Using enera's experience to complement the upcoming redispatch regime with flexibility from load & other non-regulated assets

EXECUTIVE SUMMARY

This paper proposes a pragmatic way to integrate non-regulated flexibility in the German redispatch mechanism, based on the experience acquired in the enera project. Non-regulated flexibility refers to the flexibility that is not covered by cost-based congestion management in Germany recently reformed by the law for the acceleration of the grid extension[1] (referred to as NABEG 2.0), such as demand-side flexibility and small-scale production assets. The goal is to provide system operators with a larger pool of flexibilities to improve overall congestion management efficiency.

The enera project is one of the projects of the SINTEG program. One of the key targets of enera has been to provide market-based congestion management services with decentralized installations, by trading locational ancillary services on local flexibility markets. The key achievements of the enera project in terms of flexibility markets relate to the new systems, processes and competencies which have been developed all along the project and put into operation. Besides a full-fledged operational trading platform, other systems and processes – such as a flex registry, a verification platform and a TSO-DSO coordination scheme – have been successfully developed. In addition to IT systems, an entire contractual framework (interactions and market processes) as well as a governance scheme (roles and responsibilities) have been established.

The Redispatch 2.0 mechanism, that is currently developed to implement the NABEG 2.0 regulation, is a regulated process which focuses mainly on power production assets of a certain size (referred hereafter as "regulated flexibilities"). Non-regulated flexibilities, in particular demand-side management but also production assets smaller than 100 kW that are not directly steerable by the system operators, are not covered. It is the perception of the authors of this paper that these non-regulated flexibilities are likely to play a key role in congestion management, as they

[1] Gesetz zur Beschleunigung des Energieleitungsausbaus (13.05.2019, BGBl 1 p. 706 ff.)

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enera | Bayreuth, Oldenburg, Paris. 29.10.2020

may give access to a broader pool of flexibility to system operators, allowing efficient alleviation of local grid congestions.

The developments and experience achieved in the enera project can be used to for this purpose and enhance the upcoming German redispatch mechanism, integrating load flexibility and therewith reducing the overall redispatch costs.

Indeed, the upcoming German redispatch mechanism is mandatory for production and storage facilities larger than 100kW and is based on so-called "cost-based" compensations (where assets' owners are compensated for the deviations against their schedules and should therefore be economically neutral towards the intervention). The mechanism is however not suited for load, notably due to the cost-based remuneration scheme which is hardly applicable to load flexibility. This is mainly because setting a regulated compensation mechanism that properly captures the (opportunity) costs of consumption is very challenging and is unlikely to attract load on a voluntarily basis.

This is why this paper suggests a hybrid compensation model where, in addition to the cost-based compensation in place for regulated assets (i.e. production and storage assets larger than 100kW), load and small-scale production assets can submit flexibility bids at free prices and be remunerated accordingly in case of activation.

While the objective of this proposal is by no means to reopen the discussion on the compensation scheme for regulated assets, this hybrid compensation model is seen as a credible way forward to easily attract demand side flexibility. Further, the potential gaming opportunities in such a model remain limited: the free prices submitted by consumers are constantly put in competition with the regulated prices of the producers. This guarantees that non-regulated flex is only chosen if it is cheaper than regulated flex, and at the same time limits the gaming incentives for flex providers.

The possibility to realize the gains of this hybrid approach for non-regulated flexibilities depends on the adaption of the regulatory framework. The needed regulatory changes are straightforward and allow to reap the benefits of a larger pool of flexibilities:

- First, all market-based possibilities for the procurement of demand-side flexibility should be allowed, not only tender procedures via a common internet platform for all network operators as currently the case (revision of §13 (6) EnWG in connection with §14 (1) sentence 1 EnWG).

- Second, the incentive regulation (ARegV) needs to ensure that using market-based demand-side flexibility falls under the same cost category as using cost-based supply-side flexibility to create a level playing field and give system operators the most efficient incentives.
- Finally, further procedures for demand-side flexibility need to be defined and approved, comparable to the ongoing Redispatch 2.0 project for regulated flexibility.

The implementation of the revisited German redispatch mechanism – and their related Redispatch 2.0 and Connect+ initiatives – is very challenging both technically and timewise. Instead of proposing any substantial change to this mechanism, the proposal made in this paper is to keep these processes untouched, at least at the beginning. Rather, the proposal is to complement these anticipated schemes on a voluntary and local basis as a no-regret measure, thanks to the existing enera developments. This would allow to confirm the key assumption of this paper – namely that well-located and competitive non-regulated flexibility can be harvested to alleviate local grid congestions – in a timely and cost-efficient manner.

Concretely, the idea is to allow each system operator (or group of system operators) accessing to yet untapped local flexibility, especially to non-regulated assets like demand side management. The Redispatch 2.0 mechanism provides each system operator with a set of flexibility activations stemming from the regulated pool of flexibility. A regulated cost is associated to each activation. With the proposed hybrid approach, the system operator can then substitute regulated assets by the ones available in his local flexibility market, provided these latter are located in the same geographical area and show better prices/costs (for the same grid effect) than the former. This ensures cost efficiency. Such local flexibility markets can be based on the enera platform, for which a full end-to-end environment has been designed, developed, tested and successfully demonstrated.

At a later stage, if the proposed approach proves successful, more integrated mechanisms (where load bids are directly considered in the redispatch mechanism as of the beginning of the process) can be considered. Such more unified processes would lead to further harmonization, lower transaction costs and potentially further efficiency gains in terms of redispatching. At this stage however, the proposal made in this paper is only to test the efficiency of demand side flexibility and other non-regulated flexibility in a relatively simple way, as a complement to the anticipated Redispatch 2.0 mechanism, before envisaging more advanced modifications of the overall German redispatch mechanism. To this end, changes in the regulatory framework are however required.

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1 INTRODUCTION

This paper proposes a concept to complement the upcoming German redispatch regime with flexibility stemming from load and small-scale production assets, based on the enera experience.

Chapter 2 provides the relevant background information of the proposal made in this paper, by summarizing the principle of the enera concept on the one hand, and of the upcoming German redispatch regime (implemented via the so-called "Redispatch 2.0" and "Connect+" projects) on the other hand.

Chapter 3 pleads for a hybrid compensation model, where the regulated cost-based redispatch regime is complemented by a market-based mechanism to enable the participation of load and other non-regulated flexibilities. The main reasoning held in this chapter is that – while the choice for a mandatory cost-based redispatch for what concerns larger production assets has been set – decentralized load and small-scale production assets will not abide to such a model on a voluntary basis.

Chapter 4 then proposes concrete implementation options for how such a hybrid flexibility model can be implemented in the framework of the Redispatch 2.0 concept. Different levels of integrations can be envisaged, whereas the proposal of this paper consists of a relatively simple mechanism, which does not affect the already challenging Redispatch 2.0 implementation.

Chapter 5 shows a high-level tentative implementation roadmap. The point being made is that there is no need to entirely review the redispatch mechanism to integrate load – at least at the beginning. Rather, the proposal made in this paper can be implemented gradually and where the most relevant. Only in case these first steps are successful, a more thorough integration of load into a single process is to be considered.

Chapter 6 lists the key regulatory constraints implied by such options, and how they can be relieved.

Final conclusions and recommendations are then provided at the end, in **Chapter 7**.

2 Background information

2.1 High-level description enera

2.1.1 Mission statement

The BMWI[2] has established the SINTEG (Smart Energy Showcases - Digital Agenda for the Energy Transition) funding program, which sets up large-scale showcase regions for developing and demonstrating model solutions that can deliver a secure, efficient and environmentally compatible energy supply with electricity being generated to a large extent from intermittent renewable sources such as wind or solar.

The ‘enera’ showcase located in the northwest of Lower Saxony is one of the projects of the SINTEG program and addresses three priorities, namely grid, market and data. The goal has been to find solutions for one of the key challenges of the energy transition – changing from a static to a dynamic, and from a centralized to a decentralized system.

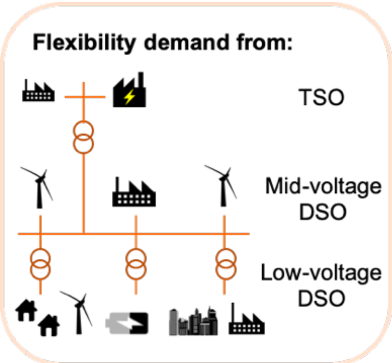
2.1.2 System operators’ coordination process

There are three system operators operating in the showcase region:

- TenneT operates the extra-high-voltage transmission system
- Avacon Netz operates the high-voltage distribution system
- EWE NETZ operates the mid- and low-voltage distribution systems

Each system operator may have assets (lines or transformers) impacted by a production surplus in the region. To resolve them, the system operators coordinate in the enera project in the following way:

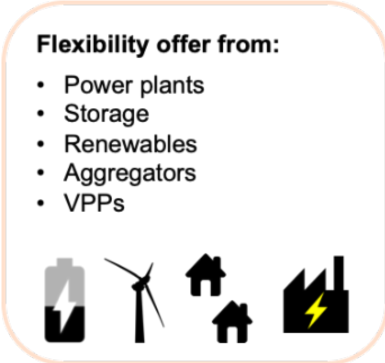
- The upstream system operator (i.e. TenneT is upstream of Avacon Netz who is in turn upstream of EWE NETZ) informs its downstream peer about the amount of power to procure via the marketplace and notifies its congestions.
- This information is processed by the downstream operator, who returns the applicable capacity restrictions (i.e. maximum amount of power that the upstream operator is able to procure).



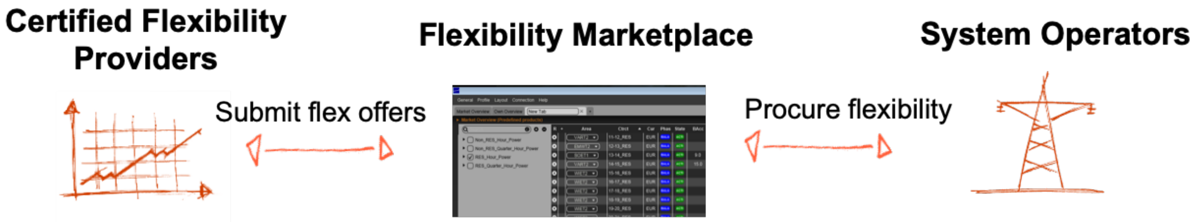
[2] (BMWI, 2016)

- This is then converted into procurement bids for flexibility and submitted by the requiring system operator to the enera marketplace.

2.1.3 Activation process



Flexibility offers (consisting in price-volume pairs applicable to a given geographical market area for a given time period) are submitted by various certified flexibility providers (i.e. local asset owners who have been certified by the relevant system operators to provide local flexibility). These providers use different kinds of flexible assets: wind farms, biogas plants, photovoltaics, storage devices, power-to-gas, power-to-heat and gas compressors. The total amount of certified flexible capacity participating in the project is of 361 MW (Dec. 2019), coming from 6 certified flexibility providers, partitioned in 23 market areas considered as homoeegeneous from a congestion management perspective.



In essence, after system operators have announced in advance their needs to the flexibility providers (via e.g. emails), system operators and flexibility providers meet on the flexibility marketplace platform by providing their orders and updating their prices. Trade occur when the enera marketplace matches flexibility demands from system operators with flexibility offers from flexibility providers, which is done via a continuous matching process.

2.1.4 Interactions with other markets

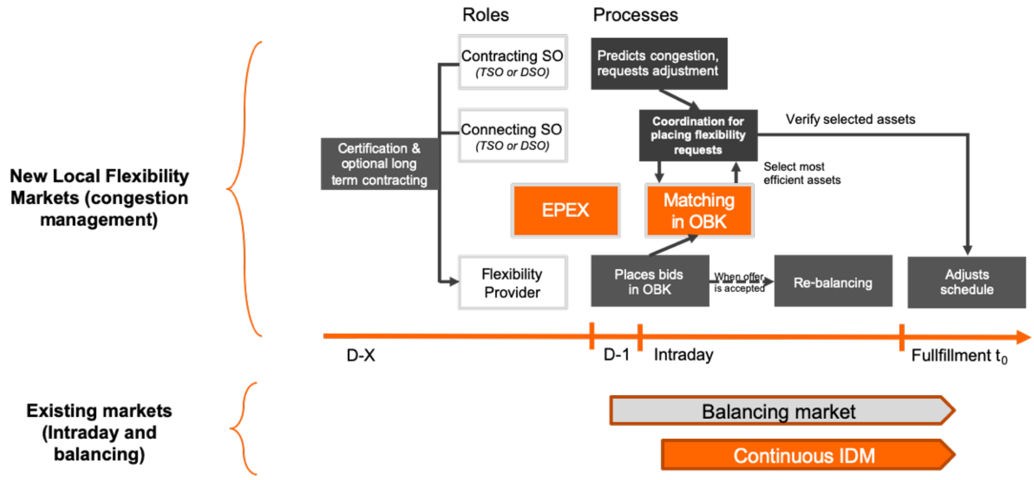


Figure 1: Stylized representation of enera processes

The above figure summarizes the main processes of the enera concept. On the one hand, system operators assess their flexibility requests (location, time, quantity) and share their grid restrictions with the other system operators to ensure an effective congestion management and to avoid new congestions. On the other hand, certified flexibility providers place their bids in the orderbooks of the relevant market areas.

Importantly, the traded products consist only of commitments to adjust physical schedules within a given market area. Such load/production changes are verified ex-post within the "verification platform" which compares the metered in/out flows of the assets to a baseline as per the schedules.

Consequent to the change of schedule of an asset, the portfolio of the party responsible for the balance of this asset is affected, so that the portfolio needs to rebalance. This is typically (but not mandatorily) done on the intraday market. However, there is no explicit interface between the enera platform and the wholesale intraday systems: each market participant (or his Balance Responsible Party) remains responsible for his own balance, irrespective of the flexibility activations. For example, if a load is increased via the enera platform to alleviate a congestion, the load asset gets a remuneration for this physical activation, but nonetheless needs to source the energy separately (this energy cost can thus be included in the market-based flexibility bid).

2.1.5 Key achievements

The key achievements of the enera market platform relate to the new systems, processes and competencies which have been developed all along the project and put into operation. This includes not only IT systems but more broadly an entire governance scheme (roles and responsibilities) as well as increased formal and informal coordination methods.

A full end-to-end environment has been designed, developed, tested and was successfully demonstrated operationally between February 2019 and June 2020, as part of the enera project's demonstration phase. Besides the trading platform itself, let us note the development of the following systems and processes:

- A Flex Registry (ledger of all assets and their characteristics which have been successfully certified)
- A digital Verification Platform (to verify the effective delivery of flexibility: adapted baselining vs. metering)
- TSO-DSO coordination (forecasting of localized congestions, coherence between the grid models, flexibility requests and market activity of each System Operator)
- A full-fledged contractual framework governing the interactions and market processes

As will be shown later, the entire set of systems and processes can possibly be reused in the approach proposed in this paper.

2.2 High-level description Redispatch 2.0[3]

2.2.1 NABEG 2.0: A new regulation for redispatch

The new Network Expansion Acceleration Act (so-called NABEG 2.0), which entered into force on 13 May 2019[4], contains new requirements for grid congestion management to be implemented by 1 October 2021. Since this goes along with fundamental changes in the redispatch framework, the new redispatch regime is called Redispatch 2.0. It covers generation and storage, harmonizes different measures for congestion management and allows system operators to access smaller flexibilities. In concrete terms, this means that renewable plants and CHP plants of 100 kW or more, as well as plants that can be remotely controlled by a grid operator at any time, will also be included in the redispatch. One major consequence of this is that DSOs also actively participate in the Redispatch 2.0 regime.

Figure 2 shows from a very high-level perspective the changes in the Redispatch mechanism implied by NABEG 2.0.

[3] Source (BDEW, 2020)

[4] NABEG 2.0 refers to the "Gesetz zur Beschleunigung des Netzausbaus (vom 13.05.2019, BGBl I S. 706 ff.)"

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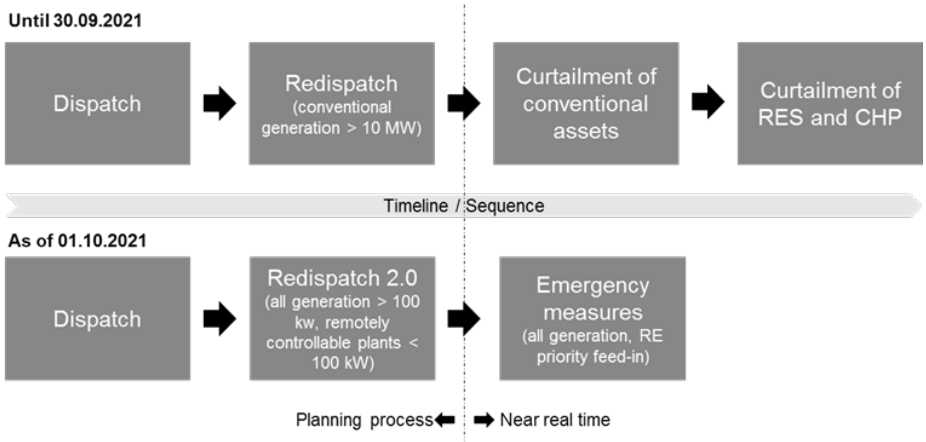

Figure 2: Overview of key changes induced by NABEG 2.0

2.2.2 BDEW Redispatch 2.0 project

In order to implement the NABEG 2.0 legal provisions, a uniform industry understanding of the roles, responsibilities and processes associated with the new tasks as well as their implementation is required. BDEW (the German association for the Energy and Water Industry) launched its BDEW Redispatch 2.0 project at the end of June 2019, with the aim of developing an industry-wide solution for the future redispatch regime in Germany.

2.2.3 Connect+ project

The Connect+ project is a parallel implementation project, with the aim of practically implementing a uniform data path for exchanging the data required for the future redispatch. It is led by the Transmission system operators and several Distribution system operators, all of whom are also part of the BDEW Redispatch 2.0 project, and is meant to be applied to all Germany. In the Connect+ project, the network operators jointly develop uniform solutions for data distribution, to coordinate data exchange between market participants and network operators in congestion management.

2.2.4 Constraints and limitations

The Redispatch 2.0 project and the Connect+ project both aim at implementing the new redispatch procedure according to NABEG 2.0. The regulation includes profound modifications, including new roles, new data requirements and the involvement of all grid operators. This is very challenging, especially with regard to the short timeline.

Redispatch 2.0 includes valuable changes, that help to harmonize the redispatch process and to access smaller flexibilities. However, Redispatch 2.0 only covers generation and storage and leaves flexibility potentials on the load side untapped.

This is because NABEG 2.0 only covers generation and storage. The current regulatory framework does not include a similar approach for demand-side flexibility (or small scale flexible production). Furthermore, the stringent time constraints set by NABEG 2.0 hardly allow to develop such a framework in the short term and to fully integrate it into the existing Redispatch 2.0 project. Therefore, a full integration of non-regulated flexibility in this process is rather unrealistic. This will be duly considered in the remainder of this document.

2.2.5 Cost-based Redispatch 2.0 and calculatroy cost for renewables5

The redispatch in Germany has been organized in a cost-based way and sticks to this principle also under the new NABEG 2.0 regulation. Cost-based redispatch means that power plant operators are reimbursed for the costs incurred by the redispatch instruction. The principle is that the remuneration for a requested adjustment of power feed-in is appropriate if it does not put the plant operator in a better or worse economic position than he would have been without the measure. The costs that are reimbursed include the necessary expenses for the actual adjustments of the feed-in, such as fuel costs. In addition, the foregone revenue opportunities and the necessary expenses for making the plant ready as well as the necessary expenses for postponing a planned inspection, are also taken into account.

Prior to NABEG 2.0, the curtailment of renewables has been regulated in a separate law as an additional instrument that can only be used as a last resort. In accordance with the priority feed-in of renewables, curtailment is therefore only used if the congestion cannot be sufficiently relieved by other suitable measures, in particular by regulating conventional power plants. Although an emergency measure, the use of curtailment has become vital to operate the grid safely and has increased significantly.

With the new Redispatch 2.0 according to the new NABEG, the curtailment of renewables is directly integrated in the redispatch process, and feed-in priority is softened. From October 2021 onwards, it becomes permissible to regulate RES and CHP plants with an installed capacity of 100 kW or more whenever a "multiple amount" of conventional generation would otherwise have to be redispatched. The “multiple amount” to be required to allow the curtailment of RES plants is defined by a so-called minimum factor, which is between at least five and at most fifteen and is

[5] Sources (BDEW, 2018), (Bundesnetzagentur, 2018)

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calculated and published by the Federal Network Agency (as of December 2020). This allows RES power plants to be included in the cost-based merit order, by using the minimum factor to define the calculatory costs of RES power plants. The higher the minimum factor, the less renewables are curtailed. In other words, RES power plants will not be included at their real redispatch costs, but with so-called calculatory costs. This calculatory cost is only important for the redisatch decisions. The cost recovery granted to renewables that have been curtailed continues to be based on their true costs (i.e. cost-based mechanism).

The uniform calculatory price also ensures that all RES are treated equally (irrespective of their actual cost) to avoid any discrimination effect and to favor renewable energy over thermal plants. The same applies to CHP plants, which also have a uniform calculatory cost in order to treat all of them equally (i.e. only based on their location – not their price efficiency).

2.2.6 Activation process

The below diagram describes the currently envisaged Redispatch 2.0 activation process. In essence:

- System operators forecast their own grid constraints & redispatch needs (see next section)
- Flexibility potentials are provided by the regulated flexibility (i.e. production and storage devices of more than 100 kW and controllable generation below 100 kW) via a common German-wide interface, of which the specification, data formats and concrete implementation are dealt with in the Connect+ initiative.
- System operators exchange restrictions concerning the activation of flexibilities due to grid constrains
- System operators select available regulated flexibility according to their needs and under respect of the exchanged restriction of downstream grid(s).
- If the flexibility has to be activated by the provider, the results are fed back to the flexibility providers via the same “Connect+” server and interface; physical schedules and commercial nominations are adapted accordingly. If the flexibility is activated by the SO, this process step is no longer required.

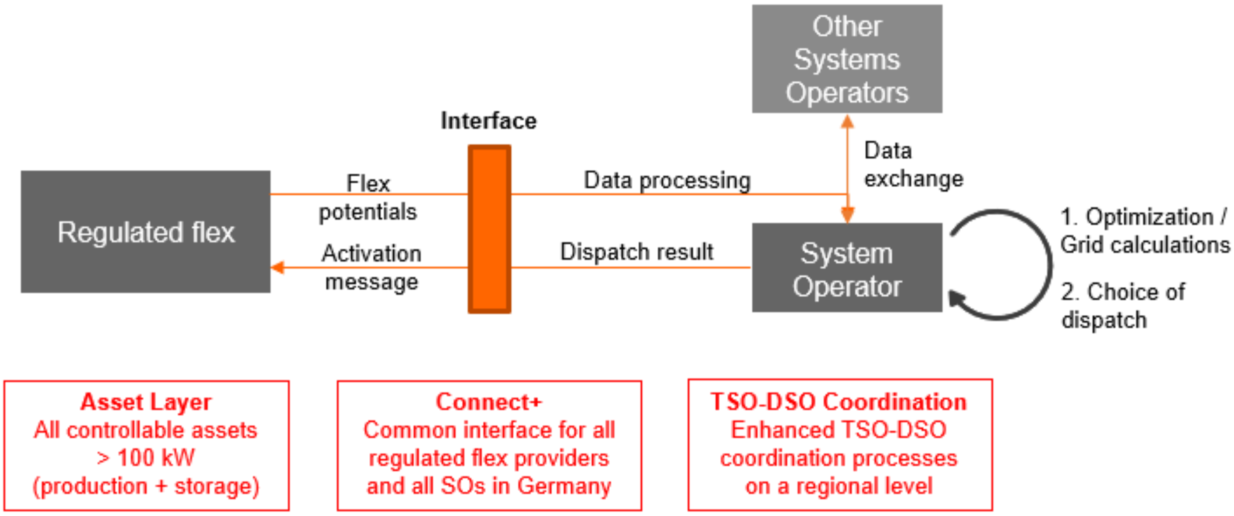

Figure 3: Stylized Redispatch 2.0 activation process cycle for regulated flexibility under NABEG 2.0

2.2.7 System operators' coordination process

The enhanced Redispatch 2.0 coordination processes between the various implied system operators happen as follows according to EG FLEX (bdew, March 2019):

Every 15 minutes the network operator at the lowest voltage level informs its upstream SOs about available flexibility. If the SOs are in need of flexibility and have other SOs below their own voltage level, they have to start a coordination process. In this process, information about the planned activation of flexibility is given downstream. The SOs at the lower voltage level calculate restrictions and give this information upstream to the requesting SO. In the absence of other available flexibilities, the distribution system operator must use the flexibilities that are connected to his network. Remaining flex-potentials are made available to the upstream network operators. As part of the coordination process, the respective network operator first carries out a network security calculation for all applicable timestamps (i.e. 24 hours of the day-ahead). This gives the network operator the opportunity to identify bottlenecks based on the basic data delivery and also:

1. Dimension measures for own bottleneck elimination,
2. Combine possible Flex potentials into effectiveness clusters,
3. Define any flexibility restrictions that restrict the availability of Flex potentials for upstream network operators and notify them accordingly
4. Determine efficiencies (i.e. grid sensitivities) for all flex potentials effective in his network

The upstream network operator and possibly other authorized network operators must be informed of the results of the network security calculations, since these in turn are included in their network security calculations.

As a result of the coordination process, all network operators have the measures that have been carried out and can be called up for all Flex data objects relevant for the network operator.

3 Complementary market-based compensation for non-regulated assets

3.1 The need for demand side management in the redispatch process

The key assumption for the discussion held in this paper is that the congestion-management of the future, taking into account the ambitious *Energiewende* objectives, cannot efficiently work solely with the production facilities currently included in the Redispatch 2.0 regulation, but also requires the involvement of power consumers[6]. This assumption is based on several grounds, namely that:

- conventional power plants will gradually be disconnected from the grid (as a result of ever decreasing revenues and as enforced by the German Nuclear and Coal phase-out plans), thus progressively eliminating the current main providers of redispatch measures;
- already now, grid congestions are not necessarily located close to those large thermal assets, and in many cases using small-scale assets closer to the congestion may be more effective;
- in particular, when centralized production facilities are currently unable to mitigate grid congestions, renewable energy needs to be curtailed. Increasing load in this case would be economically and environmentally more efficient in such situations;
- The decentralized flexibility connected to the distribution network, e.g. from battery storage systems in households, charging stations for electric cars or electric heating solutions, is denied access to redispatch services even with the amendment of the NABEG. However, these decentralized systems in

[6] This paper focuses specifically on how to integrate load, i.e. demand side management, for congestion management, although storage and production assets smaller than 100kw that cannot be controlled by the system operators may also be in principle included.

particular have a high flexibility potential. By 2035, this potential could already be up to 50 GW[7].

The core objective of this paper is to propose pragmatic ways to provide non-regulated flexibilities (most importantly electricity consumers) with the opportunity – which they do not have today within the Redispatch 2.0 scheme - to participate voluntarily in the German redispatch. Or, seen from the other perspective, this paper proposes a pragmatic way for system operators to get access to a greater pool of flexibility to manage grid congestions.

Such flexibilities would be paid on the basis of their bids when they are called up, in line with the spirit and tools of the enera project which has created a new market-based mechanism that harvests the flexibility of otherwise untapped technologies for congestion management.

3.2 Complementary cost-based and market-based mechanisms

A full market-based approach is unlikely to emerge in the short term in Germany, despite the fact that it is set as a target in the EU Regulation on the internal electricity market (2019/943). While other European countries are moving to market-based redispatch, Germany submitted an action plan to the European Commission in order to be exempted from market-based redispatch until 2025. There are two main concerns related to the decision to opt for a cost-based mechanism in Germany rather than a full market-based mechanism:

- The problem of market power of pivotal providers within certain areas, which may occur in a market-based redispatch – despite theoretically increased competition – if not enough new players voluntarily make themselves available for the redispatch market. In a market that is fully free in terms of pricing, a small number of providers whose capacities are located at central points in the system could push prices up by abusing the fact that there are little competing alternatives.
- Another theoretically conceivable exploitation of local congestions in a free redispatch market is strategic behavior, also known as Inc-Dec-Gaming[8]. Negative effects are caused by the interplay between the redispatch market and the spot market: traders who are active in both markets may be able to

[7] This is for example shown by an exemplary analysis based on the consumption and generation scenarios for the network development plan (NEP 2030 Version 2019, 1st draft)

[8] Please refer to (Schlecht, 2019) for a full description of this risk

anticipate the development of the other market (based on experience and forecasts) and already align their original position to it, thereby arbitraging between the price differential of the two markets and causing aggravated congestion along the way. Furthermore, this opens up the possibility of skimming off profits, for which remains unclear at this stage whether such behavior would be legally sanctionable.

It is not the objective of this paper to reconsider the fundamental choice to opt for a cost-based redispatch as a general principle. Rather, the proposal of this paper is to complement the cost-based mechanism applicable to regulated assets in Germany with a market-based mechanism in order to also incorporate load-based flexibility which would otherwise not be included.

The view taken here is that such assets cannot simply integrate the cost-based Redispatch 2.0 mechanism, because a sound and “acceptable-by-all-parties” mechanism to administratively calculate their “costs” is assumed to be unachievable. Already for the larger thermal assets, where compensation claims are calculated as indicated in (BDEW, 2018), there are frequent legal disputes[9] between power plant operators and the transmission system operators who carry out the compensation payments. For loads, the calculation of such compensation payments – which are expected to represent marginal costs based on economic theory – is clearly even more complex, because such costs – typically based on the opportunity cost of consuming less or more – are less tangible than for thermal assets (for which marginal costs are based on fuel costs, efficiency, CO2 emission and Operations & Maintenance costs).

Further, as it is unrealistic to oblige such load assets to participate to the mechanism, the expectation is that they would simply not participate to a cost-based redispatch mechanism if the compensations are not satisfactory. Fortunately, load assets are typically relatively smaller and are thus by definition less prone to market power, so that the concerns leading to the decision for a cost-based redispatch are less applicable to these assets, especially if this non-regulated flexibility “competes” with the regulated flexibility captured by the Redispatch 2.0 regulation. A recent study by Jacobs University (G. Brunekreeft, March 2020) also highlights that, although production and load might have the same general gaming incentives, they operate in different institutional frameworks that trigger increased gaming risks for load-based flexibility. Additionally, the participation of load may also reduce the incentives for

[9] Source (Next Kraftwerke, 2020)

gaming and there are effective measures to curb the remaining gaming potential such as targeted bid caps or specific countermeasures for grid operators to limit the players' probability of success.

Another key advantage of a market-based component in the redispatch scheme is that it leaves more space for innovation: market parties have a better incentive to organize the aggregation of small assets into tradable products. Such features are typically required for smaller (e.g. residential) loads for which realistic schedules can only be obtained if a sufficient amount of such small assets is pooled together. Unlike with cost-based regulated scheme, a market mechanism like the one developed in enera faciliates the emergence of such innovative products.

Finally, a marketplace generates reliable localized price signals for load flexibility. This has several positive effects. In the short run, such localized price signals will unlock yet untapped flexibility stemming from consumers in case owners of these assets identify opportunities to value their existing flexibility (i.e. if the local prices lead to profitable business cases for their existing infrastructure). In the long run, it will also foster efficient investments in new flexible capabilities where most appropriate, as such investments will be based on objective price signals. Ultimately, local prices will thus decrease the overall redispatch costs and facilitate the energy transition.

The objective of this paper is thus to identify the most promising ways to complement the Redispatch 2.0 mechanism currently under development with load-based flexibility, letting these assets submit their own proposals for compensation in the form of freely set flexibility offers.

3.3 Hybrid compensation model

In summary we have on the one hand, in the Redispatch 2.0 regime, generation and storage units larger than 100kW or controllable by the system operators available for Redispatch compensated on a cost-basis (i.e. regulated formula taking into account opportunity costs); and on the other hand, the remaining non-regulated flexibility which might be necessary to further alleviate congestions and bring some additional cost-efficiency to the electricity system management. Mostly consumers are in the latter and thus, a merely cost-based regime is not suitable for contracting these flexibilities for congestion management, as these costs are more difficult to determine and monitor, plus some sorts of incentives are needed to attract load-based flexibility.

Throughout the remainder of this paper, the co-existence and availability of regulated and non-regulated flexibilities for congestion-management purposes is referred to as the **hybrid model**, where regulated generation and storage assets (larger than 100

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kW), redispatched under the regulatory cost-based regime, are put in competition with the freely set bids and offers from non-regulated flexible assets that are not integrated in the NABEG 2.0 regulation on which the Redispatch 2.0 processes are based on.

In other words, the hybrid market model is defined as a model where regulated assets (i.e. the assets which fall into the Redispatch 2.0 regime) and competitive assets (i.e. any other asset willing to market its flexibility for congestion management, and especially load) are both used in an economic redispatch process, even though they are compensated with different regimes (cost-based for the regulated assets and market-based for the others).

4 PRACTICAL HYBRID MODEL IMPLEMENTATION

Different levels of integration of load with system operators' Redispatch 2.0 process are possible. A fully harmonized IT Infrastructure and related processes is probably theoretically ideal as it reduces transaction costs and guarantees a smoother process. Such a full integration of non-regulated assets into Redispatch 2.0 is however to be seen as a significant implementation effort, while the fulfillment of the Redispatch 2.0 requirements is already a huge challenge for system operators, both technically and timewise. Redispatch 2.0 therefore hardly allows for any distraction or additional requirements, so that a full integration is seen as unrealistic in the short term.

Therefore, as a first implementation step, a pragmatic hybrid model which has minimum interference with the redispatch processes planned under Redispatch 2.0 is proposed, based on the developments and experience of the enera project. Since an overall optimal redispatch cannot always be achieved with this proposal, further levels of integration might be implemented in the future.

4.1 Description of the proposed "local implementation" solution

The proposal is to complement the Redispatch 2.0 process with non-regulated flexibilities as an alternative, where economically relevant, and on a local basis only. It leaves most of the Redispatch 2.0 processes untouched because they are technically not impacted, as if non-regulated flex wouldn't exist. Rather, non-regulated flexibilities are managed separately and locally by the system operator to which the load flexible assets are connected, thanks to the enera market platform. The proposed model works as follows.

Separately from the Connect+ interface only tackling regulated flexibilities, the enera market platform collects the locational free bids from certified flexibility providers. Each bid is displayed in the orderbook of a relevant market area, which consists of a pre-defined geographical area which is seen as relevant and homogeneous from a congestion management perspective (similar to the notion of "clusters" in the Redispatch 2.0 mechanism).

Only once the regulated dispatch actions have been chosen within the regulated Redispatch 2.0 optimization process, the dispatcher of the system operator to whom the non-regulated assets are connected, has the possibility to substitute a regulated flexibility activation (from the Redispatch 2.0 mechanism) by a market-based alternative (from the enera platform). These alternatives can be identified in the pool of non-regulated flexibilities available in the enera orderbooks, as long as such alternatives (1) are more cost-effective and (2) provide the same (or a better) effect on the grid than the initial Redispatch 2.0 selection. This can be taken for given, if an alternative market-based option is located in the same market area as the regulated flex it substitutes and displays a better price.

Let us for example suppose that through the Redispatch 2.0 mechanism, EWE NETZ is requested to curtail a wind farm for a regulated price in a market area of the EWE NETZ grid. Separately, the enera platform has collected competitive bids for the market area where this wind farm is located. Let us also suppose that one of the competitive bids (e.g. power-to-gas consumption facility) offers lower prices than the compensation costs for the wind farm curtailment. In such a case, EWE NETZ can substitute the wind farm curtailment instruction by activating instead the same volume of non-regulated flex bid (i.e. the power-to-gas asset increases its consumption instead of curtailing the wind farm) because the price of this alternative is cheaper than the initial regulated instruction, while the effects on the congestions are the same.

4.2 Main benefits of the solution

The key advantage of the approach is that it is relatively easy to implement, as it builds on the existing components of the enera design and tools/platform, that are appended to the Redispatch 2.0 mechanism which remains untouched. The proposed model indeed doesn't imply any changes in the Redispatch 2.0 processes – except the ability for a system operator to "pause" the process, and "substitute" the activations from Redispatch 2.0.

Attached to this advantage comes the fact that the approach can be implemented gradually, individually and separately for each system operator. The system operator who identifies an opportunity for demand-side management in his areas can convert this opportunity on its own, without the need to coordinate with its peer system operators, as the substitution only has economic impact while the effect over the congestion remains identical. This increases the implementation flexibility and allows to test such a hybrid market concept at smaller scale and where most relevant.

Another benefit of such a separated approach (in comparison to a full integration of load in Redispatch 2.0) is linked to the wide design possibilities of products and features of the non-regulated flexibility market platform. The tradable flexibility products must be set so that they are comparable to regulated activations, but this leaves much room to adapt them as closely as possible to the needs and capabilities of the competitive flexibility resources (and of the local system operator). For example, the duration of the tradable products can be different for each area, depending on the local needs. It is thus possible to maximize the attractivity of the mechanism and consequently increase the flexibility availability for congestion-management purposes.

Importantly, attraction of non-regulated flex is expected to be mostly driven by the observation of recurrent highly priced regulated activation costs within a given area, providing an incentive for a well-placed non-regulated flexible asset to offer its flexibility at a better price. The approach therefore requires a sufficient level of transparency of the Redispatch 2.0 costs in order to efficiently attract the non-regulated flexibility.

In short, this solution is easy to implement and allows a more cost-efficient congestion-management process in all the cases where non-regulated flexibility can efficiently substitute, or complement/supplement regulated flexibility.

Such an approach may however not be perfect as the information over market-based flexibility is only considered ex-post – after a first selection of flex potentials according to Redispatch 2.0 processes. For example, curtailment of wind is rather expensive (and even further discouraged by a high "calculatory cost" under Redispatch 2.0), and Redispatch 2.0 will more seldomly activate such flexibility, even though it would have a very favorable impact over a congestion. Therefore, if the best solution consists of activating a market-based bid close to a wind mill, the above proposed model may not allow to identify this action because the outcome of the Redispatch 2.0 process would not be the curtailment of the wind mill in the first place, but some conventional powerplant in a market area further away. Another example could be congestions arising in cities, where demand side management offers a lot of potential but where regulated flexibility would not be accessible by Redispatch 2.0. Such an inefficiency is to be seen as a trade-off, given that it is nearly impossible to implement a more fundamental change in the Redispatch 2.0 processes at short notice, while it would allow to nevertheless reduce costs where possible.

Note that in Redispatch 2.0, the system operators manage the deficits and surpluses in market players' portfolios stemming from their flex activations: the modification of asset's schedules are accompanied by hub nominations such that all the markets' portfolios remain balanced. enera is currently designed differently: market players need to rebalance their portfolio (e.g. on the intraday market) as a consequence of an activation in the enera marketplace. This is however not an obstacle as it is relatively easy to adapt the enera mechanism and complement it with a transaction nomination feature in order to align with the Redispatch 2.0 approach.

In conclusion, the proposed solution is an efficient "quick-win" as it has little operational or project impacts over the Redispatch 2.0 mechanism and builds over the already existing enera infrastructure. Despite its potential imperfections (notably caused by a two-steps selection of flexibility), the proposed design is relatively easy and cheap to implement and is expected to easily demonstrate the potential of non-regulated flexibilities in the redispatch mechanism.

Further, since it is by definition to be implemented at a local level, and therefore doesn't need intense coordination schemes (and related discussions). It is consequently an elegant way to verify the key assumption of this paper, namely that the congestion-management scheme of the future cannot efficiently work solely with the production facilities currently included in the Redispatch 2.0 regulation, but also require the involvement of power consumers. Note that this nonetheless implies regulatory changes (further discussed on Chapter 6).

5 POSSIBLE IMPLEMENTATION ROADMAP

Redispatch 2.0 is expected to go-live in October 2021. In parallel, or shortly after, local implementation projects can start on a voluntary basis, leaving each system operator who feels a potential for load flexibility in his area (or for flexibility stemming from small scale production assets) and who desires to test its potential, trialing the above proposed solution. Such an implementation is very flexible and can take various degrees of sophistication, in particular for what concerns the level of automatization of the substitution process. Importantly, such choices – whether to implement the approach and with which level of sophistication – is fully left to subsidiarity and no inter system operator coordination is needed on any on these aspects. This allows for a more flexible approach.

The need for a more integrated approach, where the load flexibility is directly considered in the common system operators' coordination process, will only show up when/if local implementations are successful. At this moment, it may be decided that – despite its merits – the local approach suffers from some drawbacks which can be addressed by a more stringent integration in the Redispatch 2.0 processes.

Only at a later stage will a complete integration of load in the overall German redispatch mechanism – where load and production assets are treated fully equally – be considered. Such a more advanced and fully integrated approach can be called "Redispatch 3.0". As of now though, it makes no sense to detail how such a solution would look like. Rather, Redispatch 3.0 shall be seen as the long-term evolution of the currently envisaged German redispatch solution, where all the learnings of the previous models are taken into account. Specifically, whether load should effectively take a significative stake in the overall mechanism is yet unknown, and – realistically – such a question can only be answered empirically. This is why the above proposed high-level roadmap starts with local and relatively easy trial implementations, and only let load progressively integrate in the overall redispatch mechanism when the need to do so materializes very concretely.

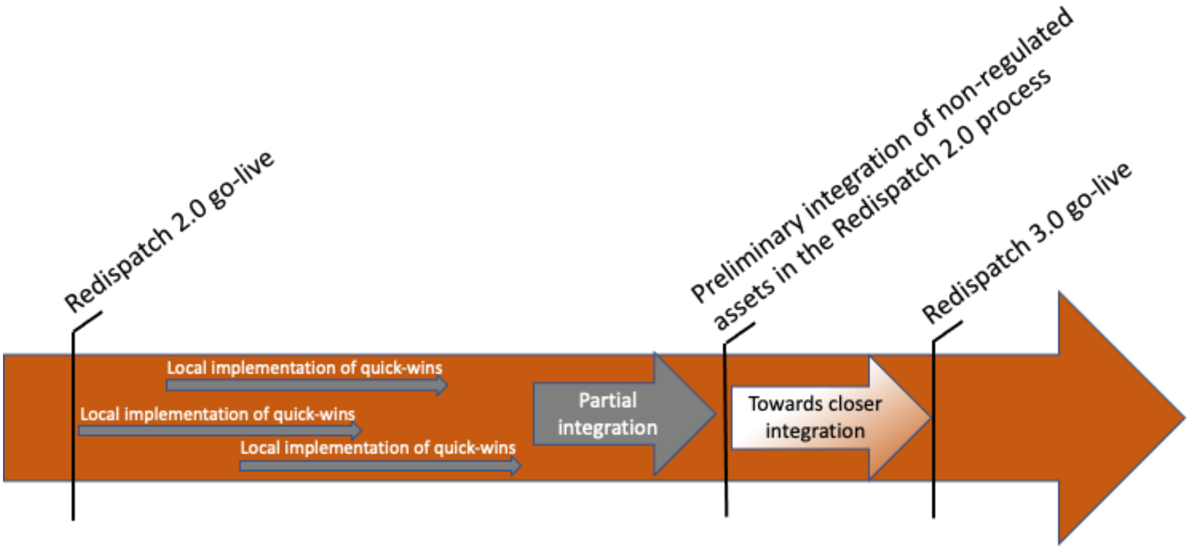

Figure 4: Tentative implementation roadmap

6 Regulatory aspects

Regulatory adjustments must be made for all possible implementations of the hybrid models. The extent of these adjustments depends on the level of integration, but none of the implementation levels can be implemented without regulatory adjustments. Currently, there is no appropriate regulatory framework for the integration of demand-side flexibility in congestion management.

Although some detailed references to contracted loads are included in the EnWG and further detailed in the regulation for curtailable loads (AbLaV), their use is very specific and limited. Nevertheless, the reference set boundaries for the contracting for loads for congestion management: EnWG details that such loads need to be chosen via a tender on an Internet platform shared with all German TSOs. The regulation has been put in place before the new requirements of the Clean Energy Package which makes market-based approaches the default solution and puts demand and supply on equal footing for the participation in markets. This requires to adapt the national regulatory framework to create a level playing field for load and supply, also in congestion management. Different regulatory solutions and approaches would be possible to integrate demand-side flexibility in the regulatory framework, based on the preference for a more integrated or separated procurement.

In this new policy context, the existing constraints with regard to tenders and the procurement over a common platform are outdated. System operators face more and more short-term needs, and the technical specifications of loads especially in the distribution grid are constantly changing. In order to integrate all flexibilities, new flexibility products are required that go beyond a weekly tender procurement.

Another regulatory gap exists with regard to the costs to be taken into account when selecting the flexibility option. System operators only have incentives to use the cheapest available flexibility option if the regulatory recognition of congestion management costs is the same for load and for supply flexibility. This would create a level playing field.

While the above questions arise at each level of integration, further regulatory clarification is required for deeper integration of loads. For example, if common data paths from Redispatch 2.0 are to be used for loads, corresponding data delivery obligations must be specified. This is currently done for supply in the framework of the BDEW Redispatch 2.0 project, subject to approval by the German regulator. For a deeper integration, an obligation for DSOs to connect loads would also be necessary.

Regulatory gaps as well as existing constraints have partly already been identified at the beginning of the SINTEG projects and resulted in the SINTEG ordinance that allowed for an exemption in order to set up local flexibility projects. This regulation will end in June 2022. It is important to reap the success of this regulation by **implementing regulatory no-regret measures complementing the existing framework:**

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1. **Revision of § 13 (6) EnWG in connection with § 14 (1) sentence 1 EnWG:**

The paragraph should allow all market-based possibilities for the procurement of demand side flexibility, not only tender procedures as in the current regulation. The establishment of a common Internet platform for all network operators should not be obligatory.

2. **Revision of the incentive regulation (ARegV)**

A common category for congestion management in the process of cost recovery for system operators is needed. Using market-based demand-side flexibility must fall under the same cost category as using cost-based supply-side flexibility.

3. **Define and approve further procedures for demand-side flexibility in congestion management, as currently done in the BDEW Redispatch 2.0 project for the supply side**
    a. The development of the (additional) data requirements of each system operator to perform the redispatch
    b. The necessary requirements of the data exchange process between demand-side flex providers and system operators as well as between system operators
    c. The preparation of the financial and the balancing regulations and the settlement of the redispatch

7 Conclusion

This paper suggests a pragmatic way to integrate load flexibility in the German redispatch mechanism, based on the experience acquired in the enera project. The strong belief of its authors is that demand side management is likely to play a key role in congestion management, as it may bring cheap and well-located flexibility able to alleviate local grid congestions.

Surely, the currently envisaged German redispatch mechanism consists of a major step forward. Given the practical challenges implied by its implementation, no functional changes to the Redispatch 2.0 are proposed, at least in the short-run.

Rather, this paper pragmatically proposes to use the enera experience to enhance the German redispatch mechanism with a complementary enera-based market platform that allows to consider supplementary flexibility options stemming from load or other non-regulated flexibilities when redispatching the grid. Only at a later stage, if this pragmatic approach proves to be successful, more integrated approaches might be considered.

One of the key advantages of the proposed approach is indeed that the necessary technology, processes and contractual framework have already been developed and successfully tested in the context of the enera project. Further, the solution can be implemented gradually and locally, leaving each system operator the choice to test the appetite of demand to participate to local redispatching.

However, legal adaptations are required to enable this model from a regulatory perspective.

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Supported by: Federal Ministry for Economic Affairs and Energy on the basis of a decision by the German Bundestag

SINTEG SMART ENERGY SHOWCASES

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