price or MCP, that is determined for each delivery period and that applies to all buyers and sellers. The EPEX SPOT DA auction is integrated into the Multi-Regional Coupling (MRC) which encompasses the Baltics, Central Western Europe, Great Britain and the Nordics.

Actors		
Actor Name	**Actor Type**	**Actor Description**
Transmission System Operator (TSO)	Actor	According to the Article 2.4 of the Electricity Directive 2009/72/EC (Directive): "a natural or legal person responsible for operating, ensuring the maintenance of and, if necessary, developing the transmission system in a given area and, where applicable, its interconnections with other systems, and for ensuring the long-term ability of the system to meet reasonable demands for the transmission of electricity". Moreover, the TSO is responsible for connection of all grid users at the transmission level and connection of the DSOs within the TSO control area. In Austria, the TSO has also the role of the control area operator. Pursuant to section §23 (2) ElWOG 2010, the control area operator has the obligation to determine grid congestions in the transmission system; and to take measures to avoid, solve and to overcome grid congestions in transmission systems as well as to maintain security of energy supply.
TSCNET	Actor	TSCNET Services is one of Europe's leading Regional Security Coordinators (RSCs). TSCNET Services is currently entrusted with a set of mandatory services for its customers according to EU legislation: • Coordinated Security Analysis • Coordinated Capacity Calculation • Outage Planning Coordination • Short and Medium Term Adequacy forecasts • Improved Individual Grid Models and Common Grid Model
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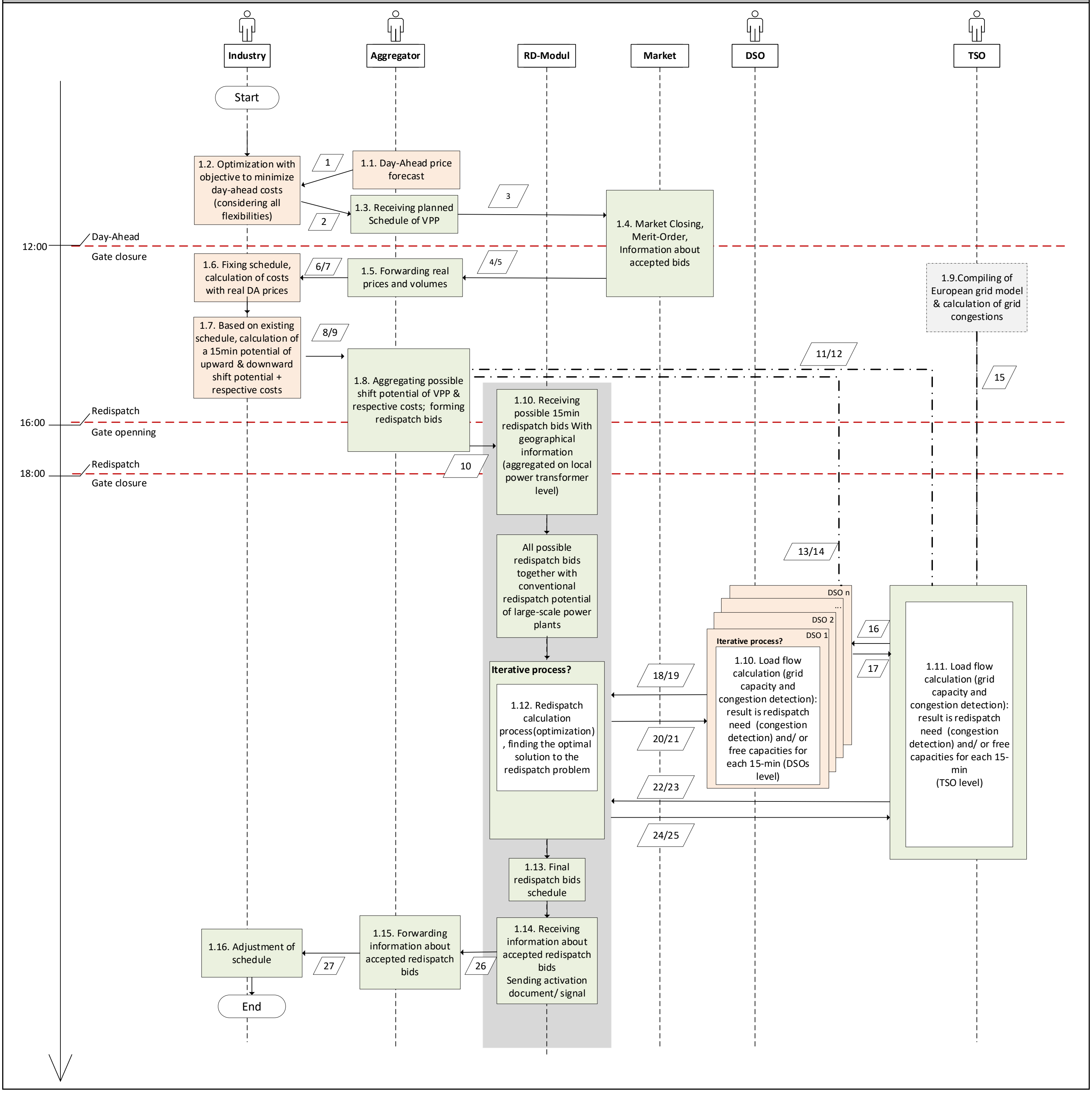
Industrial flexibility unit	Actor	An industrial consumption or generation asset in the electrical power grid which has the capability to deviate – to some extent - from its planned schedule in order to provide redispatch. It is preconditioned that the industrial flexibility unit fulfils the necessary requirements for redispatch

Actors		
Actor Name	**Actor Type**	**Actor Description**
		according to the defined list in task 3.2 and is prequalified for the provision of redispatch.
Industrial flexibility unit operator	Role	Role which links the role customer and its possibility to provide flexibilities to the redispatch provision process by the operated industrial consumption or generation asset.
Redispatch Platform	Service	Platform to which flexibility service providers send their redispatch bids. The Redispatch Platform collects and manages these redispatch bids and forwards them to the TSO as potential remedial actions. After the redispatch calculation process, the platform forwards bid accept messages to those flexibility service providers whose redispatch bids are accepted.
Balance Responsible Party (BRP)	Actor	BRPs are responsible for maintaining supply and demand on the energy market within their own portfolio.Their tasks: • obtain day ahead consumption forecasts from all the suppliers in their balancing responsible party • send these forecasts to the clearing and settlement agent • pay the clearing and settlement agent for the imbalance settlement energy • bill the suppliers for the balancing energy required

h. Sequence diagram(s) of use case

Sequence diagram(s) of use case



i. Step by step analysis of use case

Scenario name:						
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1.2	Industrial flexibility unit operator produces optimization schedule	Optimization of DA-schedule	The industrial flexibility unit operator creates a schedule for the next day by using an optimization tool and forecasts for demand and prices.	Industrial flexibility unit operator	Aggregator	2
1.3	Aggregator sends request for DA-amounts at markets	DA-trading	The aggregator trades the aggregated Schedules at the DA-market	Aggregator	Market	3
1.4	Market clearing process	Market clearing process	The clearing of the market takes place, and the market sends information back to the Aggregator, whether and at which price (clearing price) the bids have been accepted.	Market	Aggregator	4,5
1.5	Aggregator is forwarding the acception signals to the industrial flexibility unit	Forwarding information to industrial flexibility unit	The aggregator forwards the information, whether and (maybe) at which price the schedules have been accepted to the industrial flexibility unit .	Aggregator	Industrial flexibility unit	6,7

Scenario name:						
Step No.	***Event***	***Name of process/ activity***	***Description of process/ activity***	***Information producer (actor)***	***Information receiver (actor)***	***Information Exchanged (IDs)***
1.6	Industrial flexibility unit is updating its operational schedule	Industrial flexibility unit is updating its operational schedule	The industrial flexibility unit takes the information about the accepted bids and updates its schedule.	Industrial flexibility unit		
1.7	Redispatch potential is calculate based on the DA schedule	Calculation of redispatch potential	Based on existing schedule, calculation of a 15min potential of upward & downward shift potential + respective costs	Industry	Aggregator	8,9
1.8	Aggregator forwards aggregated redispatch potential to the RD platform and schedules to the BRP	Forwarding aggregated redispatch potential to the RD platform and schedules to the BRP	The aggregator clusters the redispatch potential to redispatch bids and assigns a geographical information to them. Also the individual schedules are forwarded with geo-information to the RP and to the BRP.	Aggregator	RP/TSO/DSO	11,12,13,14
1.9	Compiling of European grid model	Calculation of european redispatch demand	TSCNET is providing the output of the european grid model/grid congestion calculation to the TSO.	TSCNET	TSO	15
1.10	DSO performs capacity calculation	Information transfer to RP	The DSOs performs a load flow calculation, the result is the redispatch need (if there is a congestion) and/or free capacities for each 15-min which are sent to the RP. (with safety margin) Furthermore simplified	DSO	TSO/RP	18,19,17

Scenario name:						
Step No.	***Event***	***Name of process/ activity***	***Description of process/ activity***	***Information producer (actor)***	***Information receiver (actor)***	***Information Exchanged (IDs)***
			grid models have to be provided to the RP and the TSO has to receive schedules and other information from the observability area.			
1.11	TSO performs capacity calculations	Calculation of redispatch-need and free capacities.	The TSO performs a load flow calculation, the result is the redispatch need (if there is a congestion) and/or free capacities for each 15-min which are sent to the RP. (with safety margin) Furthermore simplified grid models have to be provided to the RP.	TSO	DSO/RP	16, 22,23
1.12	Optimisation process is performed	Optimisation and flexibility selection	The redispatch platform performs an optimisation and selects cost-optimal solution to solve the redispatch problem i.e creates a flexibility schedule from available bids. The information about activated bids is sent back to the TSO and DSOs.	RP	DSO, TSO	20,21,24,25
1.13.	Final flexibility selection	Optimisation and flexibility selection	A schedule of to-be-activated flexibility bids for the aggregator is created.	RP	RP	
1.14.	Create flexibility schedule	Final redispatch schedule created	The final redispatch bids and schedule is forwarded to the aggregator	RD	Agg	26
1.15.	Transfer of accepted bid	Forwarding acceptance information	The aggregator sends the activation signals to the industrial flexibility units.	Agg	Ind	27

Scenario name:						
Step No.	***Event***	***Name of process/ activity***	***Description of process/ activity***	***Information producer (actor)***	***Information receiver (actor)***	***Information Exchanged (IDs)***
	information					
1.16.	Adjustment of schedule	Adjustment of schedule	The industrial flexibility unit is adjusting its schedule according to the activated bids.			

iii. Information exchanged

Information exchanged (ID)	***From***	***To***	***Name of information***	***Description of information exchanged***
1	Agg	Ind	DA Forecast	Forecast of DA-Prices [€/MWh]
2	Ind	Agg	Operating Schedule	Timeseries of planned Industry DA-Schedule [kW]
3	Agg	Market	Required DA-Volumes	Timeseries [MW]
4	Market	Agg	Accepted DA-Volumes	Timeseries [MW]
5	Market	Agg	Real DA prices	DA-Clearing Prices [€/MWh]
6	Agg	Ind	Accepted Schedule	Timeseries of sold volumes (should be the same) [kW]
7	Agg	Ind	Optional: Real DA prices	DA-Clearing Prices [€/MWh]
8	Ind	Agg	Redispatch bids	For every hour a ΔP in positive and negative direction [kW]
9	Ind	Agg	Redispatch bid price	Price for activating that potential per timestep[€/MWh]
10	Agg	RP	Redispatch bids	Per timestep a ΔP in positive and negative direction [kW]
11	Agg	TSO	DA schedules	DA schedules of flexible units with geographical information [MW]
12	Agg	TSO	Geographical Information for each DA schedule	Locational information for the bids [GIS System Information?]
13	Agg	DSO	DA schedules	DA schedules of flexible units with geographical information
14	Agg	DSO	Geographical Information for each DA schedule	Locational information for the bids [GIS System Information?]

Information exchanged (ID)	From	To	Name of information	Description of information exchanged
15	TSCNET	TSO	Outcome of calculations of european grid model	Schedules [MW] and other information of common observability area
16	TSO	DSO	Outcome of load flow calculation	Schedules [MW] and other information of common observability area
17	DSO	TSO	Outcome of load flow calculation	Schedules [MW] and other information of common observability area
18	DSO	RP	Free capacities and redispatch demand for relevant network ressources	Time series of upward & downward shift potential for relevant network ressources [kW]
19	DSO	RP	Updated simplified grid model	Simplified grid model
20	RP	DSO	Selected bids	All selected bids [MW]
21	RP	DSO	Geographical information of selected bids	Geographical information of selected bids
22	TSO	RP	Free capacities and redispatch demand for relevant network ressources	Time series of upward & downward shift potential for relevant network ressources [kW]
23	TSO	RP	Updated simplified grid model	Simplified grid model
24	RP	TSO	Total of selected bids	All selected bids [MW]
25	RP	TSO	Geographical information of selected bids	Geographical information of selected bids
26	RP	Agg	Selected aggregated bids	ID of selected bids
27	Agg	Ind	ΔP schedule change	ΔP schedule change [MW]