D3.1.1 – Use cases

Contributors:

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Versioning and Authors

Version control

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2		Some restructuring
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Executive summary

The increasing penetration of renewable energy in the electricity mix calls for a greater contribution of these technologies to grid stability. Composed mainly of wind and solar plants, these new generators have been mostly integrated in a passive way to the grid up to now. First cases of active power management with renewables date several years back in Germany, with, for example, the obligation in 2012 to have capacity for active power curtailment for plants with power greater than 100kW in case of grid constraints. Yet, much remains to be done to enable variable renewable energies (RE) to provide ancillary services in a way similar to conventional generators.

The previous project, called "REstable", has demonstrated the technical ability of wind and solar plants from France and Germany, grouped in a virtual power plant (VPP), to provide positive and negative balancing reserves with a comparable quality to conventional generators. REstable nevertheless pointed out several barriers in the actual regulatory framework that prevent full RE participation and issued recommendations to overcome these problems.

The REgions project complements these analyses with the aspect of the regionality of ancillary services and related markets. After all, all ancillary services have an embedded locational factor. Even balancing reserve, which affects the grid frequency throughout Europe, regardless of where it is provided, may be subject to local constraints. In order to study these aspects in the REgions project, the flexibility offered by the different pilot plants of the project is aggregated and tested in seven Use Cases of regional and inter-regional services based on four different ancillary services: voltage control, congestion management, balancing reserve for frequency control, and a combination of these services.

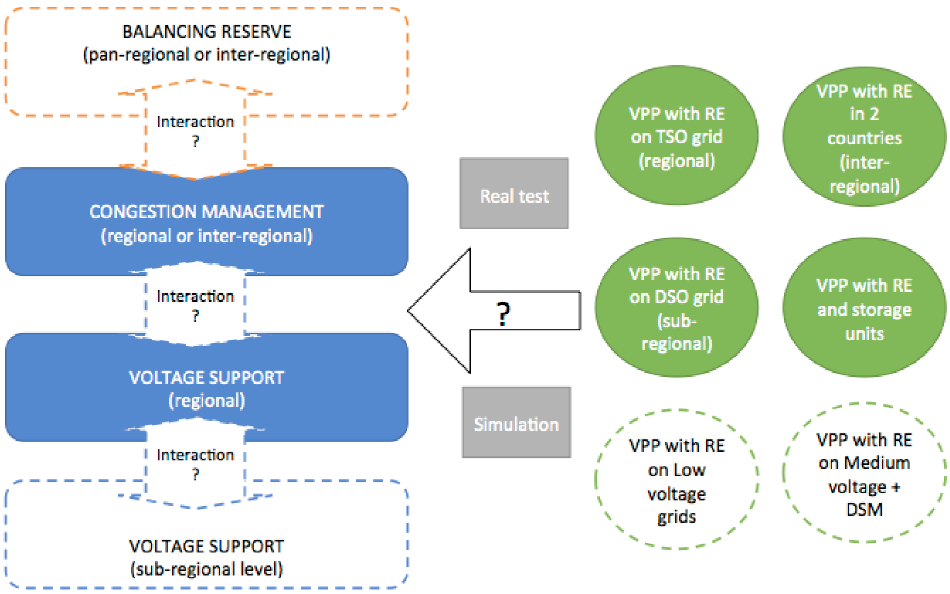

Figure 1. Summary of the use cases analysed in REgions. Source: Hespul.

Use cases

The first use case (UC1) is congestion management in France on the transmission grid, and in particular on HV lines (63/90 kV), called the "repartition grid". Congestion management is currently procured in France by the TSO through a common mechanism with tertiary reserves (manual Frequency Restoration Reserves and Replacement Reserves). Historically, congestion was mainly due to overconsumption. In 2019, the volume called to alleviate grid congestion due to overproduction (64GWh) was significantly greater than the volume called in case of overconsumption (46 GWh)[1]. Furthermore, network operators are challenged by the pace of variable development since network

[1] Data can be dowloaded on RTE website : http://clients.rte-france.com/lang/fr/visiteurs/vie/mecanisme/volumes_prix/motif.jsp

extension is a lengthy process. This situation is expected to become more critical as the rate of installed solar capacity is expected to grow 4-fold to reach the 2028 objectives. Thus, congestion management is currently considered as a useful solution to fast forward grid connection of new renewable power plants.

The second use case (UC 2) concerns voltage support for the transmission grid (63kV and over) in France. Voltage support is currently procured via bilateral contracts with all conventional generators connected to the transmission grid. Variable RE connected to the distribution grid (20kV and under) do not participate to this mechanism. Yet, these medium voltage (MV) power plants already provide reactive power to the distribution grid following regulation laws defined by the DSO and are able to do much more. The TSO RTE anticipates that overvoltage situations will become more frequent as variable RE capacities increase following France's ambitious goals.

UC 1 and 2 will explore the ability of a VPP composed of power plants in the vicinity of the constrained line or transformer station to alleviate a simulated constraint. These use cases will serve as a proof-of-concept to evaluate the costs of the solution, specify the conditions under which this service can be provided (product duration, time horizon of bids, precision, etc.), and improve the production references, the Available Active Power (AAP) and the Available Reactive Power (ARP).

The third use case aims to demonstrate RE participation in the redispatch process in Northern Germany. This area alone concentrates 64% of the overall German curtailment of renewable electricity due to delay in grid expansion. Today, RE curtailment is a means of last resort to solve grid congestion when network operators have exhausted all other means. Following recent changes in in the EU regulatory framework, Germany has put an end to the dedicated process RE curtailment known as "feed-in-management" and will integrate renewable energy in the new Redispatch 2.0 process. This UC will explore the ability of a VPP to respond to redipatch measures on power plants (curtailment) in this new process, with a specific attention to the remuneration/compensation mechanism and the so-called "Symmetrical REdispatch", for which RE are suitable due to their spatial distribution and control accuracy.

The fourth use case intends to test the participation of photovoltaic (PV) plants in the redispatch process in Austria in a context of ambitious RE goals in the country aiming at 100% RE-coverage of national electricity consumption by 2030, and high interdependance with the neighboring countries. Only conventionnal thermal plants and large hydro plants are currently participating in congestion management. UC4 will be realised by 1) improving PV forecast in order to diminish to need for balancing and redispatch, 2) testing the provision of congestion management service from a pool of PV units at different geographical locations in the country by providing short-term forecasts and their locational information to the TSO.

UC 5 will explore the subject of PV participation in the balancing market in Austria, focusing on the automatic and manual Frequency Restoration Reserve (aFRR and mFRR) products. Although balancing services procurement is market-based in Austria and is explicitly open to aggregated units, PV units currently do not participate in the market due to technical and market restrictions. The use case consists in improving the forecasting and "nowcasting" of PV systems in order to enable their compliance with the prequalification requirements for the provision of aFRR and mFRR in the balancing market.

UC 6 examines the combined value streams for PV systems from wholesale markets and ancillary service provision in Austria. Indeed, the duration of the subsidy period for PV plants is limited to 13 years beginning with the start of operation, which implies that, in the near future, spot markets, in combination with ancillary service provision, may become a more attractive source of revenue for PV operators. This UC will explore the different commercialization options for a PV pool, spot market, balancing and/or redispatch, and their combinations will be evaluated.

Beyond these 6 national use cases, all partners will be involved in the seventh use case. UC 7 is aimed at analysing the possible collateralisation of balancing reserve during congestion. Indeed, both of these ancillary services are currently procured separatly in Austria and Germany and through the same mechanism in France. Project partners will explore how using an international VPP or the communication of several VPP may solve conflicts between balancing and congestion management. Such a test addresses several still unsettled regulatory issues, not only for the conflict between balancing and congestion management, but also for the international handling and trading of balancing reserves and congestion management capacities.

Résumé

La part croissante des énergies renouvelables (EnR) variables dans le mix électricité en Europe appelle à une participation plus active de ces technologies à la stabilité du système électrique. En effet, jusqu'à présent, ces technologies, essentiellement l'éolien et le solaire photovoltaïque, ont été intégrées de manière plutôt passive au réseau électrique. Les premiers exemples de participation active des énergies renouvelables à la gestion du réseau électrique remontent à quelques années en Allemagne, avec des pré-requis techniques sur l'éolien (passage de creux de tension notamment) mais aussi sur le solaire avec l'obligation depuis 2012 d'avoir la possibilité d'écrêter la production en cas de contraintes sur le réseau pour toutes les systèmes de plus de 100kW. Néanmoins, les énergies renouvelables variables sont en capacité de fournir une palette de services bien plus large que ce qui est fait aujourd'hui.

Le précèdent projet ERA-NET "REstable" a démontré la capacité technique des parcs éoliens et centrales photovoltaïques, localisés en France et en Allemagne, à fournir des réserves positives (hausse de la production) et négatives (baisse de la production) en étant groupés dans une centrale virtuelle, et ce, avec une qualité comparable à celle obtenue pour les services fournis par les centrales conventionnelles. REstable a néanmoins identifié plusieurs obstacles à la participation généralisée des EnR aux services systèmes de réglage en fréquence, à la fois au niveau réglementaire et dans le design des marchés et mécanismes, et a établi des recommandations pour les dépasser.

Le projet REgions vise à complémenter ces premières analyses sous l'angle du caractère local des services systèmes et des marchés et mécanismes associés. Tous les services systèmes ont intrinsèquement une dimension locale. Même le réglage en fréquence, habituellement indifférent à la localisation des centrales qui y participent, peut être affecté par des contraintes locales qui empêchent certaines centrales de participer à l'équilibrage offre-demande. Pour creuser cette problématique, sept cas d'usage basés sur quatre différents services systèmes seront testés dans REgions avec des centrales de production éolienne et solaire, et éventuellement des unités de consommation et de stockage : réglage de tension, gestion des congestions, réglage en fréquence, et une combinaison de ces services.

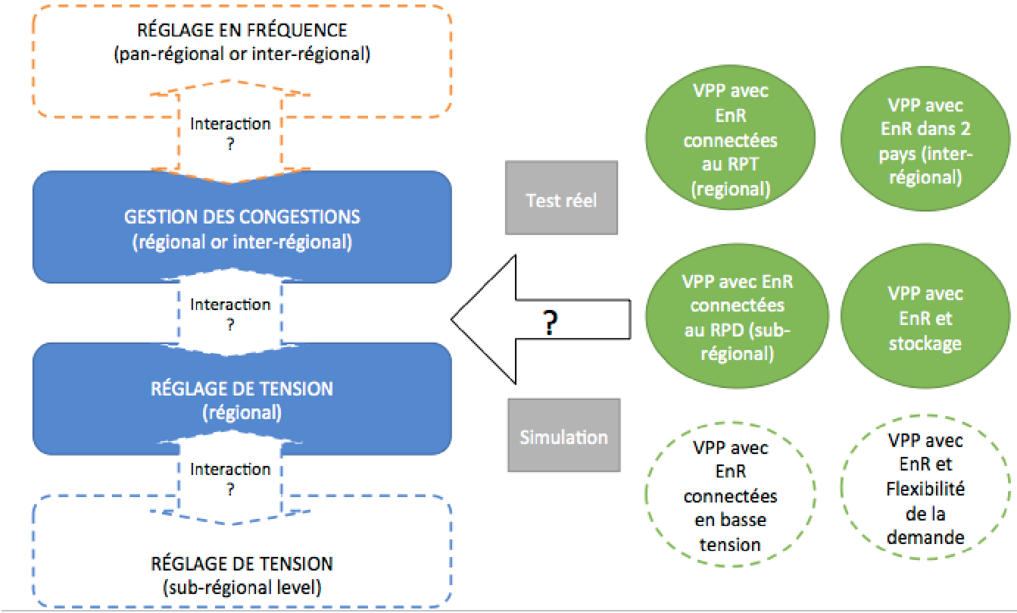

Figure 2. Résumé des différents cas d'usages testés dans REgions. Source: Hespul.

Cas d'usage

UC 1 : Le 1[er] cas d'usage est la gestion des congestions en France sur le réseau de transport (RPT), en partciulier sur les lignes de répartition (63kV et 90kV). La gestion des congestions est actuellement en

France une responsabilité de RTE, gestionnaire de réseau de transport, qui se procure les services nécessaires à travers le mécanisme d'ajustement (sous-partie du mécanisme de réserves tertiaires, mFRR et RR). Historiquement, les congestions ont plutôt été liées à une consommation trop importante dans une zone. Cependant, les cas de gestion des congestions liées à des surplus de production dans une zone qui ne peut être acheminée due à un dimensionnement insuffisant de l'infrastructure sont de plus en plus fréquents : en 2019, le volume d'énergie active à la baisse pour congestion (pour résoudre une sur-production) (64GWh) était plus important que le volume d'énergie active à la hausse pour congestion (sur-consommation) (46GWh)[2].

De plus, malgré la planification du développement du réseau via les schémas régionaux de raccordement des EnR (S3REnR), le raccordement des EnR est encore ralenti par le délai de réalisation des ouvrages dans certaines zones de fort développement. Cette situation devrait s'aggraver avec le développement attendu des EnR pour atteindre les objectifs fixés à 2028 par la Programmation Pluriannuelle de l'énergie. La gestion des congestions doit donc être regardée de près comme un moyen transitoire pour accélérer le raccordement des EnR.

UC 2 : le second cas d'usage est le réglage de tension sur le réseau de transport en France, en particulier sur le réseau de répartition. Le réglage de tension est actuellement obtenu par des contrats bilatéraux entre RTE et des centrales conventionnelles raccordées sur le réseau de transport. Les EnR variables raccordées au réseau de distribution ne participent pas à ce mécanisme. Néanmoins ces centrales sont tenues d'avoir les capacités constructives en réactif pour le réglage de tension qui sont actuellement sous-utilisées. Elles répondent aux règles de réglage définies au cas par cas par le gestionnaire de réseau de distribution pour ses propres besoins. RTE anticipe de son côté que les situations de surtension vont devenir de plus en plus fréquentes à mesure que la capacité des renouvelables variables s'accroît.

UC 1 et 2 visent à étudier la capacité d'une centrale virtuelle composée de différentes centrales d'EnR variables raccordées dans une même zone affectée par des contraintes à participer à la levée de ces contraintes. Ces cas d'usage serviront à évaluer plus précisément les coûts de cette solution, spécifier les conditions dans lesquelles les services peuvent être fournis (durée du produit, horizon de temps, précision, etc.), et améliorer les méthodes de contrôle du réalisé par le calcul de référence de production active et réactive.

UC 3 vise à démontrer la faisabilité technique de la participation des parcs éoliens au processus de redispatch, en cas de congestion, dans le Nord de l'Allemagne. Cette zone concentre 64% des écrêtements de production renouvelable du pays liés au délai dans le développement du réseau de transport. A l'heure actuelle, l'écrêtement des EnR reste un moyen de dernier recours pour lever les congestions. En réponse aux changements récents du cadre réglementaire européen, l'Allemagne a décidé d'intégrer le dispositif d'écrêtement de la production EnR datant de 2012 au processus général de gestion des congestions. Ce cas d'usage analysera la capacité d'une centrale virtuelle à répondre à des mesures de gestion des congestions, avec une attention particulière au mécanisme de rémunération ou compensation et au principe de "Redispatch symmétrique" pour lequel les EnR sont adaptées vu leur répartition spatiale et la précision du pilotage.

UC 4 vise à tester la participation des centrales photovoltaïques dans le mécanisme autrichien de gestion des congestions, dans un contexte d'objectifs très ambitieux de développement des EnR qui visent à atteindre un taux de couverture de 100% de la consommation nationale en 2030, et d'une forte interdépendance du pays avec ses voisins. Les centrales thermiques conventionnelles et les grandes centrales hydrauliques sont les seules à participer à l'heure actuelle à la levée des congestions. UC 4 consistera à 1) améliorer la prévision photovoltaïque pour diminuer les besoins en réserves et en gestion des congestions, et 2) tester la participation d'un agrégat d'installations photovoltaïques

[2] Data can be dowloaded on RTE website : http://clients.rte-france.com/lang/fr/visiteurs/vie/mecanisme/volumes_prix/motif.jsp

localisées en différents endroits dans le pays à la gestion des congestions en fournissant des prévisions court-terme et des informations spécifiques aux centrales au gestionnaire de réseau de transport.

UC 5 vise à étudier la participation des centrales photovoltaïques au réglage de fréquence en Autriche, avec un focus sur la réserve secondaire (automatic Frequency Restoration Reserve, aFRR) et la réserve tertiaire (manual Frequency Restoration Reserve, mFRR). Cette partipation n'est pas effective à l'heure actuelle à cause de barrières techniques et réglementaires, malgré la possibilité laissée aux centrales virtuelles de participer au marché de réserves. Le cas d'usage consiste à améliorer la prévision, y compris très court-terme, des systèmes photovoltaïques de manière à leur permettre de répondre aux critères de pré-qualification pour la fourniture des services aFRR et mFRR.

UC 6 examine la valeur combinée de différents revenus des marchés de l'énergie et des services systèmes pour les systèmes photovoltaïques. En effet, la duration des tarifs d'achat étant limitée à 13 ans à partir de la mise en service, ces marchés et mécanismes pourraient devenir la source de revenue des opérateurs PV. Ce cas d'usage travaillera sur différentes options de commercialisation pour une centrale virtuelle composée de centrales PV : marché spot, réglage en fréquence, gestion des congestions, et leur combinaison.

UC 7 implique tous les partenaires à travers l'analyse d'une contrainte d'accès aux réserves pour le réglage de fréquence, contrainte liée aux congestions. En Allemagne et en Autriche, ces services systèmes sont approvisionnés de manière séparée, ce qui n'est pas le cas en France comme évoqué ci-dessus. Les partenaires du projet analyseront ensemble comment l'utilisation d'une centrale virtuelle composée d'unités localisées dans différents pays peut résoudre des conflits d'usage entre réglage de la fréquence et gestion de congestions, cette conflictualité n'étant pas complètement résolue au niveau réglementaire à l'heure actuelle, tant au niveau national qu'au niveau international.

Kurzdarstellung

Die zunehmende Durchdringung erneuerbarer Energien im Strommix erfordert einen größeren Beitrag dieser Technologien zur Netzstabilität. Diese neuen Erzeuger, die hauptsächlich aus Wind- und Solaranlagen bestehen, wurden bisher meist passiv ins Netz integriert. Erste Fälle von Wirkleistungsmanagement mit Erneuerbaren liegen in Deutschland bereits mehrere Jahre zurück, beispielsweise mit der Verpflichtung im Jahr 2012, bei Netzengpässen Kapazitäten zur Wirkleistungsbegrenzung für Anlagen mit einer Leistung größer 100kW vorzusehen. Es bleibt jedoch noch viel zu tun, damit die variablen erneuerbaren Energien (EE) Systemdienstleistungen ähnlich wie konventionelle Generatoren erbringen können.

Das Vorgängerprojekt „REstable" hat gezeigt, dass Wind- und Solaranlagen aus Frankreich und Deutschland, zusammengefasst in einem virtuellen Kraftwerk (VPP), technisch in der Lage sind, positive und negative Regelreserven in vergleichbarer Qualität wie konventionelle Generatoren bereitzustellen. REstable wies dennoch auf mehrere Barrieren im aktuellen Regulierungsrahmen hin, die eine volle RE-Beteiligung verhindern, und gab Empfehlungen zur Überwindung dieser Probleme.

Das Projekt REgions ergänzt diese Analysen um den Aspekt der Regionalität von Systemdienstleistungen und verwandten Märkten. Schließlich haben alle Nebenleistungen einen eingebetteten Standortfaktor. Auch Regelreserve, die die Netzfrequenz europaweit beeinflusst, unabhängig davon, wo sie bereitgestellt wird, kann lokalen Beschränkungen unterliegen. Um diese Aspekte im REgions-Projekt zu untersuchen, wird die Flexibilität der verschiedenen Pilotanlagen des Projekts aggregiert und in sieben Anwendungsfällen regionaler und überregionaler Dienste basierend auf vier verschiedenen Hilfsdiensten getestet: Spannungsregelung, Engpassmanagement, Ausgleichsreserve für die Frequenzregelung und eine Kombination dieser Dienste.

Use Cases

Der erste Use Case (UC1) ist das Engpassmanagement in Frankreich im Übertragungsnetz und insbesondere auf HS-Leitungen (63/90 kV), das sogenannte „Umverteilungsnetz". Das Engpassmanagement wird derzeit in Frankreich vom ÜNB über einen gemeinsamen Mechanismus mit tertiären Reserven (manuelle Frequenzwiederherstellungsreserven und Ersatzreserven) beschafft. Historisch gesehen waren Überlastungen hauptsächlich auf übermäßigen Konsum zurückzuführen. Im Jahr 2019 war die Abrufmenge zur Behebung von Netzengpässen durch Überproduktion (64 GWh) deutlich höher als die Abrufmenge bei Überverbrauch (46 GWh). Darüber hinaus sind Netzbetreiber durch das Tempo der variablen Entwicklung sehr gefordert, da der Netzausbau ein eher langsamer Prozess ist. Es wird erwartet, dass diese Situation noch kritischer wird, da die Rate der installierten Solarkapazität voraussichtlich um das Vierfache steigen wird, um die Ziele für 2028 zu erreichen. Engpassmanagement gilt daher derzeit als sinnvolle Lösung für den schnellen Netzanschluss neuer erneuerbarer Kraftwerke.

Der zweite Anwendungsfall (UC 2) betrifft die Spannungshaltung des Übertragungsnetzes (63 kV und mehr) in Frankreich. Die Spannungsstützung erfolgt derzeit über bilaterale Verträge mit allen an das Übertragungsnetz angeschlossenen konventionellen Erzeugern. Variable RE, die an das Verteilnetz (20 kV und darunter) angeschlossen sind, nehmen an diesem Mechanismus nicht teil. Diese Mittelspannungskraftwerke (MV) liefern jedoch bereits Blindleistung nach den vom VNB definierten Regulierungsgesetzen in das Verteilnetz und können noch viel mehr. Der ÜNB RTE geht davon aus, dass Überspannungssituationen häufiger werden, da die variablen EE-Kapazitäten im Anschluss an die ehrgeizigen Ziele Frankreichs steigen.

UC 1 und 2 untersuchen die Fähigkeit eines VPP, dass aus Kraftwerken in der Nähe der eingeschränkten Leitung oder des entsprechenden Umspannwerks besteht, eine simulierte Einschränkung zu entschärfen. Die der Lösung zu bewerten, die Bedingungen zu spezifizieren, unter denen diese Dienstleistung erbracht werden kann (Produktdauer, Zeithorizont der Angebote, Genauigkeit usw.)

und die Produktionsreferenzen zu verbessern, die verfügbare Wirkleistung (AAP) und die verfügbare Blindleistung (ARP).

Der dritte Use Case soll die Beteiligung von RE am Redispatch-Prozess in Norddeutschland demonstrieren. Allein in diesem Bereich konzentrieren sich 64 % der gesamtdeutschen Überlastungen von erneuerbarem Strom aufgrund von Verzögerungen beim Netzausbau. Die EE-Abschaltung bzw. Begrenzung ist heute ein letztes Mittel zur Behebung von Netzengpässen, wenn die Netzbetreiber alle anderen Mittel ausgeschöpft haben. Nach den jüngsten Änderungen des EU-Rechtsrahmens hat Deutschland die dedizierte EE-Abkürzung „Einspeisemanagement“ beendet und wird erneuerbare Energien in den neuen Redispatch 2.0-Prozess integrieren. Dieser UC wird die Fähigkeit eines VPP untersuchen, in diesem neuen Prozess auf Redipatch-Maßnahmen an Kraftwerken (Abkürzung) zu reagieren, mit besonderem Augenmerk auf den Vergütungs-/Kompensationsmechanismus und den sogenannten „symmetrischen REdispatch“, für den sich RE eignen aufgrund ihrer räumlichen Verteilung und Regelgenauigkeit.

Im vierten Use Case soll die Beteiligung von Photovoltaik(PV)-Anlagen am Redispatch-Prozess in

Österreich im Kontext ambitionierter EE-Ziele im Land mit dem Ziel einer 100-prozentigen EE-Abdeckung des nationalen Stromverbrauchs bis 2030 und einer hohen Interdependenz mit den Nachbarländer untersucht werden. Am Engpassmanagement nehmen derzeit nur konventionelle thermische Kraftwerke und große Wasserkraftwerke teil. UC4 wird realisiert durch 1) Verbesserung der PV-Prognose, um den Bedarf an Ausgleich und Redispatch zu verringern, 2) Testen der Bereitstellung von Engpassmanagementdiensten aus einem Pool von PV-Einheiten an verschiedenen geografischen Standorten im Land durch Bereitstellung kurzfristiger Prognosen und ihre Standortinformationen an den ÜNB.

UC 5 wird sich mit dem Thema PV-Beteiligung am Regelenergiemarkt in Österreich beschäftigen und sich dabei auf die Produkte der automatischen und manuellen Frequenzwiederherstellungsreserve (aFRR und mFRR) konzentrieren. Obwohl die Regelenergiebeschaffung in Österreich marktbasiert und explizit offen für aggregierte Einheiten ist, nehmen PV-Einheiten aufgrund technischer und marktbezogener Restriktionen derzeit nicht am Markt teil. Der Anwendungsfall besteht darin, die Prognose und das „Nowcasting“ von PV-Anlagen zu verbessern, um deren Einhaltung der Präqualifikationsanforderungen für die Bereitstellung von aFRR und mFRR im Regelenergiemarkt zu ermöglichen.

UC 6 untersucht die kombinierten Wertströme für PV-Anlagen aus Großhandelsmärkten und Systemdienstleistungen in Österreich. Tatsächlich ist die Förderdauer für PV-Anlagen auf 13 Jahre ab Inbetriebnahme begrenzt, was bedeutet, dass Spotmärkte in naher Zukunft in Kombination mit der Bereitstellung von Systemdienstleistungen eine attraktivere Einnahmequelle werden könnten für PV-Betreiber. In dieser UC werden die verschiedenen Kommerzialisierungsoptionen für einen PV-Pool, Spotmarkt, Bilanzierung und/oder Redispatch untersucht und deren Kombinationen bewertet.

Über diese 6 nationalen Anwendungsfälle hinaus werden alle Partner am siebten Anwendungsfall beteiligt sein. UC 7 zielt darauf ab, die mögliche Besicherung von Regelreserve bei Engpässen zu analysieren. Tatsächlich werden diese beiden Nebenleistungen derzeit in Österreich und Deutschland getrennt und in Frankreich über denselben Mechanismus beschafft. Die Projektpartner werden untersuchen, wie der Einsatz eines internationalen VPP oder die Kommunikation mehrerer VPP Konflikte zwischen Ausgleich und Engpassmanagement lösen kann. Ein solcher Test adressiert mehrere noch ungeklärte regulatorische Fragen, nicht nur für den Konflikt zwischen Regel- und Engpassmanagement, sondern auch für den internationalen Umschlag und Handel von Regelreserven und Engpassmanagementkapazitäten.

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List of acronyms

General

AAP – Available Active Power

ACER - Agency for the Cooperation of Energy Regulators

aFRR – Automatic Frequency Restoration Reserve

ARP – Available Reactive Power

ASM - Active System Management

ATC - Available transfer capacity

BRP – Balancing responsible party

BSP - balancing service provider

CACM - Capacity Allocation and Congestion Management

CCR - Capacity calculation regions

CNEs - Critical network elements

CWE – Central Western Europe

DSM – Demand side management

DSO – Distribution System Operator

EBGL - European Guideline on Electricity Balancing

EHV- Extra high voltage lines

FBMC - Flow-based market coupling

FCR – Frequency Containment reserve

FiT – Feed-in-tariff

HV – High voltage lines

LV – Low Voltage

mFRR - Manual Frequency Restoration Reserve

MV – Medium Voltage

NC LFCR - Network Code on Load-Frequency Control and Reserve

RE - Variable renewable energy sources

RfG – Requirements for Generators

SO GL - System Operation Guideline

TSO – Transmission System Operator

UC – Use Case

VPP – Virtual Power Plant

vRES – Variable renewable energy sources

France

AE – Ajustement Entity

BE – Balancing Entity

Austria

ElWOG - Austrian Electricity Industry and Organization Act

TOR - national grid code, Technical and Organizational Rules

Germany

BNetzA - German Regulatory Authority for Electricity

EnWG - Energy Industry Act

NAGEB – Grid Expansion Acceleration Act

1 Introduction

The project REgions is aimed at analysing and testing how variable renewable power plants can support the stabilisation of the energy system by improving traditional Virtual Power Plants (VPPs) to include regional and inter-regional ancillary services and studying possible benefits of corresponding markets. REgions builds upon the previous project, REstable, in which German and French partners explored the capability of variable RE to provide equivalent balancing reserves as traditional power plants.

Although voltage levels and responsibilities of grid operators differ from country to country (see chapter 2), the same principles apply : inter-, sub- and regional ancillary services are services with an embedded locational factor unlike balancing services which can be provided from anywhere and which affect the grid frequency throughout Europe and therefore represent a “pan-regional” service. However, the delivery of balancing reserve may be limited by local constraints, such as local grid congestions. The present deliverable focuses on describing the use cases chosen by the project partners of each participating country for the demonstration phase of the REgions project.

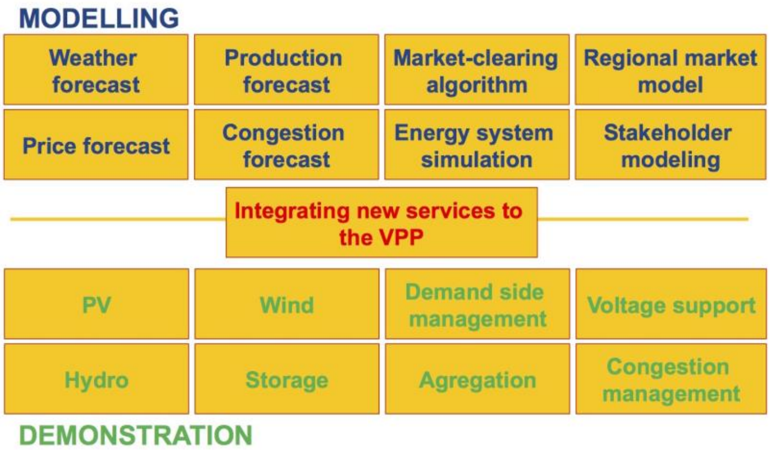

Figure 3. Global architecture of the project. Source : Hespul.

Contrary to balancing reserves, which are mostly procured through markets, voltage support and congestion management are generally procured through bilateral contracts between the TSO/DSO and the producer in the analyzed countries. The rules lack transparency and are often not adapted to variable renewable power plants and power plants connected at lower voltage levels. Thus, actual market and procurement rules will be analyzed in detail in the following tasks T3.2 and T3.3 (see https://www.regions-project.info/results/, D3.2.1 “State-of-the-art of regional markets from the research to the implementation level”, D3.2.2 “Regional market design and impact analysis of energy system scenarios” and D3.3.1 “Market interaction and regulatory framework of general and regional market”) and in WP5 to define Key performance indicators for the use case demonstration.

2 Definition of electrical regions and corresponding ancillary services

The REgions project analyses regional aspects of ancillary services and corresponding markets. For this purpose, a definition of a region from an electrical point of view is necessary. The REgions project defines its terminology (sub-regional, regional and inter-regional) based on the voltage level rather than on geographical or administrative boundaries. Electrical regions are defined as areas powered by the same the same extra-high voltage to high voltage transformer (EHV/HV). From a geographical point of view, boundaries of these high-voltage grid areas are difficult to clearly identify due to their meshing: only the TSO has knowledge of the “normal” dispatch scheme. In contrast, medium-voltage grid areas are usually clearly geographically defined due to their mostly radial topology (see Figure 4 below).

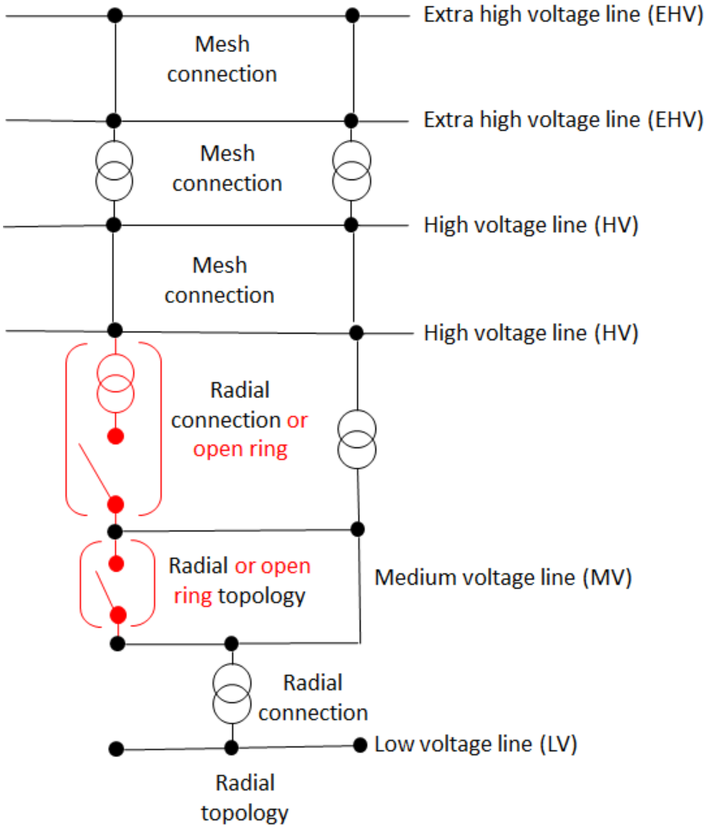

Figure 4. Typical grid topology / grid structure. Source : Fraunhofer IEE

In order to distinguish medium-voltage grid areas from the electrical regions in which they are located, the REgions project uses the term "sub-regional" or “local” for medium-voltage grid areas. Based on this definition, the terminological definition of the associated ancillary services and markets can be defined as shown in Figure 5 below. The figure also points out that the concrete voltage values of the different voltage levels and the denominations of transport and distribution grids can vary from country to country and are therefore not suitable for a generally applicable definition of electrical regions and their ancillary services and markets.

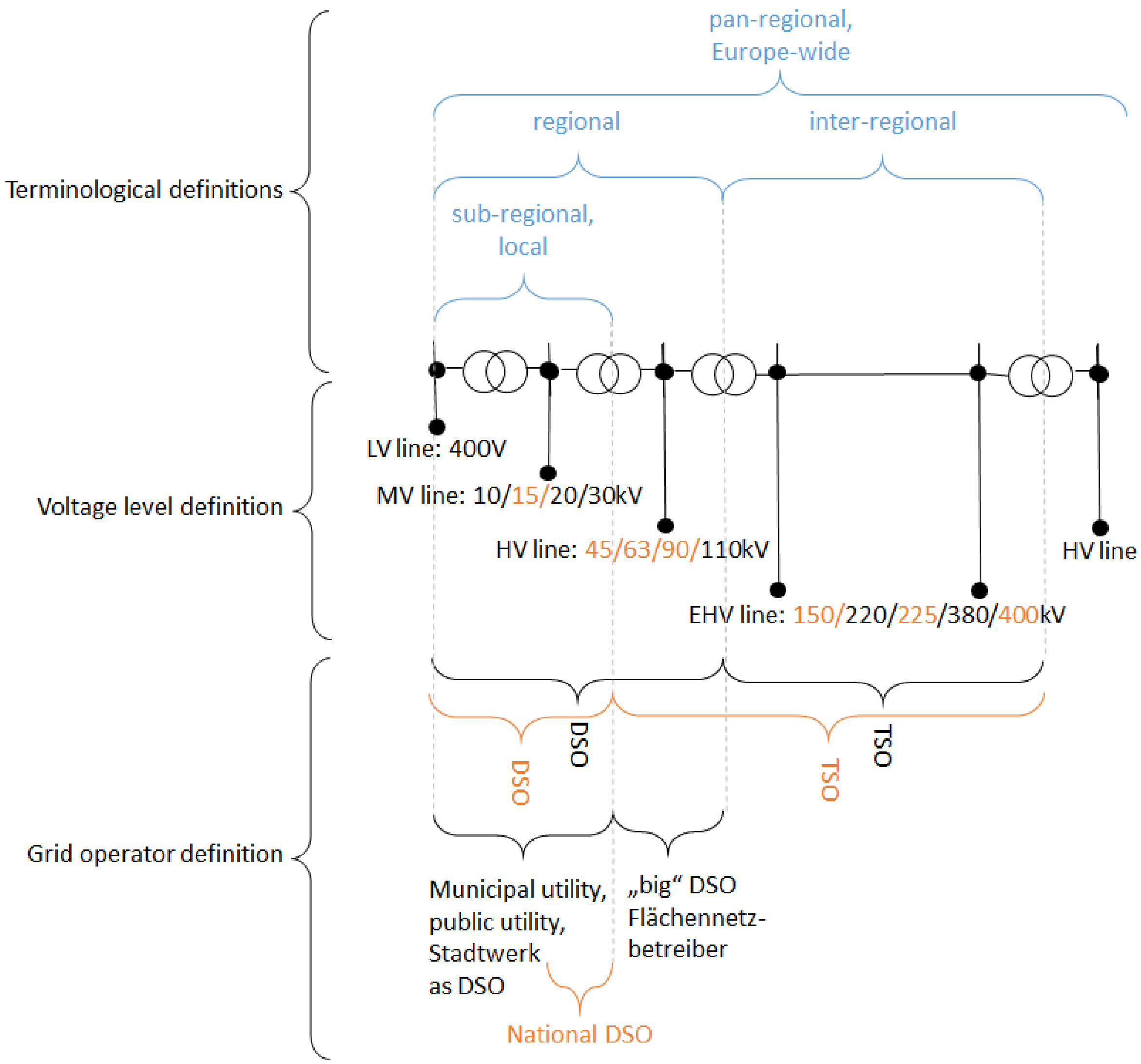

Figure 5. Definition of REgions terminology (Blue), voltage levels and grid operators in Germany (Black) and France (Orange). Source : Fraunhofer IEE, Hespul.

Based on the above considerations, ancillary services and markets can be classified according to the following table.

Table 1 : Regional classification of ancillary services analyzed in REgions (FR – France, DE – Germany, AT-Austria)

Regionality	Beneficiary	Ancillary service
Sub-regional / local	DSO (voltage level up to 40kV)	N/A (no use case on this level in REgions)
Regional	TSO (FR) /DSO (DE, AT) (voltage level 40 to 110kV)	Congestion management (FR)
		Voltage control (FR)
		(Constrained) balancing reserve (FR/DE)
Inter-regional	TSO	Congestion management (DE)
		(Constrained) balancing reserve (DE/FR)

Pan-regional / Europe-wide	TSO	Balancing reserve (AT)

The ancillary services are technically very similar at all regional levels. Their denomination differs mainly between the regional and the inter-regional level. For the general terms "congestion management" and "voltage control" the literature may also use the terminology of respectively "redispatch" and "reactive power". Another terminological difference applies to balancing reserve for frequency control purposes, which also includes spinning reserve. Frequency contained reserve (FCR), also known as "primary reserves", first level of balancing reserve, since it affects the grid frequency throughout Europe, regardless of where it is provided, is a "pan-regional" service. Secondary and tertiary reserves (aFRR, mFRR, and RR) are inter-regional, procured at a national scale. Nevertheless, balancing reserve can be subject to local restrictions, for example grid congestions, and can therefore be labeled as constrained at inter-, sub- and regional level. In fact, the conflict between the provision of balancing reserve and local grid bottlenecks is a focus of the REgions project.

The definition of the different regional levels and the associated ancillary services is summarized illustratively in **Figure 6** below.

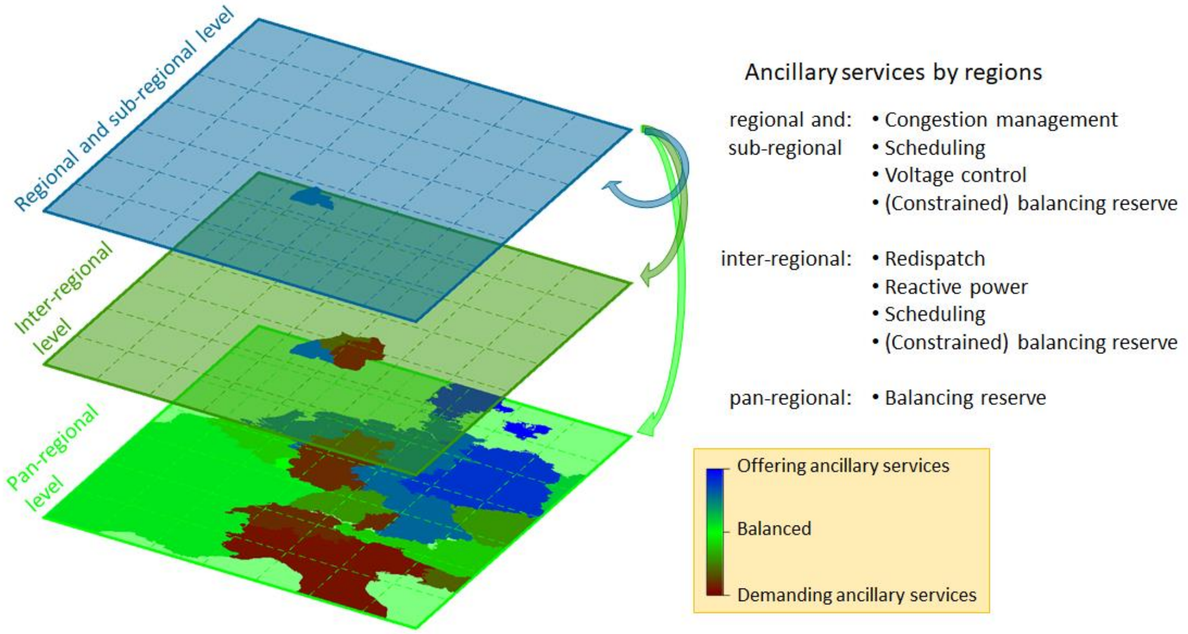

Figure 6. Illustration and definition of regional levels of ancillary services. Source : Fraunhofer IEE

3 Use cases

3.1 UC 1 – Congestion management / Redispatch in France

France' electricity mix is expected to go through important changes in the coming years following the objectives in renewable energy (RE) development set in the law. The recently adopted Energy-Climate law (November 8th 2019) [1] sets the following objectives concerning the electricity sector by modifying the legislative part of the energy code [2]:

- by 2030, renewables should represent 40% of the electricity production (this objective was already inscribed in the Energy transition law of 2015 [3]) compared to 22,7% in 2018, the large part of which comes today from hydro (12,4% of production) [4],
- by 2035, the the share of nuclear generation in the electricity production mix should go down to 50% (from 72% in 2018 [4]). This objective was initially set for 2025 in the Energy transition law of 2015.

New capacity to reach the 2030 objectives will come from wind and solar, no new major development is expected in hydro (potential is practically exhausted, production is falling every year due to climate change). It is expected that wind should slightly increase its actual growth to about 2GW/year [5] (currently around 1,5GW/year [4]), while solar power should dramatically increase its growth from around 800MW/year today [4] to 3,5GW/year [5].

The French TSO RTE covering the continental part of France has established scenarios of grid development up to 2035 based on these objectives of RE development [6]. RTE will have to face in the coming years the first large-scale renewal of its transport lines, the reinforcement of high voltage (HV) lines and the development of new substations in order to host new RE capacities. Up to 50GW of renewable capacities (wind and solar), expected to be reached in 2025), RTE is optimistic that grid optimisation can avoid large-scale modifications to the grid [6], through Dynamic Line Rating, Real Time Redispatching via in-line remote units opening and closing switches on HV lines to redistribute production on higher loaded lines, and RE production curtailment.

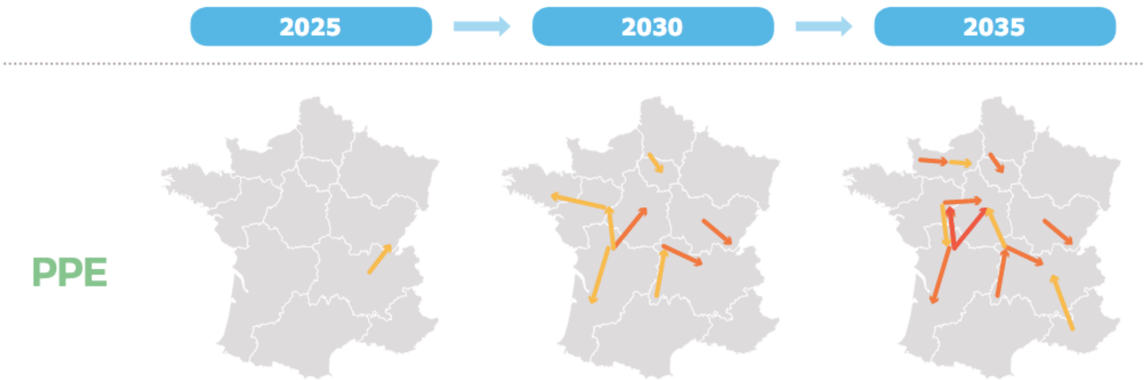

Figure 7 Map of France showing expected frequency of constraints of EHV lines (400kV) if the 2019 Energy law's RE objectives are to be reached: from 5-10% of the time (yellow) to 21-30% (red). Source : RTE's Ten year Plan [6]

In this context, RTE, Enedis (national DSO over 95% of continental France) and producers are investigating under which conditions RE's active power can be curtailed [7] in order to :

- speed up grid connection when large-scale grid work (e.g. reinforcement of HV lines, new HV lines or HV/MV substations) have realisation times greater than 4 years

- increase existing grid capacities and thus lower grid investment in areas where RE development alone does not justify expensive grid development.

RE curtailment for these applications leaves unanswered questions on the remuneration of producers for the service, the coverage of this expense and the amount it represents.

Currently, in France, renewable power plants are not obliged to participate in congestion management. Furthermore, RE under the feed-in-tariff (FiT) scheme cannot participate. We aim todemonstrate that RE can deliver a reliable congestion management service through a VPP.

For this Use Case, we shall only consider the case of curtailment service (order from the grid operator to reduce the power output of the plant – downward regulation).

3.1.1 Description of the problem

The French congestion management scheme was designed for conventional power plants. Using the present framework with renewable plants raises the following issues:

Technical issues for energy settlement: the non-generated power needs to be assessed to determine the level of execution of the curtailment service. As opposed to conventional plants, the generation program of a renewable asset can be hard to determine in advance. However, methods based on the "on-site" resource metering (wind, radiance) can be considered. For that purpose, we will rely on the concept of Available Active Power, computed in the SCADA system of the plants. This value shows the power that can be produced if no curtailment is made on the plant. It is in use in Germany [1].

Technical issues for plant dispatch: distant activation and de-activation of power generation are generally not implemented on older sites. However, plants of the latest generation generally allow remote operation. For that, we will rely on the Fraunhofer VPP software to operate the plants.

Financial issues related to service execution: the non-generated energy is subject to

1) a financial settlement between the TSO (RTE) and the Adjustment Entity (AE - the aggregator offering the reserve service) and
2) an energy settlement with the Balancing Entity (BE – EDF OA in France). The energy settlement consists in attributing the non-generated energy to the BE, in addition to the actually generated energy. The financial settlement for this non-generated energy attributed to the BE needs to be tackled. Without a fair compensation from the BE, the curtailment service presents limited interest for the plant owner.

This procurement scheme was designed for conventional power plants, i.e. for plants having a constant output over long periods of time. These methods are inapplicable to technology which power output is a function of a non-controllable resource (wind, solar). Thus, the French rules applicable for tertiary reserves to evaluate the reserve provision will need to be adapted to the case of renewables, taking into consideration:

- A general methodology to compute the non-generated power during a curtailment order
- A fair compensation from the BE for the non-generated power, at feed in tariff price

3.1.2 Technical and regulatory framework

Technical / Product Conditions

Congestion management is part of adjustment mechanism. Adjustment mechanism corresponds to the tertiary reserve (entirely manual), composed of Replacement Reserve (RR) and mFRR (manual Frequency Restoration Reserve. In France, Balancing Responsible Parties (BRPs) pay (when consumption is higher than production across their portfolio) or are paid (when consumption is lower than production across their portfolio) for imbalances, thereby financing the activation of tertiary reserves (variable cost). On the other hand, the costs of primary and secondary reserves are paid by the TSO and covered through transmission network tariffs.

- The adjustment mechanism is mandatory for all power plant connected to transmission grid (all installations > 12/17 MW). Voluntary participation by producers connected to the distribution network (MV: 20kV and LV: 400V) and consumers is possible.
- Minimal volume: Participation of any aggregate pool (consumption and/or production) of more than 1MW is allowed as long as it goes through an aggregator qualified to participate in the adjustment mechanism.
- Activation: TSO orders the offers that can participate to congestion management in the concerned zone following the merit order. Activation can be either automatic (signal sent to a control management system installed at the plant) or manual.
- Remuneration: pay as bid
- Combination with other types of reserves: The TSO can choose to exclude certain offers from its merit order for the adjustment mechanism when using them to solve congestions. The TSO can call on the adjustment mechanism when congestion management modifies the equilibrium between production and consumption at the national scale (redispatch).
- Offers can be either upward or downward, i.e. they can be asymmetrical.

To actually perform a tertiary reserve order, the test sites should be aggregated in an Adjustment Entity and get registration from RTE. They should also get the approval from their balance responsible (currently EDF).

It should be noted that performing wilful curtailment is presently not authorized under the Power Purchase Agreement (PPA) between the plants and EDF. Waiving the above constraints can be a challenge.

3.1.3 Foreseen evolution in mechanisms

TSO and DSO want to test the procurement of downward flexibility with renewables in order to postpone investments in the transmission network and in HV/MV substations linked to the increase of RE in the network [7]. Procurement would be different depending of the level at which congestion occurs:

⇨ **HV lines (63/90kV and higher)**: procurement would integrate the same process as the adjustment mechanism on the TSO perimeter (HV lines).

⇨ **HV/MV substations (63/20kV substations)**: DSO will put in place a flexibility procurement scheme common to all users (consumers, storage and producers) that are able to respond to the need.

Remuneration: the congestion procurement scheme will be adapted for congestion on HV lines requiring the curtailment of renewable energy producers. Offers will be paid as bid (feed-in-tariff price), in an effort to avoid any revenue loss for renewable energy producers. The TSO is currently asking the concerned producers to provide:

- Their price (generally the feed-in-tariff)
- A response time
- A production program (considering forecast, maintenance interventions, etc.).

3.1.4 The solution proposed

The solution proposed in REgions to implement this UC is to keep the redispatch intelligence within the VPP. The VPP responds to a need expressed by the TSO or the DSO.

Implementation in REgions will go through the following steps:

- identify constrained zones (or zones that are expected to be constrained shortly if RE development follows the expected trends) and locate assets of Engie Green and non-financed producers in these zones
- estimate the curtailment need (e.g. 20MW over 3 hours)
- describe the elements that must be considered (e.g. available active power based on forecast, production programs, priority orders, offers made on other mechanisms or markets …)
- define one or several response strategies of the VPP (e.g. activation based on cheapest plants, proportional to plant size, …).

3.1.5 Suggestions for the test

Implementation in REgions will go through the following steps:

- Engie Green, Boralex and other producers or storage operators involved in the project propose areas where they have units available to participate in Regions tests
- Pre-selection of plants taking into account concentration of plants on 63kV lines, pre-evaluation of compatibility with VPP, presence of both wind and solar plants
- Discussions with the TSO RTE to validate the relevance of the chosen areas regarding the congestion issues
- Validation of the areas and the participating power plants
- Determination of the VPP to which the power plants involved in the tests will be connected (Fraunhofer or others)
- For power plants not connected during REstable, identification of suppliers for the IT architecture that enables connection to the VPP
- Identification of the power plant capabilities by the power plant owner
- Definition of the activation order to be sent to power plants and discussion with RTE to validate the relevance

3.1.6 Questions

In the future, it is unclear how this mechanism will evolve since it is only a trial for now. Questions to be answered are:

- Will this mechanism become a market on small zones with pre-qualification of concerned actors, called upon by the TSO on the basis of a publicized need (ex: 20MW downward reserve) and a local merit order (meaning that plants at market price, i.e. which have ended their feed-in-tariff contract, or recent plants are likely to be the most frequently called)? Will VPPs be able to qualify?
- Or, conversely, will the TSO translate its needs in set points specific to each user, based on its own computation, as if operating itself a VPP? To implement this option, how far should the TSO go to collect data on production programs? Will this data be reliable?
- What are the necessary elements of TSO/DSO coordination in order to avoid conflicts in congestion management actions ?
- Should congestion management of DSO and TSO be combined in the same scheme? Would this market be also combined with Balancing market? What are the benefits and disadvantages?

3.1.7 Key performance indicator

The KPI for this use case will be defined in the subsequent deliverables upon analysing in detail the procurement mechanisms.

3.2 UC 2 - Voltage support in France

In this UC, we will focus on voltage regulation. With a high share of renewable energies, the network voltage plan can be affected. Indeed, today voltage support is provided in France through:

- Mainly, thermal and hydro power plants already started which can produce or absorb reactive power by varying their alternator's excitation current
- Compensation devises (capacitor banks, coils, static VAR compensators) installed on the transmission grid and at the interface between distribution and transmission grid.

3.2.1 Variable RE connected to the distribution grid, i.e. close to 100% of variable RE capacity, do not participate to voltage support.Description of the problem

The French TSO, RTE, realized a study in 2018 (not public) in order to assess how the voltage support currently works and what the future needs could be. In a context of rapid growth of renewable energy from wind and PV power plants in the power production, the participation of renewable producers could play an important role in guaranteeing voltage stability. Indeed, RTE observes an increasing frequency of occurrence of overvoltage on the transmission grid, whereas the problem used to be rather occurrences of undervoltage. RTE anticipates that overvoltage occurrences are bound to increase, if not prevail over undervoltage problems. Thus, RTE is considering the possibility to active reactive power constructive capabilities of plants connected on the distribution grid.

Currently, reactive power constructive capabilities are mandatory for PV and wind plants connected on the distribution grid. However, they are clearly underutilized despite their advantages compared to classical Volt Var equipment (capacitor banks, etc.): quick response time, no transient state, etc.

3.2.2 Technical and regulatory framework

French law imposes constructive reactive power capacities for power plants, which have been recently revised following the implementation of EU network codes (NC RfG – Network Code on Requirements for Generators). The TSO and DSO have translated these mandatory capacities into control laws depending on network configuration. These laws are described below.

3.2.2.1 Technical framework for the distribution grid

ENEDIS, the French DSO, distinguishes two types of connection to the medium voltage grid:

- Mixed feeders (shared between producers and consumers)
- Simple feeders (producers only)

For mixed feeders, the voltage variation along the MV line between the HV/MV substation and the connection point cannot exceed 5% with regards to the contractual voltage value. The contractual voltage value must be in a range of +/-5% of the nominal voltage value (20kV).

The DSO ENEDIS allows two options to implement voltage control [8]:

- **A power factor set – default case**

  Two cases are possible depending on the connection:

  a) When the feeder already exists, plants must be designed so as to have the constructive capability to provide reactive power (Q) from tan(φ) = -0,35 up to $tan(\varphi) = 0{,}4$. The definitive value of the tan (φ) is only known upon signing the contract with the DSO and is based on the network configuration studied by the DSO.

  b) In the case of a direct feeder, the ratio $tan(\varphi) = \frac{Q}{P}$ will be set to 0, with an operating range of 0.1, which can be either in injection or in consumption. This leads to two possible operating bands: [-0.1 ; 0] and [0 ; 0.1].

- **A local regulation law depending on voltage – only when plants can be connected to a mixed feeder**

This type of regulation is optional and must be asked by the producer to the DSO. The specificities of this type of regulation is that the ratio between reactive and active powers is not fixed, but depends on the voltage value measured at the connection point. The local regulation law is described in the figure below.

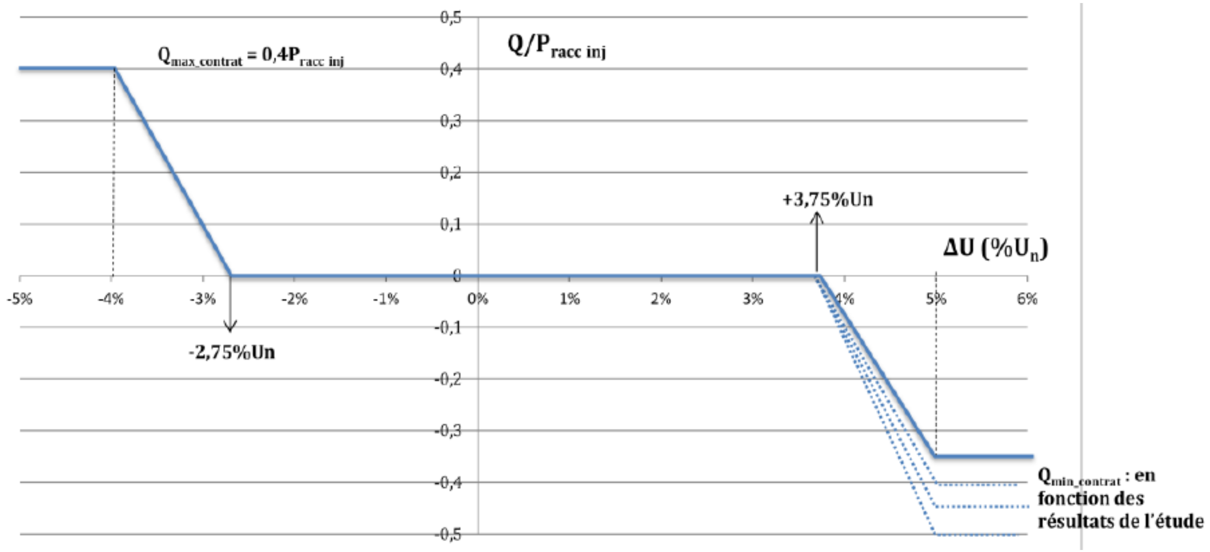

Figure 8. Enedis (French DSO) local regulation law Q=f(U). Source: Enedis.

The limits of reactive injection or absorption are defined in the law such as the maximal reactive power injected to the grid equals to 0,4 times the connection active power, and the limit of reactive power consumption depends on the machines capabilities and had to be included in [-0.5*P_connection; -0,35*P_connection]. Thus, the limit values are the same as the regulation with a fixed power factor.

Upon studying the two possibilities, if voltage constraints appear with the local regulation law and disappear with a “set power factor” regulation, the DSO will favour the second solution. The advantage of the local regulation law Q=f(U) is that both undervoltage and overvoltage can be dealt with.

The tap changer set can also be modified to connect a new production farm, in the range of [Un+2% ; Un+4%].

3.2.2.2 Technical framework for the transmission grid

Every generator connected to the French transmission grid must have constructive capabilities regarding reactive power. Those capabilities correspond to a trapeze in a Q=f(U) diagram (see figure below). The reactive power parameters come down to a local regulation law where reactive power depends on the voltage measured, thus similar to the one used by the DSO but without a dead band, and a secondary law adjusted depending on the installed capacity of the plant and the voltage level of connection (225kV and more).

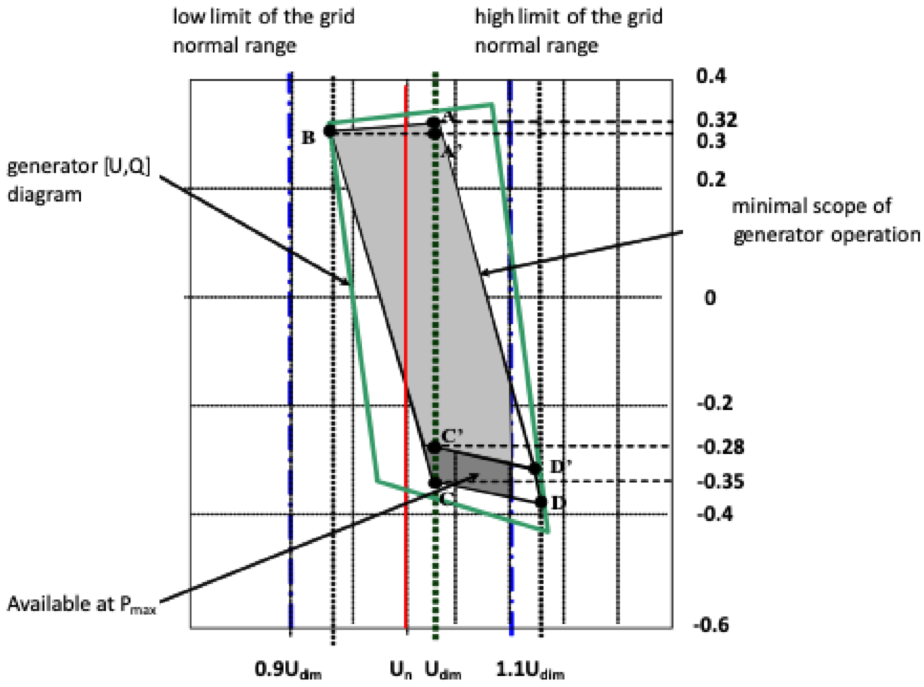

Figure 9. RTE (French TSO) reactive power provision law for producers (Source: RTE)

3.2.2.3 Regulatory framework

Not respecting mandatory connection parameters in reactive power leads to penalties applied by the DSO or TSO to the producer.

As mentioned above, beyond these mandatory regulation laws, RTE is currently considering the revision of its reactive power procurement mechanism in order to acquire reactive power from distribution network connected plants.

3.2.3 The solution proposed

The solution proposed in REgions to implement this UC is to go further than the study established by the TSO RTE on reactive power provision by distribution connected power plants, by testing the following use cases:

- keep the redispatch intelligence within the VPP: the VPP responds in priority to a need expressed by the TSO (ex: providing 20MVarh inductive) rather than having each power plants respond to a set-point fixed by the TSO or the DSO. The VPP may also address the congestion constraints of the DSO on HV/MV substations.
- test reactive power provision with a VPP composed of power plants connected on dedicated medium voltage feeders
- test available reactive power of power plants connected on medium voltage mixed feeders taking into account quality levels on the DSO network
- test reactive power provision with a VPP composed of power plants connected on medium voltage dedicated feeders and medium voltage mixed feeders selecting only plants that do not negatively impact the distribution network
- test capacitive reactive power provision, and not only inductive, in periods of high load.

3.2.4 Suggestions for the test

Implementation in REgions will go through the following steps:

- identify constrained zones (or zones that are expected to be in constraints shortly if RE development follows the expected trends) and locate assets of Engie Green and non-financed producers in these zones
- evaluate the constructive reactive power capabilities of power plants, in particular at extreme points of active power availability
- estimate the reactive power provision need (e.g. 20MVarh over 3 hours)
- describe elements that must be considered (e.g. minimal available active power needed, obligations linked to connection requirements, differences between mixed and dedicated feeders, etc.)
- define one or several response strategies of the VPP (e.g. activation based on cheapest plants, proportional to plant size, proximity to the problem, …).

3.2.5 Questions

The following questions will be addressed in part in REgions :

- Does a more frequent equipment utilisation at close to maximum load due to reactive power provision beyond DSO obligations lead to accelerated ageing of equipment (inverters, transformers, etc.)?
- How can these mandatory constructive reactive power capacities be best utilized?
- Is the utilisation of capacitive reactive power an efficient way to diminish voltage drop? If yes, what impact would this measure have on the whole voltage distribution? would it allow to lower voltage level at the transformer thereby liberating some hosting capacity?
- What is the cost-effectiveness of RE's reactive power provision considering only OPEX costs ?

3.2.6 Key performance indicator

The KPI for this use case will be defined in the subsequent deliverables upon analysing in detail the procurement mechanisms.

3.3 UC 3 – RE participation in the redispatch process in Northern Germany

Additional information on UC3 will be provided in https://www.regions-project.info/results/, D6.3 «Results of RES partcipation in flexibility market (German proof-of-concept)»

Renewable energies (RE) in Germany are currently not participating in redispatch. However, they are often curtailed in order to relieve grid congestion, especially in Northern Germany. This curtailment of RE is a well-established process, which is referred to as "feed-in management" (Einspeisemanagement, EinsMan, [2]) and which is only used curatively by the grid operators if other grid congestion management measures are not sufficient to solve the congestion. In order to minimize the extensive curtailment of wind energy in Northern Germany, a flexibility market concept called ENKO [3] was developed, which addresses regional electricity consumers to increase their consumption in times of regional wind power surpluses and grid congestions. Apart from that, several legislative changes in

EEG and EnWG laws have recently been made (summarised as "NABEG 2.0"), which demand the inclusion of RE in the redispatch process and make the present feed-in-management a phase-out model. Under the name Redispatch 2.0, an industry solution is currently being developed to implement the binding European and national targets. In REgions, we want to demonstrate how RE can participate in a new flexibility process in northern Germany.

3.3.1 Description of the problem

One of the major challenges implicated by the German energy transition is dealing with grid congestion. Grid congestion management is a local problem that is currently being dealt with centrally by the TSOs. The resulting processes appear to be optimal neither in terms of the resulting costs nor in terms of overall system efficiency. In 2015 64% of the overall German curtailment was located in Schleswig-Holstein, the most northern state of Germany with a very high penetration of wind energy. It led to a curtailed energy of 2,934 GWh at costs of 295million Euro, which results in curtailment costs of 10 ct/kWh excluding redispatch costs.

The identification and effective use of flexibility not only plays a crucial role in managing congestion, but also in balancing production and consumption. The possibility of balancing load and generation is already profitable by participating in today's balancing markets. The use of decentralised flexibility for congestion management requires knowledge of the condition of the power grid, the occurrence of congestion and the impact of individual flexibility providers on precisely this congestion. This requires a level of coordination, which is not given by today's markets. In order to make grid congestion management attractive for flexibilities, new concepts are needed.

For this reason, numerous German research projects are currently working on concepts to solve these challenges, especially within the SINTEG research framework. One of these concepts is the so-called ENKO concept [3], which was developed as part of the NEW 4.0 project to meet the challenges in Northern Germany in particular. The ENKO concept, which only addresses electricity consumers as flexibilities, was expanded in [4] to include electricity generators and price bids, resulting in a concept for a regional flexibility market.

This concept, like most others, is based on the current legal framework for congestion management in Germany and, in particular, for the curtailment of renewable feed-in, the feed-in management (EinsMan) [2]. EinsMan is a special regulation, which may only be used by the grid operator if all possible conventional capacities are already exhaused in the congestion management. EinsMan is therefore not part of congestion management but is downstream of it. However, with the so-called Redispatch 2.0 [5], which is to enter into force on 1 October 2021, the new legal framework of NABEG 2.0 calls for renewable energies to be included directly in redispatch processes. For this reason the existing flexibility concepts referring to EinsMan, must be changed and adapted.

3.3.2 Technical and regulatory framework

According to §13 (1) EnWG, if the safety or reliability of the electricity supply system in the respective control area is endangered or disrupted, the TSOs are authorised and obliged to prevent a threat or disruption through the following measures in the following order:

1. grid-related measures (grid switching)

2. market-related measures (Redispatch, Load management/(dis)connectable loads (AbLaV), Balancing reserves, Grid and capacity reserves

3. emergency measures (curtailment or shutdown of 1. conventional power plants and 2. renewable energies (EinsMan)

According to §13 (4) EnWG, there is a risk to the safety or reliability of the electricity supply system, if local failures of the transmission grid or short-term grid congestions are to be managed or if the control of frequency, voltage or stability cannot be guaranteed by the TSO to the necessary extent. In this way, the EnWG distinguishes between redispatch and balancing reserve measures. Both measures must not be interchanged, as the German Regulatory Authority for Electricity (BNetzA) stipulates in [6] that the provision and delivery of balancing reserves may not be used by TSOs to relieve grid congestions.

Redispatch in Germany can be described as an "administrative redispatch with cost reimbursement", as it is mandatory for conventional energy producers and storage facilities of 10 MW and more to participate and as the costs and lost profits a reimbursed.

3.3.3 Foreseen evolution in mechanisms

At the German level, NAGEB 2.0 defines the technical and regulatory framework for the future redispatch 2.0. The NAGEB 2.0 has the following aspects:

- Adopted on 04.04.2019 and came into force on 16.5.2019
- New regulations concerning congestion management (in EnWG-law)
  - Redispatch: Extension to RE and CHP plants
    - Plant size: usually larger than 100 kW nominal electrical power (§ 13a (1) EnWG)
    - Start: 01.10.2021
    - Request responsibility: Cooperation between TSO and DSO (DSOs decision takes precedence in distribution grids)
    - Balancing group balancing via the grid operators
  - EinsMan according to § 14 und § 15 EEG no longer applies but remains as not remunerated emergency measure
- Redispatch procedure
  - Minimum factor between 5 and 15 (decision by German Federal Network Agency) (§ 13j (6) EnWG)
    - Example for a factor of 5: 1 kWh RE curtailment replaces at least 5 kWh conv. generation that would have to be curtailed to solve the grid congestion
  - All RE have the same price (§ 13 (1a) EnWG)
  - CHP plants, if applicable, have the same price as RE plants (§ 13 (1b) EnWG)
  - Smaller systems (< 100 kW) subordinate in request because of high cost/benefit ratio (§ 13 (1) EnWG)
  - Redispatch is also possible at short notice (same cost assumptions)
  - Compensation for RE/CHP: 95 % or 100 % if revenue loss > 1 % of annual revenue) as previously in § 15 (1) EEG, now in § 13a (5) EnWG

3.3.4 Expected harmonisation (ENTSOE, EDSO…)

With the Electricity Market Regulation recast in 2019, the EU Commission opens for the option to procure congestion management in a market-based way. This, as well as the ongoing debate on market-based congestion management triggered by academics and stakeholders, motivated a study [7], that, however, concluded that a market-based redispatch should not be introduced.

The NAGEB 2.0 regulations also do not introduce a free redispatch market (see previous section) but, apart from the aforementioned changes, rather continue the existing approach of an administrative redispatch with cost reimbursement. It remains to be seen whether this will result in contradictions to the requirements of the EU commission.

3.3.5 The solution proposed

The proposed solution for this UC is to implement the intelligence within the VPP that enables its participation in a new North German flexibility process.

Implementation in REgions takes place in the following steps:

- Identification of specific wind farms in northern Germany, which
  - may participate in the demonstration,
  - can be part of the IEE.VPP
  - are sensitive to grid congestions
  - are situated on both sides of a grid congestion, in case a symmetrical REdispatch is demonstrated (see section 3.3.6)

- Modelling of the flexibility process and derivation of set point signals for the IEE.VPP
- Description of elements that must be considered (e.g. available active power based on forecast, production programs, priority orders, offers made on other mechanisms or markets …)
- Definition of one or several response strategies of the VPP (e.g. activation based on cheapest plants, proportional to plant size, …).

3.3.6 Suggestions for the test

During redispatch, deviations or temporary system imbalances can occur because, for example, the curtailment of a power plant and the ramp-up of another power plant are generally not antimetric. This effect applies both to conventional power plants (especially to start-up failures) and to RE plants (especially to deficient control systems) [8].

A solution for this problem can be a so-called antimetric redispatch, as proposed and illustrated in Figure 10 below.

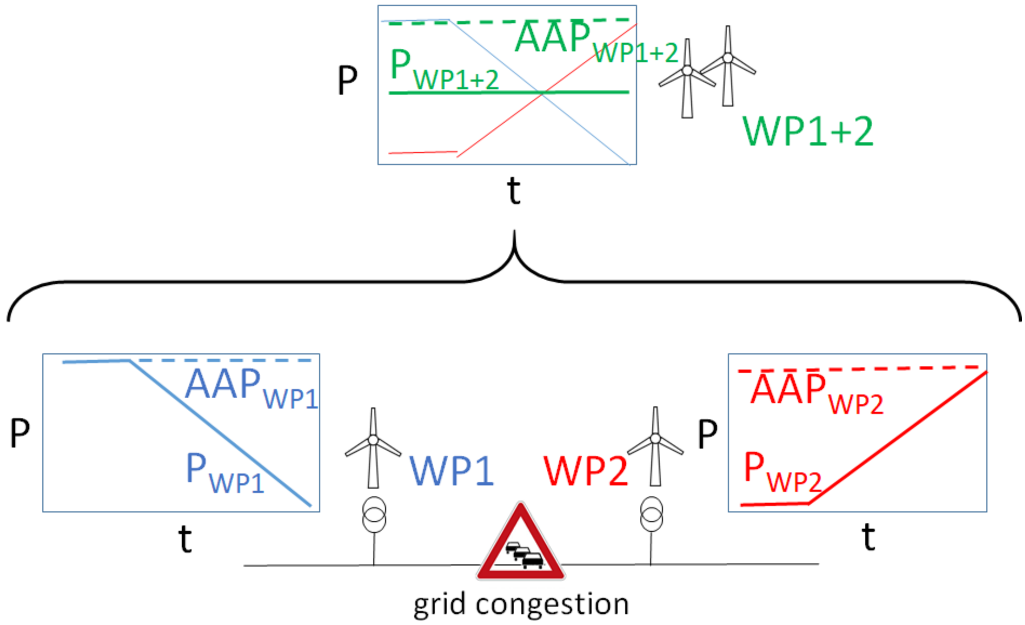

Figure 10: Illustration of antimetric REdispatch

The illustration shows a grid congestion between wind farm 1 (WP1) and wind farm 2 (WP2). This congestion can be relieved by curtailing the feed-in of WP1 (P_{WP1}) and increasing the feed-in of WP2 (P_{WP2}). WP2 has to be operated in a curtailed mode to be able to increase its feed-in. If the reason for this curtailment is the provision of positive balancing reserve, this provision of positive balancing reserve must be ensured by other plants (see UC7, chapter3.7) so that WP2 can increase its feed-in without breaking balancing reserve commitments. The feed-in changes of WP1 and WP2 in Figure 10 are antimetric, i.e. the feed-in decrease of WP1 and the feed-in increase of WP2 start at the same time and have the same ramps, only in different direction. The resulting aggregated feed-in of both wind farms WP1+2 (P_{WP1+2}) results as a horizontal line. The available active powers (AAP) of the wind farms are shown as dashed lines.

This test can be evaluated straightforwardly by analysing deviations of a measured P_{WP1+2} from the horizontal line in terms of amplitudes and time delays. As mentioned above, the deviations can result in an additional need for balancing reserve and thus to additional costs. Minimizing the need for balancing reserves gives the proposed symmetrical redispatch an added value. Typically wind energy is excellently suited to offering antimetric REdispatch as a new beneficial service due to its

- decentralisation
- ability to ramp up or down quickly
- high sensitivity to grid congestions
- integration into a virtual power plant

If WP1 and WP2 are part of a single VPP, the antimetric redispatch is most likely to be done very quickly and without major deviations. For this it is necessary that both actors (WP1 and WP2) are assigned to the same redispatch measure, e.g. by using a unique redispatch ID for setpoints and in a possible redispatch market.

The “symmetry of redispatch” can also imply the overall equilibrium of increased and reduced redispatch energy for a larger area and a longer period of time. In [9] all redispatch measures in

Germany are published, sorted by date, grid region including Switzerland, Austria, Poland, Netherlands and the aggregated remaining neighbouring countries, redispatch cause (current or voltage), power increase or reduction, instructing TSO and requesting TSO. For 2018, the current-induced (not voltage-induced) redispatch measures result in an increase of 3.25 TWh and a reduction of 5.46 TWh [9]. These values do not show symmetry: according to these values approx. 68% more energy was reduced than increased. The reason for this may be that "in the case of cross-border redispatch or countertrade measures with neighbouring countries, only the part relating to power plants or stock exchange trading within Germany is published. Cross-border trading transactions and power plant feed-in adjustments abroad are not be published" [9]. If all non-German grid regions are filtered out of the data, the asymmetry remains with 3.23 TWh increase and 5.43 TWh reduction. However, these values differ from [10], which reports 6.96 TWh increase and 7.92 TWh reduction in 2018 and explains the difference by the fact that " in cross-border redispatch measures market power plants are contracted by foreign transmission system operators. These instructions are not taken into account in the following evaluations" (of [10]). A further reason for the asymmetry of these values may be that the use of positive balancing reserves for redispatch purposes is not included (see UC7 in chapter 3.7on the interaction of balancing reserve and redispatch for more information).

3.3.7 Actors and resources

The tasks are distributed among the participating actors as follows:

1. Fraunhofer IEE, Arge, Enercon: Verification whether the demonstration of a symmetrical REdispatch is feasible within the scope of the project
2. Fraunhofer IEE, Arge, Enercon: description of the role of wind energy in a future north German flexibility/redispatch process
3. Fraunhofer IEE: Derivation of set point signals for wind turbines from the defined flexibility process
4. Arge, Enercon: Identification of specific wind turbines suitable to participate in a demonstration
5. Fraunhofer IEE: Integration of the identified wind farms and set point signals into the control system of the IEE.vpp
6. Fraunhofer IEE, Arge, Enercon: Test and demonstration of the UseCase using the identified assets
7. Fraunhofer IEE: Evaluation of results

3.3.8 Questions

- What is the reason for the difference between the redispatch values of [9] and [10]?
- What is the extent of the asymmetry and asynchrony of the redispatch data of [9]?

3.3.9 Steps

See section 3.3.7

3.3.10 Key performance indicator

The KPI for this use case will be defined in the subsequent deliverables upon analysing in detail the procurement mechanisms.

3.4 UC 4 Redispatch with PV in Austria

3.4.1 Description of the problem

Frequent congestion in Austria is mainly determined by two factors, high level of interconnection with the surrounding countries and a growing penetration of variable RE. In a highly meshed European network, the congestion situation is to a large extent affected by the situation in the neighbouring countries. In 2018 alone, the costs incurred by the TSO for redispatch amounted to approximately 130 million euro [1]. At the same time, as more volatile RE are expected to be integrated in the Austrian system to comply with the targets defined in the Austrian Climate and Energy Strategy, Mission2030 [2], the occurrence of congestion is likely to increase dramatically. More specifically, Mission2030 foresees Austria's transition to a 100% RE-based energy mix by 2030, which implies that 3 times more wind generation (from 3GW in 2018 to 9 GW in 2030) and 8,5 times more PV generation (from 1,4 GW in 2018 to 12 GW in 2030) needs to be installed to reach the target. This creates a greater impetus for finding ways in which variable RE themselves could effectively contribute to handling congestion.

So far, in Austria, RE do not participate in congestion management. Instead, the redispatch service is procured from a limited number of large generation units with the exception of one provider on the demand side (a large industrial customer). Among generation technologies used for redispatch purposes, 90% of the redispatch volume is provided by thermal generation and the remaining 10% by hydropower. This constrains the options available to the TSO. To address this issue, in the Austrian Use Case on redispatch it is envisaged by the project partners to demonstrate the provision of congestion management service from a pool of PV units at different geographical locations in the country by, among other, providing their locational information to the TSO (no public information is available).

3.4.2 Technical and regulatory framework

In Austria, redispatch is procured by the TSO, APG, separately from other ancillary services on a bilateral basis. That said, the redispatch product is currently not standardized.

Technical / Product Conditions

According to the Austrian Electricity Industry and Organization Act (ElWOG) [3], the main law guiding the national electricity sector, it is the responsibility of APG to determine congestion in the transmission network and to take measures to prevent or manage it (Art. 23(2) of ElWOG). It is noteworthy that redispatch measures can be undertaken in different timeframes, day-ahead, intraday or in real time.

In order to avoid congestion, APG, in coordination with the Austrian DSOs, concludes contracts with individual generators, according to which they commit to increasing or decreasing their output and reserve a predefined capacity for this purpose. The contracted generation is remunerated on a cost-based basis. ElWOG requires providers to present the economic justification and cost to be compensated to the TSO ((Art. 23(2.5)). In order to estimate the availability of reserve capacity for redispatch purposes, APG conducted a call for expressions of interest for a 5-year period from October 2018 to September 2023 [4], which, among others, specified the conditions that potential redispatch providers needed to fulfill in order to qualify. The conditions included the location (only Eastern part of Austria), minimum offered capacity of 25MW or the connection point at the voltage level of 110kV. It further technically allowed aggregated smaller generators with the minimum individual capacity of 5MW and a total capacity of minimum 25 MW. The call did not per se include any limitation on the type of technology used. It can be determined on a bilateral and monthly basis whether a unit or pool of units intend to participate in the electricity market, under a so-called "opt-out option" [5]. The opt-out must be notified during the previous month and implies that during the specified month the unit does not receive remuneration from APG, yet has to remain available for possible activation. The operational requirements placed on potential redispatch providers include the maximum lead time (i.e. time between the activation signal and full activation) of 10 hours from cold start whereas a subsequent full activation should be possible within 34 hours.

Importantly, the current requirements to units reserved for redispatch do not specify maximum duration of activation, meaning that the actual duration will depend on the network situation. The duration of activation is generally longer than that of balancing products. Besides, the capacity reserved for redispatch is contracted solely for upward regulation, i.e. for the output increase, whereas generation units or loads can be used for output reduction or increase of consumption on an *ad hoc* non-contractual basis, depending on the current network situation, and are not reserved in advance [5].

Finally, the Austrian regulatory framework does not currently foresee special or reduced network tariffs for providers of redispatch.

3.4.3 Foreseen evolution in mechanisms

The network code on Capacity Allocation and Congestion Management (CACM) does not exclude the possibility of introducing a market for redispatch. According to its Article 35(5), the prices of units for providing redispatch should be notified *ex ante* and based either on a market clearing or incurred costs determined in a transparent manner. So far, a redispatch market is not foreseen in Austria.

3.4.4 Expected harmonisation (ENTSOE, EDSO…)

According to the proposal submitted by ENTSO-E to ACER for classification methodology for the activation purposes of balancing energy bids (based on the requirement in Art. 29(3) of the EBGL), the activation purposes shall include not only balancing but also so-called system constraints [6]. According to the System Operation Guideline (SO GL), system constraints include congestion management. Following the TSOs' proposal, aFRR balancing bids procured from a cross-border platform should not be used for any purposes other than balancing whereas mFRR and RR balancing energy bids can be used for both purposes, ergo, also for redispatch.

3.4.5 The solution proposed

There are two ways in which PV systems could contribute to congestion management. Firstly, an improved day-ahead forecast may help reduce the need for redispatch. Secondly, PV forecasting for the next hours and minutes together with locational information can enable provision of redispatch services.

In this Use Case, it is planned to explore both modes to enable PV systems to contribute to congestion management. In particular, locational information of the PV system will be communicated to the TSO in order to allow it to better determine PV proximity to the congested line and thus the efficiency of its deployment. The Use Case will further evaluate the effect of a large geographically spread out pool of PV systems for redispatch.

3.4.6 Suggestions for the test

<u>Field test:</u> the field test will be based on the evaluation and validation of photovoltaic forecasting methods. Therefore measurement sites will be identified and monitored with a high accuracy. One PV

plant will be monitored following a traceable calibration chain using both ground-based and satellite data to improve the precision of yield forecasts.

Test of the VPP: VPP test will be conducted in the laboratory for real data in a control loop as well as in the field for a dedicated PV facility with corresponding ICT infrastructure. This will also be the site of precision measurement for the forecasting model validation.

3.4.7 Actors and resources

The tasks are distributed among the participating actors as follows:

- The data acquisition for meteorological and environmental data will be done by the BOKU and UBIMET.
- The meteorological modelling based on ground stations, cloud cameras and satellite data will be conducted by UBIMET.
- Estimation of the radiation on inclined surfaces (PV) based on direct and diffuse radiation will be calculated by UBIMET.
- Cloud evaluation and radiation transfer modelling will be performed by the BOKU.
- Data acquisition of ground stations, traceable calibration chain and precise measurement of a photovoltaic reference power plant will be done by AIT on a facility of Wien Energie.
- The PV-forecasting will be performed by AIT based on the meteorological forecast by provided by UBIMET.
- The evaluation of VPP aggregation of PV systems will be done by UBIMET in cooperation with AIT. Degradation analysis and failure determination out of data streams will be accomplished by AIT.
- Modelling of meteorological data will be done on the UBIMET computing infrastructure whereas the simulation of a PV VPP for participation for redispatch will be conducted by AIT.

The use case will use up to 12 high precision meteorological stations around Vienna, at least 3 pairs of cloud cameras, a cloud radar and traceable calibrated PV performance evaluation at the site of AIT and at a site of Wien Energie.

3.4.8 Questions

As the rules for redispatch are not currently standardized, it is important to answer the following questions in Use Case 4:

- the specific minimum technical requirements for a PV VPP to provide a redispatch service (e.g. the minimum duration of activation, precision of the location, what is the minimum volume to have an impact on congestion ? , etc.)

- how a redispatch product can be standardized and where the procurement of redispatch should be position with respect to other markets (gate closure times contracting periods, etc.)

Further questions arise with respect to the day-ahead forecasting: the ranges of precision reachable based on weather forecast and know-how of PV performance and behaviour.

Another relevant question refers to the extent to which ground-based measurements could improve pure satellite-based forecasting and how prediction errors at the beginning of the forecasting chain will evolve towards the power-in-the-grid prediction as well as the timeliness and accuracy of predicted values.

3.4.9 Steps

It is planned to improve forecasting in the day-ahead timeframe by means of reducing prediction errors and improvement of models. To achieve this, the following steps are envisaged:

(1) investigate first the still insufficient coupling of meteorological prediction and yield of PV,

(2) implement improved physical modelling of PV plant output prediction,

(3) investigate the impact of improved forecasting on regional virtual power plant (VPP) controlling,

(4) analyze interregional VPP interaction and

(5) evaluate the impact on Euro-value for balancing prediction of regional and interregional electric energy production.

Based on the granular forecast data, a simulation of PV systems with different locational data participating in congestion relief is planned.

3.4.10 Key performance indicator

Measures which are aimed for are in detail scientific and technical goals leading to significant reduction in prediction error, positive identification of failures and early determination of degradation. In detail these are:

- Improvement of irradiation prediction models' accuracy with resolutions of 100 m - 9 km for a lead time of up to 48h.
- Reduction of prediction error of the energy balance of PV facilities locally by physical modelling by at least 10% for cloudy days.
- Formation of a high-quality data basis (1/2 year up to one year) for validation and modelling
- PV energy production forecast including improved physical modelling of temperature and albedo, locally improved by at least 10% for cloudy days
- Investigation of data (parameter) interfaces and robustness of algorithms for usability in day-ahead forecasts
- Analysis of correlation of high precision prediction via modelling, validation of real facility data and quality control of PV-facilities regarding failure and degradation rates < 2% (for PV prediction)
- Evaluation of models in international cross-comparison with models from expert groups (for time ranges between 2 month and 6 month).
- Replication and validation of regional PV-VPP participation for the provision of redispatch
- Demonstration of a positive economic value for predicted electricity production of the VPPs for redispatch as compared to non-control scenarios (i.e. business as usual).

3.5 UC 5 PV participation in the balancing market in Austria

3.5.1 Description of the problem

Similar to redispatch, growing shares of volatile RE in the European networks lead, among others, to higher frequency deviations more often, which leads to high balancing costs for the TSO and the consumer.

The experience from the previous project, REstable, in Germany and France show very promising results as to the ability of a VPP of variable RE to provide balancing services, depending on the length of the contracting period.

3.5.2 Technical and regulatory framework

Unlike redispatch, balancing services in Austria are procured in a market-based way. In line with the requirements of the EU Balancing Guideline, the Austrian TSO procures 3 standard products, FCR, aFRR and mFRR (previously called, primary, secondary and tertiary control reserve, respectively), in organized auctions. Since it is technically challenging for the PV systems to provide FCR (e.g. due to symmetrical product requirement), the Use Case is focused on the provision of aFRR and mFRR.

Product Conditions

In the last couple of years, balancing market design in the country has undergone multiple changes, driven by the intention to make balancing markets more accessible to all types of technologies and providers and in this way improve competition and market efficiency. The latest status of the market rules for aFRR and mFRR products is described in Table 2 and Table 3 below:

Table 2 . Procurement of aFRR in Austria (Status: October 2019)

	aFRR
Procured amount (2019)	±200 MW
Reaction time	4 sec / latest 30 sec
Full activation time	5 min
Contracting	D-1
Product length /	4 hours (6 auctions in each direction, positive and negative)
Pricing rule	Pay-as-bid
Bid components	Available volume, balancing capacity price, balancing energy price
Control signal	central
Variable control signal	yes
Min bid size	+/- 1MW for the first offered bid; min total amount +/- 5MW, asymmetric
Pooling possibility	Yes, Austria-wide

Table 3 . Procurement of mFRR in Austria (Status: October 2019)

	mFRR
Procured amount (2019)	+280 MW / -195 MW
Reaction time	12 min
Full activation time	12 min
Contracting	D-1
Product resolution	4 hours (6 auctions in each direction, positive and negative)
Pricing rule	Pay-as-bid
Bid components	Available volume, balancing capacity price, balancing energy price
Control signal	central
Variable control signal	no
Min bid size	+/- 1MW (max. 25MW), asymmetric
Pooling possibility	Yes, Austria-wide

The bid structure of aFRR and mFRR products includes the indication of the capacity volume and the respective capacity price as well as the price for energy to be provided in case of activation. Capacity bids and respective energy bids are submitted together but the winning bid is determined by the capacity price alone[3]. After the gate closure, the TSO arranges the bids according to the merit order from the cheapest to the most expensive bid until sufficient capacity is procured[4]. Then, the energy bid is used to determine the choice and the merit order of the contracted capacities to be activated. Costs are then settled *ex post* on a monthly basis according to the average 15-minute volume of balancing energy.

The participation of vRES in the balancing market depends to a large extent on the gate closure time as their forecasting accuracy is dependent on the proximity to real time. Day-ahead gate closure, as is the case for aFRR and mFRR in the Austrian market, allows reducing forecasting inaccuracies although this period can be shortened further in line with the prescriptions of the European Guideline of Electricity Balancing (EBGL).

It is important to note that, in Austria, only non-subsidized RE can participate in the balancing market.

The EU Balancing Guideline requires all Member States to open access to the balancing market to all technologies, including all types of RE. The Guideline must be mandatorily implemented in the entire

[3] Unless two equal capacity prices were submitted. Then, the associated energy price is decisive for the ranking. Similarly, for activation of balancing energy with the same price, the capacity price will be taken into account for the merit order ranking.

[4] The amount of needed capacity is pre-established by the TSO and is currently 62MW for primary, ± 200MW for secondary (2017), +200 MW and -125MW for weekly auctions and +80MW & -45MW for daily auctions for tertiary capacity.

EU, which means that the national requirements will need to be adjusted in the future in a way to allow balancing from PV systems. However, under the current prequalification requirements, PV systems cannot participate in the balancing market.

Technical conditions

Since 2012, all three balancing products have been procured in a market-based way through an organized market in which prequalified balancing service providers (BSPs) may participate on a voluntary basis. There is no formal obligation to provide balancing capacity. Instead, the market is arranged in such a way that if during the first call insufficient capacity was procured, a second and a third (last) call is arranged. Only if the last call failed to secure the needed reserve are power plants with installed capacity of over 5MW obliged to provide it as a measure of last resort [3], Arts. 67(5) and 69(4)).

According to ElWOG, generators have to fulfill prequalification criteria in order to provide their resources for the balancing market (Art. 67(2)). The conditions for the provision of balancing capacity and energy are defined in TSO-BSP framework agreements, relevant market rules and the national grid code, Technical and Organizational Rules (TOR).

At least formally, no distinction is made between centralized and distributed providers following the EU principle of a level playing field in Austria. The TSO-BSP framework agreements follow the principle of non-discrimination irrespective of the type of the provider. Instead, the procurement of balancing services is based on the considerations of economic efficiency.

Aggregation of technical units is explicitly allowed in Austria[5]. According to the definition given in the framework TSO-BSP agreement, a technical unit is inseparable generation or load unit of a BSP. These can be aggregated into a reserve group of not more than 1000 individual generation or consumption units or a reserve pool consisting of several reserve groups.

In Austria, the whole reserve pool cannot be prequalified as a single unit, yet it does not mean that each technical unit should be able to comply with all the prescribed prequalification criteria. Rather, a BSP has to present an implementation concept in which they prove that the pool *in its entirety* can provide the required functionalities.

Concerning reserve groups or pools operated by an aggregator, in Austria, an aggregator is obliged to obtain the permission of their customers' supplier if in another balancing group. In terms of reporting, distribution-connected facilities report not only to the TSO but also to the DSO.

Currently enforced prequalification criteria were last updated in 2014 based on the then available draft version of the EU Network Code on Load-Frequency Control and Reserve (NC LFCR) and are compiled in Table 4.

As established in the Austrian Technical and Organizational Rules (TOR), part E, 49.8Hz - 50.2Hz is the range which can be regulated with the help of FCR [7]. In case of greater deviations, additional measures, FRR, are necessary to bring the frequency back to 50Hz. Similar to FCR, aFRR reserves have to react to the activation signal in a matter of seconds. Minimum bid size for aFRR is 1MW in *either or both* directions. The participating reserve pool has to be fully activated within 5 minutes at the latest and gradually deactivated in the same way. A BSP has to observe the minimum gradient when setting up a reserve pool and make sure that the pool as a whole can guarantee the provision of the minimum gradient.

[5] Website of the Austrian balancing group coordinator, APCS Power Clearing & Settlement Austria: http://www.apcs.at/de/regelenergie/regelenergiepooling

Minimum bid size for tertiary control reserve is 1MW in *either or both* directions. Full activation of the pool has to be achieved within 10 minutes at the latest and gradually deactivated in the same way. Following full activation, a reserve has to remain activated for at least 15 minutes after which it can be deactivated in 10 minutes or less.

Prequalification criteria do not include technical criteria alone but also communication requirements such as the frequency of online data exchange which is high for aFRR, 2-second intervals, while mFRR requirements are more lax: from 2 seconds to one minute.

Table 4 . Prequalification criteria applied to prospective BSPs in Austria

Requirement	aFRR	mFRR
Activation time (how fast is fully activated)	Full activation within 5 minutes, reaction in a matter of seconds	Within 10 min for min 15 minutes
Minimum bid size	1MW in either or both directions	1MW in either or both directions
Transfer of data	Every 2 seconds	from 2 seconds to one minute
Minimum power gradient	2% of rated output/min	n/a

Communication / Software Interfaces

Advanced ICT and telemetry become a prerequisite for the components to be "visible" to the TSO and to respond to an activation call.

3.5.3 Foreseen evolution in mechanisms

In order to implement the EU Balancing Guideline, three major changes of the Austrian balancing market design are expected to be introduced in Austria in mid-2020:

1. Balancing energy for aFRR and mFRR will be procured in an auction separate from balancing capacity close to the time of delivery
2. Balancing energy bids of those providers that did not previously commit their capacity for balancing will be allowed. Such bidders still have to pass a prequalification procedure.
3. Marginal pricing rule for balancing energy is expected to be introduced.

These market design changes are likely to have a positive effect on the participation of PV systems, as it considerably shortens the contracting period and allows their operators to estimate the actual PV availability much more precisely.

3.5.4 Expected harmonisation (ENTSOE, EDSO…)

The harmonization of the balancing products, rules and timeframes on the EU level is expected to facilitate the integration of national balancing markets, as the EU Balancing Guideline requires the creation of an international platform for a cross-border procurement of aFRR and mFRR using TSO-TSO model and a common merit order list. The proposal for such a platform was already submitted by the TSO in December 2018 [8] and is pending a decision by the Agency for the Cooperation of Energy Regulators (ACER) at the beginning of 2020.

3.5.5 The solution proposed

It is proposed to improve the forecasting and "nowcasting" of PV systems in order to enable their compliance with the prequalification requirements and their provision of aFRR and mFRR in the balancing market. For this, it is foreseen that in those periods when a VPP of PV plants would need to provide upward regulation, a pre-curtailment will be conducted. This would not only support economic viability of PV-system in a post-subsidy era but also allow them to proactively contribute to system stability.

3.5.6 Suggestions for the test

From the point of PV-forecasting the setup is very similar to the testing in UC4: the field test will be based on the evaluation and validation of photovoltaic forecasting methods. Therefore measurement sites will be identified and monitored with high accuracy. One PV power plant will be monitored following a traceable calibration chain and ground-based as well a satellite data will be used to improve the precision of yield prediction.

Further an international comparison on prediction models will be done using the validated test data.

Test of the VPP: this will be done in the laboratory for real data in a control loop as well as in the field for a dedicated PV facility with corresponding ICT and data infrastructure. This will also be the site of precision measurement for the forecasting model validation.

3.5.7 Actors and resources

The test setup and resources will be the same as for Use Case 4 iand as described in 2.4.7. For UC 5, in addition an intercomparison on models will be done by BOKU Vienna. The training data set of validated data basis will be used for training and the test data range for comparing the performance and error propagation in various models.

3.5.8 Questions

Questions arising corresponding to the day-ahead forecasting are the ranges of precision reachable based on weather forecast and know-how of photovoltaic behaviour.

Further a question of high importance is to what extend ground based measurements will improve the pure satellite based forecasting and how prediction errors at the beginning of the forecasting-chain will evolve towards the power-in-the-grid prediction as well as the timeliness and accuracy of predicted values.

Another question of high importance is the ability of the models of PV prediction to be used in repeating short time intervals. This will be needed for (a) short term forecasting and (b) online-solution which might be hosted server-based.

A question arising also corresponding to the time of repetitive prediction intervals is the timeliness of measurement points and different measurements to be drawn back to one unified time identifier. This is even more restrictive for data like cloud pictures because of their data-size.

3.5.9 Steps

As for UC4 the steps for PV-forecasting are comparable, while the time scale changes dramatically the constraints for calculation times and models applicable. In addition, the impact on Euro-value for balancing prediction of regional and interregional electric energy production will be evaluated. Further, the granular forecasting data of a PV-based VPP is used as an input for the simulation of a PV participation in the aFRR and mFRR markets. Finally, an economic assessment of the value of a VPP for the balancing market is conducted. The expected changes in the balancing market design in the near future will be specifically taken into account upon conducting an economic assessment of a PV-based VPP.

3.5.10 Key performance indicators

The indicators will follow those in 2.4.10, adapted for time range of prediction to Use case 5. Further, the economic value for predicted electricity production of the VPPs in the aFRR and mFRR market will be avaluated (amount of provided balancing capacity and energy, fulfilment of the setpoint, etc.).

3.6 UC 6 Combined value streams for PV systems from wholesale markets and ancillary service provision – Austria

3.6.1 Description of the problem

Electricity markets are interdependent and differ not only according to their product specifications but also according to their gate closure time, i.e. the timeframe within which a market actor can decide to participate. Participation in multiple electricity markets can help PV systems to generate several value streams and, in this way, a sufficient investment incentive. Providing operators with incentives to invest in PV plants in the future is crucial in order to advance the energy transition. It is therefore important to identify possible revenue streams for PV at the time when the subsidy regime for existing units is drawing to an end.

3.6.2 Technical and regulatory framework

The current technical and product requirements for redispatch and balancing in Austria were described in UC 4 and UC 5. The interrelations between different markets in Austria are illustrated in the figure below.

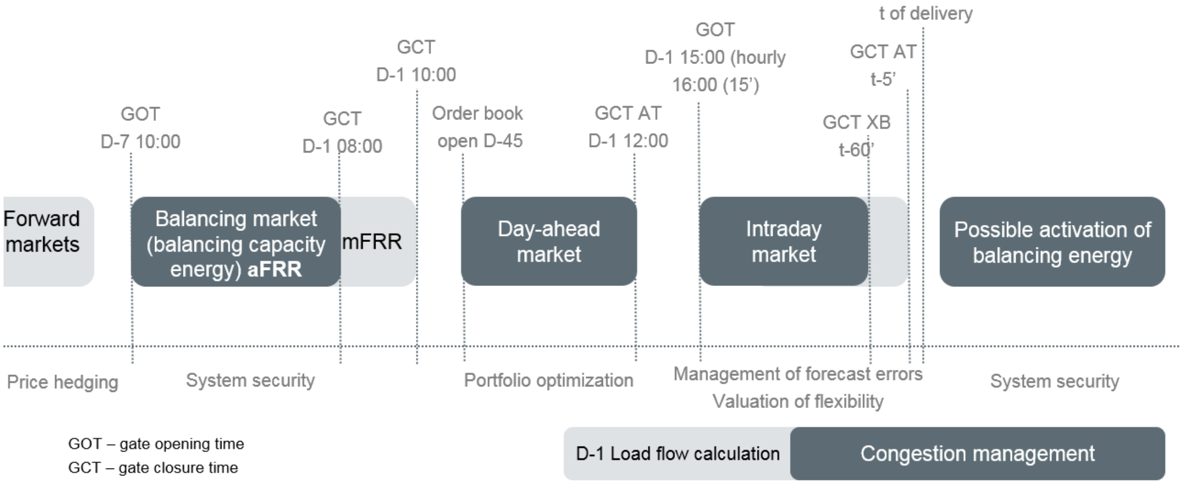

Figure 11. Time horizons of electricity markets in Austria.

The recast Electricity Directive explicitly encourages participation of RE in all types of electricity markets [9]. Access to spot markets is further allowed in Austria and the conditions, such as the minimum bid size of 0,1 MW in both day-ahead and intraday markets are realistic for even fairly small PV systems to fulfil. Different market time horizons create different requirements for the accuracy of the PV forecast: Whereas the day-ahead market closes at 12pm a day before delivery, in the intraday market, continuous intraday trade takes place up to 5 minutes to real time for national trade and 30 minutes to real time for cross-border intraday trades, which allows a PV operator to update their forecast reliably close to the time of delivery. The price levels in the spot markets are generally lower than in the balancing market but the procured volume is substantially higher.

Most of the RE generation in Austria is currently supported through technology specific feed-in tariffs that are reviewed each year and published in the Austrian Regulation on Feed-in Tariffs (ÖSET-VO). The duration of the subsidy period is limited to 13 years for PV units beginning with the start of operation, which implies that, in the near future, spot markets, in combination with ancillary service provision, can become a more attractive source of revenue for PV operators.

3.6.3 The solution proposed

Taking into account that wholesale markets, balancing markets and the procurement of redispatch take place in different timeframes, PV systems could use an optimization algorithm, which uses updated highly-granular PV forecasts to evaluate among different commercialization options or a combination thereof.

Improved PV feed-in forecast is planned to be used for a pool of PV plants of Wien Energie in order to participate in the wholesale electricity markets and reliably provide ancillary services. For this, PV feed-in forecasts should be obtained by 7:00 am day-ahead and t+6h for the intraday timeframe and updated every 15 minutes with 15-minute resolution.

3.6.4 Suggestions for the test

The test scenario is the same as was set up for UC4 and UC5. Here highly rated is gaining more accuracy in the forecasting and the best estimation of degradation of erratic failure events learned from data stream evaluation.

With the help of simulation model, the different commercialization options for a PV pool, spot market, balancing and/or redispatch, and their combinations will be evaluated.

3.6.5 Actors and resources

The test setup and resources will be the same as for Use Case 4 iand as described in 2.4.7.

Further, in UC 6, a multi-market optimization model for a PV pool will be developed by AIT.

3.6.6 Questions

As the timeframe for the procurement of redispatch is not standardized, it is intended to analyse what an appropriate gate closure time for redispatch service could be to enable the participation of PV and at the same time not to limit its options in the electricity markets.

A question of high importance the ability of the models, of PV prediction to be used in short time intervals of successive repetition. This will be needed for (a) short term forecasting and (b) online-solution which might be hosted server-based.

Another question is to find the optimum solution for reducing forecasting times while keeping up the highest possible prediction precision.

3.6.7 Steps

The steps for the PV-forecasting are the same as for UC4 and UC5. For the optimization of precision vs. time frame sensitivity analysis of models based on the test data basis will be done and compared to real scenarios. A real time testing of prediction models compared to historical production data of PV and market data will be conducted.

3.6.8 Key performance indicator

- Investigation of data (parameter) interfaces and robustness of algorithms for usability in short time (<5 min) forecast chain from meteorology via PV to market.
- Validation of real facility data and quality control of PV-facilities regarding failure and ageing.

3.7 UC 7 Collateralisation of balancing reserve during congestion (Combining congestion management and reserves)

N.B. references are those in Germany's section in Annex 1.

Additional information on UC7 will be provided in https://www.regions-project.info/results/, D6.5 «Results of interregional plattform to provide interregional ancillary services (Germany, Austria and France)»

3.7.1 Description of the problem

Both balancing and redispatch (congestion management) are ancillary services required by the TSO, yet potentially competing for the same resources. As a result, particularly in those situations when the amount of the available system flexibility is limited, there can be a conflict between providing balancing reserve and redispatch. This conflict can be described as follows:

- provision of redispatch is mandatory if the TSO is unable to solve congestion otherwise (e.g. through topological measures)
- In Germany and in Austria, balancing resources are so far not permitted to be used for congestion management purposes whereas this is allowed in France (only mFRR and RR, i.e. tertiary reserves)
- delivery of energy on call from committed balancing reserve is mandatory
- delivery of balancing energy may potentially increase congestion
- delivery of balancing energy may be technically unfeasible due to output reduction for congestion management purposes.

3.7.2 Technical and regulatory framework

The German Regulatory Authority for Electricity (BNetzA) stipulates in [6] that the provision and delivery of balancing reserves may not be used by TSOs to relieve grid congestions. Similarly, the Austrian TSO do not allow the use of balancing reserves for congestion management. The other way round, the TSOs are concerned that plant operators will misuse congestion management orders by shifting the balancing reserves to plants typically affected by grid congestions [6]. The TSOs demand in this regard a clearly defined procedure for the proof of necessity by the plant operators [6]. However, in their joint description of future redispatch processes [11], the German grid operators and power plant operators define a “special redispatch” (in addition to the "standard redispatch"), which

- must be performed in excess of the standard redispatch and its insufficient assets,
- causes the balancing reserves to be relocated or suspended and
- blocks the balancing reserves from being used.

Other countries, such as France but also the Netherlands or Belgium took a different stand on the use of balancing resources that can be deployed for the provision of the redispatch service. The French TSO uses mFRR and RR bids for this purpose.

These differences in the way balancing resources are used will become even more important in the future as the implementation of a common cross-border platform for the provision of balancing resources is planned.

Moreover, the interaction of balancing reserves and redispatch requires not only arrangements between TSOs and power plant operators (or balancing reserve providers), but also between TSOs and

DSOs. According to [12], the TSO –DSO report [13] deals with active power management from the perspective of a close collaboration of TSOs and DSOs for what concerns congestion management in both distribution and transmission grids and system balancing, in particular when they are provided in a market-based approach by third parties. This is inserted in the framework of the so called Active System Management (ASM), which according to the vision of the institutions who authored the report is “a key set of strategies and tools performed and used by DSOs and TSOs for the cost-efficient and secure management of the electricity systems.” So far, however, the level of TSO-DSO coordination and information exchange is very limited.

The report [8] analyses the interactions between the provision of balancing reserves and grid congestions in distribution grids. It defines the relationships between different relevant actors as shown in the figure below.

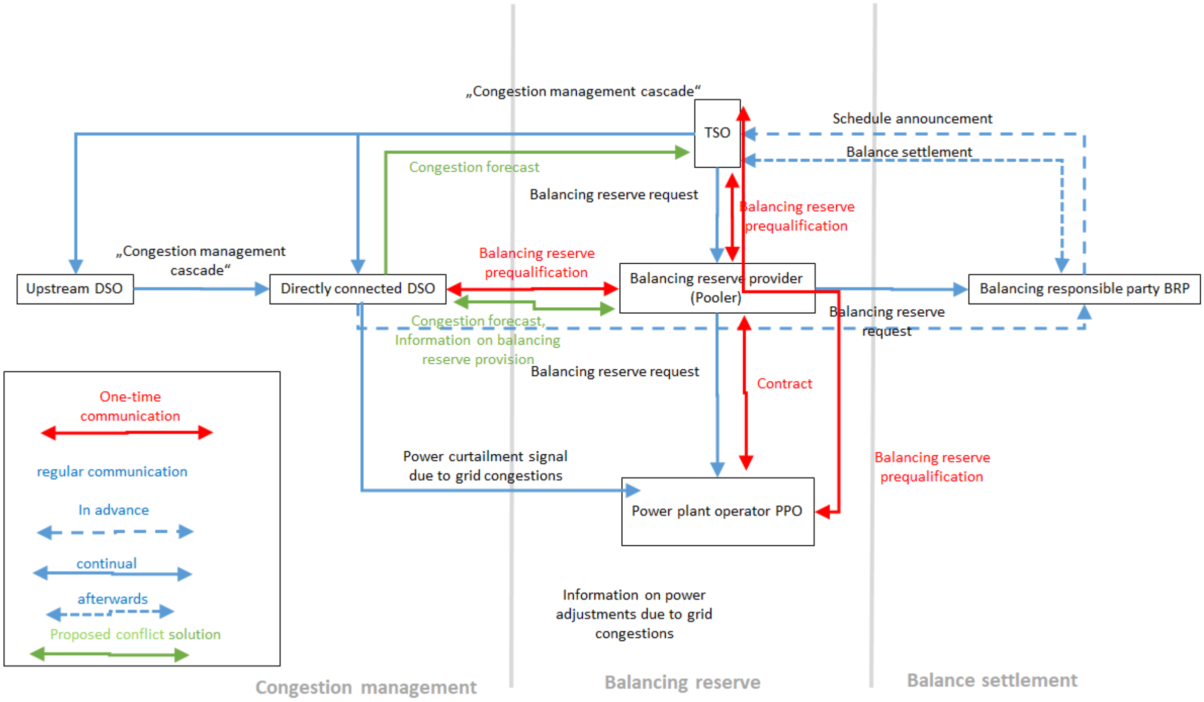

Figure 12. Relationships between the different actors that are relevant for the conflict between the provision of balancing reserves and congestion management [8].

An analysis of possible conflicts between balancing reserve and congestion management and their solutions requires consideration of the chronologies of market-based balancing reserve procurement, an example of which from Germany is shown in Figure 13, and congestion determinations as well as associated remedial actions, shown in Figure 14. The report [8] divides the chronology of balancing reserve acquisition into 5 phases. In the first phase, balancing resources are reserved based on auction results for each product, whose results are communicated in phase 2. In phase 3 short-term energy trade takes place. In phase 4, balancing energy is activated, followed by an imbalance settlement procedure in phase 5. In the other countries, the process follows a similar logic.

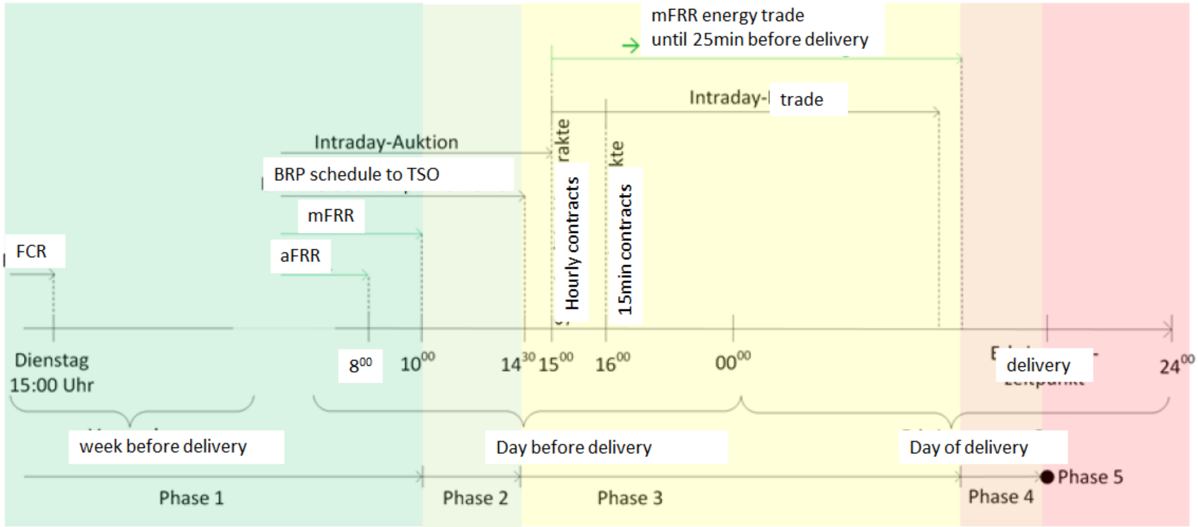

Figure 13. Chronology of balancing reserve acquisition in Germany [8].

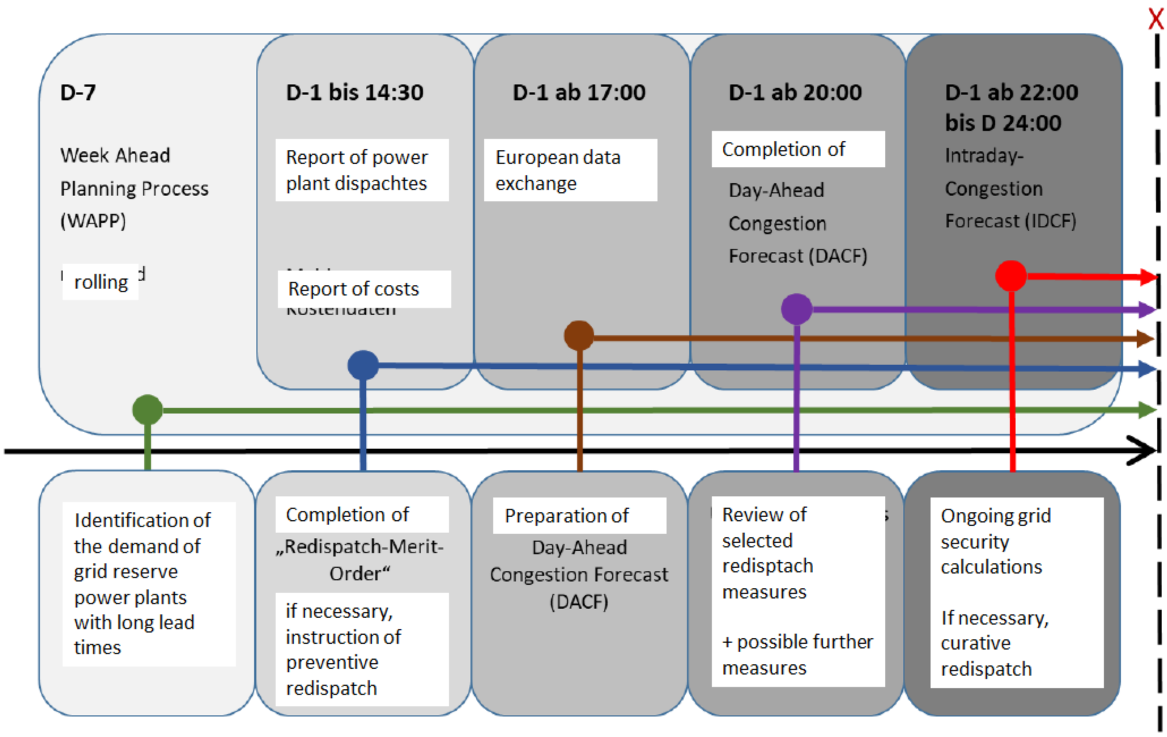

Figure 14. Chronology of redispatch planning and data exchange in Germany [14]

Figure 14 shows, among others, that remedial actions (including redispatch) can be taken by the TSOs within different timeframes and can be of either preventive or curative character. Due to a high interconnection level among the countries of the ENTSO-E area, power flows in one country may have significant effects on grid situation in the neighbouring countries, e.g. causing a congestion elsewhere or limiting cross-border capacities at a different border due to high loop flows. For this reason, particularly preventive measures to tackle congestion are coordinated among the TSOs. The cooperation among the TSOs intensified with the establishment of so-called capacity calculation regions (CCRs) in line with the EU Capacity Calculation and Congestion Management Guideline (CACM) adopted in 2015 and the introduction of flow-based market coupling (FBMC) in Central Western Europe (CWE) in the same year. The three countries of the project belong to the CWE region (together with Belgium and the Netherlands) and apply FMBC as well as the same CCR, CORE.

The main benefit of the FMBC over the available transfer capacity (ATC) approach that used to be applied in CWE and is still in use outside CWE, is a more efficient allocation of cross-border capacity for trade among the neighbouring countries and therefore improve spot-market price conversion. This is achieved through a calculation method that specifically considers the impact of so-called critical network elements (CNEs) on the available capacity whereas CNEs do not only include interconnectors but also internal CNEs. In contrast, the ATC approach only considers the aggregated available capacity at the border often leading to a more conservative result and limiting transfer capacity. The calculation of the flow-based domain is carried out based on so-called reference flows that are derived from the Base Case, a joint D-1 congestion forecast of all TSO based on expected generation and load. The calculated cross-border capacities and then passed on to the spot market operator. Since congestion forecasts are bound to be inaccurate due to the inherent system uncertainty, security calculations continue in the intraday phase where redispatch can be deployed.

3.7.3 Foreseen evolution in mechanisms

see chapters 3.1.3, 3.3.3, 3.4.3 and 3.5.3.

3.7.4 Expected harmonisation (ENTSOE, EDSO…)

See chapters 3.3.4, 3.4.4 and 3.5.4.

In 2019, ENTSO-E submitted a proposal for an allocation process of cross-zonal capacity for the exchange of balancing capacity . Although the decision on the proposal by national regulators is still pending, it provides a good idea of the TSOs' plan to formally include the exchanges of balancing capacity in the FBMC mechanism. For this, the TSO propose a co-optimization approach, according to which balancing capacity bids as well as bids in the day-ahead market are expected to be submitted within the same timeframe (D-1 12:00pm). Balancing capacity bids are then considered during the calculation of cross-border capacity for single day-ahead market coupling (SDAC), followed bid matching in the balancing capacity auction. The results of the co-optimization would then be published D-1 at 13:00. Subsequently, the allocated cross-border capacity can be used for the exchange of actual balancing energy. Such an approach is expected to better align balancing and redispatch procedures, yet many details and the exact final implementation remain to be addressed.

3.7.5 The solution proposed

The conflicts between balancing reserve and congestion management and their solutions are analysed in [8] by so called conflict tree diagrams. Conflict tree diagrams refer to the actors in Figure 12 and the phases in Figure 13 and are designed for FCR, positive aFRR, negative aFRR, positive mFRR and negative mFRR. Figure 16, Figure 17 and Figure 18 in the annex to this report show the conflict tree diagrams using the example of positive mFRR. According to them, plant operators or poolers have the possibility of resolving the conflict in all phases before delivery, i.e. phases 1 to 4 (see red circles in conflict tree diagrams). The solution consists mainly in a collateralisation of balancing reserve. Therefore, objective of UC 7 is to demonstrate the technical feasibility of securing balancing reserves during grid congestions and to assess and propose the necessary regulatory framework.

3.7.6 Suggestions for the test

There are several possible scenarios that could generate conflicts between balancing and congestion, for example:

- Forecast error on the plants participating in redispatch
- Downward regulation (below minimal provision reserve level) of plants participating in balancing reserve due to congestion

The test considers, for example, a wind farm in northern Germany that provides balancing reserve as part of a VPP-controlled balancing reserve pool. This wind farm is now curtailed due to grid congestions, which is very common in this region. The curtailment makes it impossible for the wind farm to deliver both the positive provided balancing reserve, as this would increase the congestion, and the negative provided balancing reserve, as the curtailment is too large. One solution to this problem is to provide the balancing reserve by means of other plants of the VPP, for example a wind farm in France. There are two possibilities for this collateralisation:

1. The collateralisation was planned in advance, the French wind farm is already operated in a curtailed mode and able to deliver the provided (positive) balancing reserve.

2. The French wind farm must immediately switch to a curtailed operation mode and thus deviates from its schedule.

There are also two possible temporal considerations with regard to the congestion management: (a) the congestion management was announced in advance so that the VPP excludes the German wind farm from its balancing reserve planning, (b) the congestion management is carried out unexpectedly so that the VPP has to react at short notice and possibly does not fulfil obligations or is burdened with additional costs.

Such a test addresses several still unresolved regulatory issues, not only regarding the conflict between balancing reserve and congestion management but also concerning the international management and trading of balancing reserves and redispatch capacities. Thus, the conditions of test will be refined in tasks 3.2 (Market design) and task 3.3 (Market interaction).

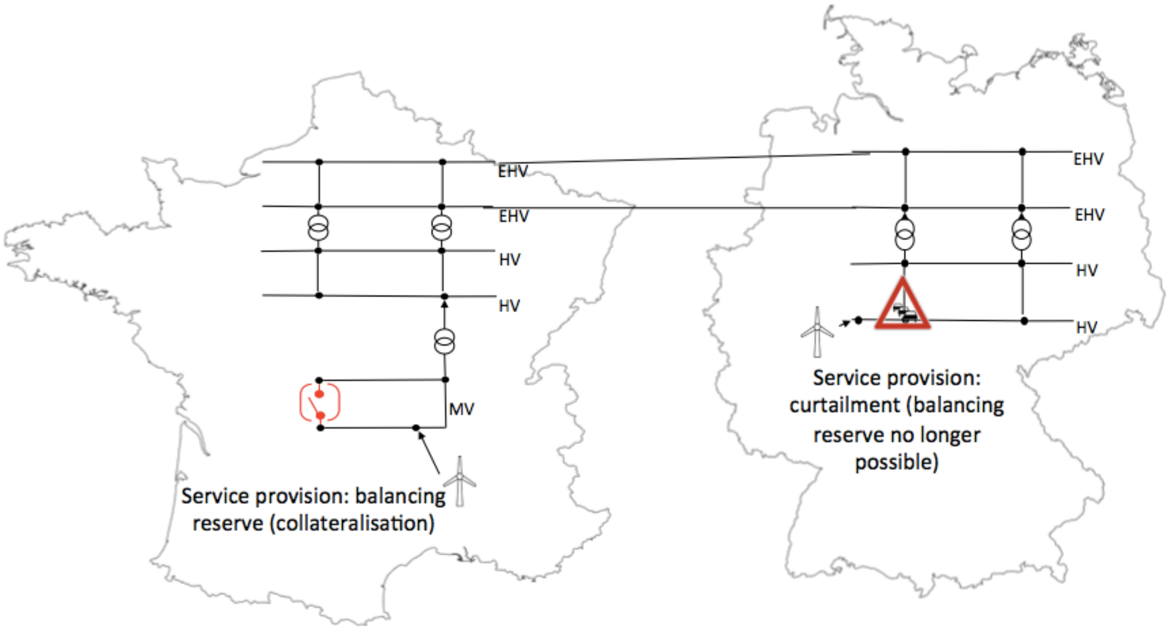

Figure 15. Illustration of the principles behind the UC7 test. Source : Fraunhofer IEE.

3.7.7 Questions

- What was the extent of the cross-border redispatch measures in 2018 (see chapter 3.3.5)? Combining voltage support and balancing : is this a subject ? Could there be reasons not to be able to bid on the two markets simultaneously ?

3.8 Rejected UCs

3.8.1 Smart Balancing

See [15] or [16] for “Smart Balancing”

4 Conclusions

In this task, the existing ancillary services and other possible VPP functionalities have been considered in order to define a limited number of relevant UCs to test during the demonstration. The main criteria used in the choice where: ancillary services that make sense to be provided at a regional scale, i.e. an area smaller than the TSO dispatch zone. The ancillary services chosen are currently not harmonized between the three countries. The possibility to couple these regional services with national or European balancing services is also of interest.

The following list of seven use cases (UC) has been defined:

- UC 1 – Congestion management / Redispatch in France
- UC 2 - Voltage support
- UC 3 – RE participation in the redispatch process in Northern Germany
- UC 4 Redispatch with PV in Austria
- UC 5 PV participation in the balancing market in Austria
- UC 6 Combined value streams for PV systems from wholesale markets and ancillary service provision in Austria
- UC 7 Collateralisation of balancing reserve during congestion (Combining congestion management and reserves)

The aim of the work is to demonstrate the capacity of variable RE to provide ancillaryservices similarly to conventional power plants. In the future work, key performance indicators for each of these use cases will be defined according to the available national technical requirements. KPI will be defined in order to evaluate both the magnitude and the quality of the services provided. They will be based on the concept that ancillary services must be provided at a specific location, within a determined time and with a determined tolerance, whereas deviations from the tolerance band must be avoided at any cost.

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5 Annex

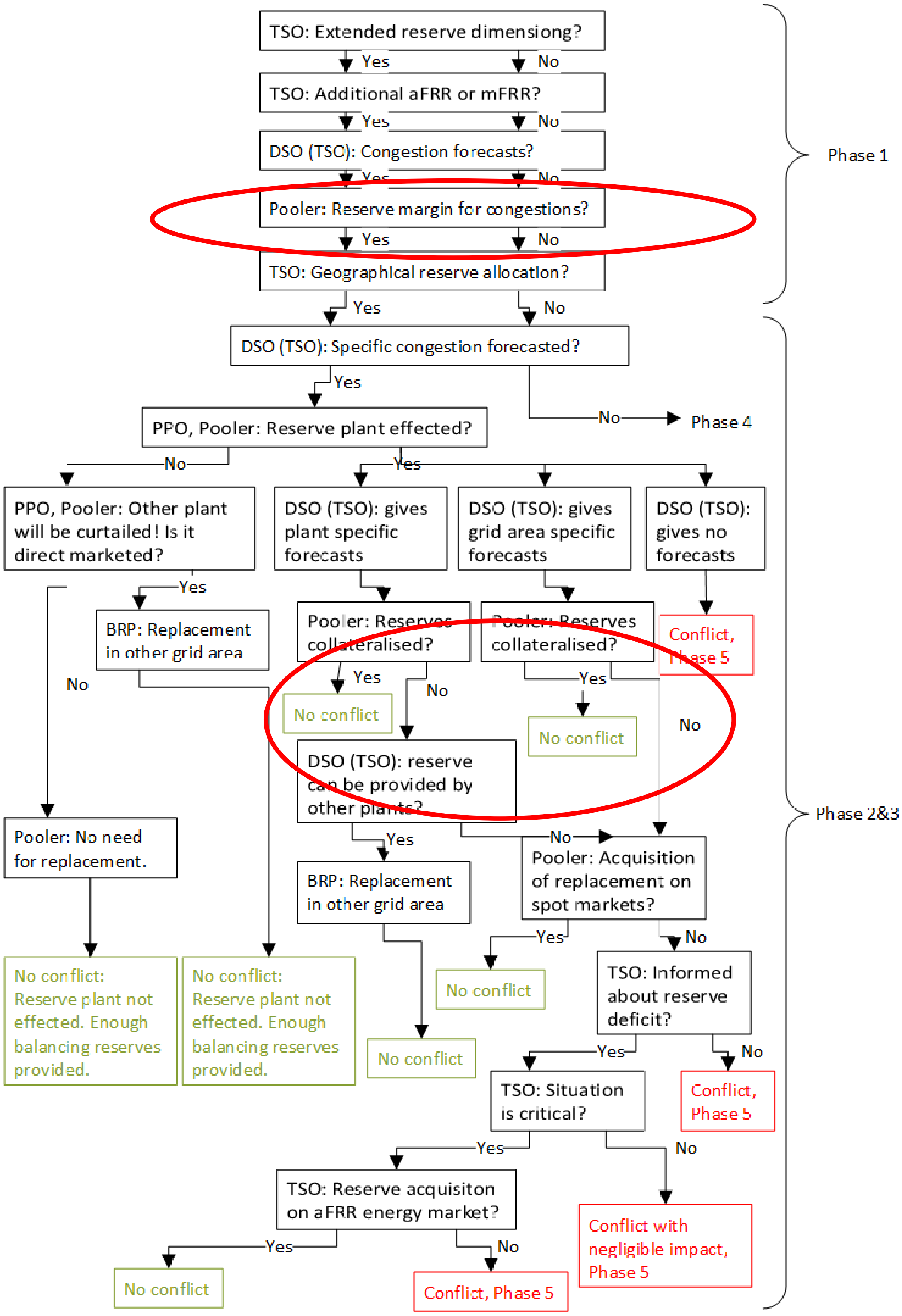

Figure 16: Conflict tree diagram for phases 1 to 3 and positive mFRR translated from [Oliver Brückl; Ulrike Mayer; et al., 2017]

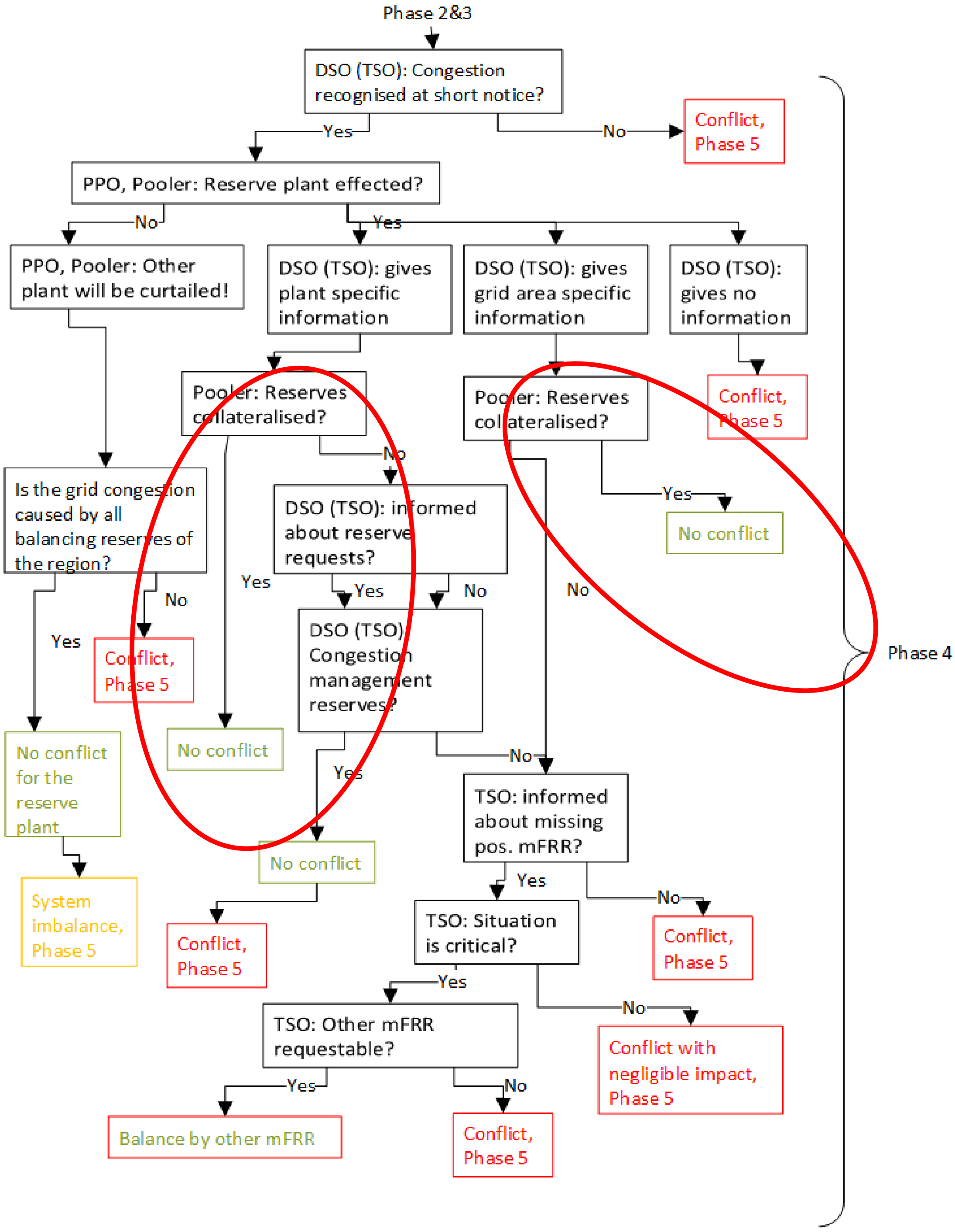

Figure 17: Conflict tree diagram for phase 4 and positive mFRR translated from [Oliver Brückl; Ulrike Mayer; et al., 2017].

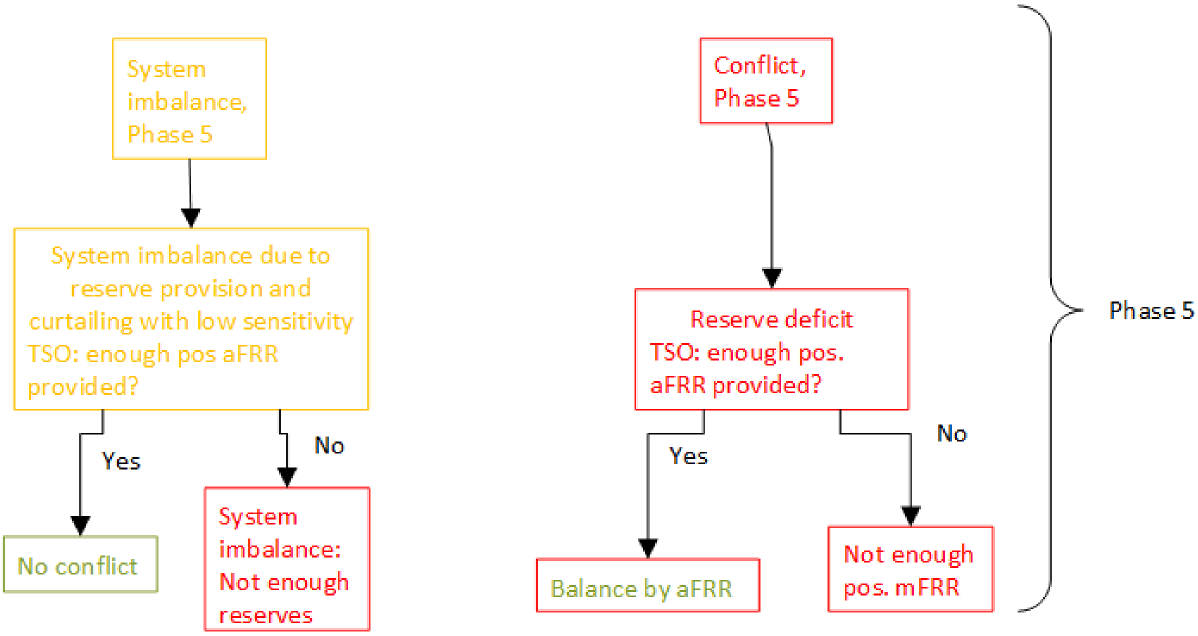

Figure 18: Conflict tree diagram for phase 5 and positive mFRR translated from [Oliver Brückl; Ulrike Mayer; et al., 2017]