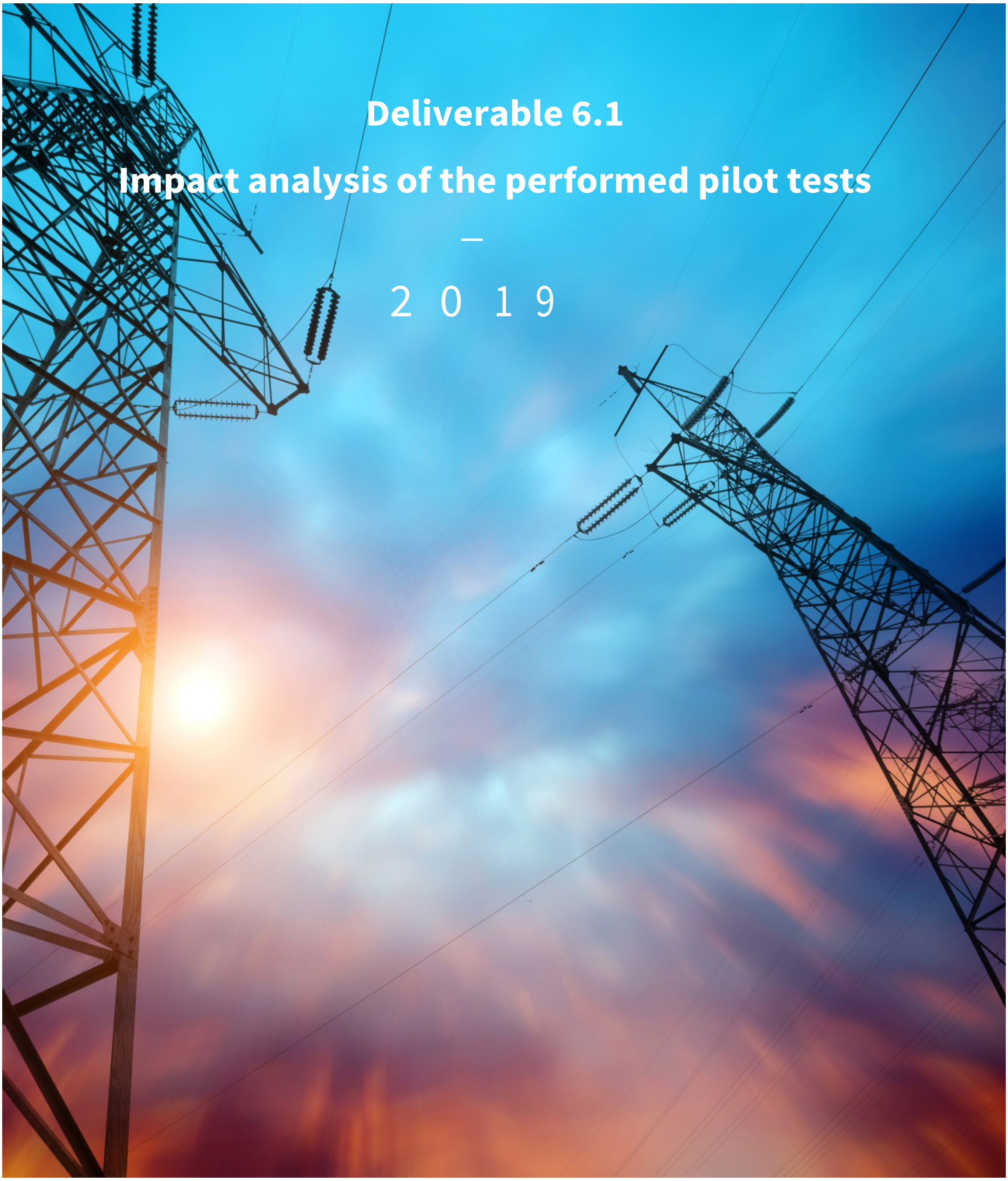
FutureFlow



# Deliverable 6.1

# Impact analysis of the performed pilot tests

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2019

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| 0.5 | 9.10.2019 | ELES | Review |

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## Table of acronyms

| Acronym | Meaning |
|---|---|
| ACE | Area Control Error |
| aFRR | Automatic Frequency Restoration Reserve |
| BEP | Break Even Point |
| BSP | Balancing service provider |
| CAF | Common activation function |
| CB | Critical Branch |
| CO | Critical Outage |
| DG | Distributed generation |
| DR | Demand response |
| EMS | Energy Management System |
| FCR | Frequency Containment Reserve |
| FF | FutureFlow |
| FTE | Full Time Employees |
| HW | Hardware |
| ICT | Information and Communication technology |
| LFC | Load Frequency Control |
| mFRR | Manual Frequency Restoration Reserves |
| RTU | Remote Terminal Unit |
| TSO | Transmission system operator |
| VPN | Virtual Private Network |
| VPP | Virtual Power Plant |
| SW | Software |
| | |

# Glossary

Refer to ENTSO-E glossary, https://www.entsoe.eu/data/data-portal/glossary/Pages/home.aspx.

# The aim of the FutureFlow Project

Four European TSOs of Central-Eastern Europe (Austria, Hungary, Romania, Slovenia), associated with power system experts, electricity retailers, IT providers and renewable electricity providers, propose to design a unique regional cooperation scheme: it aims at opening Balancing and Redispatching markets to new sources of flexibility and supporting such sources to act on such markets competitively. By means of a prototype aggregation solution and renewable generation forecasting techniques, flexibility providers – distributed generators (DG) and commercial and industrial (C&I) consumers providing demand response (DR) – are enabled, to provide competitive offers for Frequency Restoration Reserve (including secondary control activated with a response time of 30 seconds and full activation time of 15 minutes). Retailers act as flexibility aggregators and pool the resource in order to provide the products required by the TSO. A comprehensive techno-economic model for the cross border integration of such services involves a common activation function (CAF) tailored to deal with congested borders and optimized to overcome critical intra-regional barriers. The resulting CAF is implemented as a cloud solution of a prototype Regional Balancing and Redispatching Platform, which makes research activities about cross-border integration flexible while linking with the aggregation solution. Use cases of growing complexity are pilot-tested, going from the involvement of DR and DG into national balancing markets to cross border competition between flexibility providers. Based on past experience with tertiary reserve, participating C&I consumers and DG are expected to provide close to 40 MW of secondary reserve. Impact analyses of the pilot tests together with dissemination activities towards all the stakeholders of the electricity value chain will recommend business models and deployment roadmaps for the most promising use cases, which, in turn, contribute to the practical implementation of the European Balancing Target Model by 2020.

## Project Partners

| No | Name | Short name | Country |
|---|---|---|---|
| 1 | ELES DOO SISTEMSKI OPERATOR PRENOSNEGA ELEKTROENERGETSKEGA OMREZJA | ELES, d.o.o. | Slovenia |
| 2 | AUSTRIAN POWER GRID AG | APG | Austria |
| 3 | MAVIR MAGYAR VILLAMOSENERGIA-IPARI ATVITELI RENDSZERIRANYITO ZARTKORUEN MUKODO RESZVENYTARSASAG | MAVIR ZRT | Hungary |
| 4 | COMPANIA NATIONALA DE TRANSPORT ALENERGIEI ELECTRICE TRANSELECTRICA SA | TRANS | Romania |
| 5 | ELEKTROINSTITUT MILAN VIDMAR | EIMV | Slovenia |
| 6 | ELEKTROENERGETSKI KOORDINACIONI CENTAR DOO | EKC | Serbia |
| 7 | ELEKTRO LJUBLJANA, PODJETJE ZA DISTRIBUCIJO ELEKTRIČNE ENERIJE IN DRUGIH ENERGENTOV, SVETOVANJE IN STORITVE, D.O.O. | EL | Slovenia |
| 8 | GEN-I, TRGOVANJE IN PRODAJA ELEKTRICNE ENERGIJE, D.O.O. | GEN-I, d.o.o. | Slovenia |
| 9 | SAP SE | SAP SE | Germany |
| 10 | CYBERGRID GMBH | CYBERGRID | Austria |
| 11 | GEMALTO SA | GTO | France |
| 12 | 3E NV | 3E | Belgium |

# Executive summar

In delivery D6.1. the assessment of pilot tests is done, and the impacts of the DR&DG potential on the technology and economic benefits are analysed. Basic findings of the real-life tests of DR&DG in all four involved TSOs control areas are presented and analysed in the perspective of the present state of the aFRR in those areas. Initial assumptions are revised, and a final assessment of potential is given.

The first chapter represents the introduction into the deliverable.

In the second chapter a follow up of the market research is presented regarding the DR&DG potential. The extensive literature research has shown the existence of large flexibility potential  across the EU. However, there are numerous factors contributing to the reduction of the theoretical potential towards the actually realistic amount. In our attempt to locate the true flexibility potential we initiated a bottom-up research that resulted in to the identification of approximately 1289 MW flexibility potential, which can be activated within the required 5 minute time frame.

We have successfully designed and implemented the required IT infrastructure (for more details please refer to WP2 and WP3) and gathered more than 90 real active participants (end users) to join our pilot tests (for more details please refer to WP5).

More than 300 hours of testing confirmed our estimations from the WP1 regarding(unused) flexibility potential among existing DR/DGs. Throughout the different phases of WP5 (Pilot tests) we have identified the diverse array of suitable DR/DG technologies. These vary in the extent of suitability for aFRR that is demonstrated from the perspectives of the speed of response (i.e. full activation time), precision in following the set-point (i.e. stability of regulation power delivery), duration of regulation power provision. On the other hand, the differences have been found to exist also in the ease of technical integration of the DR/DG into the virtual power plant (VPP), (average) automation levels of the sectors/areas, existence of (energy) storage capabilities etc. In general, the pilot test results have shown that the speed, stability and duration of aFRR delivery is sufficient, while the suitable identified capacities for aFRR are available in minor part than those suitable for other, less demanding flexibility services.

In the third chapter, the cross-zonal capacity (CZC) availability and representation has been analysed. The general direction within the FutureFlow is to analyse in parallel both CZC approaches, and to develop the tools to support both of them. The pilot tests are done with ATC-based approach and it was necessary to investigate the influence of ATC vs Flow-based capacities application as a combination of pilot tests and simulations. These analyses confirmed the supremacy of calculated flow based CZC upon the usage of remaining ATC. Flow-based capacities in the observed timestamps, provided uncongested situation, maximal aFRR exchange and lowered activation costs.

The fourth chapter covers a techno-economic model quantification of the impacts cross-border balancing mechanism, focusing on the aggregation of the DR&DG potential. The model takes into account results from the pilot tests and provides an extrapolated potential from the pilot project results. Current demand and costs for aFRR capacity and energy in four participating TSOs are evaluated, and revenue potential for the new market players; DR&DG integrated into the aggregators is analysed. The costs of the VPP has been analysed, and the comparison between all four markets is presented.

With the development of new market players also benefits for the stakeholders are expected. We identified and presented a few of them, like a better utilisation of the existing energy resources, taking advantage of the geographical distribution of the resources, new jobs opportunities, customer empowerment and positive environmental effects.

# 1 Introduction

## 1.1 Outline

The main tasks of the FutureFlow project:

- To design a unique regional cooperation scheme for four European TSOs of Central-Eastern Europe (Austria, Hungary, Romania, Slovenia).
- To design a 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.
- To make a prototype aggregation solution and renewable generation forecasting techniques to test flexibility providers – distributed generators (DG) and commercial and industrial (C&I) consumers providing demand response (DR) in performing aFRR and re-dispatching services.
- To build a comprehensive techno-economic model for the cross-border integration of such services with a common activation function (CAF) as a cloud based solution.
- To quantify the impacts of extrapolated cross-border balancing mechanism including DR & DG.

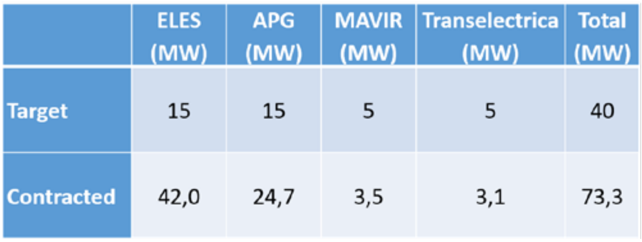
In WP1, cross-border integration of the aFRR markets with DR&DG were analysed. The existing potential of flexible power (including RES) that is available in the four control areas was evaluated and 318 MW of theoretical flexible capacity was identified.

*Table 1: Identified actual flexible capacity potential within analysed organizations.*

| (MW) | SI | AT | HU | RO |
|---|---|---|---|---|
| **DR Industry** | 43,9 | 112,7 | 50 | 12,0 |
| **DR Tertiary** | 16,1 | 0,5 | n.a. | 0,8 |
| **Distributed generation** | 1,9 | 40,2 | n.a. | 18,3 |
| **Other** | 21,2 | n.a. | n.a. | n.a. |
| **Total** | 83,2 | 153,4 | 50 | 31,1 |

30 to 45 MW of C&I DR&DG units was the target pool for FF, which we have even exceed and finally contracted 73,3 MW of flexibility from DR&DG.

*Table 2: Contracted flexibility from DR&DG*



| | ELES (MW) | APG (MW) | MAVIR (MW) | Transelectrica (MW) | Total (MW) |
|---|---|---|---|---|---|
| **Target** | 15 | 15 | 5 | 5 | 40 |
| **Contracted** | 42,0 | 24,7 | 3,5 | 3,1 | 73,3 |

In parallel with identifying the potential of DR&DG activities, a prototype DR&DG

flexibility aggregation platform for aFRR with emphasis on security and forecasting was developed.

The main focus in the early stage was on simulations, which helped us to choose the cross-border balancing and re-dispatching markets design. The market design has a lot of elements and parameters that have different effects on the Target Model, such as the Full Activation Time (FAT), bid validity, stepwise or continuous control signal, control demand or control request activation, pricing and settlement methodology etc. For comparison between current and proposed solution, we set up two base cases. Base case A was the results of real-life data (March 2017) for each country separately. In Base case B was the migration toward our target model (FAT 5min, activation merit order, stepwise, products of the 1MW size, valued for 1 hour, prices as on March 2017) was done. Those two base cases we compared for three possible technical solutions (Use cases). To choose the right target model with the best technical performances (such as ACE quality) and also other indicators, such as aFRR market liquidity, the complexity of implementation, volatility three use cases were investigated:

- Integration Case 1: Control Demand / standard bids
- Integration Case 2: Control Target / standard bids
- Integration Case 3: Control Target / standard&specific bids

With introduced regional cooperation, where CZC is represented in parallel with:

- ATC constraints
- Flow-based constraints

The FF Integration Case 1 based on Control Demand activation with Standard Product showed the best results and was chosen as a target model.

*Table 3: FF target model.*

| | |
|---|---|
| **Minimum bid to the balancing market**, *i.e.* product resolution (in size) at each product bin (in time). | 1 MW |
| **Is aggregation allowed to reach the necessary product resolution** (in size)**?** | Yes |
| **Are demand response aggregators participating in the aFRR market?** | Yes |
| **At which timeframe must bids be submitted,** *i.e.* what's the procurement cycle (distance to real-time)**?** | D-1 |
| **Is submitting a symmetrical bid a necessity?** | No |
| **At which resolution is the balancing capacity procured,** *i.e.* what's the product resolution (in time)**?** | 1h bid<br>15min act |
| **What is the asked full activation time?** | 5min |

| | |
|---|---|
| **What is the allowed tolerance limit?** | Envelope in D6.3[1] |
| **Activation rule** | Merit Order |
| **Activation rule** | Stepwise |
| **Settlement** | Marginal pricing |

In WP3, we started to design the prototype for Regional Balancing and Redispatching Platform with Common Activation Function (CAF) for aFRR.

We were dealing with transmission grid, live operational systems, and as such, we cannot compromise their operations or stability. Interfacing with SCADA/EMS systems with load frequency controller (LFC control) towards cloud platform and BSP must follow security first concerns. Therefore, we implemented a demo architecture – DEMOX. DEMOX is hosted on single TSO (ELES) and enable us to guarantee gradual system testing of building blocks and interfacing with existing IT infrastructures at TSO and BSP. It enabled us to verify the system response of real-life DR&DG units before we activated them and thereby mitigated and minimised the financial risks exposed to the aggregators and participating consumers.

In WP4, real-life tests began, where the virtual power plant integrating DR&DG units were tested through 4 use case scenarios:

- Use case 1 - Testing of building blocks and the IT prototype solution
- Use case 2 - DR/DG integration within each of the four control zones independently
- Use case 3 - DR/DG integration within the four control zones coupled with Cross Zonal Capacity
- Use case 4 - DR/DG integration, with the possibility of switching among BSPs.

## 1.2 Objective

The aim of this deliverable is to inform the reader about the results of pilot tests providing aFRR using DR and DG units in an integrated market of four countries together with quantification of the benefits of the stakeholders and social welfare.

## 1.3 Impacts analysis of the performed pilot tests

There are many studies done on the subject and several examples of actual DR&DG providing flexibility to the electrical transmission system. In Austria, one of the partners in the FF project, there is already established cooperation with Germany (since 2016) and allows participation of the aggregation and demand response in balancing services since 2014. But even for Austria, FF brought a unique experience in terms of including RES in the aggregation portfolio and the integration with the TSOs, that have currently very

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[1] https://extranet.eles.si/futureflow/Shared%20Documents/WP6/D6.3/2018%2010%2017%20FutureFlow_D6.3_Reviewed%20V1.1.DOCX (page 42)

different market model.  For Slovenia, Hungary and Romania this project was of critical importance, to gain experiences of balancing cross border cooperation in which participate the aggregation of small DR&DG units.

Successful completion of all four use cases brought all technologies at the level needed to prepare large scale demonstrations on the most promising business options. Altogether we were able to include 95 units participated in almost 300 hours of tests. On average, 4 tests were performed each week, with 20+ units participating every week.

### 1.4 Relation to other work packages

Work package 6 (WP6) with the title “Impact analysis of the performed pilot tests” is the summary of previous work packages. It provides the assessment of the simulations, pilot tests and analysis done during the FutureFlow project. Outputs of this work package bring key knowledge and information for the partners and stakeholders for participation in the aFRR integrated EU market.

## 2 Follow up market research regarding the DR&DG potential

Revision of the initial aFRR estimation from WP1 Based on outcomes and results from pilot projects the task sizes the actual potential of suitable loads to participate in the aFRR services in each of the project regions based on the technical requirements and economic limitations. The task merges the basic findings about DR potential in the involved TSOs control areas and the state of the aFRR in those areas with the pilot project results and outcomes.

### 2.1 aFRR estimation from WP1

The flexibility potential has initially been estimated in WP1/D1.1 in order to evaluate the market depth and potential for growth. Secondly the results of the analysis have been used to guide the acquisition of FutureFlow pilot participants – the C&I DR/DGs.

The extensive literature research has revealed that many other authors reported on the existence of large flexibility potential being available across the EU. We have synthesised their results into the following Table 4, where theoretical maximum was estimated in a top-down manner to several hundred MWs of flexibility in each of the countries (control zones).

*Table 4: Theoretical flexible capacity potential as identified in D1.1*

| | SI (MW) | AT (MW) | HU (MW) | RO (MW) |
|---|---|---|---|---|
| **DR Industry** | +119/-16 | +315/-103 | +156/-37 | +677/-87 |
| **DR Tertiary** | +91/-79 | +363/-321 | +349/-295 | +231/-198 |
| **DR Residential** | +128/-789 | +602/-3.546 | +530/-2.938 | +755/-4.896 |
| **Distributed generation** | +581/-581 | +6.086/-6.086 | +882/-882 | +6.408/-6.408 |
| **Total** | +894/1.440 | +6.965/-9.828 | +1.845/-4.080 | +7.966/-11.485 |

However, there are numerous factors contributing to the reduction of the theoretical potential towards the actually realistic amount. Therefore, in our attempt to locate the true flexibility potential we initiated a bottom-up research that has led to the discovery of 318 MW of potential flexible capacity amongst the surveyed companies (in all four countries combined).

In an attempt to extrapolate the findings of the bottom-up field survey towards the entire population (all available potential flexible capacity) we have estimated in Deliverable 1.2 the existence of approximately 1500 MW total, as presented in detail in Table 5 below.

*Table 5: Flexible capacity potential that is extrapolated from the field survey*

| | **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%** |

In an attempt to further specify the truly available aFRR flexibility we estimated that about 1289 MW can be activated within the required 5 minutes, as shown in the Table 6 below.

*Table 6: Flexible capacity potential that is extrapolated from the field survey as a function 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** |

All these estimations above presented opinions of: either other authors or potential flexibility providers themselves. None of these results have base in the findings of the FutureFlow pilot tests.

## 2.2 Summary of outcomes and results from pilot projects

Before the actual tests with real responses could be performed all the building blocks of the IT prototype solution had to be thoroughly tested. That is cowered in Use case 1, where a total of six tests were performed:

- Level 1: BSP- DR/DG
- Level 2: DEMO site – BSP
- Level 3: FF Cloud – DEMO site
- Level 4: TSO – DEMO site
- Level 5: Cybersecurity testing
- Level 6: Scalability testing

All levels of the systems were successfully tested and given green light, which was a prerequisite for the beginning of the actual pilot tests. The result of this project isn't just a theoretical research but an actual fully operational platform that is capable of performing real activations of aFRR in multiple TSO regions.

The physically performed tests are dividedinto three groups:

- Prequalification tests was done with manually prepared signals described in D4.1
- UC2 test signals included usage of DEMO platform with LFC controllers, local optimization function and prearranged bidding
- UC3 testing was done with included: VPPs, DEMO site, real-time LFC control (closed-loop operation), active automatic bidding, real-time monitoring and global optimization in FF cloud provided by SAP

The results have showed that the response of the participating units can fulfill strict demand of full response in 5 min. During additional pilot tests using solar and wind power plants it has become clear that the forecast for a specific unit can deviate a lot on a day with unpredictable weather. There were only a handful of those units in the pool, so within a wider sample of units a better accuracy is expected.

*Figure 1: Example of the successfully performed test in Eles (Test ID number 216)*

Use case 4 addressed how an active resource is able to switch between two different VPPs. The results in the simulated environment have shown how it can be done. BSP must in that case make sure they have enough reserve in their portfolio so that the quality of ancillary services towards TSOs is sufficient by all terms.

A short summary of different technologies used in the tests:

- Hydro units (especially small power plants) showed fast and accurate response.
- Biogas and cogeneration units showed very fast and accurate responses.
- Industry showed fast responses (especially in AT, where the market is more developed) with sufficient accuracy.
- Diesel shows fast and accurate responses, but its use is not recommended for a larger number of short activations, so it is important where on the merit order list they are placed.
- Solar power plants showed very fast responses with great variability in accuracy (deviation from the forecast) that is closely related to the weather and
- Wind power plants showed fast responses but a very bad accuracy that was a consequence of a very unstable output that is closely related to the weather as well.

It is recomended  in order to improve the results with the existing set of units, an algorithm for organizing the priority of specific units in the VPP should be developed. The algorithm should accept the type and technical parameters of the units and arrange them into optimal priority list for achieving a fast and accurate response towards the TSOs.

Further research of this topic by including a large number of renewable energy sources into the existing platform is suggested to obtain a more statistically representative sample of processing. The results of this project are a good reference for the further integration of renewable energy sources into the system services.

## 2.3 Technical requirements and economic limitations

In WP1 we have reviewed the state of the aFRR market design that was valid for 2015.

The findings revealed large differences between the TSOs (APG, ELES, MAVIR, TRANSELECTRICA) in many aspects. These are presented in detail in Section 2 of the Deliverable 1.1.

Below we display the Table 7 with updated market requirements and economic limitations for the participating TSOs with data valid for 2019. The results show that the following changes occurred since 2015:

- In Austria (at APG's zone) the minimum bid size has reduced from 5 to 1 MW, aFRR capacity and energy bids are collected daily (day ahead of delivery). Bid resolution reduced to 4-hourly blocks. The price reduced considerably, for both upward and downward aFRR capacity as well as for energy, by more than 50%.
- In Slovenia (at ELES's zone) symmetrical bids are no longer required. The average price for provision of aFRR capacity in 2019 has reduced by more than 55% to 9,05 and 9,02 EUR/MW/h for upward and downward capacity, respectively. On the other hand the average price for provision of aFRR upward and downward energy have changed by 50 and 27 %, respectively, to benefit the aFRR providers. .
- In Hungary (at MAVIR's zone) the demand response aggregators have appeared in the market. There have been some changes in the prices as well: the upward capacity price has increased from 12 to 20 EUR/MW/h, while downward capacity price declined to 10 EUR/MW/h. The energy prices have not changed much for upward (less than 10%), while the downward regulation energy reduced significantly from 37 to 1 EUR/MWh (the later is paid by BSPs to TSO).
- In Romania (at TRANSELECTRICA's zone) the price for aFRR capacity increased by 30%. Due to changes in balancing market bid limitations, price of provided aFRR energy changed significantly; for upward regulation it has more than doubled (224%) and for downward regulation it dropped to 5% of previous prices

*Table 7: aFRR market design and characteristics in the 4 control zones*

| | **APG**<br>*Austria* | **ELES**<br>*Slovenia* | **MAVIR**<br>*Hungary* | **TEL**<br>*Romania* |
|---|---|---|---|---|
| **Minimum bid to the balancing market**, *i.e.* product resolution (in size) at each product bid (in time). | 1 MW | 1 MW | 1 MW | 10 MWh |
| **Is aggregating generators allowed to reach the necessary product resolution** (in size) **?** | Yes | Yes | Yes | No |
| **Are demand response aggregators participating in the aFRR market?** | Yes | Yes | Yes | No |
| **At which timeframe must bids be submitted,** *i.e.* what's the procurement cycle (distance to real-time)**?** | weekly-1 | In November, annually | D-1 | D-1 |
| **Is submitting a symmetrical bid a necessity?** | No | No | No | Yes |
| **At which resolution is the balancing capacity procured,** *i.e.* what's the product resolution (in time)**?** | 4h | yearly bid | 1h bid,<br>15min act | 1h |

| | | | | |
|---|---|---|---|---|
| **What is the asked full activation time?** | 5 min | 5 min | 15 min<br>Min 2 MW/min | 15 min<br>Min 2 MW/min |
| **What is the allowed tolerance limit?** | 3% | Contractually set (in MW per BSP), depends on technology | Min(1%, 2 MW) | 1% |
| **Average price for provision of aFRR capacity in 2019 (upward / downward in EUR/MW/h)** | Peak+3,07<br>Off-peak+1,87<br>Peak -1,52<br>Off-peak -3,12 | 9,05 / 9,02 | 20 /10 | 16,78 / 16,78 |
| **Average price for provision of aFRR energy in 2019 (upward / downward in EUR/MWh)*** | 89,90/9,54 | 97,27 / 15,37 | 130 / 1 | 147,32 / 0,03 |

** Positive prices of upward regulation energy and negative prices of downward regulation energy indicate payment by TSO to the BSP, and vice versa.*

## 2.4 Actual potential of suitable loads to participate in the aFRR services

The results of the pilot tests have largely confirmed the estimations from the WP1 on the abundance of (unused) flexibility potential among existing DR/DGs. Throughout the different phases of WP5 (Pilot tests) we have identified the diverse array of suitable DR/DG technologies. These vary in the extent of suitability for aFRR that is demonstrated from the perspectives of the speed of response (i.e. full activation time), precision in following the set-point (i.e. stability of regulation power delivery), duration of regulation power provision. On the other hand, the differences have been found to exist also in the ease of technical integration of the DR/DG into the virtual power plant (VPP), (average) automation levels of the sectors/areas, existence of (energy) storage capabilities etc. However, the reasons from where those differences originate from have not been the focus of this research.

In general the pilot test results show that the speed, stability and duration of aFRR delivery is sufficient, while the capacities, which are suitable for aFRR are significantly less than those suitable for other, less demanding flexibility services. More specifically are findings on DR/DG suitability for aFRR are stated below:

- The “spinning” generation units (DGs), such as small hydro power plants, natural gas CHPs, biogass plants, steam turbines etc, are technically very well suited to participate in the aFRR services, since they are fast to respond to any requested change in the output power. The downside that we identified is that DGs are mostly capable to provide negative aFRR reserve capacity since they operate at (close to) full capacity that is available at any given moment. The reasons for that may be their motivation to maximize electricity production (maximisation of financial revenues), lack of fuel reservoirs (hydro run-of-river) or purchase contract responsibilities (CHP engines’ heat production and sales).
- The solar PV and wind turbine RES technologies have shown considerable capacity potential as well as quite reasonable (active) power control ability. This may have been a surprise and their readiness to participate in aFRR services was remarkable at certain

moments, namely in times of abundant and constant RES energy source (sun, wind) input. However throughout the pilot tests these periods have shown the lack of RES technologies to be a viable to qualify for aFRR provision in full. The reason lies mainly in their (well reported) high intermittency and variability that leads to inaccurate forecasts, baseline creation and validation of regulation delivery. We conclude that solar PVs and wind turbines are not suitable for aFRR provisions at the current state of organisation on the aFRR markets. Nevertheless, the provision of small shares of capacity from large number of units (such as wind parks) may be feasible in a frequent (e.g. intraday) aFRR capacity market organisation in the future.

- The loads (DR) that we were able to test consisted of electrolysis (metal production) and water cooling units in the industry. We have identified them suitable although more complex for the provision of aFRR then DGs. The reason lies in the fact that the majority of large electrical loads (i.e. large flexibility capacity potentials) produce the products that represent the core business stream of the corresponding companies. Therefore even though the potential for flexibility existed we found the owners were not willing to risk any changes to the production process regarding their quality. Further, we identified in many cases during recruitment phase that the consumption processes were not designed to enable flexibility, since sufficient energy or material storage was missing. In this sector, within DR, we estimate the existence of the most unused aFRR potential, should overcome the existing barriers in the future.

Based on the pilot tests that we have performed within the duration of one year we can conclude that there exists significant amount of untapped flexibility potential, which confirms our initial estimations as described in section 2.2.1. However, the aFRR has proven to be the most challenging ancillary service, as expected, therefore not all tested flexibility is suitable for its usage. The actual estimation of all existing true aFRR potential (for each of the control zones) based on flexibility acquisition and pilot testing that we performed within FutureFlow proved to be a figure that is difficult to define. There exist too many factors and assumptions which influence the results therefore the figures in megawatts of available (existing) true aFRR potential cannot be stated as a single figures with high certainty. Some of these factors include: seasonal variations in electricity production (RES, biomass), (daily) weather related electricity production (hydro, wind, solar), technical potential versus potential with economical constraints that needs to be approved, aFRR price level impacts, amount of penalties regardingpower delivery reglation, regulatory barriers permitting certain resources to participate (such as receivers of subsidies in certain countries), aFRR product duration (yearly vs. hourly), frequency of auctions and gate closure time (GCT) before delivery (year ahead vs day ahead)etc.

# 3 Cross Zonal Capacity among the control zones and the potential for cross border balancing

## 3.1 Approach

The Deliverable 1.4 “Results from simulations of XB balancing and re-dispatching mechanisms with Common Activation Function (CAF)” verified the theoretical background from the Deliverable 1.2 and provided the simulation support about the availability and usage of Cross Zonal Capacity (CZC) for the exchange of aFRR energy.

The main messages are:

- The two different approaches can be applied for defining the transmission constraints, for the real-time exchange of aFRR energy:
    - ATC-based capacities, as capacity remaining after the Intra-day commercial trade.
    - Flow-based (PTDF/RAM) capacities, as capacity recalculated on the basis of Intra-day network models for each following timestamp.
- ATC values (as remaining after Intra-day) provide more conservative constraints to the balancing exchanges since original NTC values are currently calculated at two-days-ahead time horizon.
- Being calculated as late as possible, FB values can be more relaxed in sense of forecasting the network situations roughly half an hour before its application.
- Reservation of portion of CZC for the needs of cross-border balancing is applicable according to the EB GL, but not desirable since it definitely decreases the CZC for commercial exchanges, and it would be better to invest into the late Flow-based capacity recalculation for the needs of balancing.

The general direction within the FutureFlow is to analyse both CZC approaches, and to develop the tools to support both of them in parallel. The pilot tests are done with ATC-based approach. Since tests can not be repeated with different CZC but holding the same conditions, and due to the fact that pilot tests alter the small part of overall balancing portfolio of involved countries, it was necessary to investigate the influence of ATC versus Flow-based capacities application as a combination of pilot tests and simulations.

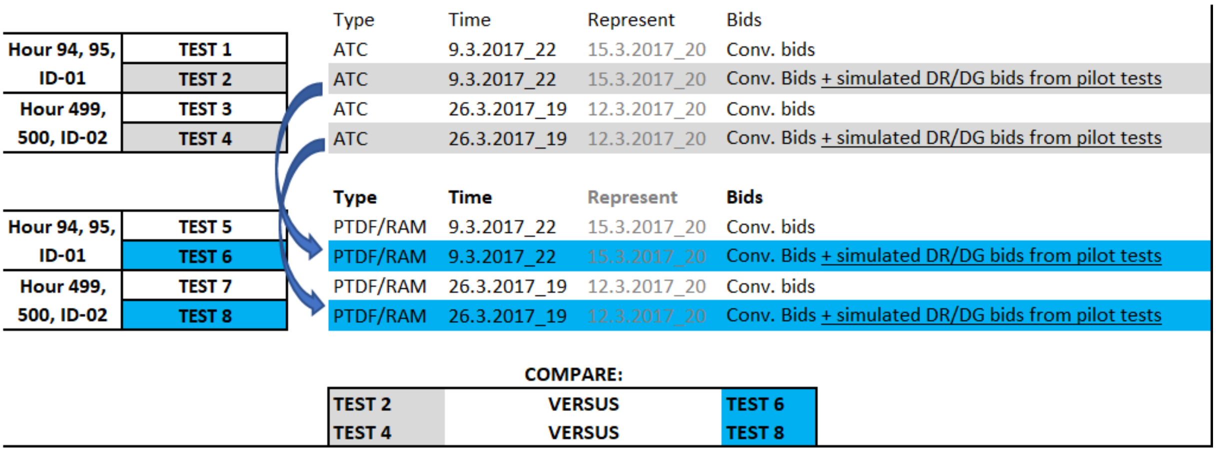
Tests were performed as follows:

- (ATC-based) Representative tests are selected:
    - “Test 1”: Hour 94, (regular day), using conventional bids (UC3_RE-01_ID-01)
    - “Test 3”: Hour 499, (extreme day), using conventional bids (UC3_RE-01_ID-02)
- (ATC-based) They are extended with the results of pilot tests related to DR/DG units:
    - “Test 2” = “Test 1”, with added response of DR/DG, as in pilot tests
    - “Test 4” = “Test 2”, with added response of DR/DG, as in pilot tests
- (Flow-based) The image of the Tests 1 and 3 are done with FB constraints:
    - “Test 5”: Hour 94, UC3, ID-01 (regular day), using conventional bids
    - “Test 7”: Hour 499, UC3, ID-02 (extreme day), using conventional bids
- (Flow-based) They are extended with the results of pilot tests related to DR/DG units:

- ○ "Test 6" = "Test 5", with added response of DR/DG, as in pilot tests
- ○ "Test 8" = "Test 7", with added response of DR/DG, as in pilot tests

The sequence is presented in the Table 8:

*Table 8: Comparison of ATC and FB tests*



| | | Type | Time | Represent | Bids |
|---|---|---|---|---|---|
| **Hour 94, 95, ID-01** | **TEST 1** | ATC | 9.3.2017_22 | 15.3.2017_20 | Conv. bids |
| | **TEST 2** | ATC | 9.3.2017_22 | 15.3.2017_20 | Conv. Bids + simulated DR/DG bids from pilot tests |
| **Hour 499, 500, ID-02** | **TEST 3** | ATC | 26.3.2017_19 | 12.3.2017_20 | Conv. bids |
| | **TEST 4** | ATC | 26.3.2017_19 | 12.3.2017_20 | Conv. Bids + simulated DR/DG bids from pilot tests |

| | | **Type** | **Time** | **Represent** | **Bids** |
|---|---|---|---|---|---|
| **Hour 94, 95, ID-01** | **TEST 5** | PTDF/RAM | 9.3.2017_22 | 15.3.2017_20 | Conv. bids |
| | **TEST 6** | PTDF/RAM | 9.3.2017_22 | 15.3.2017_20 | Conv. Bids + simulated DR/DG bids from pilot tests |
| **Hour 499, 500, ID-02** | **TEST 7** | PTDF/RAM | 26.3.2017_19 | 12.3.2017_20 | Conv. bids |
| | **TEST 8** | PTDF/RAM | 26.3.2017_19 | 12.3.2017_20 | Conv. Bids + simulated DR/DG bids from pilot tests |

**COMPARE:**

| | | |
|---|---|---|
| **TEST 2** | **VERSUS** | **TEST 6** |
| **TEST 4** | **VERSUS** | **TEST 8** |

The results for Test 3 and Test 4 (Table 8) are generally provided within the Deliverable 4.3. The difference of major system-wise KPIs among ATC-based and Flow-based run was analysed.

## 3.2 Cross zonal exchanges and congestions: comparison

The ATC-based Cross Zonal Capacities are the ones used within the UC3 pilot tests, as given in Table 9:

*Table 9: ATC values*

| ATC | | AT > SI | SI > AT | AT > HU | HU > AT | RO > HU | HU > RO |
|---|---|---|---|---|---|---|---|
| **Test 1,2** | (15/03, h20) | 174 | 1726 | 0 | 1200 | 1150 | 0 |
| **Test 3,4** | (12/03, h20) | 0 | 1900 | 0 | 1200 | 280.6 | 1029 |

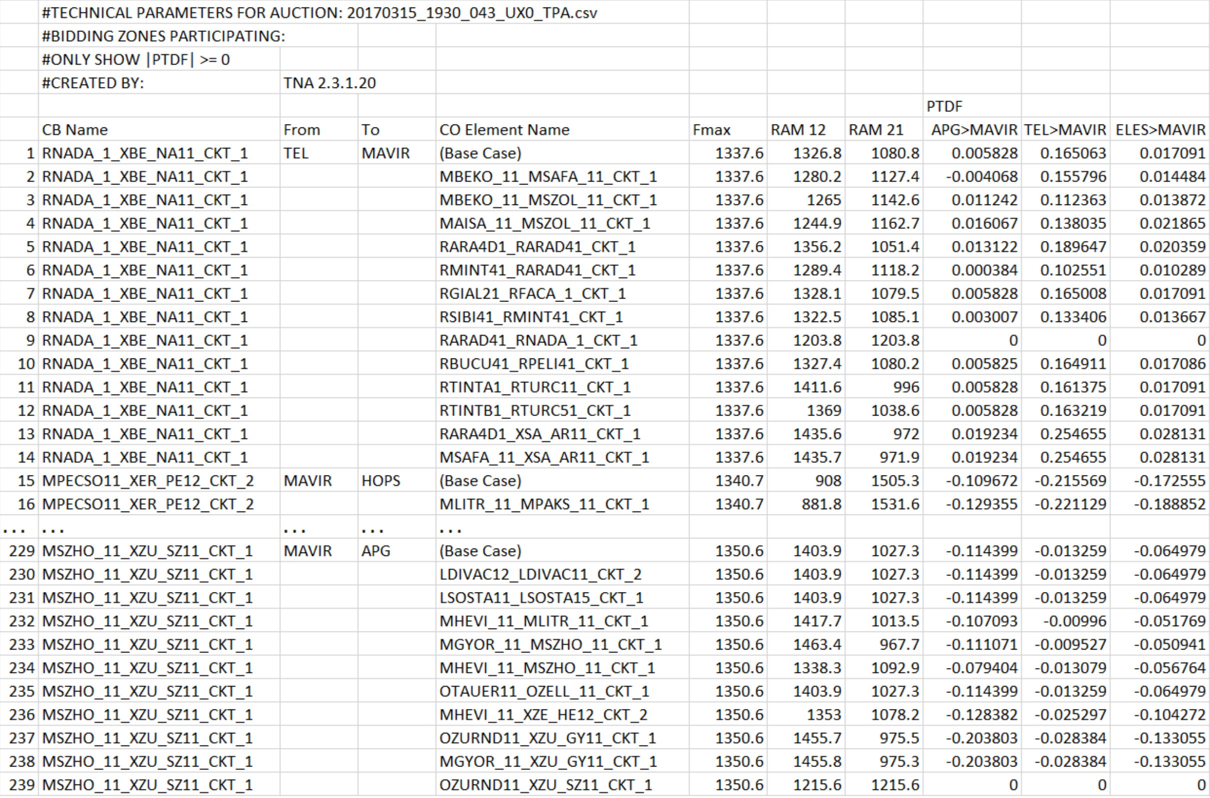
Generally, ATC-based tests record the congestions since real ATC values in certain directions were lower than the required maximal correction signal (Tests 3/4: RO-HU 280.6 MW), or they are even zero in certain directions (AT-HU in all tests, AT-SI in tests 3/4, HU-RO in tests 1/2), presented in the Table 9.

The Flow-based Cross Zonal Capacities are calculated on the basis of Intra-day merged network models for the same timestamps. They are defined for the selected 239 CB/CO pairs of interest for the exchanges among the concerned four countries (PTDF threshold >5%). Excerpt of PTDF/RAM matrix is provided at Table 10.

*Table 10: Flow-based values (excerpt)*

**FB**

| | | |
|---|---|---|
| **Test 5,6** | (15/03, h20) | **PTDF/RAM** 20170315_1930_043_UX0_TPA.csv |
| **Test 7,8** | (12/03, h20) | **PTDF/RAM** 20170312_1930_047_UX0_TPA.csv |



#TECHNICAL PARAMETERS FOR AUCTION: 20170315_1930_043_UX0_TPA.csv
#BIDDING ZONES PARTICIPATING:
#ONLY SHOW |PTDF| >= 0
#CREATED BY: TNA 2.3.1.20

| | | | | | | | | PTDF | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | CB Name | From | To | CO Element Name | Fmax | RAM 12 | RAM 21 | APG>MAVIR | TEL>MAVIR | ELES>MAVIR |
| 1 | RNADA_1_XBE_NA11_CKT_1 | TEL | MAVIR | (Base Case) | 1337.6 | 1326.8 | 1080.8 | 0.005828 | 0.165063 | 0.017091 |
| 2 | RNADA_1_XBE_NA11_CKT_1 | | | MBEKO_11_MSAFA_11_CKT_1 | 1337.6 | 1280.2 | 1127.4 | -0.004068 | 0.155796 | 0.014484 |
| 3 | RNADA_1_XBE_NA11_CKT_1 | | | MBEKO_11_MSZOL_11_CKT_1 | 1337.6 | 1265 | 1142.6 | 0.011242 | 0.112363 | 0.013872 |
| 4 | RNADA_1_XBE_NA11_CKT_1 | | | MAISA_11_MSZOL_11_CKT_1 | 1337.6 | 1244.9 | 1162.7 | 0.016067 | 0.138035 | 0.021865 |
| 5 | RNADA_1_XBE_NA11_CKT_1 | | | RARA4D1_RARAD41_CKT_1 | 1337.6 | 1356.2 | 1051.4 | 0.013122 | 0.189647 | 0.020359 |
| 6 | RNADA_1_XBE_NA11_CKT_1 | | | RMINT41_RARAD41_CKT_1 | 1337.6 | 1289.4 | 1118.2 | 0.000384 | 0.102551 | 0.010289 |
| 7 | RNADA_1_XBE_NA11_CKT_1 | | | RGIAL21_RFACA_1_CKT_1 | 1337.6 | 1328.1 | 1079.5 | 0.005828 | 0.165008 | 0.017091 |
| 8 | RNADA_1_XBE_NA11_CKT_1 | | | RSIBI41_RMINT41_CKT_1 | 1337.6 | 1322.5 | 1085.1 | 0.003007 | 0.133406 | 0.013667 |
| 9 | RNADA_1_XBE_NA11_CKT_1 | | | RARAD41_RNADA_1_CKT_1 | 1337.6 | 1203.8 | 1203.8 | 0 | 0 | 0 |
| 10 | RNADA_1_XBE_NA11_CKT_1 | | | RBUCU41_RPELI41_CKT_1 | 1337.6 | 1327.4 | 1080.2 | 0.005825 | 0.164911 | 0.017086 |
| 11 | RNADA_1_XBE_NA11_CKT_1 | | | RTINTA1_RTURC11_CKT_1 | 1337.6 | 1411.6 | 996 | 0.005828 | 0.161375 | 0.017091 |
| 12 | RNADA_1_XBE_NA11_CKT_1 | | | RTINTB1_RTURC51_CKT_1 | 1337.6 | 1369 | 1038.6 | 0.005828 | 0.163219 | 0.017091 |
| 13 | RNADA_1_XBE_NA11_CKT_1 | | | RARA4D1_XSA_AR11_CKT_1 | 1337.6 | 1435.6 | 972 | 0.019234 | 0.254655 | 0.028131 |
| 14 | RNADA_1_XBE_NA11_CKT_1 | | | MSAFA_11_XSA_AR11_CKT_1 | 1337.6 | 1435.7 | 971.9 | 0.019234 | 0.254655 | 0.028131 |
| 15 | MPECSO11_XER_PE12_CKT_2 | MAVIR | HOPS | (Base Case) | 1340.7 | 908 | 1505.3 | -0.109672 | -0.215569 | -0.172555 |
| 16 | MPECSO11_XER_PE12_CKT_2 | | | MLITR_11_MPAKS_11_CKT_1 | 1340.7 | 881.8 | 1531.6 | -0.129355 | -0.221129 | -0.188852 |
| ... | ... | ... | ... | ... | | | | | | |
| 229 | MSZHO_11_XZU_SZ11_CKT_1 | MAVIR | APG | (Base Case) | 1350.6 | 1403.9 | 1027.3 | -0.114399 | -0.013259 | -0.064979 |
| 230 | MSZHO_11_XZU_SZ11_CKT_1 | | | LDIVAC12_LDIVAC11_CKT_2 | 1350.6 | 1403.9 | 1027.3 | -0.114399 | -0.013259 | -0.064979 |
| 231 | MSZHO_11_XZU_SZ11_CKT_1 | | | LSOSTA11_LSOSTA15_CKT_1 | 1350.6 | 1403.9 | 1027.3 | -0.114399 | -0.013259 | -0.064979 |
| 232 | MSZHO_11_XZU_SZ11_CKT_1 | | | MHEVI_11_MLITR_11_CKT_1 | 1350.6 | 1417.7 | 1013.5 | -0.107093 | -0.00996 | -0.051769 |
| 233 | MSZHO_11_XZU_SZ11_CKT_1 | | | MGYOR_11_MSZHO_11_CKT_1 | 1350.6 | 1463.4 | 967.7 | -0.111071 | -0.009527 | -0.050941 |
| 234 | MSZHO_11_XZU_SZ11_CKT_1 | | | MHEVI_11_MSZHO_11_CKT_1 | 1350.6 | 1338.3 | 1092.9 | -0.079404 | -0.013079 | -0.056764 |
| 235 | MSZHO_11_XZU_SZ11_CKT_1 | | | OTAUER11_OZELL_11_CKT_1 | 1350.6 | 1403.9 | 1027.3 | -0.114399 | -0.013259 | -0.064979 |
| 236 | MSZHO_11_XZU_SZ11_CKT_1 | | | MHEVI_11_XZE_HE12_CKT_2 | 1350.6 | 1353 | 1078.2 | -0.128382 | -0.025297 | -0.104272 |
| 237 | MSZHO_11_XZU_SZ11_CKT_1 | | | OZURND11_XZU_GY11_CKT_1 | 1350.6 | 1455.7 | 975.5 | -0.203803 | -0.028384 | -0.133055 |
| 238 | MSZHO_11_XZU_SZ11_CKT_1 | | | MGYOR_11_XZU_GY11_CKT_1 | 1350.6 | 1455.8 | 975.3 | -0.203803 | -0.028384 | -0.133055 |
| 239 | MSZHO_11_XZU_SZ11_CKT_1 | | | OZURND11_XZU_SZ11_CKT_1 | 1350.6 | 1215.6 | 1215.6 | 0 | 0 | 0 |

As already happened within the simulation in D1.4, also here with flow-based capacities used under the actual simulations, there are no congestions, and we practically have copper-plate situation.

### Comparison, exchanges: Test 2 vs Test 6

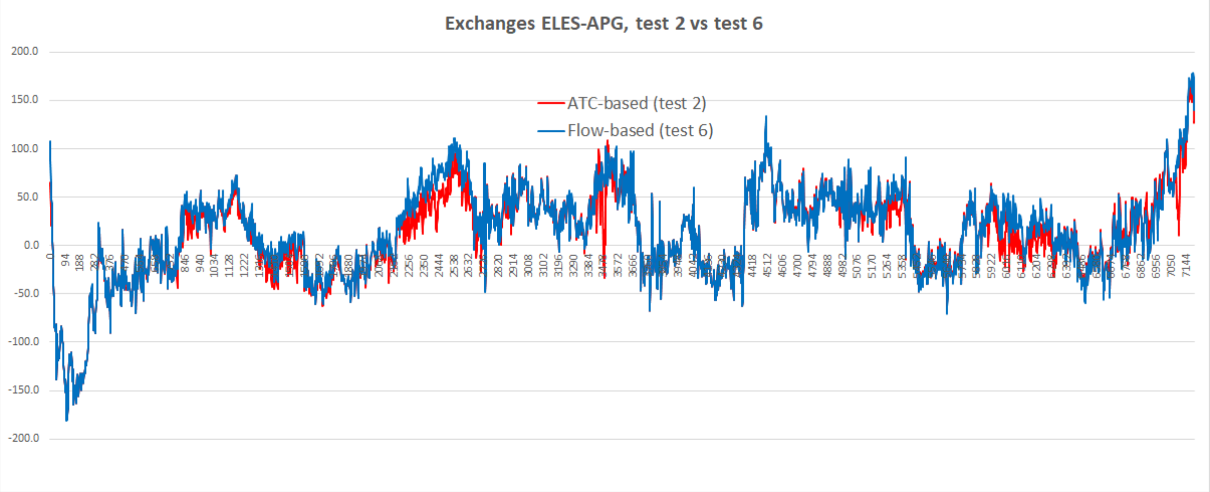


*Figure 2: Exchanges ELES-APG, with ATC based and Flow-based constraints (regular day)*

ATC APG-ELES=174 MW, makes no significant constraint at ATC-based case.

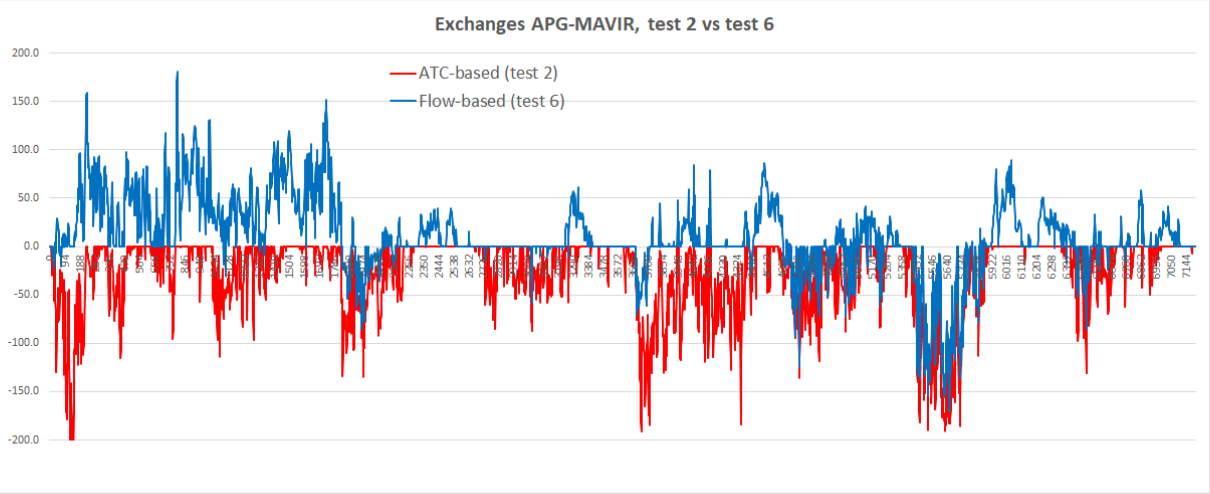


*Figure 3: Exchanges APG-MAVIR, with ATC based and Flow-based constraints (regular day)*

ATC APG-MAVIR=0 MW, which prevents the exchanges in this direction (no positive “red” exchanges), while FB case goes unconstrained.

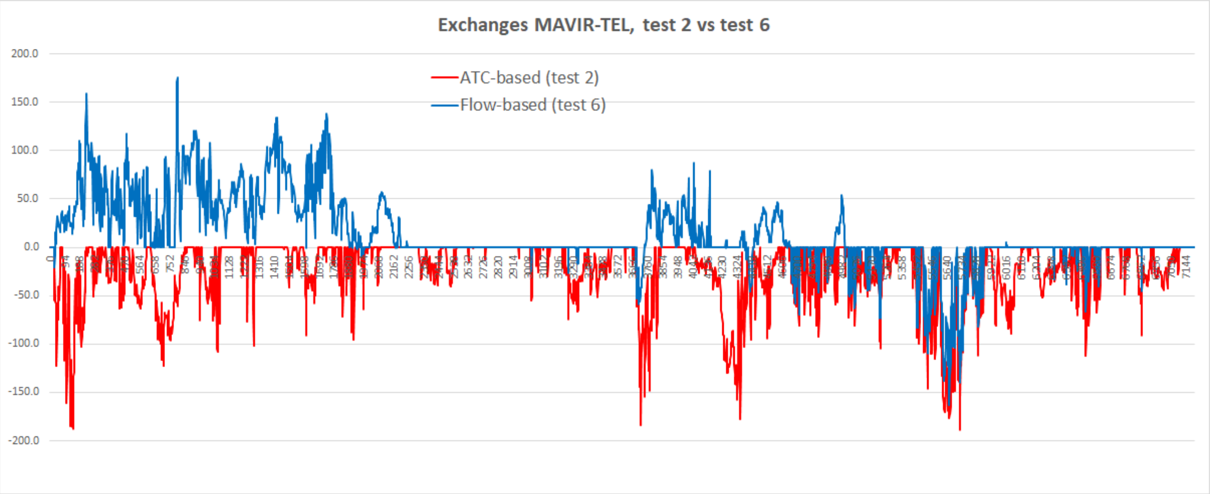


*Figure 4: Exchanges MAVIR-TEL, with ATC based and Flow-based constraints (regular day)*

ATC MAVIR-TEL=0 MW, which prevents the exchanges in this direction (no positive “red” exchanges), while FB case goes unconstrained.

**Comparison, exchanges: Test 4 vs Test 8**

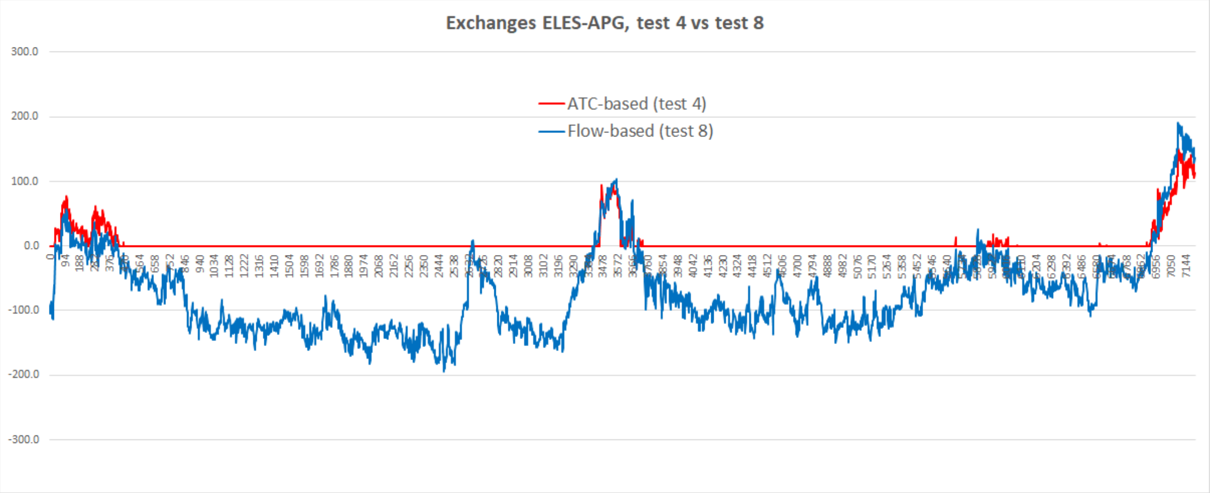


*Figure 5: Exchanges ELES-APG, with ATC based and Flow-based constraints (extreme day)*

ATC APG-ELES=0 MW, which prevents the exchanges in this direction (no negative “red” exchanges), while FB case (blue) goes unconstrained, and dominantly in the direction towards ELES.

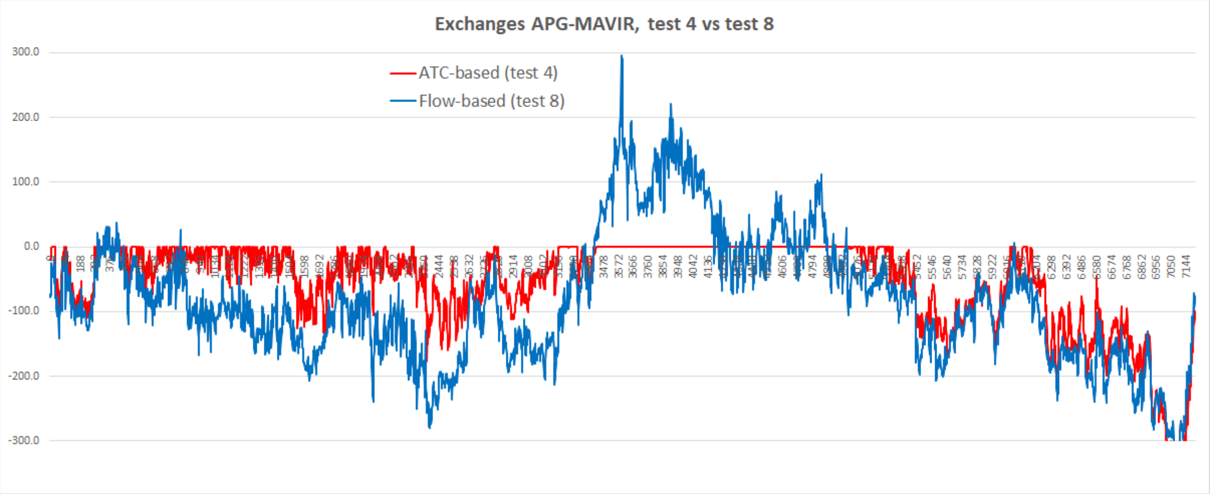


*Figure 6: Exchanges APG-MAVIR, with ATC based and Flow-based constraints (extreme day)*

ATC APG-MAVIR=0 MW, which prevents the exchanges in this direction (no positive “red” exchanges), while FB case (blue) goes unconstrained.

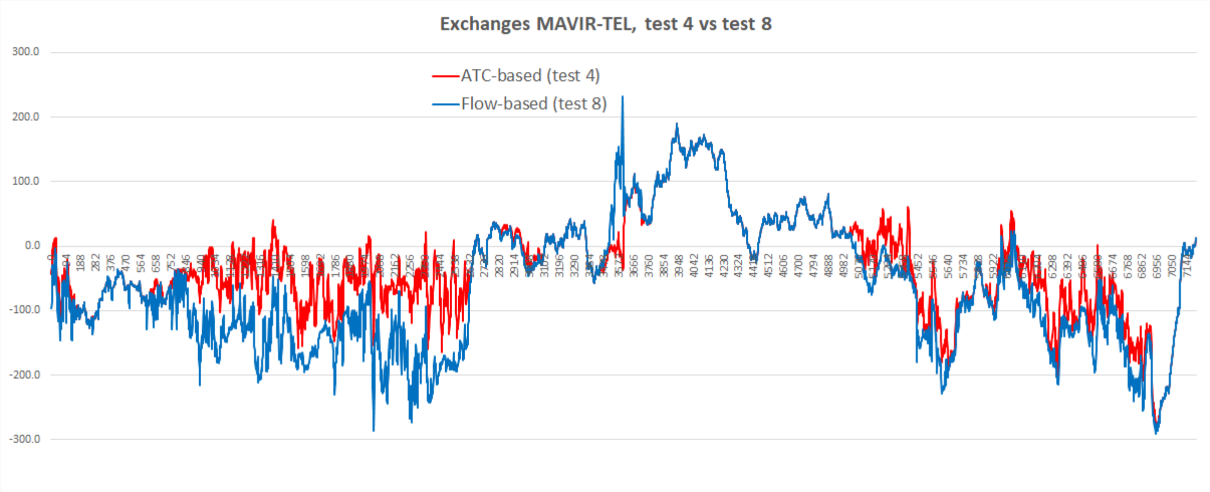


*Figure 7: Exchanges MAVIR-TEL, with ATC based and Flow-based constraints (extreme day)*

ATC TEL-MAVIR=280.6 MW, which leaves enough space for ATC-base exchanges in this direction as well.

In general, Flow-based as unconstrained cases, allow significantly higher exchanges than the corresponding ATC-based cases.

*Table 11: Comparison of cross-border aFRR exchanges*

| | ATC-based (test 2) | | | Flow-based (test 6) | | | DIFFERENCE | | |
|---|---|---|---|---|---|---|---|---|---|
| **MW** | **ELES->APG** | **APG->MAVIR** | **MAVIR->TEL** | **ELES->APG** | **APG->MAVIR** | **MAVIR->TEL** | **ELES->APG** | **APG->MAVIR** | **MAVIR->TEL** |
| **hour 1 forward** | 20.7 | 0.0 | 0.0 | 25.0 | 25.7 | 29.9 | 4.3 | 25.7 | 29.9 |
| **hour 1 reverse** | -18.1 | -20.1 | -17.2 | -16.9 | -1.9 | -0.1 | -1.2 | -18.2 | -17.0 |
| **hour 2 forward** | 26.1 | 0.0 | 0.0 | 28.2 | 9.3 | 4.7 | 2.1 | 9.3 | 4.7 |
| **hour 2 reverse** | -7.1 | -33.3 | -30.4 | -7.3 | -11.5 | -8.2 | 0.1 | -21.8 | -22.2 |
| **hour 1 cummulat.** | 2.6 | -20.1 | -17.2 | 8.1 | 23.8 | 29.8 | 5.5 | 43.9 | 47.0 |
| **hour 2 cummulat.** | 19.0 | -33.3 | -30.4 | 20.9 | -2.2 | -3.4 | 2.0 | 31.1 | 27.0 |

| | ATC-based (test 4) | | | Flow-based (test 8) | | | DIFFERENCE | | |
|---|---|---|---|---|---|---|---|---|---|
| **MW** | **ELES->APG** | **APG->MAVIR** | **MAVIR->TEL** | **ELES->APG** | **APG->MAVIR** | **MAVIR->TEL** | **ELES->APG** | **APG->MAVIR** | **MAVIR->TEL** |
| **hour 1 forward** | 5.8 | 0.0 | 3.0 | 4.0 | 5.0 | 4.9 | -1.8 | 5.0 | 2.0 |
| **hour 1 reverse** | 0.0 | -36.4 | -47.3 | -92.8 | -105.0 | -96.1 | 92.8 | 68.7 | 48.8 |
| **hour 2 forward** | 6.8 | 0.0 | 30.8 | 8.7 | 21.8 | 29.4 | 1.9 | 21.8 | -1.4 |
| **hour 2 reverse** | 0.0 | -67.4 | -48.4 | -66.8 | -88.1 | -64.4 | 66.8 | 20.8 | 15.9 |
| **hour 1 cummulat.** | 5.8 | -36.4 | -44.3 | -88.8 | -100.0 | -91.1 | -94.6 | -63.7 | -46.8 |
| **hour 2 cummulat.** | 6.8 | -67.4 | -17.6 | -58.2 | -66.3 | -35.0 | -65.0 | 1.1 | -17.4 |

**Shadow prices**, as the economic measure of congestions, appear at the constrained ATC borders/directions. On the contrary, at Flow-based capacities, they would appear at the respective congested CB (Critical Branch)/CO (Critical Outage), which is not the case here. The occurrence of non-zero shadow prices at ATC cases and its correspondence with low or zero ATCs is already analysed at similar test cases within the D4.3.

### 3.2.1 aFRR control quality: comparison

In the following two tables, the standard deviation and mean value of ACE are compared, for relevant ATC and FB tests, calculated upon the entire 2-hour tests level.

*Table 12: Comparison of standard deviation of ACE*

| St.dev ACE | ELES | | APG | | MAVIR | | TEL | |
|---|---|---|---|---|---|---|---|---|
| | ATC | FB | ATC | FB | ATC | FB | ATC | FB |
| Test 2\|atc vs Test 6\|fb (regular day) | 16.6 | 13.4 | 42.4 | 31.4 | 20.6 | 24.7 | 64.7 | 76.7 |
| Test 4\|atc vs Test 8\|fb (extreme day) | 53.1 | 17.2 | 37.0 | 29.5 | 40.2 | 40.5 | 54.9 | 54.5 |

*Table 13: Comparison of mean value of ACE*

| Mean value ACE | ELES | | APG | | MAVIR | | TEL | |
|---|---|---|---|---|---|---|---|---|
| | ATC | FB | ATC | FB | ATC | FB | ATC | FB |
| Test 2\|atc vs Test 6\|fb (regular day) | 0.8 | 0.6 | 3.5 | 2.2 | 0.5 | 0.6 | 3.2 | 4.5 |
| Test 4\|atc vs Test 8\|fb (extreme day) | -61.8 | -1.3 | -2.1 | -2.0 | -3.8 | -3.4 | -4.18 | -4.22 |

Exchanging more power in case of Flow-based tests improves the ACE quality in ELES and APG, and deteriorates the ACE quality in Transelectrica, since now in copper-plate situation, more of the correction signal is transferred to Transelectrica.

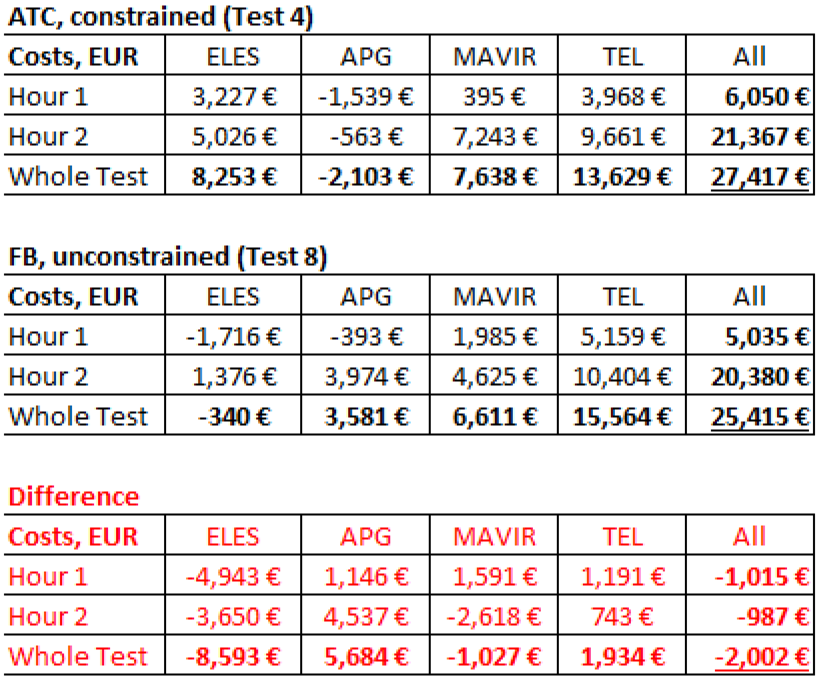
## 3.3 Costs: comparison

Here the costs of activation of aFRR energy in two cases are compared:

- ATC-based (test 4), being constrained
- Flow-based (test 8), being unconstrained,

The following table shows that the activation costs are lower in the case of unconstrained, Flow-based case.

*Table 14: Comparison of activation costs*



**ATC, constrained (Test 4)**

| **Costs, EUR** | ELES | APG | MAVIR | TEL | All |
|---|---|---|---|---|---|
| Hour 1 | 3,227 € | -1,539 € | 395 € | 3,968 € | **6,050 €** |
| Hour 2 | 5,026 € | -563 € | 7,243 € | 9,661 € | **21,367 €** |
| Whole Test | **8,253 €** | **-2,103 €** | **7,638 €** | **13,629 €** | **27,417 €** |

**FB, unconstrained (Test 8)**

| **Costs, EUR** | ELES | APG | MAVIR | TEL | All |
|---|---|---|---|---|---|
| Hour 1 | -1,716 € | -393 € | 1,985 € | 5,159 € | **5,035 €** |
| Hour 2 | 1,376 € | 3,974 € | 4,625 € | 10,404 € | **20,380 €** |
| Whole Test | **-340 €** | **3,581 €** | **6,611 €** | **15,564 €** | **25,415 €** |

**Difference**

| **Costs, EUR** | ELES | APG | MAVIR | TEL | All |
|---|---|---|---|---|---|
| Hour 1 | -4,943 € | 1,146 € | 1,591 € | 1,191 € | **-1,015 €** |
| Hour 2 | -3,650 € | 4,537 € | -2,618 € | 743 € | **-987 €** |
| Whole Test | **-8,593 €** | **5,684 €** | **-1,027 €** | **1,934 €** | **-2,002 €** |

The activation costs are calculated on the basis of Pay-as-bid principles, which corresponds to the optimisation function criteria (costs minimisation).

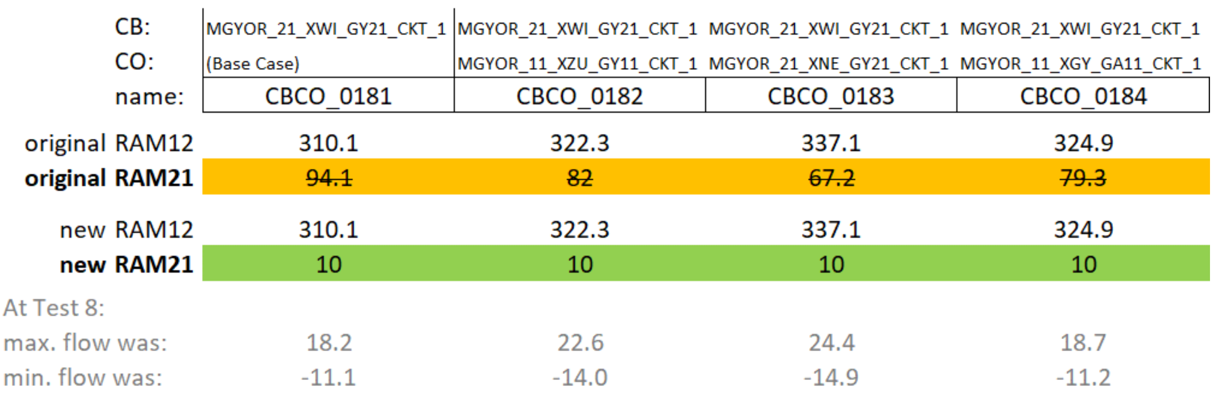
## 3.4 An exemplary case of constrained FB

Since FB case is unconstrained, there are no congestions nor limitations to the maximally beneficial exchanges among the involved areas. Also, the shadow prices at all CB/CO elements are zero.

In order to test the software solution and to experience potential congestions at Flow-based constraints, an exemplary case has been made, with hypothetic low RAM values at certain CB/CO, just to create artificial congestion. This is done on the basis of Test 8.

The RAM values at a Critical Branch 220 kV CB tie-line Gyor(HU)-Wien(AT) are lowered to the value of 10 MW (for Base Case and for three different Critical Outages), in the direction towards Hungary.

*Table 15: Changed RAM values to create the exemplary congestion*



|  |  |  |  |  |
|---|---|---|---|---|
| CB: | MGYOR_21_XWI_GY21_CKT_1 | MGYOR_21_XWI_GY21_CKT_1 | MGYOR_21_XWI_GY21_CKT_1 | MGYOR_21_XWI_GY21_CKT_1 |
| CO: | (Base Case) | MGYOR_11_XZU_GY11_CKT_1 | MGYOR_21_XNE_GY21_CKT_1 | MGYOR_11_XGY_GA11_CKT_1 |
| name: | CBCO_0181 | CBCO_0182 | CBCO_0183 | CBCO_0184 |
| original RAM12 | 310.1 | 322.3 | 337.1 | 324.9 |
| **original RAM21** | ~~94.1~~ | ~~82~~ | ~~67.2~~ | ~~79.3~~ |
| new RAM12 | 310.1 | 322.3 | 337.1 | 324.9 |
| **new RAM21** | 10 | 10 | 10 | 10 |
| At Test 8: |  |  |  |  |
| max. flow was: | 18.2 | 22.6 | 24.4 | 18.7 |
| min. flow was: | -11.1 | -14.0 | -14.9 | -11.2 |

When repeating the Test 8 with such artificially low RAM values at selected CB/CO, the congestion appears at Critical Branch, 220 kV tie line Gyor (HU)-Wien (AT) for Critical Outage of parallel 220 kV tie line outage (CO) Gyor (HU) – Neusiedler (AT). It happens in few 2-sec timestamps in the period between 3586-4024 seconds of the test. The maximum shadow price is 1098 EUR/MWh.

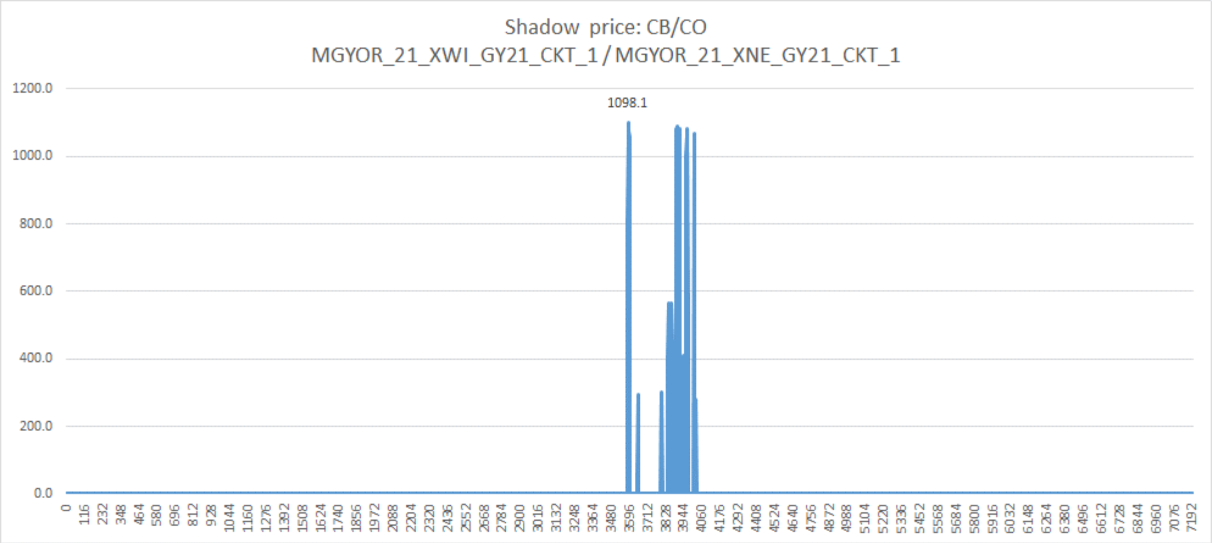


*Figure 8: Shadow price at congested CB/CO, artificial congestion at FB test 8*

When comparing the flows over the congested CB/CO, at the test 8 before and after putting the low RAM values, it is obvious how the RAM constrain of 10 MW in reverse directions, limits the flows, and thus the aFRR exchanges in few mentioned timestamps.

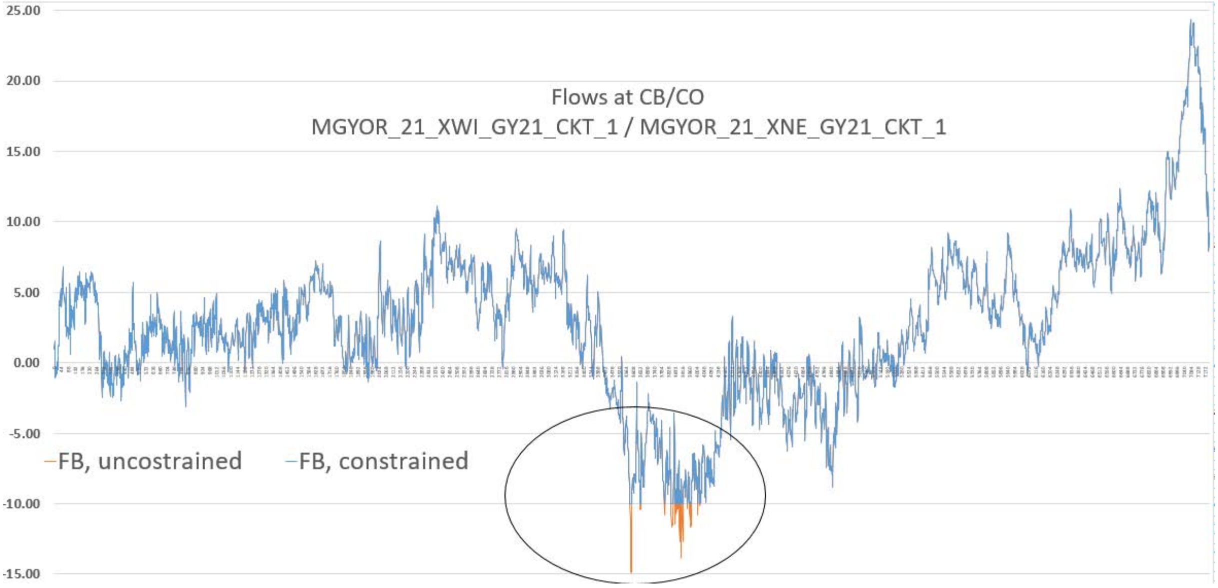


*Figure 9: Flows over a CB/CO, in unconstrained vs constrained test 8 case*

# 4 Techno-economic model

In this subchapter techno-economic assessment of the target model, taking into account the results of the pilot tests is performed.

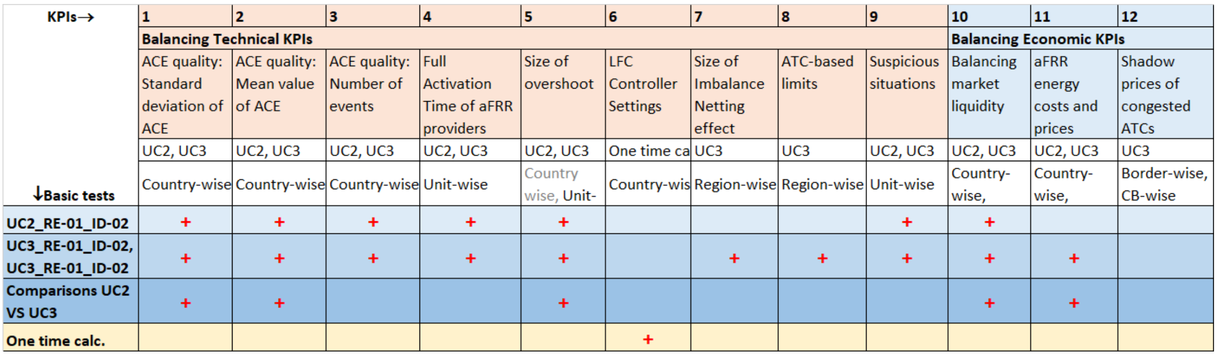
## 4.1 Analysis of the performed pilot tests

In the recapitulation from D4.3 [1], the evaluation of KPIs from the most important technical and economic parameters are presented:

- Technical
    - ACE quality
        - Standard deviation of ACE
        - Mean value of ACE
        - Number of events
- Economic
    - Balancing Market liquidity
    - aFRR energy prices and costs
- Specific KPIs related to cross-border aFRR exchange
    - Size of Imbalance Netting Effect
    - ATC vs FB based transmission capacity limits and congestions
    - Shadow prices of congested borders/elements

Table 16 shows the summarisation of the results, which are described much more into the details in D4.3. [1]

*Table 16: Pilot tests: comparison of performance through balancing KPIs.*



| KPIs→ | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **Balancing Technical KPIs** | | | | | | | | | **Balancing Economic KPIs** | | |
| | ACE quality: Standard deviation of ACE | ACE quality: Mean value of ACE | ACE quality: Number of events | Full Activation Time of aFRR providers | Size of overshoot | LFC Controller Settings | Size of Imbalance Netting effect | ATC-based limits | Suspicious situations | Balancing market liquidity | aFRR energy costs and prices | Shadow prices of congested ATCs |
| | UC2, UC3 | UC2, UC3 | UC2, UC3 | UC2, UC3 | UC2, UC3 | One time ca | UC3 | UC3 | UC2, UC3 | UC2, UC3 | UC2, UC3 | UC3 |
| **↓Basic tests** | Country-wise | Country-wise | Country-wise | Unit-wise | Country wise, Unit- | Country-wis | Region-wise | Region-wise | Unit-wise | Country-wise, | Country-wise, | Border-wise, CB-wise |
| **UC2_RE-01_ID-02** | + | + | + | + | + | | | | + | + | | |
| **UC3_RE-01_ID-02, UC3_RE-01_ID-02** | + | + | + | + | + | | + | + | + | + | + | |
| **Comparisons UC2 VS UC3** | + | + | | | + | | | | | + | + | |
| **One time calc.** | | | | | | + | | | | | | |

## 4.2 The role of the Virtual Power Plant

The main effort in the pilot test was concentrated on VPP and its capabilities to engage different DR&DG units, from which they can combine the proper portfolio that enables VPP to provide the guaranteed capacity in the time of activation under the conditions foreseen with FF model. VPP task is to balance its power generation by combining individual DR/DG, with different technical specifications, to achieve maximum performance in a technical and economic sense. For that purpose we have developed an aggregation platform [2], that was responsible for building a merit order list of DR&DGs available in the VPP portfolio, with the optimal technical and economic parameters (e.g. weather, hydrology, fuel supply, market prices, FAT, ramping ). The important part was the forecasting data, which enabled us to include also RES into aFRR.

In general, tests have shown that multiple DR/DGs with the proper mix of technologies yield the best VPP portfolio with the most stable and adequate response. From D4.3[3] we present the reasons why the mix of technologies with multiple DR/DGs in the portfolio is better:

- DR/DGs with slower response can be used for covering baseline power in VPP (placed at the beginning of VPP's MOL) while faster response DR/DGs are used to cover fast-changing setpoint signal.
- There can always be unpredictable events in the power system; therefore, a single DR/DG or single technology could be prone to these disturbances, while the mixture of multiple DR/DGs and technologies is more flexible in case of such events.
- If the portfolio contains renewables (solar, wind) which are highly dependent on local weather, there can be sudden unpredicted changes in their capacity, especially if their forecasting is insufficient. In this case, additional DR/DGs which are highly dispatchable, have fast response times and sufficient energy reserves should be used in the portfolio to cover for such events.

**It is also highly important that BSP offering VPP capacity on the market has insight in DR/DG's power production/consumption, business processes, operation and maintenance procedures, scheduling methodologies, etc.** This information helps to construct more high-quality portfolio with better response characteristics and reduce the chance for the unpredicted power loss in VPP's operation. It is recommended that VPP is over-dimensioned, so few of the units are used as a reserve or substituted each other in times when the certain unit is not available. Algorithm(s) used by VPP to control the output of VPP should be able to compensate the volatile behavior of certain technologies, e.g. wind and solar, by appropriate activation/deactivation of more stable sources. Such algorithms would also help to improve the result of a challenging task of forecasting the base lines of highly volatile sources. Such mitigation measure could, in our view improve the quality of delivered service.

The pilot test proved that DR&DG could be a solution for the increasingly complex electric power system, where the line between the generation and the consumption is not clear anymore. The regional integration by itself brings many benefits, where maximising the potentials of aFRR exchange is one of the more important ones. But since more and more energy is coming from less predictable renewable energy resources (RES), there are less and less classical power plants, that are high dispatchable as the need for balancing services are rising up and despite the integration of

EU market, also new sources of flexibility will be needed. DR&DG can be a substantial part of it.

Figure 11 presents the inner structure of one average variation of VPP, if we would combine portfolio out of our most successful use case combinations. For regulation up the most appropriate are Industry, Disel, Biogas and Hydro (if they have a reservoir). For regulation down Industry, CHP, Biogas, Hydro, PV and Wind were used.

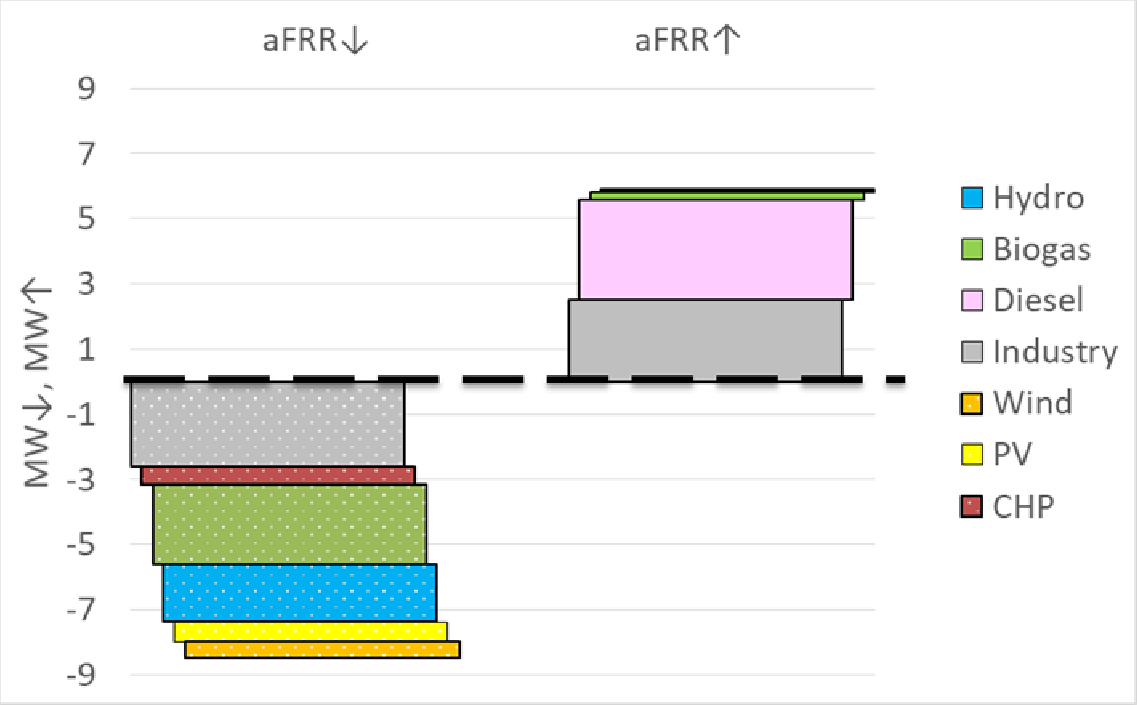


*Figure 10: Internal DR&DG units structure from FF*

In D1.4.[4] and D4.3.[1] we have already shown the positive effects on the prices in case of the integrated regional markets, that can bring significant social benefits. In this deliverable, we will take a look at how can virtual power plants trough integration of many dispersed small DR&DG units additionally contribute to the social welfare and efficiency.

## 4.3 Social benefits

The introduction of the role of aggregator into a market creates critical momentum around the exploitation of DR&DG. Under the chapter 2. Follow up market research, we showed that there is enough market potential. For the FF pilot project, we were even able to double the number of clients that were willing to participate. Most of them came from Slovenia. The reason for that was that the trust and personal relationship was of the great importance for the participating DR&DG, and while participating BSPs have their main operation in Slovenia the trust of the customers in Slovenia was the biggest.

Figure 12shows how the If we extrapolation of the potential of the DR&DG from Slovenia to the other three participating countries (per capita), would result in the 180MW of flexibility.

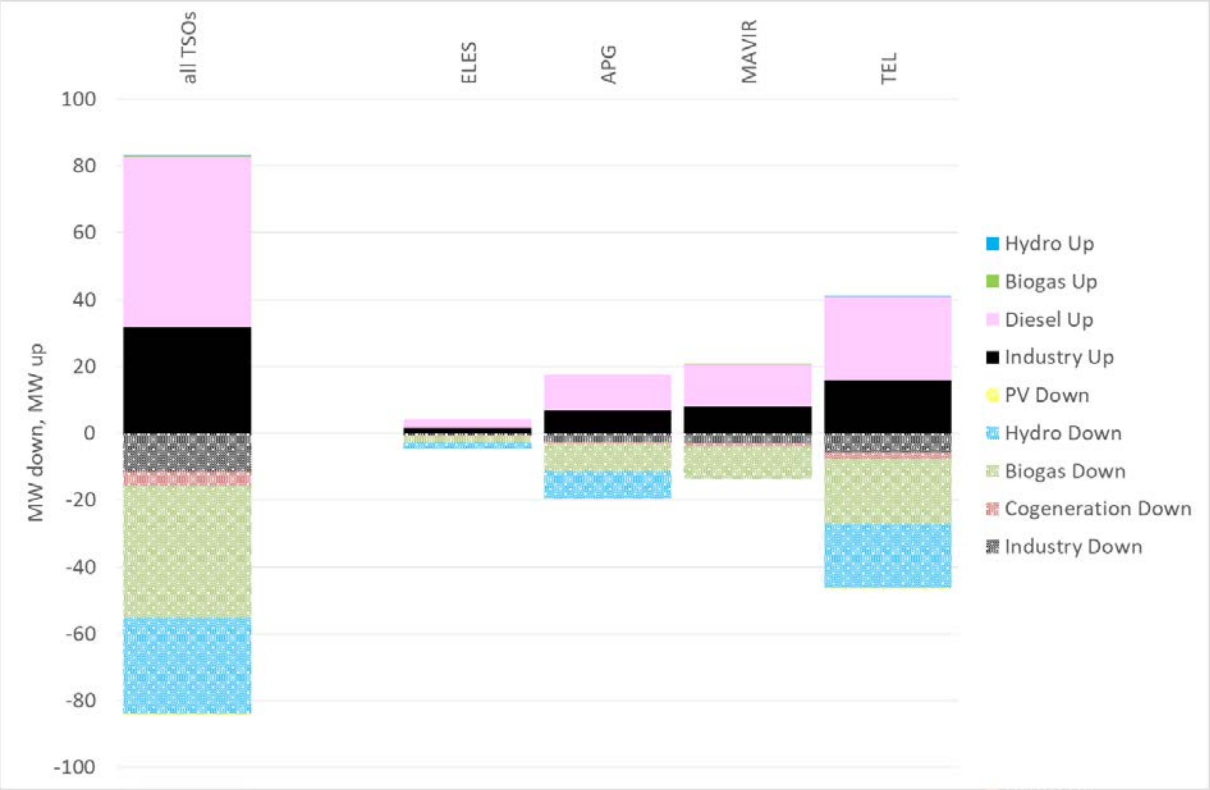


*Figure 11: A vision of possible DR/DG contributions to aFRR by the TSOs.*

Possibility for prosumers to actively participate in the energy market, even in the most demanding services as aFRR, will have a great effect on the future. It will result in:

- Better use of available resources
- Taking advantage of the geographical distribution of the resources
- Creation of new jobs
- Consumers will have the power to influence the electricity market

### 4.3.1 Better utilization of the existing resources.

Industry, tertiary and even primary resources will be able to participate on the energy market and therefore better utilise their investments. Private investors (even smaller) could invest in small DG units, that can participate on energy market. Use of available resources will have a beneficial effect on the energy sector as whole, while fewer dedicated investments for scarcity situations will be needed. This shall reflect in lower prices for the users.

### 4.3.2 Optimization of the existing distributed energy resources regarding their geographical location

DER enables TSOs and DSOs to manage congestions much more effective. It enables them to release power lines, where demand is high and use less overloaded ones. Therefore, the need for investments into the cable line infrastructure is also lower, which again lower the price of electricity.

### 4.3.3 Social welfare

New market models, as also new products and new players on the market, will bring new jobs. Automatization, digitalisation and security will be of huge importance once so many new players enter the market, all area bringing with them new high-quality new jobs.

- Industry and tertiary sector will be able to benefit from new services in the market and will, therefore, need experts to manage new services.
- New players on the market – aggregators will appear.
- The new market for the SW solutions, like forecasting, optimising resources, predictions, data management, billing etc. will be needed.
- New products connected to energy management will be developed.

### 4.3.4 Consumer empowerment

Today a consumer has very little possibilities to influence on his own electricity bill. Most of the bill is composed of different fees, that do not reflect or stimulate rational behaviour of the customer. With more information and more possibilities for the market, the consumer will clearly change his role and be able to actively participate and influence EU energy politic. As prosumers will need data to be able to decide upon their acts, to be able to decide which energy (from which source) are they buying, what kind of the quality of service he is willing to pay for. Fee oriented pricing models for electricity bills will change in the future, and fewer services will be socialised through the fee tariffs, while the larger part will depend on defined services for customers.

### 4.3.5 Environmental effect

aFRR is currently produced mostly with thermal and hydro power plants. Specially Slovenia and Hungary are highly dependent from thermal resources. In calculation below we will show on case of FF, how can use of DR&DG in aFRR contribute toward the reduction of $CO_2$.

**Calculation of $CO_2$ reductions**

We calculated the amount of energy that was produced in the project's 160 hours of pilot testing (12.07 GWh). Then we calculated what amount of $CO_2$ emissions would be produced by a thermal power plant TEŠ 6 (one of the most advanced thermal power plants in Balkans and Slovenia, operational in 2015) if this energy would be produced by them:

TEŠ 6 $CO_2$ emissions = 0.87 kg / kWh [5]

If the aFRR for all the pilot tests would be done by Slovenian thermal power plant TEŠ6, $CO_2$ emissions would be:

$CO_2$ emission = 12.07 GWh * 870 t/GWh = 10 500 tons

For the comparison we calculated the $CO_2$ emissions that were produced by DR / DGs during 160 hours of pilot tests:

- Non-run of river hydro power plants (24 units with a total capacity of 6.745 MW): estimated $CO_2$ production = 18 kg/MWh
- Biogas power plants (8 units with a total capacity of 6.496 MW): estimated $CO_2$ production = 50 kg/MWh
- Wind power plants (4 units with a total capacity of 7.16 MW): estimated $CO_2$ production = 5 kg/MWh
- Solar power plants (2 units with a total capacity of 1 MW): estimated $CO_2$ production = 35 kg/MWh
- C&I lowering energy consumption (5 units with total capacity of 54.06 MW): estimated $CO_2$ production is almost impossible to asses since DR/DGs are from various industries and production sectors with different installations, technologies, etc. But since these DR/DGs were lowering energy consumption they only reduced additional $CO_2$ emissions in the tests. For simplification, we assigned a worst-case scenario of 0 kg/MWh of $CO_2$ emissions from C&I lowering their energy consumption.

$CO_2$ emissions of DR/DGs on pilot tests = 160 h * ((18 kg/MWh * 6.745 MW) + (50 kg/MWh * 6.496 MW) + (5 kg/MWh * 7.16MW) + (35 kg/MWh * 1 MW)) = 82 721 kg = 82.7 tons!

The final calculation is subtraction of TEŠ 6 and DR/DGs $CO_2$ emissions. Therefore, the reduction of $CO_2$ emissions due to pilot tests was:

10 500 t - 82.7 t = 10 417 tons of $CO_2$

## 4.4 Cost and benefits estimation

The European Commission places the potential of DER at 100GW, rising to 160GW in 2030. To be able to mobilise this potential, aggregators will be needed.

The main role in building a VPP has an aggregator. An aggregator can invest in its own energy production/reduction resources, or he can contract available DR&DG on the market. An aggregator is responsible for building the VPP infrastructure, establishing secure communication and taking care of the prequalification process of the newly established VPP. The aggregator is the one that contracts DR&DG and sells its flexibility on the market. As such, an aggregator is also responsible for imbalances caused by VPP.

We will focus only on the costs of an aggregator and assume that DER is already available. To set up a VPP is an upfront investment needed. Table 17 contains the expected upfront costs.

Table 17: Upfront investment

| CAPEX |
|---|
| Setup & test VPP software |
| Weather forecast setup |
| Setup & test ICT |
| Prequalification tests with TSO |
| RTU hardware & software |
| Integrate DER |

Additional to one-time costs, maintenance and operational cost of VPP should be considered as in Table 18.

Table 18: Operational and maintenance costs.

| OPEX |
|---|
| VPP license |
| VPP software license |
| VPP maintenance |
| VPP hosting |
| Weather forecast |
| Communication with the market operator |
| Communication with DERs |
| Communication costs per RTU |
| VPP Operator FTE |
| Average total personnel costs |
| VPP operator (personnel) |
| Costs for Trading |

FF is a development project based on a tailor made IT infrastructure including VPP software and many new tools for weather forecast. Human resources on one hand were covered within the project but many of the solutions used on the other hand were not jet available on the market and had to be developed, so the actual cost of the FF project is not fully representable for a regular business case. Nevertheless, we managed to gain enough experiences to estimate costs (including exploitable results from the FF) to give a cost estimation for a VPP that offers 4MW of flexibility in both directions, so 8MW altogether. If a VPP wants to offer this flexibility at any time, VPP has to have bigger portfolio that the actual flexibility offered on the market. We have calculated 25% over dimensioned portfolio in terms of the capacity of DR&DG that has to be additionally contracted for the pool. Including the margin, the required contracted capacity for the +/- 4 MW unit is +/- 6,25MW.

In our calculations, we also assumed 80% hit rate while participating only on the aFRR market in both directions (for up and down-control of energy). This means that in 80% of the time, the bids for 4MW capacity and 4MWh of energy in both directions from VPP are delivered to the system and paid by the TSO.

We assumed that 60% of the revenue goes to the DR&DG, offering the flexibility and the rest of the income stays to the VPP owner (aggregator).

A VPP can offer diverse services, but we will focus in this paper specifically at aFRR. For the aFRR a full automation control is needed, so we assumed that human operators will be minimally involved in VPP operation for aFRR and hence only 10% of FTE was assumed necessary for the VPP supervision and maintenance.

Nevertheless, a VPP should operate continuously, which can be a challenge for dedicated independent aggregators (if this would be their single service). In the case of FutureFlow, the BSP took the role of aggregator, which allow us to calculate a sharing of resources. Our assumption is that also potential revenue from aFRR will not exceed 10% of all revenue of the company, so 10% of FET costs is a reasonable assumption. The same task force can support also other activities in the company, and the same VPP can provide more services as follows:

- Energy selling on a day to day market
- Selling balancing services to TSO (aFRR, mFRR)
- Redispatching services

In our calculation, we have included also the payment of the penalties.

In **Austria**, for example, TSOs tray to encourage BSP to control their performance and take in their penalties into consideration the following aspects:

- Duration of non-fulfilment
- Amount of energy
- Accepted bids - price of capacity
- Accepted bids - price of energy
- Time of notification of the problem

1. In case there was no notification at all 75% of the price of energy has to be paid for the not-delivered reserve (energy).
2. In case notification is done one day after the occurrence of the problem, 60% have to be paid.
3. In case the notification happens during the delivery period the percentage drops to 35%

In addition to every non-fulfilment of energy, also the capacity obligations are under inspection. If BSP offered capacity 20MW in the form of 4 bids for 5MWh products, and by activation of 2 of offered bids fail to provide 10MW in is considered that they do not lack only 5MWh of non-provided, but chosen bid, but also next 10MW of guaranteed power was not available, so in reality they failed to reserve 15MW of power. Therefore, the price for capacity between activated power and maximum accepted bid (power) is not remunerated.

Penalties in **Slovenia**[8] are calculated on the basis of the one minute energy discrepancy, which is the missed energy, that VPP failed to provide:

TSO recognise delivered energy to PSI according to the following equation:

*Equation 1: delivered energy in a minute*

$$Rpri,+,t= \Sigma\max\{PaRPF,zm,j,t;0\}j$$

$$Rpri,-,t= \Sigma\min\{PaRPF,sm,j,t;\ 0\}j$$

Where represents:

$Rpri$,+,t – confirmed aFRR of up regulation in 1 min (round on 3 digits)

$Rpri$,−,t - confirmed aFRR of down regulation in 1 min (round on 3 digits)

$PaRPF$,,, – average level on the upper limit in a minute in MW (round on 3 digits)

$PaRPF$,,,– average level on the lower limit in a minute in MW (round on 3 digits)

J – portfolio group

*Equation 2: recognized regulation contribution of energy in up and down direction*

$$Rpri,h= \frac{1}{60}\sum\nolimits_{t\in h}\mathrm{Rpri,t}$$

$Rpri,h$ - recognised energy contribution in an hour in MW (round on 3 digits)

$Rpri,$ - recognised energy contribution in a minute in MW (round on 3 digits)

Missing control power Rman,h is a difference between contracted energy and produced (recognised) energy in an hour:

$Rman,h=\max\{Pzak,h-Rpri,h;0\}$

$Rman,h$ - missing energy

$Pzak,h$ - contracted power per hour

$Rpri,h$ - recognised energy contribution in an hour in MW (round on 3 digits)

Penalty for underperforming or over performing is:

$$PENaRPF,h= \max(Rman,\mathrm{zak},h;Rman,h)\cdot p\cdot 2$$

$PENaRPF,h$ - penalty for not performing PSI

$Rman,,h$ - part of contracted capacity for which PSI failed to provide energy bids

$Rman,h$ - missing energy

P – the cost of the highest excepted bid

In **Romania** penalties for contracted, but not activated reserved capacity are 2% of total capacity. The value of the penalty is 200% of the received price for the period of time when it was called for activation, but it was not activated.

The aFRR energy provided is controlled together with other reserves as integral of the unit during the settlement interval. For each time interval (one hour), the disequilibrium between the requested energy and the delivered energy (from metering) is multiplied by the hourly price for incident respectively for the deficit.

In **Hungary** is the general rule in this case that a BSP doesn't fulfil its contracted volume, its punishment will be at least 20% of its contracted price and the contracted amount won't be paid for them.

However, if MAVIR has to replace the non-fulfillment volume a day before (D-1) by contracting another or other BSPs and the difference between the prices of the BSPs (replaced and replacing) is higher than the beforementioned 20%, the increased expense will be imposed to the failing BSP.

During real-time operation, if a redispatch become necessary due to non-fulfillment, the expense of redispatch will be invoiced to the non-completing BSP.

For the simplification, we used the penalty value of 1% of total revenue from our 8MW VPP. In reality, penalties were until now rarely implemented, but we expect the stricter implementation of the rules in the future. The cost of penalties is also divided between the DR&DG that caused the imbalance and the VPP (60:40).

Penalties are not the main reason that aFRR service providers are keeping their service on the requested level. Much more important for the BSP is the possibility to lose the right to offer aFRR and they have to go again trough quite demanding prequalification process, that take time and resources, and in the meantime, BSP cannot sell the aFRR at all.

All four TSOs reported that they charged under 0.5% of total revenue back to the BSPs for their unavailability or underperformance in 2018.

### 4.4.1 Revenue from aFRR

#### Austria

Within this chapter, we are representing the costs of aFRR for all four countries. Austria as the most mature market is analysed first.

| **Market up:** | **AT, aFRR+** | | |
|---|---|---|---|
| **Capacity fee:** | 5.02 | EUR/MW/h | average 2018 |
| **Energy fee:** | 124.94 | EUR/MWh | average 2018 |
| **Market down:** | AT, aFRR- | | |
| **Capacity fee:** | 1.69 | EUR/MW/h | average 2018 |
| **Energy fee:** | -26.77[2] | EUR/MWh | average 2018 |

*Table 19: aFRR prices 2018 Austria*

The revenue of each VPP is calculated from the value of the accepted bids. Where available, we operated with monthly prices for aFRR capacity and energy, taking into consideration also peak and off-peak tariffs (Austria), while in other countries we took yearly average prices and average activation volumes into consideration. Equation (Equation 3) shows the calculation of the income that VPP can achieve under assumptions presented in 4.4.

*Equation 3: aFRR income*

$$R = C^{+} \times Cf^{+} \times Ta^{up} + C^{-} \times Cf^{-} \times Ta^{down} + Ah^{+} \times Ef^{+} \times E^{up} + Ah^{-} \times E^{down} \times Ah^{-}$$

Where is:

R= capacity income + energy income = Revenue of VPP

$Cf^{+}$ - Capacity fee up

$Ef^{+}$ – Energy fee up

$Ah^{+}$ - Activated hours up

$Ah^{-}$ - Activated hours down

$Cf^{-}$ Capacity fee down

$Ef^{-}$ – Energy fee down

$C^{+}$ - Available capacity up

$C^{-}$ - Available capacity down

$E^{up}$ - Energy sold

$E^{down}$- Energy reduction sold

$Ta^{up}$-Power availability reserve up sold

$Ta^{down}$-Power of reserve down sold

We have divided revenue between VPP and DR in 60:40 ratio. So for a VPP dimensioned on 6,5MW in up and down direction is capable of offering 4MW of reserves and energy up and down all year long and has 80% hit rate will receive in Austria for offered aFRR approximately

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[2] Negative prices show that TSO have to pay their BSP not to provide electric energy (to curtail production)

250.000 €, while the participating DR&DG received 330.000 € for the flexibility provided to the VPP.

The cost is calculated according to the tables(Table 17 and Table 18), for 8 MW flexibility and with the fix costs for the first year, which for Austria is ranging around approximately 242.500 € and operational yearly costs that for Austria are 166,000 €.

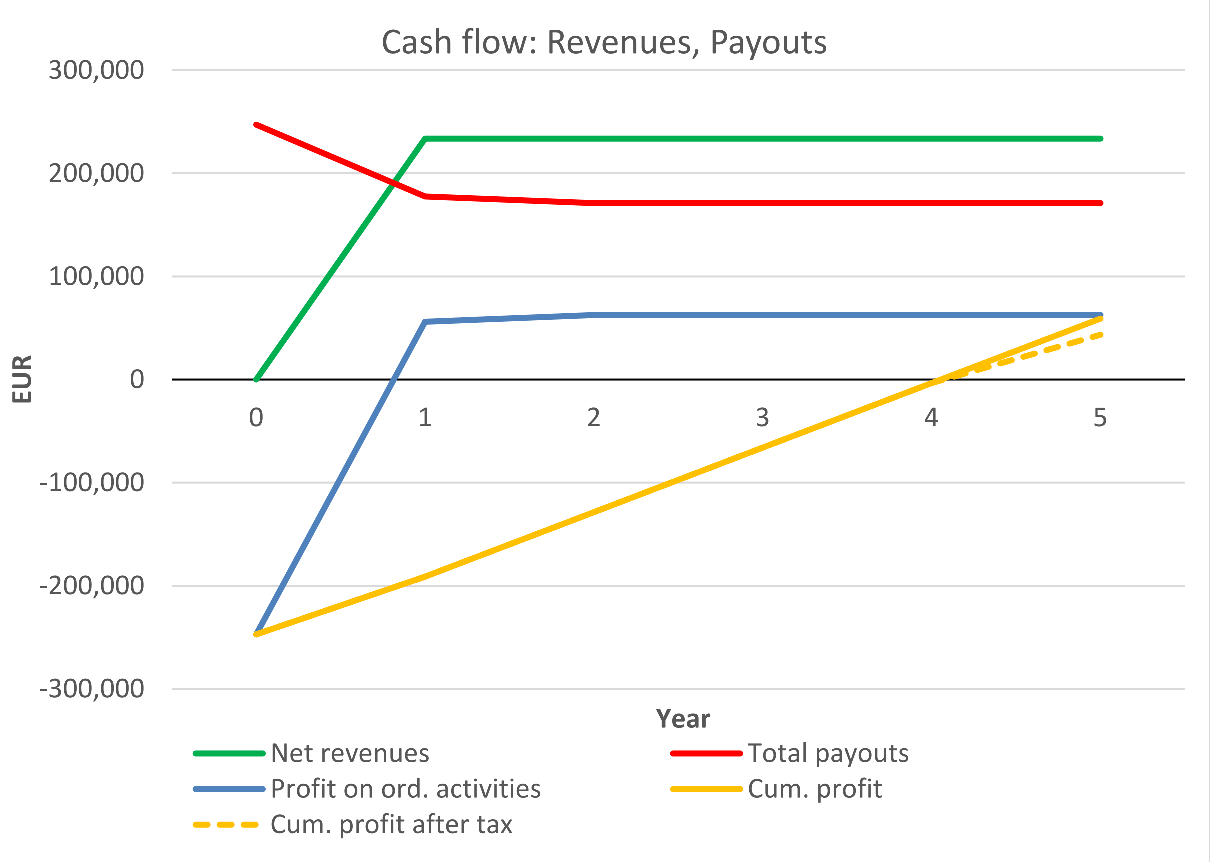

*Figure 12: Cost, revenue analysis Austria.*

The calculation shows that under our initial assumptions, the BEP can be reached in the fourth year.

The sensitivity analysis shows that independently from the size of VPP the BEP cannot be reached in the first year. But after the second year, the revenue growth is almost linear to the size of VPP.

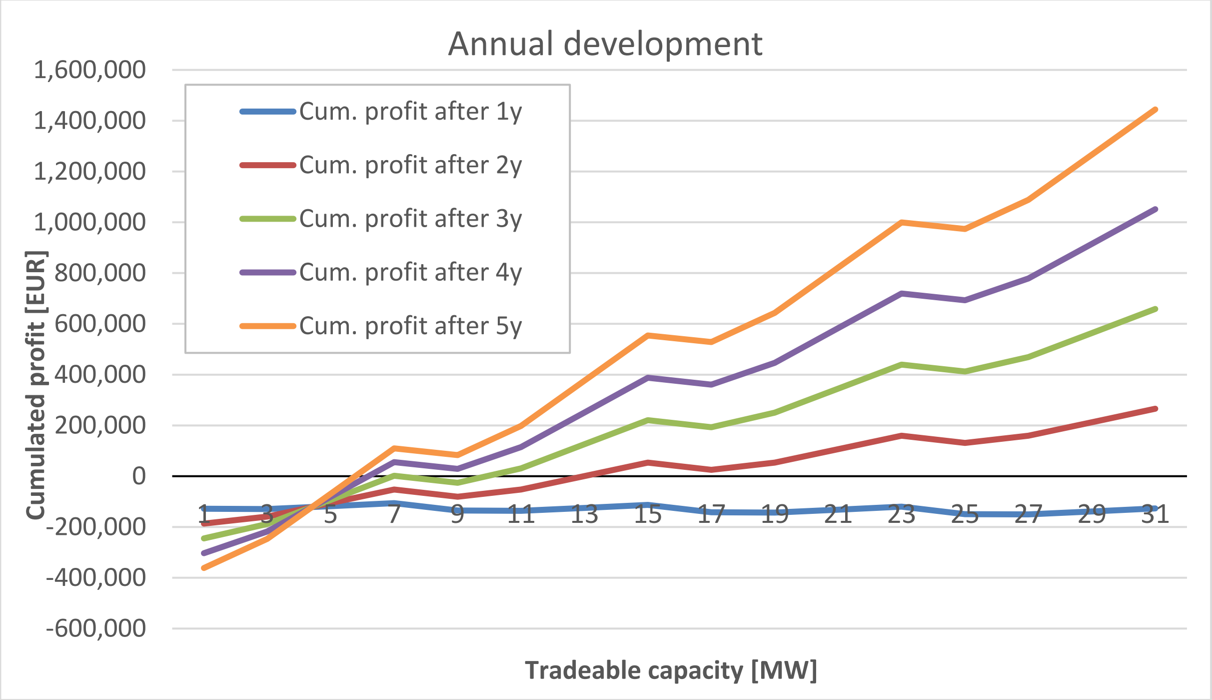

*Figure 13: Sensitivity analysis Austria*

One of the parameters that has a big influence on the profitability of the VPP is how efficiently it is organized and how dispersed are the activities of the company, which offers aFRR as one of the products on the market. Calculation improves if a VPP is part of a larger organization able to share the FTE needed for supervision of the VPP on a 24/365 basis. We have calculated five full-time employees, but only 10% of their costs are dedicated to the VPP since VPP is fully automated. Especially in Austria, where the cost of labour is the highest among the four participating countries (72000 EUR/Year/FTE). Should we increase the amount of FTE needed to run a VPP to 20% of FTE, the BEP in Austria would reach BEP only after the year 9. However assuming this scenario, the VPP would surely offer more capacity, which would improve its profitability. Figure 14 shows how the growth of the capacity affects the BEP.

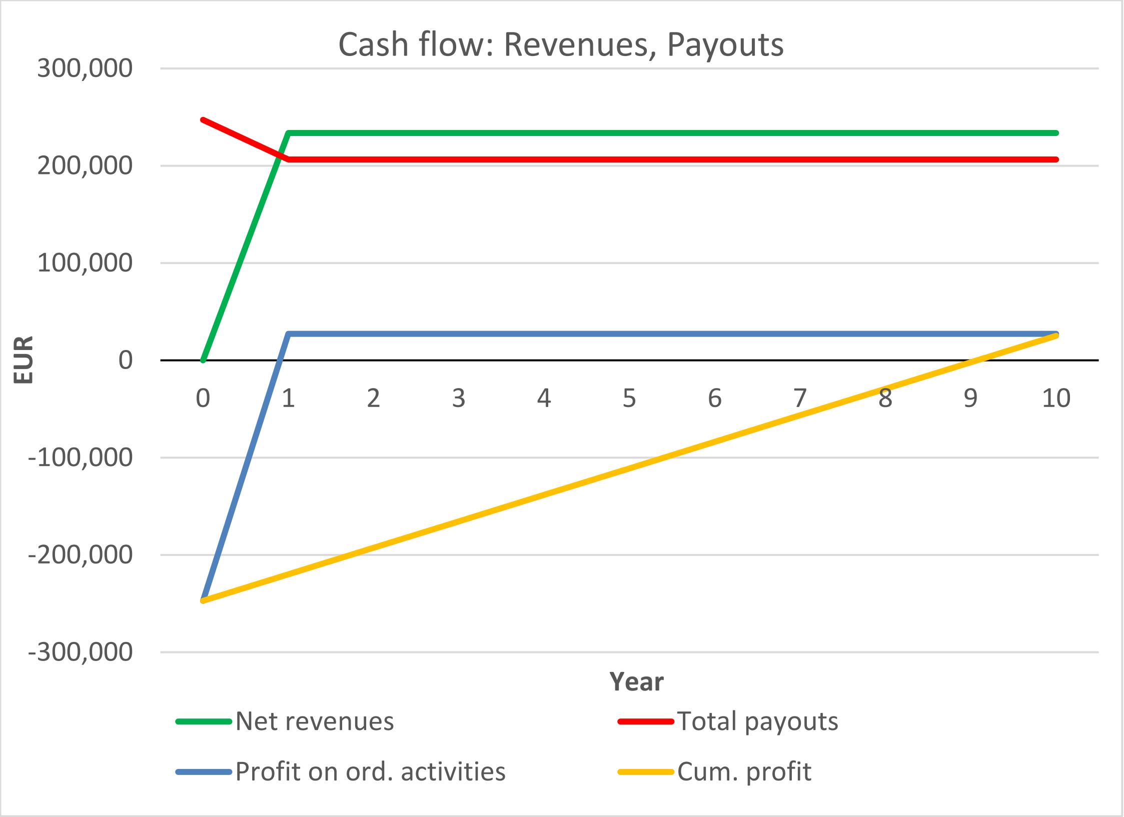

*Figure 14:Cash flow in case of 20%  FTE costs*

We did the calculation under the same assumptions also for other three markets. At this point one should not forget that Austria is the only country that already runs an established aFRR market with 4-hour products and weekly auctions, while others are still facing limitations and barriers described in D6.2 Barriers to scaling up and replication of the most promising field test results.

**Slovenia**

Slovenia has in 2018 activated 54285 MWh +aFRR (up) and 92320 MWh -aFRR (down). We assumed that the same amount of the energy would be bought in 2019 and took into consideration that Slovenia is obliged to purchase ±60MW capacity reserves for aFRR.

| **Market up:** | **SI, aFRR+** | | |
|---|---|---|---|
| **Capacity fee:** | 9 | EUR/MW/h | 2019 |
| **Energy fee:** | 145,02 | EUR/MWh | 2019 |
| **Market down:** | SI, aFRR- | | |
| **Capacity fee:** | 9 | EUR/MW/h | 2019 |
| **Energy fee:** | -32,67[3] | EUR/MWh | 2019 |

*Table 20:  aFRR prices 2019 Slovenia.*

For Slovenia, as for Austria, we assumed the same share, 60% of the revenue goes to DER. The hypothetical revenue that remains for the VPP with 8MW of the offered flexibility assuming the

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[3] Negative prices show that TSO have to pay their BSP not to provide electric energy (to curtail production)

prices from 2019 and the amount of aFRR energy bought in Slovenian market in 2018 would be approximately 1.16M€. The participating DER would receive 690k € for the flexibility, the rest would go to the VPP. In Slovenia, the revenue for a 8MW VPP would be 1,12M€ from which DR&DG share (60%) is 690k€. The hypothetical revenue that would remain to the VPP would be approximately 430k€. We have also considered that 12k€ has to be reserved for penalties, the cost of which is also divided between the DR&DGs that caused the imbalance and the VPP.

The input costs that are calculated according to Table 17 and Table 18 are the same as in the case of Austria. For the first year the Capex would be around 247000 €, and for each year the operational costs are a little lower than in Austria, which equals to 151k€.

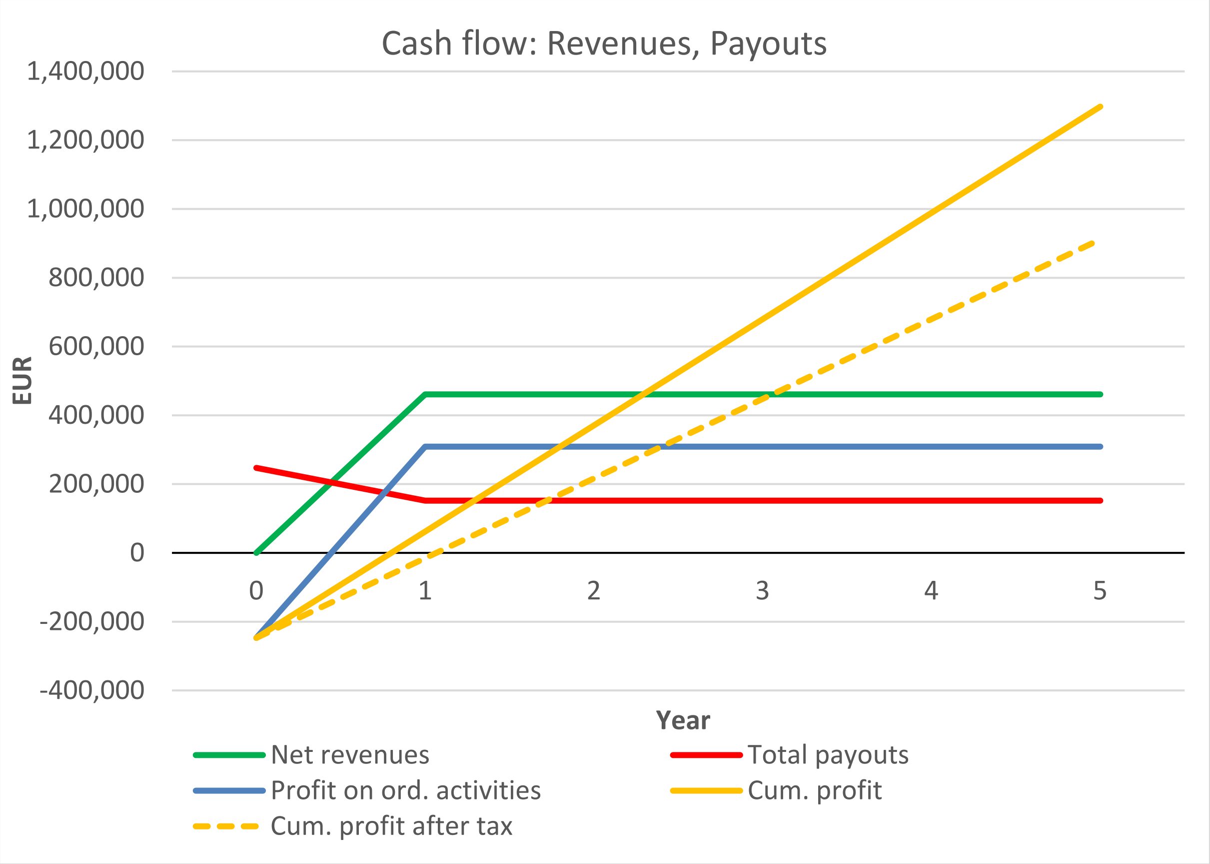

*Figure 15: Cost, revenue analysis, Slovenia.*

Should we change our assumption and increase the part of the costs from FTE needed for supervision of the VPP 24/365 to 20%, as we did in Austria, the effect is not so significant as for Austria. On one side the cost of labour is half the Austrian cost, and on the other the profits are higher.

But Slovenia currently still runs only yearly tenders for aFRR, which makes the participation of aggregators offering aFRR very difficult. Nevertheless, the changes have been foreseen for 2020. Yearly, monthly and weekly auctions including the participation of aggregators is in the progress.

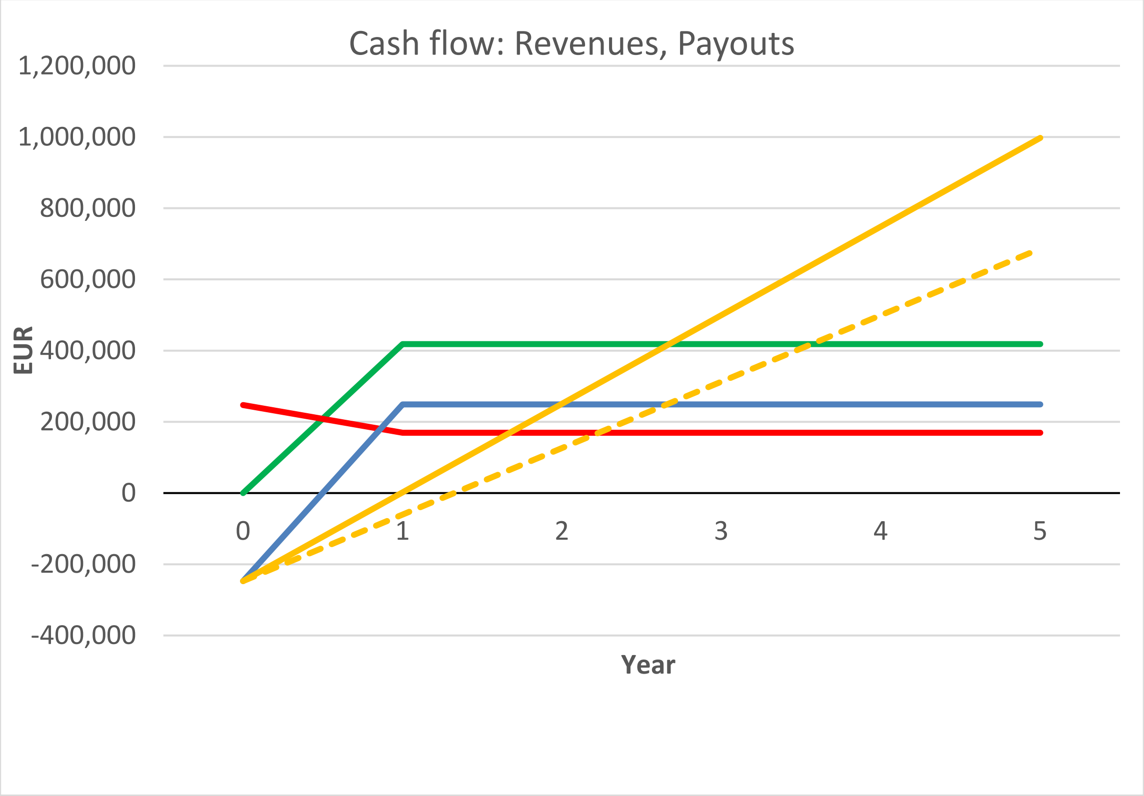

*Figure 16 Cash flow in case of 20% of FTE costs*

**Romania**

Romania has a similar situation as Slovenia. On one hand the capacity for the aFRR is not contracted therefore there is no obligation for a grid user to offer the reserve. The grid user can voluntary participate in the market. But on the other hand there is a specific rule for the energy, where Generators connected to the grid are obligated to reserve a certain amount of capacity in order to meet the TSO requirements, for a fixed price set by TSO, NRA or for free. Romania doesn't allow aggregation and requires symmetrical products of the size of at least 10 MW, which limits provision of aFRR solely to the generators. Romania is using marginal pricing of capacity and balancing energy therefore the price reflects the offer of the most expansive bid procured or activated.

Romania has in 2018 activated 466691 MWh +aFRR (up) and 528200 MWh -aFRR (down). Transelectrica is obliged to purchase ±250MW capacity reserves for aFRR.

| **Market up:** | **RO, aFRR+** | | |
|---|---|---|---|
| **Capacity fee:** | 15.866 | EUR/MW | 2018 |
| **Energy fee:** | 93.830 | EUR/MWh | 2018 |
| **Market down:** | RO, aFRR- | | |
| **Capacity fee:** | 15.866 | EUR/MW | 2018 |
| **Energy fee:** | -3.458[4] | EUR/MWh | 2018 |

*Table 21: aFRR prices 2018 Romania*

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[4] Negative prices show that TSO have to pay their BSP not to provide electric energy (to curtail production)

In Romania, the revenue of 8MW VPP would be 1,7M€ from which DR&DG share (60%) would amount to 900k€. The hypothetical revenue that would remain for the VPP is approximately 620k€. Another 17k€ would be reserved for the penalties, the cost of which is also divided between the DR&DG that caused the imbalance and the VPP.

According to the input data from Table 17 and Table 18 the Capex for 8 MW flexibility unit for the first year equals for all four countries. We believe that the ICT infrastructure is defined on a global market therefore the costs of ICT SW and HW does not differ much. Capex for the first year would hence amount to approximately 247k€, and the yearly operational costs for Romania are a bit lower than in Austria or Slovenia, due to the lower cost of labour and equal 135k€.

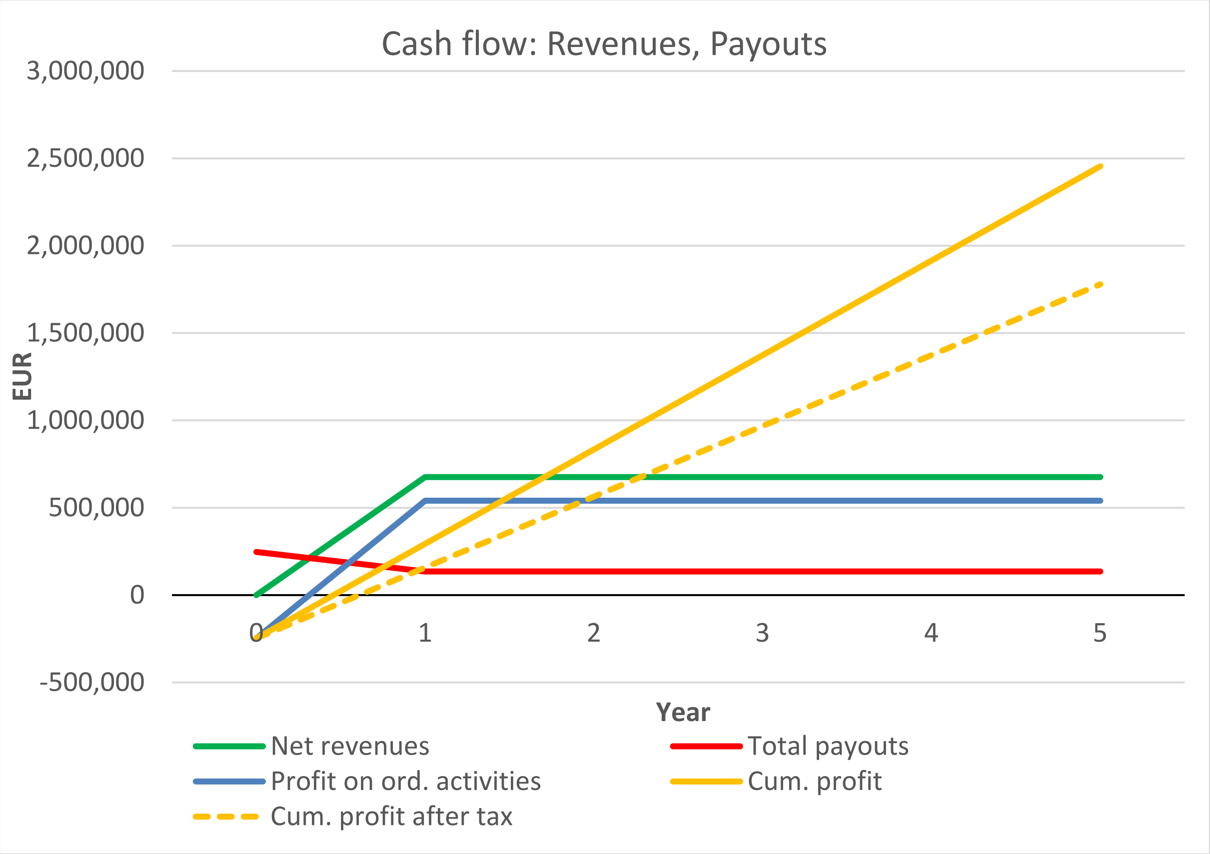

*Figure 17: Cost, revenue analysis, Romania.*

**Hungary**

Hungary in 2018 activated 270228 MWh +aFRR (up) and 246301MWh -aFRR (down). MAVIR is obliged to purchase +248MW and -128MW reserve capacity for aFRR.

| **Market up:** | **HU, aFRR+** | | |
|---|---|---|---|
| **Capacity fee:** | 14.75 | EUR/MW | 2018 |
| **Energy fee:** | 105.37 | EUR/MWh | 2018 |
| **Market down:** | HU, aFRR- | | |
| **Capacity fee:** | 10.82 | EUR/MW | 2018 |
| **Energy fee:** | -6.46 | EUR/MWh | 2018 |

*Table 22: aFRR prices 2018 Hungary*

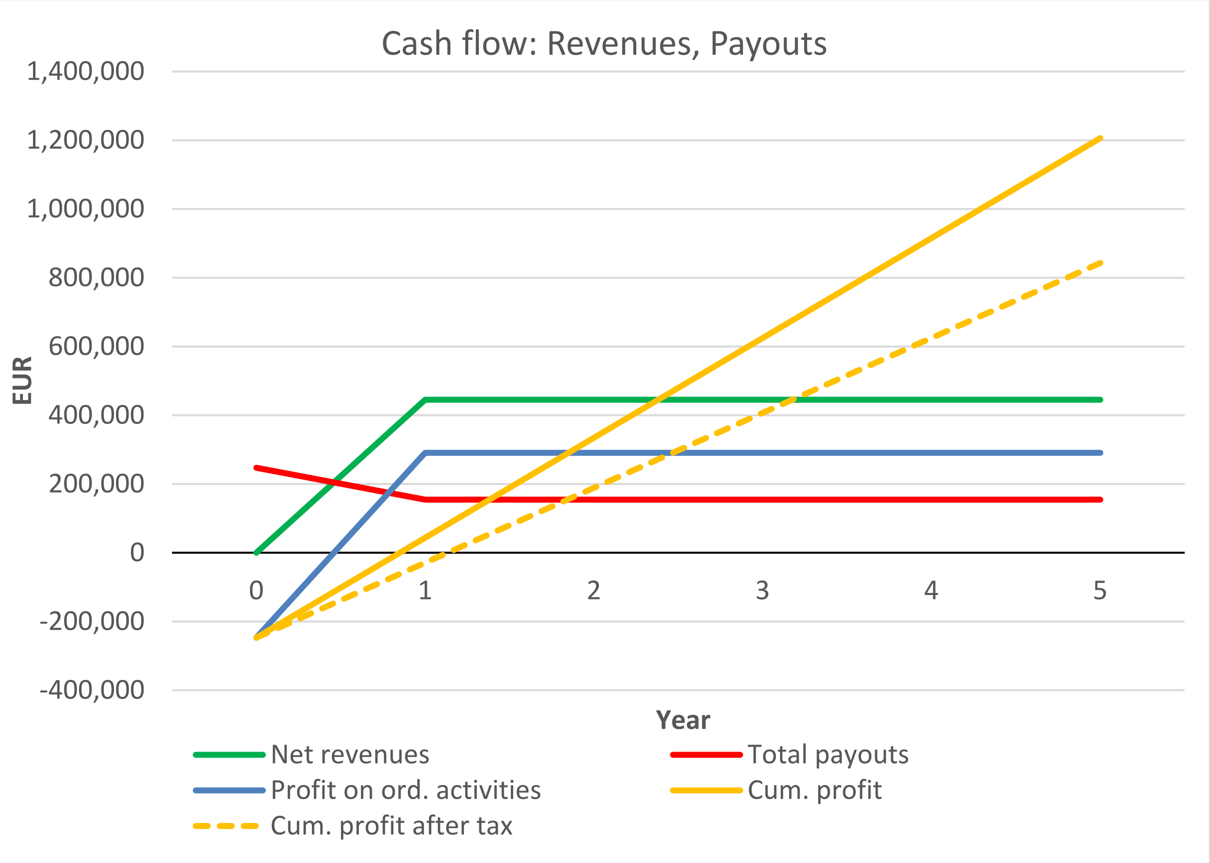

*Figure 18: Cost, revenue analysis, Hungary*

In Hungary, the revenue of 8MW VPP under the same conditions as described before would amount to 1,1M€ from which DR&DG share (60%) would amount to 900k€. The hypothetical revenue for the VPP would amount to approximately 445k€. Another 11k€ would be reserved for penalties, the cost of which is divided between the DR&DG that caused the imbalance and the VPP.

The Capex cost for installation of 8 MW flexibility unit that occurs in the first year is the same as for other three countries and amounts to 247k€. The operational and maintenance costs equals 154k€ per annum.

### Conclusions related to the profitability calculations

The comparison between Austria and the other three countries shows that VPP can be more profitable and reaching BEP already in its first year, while in Austria it takes 4 years. But in reality, Austria is the only one that has already an established liquid aFRR market, while Slovenia, Romania and Hungary are still in early development phase on DER participation in aFRR through VPP. Table 23 shows the costs of aFRR capacity and energy in 2019 in all four countries.

Table 23: aFRR costs

| Austria | | | Slovenia | | | Romania | | | Hungary | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| TSO, aFRR+ | | | TSO, aFRR+ | | | TSO, aFRR+ | | | TSO, aFRR+ | | |
| +/- 200 MW | | | +/- 60 MW | | | +/- 250 MW | | | +248/ -128 MW | | |
| Avrage price | | | Avrage price | | | Avrage price | | | Avrage price | | |
| 5.02 | EUR/MW/h | average 2018 | 9.000 | EUR/MW/h | average 2019 | 15.866 | EUR/MW/h | average 2018 | 14.75 | EUR/MW/h | average 2018 |
| 124.94 | EUR/MWh | average 2018 | 145.02 | EUR/MWh | average 2019 | 93.830 | EUR/MWh | average 2018 | 105.37 | EUR/MWh | average 2018 |
| 163000 | MWh | In 2018 | 54285 | MWh | In 2018 | 466691 | MWh | In 2018 | 270228 | MWh | In 2018 |
| | | | | | | | | | | | |
| TSO, aFRR- | | | TSO, aFRR- | | | TSO, aFRR- | | | TSO, aFRR- | | |
| Avrage price | | | Avrage price | | | | | | Avrage price | | |
| 1.69 | EUR/MW/h | average 2018 | 9.000 | EUR/MW/h | average 2019 | 15.866 | EUR/MW/h | average 2018 | 10.82 | EUR/MW/h | average 2018 |
| -26.77 | EUR/MWh | average 2018 | -32.67 | EUR/MWh | average 2019 | -3.458 | EUR/MWh | average 2018 | 6.46 | EUR/MWh | average 2018 |
| 156027 | MWh | In 2018 | 92320 | MWh | In 2018 | 528200 | MWh | In 2018 | 246301 | MWh | In 2018 |

### 4.4.2 Boost of private investments

Mobilisation of the existing DR&DG into the pool of available resources for flexibility will certainly ease the burden on the investments in new power plants, electricity transport infrastructure and big investments connected to the generation and demand of electricity. The introduction of the aggregator into a market creates a critical momentum around the exploitation of DER, attracts private investments and spurs competition between service providers.

The analysis above shows the benefits that can be reached through the implementation of the proposed FF market model, where special shorter auction time and participation of DR&DG will play an important role. Theoretically, an investment in VPP in Slovenia, Romania or Hungary would be a very profitable business, but only theoretically, since aggregators are not yet developed or allowed to offer aFRR. And there are higher risks (like the penalties for underperformance, which are very high in Slovenia) and also the outlook of decreasing prices and revenues on the market as a result of the international integration initiatives (considering the high prices compared to AT, DE).

It is safe to assume that the further development of the aFRR market will influence the cost of the capacity and energy in the future. Which will later probably result in cheaper aFRR for the EU citizens. But we have shown also how fragile a small VPP could be, when the prices go down, while the costs remain unchanged.  It can easily happen that after the first successful hype of aggregators entering the market, they will begin to struggle. This is, of course, logical when the new market is open and when the cost stabilisation happens due to the market rules.  Normally this will result in higher prices of energy, which can become very volatile as soon as the auctions periods become shorter. As observed in Austria in 2018 the monthly prices for the positive aFRR reached the lowest point in February with 66 €/MWh and the highest point of 341 €/MWh in August.  In future, with daily and even hourly auctions, we can expect even higher volatility.

If we add the increased volatility of the energy market as a whole, with a much bigger share of RES in the future scenarios, it could happen that different parts of Europe will face a shortage of balancing energy even more often and more rapidly as ever before. ELIA, for example, reports that in 2018, because of a sudden strong variation of the system imbalance, the available volume of aFRR gets fully activated on average 2 times per day per direction[6].

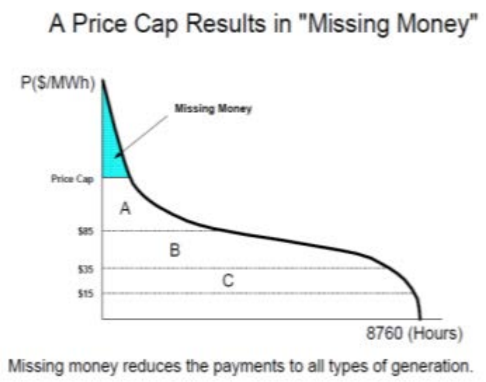

Fig. 1 Missing money emerging from price cap

*Figure 19: Missing money[7]*

If we compare this situation with the USA, we can see how the shortage of energy results in extreme prices. This was hardly the case in Europe in the past, but with the market liberalization, market rules shall be the one that will signalise the lack of resources on the market through the higher prices[5]

Europe is highly regulated and uses different approaches to prevent scarcity prices. One of the measures is to set up a price cap that the market cannot exceed, which results in missing money problem as you can see in Figure 20: Missing money[7]. The scarcity rent is very important for the investors into the peak generation or balancing services generation, to give the right signals. The missing money problem might result in fewer investments from the private sector, which includes DR&DG and VPPs.

Additionally, to that, the balancing service providers are also exposed to the threat of being penalised if they do not provide the service within a set of very strict rules.

Very high penalties can also scare away potential investors at the beginning. If we include the penalties in the calculations of VPP profitability, we can observe how the size of penalties affects a revenue of VPP and DER, considering that the same percentage of penalties is allocated toward the DER that caused the imbalance. This “fear of penalisation” will also hinder DR&DG decision to participate in VPP.

Missing money problem and the penalties hinder the investments in DG and VPP and influence the decision of DR to take part in the service. Lack of investment can result in a lack of capacity and especially reserves. New market models should allow mobilisation of resources in the times of need, which can be most effectively done with mobilisation of DR&DG inside of aggregation.

That is why it is really important not to neglect also other benefits that aggregators and DR&DG are bringing to the society and take really good care that the new market players will have equal possibilities than the old ones.

# 5 Conclusions

After more than 300 hours of real-life tests with more than 95 units put into the operation the FutureFlow project has a particular story to tell. The DR&DG units if aggregated in a proper portfolio inside the VPP are able to provide a fast, reliable, technical and economical competitive aFRR service on the European energy market.

Based on the pilot tests that have been performed within the duration of one-year tests it can be concluded that a significant amount of untapped flexibility potential exists, which confirms our initial estimations as described in section 2.2.1. However, the aFRR has proven to be the most challenging ancillary service, as expected, therefore not all flexibility that was tested is suitable for the use.

Analysis of the current potential in all four countries and the comparison with Austria, which has the most developed aFRR market with 4-hour products and weekly auctions, have shown that in the current situation the potential for the aggregators and DR&DG is high. But at the same time the volatility and the risks that aggregators are exposed to cannot be neglected. While currently most of the barriers for the participation are the regulatory barriers and lack of experience it could also happen in the future, that regulation, like price caps or regulated prices, could hinder further development of the VPPs.

But the main motivation to encourage VPP and DR&DG to participate in aFRR mechanisms lies in the future electrification trends on the European (ENTSO-E) level. The volatile behaviour of certain power sources, like wind and solar, will need more balancing resources and VPP could contribute to this problem by mobilizing DR&DG resources. Besides, the benefits for the stakeholders, like better utilization of available resources, the advantage of the geographical distribution of sources, new jobs opportunities, consumer activation and positive environmental effects are also an important motivator for the future.

The target model defined, simulated and pilot-tested within the FutureFlow, is in line with European target model (PICASSO), contributing to it with applied practical experiment, with real cross zonal capacities, both NTC-based and Flow-based. The supremacy of the Flow-based concept has also been demonstrated.

# 6 Reference

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