



Deliverable 1.2

Cross-border balancing and redispatching mechanisms tailored
to congested borders situation

and

design of a Common Activation Function

—

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Authors:	Zoran Vujasinović, EKC Dušan Vlasisavljević, EKC Nebojša Jović, EKC Iva Mihajlović Vlasisavljević, EKC David Gerbec, ELES Matjaž Dolinar, ELES Darko Kramar, ELES Milan Vukasović, APG Alexander Stimmer, APG Doina Ilisiu, TRANSELECTRICA Andrej Souvent, EIMV Zvonko Bregar, EIMV Rok Lacko, GEN-I Ursula Krisper, EE
Reviewers:	MAVIR team

Document management

	D1.2. – chapters	Responsible
0	Summary&Conclusions	EKC
1	Introduction	EKC
2	Current state at balancing and redispatching markets	APG, ELES, MAVIR, TEL
3.1-3.5, 3.8.	<i>aFRR market design-related chapters</i>	EKC
3.6.	CAF design: aFRR cross-border activation and integrations into AGC	ELES
3.7	CAF design: algorithm	APG, EIMV, EKC
4	Cross-zonal capacity for balancing	EKC
5	Redispatching mechanism	EKC
6	Annex 1: Impact of different FAT to DR&DG participation in the aFRR market	GEN-I / EE

Abbreviations

Acronym	Term	Acronym	Term
ACE	Area Control Error (= Frequency Restoration Control Error)	GL	Guideline
aFRP	Automatic frequency restoration process	GSK	Generation Shift Key
aFRR	Automatic frequency restoration reserve	HPP	Hydro Power Plant
AGC	Automated Generation Control	ID	Intra-day
AMF	Available Maximum Flow	IN	Imbalance Netting
ANF	Already Nominated Flow	IP	Imbalance Price
ATC	Available Transfer Capacity	IS	Imbalance Settlement
BFL	Base Flow	ISP	Imbalance Settlement Period
BRP	Balance Responsible Party	IT	Information Technologies
BSP	Balancing Service Provider	JAO	Joint Allocation Office
BSG	Balancing Stakeholder Group	KPI	Key performance indicators
C&I	Commercial and industrial	LFC	Load-frequency control
CACM	Capacity Allocation and Congestion Management	LFCR	Load-frequency Control & Reserve
CAF	Common Activation Function	MC	Market Coupling
CB	Critical Branch	MCP	Market Clearing price
CEE	Central-East Europe	mFRR	Manual Frequency Restoration Reserves
CGM	Common grid model	MOL	Merit Order List
CMO	Common Merit Order	MP	Marginal Price
CMOL	Common Merit Order List	MRC	Multi-Regional Coupling
CO	Critical Outage	MW	Megawatt
CoBA	Coordinated Balancing Area	MWh	Megawatt-hour
CWE	Central-West Europe	NC	Network Code
CZC	Cross Zonal Capacity	NPP	Nuclear Power Plant
D-1	Day-ahead	NRA	National Regulatory Authority
D-2	Two-days ahead	NTC	Net Transfer Capacity
DG	Distributed generation	OH	Continental Europe Operation Handbook
DR	Demand response	OL	Open Loop
DSM	Demand side management	OPF	Optimal Power Flow
EA	Explicit Auction	PFC	Power Flow Colouring
EB	Electricity Balancing	PFD	Power Flow Decomposition
EC	European Commission	PI	Proportional-Integral
ENTSO-E	European Network of Transmission System Operators for Electricity	PTDF	Power Transfer Distribution Factors
EU	European Union	RAM	Remaining Available Margin
FAT	Full Activation Time	RES	Renewable energy sources
FB	Flow-based	RR	Replacement Reserves
FCFS	First come - first served	RSCI	Regional Security Coordination Initiative

FCR	Frequency Containment Reserves	SEE	South-East Europe
FF	FutureFlow	SHB	Slovenia-Croatia-BiH (Control block)
Fmax	Maximum Flow	SO, SysOp	System Operation
FRCE	Frequency Restoration Control Error (\equiv Area Control Error)	SO, SysOp	TMF
Fref	Reference Flow	TPP	Thermal Power Plant
FRM	Flow Reliability Margin	TSC	TSO Security Cooperation
FRP	Frequency Restoration Process	TSO	Transmission system operator
FRR	Frequency Restoration Reserves	WP	Work Package
GCC	Grid Control Cooperation	XB	Cross-Border
GCT	Gate Closure Time		

Summary and conclusions

GENERAL

- The FutureFlow target model is provided herein, describing the concept of aFRR energy exchange among the countries, with limited transmission capacity available for such exchange. It provides the algorithm of the common activation and optimisation function suited to the aforementioned concept.
- The target model of FutureFlow redispatching mechanism is provided, decoupled from the aFRR concept; redispatching concept includes the algorithm of the redispatching common optimisation, and related concept of the costs share, based on the analyses of the power flows.
- Both concepts (aFRR energy exchange and Redispatching) are exercised on the basis of the markets of the countries involved in the FutureFlow project (Austria, Hungary, Romania, Slovenia), however these concepts are suited to be as much as possible universal within the scope of European electricity markets, and thus replicable to other countries and regions.
- The four involved countries are different in size of electricity markets, generation portfolio, and the aFRR and redispatching markets organisation, so they should provide sufficient level of diversity to exercise and develop the FutureFlow concepts which are general enough.

BALANCING

- One of the main tasks of FutureFlow project is to design the feasible target model for the exchange of aFRR balancing energy, by defining the proper configuration and correlation among the national balancing markets and practices, its pan-regional integration, taking into account cross-border transmission constraints and the operation of commercial markets.
- FF Target Model design has to provide innovation in the field of balancing, be in line with the EU Target Model (mainly defined by Guideline on Electricity Balancing (EB GL) and Guideline on electricity transmission system operation (SO GL)), and at the same time be secure, sustainable, replicable and applicable in the situations of congested borders.
- Since the draft EB GL clearly defines TSO-TSO as the standard and target model for the exchange of balancing services. For the FutureFlow also the TSO-TSO model is recommended.
- The process of aFRR energy exchange is divided in the main phases: Prequalification, Bidding, Activation, Exchange and Settlement.
- The main issue in defining the standard product for aFRR energy exchange is the Full Activation Time (FAT), currently being different among Austria (5 min) and other three countries (15 min), Options are either to define the single, standard FAT per all countries, or to explore the possibility for the combined usage of standard, universally applicable

bids (5 min), and specific bids (e.g. 15 min), applicable (allowed) only by certain countries. Second option obviously requires detailed analyses of possibilities and reasonableness to implement such complex CAF algorithm.

- Working assumption is that the product resolution (bids validity) is to be set in the timeframe 1-4 hours; among that, when single resolution is to be selected, it would be 1 hour. Shorter times would be too close to the Full Activation Times (5-15 min), while longer times (e.g. peak/off-peak) would not be in favour of DR/DG energy providers, which are under special focus of FutureFlow project, and which nature requires rather shorter availability time.
- FutureFlow proposed procurement procedure envisages separate procurement of aFRR balancing capacity and balancing energy; aFRR energy is in the main focus of the FutureFlow project.
- One of the feasible patterns of the procurement, is combined bidding for aFRR balancing capacity and energy, where the national required level of reserve would be selected based on capacity prices; these bids would automatically be transferred to the CMOL for aFRR energy (with separate respective price for energy), along with additional energy-only bids.
- Since EB GL defines Common Merit Order as the target model, Merit Order activation is adopted for the FutureFlow also. Merit Order activation still considers portfolio-based activation inside bidder entities.
- Typically in Europe, merit order activation is combined with the stepwise control signal, opposed to the continuous control signal. Hungary is one of the exceptions, currently applying merit order activation and continuous control signal.
- Under the CAF design, two main options are being considered: the first one is based on control demand (i.e. open loop deviation of control area), while the other is based on control target or control request (i.e. ramp rate limited/unlimited output of aFRR controller).
- The Option 1 (integration based on control demand) advantages are: relatively easy local integration, as-well as the self-sustainability in sense of relatively easy fallback to local control. Its drawbacks are: apparent worsening of ACE in area taking over the imbalance; the fact that different balancing energy volumes are settled between CAF and TSOs (connecting TSO and requesting TSO) and between connecting TSO and its BSPs; inability of this integration approach to support use of specific aFRR products.
- The Option 2 (integration based on control target/request) advantages are: the same volumes are activated between CAF and TSO and between connecting TSO and its local aFRR units as CAF activated power is directly distributed to aFRR units; demand signals are expected to be less volatile than at Option 1. The main downside of this approach is that the output of local controller's distribution function isn't connected to signal forwarding function anymore, and the fallback to the national control mechanism is not easy.

- Both options will be analysed, modelled and simulated within the next phase of the FutureFlow project. The mathematical model and the simulations will consider: integration Options 1/2; ATC-based and Flow-based constraints; standard, and standard&specific bids (for Option 2 only).
- Common proposal for FutureFlow target model is Imbalance Settlement Period (ISP) of 15 minutes, which also represents a recommendation from the ACER.
- Each TSO will settle the activated aFRR balancing energy with the bidders whose technical units providing aFRR balancing energy are connected at the TSO's control area, independently where a certain volume of control energy is requested (i.e. "connecting TSO" principle).
- Current working assumption within the FutureFlow market design is implementation of marginal pricing, as the alternative to pay-as-bid pricing. This proposal is in line with EB GL recommendation and it incentivises higher level of participation for DRs & DGs.
- The existence of free Cross-Zonal Capacity is the essential prerequisite for aFRR exchange; only in periods (hours) when certain portion of CZC is available, the Imbalance Netting and/or aFRR exchange based on Common Merit Order list can take place.
- At the same time, FutureFlow concept of aFRR energy exchange is proposed in a way to ensure (i.e. to leave) the self-sustainability of aFRR control at national level: exchange of aFRR will be realised in periods when there is an available CZC; when no possibility ~~(CZC), systems are capable to operate alone~~
- On the basis of year/month/day-ahead allocations at the concerned borders and directions, it can be seen that at certain directions (AT->HU, AT->SI, RO->HU) rather heavy congestions are regularly present.
- At the after-intraday time horizon, substantial capacity stays even in the previously congested directions. The main reasons are that after the day-ahead nominations of transmission capacities, not all allocated capacity is being nominated; after the nominations, the netting of counter-transactions is possible, and it is being applied - which relieves some portion of the capacity.
- The needs for potential reservation of additional CZC at some profiles (which would increase the total welfare), will be analysed during the next year of the FutureFlow project.
- FutureFlow will involve both ATC-based and Flow-based CZC definitions in the CAF algorithm; while ATCs remaining after the intra-day can be extracted from the actual NTC values at involved borders, Flow-based parameters (PTDF/RAM) can be recalculated for each observed period, on the basis of Intra-day network models.

REDISPATCHING

- The FutureFlow redispatching concept includes the co-optimization of technical (sensitivity factors based on network locations) and economic criteria (redispatch bid price) for the selection and application of Redispatching actions to solve the network

congestions, seeking for the potential of DR/DG units to participate at Redispatching (and required additional information, such as network locations of DR/DG), as well as the cost allocation and cost sharing principles of Redispatching among the TSOs, including the determination of the amounts and the origins of unscheduled flows in case congestion happens.

- The first part of redispatching concept provides an optimal redispatching action and gives the information on redispatching costs of each TSOs involved in these actions. Based on the network information location and size of the congestion (calculated on the basis of nodal injections and PTDF factors), the information from the redispatching bidding list, the objective function considers upward/downward bids (with the amount and the price) located at particular nodes, and finds the solution that provides minimum of redispatching costs.
- The second part of the redispatching concept, herein defined as the "Power Flow Colouring" method, based on decomposing power flows into its components (loop flows/internal flows and exchange flows/transit flows), determines which TSO and in what amount caused congestion on a certain line that eventually led to redispatching. This way it is possible to apply cost-share principle on total flow deviation (difference between total flows from the last model which required redispatching and the previous forecast model which satisfied security criteria), i.e. determine responsibility of each TSO for unscheduled flows on a congested line.

Contents

Document Information	2
Abbreviations	3
Summary and conclusions	5
Contents	9
1 Introduction	10
1.1 Document organisation	10
1.2 Relation to other tasks and work packages	10
2 Current state at balancing and redispatching markets	12
2.1 Slovenia	12
2.2 Hungary	15
2.3 Romania.....	18
2.4 Austria	23
3 FutureFlow aFRR mechanism – target model	27
3.1 TSO-TSO model	28
3.2 Balancing - aFRR energy exchange	28
3.3 Prequalification	29
3.4 Bidding – procurement procedure of aFRR balancing energy	33
3.5 Activation principles of aFRR	36
3.6 CAF design: aFRR cross-border activation and integrations into AGC.....	37
3.7 CAF design: algorithm	43
3.8 Settlement.....	50
4 Cross-zonal Capacity for balancing	58
4.1 CZC available after Intra-day trade	58
4.2 Transmission capacity reservations	62
4.3 Definitions of Cross-zonal Capacity: ATC-based Vs. Flow-based	64
4.4 Timing of CZC update for balancing market.....	67
4.5 Value of CZC	67
5 FutureFlow - Redispatching mechanism	69
5.1 Optimisation function for minimization of redispatching costs	71
5.2 Allocation of redispatching costs based on Power Flow Colouring Method (PFC)	77
6 Annex 1: Survey of DR/DG flexibility vs. FAT	84
6.1 Introduction	84
6.2 The mission - FAT	84
6.3 Methodology and results	84
6.4 Conclusions and discussion.....	86

1 Introduction

This document mainly deals with target models of the concept of aFRR energy exchange among the control zones (countries), with scarce transmission capacity that is available for such exchange. It provides the algorithm of the common activation and optimisation function suited to the aforementioned concept.

Document also deals with decoupled target model of redispatching mechanism, including the algorithm of the redispatching common optimisation, and related concept of the costs share, based on the analyses of the power flows.

Both aFRR energy exchange and Redispatching concepts are exercised on the basis of the markets of the countries involved in the FutureFlow project (Austria, Hungary, Romania, Slovenia), however these concepts are suited to be as much as possible universal within the scope of European electricity markets, and thus replicable to other countries and regions.

1.1 Document organisation

The document is organised through the following key chapters:

- Summary, Conclusions and Introduction give condensed overview of the work described in the document, and the key findings
- Chapter 2 provides current state of balancing and redispatching markets in the four countries being part of the FutureFlow project
- Chapter 3 provides the target model of FutureFlow aFRR energy exchange mechanism, with its key technical and market aspects, and including the Common Activation Function design and algorithm
- Chapter 4 deals with the current congestions, available cross-zonal capacities and ways how to ensure it for the aFRR exchange, covering both ATC-based and Flow-based principles
- Chapter 5 deals with the redispatching mechanism, being decoupled from the aFRR one; it provides the concept and the algorithm of the function for resolving the congestions via redispatching, as well as the concept of the cost distribution for redispatching services among the TSOs
- Annex 1 provides the survey of DR/DG flexibility versus Full Activation Time for aFRR, within the concerned countries

1.2 Relation to other tasks and work packages

This deliverable is related to the work being done within Tasks 1.2. and 1.3 of the WP1.

- It correlates with the Task 1.1 and D1.1 with the DR&DG participation requirements, i.e. its

prequalification conditions. Also, FAT of available DR&DG portfolio is assessed within the Annex 1.

- D1.2. also predefines mechanisms and processes of aFRR energy exchange and Redispatching, which require the definitions of use cases, data needs and formats processed within Task 1.4 and D1.3 (due end 2016)
- Opened alternatives and proposed theoretical concepts recognised within D1.2 will be simulated and refined within Task 1.5 and finally summarized in related D1.4 (end 2017).
- Finally, the cross-WP relevance of D1.2 is strongest towards the WP3, defining the target model for the prototype of the regional platform for balancing and redispatching.

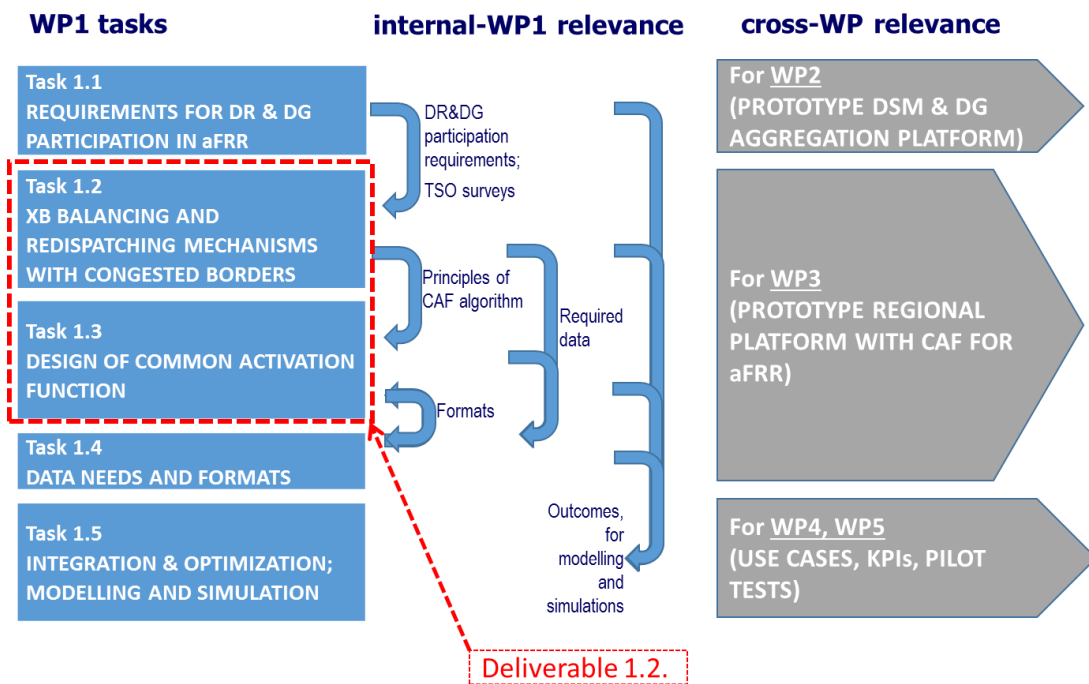


Figure 1 – Overview of the relations among WP1 tasks and with other Work packages

2 Current state at balancing and redispatching markets

This chapter describes a current state of the art at balancing and redispatching markets, respectively for each individual TSO involved in the FutureFlow Project. A main attention is given to the description of market settings which shall be further used and addressed later on in the document when cornerstones of processes and common activation function (CAF) developed under the FutureFlow Project shall be defined, namely balancing and redispatching processes, technical characteristics, cross-border capacity allocation and any relevant plans for future development. Since the main focus of the FutureFlow project is on aFRR (to some extent also mFRR) processes and redispatching, FCR and RR processes are not further addressed in the report.

2.1 Slovenia

2.1.1 SLO: Balancing process

The balancing process for aFRR and mFRR at ELES consists of the following steps:

1. **Balancing capacity dimensioning,**
2. **Procurement of balancing capacity,**
3. **Activation of balancing energy,**
4. **Monitoring of provided balancing services/energy**
5. **Settlement of balancing energy between TSO and BSPs**
6. **Imbalance settlement and cost recovery**

Ad 1: Balancing capacity dimensioning

Balancing capacity dimensioning is done for each balancing process separately. Dimensioning of aFRR is based on ENTSO-E rules (OH, LFCR NC) where both, empiric formula and historical upward and downward imbalances are used. Almost the same results ± 60 MW of aFRR are obtained regardless which method is used.

Dimensioning of mFRR is done according to the loss of the largest production/demand unit based in the control area of ELES. The two upward and downward mFRR limiting units are 696 MW and/or 553 MW of generation and 185 MW of load, respectively used for procurement of positive and negative balancing capacity.

In principle, one standard deviation in historical imbalance distribution should be covered by aFRR, the rest is covered by mFRR when splitting between aFRR and mFRR based on ACE is used.

Ad 2: Procurement of balancing capacity

All BSP offering both aFRR and mFRR services must be pre-qualified and equipped with appropriate communication and measuring equipment. Both aFRR and mFRR capacity is

procured via bilateral negotiations directly with BSPs. Procurement cycle (distance to real time) as well as procurement resolution for capacity, are one year or more where implicit bids are used. Products resolution for energy is one hour. Price caps are set for capacity reservation, while there are no price caps and/or floors for balancing energy. Yearly procurement cycle is applied due to lack of competition, since all available and needed aFRR capacity (symmetric products in the amount of ± 60 MW in total are provided by two BSPs) is procured by the TSO, while for mFRR only 384 MW of needed positive capacity is procured by the TSO (provided by existing five BSPs including two DSM providers), which amounts one half of biggest generating unit in control area of ELES. The remaining half is, according to interstate agreement between Slovenia and Croatia, provided by Croatian utility HEP, since they own half of the NPP Krško. The remaining needed mFRR capacity up to the second biggest loss of generation (553 MW) is fulfilled by sharing the reserve within a control block SHB and by a bilateral contract with TERNA.

In addition, defined by the law, ELES needs to procure all within Slovenia available balancing capacity. In case that is not sufficient to cover all the needs, ELES may procure it outside of Slovenia.

Current BSP are only generators and pumps or generators and load respectively for aFRR and mFRR, where aggregation is allowed to fulfil criterion regarding the minimal bid size which is 1 MW.

Ad 3: Activation of balancing energy

Activation of aFRR and mFRR balancing energy is currently done only from pre-contracted BSPs, however in Slovenia no law is imposing that balancing energy bids only from pre-contracted sources could be used by TSO. BSPs are allowed to offering balancing energy from non-pre-contracted sources as long as they are pre-qualified and appropriate technical equipment/systems would be installed both at BRPs and at ELES side. In principle, a self-dispatch portfolio-based activation process is implemented with some specificities for aFRR where biggest thermal units receive control signal directly from ELES, while some run-of-river hydro units receive a control signal indirectly. Dispatch between them in real time is done by BSP. Activation cycle for set point is 2s. For aFRR proportional (pro-rata) continuous activation is applied, while for mFRR a modified merit order list is used. A modification is needed due to specificities of demand response product included in the mFRR portfolio.

Currently, ELES is a member of "Imbalance Netting Cooperation" (INC) that has been put successfully into operation between APG and the Slovenian TSO ELES in 2013. Recently (April 2016), Croatian TSO HOPS joined the INC which now counts 3 members.

Ad4: Monitoring of provided balancing services

Monitoring is done in real time and ex post.

Ad 5: Settlement of balancing energy between TSO and BSPs

Settlement of balancing energy between TSO and BSPs is based on pay-as-bid principle where delivered energy is settled according to metered response for aFRR and according to requested response for mFRR. Hourly resolution is used for settlement, although all BSPs

(including DSM) are equipped with measuring equipment capable of processing results in 15-minute resolution.

Ad6: Imbalance settlement and cost recovery

Cost recovery is organised through network tariff for capacity procurement costs and via BRPs for balancing energy costs. For imbalance settlement where hourly resolution is used market operator is responsible. Dual pricing where main influencing factors are average balancing energy costs both for positive and negative direction is used. In case of no balancing energy is activated in a certain direction, day-ahead energy price is used for determination of imbalance price. In addition, some mark-ups in a form of fixed and variable prices are added/subtracted to the price of balancing energy.

Financial neutrality of a TSO is not guaranteed, since according to NRA decision portion of incomes resulting from imbalance netting are retained/paid by TSO and not directly settled with BRPs.

2.1.2 SLO: Additional technical characteristics of a controller and products

Requirements regarding the response time both for aFRR and mFRR providers are defined based on ENTSO-E requirements, e.g. 15-minute full activation time for mFRR and first response time and minimum ramp rate for aFRR. A PI controller delivers a global set point which is distributed among contracted units according to the size of actual reserve and provided ramping capabilities.

2.1.3 SLO: Cross-border capacity allocation and congestions

For the FutureFlow project Austrian-Slovenian border is relevant. Here yearly and monthly explicit auctions performed by Joint Allocation Office (JAO) are applied. Explicit day-ahead auctions had been also performed by JAO until July 21, when implicit auctions started. In the intra-day time frame first-come-first-served principle is applied.

2.1.4 SLO: Redispatching process

Slovenian internal transmission grid is considered as a copper plate where internal congestions accrue very rarely, once a year. This is also the reason why ELES currently does not have bilateral redispatching contract with internal power plants, but uses mFRR bids, topological changes or other non-costly remedial actions, e.g. phase shifter, to solve the congestions. However, since ELES is a member of regional security coordination initiative (RSCI) TSCNET where requests for bilateral or multilateral redispatching are more often, e.g. few times a year and up to 10 times a year respectively, ELES is considering concluding a bilateral contract with power plants located in our control area.

In case a request for bilateral or multilateral redispatching is received by ELES, an inquirer is sent out to generators asking for the available location, amount and price of power/energy. This data is then shared with requester(s) where both technical and economic criteria is used to decide which power plants shall be redispatched.

2.2 Hungary

2.2.1 HU: Balancing process

The entire process of balancing at MAVIR consists of six main steps:

1. **Balancing capacity dimensioning,**
2. **Procurement of balancing capacity,**
3. **Activation of balancing energy,**
4. **Monitoring of provided balancing services/energy**
5. **Settlement of balancing energy between TSO and BSPs**
6. **Imbalance settlement and cost recovery**

2.2.2 HU: aFRR capacity

Balancing capacity dimensioning

Balancing capacity dimensioning is done for each balancing process separately. Dimensioning of secondary and tertiary control reserve (aFRR and RR) is based on ENTSO-E rules (Operation Handbook). In case of secondary control reserve dimensioning, both empiric formula and historical upward and downward imbalances are used. Furthermore, there is an additional parameter used in case of upward direction, which results in +248 MW and -128 MW (approximate values).

In case of tertiary control reserve dimensioning, the loss of the largest production/demand unit and secondary control reserve replacement function in the control area of MAVIR is considered. The size of the largest unit is 500 MW, causing a 500 MW upward tertiary control reserve need, in downward direction the requested amount is equal to the secondary control reserve in downward direction, 128 MW. These amounts are the main input for procurement of positive and negative directed balancing capacity.

Procurement of balancing capacity

The main technical condition of becoming a Balancing Service Provider (BSP) is to succeed in prequalification, which is a predefined accreditation procedure (including also communication, interoperability, measurement).

For BSPs it is mandatory to offer all the balancing services to the TSO. Every balancing service is procured through tendering procedures. Procurement procedure ("long-term procurement") can be quarter-yearly, monthly and weekly, which conclude in framework agreements. These agreements can be a so-called market maker contract and optional contract. The first one contains a two-party obligation regarding the balancing capacity availability, the second one contains the framework of balancing services based on the mandatory provision. Both of these contracts are the basis of the daily bidding (distance to real-time) procedure, which is the timeframe for every BSP to offer their balancing services in bids (including balancing capacity, ramp rate, availability fee and balancing energy price). Upward and downward direction of balancing reserves in case of secondary and tertiary

control reserve (aFRR and RR) are separate products. In case of long term procurement, working days and weekends (quarter-yearly) or working days high-tariff, working days low-tariff and weekends (weekly) product resolution is applied. In case of daily bidding, product resolution is one hour for both balancing capacity and balancing energy bids. The minimum bid size is 1 MW and the product resolution for daily bidding is also 1 MW. Since during long term procurement there are auctions applied, there are price caps and floors for availability fee of balancing capacity and there are price caps for price of balancing energy.

BSPs of these balancing services are generator, load, which can provide the balancing services individually or in aggregated (for instance virtual power plant) way.

The following table represents average balancing capacity procurement prices for aFRR and RR separately for upward and downward direction in years 2014 and 2015.

Table 1: Prices of balancing capacity procured for aFRR and RR.

Market results - avg. price for provision of balancing services	2014		2015	
	upward	downward	upward	downward
aFRR capacity [EUR/MW/h]	13	14	12	15
RR capacity [EUR/MW/h]	10	NAP	9	NAP

2.2.3 HU: aFRR energy

Activation of balancing energy

Since daily bidding enables every BSP to provide their bids, the activation of both secondary and tertiary control reserves (aFRR and RR) is in accordance with the balancing energy price based merit order list. In the Hungarian system there is no limitation applied for membership of merit order list, every BSP, which have the ability and capability to provide balancing services for any period of time during the business day is considered. In other words, not only the reserved balancing capacity can be activated, but every available MW.

From April 2013, MAVIR is involved in regional cooperation of real-time imbalance netting procedure with Czech and Slovakian TSOs (CEPS and SEPS). It allows avoiding (minimizing as much as possible) the simultaneous activation of reserves in opposite directions, taking into account the respective situation of each control area and by correcting it.

Monitoring of provided balancing services

Monitoring of availability and activation of balancing services is done both in real time and ex post.

Requirements regarding the response time both for aFRR and mFRR providers are defined based on ENTSO-E requirements, e.g. 15-minute full activation time, response time and minimum ramp rate for aFRR.

Settlement of balancing energy between TSO and BSPs

Settlement of activated balancing energy is done in 15 minute resolution and based on pay-as-bid principle.

From the aspect of total activated balancing energy, most of it is coming from secondary control reserve (aFRR) activation, by the year there is an increasing share of imbalance netting based energy. The following table represents the average balancing energy prices of MAVIR.

Table 2: Average prices of activated balancing energy for aFRR and RR.

Market results - avg. price of balancing energy	2014		2015	
	upward	downward	upward	downward
aFRR energy (activated) [EUR/MW/h]	102	7	140	37
RR energy (activated) [EUR/MWh]	159	40	256	-

Imbalance settlement and cost recovery

Based on balancing energy settlement, there is imbalance settlement applied for those Balance Responsible Parties (BRPs), which were not in balanced position in the respective quarter of hour, which is the imbalance settlement period as time unit. For imbalance settlement there is dual pricing applied, where dual means, depending on the final position of the BRP, the applied imbalance settlement price is different. By using dual pricing mechanism, the main influencing factors are average balancing energy price, both for positive and negative direction, and day-ahead market price is used for determination of imbalance price (the last one is applied in case of no balancing energy settlement in a certain direction or in case the balancing energy price is lower). In addition, some mark-ups in a form of variable components are applied in order to effectively incentivise the BRPs.

From the aspect of covering the costs of balancing capacity payment, there is tariff system applied.

The following table represents the average imbalance price paid by BRPs.

Table 3: Average imbalance prices payed by BSPs

Market results	2014		2015	
	upward	downward	upward	downward
Average imbalance settlement price [EUR/MWh]	70	16	77	6

2.2.4 HU: Cross-border capacity allocation and congestions

For the FutureFlow project Austrian-Hungarian and Romanian-Hungarian borders are relevant. There are yearly, monthly, daily and intraday auctions performed on these borders. On day-ahead level the Romanian-Hungarian border is involved in 4M Market-coupling including Czech, Slovakian, Hungarian and Romanian markets. In the intra-day time frame first-come-first-served principle is applied on both borders.

2.2.5 HU: Redispatching process

The Hungarian internal transmission grid is considered as a copper plate where internal congestions occur very rarely. Based on the currently existing market design, the framework agreement in between BSPs and TSO includes the redispatch services as well. MAVIR uses both non-costly (topological) and costly (redispatch) measures as remedial actions. Costly measures are only exceptional according to the current practice. Redispatching under TSCNET umbrella can be applied only in case more than 2 TSOs from the different countries are involved in activation. Those measures are therefore multilateral and used only as a last resort (means that internal and bilateral measures between TSOs with the limiting network elements are not available to solve security violation). MAVIR is generally not a requester of these multilateral remedial actions.

2.3 Romania

2.3.1 RO: Balancing process

The balancing process for aFRR and mFRR at Transelectrica consists of the following steps:

1. **Balancing capacity dimensioning,**
2. **Procurement of balancing capacity,**
3. **Activation of balancing energy,**
4. **Monitoring of provided balancing services/energy**
5. **Settlement of balancing energy between TSO and BSPs**
6. **Imbalance settlement and cost recovery**

Ad 1: Balancing capacity dimensioning

Balancing capacity dimensioning is done for each balancing process separately (aFRR, mFRR and RR). The dimensioning process of aFRR is based on ENTSO-E Operational Handbook recommendations (empiric formula), and takes into consideration the variation rates of internal production and consumption, scheduled exchanges and the type of regulation generating units. ENTSO-E provides the need to increase aFRR reserve in intervals with high variations of production/consumption, or export.

Based on the above criteria and taking into account the specific features of the National Power System, the consumption variations between peak and off-peak hours, the performances of the generators speed controllers and the experience in operating the power

system, the minimum aFRR capacity band for peak hours established is 500 MW and 400 MW for off-peak hours. For aFRR, the capacity is centered on the base line of generating units and the real activated reserve is 200-250 MW in both senses (half-band).

The mFRR is dimensioned to cover at least the biggest generation unit outage (860 MW installed capacity) and/or sudden wind power park generation fluctuations from the forecast. Currently, the average hourly mFRR reserve is about 800 MW considered in up direction only. The reserve dimensioning strategy is subject of internal procedures C.N.T.E.E. Transelectrica S.A., "Determining the maximum installable in WPP and additional power reserves necessary for the NPS safety", and the values of reserves is yearly approved by Romanian NRA (ANRE).

The RR must restore the mFRR reserve and to ensure balance production - consumption in case of a lasting shortage. RR is mobilized between 15 minutes and maximum 7 hours, in most cases is a matter of hours, referring to TPP- Thermal Power Plants, the time of boiler start-up being dominant in the process of RR activation. For this reason, slow tertiary reserve is dimensioned taking into account the second largest active power loss possible in the national power system. The minimum amount of RR is 700 MW in up direction, corresponding to the second biggest generation outage considered permanently in operation (the installed power of a NPP unit).

Ad 2: Procurement of balancing capacity

The balancing capacity for aFRR, mFRR and RR reserves is procured within organized market. All BSPs offering aFRR, mFRR and RR reserves are invited to participate to the auctions organized by Transelectrica. The participating BSPs must be pre-qualified for the service provided/auctioned. The prequalification process refers to performance of generating units for power activation, providing and maintaining in operation of the required active power during the process of reserves activation and to the endowment with communication and measuring equipment. The procurement cycle (distance to real time) can be from one year till one day before delivery time.

Products resolution for the capacity is one hour. For the capacity market, marginal price is used for all auctioned intervals and reserves. Price is not capped for capacity auctions.

Current BSPs for aFRR, mFRR and RR are generator units only.

The following table represents average balancing capacity procurement prices for aFRR, mFRR, and RR separated for upward and downward direction for years 2014 and 2015.

Table 4: Prices of balancing capacity procured for aFRR, mFRR and RR.

Market results - avg. price for provision of balancing services	2014		2015	
	upward	downward	upward	downward
aFRR capacity [EUR/MW/h]	13,88	13,88	12,83	12,83

Market results - avg. price for provision of balancing services	2014		2015	
	upward	downward	upward	downward
mFRR capacity [EUR/MW/h]	7,08	N/A	6,64	N/A
RR capacity [EUR/MW/h]	8,36	N/A	6,87	N/A

Ad 3: Activation of balancing energy

Capacity activation of aFRR, mFRR and RR balancing energy is currently done within Balancing Market, in merit order list. The energy activation of mFRR and RR is made using a merit order list, while the energy activation of aFRR is pro rata.

All BSPs are obliged to offer all available balancing capacity from pre-contracted and non-pre-contracted sources, as long as they are pre-qualified to provide ancillary services. For pre-contracted capacity, the repartition between generation units, is made by BSP.

Regarding aFRR process, the Load frequency controller is a proportional-integral (PI) type. The integral term is limited in order to have a non-windup control. The cycle time for the automatic controller is 2s. For aFRR, activation is pro-rata. The controller has actions only on generating units or power plants capable to exchange in real time a specific flux of data. The controller represents a control function inside the EMS SCADA system provided by AREVA. The units/power plants receive a set-point as a percentage (named control order) from the total regulating band selected. In some cases, this setpoint (control order) is send as one value to one Power Plant and it is redistributed between power plant units, as same value reported to each generation unit control band.

The unit reacts to the set point after at least 30 seconds to maximum 2 minutes.

The activated energy on Balancing Market, from pre-contracted and non-pre-contracted aFRR, mFRR and RR (free energy bids) is selected based on the merit order list for all services.

Ad4: Monitoring of provided balancing services

Monitoring capacity is done ex-post check (for all services), monitoring energy is done both real time and ex-post check.

Ad 5: Settlement of balancing energy between TSO and BSPs

Settlement of balancing energy between TSO and BSPs is based on marginal price for aFRR (delivered energy is settled according to metered response for aFRR) and pay-as-bid according to requested energy for mFRR.

Hourly resolution is used for settlement.

In 2015, the share of aFRR in a total activated balancing energy represent 10,87% and 11,80% respectively for positive and negative direction. The following table represents the average balancing energy price, paid by Transelectrica to BSP.

Table 5: Average prices of activated balancing energy for aFRR, mFRR and RR.

Market results - avg. price for provision of balancing services	2014		2015	
	upward	downward	upward	downward
aFRR capacity (activated) [EUR/MW/h]	62,61	0,19	66,28	0,59
mFRR capacity (activated) [EUR/MW/h]	52,91	9,15	57,26	8,77
RR energy (activated) [EUR/MWh]	49,91	17,99	54,02	13,55

Ad6: Imbalance settlement and cost recovery

Cost recovery is organised through network tariff for capacity procurement costs and via BRPs for balancing energy costs. For imbalance settlement where hourly resolution is used market operator is responsible. Dual imbalance pricing based on weighted average prices of balancing energy both for positive and negative direction is used. In case of no balancing energy is activated in a certain direction, day-ahead energy price is used for determination of imbalance price. The following table represents the average imbalance price paid by BRPs

Table 6: Average imbalance prices paid by BSPs

Market results	2014		2015	
	upward	downward	upward	downward
Average imbalance settlement price [EUR/MWh]	54,75	6,88	57,32	3,59

2.3.2 RO: Additional technical characteristics of a controller and products

The response time (full activation time) both for aFRR and mFRR is 15 minutes. This time is considered as full activation time and the difference between aFRR and mFRR is the request that aFRR must deliver a first response after 30 seconds. The ramp rate must be respected permanently and can assure the total reserve activation in 15 minutes. This ramp rate is different according the technology (TPP or HPP) and for TPP of combustible oil, coal, gas. All units qualified for aFRR or mFRR must have an active power controller with PI or PID control law.

Regarding the AGC, the basic diagram is:

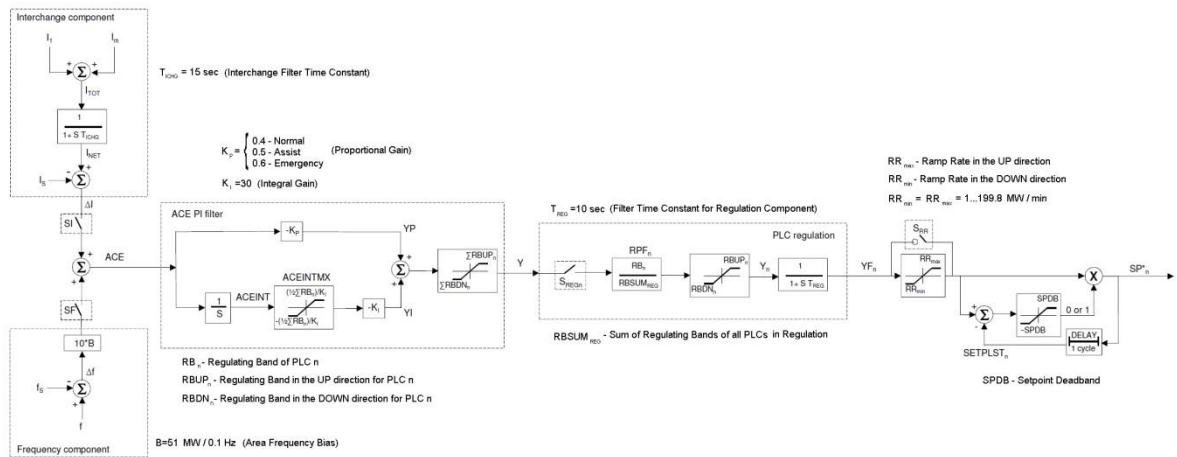


Figure 2 – The basic control diagram of AGC in Romania

The concept is based on PI controller with non-wind-up action. The controller use the total regulating band of units activated for aFRR control. The output of controller is reported to total regulating band resulting and it is sent as a percentage as pro rata activation for each participant units.

2.3.3 RO: Cross-border capacity allocation and congestions

For the FutureFlow project Romanian-Hungarian border is relevant. On this border, the bilateral coordinated allocation, is done for 100% of total capacity by MAVIR (Hungarian TSO) for yearly and monthly auctions (based on Allocation Rules for Forward Capacity Allocation (HAR and border-specific Annex) and by Tranelectrica for explicit intra-day auctions (six sessions). Implicit daily allocations are held since November 20th 2014 when the CZ-SK-HU-RO day-ahead market coupling started. In the event of decoupling, MAVIR is in charge with the explicit daily auctions (shadow auctions) for RO-HU border. Netting and UIOSI („use it or sell it”) principles are applied to daily and intra-day allocation.

2.3.4 RO: Redispatching process

To solve the internal congestions Tranelectrica uses mFRR and RR bids provided on the balancing market or topological changes. The remuneration received by generators for internal redispatching is according with „pay-as-bid” principle. The process of Tranelectrica integration in TSCNET is in progress.

2.4 Austria

2.4.1 AT: Balancing process

The balancing process for aFRR and mFRR at APG consists of the following steps:

1. Dimensioning of Balancing Reserves
2. Procurement of Balancing Reserves,
3. Activation of Balancing Reserves
4. Monitoring of activation of Balancing Reserves
5. Settlement

Ad 1: Dimensioning of Balancing Reserves

Balancing capacity dimensioning is done separately for aFRR and mFRR.

Dimensioning of aFRR is currently based on the empiric formula of the ENTSO-E OH. The application of the formula results in an aFRR capacity of ± 200 MW.

Dimensioning of mFRR is done according to the loss of the largest generation unit and the largest expected loss of demand and results in an mFRR capacity of $+280/-170$ MW.

Experience has shown that current dimensioning ensures very good control quality.

Ad 2: Procurement of Balancing Reserves

BSPs who intend to offer aFRR and/or mFRR services have to run through a pre-qualification process. They have to guarantee appropriate unit features, communication and measuring equipment and have to operate a reviewed capacity and operation concept. Both aFRR and mFRR capacity is procured via a tendering procedure with BSPs.

- aFRR: weekly tendering, peak/off-peak product, minimum size 5 MW, increment 1 MW
- mFRR: weekly tendering, 4-hour-products, size 1-50 MW,

Both aFRR and mFRR have a capacity price component and an energy price component. The acceptance of a bid is based on the respective capacity price.

BSPs run in general pools of units and receive respectively only one signal, which is distributed to the individual units based on activation schemes that have to be pre-qualified. The size of the units is quite different (from tens of MW to hundreds of MW). Both generation and demand units are used. There are also some aggregators registered as BSPs, which do not own/operate the units in their reserve-pool.

In general no distinction is made between aggregators/non-aggregators, generators/loads and between technologies as long as the quality requirements for the pool of the BSP can be met. Nevertheless there exist specific solutions to reflect different boundary conditions –

e.g. the definition of the set value (needed to calculate the activated reserve).

Ad 3: Activation of balancing energy

Activation of aFRR and mFRR balancing energy is based on the Merit Order List (MOL) resulting from the tendering.

The aFRR activation signal for the BSPs is the output of the LFC of APG with a time resolution of 2s (merit order activation) and transferred via IEC 60870-5-101 protocol.

The activation of mFRR is transferred by means of a web-service where the BSPs have to be connected to.

In general the quality of control in the CB APG is very good. This high quality is reflected in the quality parameters in the regular ENTSO-E "Report of the performance of the primary and secondary LFC"

In addition to procurement and activation of reserves two layers of imbalance netting are applied (first layer: INC with ELES and HOPS, second layer IGCC).

Ad4: Monitoring of provided balancing services

Monitoring data by means of online activation data has to be provided per BSP (2 s time resolution for aFRR, 2 s up to 60 s time resolution for mFRR). In addition a BSP has to archive data with the same time resolution for every unit for spot checks (exceptions for a high number of identical units possible).

Ex-post-monitoring is the basis for accounting, since only real activated reserves are remunerated. In addition a penalty procedure is currently being implemented.

Ad 5: Settlement of balancing energy between TSO and BSPs

Settlement of balancing capacity between APG and the BSP is based on pay-as-bid principle. Balancing energy is for aFRR settled based on real activated aFRR (no cap is applied) and for mFRR based on the request. Settlement period is 15 minutes.

Ad6: Imbalance settlement and cost recovery

The expenses for reserves are distributed based on the tariff regulation.

2.4.2 AT: aFRR technical characteristics

The block diagram of AGC concept with PI-controller is given below:

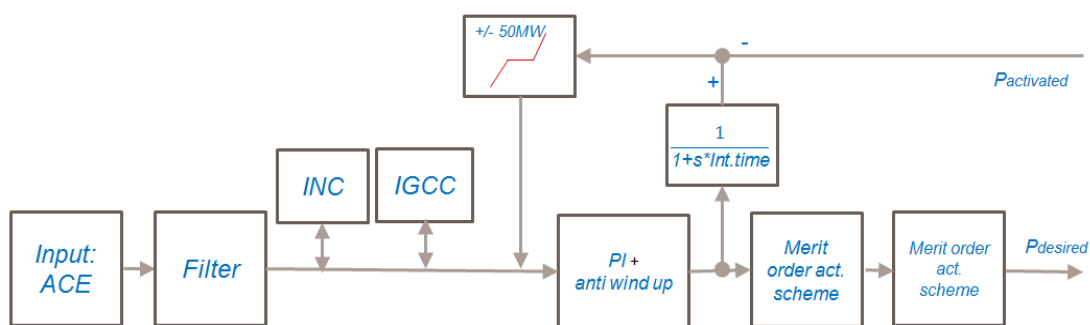


Figure 3 – The basic control diagram of AGC in Austria

Additional Details are the following:

- Frequency filter: Time constant 25sec
- Compensation factor 0,6
- LFC: Cycle time 2sec, integration time 60 sec, large signal gain 0,4, small signal gain 0,5, dead band 5MW

2.4.3 AT: Cross-border capacity allocation and congestions

For the FutureFlow project two borders in the control area of APG are relevant – namely, Austrian-Slovenian and Austrian-Hungarian. On both profiles yearly and monthly explicit auctions are performed by JAO. On the border Austria-Slovenia explicit day-ahead auctions had been also performed by JAO until July 21, when implicit auctions started. Explicit auctions of transmission capacities are still performed on the border Austria-Hungary. In the intra-day time frame first-come-first-served principle is applied.

2.4.4 AT: Redispatching process

The redispatching mechanism is organised over the bilateral contracts with the largest power producers in the control area of APG. In case of overloads in the network, first non-costly (topological measures) are used to solve them. Internal redispatch, which is used to solve congestions in the control area of APG, is rarely used (frequency of activation is low). Bilateral redispatch with either Germany or Czech Republic is used more often (when compared to the internal one). Lately more frequent activations of multilateral remedial actions (MRAs) in the region of continental Europe are observed. As APG is a member of regional security coordination initiative (RSCI) TSCNET, frequency of MRA activations in this case is dependent on problems faced by 12 partners (Requesting Parties).

In case a request for redispatching is received by APG or remedial actions are needed by APG, an inquiry is sent out to generators asking for the price/energy offer as well as the location of the network (power plant) in which the change of generation should take place. This data is then either used by APG (internal redispatch) or shared with the partners of TSCNET cooperation, where both technical and economic criteria is used to decide which

power plants shall be redispatched.

2.4.5 AT: Short-term plans and projects for further development of redispatching processes

Currently APG is working to implement the requirements set in CACM GL (Capacity Allocation and Congestion Management Guideline) and System Operation Guideline. Both documents define how the future cooperation among TSOs in the field of coordinated redispatching and countertrading needs to be done. This includes coordination on the regional level (over RSCIs), as well as the cost-optimal activation of remedial actions taking into account technical network constraints.

aFRR energy, current state:

Market | Technics

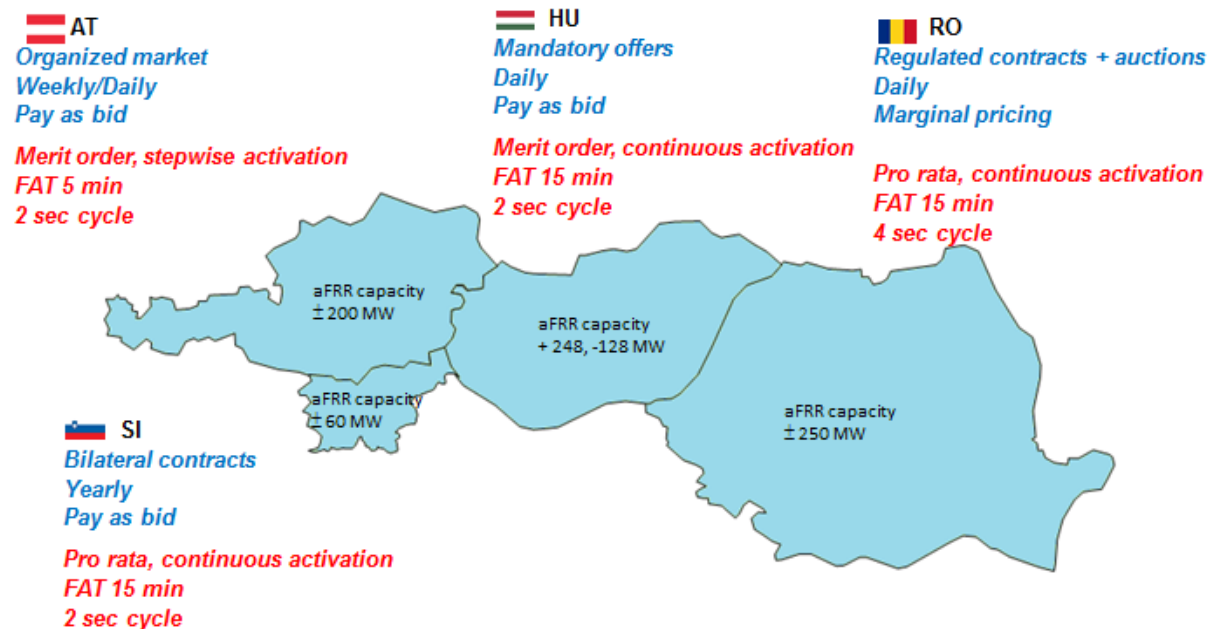


Figure 4 –aFRR energy, current state

3 FutureFlow aFRR mechanism – target model

One of the main tasks of FutureFlow project is to design the feasible target model (FF Target Model) for the exchange of balancing energy from FRR with automatic activation, by defining the proper configuration and correlation among the national balancing markets and practices, its pan-regional integration, taking into account cross-border transmission constraints and the operation of commercial markets.

Having in mind that according to the relevant legislation, based on the specific of aFRR and redispatching services, these two should not be operated through the common availability list, FutureFlow has a separate target also to provide innovative solution at the field of redispatching.

FF Target Model design has to provide innovation in the field of balancing, be in line with the EU Target Model (mainly defined by Guideline on Electricity Balancing (EB GL) and Guideline on electricity transmission system operation (SO GL)), and at the same time be secure, sustainable, replicable and applicable in the situations of congested borders.

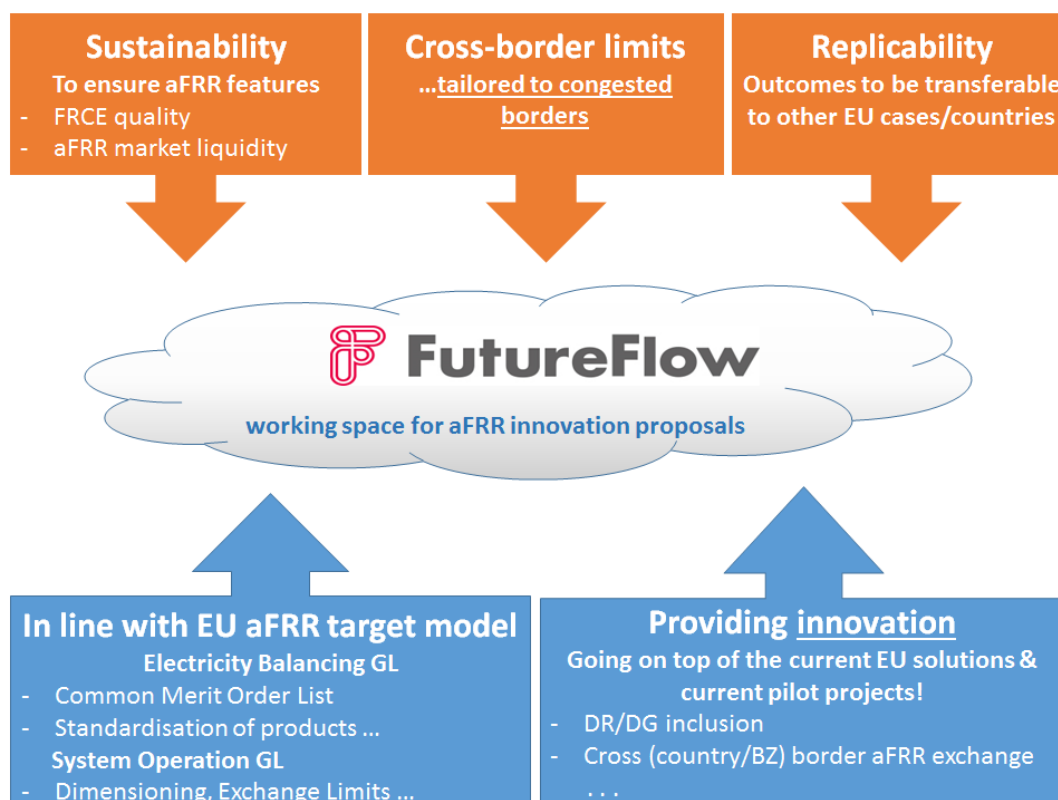


Figure 5. FutureFlow - working space for aFRR innovation proposals

Under these conditions, the key cornerstones of FutureFlow Market Design are summarized and thoroughly discussed. While the resolution for some of the cornerstones was quite straightforward (e.g. when directly related to EU Target Model), some other raised lots of discussions, and still are left with open alternatives that will be investigated within Task 1.5 of this project. The crucial topics are listed herein.

3.1 TSO-TSO model

Since the draft version of EB GL clearly defines TSO-TSO as the standard and target model for the exchange of balancing services. For the FutureFlow also the TSO-TSO model is recommended. The TSO-TSO model means the exchange of any kind of balancing services is possible exclusively by involved Transmission System Operators (requesting TSO and connecting TSO). It means, all activations of Balancing Service Providers (BSPs) of aFRR energy, both conventional and DR/DG providers, in another area of responsibility are realized through the Connecting TSO.

3.2 Balancing - aFRR energy exchange

The process of exchange of aFRR balancing energy, from the regional cooperation point of view, can be summarized with the following high level activities:

- **Prequalification** – Activity that has been performed before real-time operation, in which TSOs set the technical requirements for aFRR product and perform testing of the BSP's technical capabilities to provide required aFRR product (in accordance with Balancing service guidelines or Grid codes); BSP providers are obliged to fulfil these requirements if they want to participate in the regional balancing market.
- **Bidding** – Activity that has been performed before real-time operation (depending on the applied bidding procedure) with the goal to create Common Merit Order List (CMOL) based on individual offers for aFRR energy from the Balancing Service Providers on the national level.
- **Activation** – Real-time activity (typically within few seconds) in which each participating TSO submits its current demand for activation of aFRR energy, while Common Activation Function (CAF) optimizes all submitted demands and sends back correction signals to obtain the most efficient economic solution under the given transmission constraints (limited Cross-Zonal Capacity).
- **Exchange** – Real-time activity in which participating TSOs exchange aFRR balancing energy, physically through existing interconnection lines and administratively through virtual tie-lines.
- **Settlement** – Ex-post activity in which participating TSOs account activated aFRR energy.

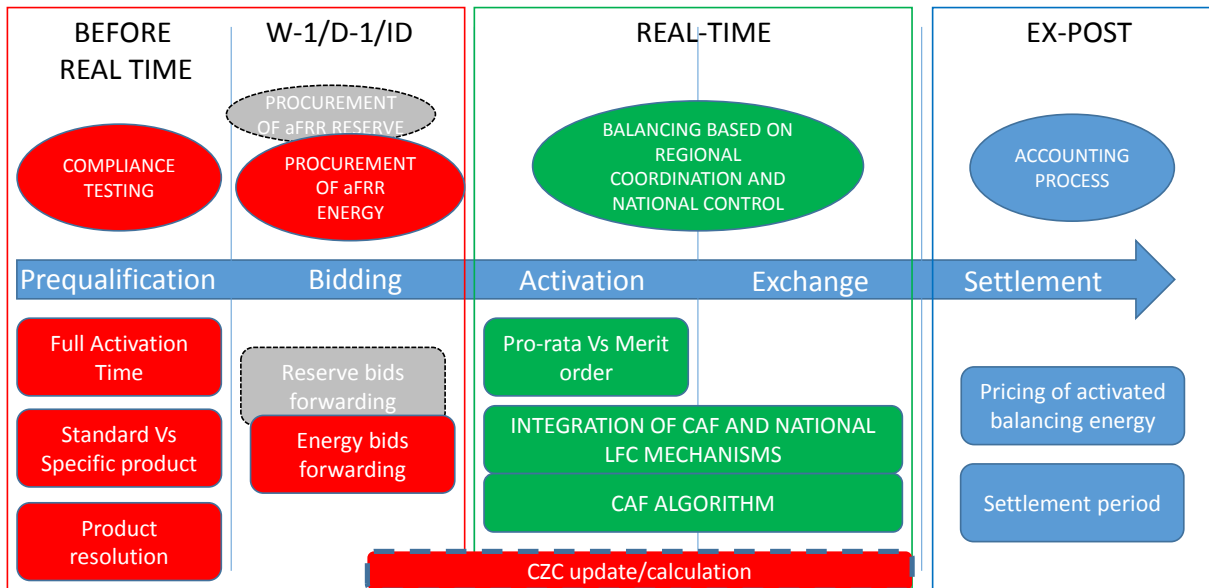


Figure 6 – The process of exchange of aFRR balancing energy

3.3 Prequalification

- **Product specification - Full Activation Time (FAT)**

The aFRR Full Activation Time (FAT) is the time period between the moment of requesting of aFRR energy delivery by the LFC module within SCADA/EMS system and the corresponding moment of the full delivered aFRR energy amount. It can be noticed that there are lots of diversities in FAT ranges throughout the analysed region, as well as in Europe as a whole, due to different control strategies and different generation fleet within each country (which results in different market liquidities of aFRR markets).

The explanation of the standard balancing product specification and FAT period is shown in the following picture.

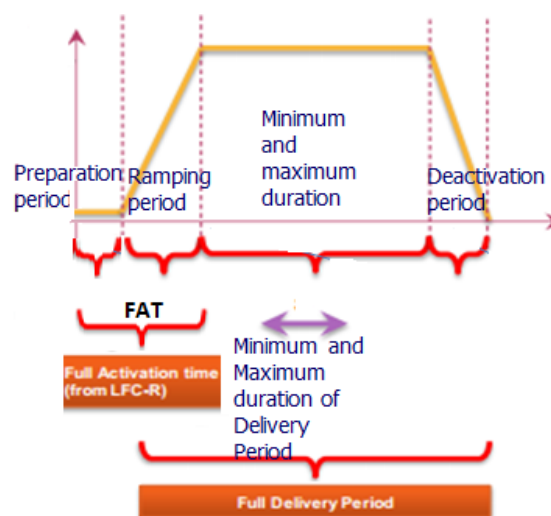


Figure 7 – The standard balancing product specification

It can also be stated that for aFRR standard product, preparation period should be of at most 30 seconds according to System Operation Guidelines. Deactivation period is irrelevant for the aFRR product.

In general, smaller FAT increases the overall control quality but on the other hand it influences the volume of aFRR capacity that can provide such aFRR product (for smaller FAT values one can expect smaller volumes of available aFRR capacity). In addition, from the pure technical perspective and aFRR control quality, the necessity for smaller FAT values depends on stochastic rate of change of load or generation (particularly renewables) within the country. It can be seen that among analysed countries, due to the high percent of renewables, only Austria applies fast FAT of 5 minutes, while other countries still can achieve good control quality with slower FAT of 15 minutes.

The comparison of technical requirements for aFRR activation of interest is shown in the following table:

Table 7: Comparison of technical requirements for aFRR activation, current state

	Austria	Hungary	Slovenia	Romania
FAT	5 minutes	15 minutes (minimum ramp rate is 2 MW/min)	15 minutes (minimum ramp rates for each power plant are agreed individually)	15 minutes (10% of installed capacity/min)
Activation rule	Merit order	Merit order	Pro-rata	Pro-rata
Activation rule	Stepwise	Continuous	Continuous	Continuous
Control request in LFC module	Not based on ramping capabilities of the machines	Based on ramping capabilities of the machines	Based on ramping capabilities of the machines	Based on ramping capabilities of the machines
Average required aFRR capacity	±200 MW	248 (upward) 128 (downward)	±60 MW	±250 MW

The possible solution for regional cooperation would be to harmonize FAT between the involved countries to the fastest FAT of 5 minutes, but on the other hand that might impose situation where eligible aFRR reserve in some countries can be endangered. In addition, due to applied control strategy in Austria, they cannot receive aFRR energy with slower response (e.g. 15 min), because the overall FRCE control quality might be lowered.

From the current operational practice and control strategy, it can be concluded that Slovenia

cannot easily apply 5 minutes FAT due to expected total required aFRR capacity of ± 60 MW in off-peak hours and during summer period where hydro units operate less as they currently rely significantly on TPP Sostanj 6 in the generation portfolio. In case of applying 5 minutes FAT, total aFRR capacity of TPP Sostanj 6 will be much lower and total required aFRR capacity in Slovenia will be lower than required in certain hours.

In Hungary, taking into account the technical capabilities of the machines, achieving the total required level of the aFRR capacity (average yearly level is 248 for upward and 128 for downward) would have serious issues with overall market liquidity and price for aFRR capacity could be expected in case of applying 5 minutes FAT as many of the Hungarian power plants depend highly on balancing market due to their non-competitiveness compared to import energy and the rest of the units have slower ramp rates for aFRR.

Romania currently relies on diverse machines inside generation portfolio for aFRR (mainly hydro units but there are also lot of capacities in gas fired and coal fired thermal units, such as OMV Petrom, Turceni and Rovinari).

Taking into account all mentioned issues, the following alternatives of FAT are recommended to be analysed in details within Task 1.5 (during year two of FutureFlow project - 2017):

- **Alternative 1:** Harmonized FAT within the region, as the best possible FAT value between 5 and 15 minutes; It requires the following assessments:
 - Assessment of the potential deterioration of aFRR capacity market and overall FRCE control quality for different FAT values
 - Technical possibility to implement explained principles of cross border aFRR activation integrations into existing aFRR controllers.

The outcome of these in-depth analyses will be optimal and harmonized FAT value for the observed region taking into account all corresponding issues.

- **Alternative 2:** Hybrid solution of FAT within the region, as potentially feasible option (feasibility to be confirmed during Task 1.5). In this case, option "business as usual" will be analysed that comprises no changes within the current aFRR product in observed countries. This option requires detailed analyses of technical possibilities to implement Common Activation Function that will put the bids into a price based common merit order list with different (better and worse) product quality specifications, or in other words to allow that certain bids can be triggered by all systems (e.g. those with 5 min FAT), while other bids (e.g. 15 min FAT) could be triggered only by systems that apply 15 minutes FAT products.

In relation to previously mentioned alternatives for FAT, three possible options were initially seen, out of which two are considered as potentially feasible:

- **Option 1:** The solution where only one standard product is allowed (e.g. bids with single standardized FAT).
- **Option 2:** The solution where both standard (equal to currently fastest FAT product

in involved countries, 5 minutes FAT product) and specific products (equal to 15 minutes FAT products; and possibly others) are allowed to be sent to CAF and additional flag allows them to be used by specific TSOs or not. This obviously requires detailed analyses of possibilities and reasonableness to implement such a complex CAF algorithm.

- **Option 3:** The solution where only standard products are allowed to be sent to CAF, while specific products are allowed to be on the local MOL. This would require LFC to produce “split” control requests, one from the local controller and one from the CAF, which is foreseen as very complex and suboptimal solution. This option has been discarded for further analyses.

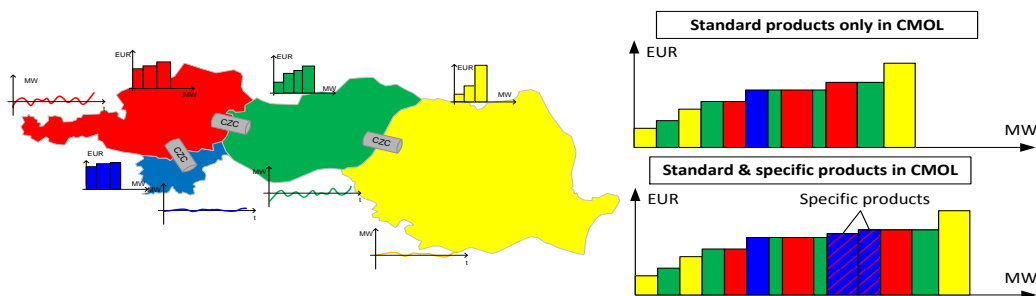


Figure 8 – The aFRR product specification

- **Product resolution**

Proposed FF solution is that the product resolution in time (i.e. bids validity in the terms of price and amount of available capacity) is to be set in the timeframe 1-4 hours; Working assumption is that it would be 1 hour.

The lowest volume of capacity within the hour should be always provided by BSPs due to 15 minutes schedules. This leads to some extent of inefficiency, but on the other hand 15 minutes product resolution will cause possibility of too frequently change of merit order list on voluntary market.

In addition, shorter times of product resolution would be too close to the Full Activation Times (5-15 min), and it is currently seen as a threat that frequent changes of accepted bids would impose unnecessary fluctuations and might deteriorate FRCE quality. Having 1-hour product resolution would ensure certain level of stability in the conditions of bids with 5-15 min FAT.

On the other hand, longer times (e.g. peak/off-peak which is 12 hour product resolution) would not be in favour of DR/DG energy providers (in case of DG it is valid especially for renewables), which are under special focus of FutureFlow project, and which nature requires rather shorter availability time.

These are working assumption based on theoretical assessments; they need to be further discussed and possibly experienced through simulations.

3.4 Bidding – procurement procedure of aFRR balancing energy

FutureFlow proposed procurement procedure (Figure 10) envisages separate procurement of aFRR balancing capacity and balancing energy. One of the main argument for this is that combined procurement of balancing capacity and energy cause lower liquidity of balancing market. With combined procurement, gate closure time for balancing energy bids must be aligned with the gate closure time of balancing capacity bids, which is at best one day ahead (currently in FF related countries it is: Hungary Quarter yearly/W-1/D-1, Romania Quarter yearly/W-1/D-1; Austria W-1; Slovenia Y-1). This longer distance between bidding and energy delivery causes more uncertainties for potential suppliers and leads to reduced market competition. Reduced market competition produces in most cases exercise of market power and higher costs for balancing services. On the other hand, unbundled procurement of these two services and closer to real time balancing energy bids submission, will favour participation of smaller portfolios also, especially the ones combined of DR/DG (mainly RES).

Therefore, working assumption for FF target model is that balancing capacity is procured on a week-ahead timeframe. Bids for aFRR balancing capacity (in general standard and specific) include:

1. offered quantity for balancing capacity,
2. direction of activation (upward/downward),
3. product resolution
4. balancing capacity price
5. connecting TSO

All selected bids for provision of balancing capacity are obliged to submit the energy bids in bidding for balancing energy. These selected balancing capacity bids, which guarantee balancing capacity, will submit the energy price in bidding for balancing energy.

Bidding for balancing energy provision is organized on intraday timeframe, with gate closure time 30 min before the real time. Balancing energy bidding list is comprised from energy bids of pre-procured balancing capacity providers and additional “free” energy-only bids from other prequalified market participants.

Bids for aFRR balancing energy include:

- offered quantity,
- direction of activation (upward/downward),
- price and

- product type (standard /specific)
- in case there was balancing capacity exchange among the TSOs: connecting TSO, contracting TSO¹

FutureFlow will investigate both options: one with only standard products with harmonized FAT in all participating TSOs allowed on the CAF platform, as well as the hybrid solution with both standard and specific products allowed to be exchanged over the CAF platform (with standard product being eligible for activation in all four control areas, and specific products with slower FAT being e.g. eligible for activation in Slovenia, Hungary and Romania, but not in Austria)

On the basis of submitted and verified balancing energy bids, each TSO will create local merit order lists for both upward and downward direction (based on bid prices) which will be forwarded to the regional FutureFlow common activation platform. Local merit order lists will be aggregated on the platform to form a Common Merit Order List (one for upward, and one for downward direction) which will include all previous information on bids with additional information of originating control area for each bid.

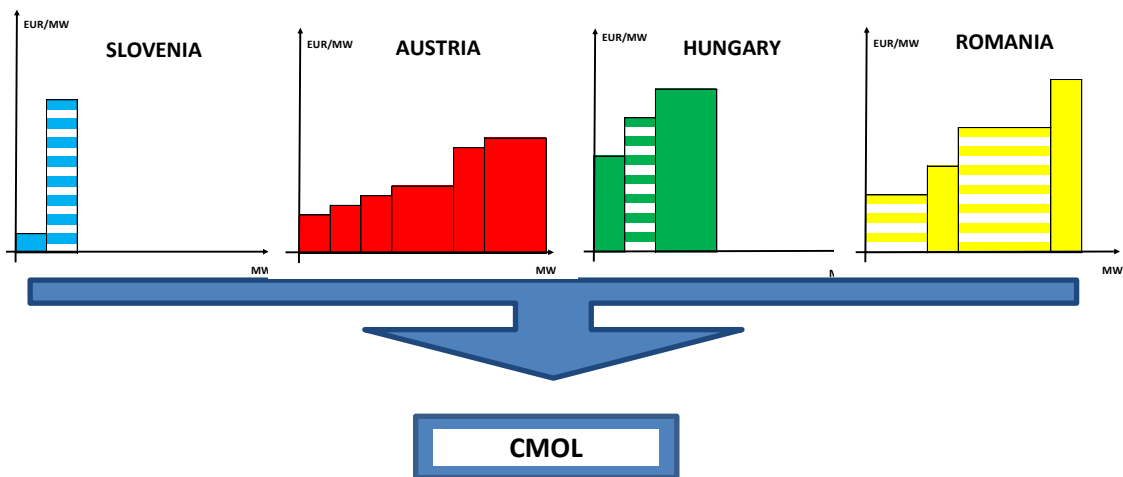


Figure 9 – Example of Common Merit Order List creation

¹ Eventual Cross-Zonal Capacity reservations for the balancing capacity exchange, are processed by the TSOs; they are not part of the bids.

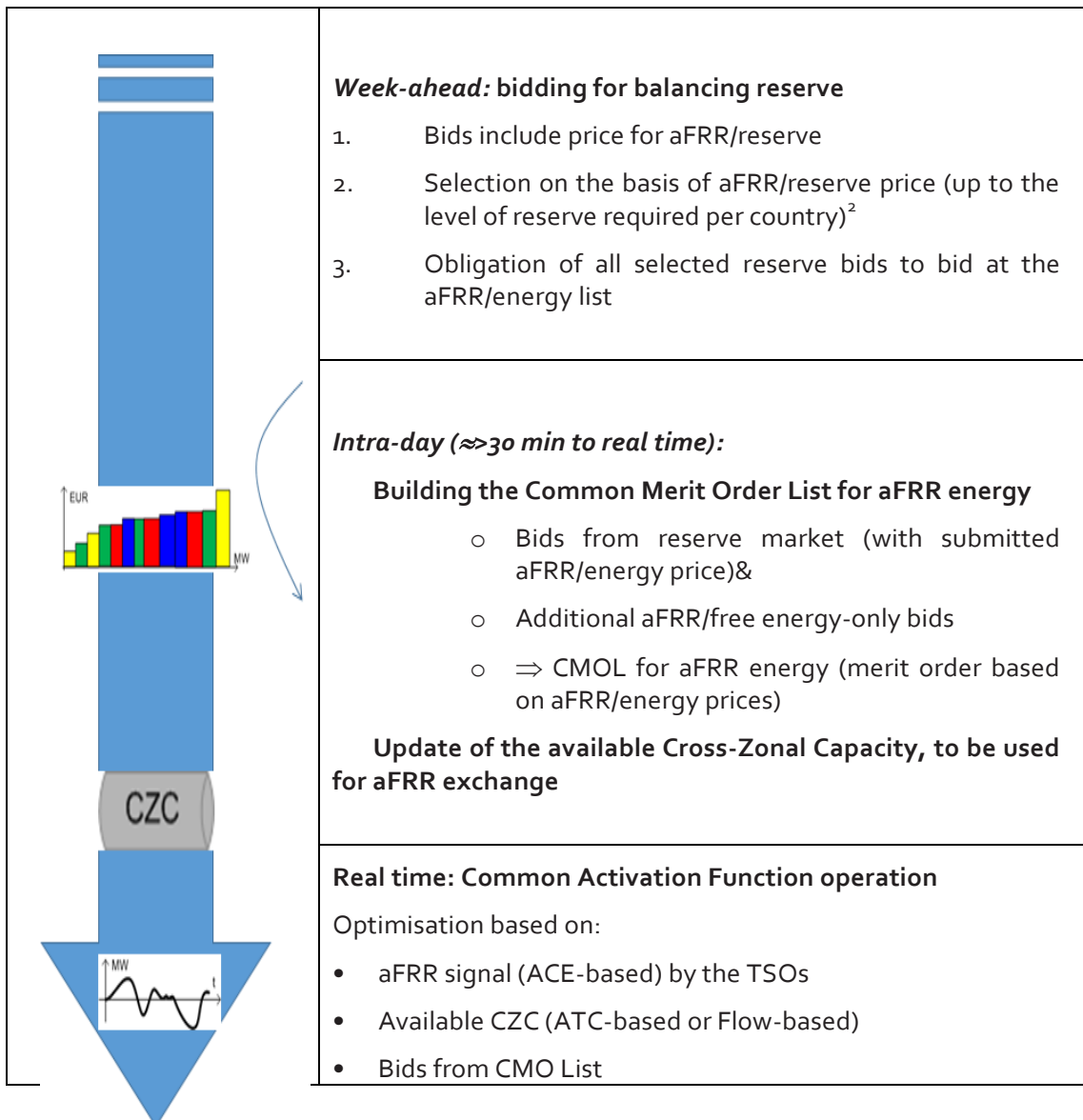


Figure 10 – Summary of proposed FutureFlow procurement procedure

² Only the basic features of balancing capacity procurement mechanism are addressed, since the main focus of the FutureFlow target model is on designing a mechanism for aFRR exchange of balancing energy that should be robust to moderate deviations in balancing capacity procurement procedures. Therefore, the envisaged FutureFlow aFRR platform for common activation of balancing energy does not depend on the procurement procedure of aFRR capacity, since in case it is one procurement procedure or separate for each TSO, the resulting balancing energy bids (voluntary or related to already reserved balancing capacity) is considered only by the CAF.

3.5 Activation principles of aFRR

Pro-rata vs. Merit Order activation

Currently Austria and Hungary apply Merit Order principle for the aFRR bids activations, while Romania and Slovenia apply pro-rata activation. Since EB GL defines Common Merit Order as the target model, Merit Order activation is adopted for the FutureFlow also.

One of the potential drawbacks of CMOL activation comparing to pro-rata is that in case of different prices of the bids, in some cases it enables altogether slower interaction (less bids can be activated simultaneously - therefore reaching the target output can be slower); this effect is expected in cases of smaller ACE (smaller control demand \Rightarrow less bids are activated in parallel).

The following picture illustrates the difference between two activation principles. Blue areas on both pictures are the same, representing the same amount of activated energy in both cases.

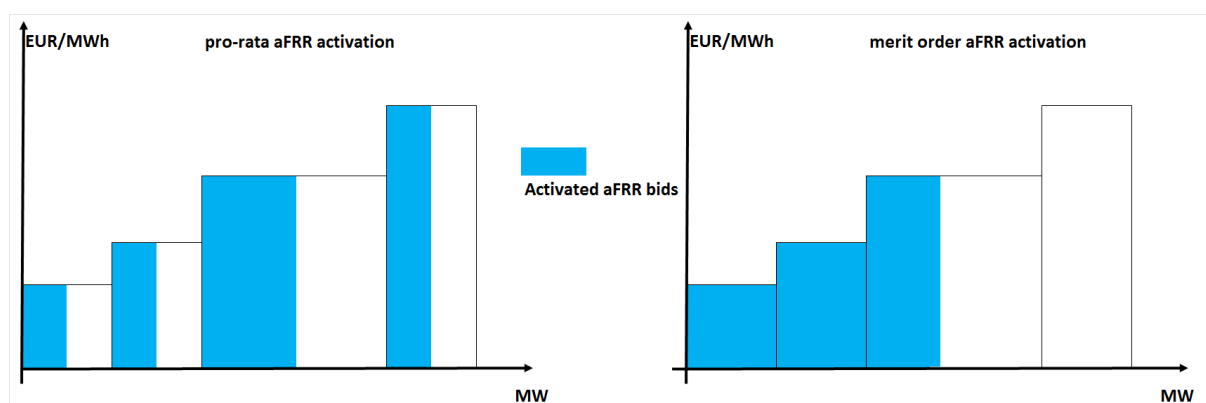


Figure 11 – Pro-rata vs. merit order activation

Stepwise vs. Continuous activation

Currently in Europe, there are two main methods to activate aFRR energy bids in national LFCs. Most of the TSOs apply **continuous activation** which respects required ramp of the aFRR provider; in other words set-point signal is being sent to aFRR provider every 4-10 seconds depending on the AGC cycle. It can be noticed that within continuous activation method, “control target” value, as an ACE signal that has been filtered and usually passed through PI controller, has been transferred to “control request” signal that is respecting required ramp rates of the units. This “control request” signal can be activated by using either pro-rata activation scheme or merit order activation scheme. Typically, continuous activation is used with pro-rata scheme while there are exceptions as in Hungary or in Netherlands which are using merit order activation scheme and continuous activation of the bids.

Opposite to continuous activation, **stepwise activation** method does not respect ramp rate of the aFRR provider, because fixed ramp rate is not being required. It is up to the aFRR provider to respect required FAT and minimum ramp rate (as well as at least linear ramp to set-point value) that has been tested during the prequalification phase. In other words, that means that each aFRR provider has to take into account its ramp rate or its pool ramp rate when it is determining the

volume of its bid. In this method, there is no transferring of control target signal to one that is respecting unit's ramping capabilities. It is common that this method is applied in these TSOs which have implemented merit order activation scheme. Together with this method, "per metered" settlement method is usually applied.

3.6 CAF design: aFRR cross-border activation and integrations into AGC

This chapter deals with integration of CAF with automatic generation control (AGC, aFRR controller or secondary controller or LFC), that is a control system for adjusting power output of balancing service providers (mostly multiple generators at different power plants), in response to interchange deviations of the regulated control area. Automatic generation control is located within each TSO's SCADA/EMS system environment (see FutureFlow system architecture shown in figure 2 in D 1.2).

FutureFlow project focuses on cross border exchange of aFRR balancing energy. For that, existing TSOs' aFRR controllers, currently deals with activation of local balancing services and does not deal with the cross-border exchange of these with other TSOs. However, when implementing changes to current traditional, simple and robust aFRR controllers, one has to have in mind the importance of Frequency Restoration Process (FRP) and consider all the possible adverse effects of cross border aFRR activation on LFC.

In European power system two basic principles (in resume: approaches) of cross-border exchange of aFRR balancing energy are considered. For the first one, for a cross border aFRR balancing energy exchange (used as general term for describing TSO's need for cross border balancing) is based on control demand (i.e. open loop deviation of control area), while the other is based on control target or control request (i.e. ramp rate limited/unlimited output of aFRR controller).

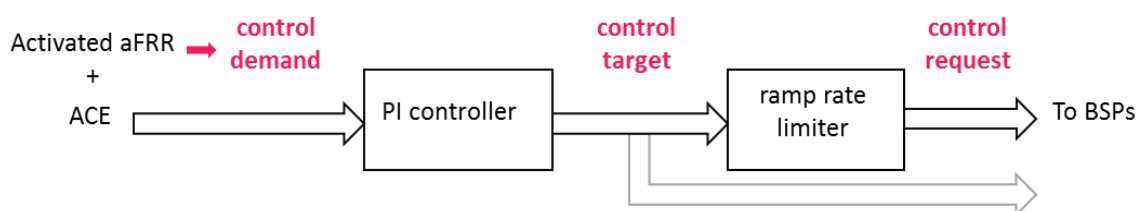


Figure 12: LFC and possible aFRR exchange demand sources: control demand, control target and control request

Both approaches (in resume: control demand approach and control target/request approach) are in line with TSO-TSO model from prequalification process, to real time activation, monitoring and settlement. Description of both approaches with some advantages and disadvantages is presented below.

Control demand approach - integration based on open loop control area deviation

In this approach, demand for cross border exchange of aFRR is based on TSO's control demand, that is an open loop deviation of a control area (considering already activated aFRR balancing services and existing imbalance nettings). Those demands are then sent to Common Activation

Function (CAF), where individual control demands are processed and optimal common aFRR activation solution is found. CAF returns an optimal individual TSO correction signal to each TSO, where correction signal is added to TSO's actual ACE. This modified ACE is then processed by aFRR controller, which responds with increased/decreased activation of aFRR. Cross-border aFRR balancing energy exchange (i.e. correction signal from CAF) can be done step-wise activation or continuous activation (with ramp limitation). Control diagram of described integration approach is shown in Figure 13.

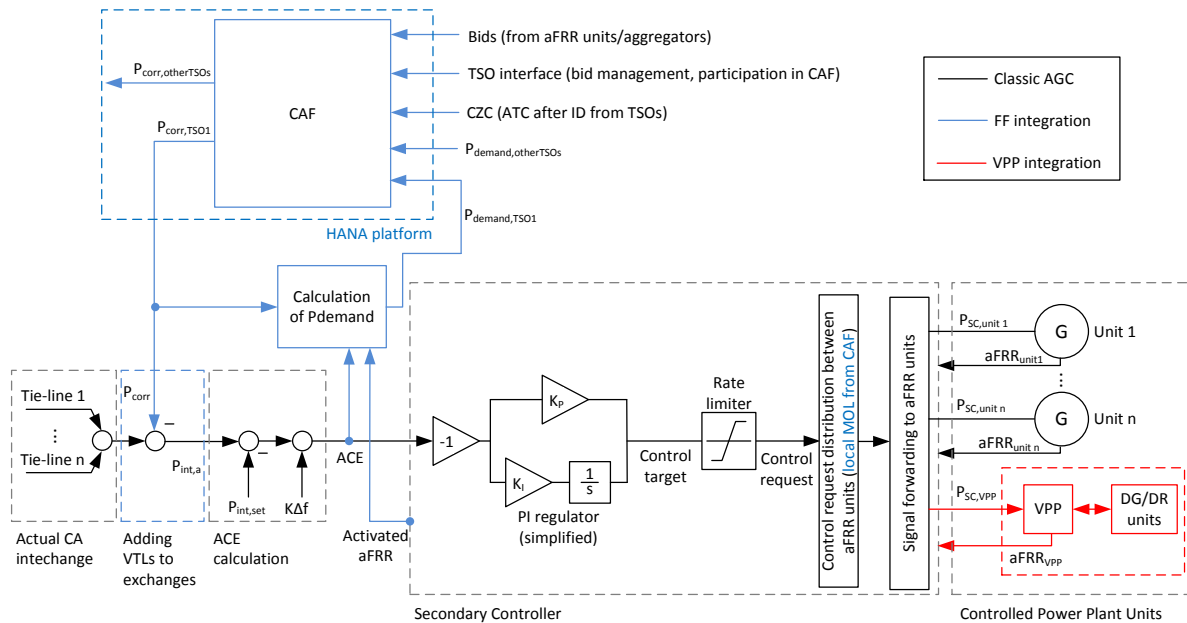


Figure 13: Control diagram for aFRR cross border implementation with aFRR activation demand based on control demand

This approach uses same principle that many Grid Control Cooperation (GCCs) across Europe do for imbalance netting. Additionally, its feasibility has already been proven in real-time operation as it is in operational use in DE-AT aFRR cross border balancing energy exchange cooperation since August 2016. However, an important and challenging topic of CZCs handling is not addressed in this cooperation as there are no CZCs between involved TSOs.

One of the main advantages of this approach is an easy integration into existing LFC. The local controller needs to support calculation of demand (sum of ACE and already activated aFRR), be able to receive single correction signal and add it to ACE. What is more, demand calculation and application of correction signal in this approach is the same as for imbalance netting, so often no modification of local controller is needed. If TSO's controller doesn't support local MOL, this functionality has to be added too. The advantage is also that in case connection to CAF is lost, controller continues to operate locally without any automatic or manual intervention or mitigation measures.

This approach has three main downsides. The first is a fact that solution directly targets ACE, which has a positive impact in case of imbalance netting, where demands of two control areas are immediately netted and negative in case of cross border exchange of balancing energy. For cross

border exchange of aFRR, deviations are exported from requesting TSO to connecting TSO and as correction is added to connecting TSO's ACE, it temporarily increases this ACE as BSPs of aFRR respond with delay of PI-controller and local BSPs participating in aFRP. On long term, for control areas with considerably different aFRR energy market prices, this might cause worse ACE performance in control areas where more aFRR would be activated, while improving ACE performance in control areas with higher aFRR energy prices. There are possible "administrative" mitigation measures for this problem such as assessment of ACE quality taking into account that TSOs are operating together or implementation of compensation mechanism in case unintended exchanges will have to be settled based on common settlement rules applicable by the TSOs in the future.

The second downside is the fact that different balancing energy volumes are settled between CAF and TSOs (connecting TSO and requesting TSO) and between connecting TSO and its BSPs. This is unavoidable, as cross border aFRR exchange is seen by the regulator as modification of local ACE and after ACE is changed, it takes a while that PI controller actually responds with new control request. The delay from adding received correction to ACE to reflection of this correction in the set-points may vary considerably from TSO to TSO, as PI controllers and filter settings are often tailored by LFC providers to fit each TSO power system configuration individually.

The third downside is inability of this integration approach to support use of specific aFRR products. Cross border exchange of aFRR is realized as virtual power exchange added to the existing local ACE and resulting modified ACE is sent to the LFC. Because correction signal does not contain information of activated product type and because correction signal is added to ACE and later filtered and processed by aFRR controller, track whether specific or standard product is requested for cross border exchange, is inevitably lost. The output is then sent to local MOL by the TSO, where cheapest products are always activated first, regardless whether they are standard or specific. This integration therefore cannot ensure that product types that were activated as cross border aFRR exchange are actual products activated according to local MOL. There is a possible mitigation of this issue, namely assumption that specific products are always at the end of local MOL, however this might produce economically suboptimal solution. The conclusion is that this integration approach is from technical perspective incompatible with simultaneous use of standard and specific products. Although this might not be a problem for control areas with enough BSPs suitable of offering standardized aFRR product, it might prevent control areas with not enough such potential from entering cross border aFRR activation cooperation with this integration principle.

What is also worth to mention is that demand signals (control demand or control target/request) from TSOs are expected to be fairly volatile due to use of naturally volatile ACE as part of demand signal, therefore optimization in CAF won't be able to rely on previous cycle solution and as result correction signal from CAF might also be volatile.

Control request approach - integration based on CA control target/request

In the second approach of cross border aFRR activation integration, demands are based on aFRR controller control target, which is an output signal from PI controller not limited by finite ramping

rates of aFRR units. Alternatively, a control request, which is control target limited by local units' ramp rates, can be used instead of control target itself, however this unnecessarily limits demand signal (control demand or control target/request) and therefore slightly lowers overall performance of FRP, so this approach is deprecated and not investigated further within the project. The demand signals, either based on control target/request approach, are then optimized by CAF and each TSO receives a signal with information which bids were activated and for how much. This information is then forwarded by the TSO's Signal forwarding function of LFC to selected BSPs. At the same time, correction in the amount of cross border activated aFRR is added to connecting TSO's ACE to "counteract" effect of locally activated aFRR for other TSOs.

Control diagram of described cross border aFRR activation integration approach is shown in Figure 14.

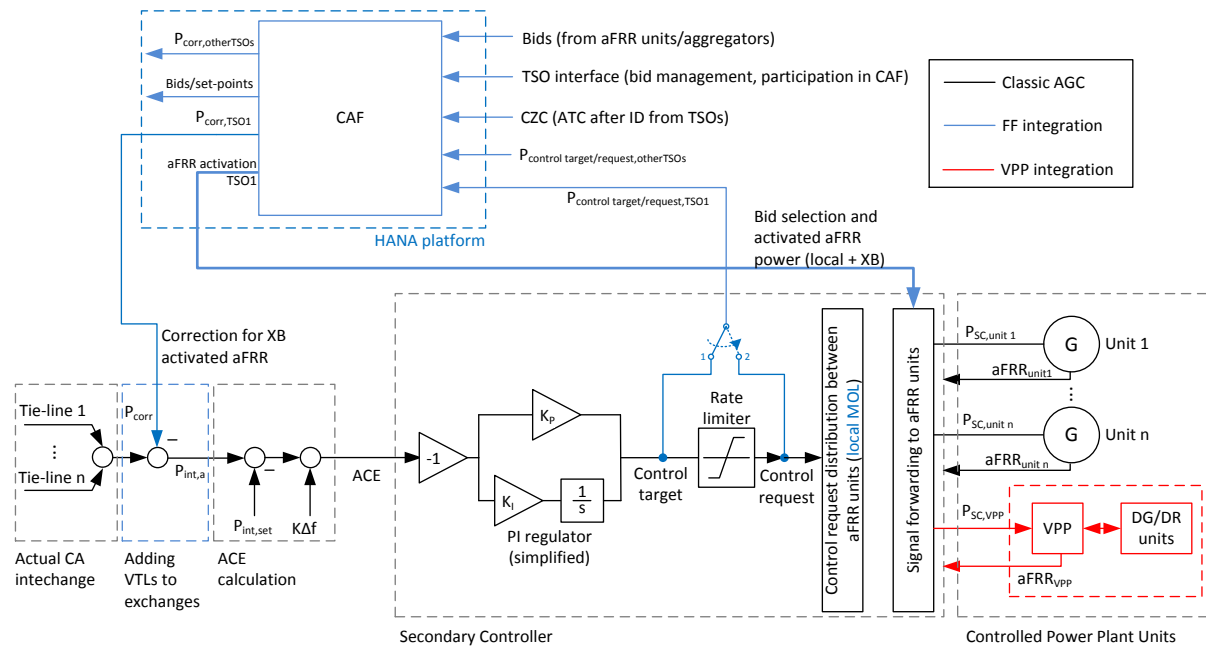


Figure 14: Possible control diagram for aFRR cross border implementation with aFRR activation demand based on control target/request

The main advantage of this approach is that same volumes are activated between CAF and TSO and between connecting TSO and its local aFRR units as CAF activated power is directly distributed to aFRR units.

Demand signals (control demand or control target/request) from TSOs are expected to be less volatile than for control demand approach as filtered signals from PI controller output are used, therefore optimization in CAF could benefit from previous cycle solution and resulting correction signal from CAF might be less volatile ensuring more stable aFRR activation.

The main downside of this approach is that the output of local controller's distribution function isn't connected to signal forwarding function anymore. In case the connection with CAF is lost,

controller cannot simply continue to operate and only solution is that controller structure is changed so local distribution function with local MOL is rerouted to signal forwarding function. Additionally, controller internal variables have to be reseted or adapted. For such occasions, a reliable and fully automated back-up procedure is needed.

Potential downside of this approach is also risk that control request netting is not as efficient as control demand netting, therefore additional control demand netting optimization cycle (so called pre-netting, which would be the same for control target/request netting optimization) might be needed for this approach prior entering cross border aFRR activation optimization. Due to possible undesired cross-influences of both consequent cross border netting/aFRR activation optimizations, undesired consequences might occur, what needs to be checked and confirmed or rejected by the simulations and/or practical testing.

What can also be considered as a drawback is that this approach, although now widely discussed in various ENTSO-E groups and pilot models, has not yet been implemented on field. Therefore, stability of overall control loop is not confirmed yet and extensive additional simulations are needed to prove the concept is reliable enough to work on field.

Ramp rating of aFRR exchange (Continuous activation)

Ramp rating of cross border aFRR exchange is controversial and highly debated topic between TSOs. Ramp rate limiting is not favoured by TSOs of control areas with stepwise activation of control units and control areas with fast aFRR providing units. For such control areas, ramp rate limited cross border exchanges can worsen ACE performance when external BSP activation is exchanged on cross-border instead of local activation. On the other hand, control areas with slower units, usually cheaper than the faster ones, argue, that ramp rates are necessary, otherwise ACE performance of reserve connecting TSO with cheaper units can be decreased considerably. Both FutureFlow integration approaches (control demand approach and control target/request approach) described above can be implemented considering ramp rates or not (stepwise or continuous activation). For the first approach, the “natural” way is not to include any ramp rates, especially if imbalance netting is integrated. Theoretically it is possible to design CAF in such a way it would not limit imbalance netting part, but only aFRR balancing energy exchange part. For the control target approach, the more natural way is to consider ramp rates of units in that control area. If both correction signal and activation signals sent to aFRR units are respecting ramp rates of local aFRR units, this considerably reduce transfer of imbalances from one TSO to another TSO as in case of control demand approach. Without following ramp rates, control request approach exhibits similar ACE performance issues as the control demand approach.

Some TSOs, members of FutureFlow project, are of a general opinion that cross-border exchange of aFRR activation should be limited to ramp rate(s) defined by the ramp rate of the standard product(s) used for exchange of the aFRR energy. Thus, both economic and technical objectives of cross border aFRR exchange could be pursued, i.e. economic optimization and reduction of costs for end consumers, and not deteriorating the ACE quality of reserve connecting TSOs beyond the acceptable level defined by the standard products.

Definition of simulation cases

To conclude, FutureFlow members are currently unable to define the best approach for FutureFlow cross border aFRR balancing energy exchange integration into FutureFlow Demo site. On one hand, already field proven solution using control demand approach is available, however it does have considerable drawback that it can, especially in conjunction with stepwise activation, increase deviations of control areas with cheaper (slower) aFRR providing units. On the other hand, second, not yet field proven control target/request approach, can reduce those effects by following individual units' ramp rates, however this might slightly decrease performance of control areas with fast local units in case of cross border aFRR balancing energy exchange. The agreed solution was to numerically simulate different options of LFC integration and CAF implementations using real-life data time series and monitor all theoretically defined drawbacks of different combinations. The following integration approaches/CAF designs are proposed to be simulated:

Table 8: Proposed integrating approaches and CAF designs to be simulated

Integration approach	Border constraints (ATC, FB)	Pre-netting	Products	Ramp rate limiting
Control demand	ATC	No	Standard	Yes
				No
	FB	No	Standard	No
Control request	ATC	No	Standard+ Specific	Yes
				No
			Standard	Yes
		Yes	Standard	No
	FB	No	Standard	No

Based on extensive numerical analysis of results and if necessary also field tests, FutureFlow members will finally decide which is the target solution for cross border aFRR activation integration into LFC.

3.7 CAF design: algorithm

3.7.1 Mathematical model

The mathematical formulation is given for the option 1, i.e. control demand integration approach with standard product, supporting both ATC and flow-based network representation.

Within the Task 1.5, simulation and optimization tool will be fully developed with features to test also remaining simulation cases (i.e. Option 2, and usage of standard & specific product).

Upon the analysis of simulations results, final recommendation will be provided for target solution algorithm(s).

- **Algorithm objective**

The aim of the algorithm is to perform optimal bid selection for aFRR activation from the FF common merit order list. Selected combination of bids must fulfil the aFRR needs of TSOs in FF cooperation, with objective to maximize social economic welfare under defined operational and cross border exchange constraints. Maximization of social economic welfare in this case is achieved by minimization of costs for aFRR balancing energy, therefore optimization function is defined as least-cost objective function for each calculation cycle:

$$\min_{\Delta q_{ik}^{\text{up}}, \Delta q_{ik}^{\text{down}}} \left\{ \sum_{i=1}^{n_{CA}} \sum_{k=1}^{B_i^{\text{up}}} c_{ik}^{\text{up}} \Delta q_{ik}^{\text{up}} - \sum_{i=1}^{n_{CA}} \sum_{k=1}^{B_i^{\text{down}}} c_{ik}^{\text{down}} \Delta q_{ik}^{\text{down}} \right\}$$

Where:

n_{CA} - is a total number of control areas;

$i=1, 2, \dots, n_{CA}$ representing each control area.

$k=1, 2, \dots, B_i^{\text{up}}$ representing each bid within control area i .

$B_i^{\text{up}}, B_i^{\text{down}}$ - total number of upward and downward energy bids in i^{th} control area, respectively;

$\Delta q_{ik}^{\text{up}}, \Delta q_{ik}^{\text{down}}$ – optimized/selected quantity of upward and downward aFRR balancing energy bids in i^{th} control area, respectively;

$c_{ik}^{\text{up}}, c_{ik}^{\text{down}}$ – submitted price of upward and downward aFRR balancing energy bids in i^{th} control area, respectively;

P_l – cross border energy exchange (aFRR related) over border l . It could be both positive and negative, with positive sign defining the flow in reference direction³

Agreed FF target model sign convention for the bid price defines that:

- positive price value for upward bids and negative price value for downward bids refer to request of TSO to BSP payment;
- positive price value for downward bids refer to request of BSP to TSO payment.

- **Optimization constraints**

Since bids are defined as divisible (smallest amount is 1 MW), for all aFRR balancing energy bids ("upward" and "downward") lower/upper bounds are determined as (0 means that bid is not activated):

³ If we define border as AT-HU, then positive value of P_l refers to flow from AT to HU, and negative value of P_l refers to flow from HU to AT

$$0 \leq \Delta q_{ik}^{\text{down}} \leq q_{ik}^{\text{down}}$$

$$0 \leq \Delta q_{ik}^{\text{up}} \leq q_{ik}^{\text{up}}$$

Where:

$q_{ik}^{\text{up}}, q_{ik}^{\text{down}}$ – submitted quantity of upward and downward aFRR balancing energy bids in i -th control area, respectively;

Bid selection is performed in such manner that level of outgoing/incoming cross border exchanges through all borders of a control area corresponds to the level of requested export/import of aFRR balancing energy. Therefore, equality constraint for power balance of each control area is defined as:

1. For all control areas $i = 1, 2, \dots, n_{CA}$ are:

$$CD_i + \sum_{k=1}^{B_i^{\text{up}}} \Delta q_{ik}^{\text{up}} - \sum_{k=1}^{B_i^{\text{down}}} \Delta q_{ik}^{\text{down}} = \sum_{\ell \in \Omega_i} P_\ell, \text{ i.e.}$$

$$\sum_{k=1}^{B_i^{\text{up}}} \Delta q_{ik}^{\text{up}} - \sum_{k=1}^{B_i^{\text{down}}} \Delta q_{ik}^{\text{down}} - \sum_{\ell \in \Omega_i} P_\ell = -CD_i$$

2. Also, balance of the whole system in cooperation is defined as:

$$\sum_{i=1}^{n_{CA}} \sum_{k=1}^{B_i^{\text{up}}} \Delta q_{ik}^{\text{up}} - \sum_{i=1}^{n_{CA}} \sum_{k=1}^{B_i^{\text{down}}} \Delta q_{ik}^{\text{down}} = - \sum_{i=1}^{n_{CA}} (CD)_i$$

Where:

CD_i - is a control demand of in i^{th} control area (positive value represents demand for balancing in downward direction from the aspect of requesting TSO, and negative value represents demand for balancing in upward direction from the aspect of requesting TSO);

Ω_i - is set of borders/CZCs of the i^{th} control area with neighbouring areas, i.e. $\sum_{\ell \in \Omega_i} P_\ell$ represents a sum of outgoing/incoming cross border exchanges over all borders of control area i .

Each cross border exchange must meet the network limits (CZCs), therefore inequality network constraints are defined.

ATC-based constraints

In the case that CZCs are defined with ATC values for each border and direction, lower/upper bounds for energy flow (P_ℓ) are defined as:

$$-ATC_\ell^{\text{a.f}} \leq P_\ell \leq ATC_\ell^{\text{w.f}}; \ell = 1, 2, \dots, m_\ell$$

Where:

$ATC_\ell^{\text{w.f}}, ATC_\ell^{\text{a.f}}$ – defined ATC values for border l and directions respectively;

m_l – is total number of borders.

Flow-based constraints

In case of aFRR balancing energy exchange with flow-based network parameters, network constraints are defined with PTDF matrix and Remaining Available Margin (RAM) related to the pairs of critical branches/critical outages (cbco):

$$-RAM_{cbco}^{a.f} \leq \sum_{\substack{i=1 \\ i \neq ref}}^{n_{CA}} PTDF_{cbco}^{i \rightarrow ref} \times NEX_{cbco}^i \leq RAM_{cbco}^{w.f}; cbco = 1, 2, \dots, m_c \text{ i.e.}$$

$$-RAM_{cbco}^{a.f} \leq \sum_{\substack{i=1 \\ i \neq ref}}^{n_{CA}} PTDF_{cbco}^{i \rightarrow ref} \times \left(CD_i + \sum_{k=1}^{B_i^{up}} \Delta q_{ik}^{up} - \sum_{k=1}^{B_i^{down}} \Delta q_{ik}^{down} \right) \leq RAM_{cbco}^{w.f}$$

Where:

$RAM_{cbco}^{w.f}, RAM_{cbco}^{a.f}$ – defined RAM values for monitored critical branches and respective critical outage in both directions respectively;

$PTDF_{cbco}^{i \rightarrow ref}$ – power distribution factor on critical branch cb (paired with critical outage co) for the exchange between control area i and the reference area ref ;

NEX_{cbco}^i – net exchange of control area i and co network topology;

m_c – is total number of cb/co pairs.

A computer program CAFX has been developed according to the mathematical description of Common Activation Function in previous subchapter. The program is written in Python 2 computer language. It currently uses a freeware library Gnu Linear Programming Kit GLPK to perform the optimisation. In addition, an internet platform CAFX (in Python 3) <https://futureflow.eimv.si/futureflow> has been established enabling program access to selected FutureFlow participants thus facilitating program testing, data sharing, etc.

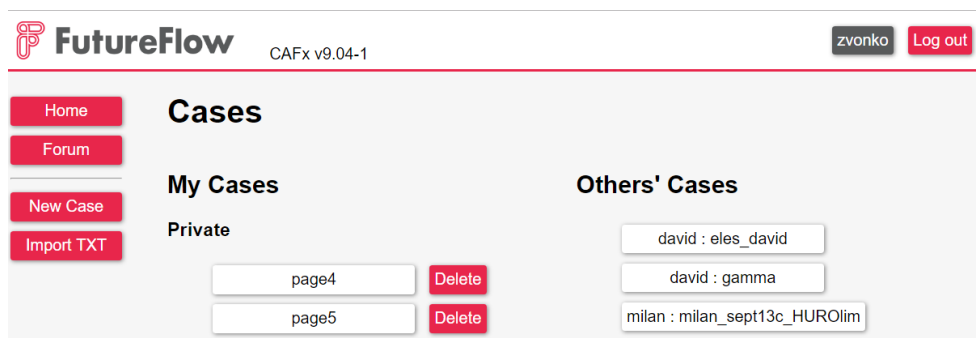


Figure 15: CAFX screen illustration

The current CAFX usage will be presented in following subchapters with two examples illustrative of one activation cycle optimization. The simulation tool will be further developed and finalized for all cases simulation runs under the Task 1.5.

- **Example 1**

Four FutureFlow zones of Slovenia (SI), Austria (AT), Hungary (HU) and Romania (RO) and four interconnections between them (SI-AT, SI-HU, AT-HU AND HU-RO) are presented when using the internet CAFX computer program. Although currently there is no electrical border (interconnection) between Hungary and Slovenia, the planned new connection between them is inserted in the model, in order for program to work with more general network case, i.e. with a part of network being meshed, which is not the current situation (SI-AT-HU-RO form a radial connection). With such setup, the radial case simulation is also easily applicable, with user only needed to defined ATC value of zero for SI-HU border in both directions.

In the example 1, all four interconnections have a limit of 100 MW in both directions:

Zone 1	Zone 2	Capacity 1 → 2 [MW]	Capacity 2 → 1 [MW]
si	at	100	100
si	hu	100	100
at	hu	100	100
hu	ro	100	100

Figure 16: CAFX screen: ATC values input

Interconnection is deleted by using the 'X' button on the right. A new interconnection is introduced simply with a '+' button in the bottom line.

The control demand and bids input for the considered zones is presented in the following screen shot:

The figure shows four separate windows for zones SI, AT, HU, and RO. Each window displays the 'CAF Input [MW]' and 'FAT [min]' values. Below this, there is a table of bids with columns for Seller, Selling [MW], Price [€/MWh], and FAT [min].

Zone	CAF Input [MW]	FAT [min]	Seller	Selling [MW]	Price [€/MWh]	FAT [min]
SI	-200	5				
AT	0	5	bi1	50	20	5
AT	0	5	bi2	100	80	5
AT	0	5	bi3	100	50	5
HU	0	5	bi4	210	40	5
RO	-150	5	bi5	200	60	5

Figure 17: CAFX screen: Control demand & bids input

There are three bids in (AT) zone, one in (HU) zone, one in (RO) zone and no balancing bid in (SI) zone. All bids are Standard product having FAT equal to 5 min. The cheapest bid is bid1 in (AT) zone at 20 €/MWh and the most expensive bid is bid2 in (AT) zone at 80 €/MWh.

All four zones accept only the Standard products with defined FAT of 5 min. The control demand values (labeled as 'CAF Input [MW]') at (SI), (AT), (HU) and (RO) zones amount to:

-200 0 0 -150

respectively. Since all control demands have the same sign, there can be no imbalance netting.

For better readability the CAFX internet platform presents the results only for (SI) and (RO) zones, since only those two zones had non-negative ACE-s (labeled as 'CAF Output [MW]' here). The optimal value amounts to 14400 €.

si			ro		
CAF Output [MW]:		-200.0	CAF Output [MW]:		-150.0
From Zone	Unit	Solution [MW]	From Zone	Unit	Solution [MW]
hu	bi4	200.0	at	bi1	50.0
			hu	bi4	10.0
			at	bi3	40.0
			ro	bi5	50.0

Figure 18: CAFX screen: Results output

The solution managed to include the cheapest bid bid1 from (AT) zone and the second cheapest bid bid4 from (HU) zone to their maximal bidding values 50 MW and 210 MW respectively. Bid4 (RO), although more expensive than bid3 (AT) is partially activated since the flow on HU→RO border reaches defined ATC, i.e. causing the market congestion on HU-RO border.

- Example 2**

In example 2, current situation, with three radial interconnections is analyzed.

Zone 1	Zone 2	Capacity 1 → 2 [MW]	Capacity 2 → 1 [MW]	Price 1 → 2 [€/MWh]	Price 2 → 1 [€/MWh]	
si	at	100	100	0,0	0,0	✕
at	hu	70	70	0,0	0,0	✕
hu	ro	70	70	0,0	0,0	✕
+						

Figure 19: CAFX screen: ATC values input – example 2

The control demand values for (SI), (AT), (HU) and (RO) zones amount to:

-100 0 100 -100

respectively. All bids are for balancing energy in the upward direction, except of bid4 (HU) that is defined with downward bid (as indicated by its negative sign⁴).

⁴ In CAFX, negative bids define downward direction.

si				FAT [min]:	5	x
CAF Input [MW]:				-100		
Seller	Selling [MW]	Price [€/MWh]	FAT [min]			x
bi1	100	50	5			x
bi2	100	150	5			x
					+	

at				FAT [min]:	5	x
CAF Input [MW]:				0		
Seller	Selling [MW]	Price [€/MWh]	FAT [min]			x
bi3	100	30	5			x
					+	

hu				FAT [min]:	5	x
CAF Input [MW]:				100		
Seller	Selling [MW]	Price [€/MWh]	FAT [min]			x
bi4	-100	5	5			x
					+	

ro				FAT [min]:	5	x
CAF Input [MW]:				-100		
Seller	Selling [MW]	Price [€/MWh]	FAT [min]			x
bi5	100	40	5			x
					+	

Figure 20: CAFX screen: Control demand & bids input – example 2

Since the control demands have different signs this time, the imbalance netting⁵ can be performed yielding the following distribution of new control demands:

-50 0 0 -50

The total netted value was 100 MW from (HU) zone: 50 MW to (RO) zone and 50 MW to (SI) zone through (AT) zone. Control demand of (HU) zone has been thus reduced to 0 MW making the only upward activation request to remain. Bids 3 (AT) and 5 (RO) are activated again in respect to CZC limitations (although cheaper bid3 cannot be fully activated due to market congestion on HU-RO border). The optimal value of objective function is 3300 €.

si		
CAF Output [MW]:		-50.0
From Zone	Unit	Solution [MW]
at	bi3	50.0

ro		
CAF Output [MW]:		-50.0
From Zone	Unit	Solution [MW]
at	bi3	20.0
ro	bi5	30.0

Figure 21: CAFX screen: Results output

⁵ Note that there is no two separate steps (imbalance netting and afterwards aFRR activation); Imbalance netting effect is embedded within the optimization, simultaneously with aFRR activation. The example explains imbalance netting and aFRR activation separately, for better understanding of results.

3.8 Settlement

2. Imbalance settlement period

Current imbalance settlement period in Slovenian and Romanian balancing market is 1h, and in Hungarian and Austrian it is 15 minutes. The lower imbalance settlement period of 15 minutes influence lower probability of imbalance occurrence in both directions and possibility for more efficient allocation of imbalance costs to BRPs.

Common proposal for FutureFlow target model is ISP of 15 minutes, which also represents a recommendation from the ACER.

3. Principles of balancing energy settlement

Each TSO within cooperation will settle the activated aFRR balancing energy with the BSPs connected at the TSO's control area, independently where a certain volume of control energy is requested. The energy volumes relevant to the remuneration of deployed aFRR balancing energy will be calculated for each bid of each BSP and for each imbalance settlement period, i.e. quarter of an hour. Separated settlement of upward and downward activation will be implemented. For each BSP, only one TSO will be responsible for settlement and accounting (connecting TSO).

4. Pricing

Two options, marginal pricing and pay-as-bid pricing, are analysed for FutureFlow pricing mechanism of activated aFRR balancing energy.

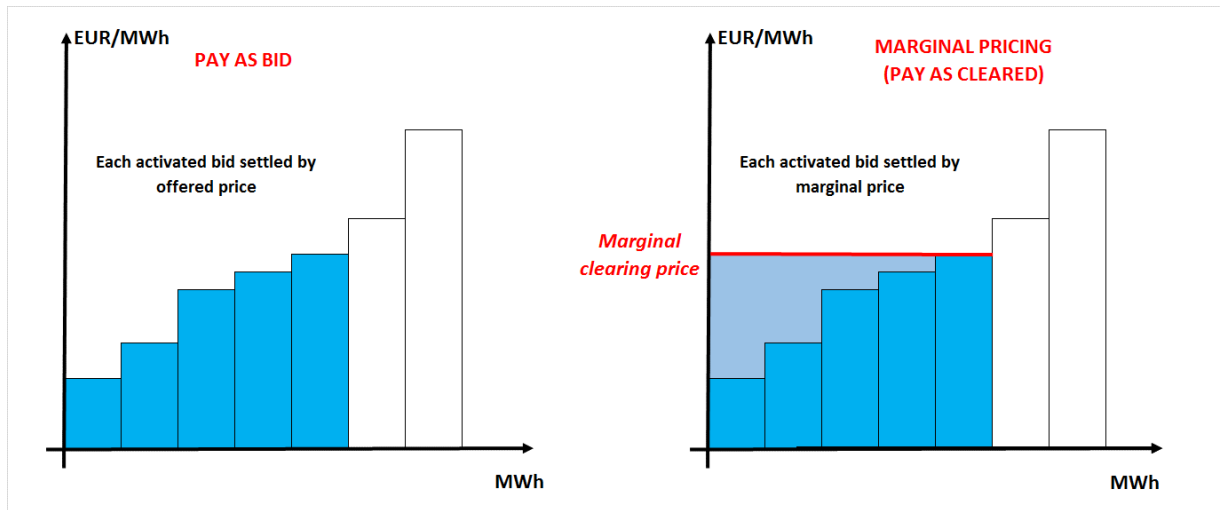


Figure 22 – Pricing mechanisms: pay-as-bid & marginal pricing

The rationality of implementing pay-as-bid system is that in some extent, it should shield the TSOs against occurrence of excessive balancing energy costs in highly concentrated markets with low level of competition. On the other hand, if sufficient competition is present, marginal pricing produces numerous potential benefits:

- incentives for participants to bid at short run marginal costs

6. more efficient dispatch
7. it is easier to prepare bids and therefore better for smaller providers (DR & DG)
8. Provides stronger incentives to BSPs to invest in balancing capacity and BRPs to be balanced/support the system balance

Currently, Austria, Hungary and Slovenia apply pay-as-bid method, while Romania uses marginal pricing. The EB GL refers to that all TSOs shall harmonise their pricing methods. It also defines that mechanism shall be based on marginal pricing (pay-as-cleared), unless TSOs complement the proposal with a detailed analysis demonstrating that a different pricing method is more efficient for European-wide implementation.

Current working assumption within the FutureFlow market design is implementation of marginal pricing. This proposal is in line with EB GL recommendation and it incentivises higher level of participation for DRs & DGs. Also, in case there is market liquidity, creation of regional aFRR balancing energy exchange cooperation will benefit increase of competition and decrease of possible exercise of market power.

However, within the project simulations (Task 1.5) and pilot tests impact analysis (WP6), more detailed quantitative analysis will follow, that will, among other relevant topics, examine the market impact of introduction of marginal pricing compared to pay as bid system. If simulations indicate that market concentration is high and that balancing costs will be significantly impacted with introduction of marginal pricing for TSOs which didn't apply marginal pricing, pay-as-bid method will be considered as alternative for final recommendation.

9. Inter TSO Settlement & pricing

Beside remuneration of aFRR providers for activated balancing energy (i.e. TSO-BSP settlement), FutureFlow market design defines also the TSO-TSO settlement for cross border exchange of balancing energy. Cross zonal marginal pricing will be used as a pricing mechanism, with the most expensive bid activated in a non-congested area determining the price within all zones in this non-congested area.

Payment flow between the TSOs is defined by the difference of:

- target costs of the each TSO: based on the TSO required⁶ quantity of upward & downward aFRR balancing energy within 15 minutes accounting period, and separate marginal price (pay-as-cleared) for upward & downward aFRR balancing energy within the same settlement period
- actual costs which arise in each TSO's control area: actual costs of activated upward & downward aFRR balancing energy within 15 minutes settlement period within the TSO control area (i.e. due to the "connecting TSO" principle, in each control area, BSPs can be activated both for the needs of the local TSO, as well as

⁶ The required quantity (requested/metered/hybrid) will be determined in correlation with FF target model of CAF integration into national LFC mechanism

for the cross border exchange, which produces the difference between actual and target costs).

This difference, defines compensation payments that each TSO has to settle or receive.

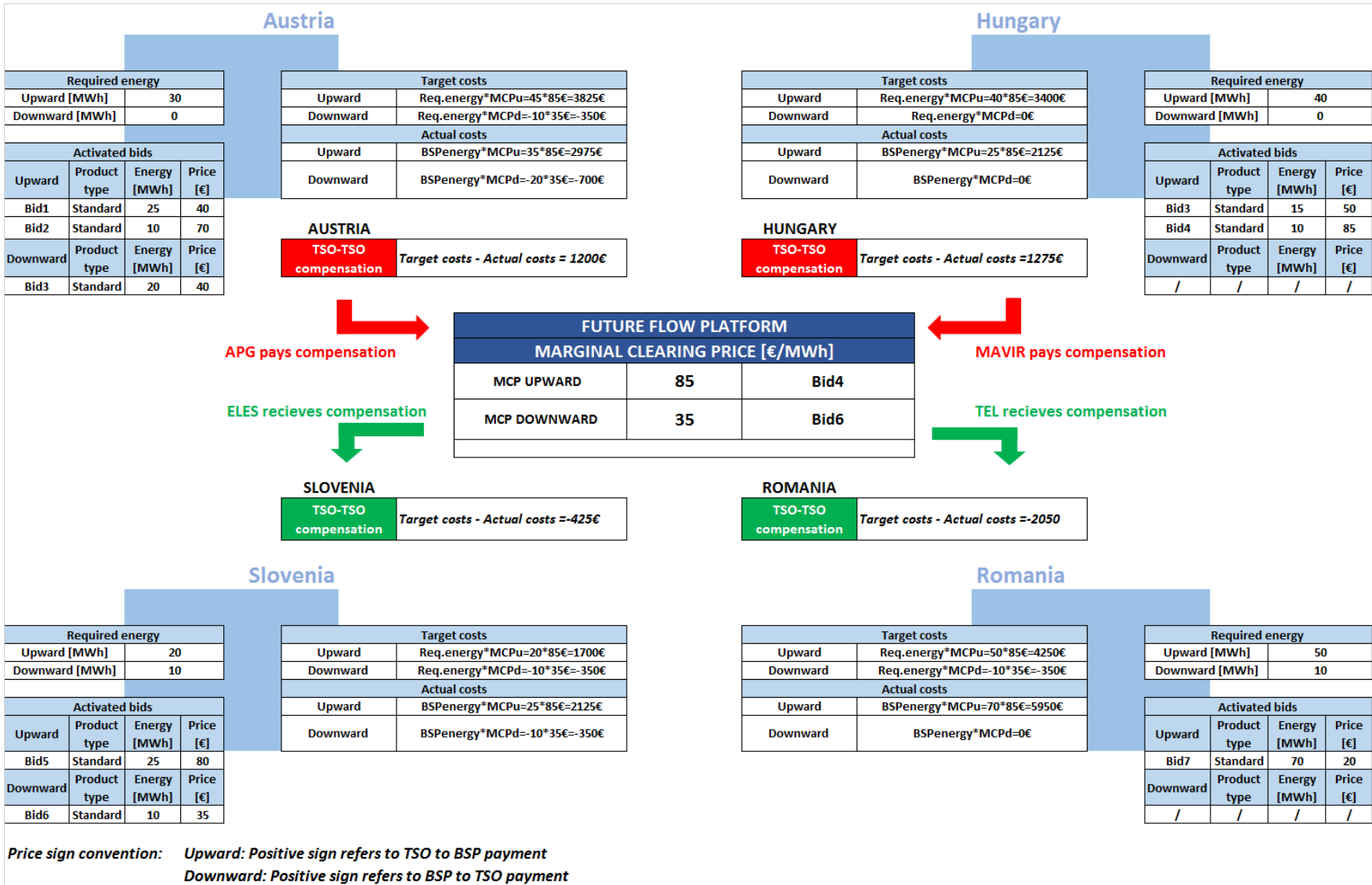


Figure 23 – Example of TSO-TSO settlement & pricing

In Figure 23, the demonstration case of inter TSO settlement & pricing is given:

- In the first step, on the basis of activated aFRR bids, marginal clearing price (MCP) is determined. For analysed case, upward **Bid₄** (located in Hungary) and downward **Bid₆** (located in Slovenia) define upward MCP of 85€/MWh and downward MCP of 35€/MWh.
- In the second step, for each TSO, target costs are calculated for both direction, as a product of marginal clearing price (MCP) and required energy (RE); e.g. for Austria (APG) target costs (TC) are calculated as:

$$\begin{aligned}
 TC(AT) &= TC_{up}(AT) - TC_{down}(AT) \\
 &= RE_{up}(AT) \times MCP_{up} - RE_{down}(AT) \times MCP_{up} = 3475\text{€}
 \end{aligned}$$

- In the third step, for each TSO, actual costs are calculated for both direction, as a product of marginal clearing price and activated energy (for both local TSO control demand, as well as for the cross border exchange of aFRR); e.g. for Austria (APG) actual costs (AC) are calculated as:

$$\begin{aligned}
 AC(AT) &= AC_{up}(AT) - AC_{down}(AT) \\
 &= (Bid_1 + Bid_2) \times MCP_{up} - Bid_3 \times MCP_{up} = 2275\text{€}
 \end{aligned}$$

- In the fourth and final step, for each TSO, compensation payment is calculated as a difference of target costs and actual costs (positive sign defines that TSO is required to pay, and negative sign defines that TSO shall be paid); e.g. for Austria (APG) compensation payment (CP) is calculated as:

$$CP(AT) = TC(AT) - AC(AT) = 1200\text{€}$$

It can be concluded that, compensation payment is positive for APG, i.e. APG is required to pay to the other TSOs. This amount represents the costs of overall APG cross border aFRR balancing energy exchange.

The above analysed cases assume marginal pricing as pricing mechanism in FutureFlow concept, as previously described. As previously mentioned, if the results of simulations and pilot tests indicate that pay-as-bid method for energy pricing will be more beneficial for the FutureFlow cooperation (due to the potential lack of market competition), TSO – TSO settlement will be still done on the same principles, with only difference in calculation of target and actual costs. In case of the pay-as-bid pricing mechanism, target and actual costs will be calculated not on the basis of marginal price, but on the basis of prices of accepted bids.

In case there is no exchange of aFRR balancing energy within settlement period between one control area with other control areas (due to unavailability of CZC; control demand satisfied from local units activation, etc.), the target and actual costs are equal for that TSO. In this case also, marginal price of that control area is determined by the most expensive activated local unit.

Besides the market design with only standard products, FutureFlow will also examine the potential hybrid solution that assumes existence of both standard and specific products, with standard products of 5 minutes FAT being eligible for all involved TSOs and specific products of 15 minutes FAT being eligible for Hungary, Slovenia and Romania, but not for Austria. Differences in method for TSO – TSO settlement & pricing between the hybrid solution and the option with only standard products include:

- On the basis of activated aFRR bids, marginal clearing price (MCP) is determined for both standard and specific products
- Target costs of each TSO are calculated separately for required energy from standard bids and required energy from specific bids. For the APG, all target costs are related to only standard bids activation, with target costs related to specific bids being equal to zero. For the each of the other TSOs, required energy from specific bids is determined as a product of sum of all activated energy from specific bids and share of required energy of that TSO in total required energy of all TSOs, excluding APG. Required energy from standard bids of these TSOs (all but APG), is then calculated as a difference between the required energy of each TSO and required energy from specific bids.
- Actual costs of each TSO are calculated in the same manner as before, with only difference that activated bids depending of the product type, are multiplied by either marginal price of standard or specific products.

In Figure 23, the demonstration case of TSO-TSO settlement & pricing for hybrid solution is provided. Following the above explained principles of hybrid solution pricing, step by step analysis for the demonstration case and example of one control area (e.g. Hungary/MAVIR) is provided:

- Step 1: Marginal clearing prices (MCP) are determined for the standard and specific product: **Bid1** (located in Austria) defines MCP of 60€/MWh for upward standard products, **Bid3** (located in Slovenia) defines MCP of 42€/MWh for upward specific products and downward **Bid5** (located in Romania) defines MCP of 10€/MWh for downward specific products. Downward standard products were not activated within analysed case.
- Step 2: Target costs (TC) of the control area are calculated as:

$$TC(HU) = TC_{up}(HU) - TC_{down}(HU)$$

Where TC_{up} represents target costs associated to upward direction, defined as a function of required energy from standard and specific bids (RE_{upst}, RE_{upsp}), as well as marginal clearing prices for standard and specific bids (MCP_{upst}, MCP_{upsp}) and activated balancing energy from standard and specific bids (BE_{upsp}, BE_{upst}):

$$\begin{aligned}
 RE_{upsp}(HU) &= \frac{RE_{up}(HU)}{RE_{up}(HU)+RE_{up}(RO)+RE_{up}(SI)} \times (BE_{upsp}(HU) + BE_{upsp}(RO) + BE_{upsp}(SI)) \\
 &= \frac{30MWh}{30MWh+30MWh+15MWh} \times (18MWh + 0MWh + 32MWh) = 20MWh
 \end{aligned}$$

$$RE_{up_{st}}(HU) = RE_{up}(HU) - RE_{up_{sp}}(HU) = 30MWh - 20MWh = 10MWh$$

$$TC_{up}(HU) = TC_{up_{st}}(HU) + TC_{up_{sp}}(HU) = RE_{up_{st}}(HU) \times MCP_{up_{st}} + RE_{up_{sp}}(HU) \times MCP_{up_{sp}}$$

$$= 10MWh \times 60 \frac{\text{€}}{MWh} + 20MWh \times 42 \frac{\text{€}}{MWh} = 1440\text{€}$$

Since target costs associated to downward activation (TC_{down}), calculated on the same method as TC_{up} are zero (no downward aFRR energy required by MAVIR), total target costs TC are equal to upward target costs TC_{up} .

- Step 3: Actual costs (AC) of the control area are calculated as:

$$AC(HU) = AC_{up}(HU) - AC_{down}(HU)$$

Where AC_{up} represents actual costs associated to upward direction, defined as a sum of product of standard bids marginal clearing price ($MCP_{up_{st}}$) and activated aFRR balancing energy ($BE_{up_{st}}$) and specific bids marginal clearing price ($MCP_{up_{sp}}$) and activated aFRR balancing energy ($BE_{up_{sp}}$)

$$AC_{up}(HU) = AC_{up_{st}}(HU) + AC_{up_{sp}}(HU) = BE_{up_{st}}(HU) \times MCP_{up_{st}} + BE_{up_{sp}}(HU) \times MCP_{up_{sp}}$$

$$= 0MWh \times 60 \frac{\text{€}}{MWh} + 18MWh \times 42 \frac{\text{€}}{MWh} = 756\text{€}$$

Since actual costs associated to downward activation (AC_{down}), calculated on the same method as AC_{up} are zero (no downward aFRR energy activation in MAVIR control area), total actual costs AC are equal to upward actual costs TC_{up} .

- Step 4: The compensation payment (CP) is calculated as a difference of target costs and actual costs (positive sign defines that TSO is required to pay, and negative sign defines that TSO shall be paid):

$$CP(HU) = TC(HU) - AC(HU) = 684\text{€}$$

It can be concluded that, compensation payment is positive for MAVIR, i.e. MAVIR is required to pay to the other TSOs. This amount represents the costs of overall MAVIR cross border aFRR balancing energy exchange.

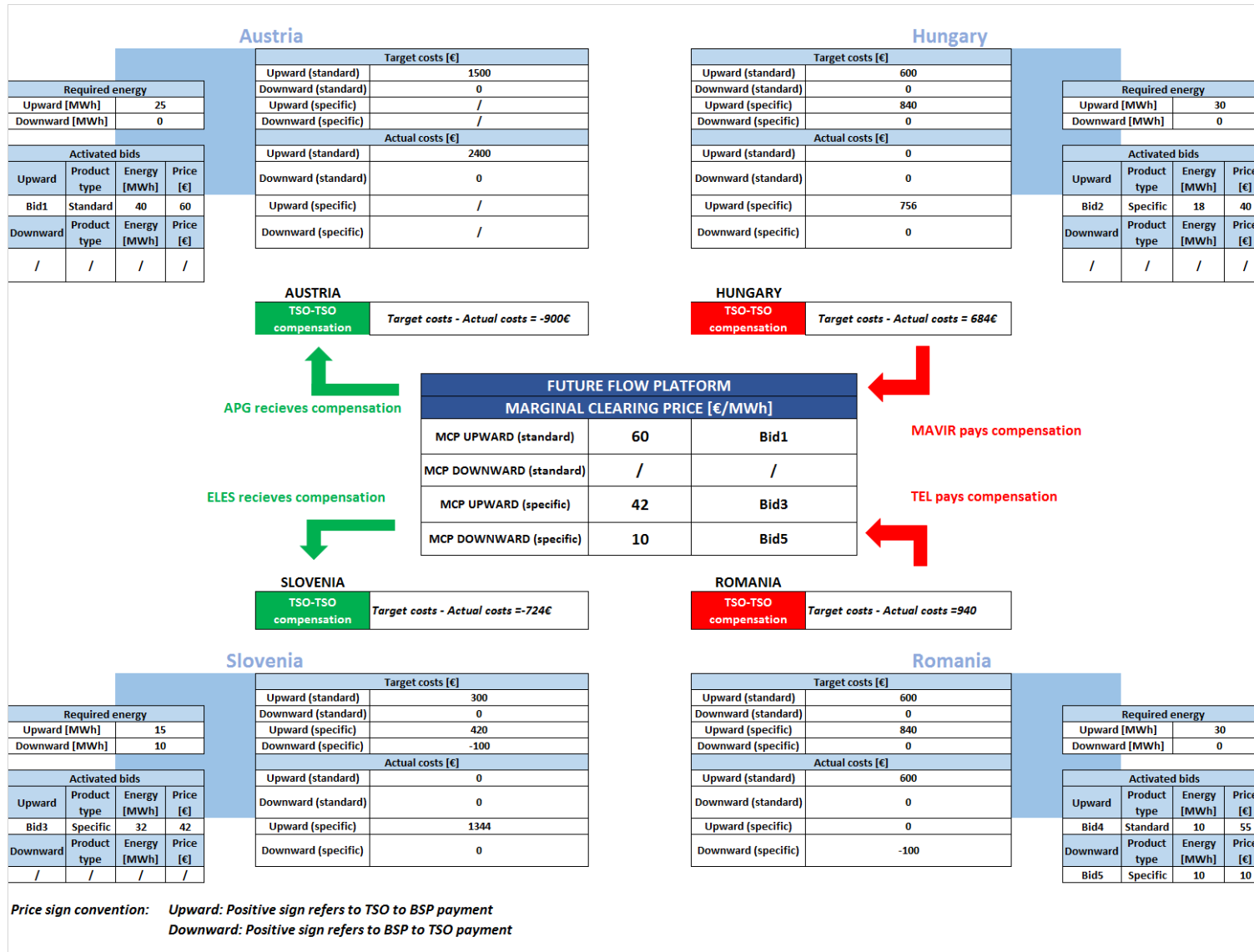


Figure 24 – Example of TSO-TSO settlement & pricing for FF hybrid solution

4 Cross-zonal Capacity for balancing

This Chapter provides the correspondence of FutureFlow cross-border balancing concept with the congested borders situation, as they are among the concerned countries, but also in general among the Continental European bidding zones. The main goals are:

- to explore the current situation and the available cross-border capacities among the concerned countries
- to introduce the ways of ensuring the CZC for aFRR exchange: free capacity after intra-day trade, and eventual capacity reservations
- to introduce the two definitions of Cross-Zonal Capacities (CZC): transaction-based (ATC) and Flow-based (PTDF/ RAM)
- to define the general way of inclusion of the CZC into the CAF algorithm

The existence of free Cross-Zonal Capacity is the essential prerequisite for aFRR exchange; only in periods (hours) when certain portion of CZC is available, the Imbalance Netting and/or aFRR exchange based on Common Merit Order list can take place.

At the same time, FutureFlow concept of aFRR energy exchange is proposed in a way to ensure (i.e. to leave) the self-sustainability of aFRR control at national level, in a similar way Imbalance Netting co-operations are working nowadays: systems are trying to minimize counter-activation of aFRR on regional level in periods when there is an available CZC; when no possibility ($CZC=0$), systems are capable to operate alone.

Sources of CZC available for aFRR energy exchange are:

- CZC unused after the latest commercial cross-border trade (Intra-day), and/or
- Eventual transmission capacity reservations for the balancing purposes, which are allowed according and under the conditions defined in the draft Electricity Balancing Guideline.

4.1 CZC available after Intra-day trade

The power systems of Austria, Slovenia, Hungary and Romania are well-connected with 400 kV and 220 kV links, within the highly-meshed Continental European synchronous area. Currently Slovenia, Hungary and Romania are the bidding zones as well, while Austria is a part of common DE-LU-AT Bidding Zone (Germany-Luxemburg-Austria). The country borders among Austria, Slovenia, Hungary and Romania are at the same time the bidding zones borders. There are three electrical borders among these four countries, SI-AT, AT-HU and HU-RO; in perspective the link SI-HU would be built and then the direct triangle connection SI-AT-HU-SI would exist.



Figure 25 – Austria, Slovenia, Hungary, Romania - interconnected networks

At all three borders, for both directions, currently the ATC-based capacity allocations are performed, at all time horizons. These are mainly Explicit Auctions, performed by some of the TSOs, by JAO or by entity acting as intraday Transmission Capacity Allocator (CEPS); only at the borders Hungary-Romania and Slovenia-Austria (since July 2016) the transmission capacity is implicitly allocated at the day-ahead level. Hungary and Romania are part of 4M ATC-based Market Coupling mechanism, while Slovenia and Austria are within pan-European Multi-Regional Coupling (MRC) mechanism. At intra-day level also First-come-First Served mechanism is applied.

Border:	Yearly		Monthly		Day-ahead		Intra-day	
	Type:	By:	Type:	By:	Type:	By:	Type:	By:
AT<->SI	ATC, E.A.	JAO	ATC, E.A.	JAO	ATC, MC*	MRC	ATC, FCFS	ELES
AT<->HU	ATC, E.A.	JAO	ATC, E.A.	JAO	ATC, E.A.	JAO	ATC, FCFS	CEPS
HU<->RO	ATC, E.A.	MAVIR	ATC, E.A.	MAVIR	ATC, MC	4MC	ATC, E.A.	TEL

E.A. Explicit auction
 FCFS First-come, first served
 MC Market Coupling

* MC since July 2016; examples of allocation results are from the period of explicit auctions (by JAO)

Table 9: Applied transmission capacity allocation mechanisms per time horizons / borders

At all three borders, typical values of transmission capacity in period 2015-2016 are given in the table below, as well as the sample results of year-ahead (2016), month-ahead (Jan-2016) and day-ahead (20-Jan-2016) allocations. For the explicit auctions, the auction price is provided, while for the Market Coupling (4MC at HU-RO at day-ahead) the market clearing price difference is given. Red figures are pointing the prices at the highly congested directions.

Border: Total NTC [≈]	Yearly			Monthly			Day-ahead			Intra-day			
	2016			Jan 2016			20th Jan 2016 - average values for 24 hours						
	MW	ATCy Requests	Price	ATCm Requests	Price	ATCd [≈] Requests [≈]	Price [≈]	ATCd [≈] Requests [≈]	Price [≈]	ATCd [≈] Requests [≈]	Price [≈]		
AT-SI	950	450	1517	10.84	200	741	14	256	1028	4.93	75	0	n/a
SI-AT	950	450	1869	0.03	200	814	0.01	1444	2356	0	1625	0	n/a
AT-HU	800	300	1449	11.1	100	782	14.1	387	1652	2.77	64	3	n/a
HU-AT	800	300	1489	0.05	200	1014	0.02	787	1958	0.05	1136	14	n/a
HU-RO	600	300	981	0.08	240	820	0.02	1027	(4mc)	0	909	2	n/a
RO-HU	650	300	1146	4.04	280	1075	2.3	223	(4mc)	3.6	341	4	n/a

Table 10: Transmission capacity allocations, sample results

Based on these sample results, but also in general on the basis of yearly/monthly/daily allocations at the concerned borders and directions, it can be seen that at certain directions (AT->HU, AT->SI, RO->HU) rather heavy congestions are regularly present.

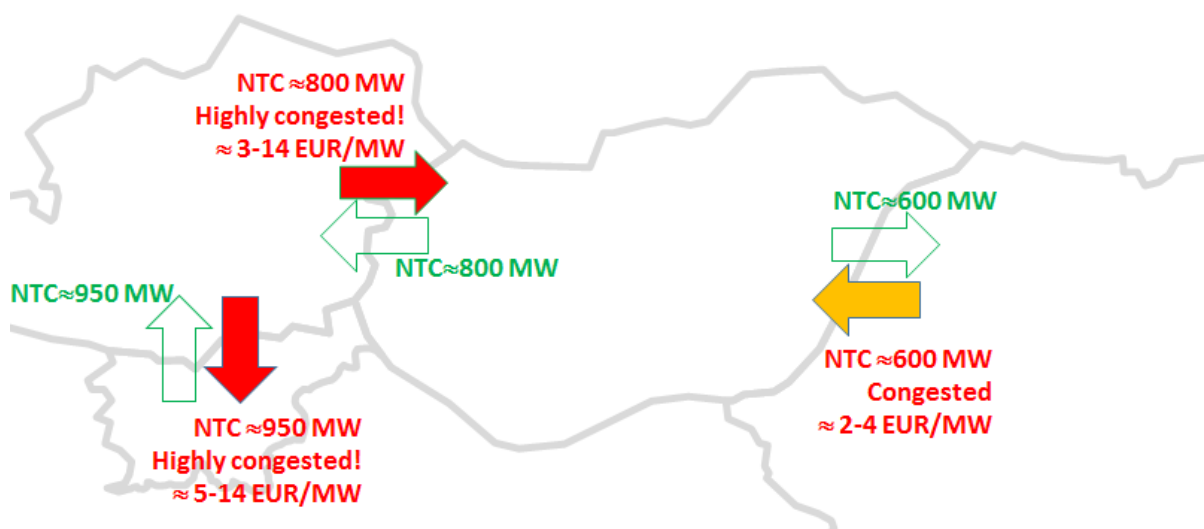


Figure 26 – Year/month/day-ahead allocations, sample results

Based on the above results, it could be expected that at Intra-day level, and after the Intra-day trade, in these directions some free capacity would hardly be left.

However, on the basis of detailed questionnaires filled by the four TSOs, the data in one and a half year period have been analysed (1st January 2015 - 30th June 2016), with the Intra-day transmission capacity allocations and consequential ATC values left after them, which would then become free for cross-border balancing purposes.

These analyses show that at the after-intraday time horizon, substantial capacity stays even in the previously congested directions. Main reasons are:

- after the day-ahead nominations of transmission capacities, not all allocated capacity is being nominated
- after the nominations, the netting of counter-transactions is possible, and it is being applied - which relieves some portion of the capacity

This indicates that notable transmission capacity for balancing purposes exists most of the time, in

both directions at each border. The results are summarized at the following diagrams.

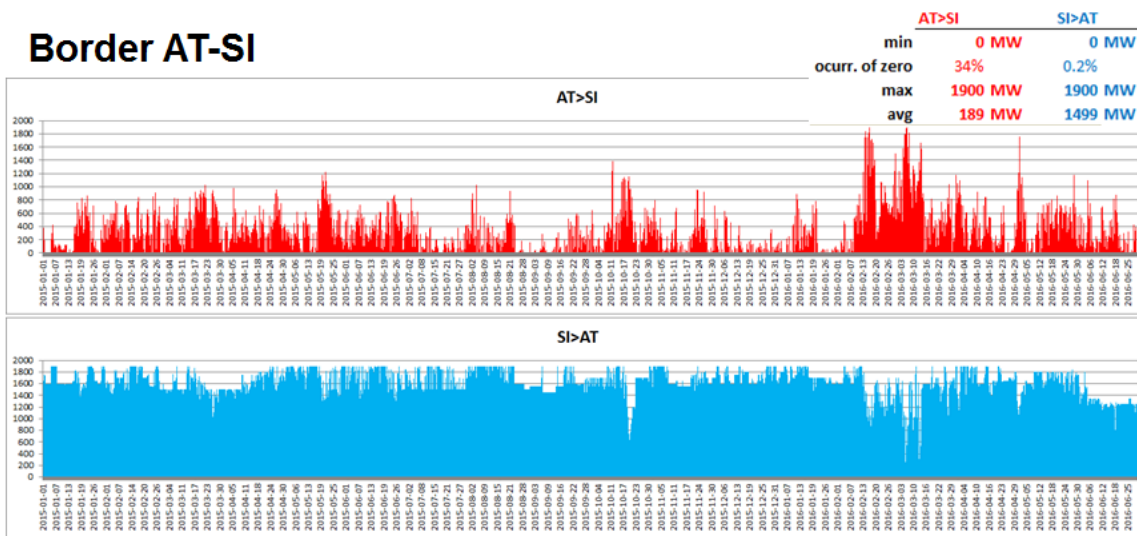


Figure 27 – ATC available after intra-day trade (1.1.2015-30.06.2016), border AT-SI

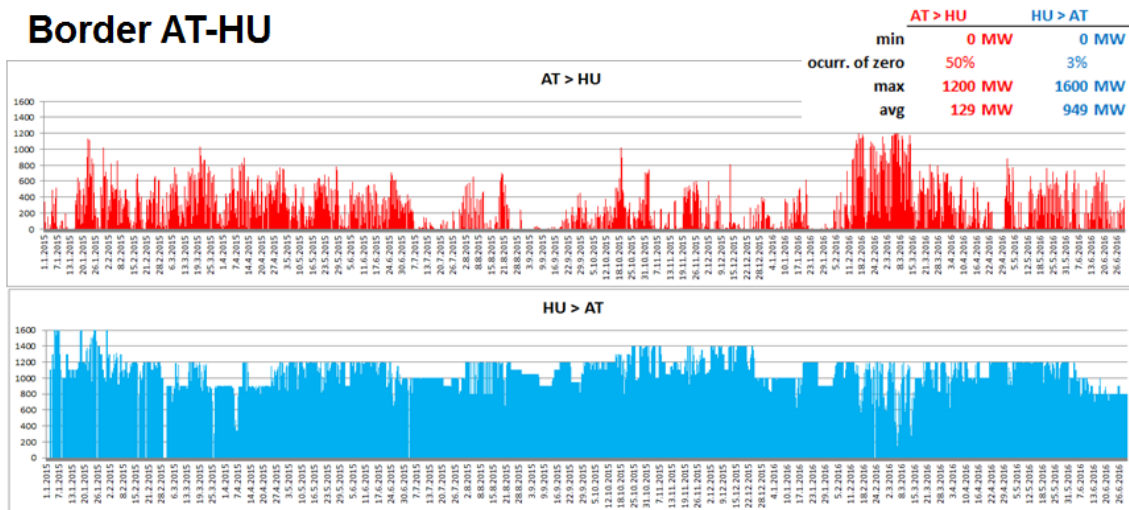


Figure 28 – ATC available after intra-day trade (1.1.2015-30.06.2016), border AT-HU

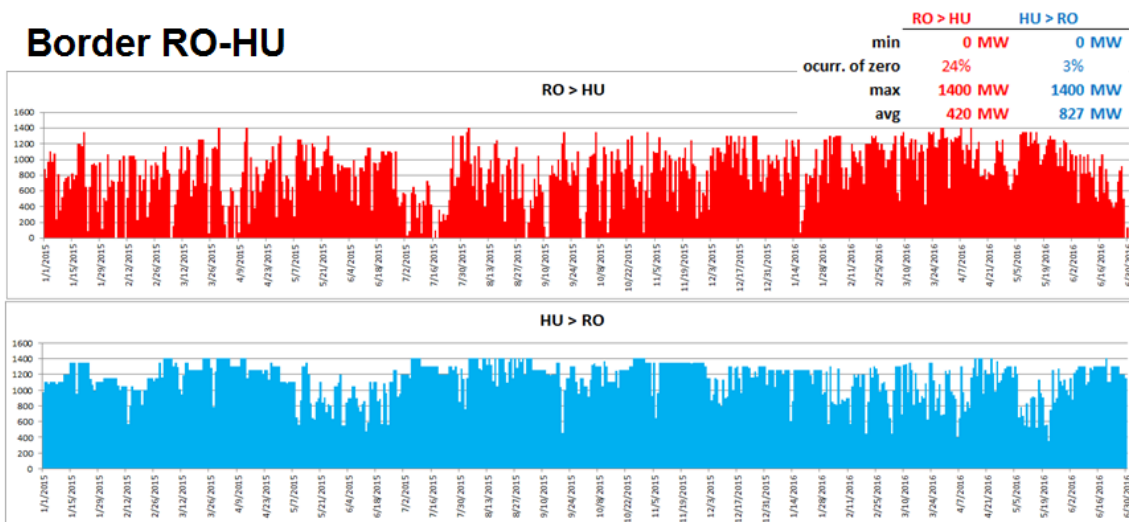


Figure 29 – ATC available after intra-day trade (1.1.2015-30.06.2016), border RO-HU

4.2 Transmission capacity reservations

Reservations of transmission capacity for balancing purposes are allowed according to the draft EB GL, if such reservations would increase the total socio-economic welfare, having in mind that they take the portion of transmission capacity from the commercial cross-border trade.

EB GL recognises the possibility of cross-zonal capacity reservations for the exchange of balancing capacity, while such reservation can be further used for the later exchange of balancing energy. Within the FutureFlow project the exchange of aFRR energy is in focus, therefore the potential CZC reservation will be considered mainly from the effects to the aFRR energy exchange.

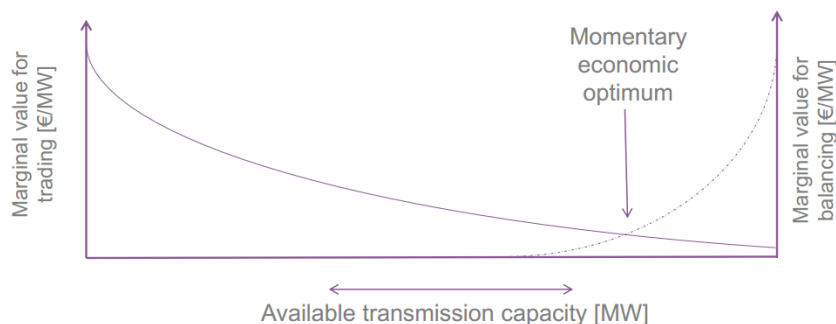


Figure 30 – Transmission capacity reservation: trade-off between CZC used for commercial trade and for balancing (source ENTSO-E Balancing Stakeholder Group)

It is also shown that at the concerned borders within the FutureFlow scope, the significant part of transmission capacity is nowadays free after the Intra-day trade. Nevertheless, it could appear that the reservation of an additional transmission capacity at some profile(s) would increase the total welfare. Here the available reservation methods are briefly explained, as currently given in the Electricity Balancing Guideline, and discussed within ENTSO-E Balancing Stakeholder Group. The assessment of the level of CZC which reservation could potentially be economically justified would be furtherly investigated within the Task 1.5 of the FutureFlow project.

There are three reservation methods according to the EB Guideline and potentially an additional one according to the ENTSO-E BSG; their main features are briefly explained.

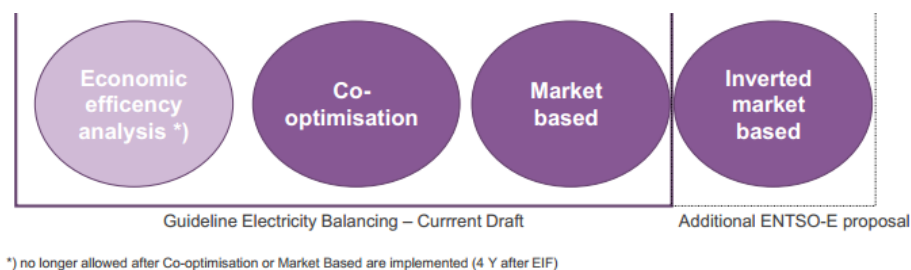


Figure 31 – Transmission capacity reservation methods

Co - Optimization Approach:

- This is a single optimization process for allocation of cross-zonal capacity between energy market and balancing market (both implicit and explicit auctioning)
- TSOs shall bid the Market Value into the co-optimized allocation (= forwarding of balancing capacity bids of BSPs)
- Procurement of balancing reserves must take place in parallel to the existing CZC allocation auction or Day-ahead Market Coupling
- Price of CZC: real market value

General comment: This method is more suitable for explicit/LT procurement because of high complexity in DA and ID timeframe.



Figure 32 – Co-optimisation based reservation

Market-based reservation:

- Market Based Reservation shall compare the actual market value of CZC for balancing with the forecast market value of CZC for the energy market
- Reservation could take place whenever balancing reserves shall be procured -> for instance weekly or in D-2 before the Day-ahead allocation
- Price of CZC: forecasted market value

General comment: This method is more suitable for shorter timeframes processes, to limit the risk of wrong estimations.

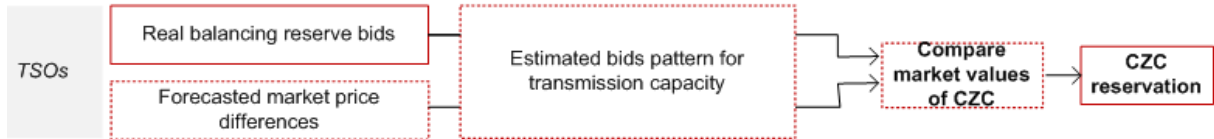


Figure 33 – Market-based reservation

Economic efficiency analysis:

- Estimation and study (Cost-Benefit Analysis) on the level of reservation to increase the overall welfare
- Every reservation proposal needs to be approved by the competent NRAs
- Price of CZC: forecasted market value

General comment: This is long-term oriented method. It is also considered as transitional only, allowed only in period 4 years after entry into force of EB Guideline.

However, the study principles of this method could be used within the Task 1.5 of the FutureFlow project, for the assessment of CZC reservations eventually needed among the concerned countries. This would include also the consideration of value of the reserved capacity, as required by the EB Guideline.



Figure 34 – Economic efficiency analysis based reservation

Inverted market-based reservation (ENTSO-E additional proposal):

- Reservation can take place in any given CZC allocation auction before the procurement of balancing reserves
 - If applied in Long Term market, TSOs bid for capacity in explicit auctions
 - If applied in the Day-ahead market, it creates additional capacity-only product (like co-optimization)
- Price of CZC: forecasted market value

General comment: This is ENTSO-E additional proposal, expected to be included in EB Guideline as the fourth possible method.

4.3 Definitions of Cross-zonal Capacity: ATC-based Vs. Flow-based

As previously seen, ATC-based allocations have been applied at the borders among Slovenia, Austria, Hungary and Romania, and consequently ATC remaining after the Intra-day trade can unanimously be determined, as the resource for cross-border balancing.

Besides ATC-based constraints, within the FutureFlow project also the Flow-based definitions of

CZC will be defined in parallel as an alternative transmission constraint to the CAF, since Flow-based approach is the perspective target model for the highly meshed networks (as Continental Europe is) according to the EC Capacity Allocation and Congestion Management Guideline. Its application started during 2015 in Central-west Europe (Germany&Austria, France, Netherlands, Belgium) within Flow-based Market Coupling, and its further spreading towards Central-East Europe is planned soon⁷.

4.3.1 Transaction-based CZC (ATC)

At the previous chapters it is implicitly considered that the principles and definitions of transaction-based CZC (Net Transfer Capacity, Available Transfer Capacity) are well-known, since this approach is applied for many years all over Europe, including the three borders involved in the FutureFlow project. Here is the brief reminder:

NTC is the maximum exchange program between two areas compatible with security standards applicable in both areas (TTC), taking into account the technical uncertainties on future network conditions, given through the Transmission Reliability Margin (TRM). $NTC=TTC-TRM$

The Available Transmission Capacity (ATC) is the part of NTC that remains available, after each phase of the allocation procedure (Already Allocated Capacity - AAC), for further commercial activity. $ATC=NTC-AAC$

Illustrative example of ATC matrix, with would contain ATC values available after Intra-day trade (including eventual reservations), to be used in CAF optimisation is given below. Red colour points the perspective additional electrical border Slovenia-Hungary.

FutureFlow_ATC: YYYY-MM-DD	1	2	3	24
SI-AT	1555	1666	1633	1600
AT-SI	88	118	116	0
AT-HU	33	0	86	0
HU-AT	22	0	0	0
RO-HU	657	583	568	180
HU-RO	442	516	532	987
SI-HU	0	0	0	0
HU-SI	0	0	0	0
<i>(figures are placeholders)</i>						

Figure 35 – ATC matrix example

4.3.2 Flow-based CZC (PTDF/RAM)

At the Flow-based approach, instead of border-wise limit for the maximum commercial transfer, the set of constraints is defined for each physical Critical Branch (CB), in Base Case topology and for selected Critical Outages (CO). CB can be cross-border tie lines or internal network elements highly influenced with cross-border exchanges.

The mentioned physical constraints at CBs are called Remaining Available Margin (RAM) according

⁷ <https://www.entsoe.eu/news-events/announcements/announcements-archive/Pages/Advancing-the-merger-of-the-CWE-and-CEE-capacity-calculation-regions-.aspx>

to the definitions used in CWE region, while in CEE and SEE region the so-called Available Maximum Flow (AMF) is defined in similar way. Currently the common Flow-based approach is under development among CWE and CEE⁸.

Flow-based constraint RAM per each CB/CO pair is calculated as $RAM = Fmax - FRM - Fref$:

- $Fmax$ is total MW capacity of a CB ($\sqrt{3} \cdot U \cdot I_{max} \cdot \cos \phi$)
- FRM is a Flow Reliability Margin, coping with calculation and forecasting uncertainties,
- $Fref$ is the already occupied flow at each CB (for each CO topology), which include:
 - loop flows (inevitable effect at the interconnected AC systems), and
 - the flows originated by the previously allocated and nominated transactions: in case of capacity calculation for balancing, these would be the flows by all nominated Day ahead and Intra-day transactions

Besides RAM, the linearized sensitivity factors of each CB/CO for the transactions between each pair of bidding zones are defined. These are so-called Power Transfer Distribution Factors (PTDF).

At the table below, there is an example of PTDF/RAM matrix in explicit zone-to-zone form; they can be presented also in zone-to-hub form (all zones - towards an arbitrarily chosen hub). Such matrix can be defined for each operational hour.

FutureFlow_PTDF/RAM: YYYY-MM-DD_hh					RAM (=AMF)		PTDF											
critical_branch	critical_outage		from	to	RAM+	RAM-	RO>HU	HU>RO	HU>SI	HU>AT	RO>SI	AT>SI	AT>RO	...				
_KA_MA1X	MARIBX (base case)		AT	SI	123	101	-1.5%	1.5%	13.8%	-2.5%	12.4%	16.4%	4.0%	...				
_KA_MA1X	MARIBX MARIBX KRSKXX		AT	SI	111	110	-1.1%	1.1%	9.7%	-0.1%	8.6%	9.8%	1.3%	...				
_KA_MA1X	MARIBX PODLOX MARIXX		AT	SI	123	101	-1.0%	1.0%	10.2%	-3.5%	9.2%	13.7%	4.5%	...				
_NE_GY2X	NEUSIX (base case)		HU	AT	33	22	-0.6%	0.6%	2.6%	3.0%	2.0%	-0.4%	-2.4%	...				
_NE_GY2X	NEUSIX SARAXX ZURNDXX		HU	AT	32	22	-0.8%	0.8%	3.2%	3.6%	2.4%	-0.4%	-2.9%	...				
_NE_GY2X	NEUSIX ZU_GYX GYOXX		HU	AT	22	23	-0.8%	0.8%	3.2%	3.6%	2.4%	-0.4%	-2.9%	...				
_WI_GY2X	WIEXXX (base case)		HU	AT	30	15	-0.6%	0.6%	2.6%	3.1%	2.0%	-0.4%	-2.5%	...				
_WI_GY2X	WIEXXX SARAXX ZURNDXX		HU	AT	30	15	-0.8%	0.8%	3.3%	3.7%	2.5%	-0.4%	-2.9%	...				
_BE_NA1X	BEKXXX (base case)		RO	HU	133	144	16.0%	-16.0%	-1.3%	-0.4%	14.7%	-0.9%	-15.6%	...				
_BE_NA1X	BEKXXX AISAXXX SOLXXX		RO	HU	122	145	12.9%	-12.9%	-2.2%	-2.0%	10.7%	-0.2%	-10.9%	...				
_BE_NA1X	BEKXXX BEK0XXX SAFAXX		RO	HU	123	154	14.2%	-14.2%	-0.6%	1.4%	13.5%	-2.0%	-15.6%	...				
_BERICXX	KLECEX (base case)		SI	SI	40	40	-0.4%	0.4%	-3.0%	1.0%	-3.4%	-4.0%	-0.6%	...				
_BERICXX	KLECEX DIVAXX BERIXX		SI	SI	41	31	-0.8%	0.8%	-5.6%	1.7%	-6.3%	-7.3%	-0.9%	...				
_BERICXX	KLECEX ME_DIXX MELIXX		SI	SI	43	30	-0.7%	0.7%	-3.5%	-0.3%	-4.2%	-3.2%	1.0%	...				
_BERICXX	KLECEX PA_DIXX PDRVXX		SI	SI	44	33	-0.6%	0.6%	-2.2%	-1.0%	-2.7%	-1.2%	1.5%	...				
...					<i>(elements and figures are placeholders)</i>													

Figure 36 – PTDF/RAM matrix example

The uniformity of the Flow-based calculation approach and the fact that all data are calculated in a single calculation run for all CBs, allows not only pure subtracting of the allocated quantities from previously calculated data (like it is typically expected at the ATC approach); the complete recalculation of available Flow-based capacities can be done for each capacity calculation timestamp, before the real time, on the basis of the latest network data:

- for the actual following hour, the latest Common Grid Model (CGM) of Continental Europe can be used, from the Intra-day merging cycle;

⁸ CWE definitions generally correspond with CEE and SEE ones: $Fmax \approx TMF$, $RAM \approx AMF$, $Fref \approx BFL + ANF \dots$

- this model is expected to contain generation & load pattern and consequential areas' Net positions corresponding to the results of previous commercial trades⁹ (day ahead and intra-day nominated transactions); therefore the consequential power flows ($F_{ref_{cb,co}}$) would contain both loop flows and the flows originated by the D-1 and ID transactions¹⁰ - which are actually the already occupied part of the total capacity of each CB
- at the close-to-real time horizon, uncertainties in network conditions are rather small, therefore the size of reliability margin (FRM) could be low
- consequently, for each CB/CO the capacity available for balancing would be:
 $RAM_{cb,co} = F_{max} - FRM - F_{ref_{cb,co}}$

4.4 Timing of CZC update for balancing market

As previously explained, ATC values or PTDF/RAM values (both as remainders of transmission capacity after the Intra-day commercial trade), can be updated quite close to the real time. CZC update should take place after the gate closure of an Intra-day market for the given timestamp.

Therefore CZC update can regularly be done in the period of half-an-hour before the real time. Within this process the data file with either ATC or PTDF/RAM values for the actual following hour would be provided from the capacity calculation/allocation and scheduling processes, to the regional balancing platform, and there it would be used as the transmission constraint at the Common Activation Function.

4.5 Value of CZC

According to the draft EB GL, CZC used for the exchange of balancing energy (and for Imbalance netting) is to be priced consistently with pricing methods for the exchange of energy in the intraday timeframe and it shall provide an adequate compensation for CZC. Pricing should reflect the market congestion, and it is to be based on actual Balancing Energy bids.

As a reference, CACM GL (Article 55) envisages pricing of CZC used at Intra-day commercial market, (also) with reflecting market congestion and based on actual bids (from Intra-day trade).

FutureFlow target model would follow the propositions by the above legislation regarding the need that CZC used for aFRR exchange should have a value, while detailed methodology for the determination of this value is not in the main scope herein. In any way, the value of CZC would not be a part of an online Optimisation within the Common Activation Function, but it is considered that this value would be determined post-festum.

⁹ In case of eventual discrepancy between the final Net position of Continental Europe areas and the ones in the Intra-day Common Grid Model, the adjustment can be done by multiplying the difference between real and modelled Net Positions with the PTDF factors at each CB/CO: $\Delta F_{ref} = [NetPos(real) - NetPos(model)] \times PTDF_{cb/co}$. In CWE approach this generally corresponds to the calculation of F_{ref}^* . Due to the linearity of PTDFs, such approach is possible.

¹⁰ The value F_{ref} is currently calculated by the DC Load Flow in CWE; AC Load Flow can be used and thus obtain more accurate figures, however with risking the calculation divergence in certain hours

5 FutureFlow - Redispatching mechanism

While the substantial part of FutureFlow project is related to the design of the mechanism for the exchange of energy within automatic frequency restoration reserve (aFRR), it also deals with practices of Redispatching and innovations in cross-border cooperation in this respect, and potential co-existence of aFRR exchange and Redispatching over the common platform.

After the analysis of relevant European target models, and the extensive questionnaire filled by the concerned TSOs, two facts streamlined the Redispatching design within Future Flow project from the very beginning:

- Electricity Balancing Guideline, at Section 5, "Activation of balancing Energy bids", Article 40, paragraph 5, states that "Balancing Energy bids for Frequency Restoration Reserves with automatic activation shall be exclusively available for the purpose of maintaining the active power balance." Therefore, Redispatching process should be developed in a way parallel to the aFRR process¹¹.
- All four TSOs are members of TSO Security Cooperation (TSC), and share the principles of cooperation of the cross-border Redispatching to be applied.

The following initial considerations led towards the development of the redispatching concept:

- the co-optimization of technical (sensitivity factors based on network locations) and economic criteria (redispatch bid price) for the selection and application of Redispatching actions to solve the network congestions;
- seeking for the potential of DR/DG units to participate at Redispatching (and required additional information, such as network locations of DR/DG);
- cost allocation and cost sharing principles of Redispatching among the TSOs, including the determination of the amounts and the origins of loop flows/internal flows and exchange flows/transit flows.

This concept gathers:

1. Optimization function for coordinated (cross-border) redispatching actions and minimization of redispatching costs
2. Allocation of redispatching cost based on PFC method

The main idea of redispatching concept is compensation of cost for redispatching among TSOs who provided redispatching services and those who caused it (actually, who's connected generation and consumption caused it). It doesn't deal with financial compensation, yet determines TSOs costs for redispatching actions applied to resolve congestion on a particular line, and the responsibility of other TSOs, in a form of cost-share, for causing that congestion.

- The first part should provide an optimal redispatching action and give the information on

¹¹ Still, it is expected that, for system security a unit (or portfolio) behind an aFRR bid can be removed for the sake of system security at any point in time.

- redispaching costs of each TSO involved in these actions.
- The second one determines which TSO and in what amount caused congestion on a certain line that eventually led to redispaching.

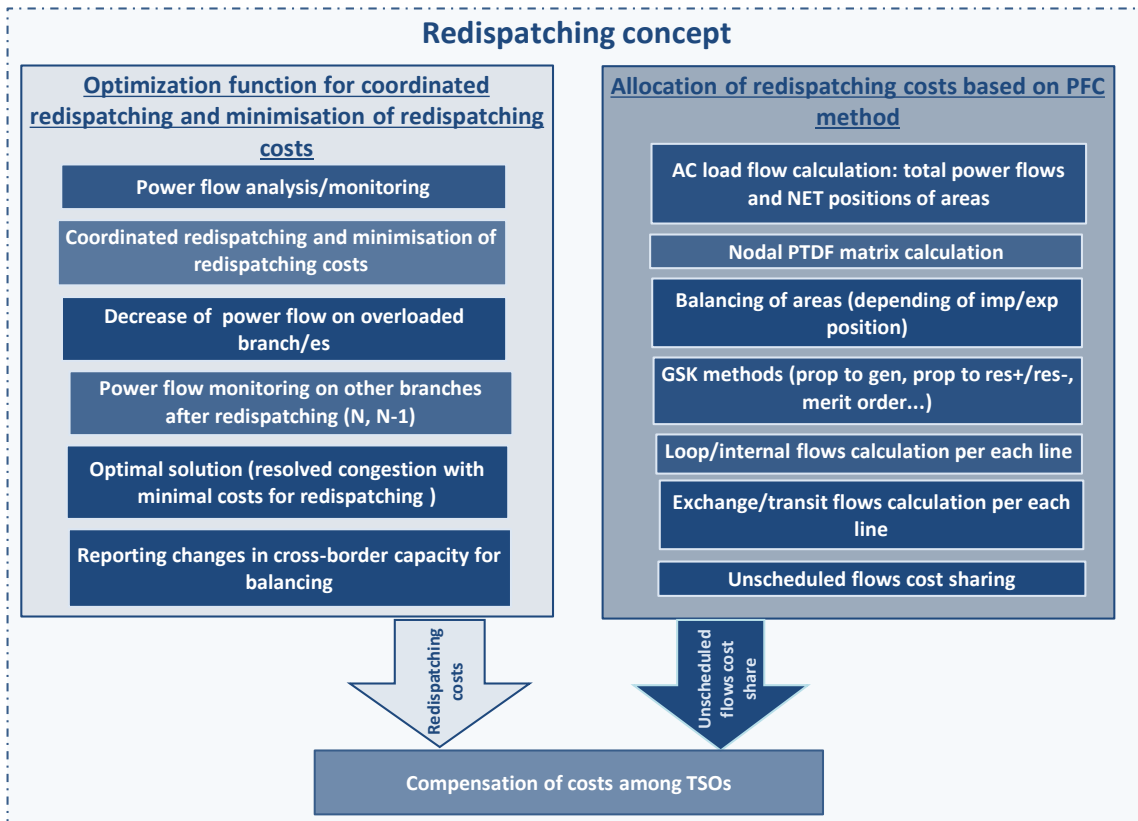


Figure 37. Redispatching platform modules

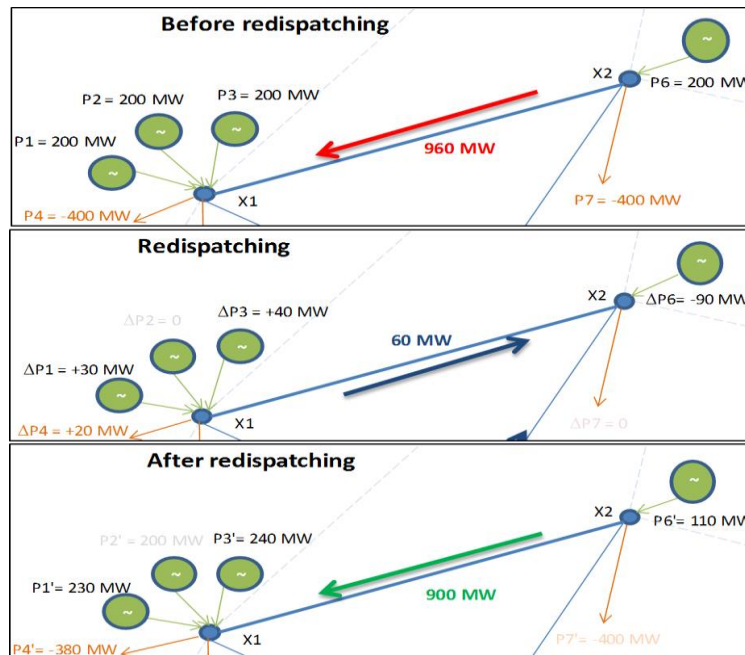


Figure 38. Redispatching illustration

5.1 Optimisation function for minimization of redispatching costs

In order to efficiently resolve congestion on a particular line, coordinated redispatching based on minimization of costs could be the right solution, in case no other measures, such as non-costly remedial actions, give the proper results. This type of redispatching is in fact based on optimal power flow (OPF), where the optimal solution is the one that gives the minimum of costs and at the same time satisfies all predefined constraints. For all providers, there could be some additional preconditions they have to satisfy in order to be placed on the list, for example their operational characteristics, but this choice actually depends on the particular control area system operator, as well as on the time-frame on which redispatching should be applied.¹² The inclusion of DR and DGs in redispatching, as an added value of this project, can provide more options in resolving this issue.

For those generators and dispatchable loads participating in the bidding list for redispatching there are several crucial information:

1. Amount of power available for upward/downward redispatching [MW]
2. Price for upward/downward redispatching [€/MWh]
3. Location of particular generator/load in the system

Bidding list							
Unit	Serial number <i>i</i>	Location Node name	Node number <i>x</i>	Upward bid		Downward bid	
				ΔP_{xi}^{up} [MW]	C_{xi}^{up} [€/MW]	ΔP_{xi}^{down} [MW]	C_{xi}^{down} [€/MW]
G1	1	Node 1	1	50	1.2	-30	1.3
G2	2	Node 1	1	70	1.8	-50	0.2
L1	3	Node 1	1	40	4.6	-20	5.2
G3	1	Node 2	2	100	2.4	-50	1.5
G4	2	Node 2	2	30	2.5	-30	0.5
G5	3	Node 2	2	10	2.8	-10	0.4
G6	1	Node 3	3	25	3.3	-25	0.1
L2	1	Node 4	4	10	4.8	0	0.0

Figure 39. The example of a bidding list for redispatching

¹² Bidding lists for redispatching should differ depending on the time frame on which redispatching measures are to be applied. For D-1 redispatching, some of slower units (such as thermal ones) can be used, as well as those not committed at that proper moment. In this case, start-up costs should also be considered. On the other hand, for real time redispatching, such units are not an option. Only those with appropriate lead-time can participate in real time redispatching bidding list.

This list may contain generators that can be used either for redispatching or balancing, but as already mentioned, without aFRR units used for balancing with full capacity.

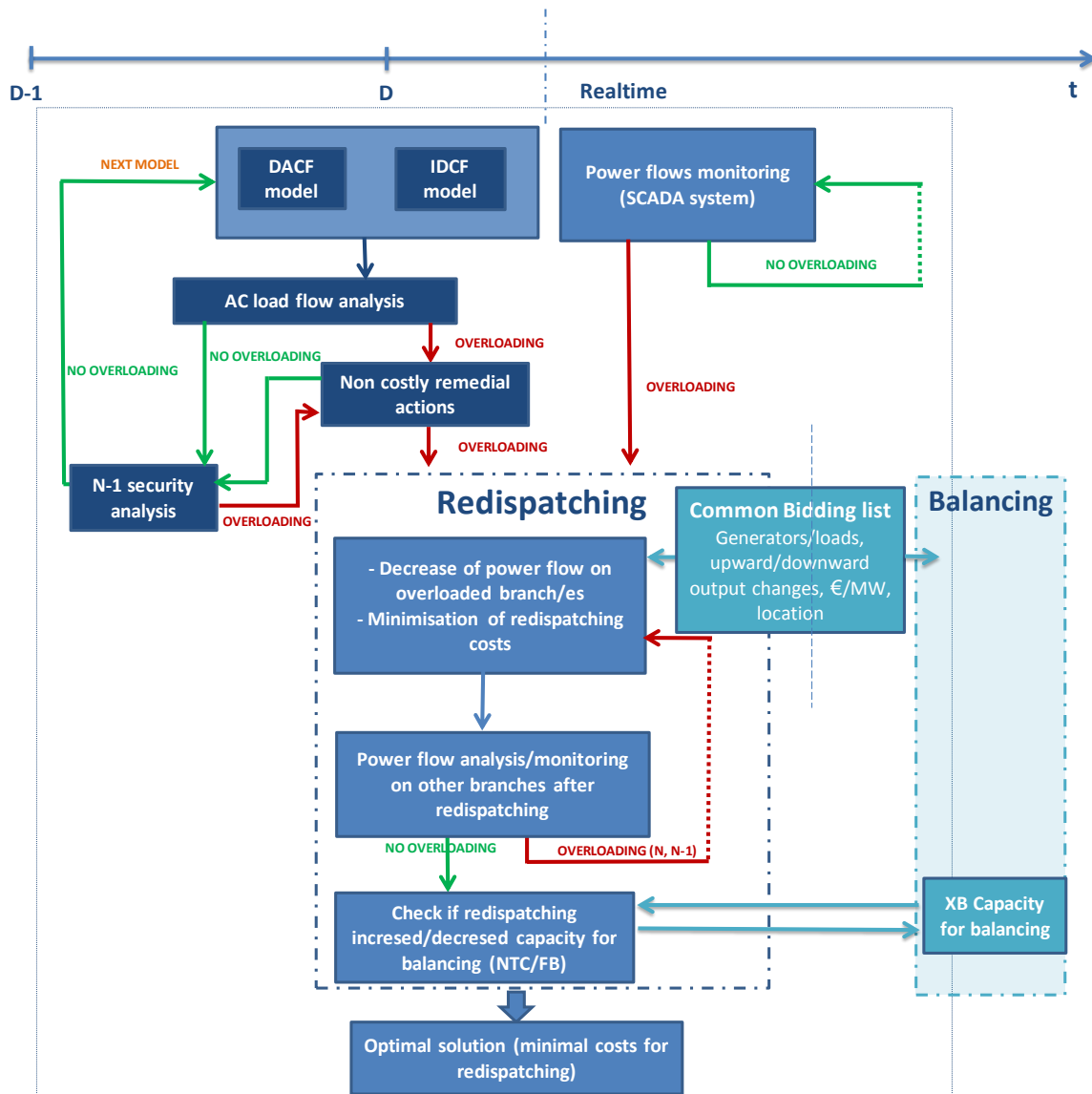


Figure 4.0. Redispatching optimization function algorithm

There are different time-frames on which redispatching can be applied (day ahead, intraday and real time). Since redispatching represents costly remedial action it is often used only as the last resort. In either case, if redispatching is recognized as an inevitable operation, the following optimization function could make an improvement considering redispatching procedures currently being used by European TSOs.

In the focus of this concept is real time redispatching. Each line is able to stand the overloading of several percent's up to the limit defined by each responsible TSO. From the moment a line becomes overloaded till the relay protection activates and switches off the line, the TSO should perform redispatching. Since this time-frame is very limited, the optimization needs to be performed some

time earlier. This way each TSO will have the list of optimal redispatching actions for each critical branch and even for contingencies, timely prepared for application in case overloading happens in the network.

Objective function represents minimization of redispatching costs:

$$\min_{\Delta P_{xi}^{up}, \Delta P_{xi}^{down}} \left\{ \sum_{x=1}^n \sum_{i=1}^{n_x^{up}} \Delta P_{xi}^{up} \cdot C_{xi}^{up} + \sum_{x=1}^n \sum_{i=1}^{n_x^{down}} \Delta P_{xi}^{down} \cdot C_{xi}^{down} \right\}$$

Notation:

x – Particular node

n - Total number of nodes in the system

i – Serial number of a generator/load in a particular node x

n_x^{up} – Total number of upward bids in the node x

n_x^{down} – Total number of downward bids in the node x

ΔP_{xi}^{up} – optimized/selected upward bid amount of a generator/load i in the node x

ΔP_{xi}^{down} – optimized/selected downward bid amount of a generator/load i in the node x

C_{xi}^{up} – Upward bid price of a generator/load in the node x

C_{xi}^{down} – Downward bid price of a generator/load in the node x

up – Refers to generation increase i.e. load decrease

down – Refers to generation decrease i.e. load increase

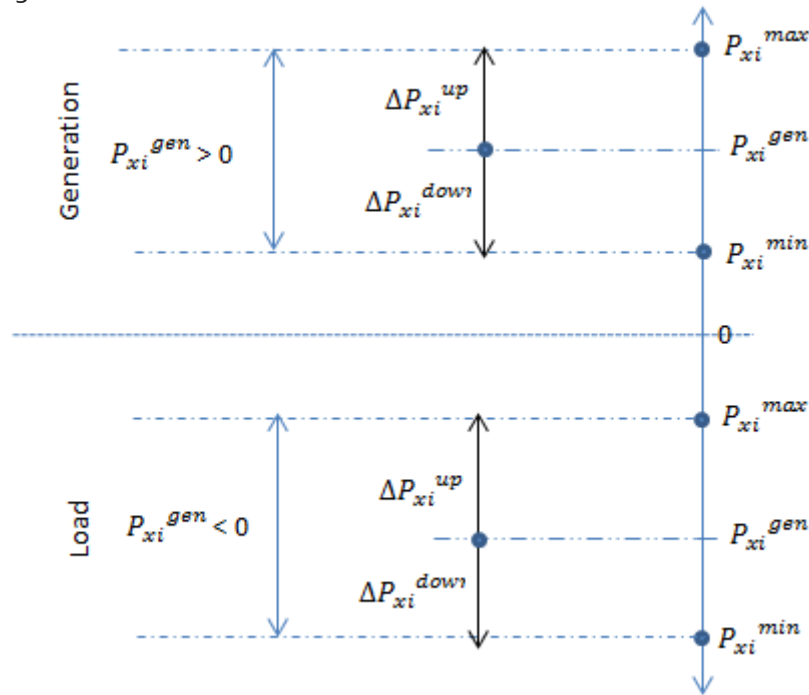


Figure 4.1. Generator/Load constraints

As shown on the (Figure 4.1), the load is treated as a negative generation. For upward bids, ΔP_{xi}^{up} is defined with non-negative value, while for downward ones ΔP_{xi}^{down} is always negative or equal to zero. This defines following bound constraints within the optimization:

$$0 \leq \Delta P_{xi}^{up} \leq P_{xi}^{max} - P_{xi}^{gen}$$

$$P_{xi}^{min} - P_{xi}^{gen} \leq \Delta P_{xi}^{down} \leq 0$$

Notation:

P_{xi}^{max} – Maximum unit generation/minimum load

P_{xi}^{min} – Minimum unit generation/maximum load

P_{xi}^{gen} – Unit generation/load before redispatching

In case a certain bid from the bidding list doesn't fulfil these conditions it cannot be used for redispatching.

When it comes to the bid price, for upward bids (C_{xi}^{up}) it is always positive, while for the downward ones (C_{xi}^{down}) it can be either negative or positive. Positive sign defines service provider willingness to pay for delivering the energy, while negative sign defines service provider request to receive the money for activated service. Most commonly C_{xi}^{down} is positive, taking into account that the power utility operators realize fuel savings from the energy not produced.

Redispatching action must produce congestion relief on critical branch k, i.e. the current flow P_k has to be decreased below or to the level of the allowed branch loading limit:

$$\left| \sum_{\substack{x=1 \\ x \neq ref}}^n PTDF_k^x \cdot \left[\sum_{i=1}^{n_x^{up}} \Delta P_{xi}^{up} + \sum_{i=1}^{n_x^{down}} \Delta P_{xi}^{down} \right] \right| \geq P_k - P_k^{limit}$$

Equality constraint is, in fact, energy balance equation which has to be preserved when redispatching is applied:

$$\sum_{x=1}^n \sum_{i=1}^{n_x^{up}} \Delta P_{xi}^{up} + \sum_{x=1}^n \sum_{i=1}^{n_x^{down}} \Delta P_{xi}^{down} = 0$$

Undertaken redispatching measures for relieving congestion on branch k shouldn't cause overloading on other monitored branches ($t \in [1, T]$, $t \neq k$):

$$\sum_{\substack{x=1 \\ x \neq ref}}^n PTDF_t^x \cdot \left[\sum_{i=1}^{n_x^{up}} (P_{xi}^{gen} + \Delta P_{xi}^{up}) + \sum_{i=1}^{n_x^{down}} (P_{xi}^{gen} + \Delta P_{xi}^{down}) \right] < P_t^{limit}$$

Notation:

k – Critical branch for which redispatching needs to be applied

t – Other branches in the system

T – Total number of branches in the system

P_k – Loading on the line k

P_k^{limit} – Maximum allowed loading on the line k

P_t^{limit} – Maximum allowed loading on the line t

ref – reference node for node to reference PTDF matrix calculation

PTDF_k^x – PTDF factor on line k for the exchange between node x and the reference node

PTDF_t^x – PTDF factor on line t for the exchange between node x and the reference node

Based on all the information from the bidding list, for each node in the system, the objective function considers upward/downward bids (with the amount and the price) located at that particular node, and finds the solution that provides minimum of redispatching costs.

What is also important to emphasize here is the correlation between redispatching and balancing. After finding the optimal solution and performing coordinated redispatching, transmission capacity left after intraday market will be different. In one direction it will be decreased, which may cause problems for balancing in case these capacity changes haven't been reported on time.

5.2 Allocation of redispatching costs based on Power Flow Colouring Method (PFC)

Power Flow Colouring Method (PFC) is developed with the goal to obtain loop flows and exchange flows, produced by particular control area, and even goes further on to the level of generator-load pairs. This approach is in fact based on decomposing power flows into its components (loop flows/internal flows and exchange flows/transit flows) with the information on their sources. This way it is possible to apply cost-share principle, i.e. determine responsibility of each TSO for power flow on a particular line in the system. As a constituent part of redispatching platform it can be used for compensation among TSOs who provided redispatching and those who caused it.

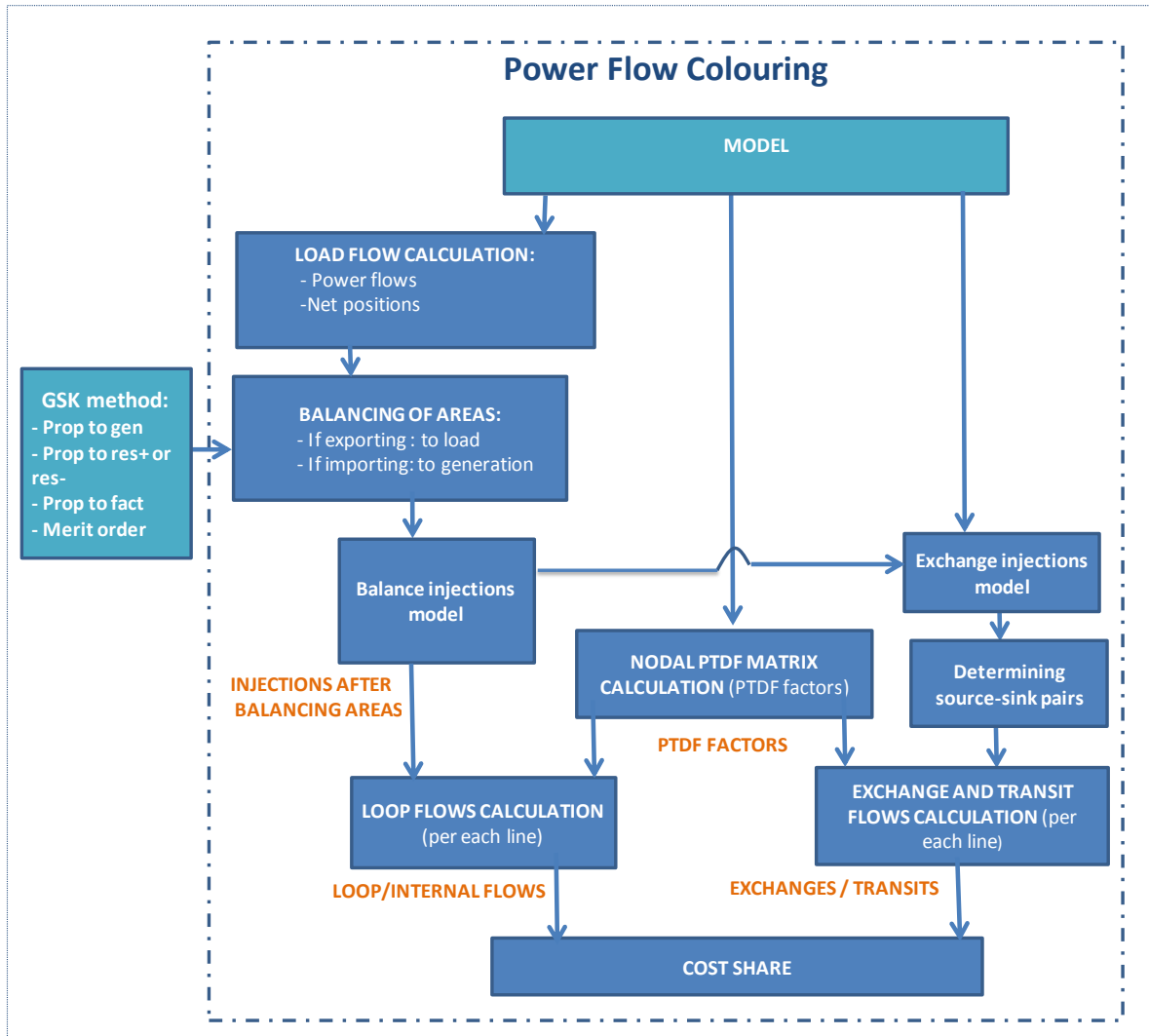


Figure 42. Power Flow Colouring method

The described process doesn't have to be done in the real time. However, it should be performed on a model just before redispatching measures are undertaken. The main idea of this concept is to create two new models, out of this initial one:

1. Balanced model (to get Loop flows/Internal flows)

2. Model with exchanges (to get Exchange flows/Transit flows)

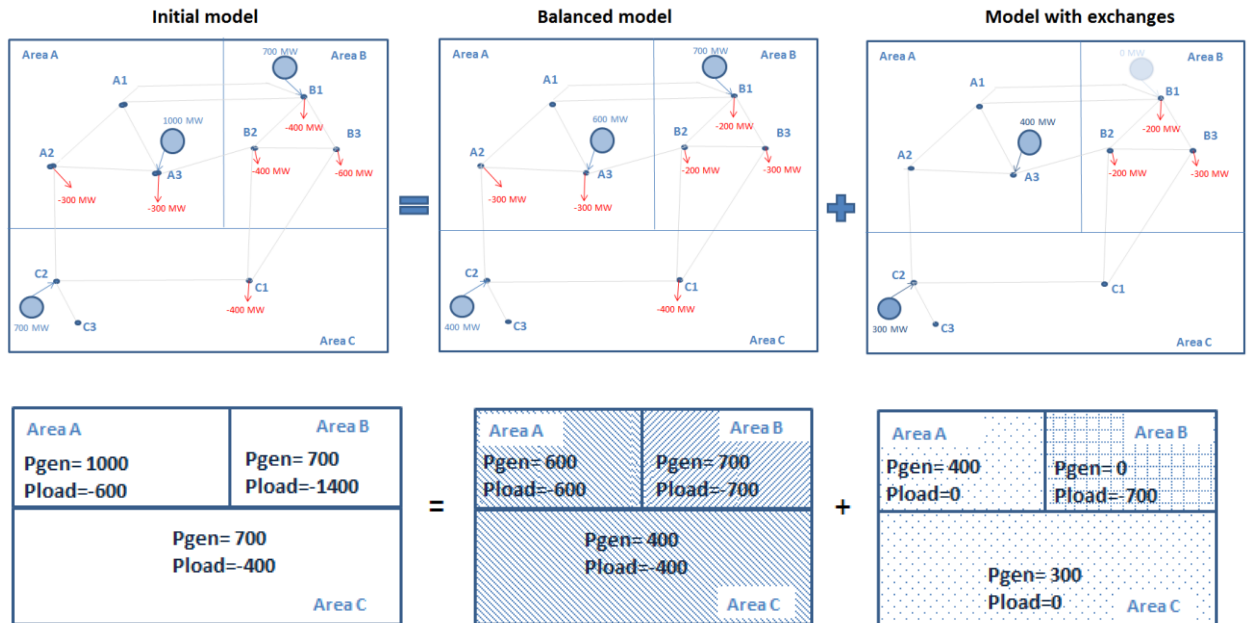


Figure 43. PFC decomposition

5.2.1 Balanced model

Balanced model is created out of the initial model by balancing each control area. The first assumption within PFC method is related to area balancing principle. If an area is:

- Exporting – Total area's generation decreases to the level of its load
- Importing – Total area's load decreases to the level of its generation

In case an area is exporting, its total generation should be decreased to the level of its load while the excess generation should be considered only in the model with exchanges. On the other hand, if an area is importing its total load should be decreased to the level of its generation with the excess load being considered in the model with exchanges, as well. This way each area will first supply local load centres, and only afterwards others in surrounding areas.

If an area (O) is exporting, then the sum of generation in all its nodes x has to be greater than the sum of all its loads:

$$\sum^O P(x)_{gen} > - \sum^O P(x)_{load}$$

When balancing areas, total generation in area O needs to be shifted down to the total load in area O:

$$\forall x \in O, \sum^O P(x)_{gen\ balance} = - \sum^O P(x)_{load}$$

In order to get new nodal generation in this balanced model, the total balanced generation i.e. load of area O has to be distributed per nodes according coefficients obtained from the applied balancing method:

$$P(x)_{gen\ balance} = -coef(x) \cdot \sum^O P(x)_{load}$$

Depending on the selected balancing method, these coefficients will have different values:

$$\forall x \in O, \forall O \in Z, coef(x) \in [0,1], \quad coef(x) = \begin{cases} \frac{P(x)_{gen}}{\sum^O P(x)_{gen}}, & \text{prop to gen} \\ \frac{P(x)_{load}}{\sum^O P(x)_{load}}, & \text{prop to load} \\ \frac{P(x)_{max} - P(x)_{gen}}{\sum^O P(x)_{max} - \sum^O P(x)_{gen}}, & \text{prop to res +} \\ \frac{P(x)_{gen} - P(x)_{min}}{\sum^O P(x)_{gen} - \sum^O P(x)_{min}}, & \text{prop to res -} \\ \frac{1}{CO_{u'-(x-1)} \cdot \sum_{x=1}^{u'} \frac{1}{CO_x}}, & \text{prop to fact} \\ \text{Merit order list} \end{cases}$$

As a result of balancing the exporting areas, nodal generation will be different, while the loads will stay the same:

$$P(x)_{load\ balance} = P(x)_{load}$$

The node x generation in exchange model is calculated as a difference between the same node's generation in the initial model and the balanced one:

$$P(x)_{gen\ exc} = P(x)_{gen} - P(x)_{gen\ balance} = P(i)_{gen\ exc}$$

There is no residual load on the node x in the exchange model, since all the loads in area O where node x is located are supplied in the balanced model:

$$P(x)_{load\ exc} = P(x)_{load} - P(x)_{load\ balance} = P(i)_{load\ exc} = 0$$

If an area (O) is importing, then the sum of loads in all its nodes x has to be greater than the sum of all its generation:

$$\sum^O P(x)_{gen} < - \sum^O P(x)_{load}$$

Total load of area O is shifted down to the level of its total generation:

$$\sum^O P(x)_{load\ balance} = - \sum^O P(x)_{gen}$$

New nodal loads can be obtained when total balanced load in area O i.e. total generation (before balancing) is multiplied by corresponding coefficient:

$$P(x)_{load\ balance} = -coef(x) \cdot \sum^O P(x)_{gen}$$

Nodal generation in balanced model remains the same as in the initial model:

$$P(x)_{gen\ balance} = P(x)_{gen}$$

The residual load of the node x in exchange model is calculated as the difference between the nodal load from the initial model and the balanced one:

$$P(x)_{load\ exc} = P(x)_{load} - P(x)_{load\ balance} = P(j)_{load\ exc}$$

There is no residual nodal generation left for exchange model:

$$P(x)_{gen\ exc} = P(x)_{gen} - P(x)_{gen\ balance} = P(i)_{gen\ exc} = 0$$

Notation:

- O - Particular area
- Z - Total number of areas
- x - Particular node
- u - Total number of nodes in the system
- u' - Total number of nodes in area O
- i - Node with generation only in exchange model
- n - Total number of nodes with generation only, in exchange model
- j - Node with load only in exchange model
- m - Total number of nodes with load only, in exchange model
- k - Particular line
- T - Total number of lines in the system
- coef (x) - Balancing coefficient which depends on chosen GSK method
- $P(x)_{gen}$ - Generation in node x from the initial model
- $P(x)_{load}$ - Load in node x from the initial model
- $P(x)_{gen\ balance}$ - New generation in node x in balanced model
- $P(x)_{load\ balance}$ - New load in node x in balanced model
- $P(x)_{gen\ exc}$ - New generation in node x in exchange model
- $P(x)_{load\ exc}$ - New load in node x in balanced model

In order to distribute new area generation/loads to particular nodes, GSKs should be used. New obtained nodal injections in balanced model, multiplied by nodal PTDF matrix, as a result give loop flows per each line in the system. Depending on GSK method chosen (proportionally to generation, proportionally to load, proportionally to reserve, proportionally to predefined coefficients or merit

order list) different loop flow and therefore exchange flow results can be expected.

For each area O and node x located in O , as well as for each branch k , loop flow produced by area O over the branch k is:

$$P(k)^O_{balance} = \sum^O [PTDF(k, x \rightarrow ref) \cdot (P(x)_{gen\ balance} + P(x)_{load\ balance})] = Loop\ flow(k)^O$$

5.2.2 Model with exchanges

Model with exchanges contains only imports and exports of all areas (left after balancing) with residual injections in each node obtained as a difference between initial model and balanced model injections. The second assumption within PFC method is related to determining source-sink pairs i.e. which generator and in what amount feeds in which load. The proposed solution considers each generator supplying each load proportionally to the load in each node in the system. This way it is possible to get the exchanged amount of energy between each generator and load, while its influence on a particular line can be determined when multiplied by corresponding PTDF factor.

$$P(k)^{i \rightarrow j}_{exc} = PTDF(k, i \rightarrow j) \cdot \frac{P(j)_{load\ exc}}{\sum_{j=1}^m P(j)_{load\ exc}} \cdot P(i)_{gen\ exc}$$

The responsibility of an exchange is divided equally between the involved parties:

$$P(k)^i_{exc} = P(k)^j_{exc} = \frac{1}{2} \cdot P(k)^{i \rightarrow j}_{exc}$$

The exchange flow over the line k produced by area O :

$$P(k)^O_{exc} = \sum^O \frac{1}{2} \cdot P(k)^{i \rightarrow j}_{exc} = Exchange\ flow(k)^O$$

Notation:

$P(j)_{load\ exc}$ – new load in node j in exchange model

$P(k)^{i \rightarrow j}_{exc}$ – exchange flow over the line k between generation in node i (source) and load in node j (sink)

$P(k)^O_{exc}$ - exchange flow over the line k created by area O

$PTDF(k, x \rightarrow ref)$ - PTDF factor of node x for line k

$PTDF(k, i \rightarrow j)$ - PTDF factor for the exchange between i and j over the line k

5.2.3 Cost-share principle

Based on previously explained PFC methodology, it is possible to decompose power flow on each line to loop flows/internal flows and exchange flows/transit flows created by different TSOs. The influence of each TSO on a particular line is expressed in their cost-share. However, not all flows are responsible for congestion. Some of the flows (scheduled flows) have already been nominated by considering maximal transmission limits on the border and therefore there is no need for them to be considered in cost-share. On top of that, those rights are awarded by paying fees for the cross-border transfer. Therefore, only unscheduled flows can be considered as a causer of potential

redispatch activation and used for cost-sharing, which is in line with ACER recommendation. These unscheduled flows on congested line can be determined as the difference between total flows created by particular TSO in case of the last model which required redispatching measures and the previous forecast model which satisfied security criteria. For real time redispatching, the cost-share principle is determined based on the difference between total flows created by particular TSO in real time and the latest intraday model which satisfies security criteria. For intra-day redispatching, the cost-share principle is determined based on the difference between total flows created by particular TSO obtained from intra-day model (which requires redispatching) and previous intraday model which satisfied security criteria. On the other hand, for D-1 redispatching the cost-share principle is determined only upon absolute total flow per TSO, since there is no previous reliable model to be compared to.



Figure 44. Illustration for real time redispatching case

$$\Delta Total\ flow(S)^k = Total\ flow'(S)^k - Total\ flow(S)^k$$

$$Cost\ Share(S)^k\ [\%] = \frac{\Delta Total\ flow(S)^k}{\sum \Delta Total\ flow(S)^k} \cdot 100$$

Notation:

S – Particular TSO

Total flow (S)^k – Total flow on line k caused by TSO S from the model which satisfies security criteria

Total flow'(S)^k – Total flow on line k cause by TSO S from the model which requires redispatching

ΔTotal flow(S)^k – The total deviation of the flow on line k i.e. the difference between total flows over the line k caused by TSO S in case of the model which requires redispatching and the previous model which satisfies security criteria

Cost share(S)^k [%] – The share of particular TSO S in total deviation on line k

Example1: The latest intraday model which satisfied security criteria showed the total flow over the line A3-B2 of 270 MW. Based on PFC methodology TSO A was responsible for 100 MW, TSO B for 120 MW, and TSO C for 50 MW. In the real time, this line was overloaded, with 403 MW of total flow, out of which TSO A caused 153 MW, TSO B 177 MW and TSO C 73 MW. This means that TSO A caused additional flow of 53 MW, which represents 40% of 133 MW deviation (i.e. the cost share of 40%), TSO B 57 MW (cost share of 43%), and TSO C 23 MW (cost share of 17%).

Table 11: Example 1

Line A3-B2	Intraday model which satisfy security criteria			Real time model which requires redispatching			Total flow Deviation [MW]	Cost share [%]
	Loop flows [MW]	Exchange flows [MW]	Total flows [MW]	Loop flows [MW]	Exchange flows [MW]	Total flows [MW]		
TSO A	30	70	100	58	95	153	53	40%
TSO B	30	90	120	58	119	177	57	43%
TSO C	35	15	50	50	24	73	23	17%
Total [MW]	95	175	270	166	237	403	133	100%
Allowed line limit [MW]	/	/	305	/	/	305	/	/

Example2: The day-ahead forecast model which requires redispatching showed the total flow over the line A3-B2 of 470 MW. Based on PFC methodology TSO A was responsible for 170 MW, TSO B for 210 MW, and TSO C for 90 MW. The share of each TSO in total line loading is calculated proportionally to their contribution to the total flow. Therefore, TSO A has the cost-share of 36%, TSO B 45% and TSO C 19%.

Table 12: Example 2

Line A3-B2	Day-ahead model which requires redispatching			Cost share [%]
	Loop flows [MW]	Exchange flows [MW]	Total flows [MW]	
TSO A	60	110	170	36%
TSO B	70	140	210	45%
TSO C	50	40	90	19%
Total [MW]	180	290	470	100%
Allowed line limit [MW]	/	/	305	/

6 Annex 1: Survey of DR/DG flexibility vs. FAT

6.1 Introduction

Traditionally the power systems engage conventional production units for balancing the electrical grid. These can be considered as small number of big and centralized units (as opposed to the large number of small decentralised DG/DR units). One important characteristic of balancing units is their capability of responding quickly to the change in power set-point, also known as the Full Activation Time (FAT). This capability has been studied in detail for conventional balancing units¹³, where the dependencies of available capacity for providing aFRR have been identified with respect to the full activation time and power generation technology (e.g. gas, coal, nuclear, big hydro etc.).

6.2 The mission - FAT

While FutureFlow project (also) aims at revealing the ways and potentials of (partly) replacing conventional production units with DR/DG and small renewables (e.g. small and micro hydro, solar, combined heat and power, wind turbines etc.) it's task is also to identify how the existing aFRR performances would be affected by the introduction of flexible DR/DG units into aFRR, and what FAT could these "new" units provide to transmission system operators. Since the DR/DG units are by definition small in capacity but large in number and dispersed, they are also quite different one from another (compared to conventional aFRR providing units). Thus, the identification of the DR/DG flexibility vs. FAT is not a simple, straight forward task.

6.3 Methodology and results




The fact has come to light also during the field survey, which was the method used for this mission. Due to the fact that tighter customer relation links are maintained by the consortium in Slovenia and Austria, and rather low retailers' activities in Romania and Hungary, the first two markets have been considered more representative cases for the analysis, and thus used as a reference (the results for Romania and Hungary have been extrapolated from the reference, and are only orientational). The survey has been conducted in 2 steps: (i) identifying total flexible capacity and (ii) detailing the ramping capability (FAT capability).

Firstly, the most promising flexible candidates from the commercial and industrial sectors, with process and non-process loads have been identified based on the understanding and experience of retailers (GEN-I and Elektro Energija). Assessing the survey market reach by energy consumption 27% of Slovenian and 9% of Austrian total C&I market has been covered (the survey reach is larger if evaluated by flexibility potential; 38% in SI and 12% in AT). These individuals have been contacted and asked for power flexibility (self)-estimation. 54% and 18% of identified candidates have responded to the survey in Slovenia and Austria, respectively. Their answers have revealed that 83 MW and 244 MW of flexible capacity is estimated to exist within their assets, respectively. Due to the missing survey answers and the flexible potential that was regarded non-reachable due

¹³ [On behalf of ENTSO-E: Impact of Merit Order activation of automatic Frequency Restoration Reserves and harmonised Full Activation Times, E-Bridge, Germany 2016](#)

to sheer number of small, dispersed DR/DGs we have made an estimation of flexible capacity in these missing segments. The estimation is calculated based on the reference relative flexible potential that was identified with the survey (in MW per GWh of electricity consumption). The identified relative potential of actual survey responses is 0,025 and 0,059 MW/GWh in Slovenia and Austria, respectively. The 2 missing segments (“not-replied” and “not-contacted”) can be (arbitrarily) considered as less promising, compared to the candidates that have replied to the questionnaires. Considering the best estimates of “not-replied” group being half as promising and “not-contacted” group as 10% as promising as actual replies, then the allocated potential equals 36 MW and 8 MW in Slovenia, and 120 MW and 213 MW in Austria, respectively. The total absolute estimated flexible capacity potential can therefore be estimated to 126 MW in Slovenia and 577 MW in Austria (which corresponds to relative flexible capacity potential of 0,013 MW/GWh of C&I consumption for both countries). These values apply considering the given estimates, and are therefore subjected to sensitivity – in case the market share that was not directly reached is considered more promising the total estimated flexible potential shall be more, and vice versa. The following table is graphically explaining the estimation algorithm of flexibility potential for the Slovenian case.

Table 13: Estimation algorithm of flexibility potential for the Slovenian case

Electricity consumption	GWh			
Total C&I SI	9.400			
Sent C&I Q SI	6.247			
Received C&I Q SI	3.358			
Flexible capacity	MW			
Total C&I SI	?	83	?	?
Sent C&I Q SI	?	83	?	
Received C&I Q SI	83	83		
Specific flexibility	MW/GWh			
Total C&I SI	?	0,025	0,012	0,002
Sent C&I Q SI	?	0,025	0,012	
Received C&I Q SI	82	0,025		
Absolute flexibility	MW			
Total C&I SI	126	83	36	8
Sent C&I Q SI	118	83	36	
Received C&I Q SI	83	83		

Annotations in the table:

- 10% arrow pointing to the 0,002 value in the Specific flexibility Total C&I SI row.
- 50% arrow pointing to the 0,012 value in the Specific flexibility Sent C&I Q SI row.
- 100% arrow pointing to the 0,025 value in the Specific flexibility Received C&I Q SI row.

Secondly, detailed power ramping information of candidate flexible assets, where maximum 1 hour of activation duration was assumed, has been analysed. Additionally, full time availability of the capacity has been assumed in the research. Thus, the identified capacity is idealized and in reality cannot be fully used for all hours (of the year). Out of initially analysed 83 MW and 244 MW in Slovenia and Austria, the detailed “FAT analysis” has been performed on 71 MW and 183 MW, respectively. In the survey we have analysed the available capacity in 1, 5, 10, 15, 30 and 60 minutes

after the activation notification. The survey has revealed that the flexible C&I units in Austria are capable of faster ramping rates than the units in Slovenia. The results show that initially the Austrian units (on average) can respond slower than Slovenian by reaching 18%, compared to 36% of total flexible capacity within 1 minute. It follows a steep increase in ramping rate where the units in Austria already can fulfil 92% of total request, while in Slovenia "only" 72%. The full activation time recorded in the Austrian case is 10 minutes, while in Slovenia the FAT could be considered as 15 minutes if 99% of the total flexible capacity would be used. The tables below are condensing the results of the "FAT survey" as well as their extrapolation to the entire potential.

Table 14: Results of the "FAT survey" as well as their extrapolation to the entire DR/DG potential (case Slovenia)

	Full Activation Time (minutes)					
	<1	<5	<10	<15	<30	<60
Available capacity [MW]	25	51	66	71	71	71
Available capacity [%]	36%	72%	92%	99%	100%	100%
Available capacity of 83 MW [MW]	30	59	76	82	83	83
Available capacity of 36 MW [MW]	13	25	33	35	36	36
Available capacity of 8 MW [MW]	3	6	7	8	8	8
Total C&I customers in SI [MW]	45	90	116	125	126	126

Table 15: Results of the "FAT survey" as well as their extrapolation to the entire DR/DG potential (case Austria)

	Full Activation Time (minutes)					
	<1	<5	<10	<15	<30	<60
Available capacity [MW]	33	168	183	183	183	183
Available capacity [%]	18%	92%	100%	100%	100%	100%
Available capacity of 244 MW [MW]	43	224	244	244	244	244
Available capacity of 120 MW [MW]	21	110	120	120	120	120
Available capacity of 8 MW [MW]	38	196	213	213	213	213
Total C&I customers in AT [MW]	102	530	577	577	577	577

6.4 Conclusions and discussion

Based on the survey results within two of the four participating countries in FutureFlow we have made our best estimates, which are a subject of arbitrage and sensitivity. The relative flexible potentials in both analysed cases have produced comparable results (0,0134 compared to 0,0131 MW/GWh), which is indicating that the surveys' results can be considered as valid. The estimation of flexible potential of other countries using conservative estimation of potential at 0,013 MW/GWh therefore seems feasible. The total estimated flexible potential is estimated at 1.522 MW in all four countries together. The estimated survey results of flexible potential capacity, compared to the theoretical maximum potential taken from the literature are presented in Table 16, while the DR/DG flexibility as a dependant variable of full activation time can be seen in Table 17 (based on the average values identified for Slovenia and Austria).

Table 16: Estimated survey results of flexible potential capacity

	Estimated Flexible Capacity (survey)	Estimated Theoretical Max Flexible Capacity (other authors)	index
	MW	MW	%
Slovenia	126	305	41%
Austria	577	1,102	52%
Hungary (≈)	374	837	45%
Romania (≈)	445	1,193	37%
total	1,522	3,437	44%

Table 17: DR/DG flexibility as a dependent variable of full activation time

	Full Activation Time (minutes)					
	<1	<5	<10	<15	<30	<60
Available capacity SI [MW]	45	90	116	125	126	126
Available capacity AT [MW]	102	530	577	577	577	577
(≈)Available capacity HU [MW]	100	306	360	373	374	374
(≈)Available capacity RO [MW]	119	363	427	442	444	445
total C&I FAT [MW]	366	1,289	1,480	1,517	1,521	1,522