STREAM

STREAMING FLEXIBILITY TO THE POWER SYSTEM

D6.2 ECONOMIC IMPACT ASSESSMENT

Delivery Date: September 2026 (M48)

STREAM

STREAMING FLEXIBILITY TO THE POWER SYSTEM

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Abstract

This deliverable assesses the economic impact of flexibility services across the STREAM pilot sites. A cost-benefit analysis is conducted to evaluate the value of flexibility for distribution system operators (DSOs), aggregators, charging point operators and asset owners. Flexibility can create value for DSOs by deferring grid reinforcement when network constraints are temporary or localised, while aggregators can generate revenues through participation in existing ancillary-service markets or prospective local flexibility markets (LFMs). It was highlighted that aggregators require sufficiently large and reliable portfolios and adequate remuneration to create a viable business case and generate adequate revenues for the asset owners. The macroeconomic assessment indicates that wider demand-side flexibility deployment may shift economic activity and employment from conventional grid construction towards other sectors, although the scale of these effects remains country-specific.

Keywords

Economic impact assessment, Business models, Value of flexibility, Grid reinforcement, Input Output modelling

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EXECUTIVE SUMMARY

This deliverable assesses the economic impact of flexibility services in the STREAM pilot sites. Its purpose is to identify whether flexibility can create economically feasible business cases for the relevant actors (DSOs, aggregators, charging point operators (CPO), asset owners) and to quantify the associated costs, revenues and savings. To do so, a cost benefit analysis was conducted using technical and economic data from each STREAM pilot. It also includes a macroeconomic assessment of the potential effects of wider demand-side flexibility deployment in the EU.

The sPLAN grid planning assessment analysed a Slovenian low-voltage network under 16 technology-deployment scenarios (photovoltaics, battery storage, electric vehicles and heat pumps) to test whether demand-side flexibility and PV curtailment can defer or avoid conventional grid reinforcement. The 16 scenarios comprise one baseline scenario reflecting the current network state and five future technology groups (PV, PV with battery storage, electrification through EVs and heat pumps, electrification combined with PV, and a fully combined case), each evaluated under three stress levels (low, reference, and high). Flexibility eliminated all additional reinforcement in the balanced stress scenarios and, even under high stress, avoided most of it, reducing the high-stress combined case from 22 network elements to only two transformers while the activated energy stayed below 0.5% of annual EV and heat pump consumption. The associated Grid Investment Savings Ratio reached up to 64 % in the high-stress combined scenario. Behind-the-meter batteries reduced PV curtailment but not the reinforcement need, confirming that a battery's network value depends on its operating strategy rather than its capacity.

The results show that the economic viability of flexibility depends strongly on the business case and the actors considered. In Finland, the aggregator business case was profitable, with higher profitability for larger portfolios, however end users did not receive direct revenues under the assessed model. In the Italian pilot, flexibility provision through a theoretical local flexibility market (LFM) reduced charging costs for EV owners, while EMOT gained value through improved customer attractiveness. In addition, day-ahead-market (DAM) based pumping optimisation enabled ASM to shift pumping activity to lower price periods while maintaining daily water supply requirements, delivering substantial electricity cost savings and a positive NPV even under conservative assumptions due to low investment costs and the system’s high operational flexibility. In Slovenia, the business case for KOL (aggregator) was close to economic feasibility but was highly sensitive to the revenue share provided to asset owners and to uncertain flexibility activation volumes. The business case for AVANTCAR, the CPO, depended on the type and size of the charging portfolio, with the upscaled AVA portfolio presenting a profitable case. The business case comparing flexibility to defer grid reinforcement proved to be economically feasible for the analysed Slovenian grid segment. However, these findings should be interpreted cautiously given the single-component, case-specific analysis and the assumption of adequate flexibility supply. In Spain, flexibility was identified as a potentially preferable option for the DSO in the analysed grid section compared with conventional grid reinforcement, while the aggregator business case was not viable because expected revenues could not cover high upfront IT investment costs for the needed STREAM tools.

The assessment confirms that flexibility can be particularly valuable for DSOs when grid constraints are temporary, as it can defer grid reinforcement and provide time for more informed network planning. Flexibility, however, is less likely to replace reinforcement where electricity demand or

distributed generation continues to grow structurally over time. The assessments also showed that for aggregators, a viable business case requires a sufficiently large portfolio, adequate remuneration, and an appropriate allocation of revenues between the aggregator and participating asset owners. Asset owners need sufficient benefits to accept potential reductions in comfort, convenience, or autonomy.

Another conclusion is that the development of functioning LFMs is essential for evaluating the value of LFMs. The lack of established local market prices currently makes it difficult to quantify the value of flexibility, compare it consistently with grid reinforcement, and account for price and non-delivery risks.

The macroeconomic assessment indicates that a wider uptake of demand-side flexibility can generate economic effects beyond the energy sector. By reducing or deferring expenditure on conventional grid infrastructure, flexibility shifts economic activity and employment between sectors. The results suggest that flexibility-related expenditure may support more labour-intensive sectors compared with conventional grid construction, potentially creating additional domestic value added and employment opportunities. However, the size and direction of these impacts vary significantly across countries, depending on the structure of the national economy. The macroeconomic assessment therefore highlights that the benefits of flexibility are not limited to direct savings for individual market participants but may also contribute to broader economic activity and sectoral transformation.

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1 INTRODUCTION

1.1 PURPOSE OF THE DOCUMENT

The aim of this document is to quantify the economic impact of flexibility services across the STREAM pilot sites as well as broader macroeconomic impacts. It identifies where viable business cases related to flexibility could already be implemented and where they are not economically feasible under the current assumptions. The analysis is based on data and insights provided by the pilot partners, which were used to develop realistic business model assumptions, while UL was responsible for the description of sPLAN. This deliverable builds on D2.3, which outlines the theoretical background for the valorisation of flexibility services and presents qualitative business models for the pilots. Moreover, technical data generated in WP5 is used for the economic analysis.

1.2 SCOPE OF THE DOCUMENT

This deliverable introduces the business models assessed across the STREAM pilot sites and explains the related value chains, including the roles, interactions, and value flows among key actors. Moreover, the sPLAN tool, is presented, which allows to assess a business model in which flexibility services are used to defer or avoid conventional grid investments. Quantitative business cases are developed for each pilot site to evaluate their economic viability and potential benefits for the involved actors.

1.3 STRUCTURE OF THE DOCUMENT

The deliverable is structured as follows: Chapter 2 introduces the business models for flexibility services and the underlying value chains, while Chapter 3 presents the sPLAN tool. Chapter 4 outlines the methodology for the cost-benefit analysis used to assess the economic impact. Chapter 5 provides the quantitative business cases developed for the different STREAM pilot sites. Chapter 6 complements the pilot-level analysis with a broader macroeconomic assessment of demand-side flexibility in the EU, using input–output modelling. Finally, Chapter 7 summarises the main findings and discusses their implications and limitations.

2 STREAM BUSINESS MODELS FOR FLEXIBILITY

This chapter describes the value creation of flexibility services for different actors in the STREAM context. For theoretical content regarding business models for flexibility, please refer to D2.3. Business model structure.

The business models assessed in STREAM are not built around a single product but around the way value is created, exchanged, and settled between the actors of the flexibility value chain. Figure 1 shows the actors considered in the analysis and the two directions of exchange that define the business case. Physical flexibility flows from assets owner towards the flexibility buyer. Financial remuneration flows from the buyer back to the asset owner. The value creation is supported by the tools developed in STREAM.

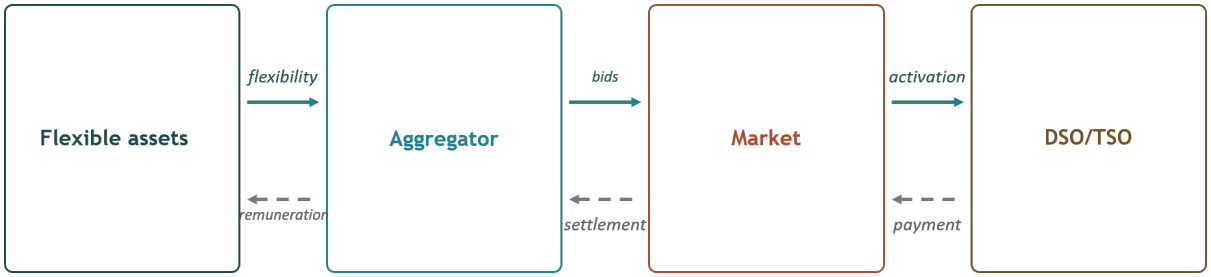


Figure 1: Flexibility value stream

Applied to the pilot settings, the D2.3 value-chain logic results in four distinct configurations. In Slovenia, industrial and EV flexibility is aggregated by KOL and can be offered to EPR on the distribution level through LFMs or to the TSO, ELES, on the transmission level, through established ancillary-service arrangements. Borzen is responsible for the operation of these markets. In Spain, ENER is represented separately as a DSO and as an aggregator, OMIE operates the local market, and flexibility is drawn from the energy community. In Italy, ASM combines DSO and aggregation functions and interacts with the energy community and EMOT's EV and charging assets. In Finland, OPT aggregates residential heating loads. The assessed route to market is primarily the established, frequency containment reserve for disturbances (FCR-D) market, while spot-price optimisation is an existing service and scheduled local flexibility remains prospective.

Market and contractual arrangements determine how these value streams can be monetised. Established ancillary-service markets such as FCR-D and Manual Frequency Restoration Reserve (mFRR) operate with defined products, bidding/activation and settlement rules. In STREAM the value creation on LFMs is also considered. While such markets are not yet operational in the pilot, estimations regarding prices and quantities are required. Contracts between aggregators and participating asset owners determine how market remuneration is shared.

Accordingly, the economic assessment is limited to actors for which costs, revenues /savings can be attributed. Business cases are therefore developed for aggregators, asset owners, CPOs and DSOs as applicable. No business cases are created for Borzen and OMIE due to their operation as a regulated activity. Their role remains essential for market access, process integrity and settlement, but it is represented as an enabling function rather than a separate profitability target. Transmission system operator (TSO) roles are considered where required to define ancillary-service access and DSO-TSO coordination.

Table 1 presents the assessed business cases in Chapter 5. It highlights for each pilot how value is created and for which actor. While for ancillary markets, this can be demonstrated, as these are already established, LFMs are not yet operational in the pilot countries and are therefore mostly build on estimations. The use of flexibility to avoid grid reinforcement is also not yet commonly applied and is therefore based on estimations.

The non-monetary value creation mechanisms, including the P2P marketplace concept, were initially included in the proposal. However, following changes in the consortium and the development of the pilot activities, the P2P marketplace use case was removed from the scope of the Italian pilot.

Table 1 STREAM Business cases

Actor	Value creation	Finnish pilot	Italian pilot	Slovenian pilot	Spanish pilot
Aggregator	Offering flexibilities on the ancillary market	X		X	
	Offering flexibilities on an LFM				
	Optimising demand according to DAM prices		X	X	
DSO	Using flexibility to defer grid investment			X	X
CPO	Higher customer attractiveness/lower customer churn		X		
Asset owner	Lower electricity costs		X		
	Revenues from flexibility provision			X	
	Service credit or compensation for FCR-D participation	X			

The DSO business case of using flexibility to defer grid investment is supported methodologically by sPLAN (Chapter 3). sPLAN provides technical insights to quantify how much flexibility would be required to keep the network within limits, and to compare that requirement against the conventional reinforcement alternative. In combination with the market layer, it allows the deferral case to be expressed in the terms a regulated DSO can act on: which investment is postponed, by how many years, at what flexibility procurement cost, and with what residual risk if the flexibility is not delivered. This tool therefore allows analysing the economic feasibility of the business case and is therefore included in this deliverable.

3 sPLAN – BASED GRID PLANNING ECONOMIC ASSESSMENT

This section presents the sPLAN-based economic assessment of low-voltage grid planning, which examines whether demand-side flexibility and PV curtailment can defer or avoid conventional grid reinforcement, and at what cost. The assessment is applied to a real low-voltage network operated by the Slovenian DSO Elektro Primorska (EPR), across a set of representative deployment scenarios covering photovoltaic generation, battery storage, and the electrification of heating and transport. The section first sets out the scenario design process and the inputs and outputs of the tool, and then reports the resulting reinforcement needs, the role of flexibility, and the associated costs over a 20-year planning horizon.

3.1 SCENARIO DESIGN PROCESS

The purpose of scenario design within sPLAN is not to explore all technically possible configurations, but to define a limited set of representative, policy- and operation-relevant scenarios that reflect plausible near- and mid-term developments in the distribution network. These scenarios serve as structured test cases that allow the DSO to assess network impacts, investment needs, and the potential role of flexibility under controlled and transparent assumptions. The proposed scenarios and their parameter ranges were developed and validated together with the DSO EPR, so that they represent realistic and policy-relevant developments for the analysed network.

Each scenario represents a specific asset deployment in the low-voltage network. For every scenario, sPLAN evaluates two solution paths: (i) grid upgrades only, and (ii) grid upgrades combined with flexibility-enabled operation. Each scenario is analysed under three stress levels to capture uncertainty in asset uptake, operating conditions, and background demand evolution:

- **Low-stress**: conservative deployment and limited coincidence effects.
- **Balanced**: reasonable expectations aligned with current planning assumptions.
- **High-stress**: accelerated uptake and unfavourable coincidence of generation and demand.

The common simulation settings comprise the network model and the simulation period. One representative week is calculated for each season (winter, spring, summer and autumn) jointly with the DSO. Each seasonal week is then scaled to represent its full three-month period, so that the four seasonal weeks together form the annual assessment. These settings are kept consistent across all scenarios to ensure comparability of results. Because each season is represented by such a characteristic week, the peak of the representative winter week, for example, should not be interpreted as the absolute annual winter peak or as an extreme design condition: averaging measurements across December, January and February smooths short-duration extremes, so the results primarily describe representative seasonal network conditions and may underestimate loading during rare peak-demand events.

For each scenario, sPLAN compares two planning options over a 20-year horizon: (i) conventional grid reinforcement alone, and (ii) the combined use of flexibility measures (demand-side flexibility and PV curtailment) together with any reinforcement that remains necessary. Flexibility is prioritised wherever it can resolve the identified network constraints and is economically preferable, that is, where its 20-year net present cost is lower than that of the equivalent grid reinforcement.

Where flexibility cannot technically resolve a constraint, for example a persistent overload that demand shifting or curtailment cannot relieve, conventional reinforcement is retained for the affected element. The solution reported for each scenario is therefore the least-cost combination of flexibility and targeted reinforcement, with conventional grid reinforcement serving as the fall-back option.

3.1.1 Inputs and outputs of the tool

The sPLAN tool operates by combining a defined set of input parameters describing the LV network, asset deployment, and operating assumptions, and producing quantitative outputs related to network performance, reinforcement needs, and flexibility use. Table 2 and Table 3 provide an overview of the key inputs and outputs used across all scenarios.

Table 2: Overview of sPLAN input parameters

Parameter	Description
PV deployment	Number of PV installations and installed power per unit
BESS deployment	Battery storage power and energy capacity per unit, deployed one-to-one with PV
EV profiles	Number of EV charging demand profiles applied to customer connection points
Heat pump deployment	Number of heat pumps, heating area, and specific space-heating demand
Uncontrollable loads	Background demand scaling applied to baseline consumption profiles
Flexibility availability	Duration and activation assumptions for flexible operation (where applicable)

Table 3: Overview of sPLAN output parameters

Output parameter	Description
Network loading	Line and transformer loading levels
Voltage quality	Voltage deviations at network nodes
Grid reinforcements	Required network upgrades to resolve overloads or voltage issues
Investment cost	Estimated cost of required grid reinforcements
Flexibility utilisation	Activated flexibility volumes and curtailed energy
Deferred investments	Avoided or postponed grid reinforcements compared to a grid-only solution

3.2 OVERVIEW OF SCENARIO PARAMETERS AND JUSTIFICATION OF VALUE RANGES

This section summarises the key parameters used to identify and differentiate scenarios in sPLAN and provides the rationale for the selected value ranges. The values are chosen to reflect realistic residential deployment patterns, observed technology adoption dynamics, and DSO planning practice, while ensuring sufficient spread to reveal non-linear network effects.

3.2.1 Photovoltaic penetration (additional number of PVs)

PV penetration levels of 200, 400, and 600 units correspond to approximately 10%, 20%, and 30% of the additional LV customers considered for PV installation (the total number of consumers in the grid is 2324). These levels reflect gradual but sustained uptake of residential self-consumption systems. The lower bound represents early deployment that is already common in many LV networks, while the upper bound captures accelerated adoption without assuming saturation of rooftop PV across all households.

3.2.2 Installed PV power per unit

The installed PV capacity at each selected connection point is determined in proportion to the customer's connection capacity. It is calculated as 80% of the connection capacity (P_{conn}) and ensures that PV system size remains consistent with the scale of the connected customer. It prevents large consumers from being assigned unrealistically small PV installations and, conversely, avoids assigning disproportionately large PV systems to customers with low connection capacities. The PV stress levels are therefore represented primarily by varying the number of installations, while the capacity of each installation remains linked to its connection point.

3.2.3 Battery storage power and energy capacity

BESS is modelled exclusively as behind-the-meter residential storage and is deployed one-to-one with the selected PV installations. The battery power rating is set equal to the installed PV power, while its energy capacity is defined as twice the PV power. This corresponds to an energy-to-power ratio of two hours and scales each battery system according to the associated PV installation and customer connection capacity. The approach avoids assigning disproportionately small or large storage systems to individual customers.

3.2.4 Electric vehicle penetration

EV adoption levels of 200, 600, and 1,200 vehicles correspond to roughly 10%, 30%, and 60% of LV customers. These values reflect the faster turnover of vehicles compared to buildings and heating systems and are consistent with medium- to long-term electrification trajectories considered in DSO planning. Higher EV penetration relative to PV and heat pumps is intentional and reflects observed adoption dynamics.

3.2.5 Electric vehicle charging

EV charging profiles are generated individually for each selected customer, following a stochastic approach. Charging power is linked to the customer's connection capacity and is set to 3.6, 7.2, or 11 kW. Daily charging energy is estimated from the travelled distance and vehicle-specific electricity consumption, while charging is initiated around the evening arrival time with an assumed home-charging probability of 85%.

3.2.6 Heat pump penetration

Heat pump deployment levels of 100, 300, and 600 units (roughly 5%, 15%, and 30% of customers) represent plausible uptake rates in existing residential building stock. The values are lower than EV penetration to reflect longer replacement cycles for heating systems, higher investment costs, and physical constraints related to building suitability.

3.2.7 Heated area for heat pump load estimation

Heated areas of 120, 140, and 160 m^2 represent typical sizes of detached and semi-detached residential buildings. Increasing heated area across stress levels introduces additional demand growth while keeping technology assumptions unchanged.

3.2.8 Specific space-heating demand of the areas

Specific heat demand values of 90, 100, and 110 kWh/m^2 represent the thermal energy demand of the building stock and not the heat pump efficiency. These values are appropriate for existing or partially renovated residential buildings and do not assume nearly zero-energy building performance. The progression across stress levels reflects increasing representation of older or less energy efficient buildings.

3.2.9 Change of uncontrollable loads

Background load changes of 0%, +2.5%, and +5% represent general growth in electricity consumption unrelated to explicitly modelled assets, such as increased appliance use, digitalisation, or behavioural effects. Only non-negative changes are considered, reflecting conservative DSO planning practice that does not rely on assumed net load reductions.

3.3 PROPOSED SCENARIOS

The scenarios are presented in order of increasing deviation from the balanced case, starting from the current network state and progressively introducing additional drivers and mitigation options. Tool-based optimal sizing is disabled to preserve transparency and replicability of the scenarios. Proposed list of scenarios:

3.3.1 Baseline scenario

Represents the current reference state of the network, using the selected DSO network model and season-specific average consumption profiles. No additional PV, BESS, EVs, or HPs are introduced beyond what is already present in the input data. This scenario establishes the reference values for line and transformer loading, voltage levels, and upgrade needs, and serves as the benchmark for all subsequent scenarios.

3.3.2 PV scenario without BESS

This scenario introduces new PV installations without BESS. Each new PV connection point is sized at 80% of its connection capacity (Pconn). The stress levels differ in the number of installations and not in the per-unit size. Uncontrollable loads are adjusted according to the stress definition (0%, +2.5%, +5%). The scenario isolates the impact of increasing distributed generation without storage.

Table 4: PV scenario (without BESS)

Parameter	Low-stress	Balanced	High-stress
Number of PVs [#]	200	400	600
Installed PV power [kW]	$0.8*P_{conn}$	$0.8*P_{conn}$	$0.8*P_{conn}$
Change of uncontrollable loads [%]	0	2.5	5

3.3.3 PV scenario with BESS

This scenario builds on the PV-only case by adding BESS. BESS is deployed strictly one-to-one with PV installations, with each battery sized to its associated PV installation (power equal to the PV power and energy twice the PV power). Uncontrollable load adjustments follow the same percentage changes as in the corresponding PV-only scenarios.

Table 5: PV scenario (with BESS)

Parameter	Low-stress	Balanced	High-stress
Number of PVs [#]	200	400	600
Installed PV power [kW]	$0.8*P_{conn}$	$0.8*P_{conn}$	$0.8*P_{conn}$
BESS power per unit [kW]	$0.8*P_{conn}$	$0.8*P_{conn}$	$0.8*P_{conn}$
BESS energy capacity per unit [kWh]	$1.6*P_{conn}$	$1.6*P_{conn}$	$1.6*P_{conn}$
Change of uncontrollable loads [%]	0	2.5	5

3.3.4 Electrification scenario (EV + HP, without PV and BESS)

This scenario introduces EVs and HPs without additional PV or BESS. EV charging profiles are added to baseline consumption, while HP demand is derived from the heated area and the specific space-heating demand. Uncontrollable loads follow the stress-level definition.

Table 6: Electrification scenario (EV + HP, without PV and BESS)

Parameter	Low-stress	Balanced	High-stress
Number of EVs [#]	200	600	1200
Number of heat pumps [#]	100	300	600
Heat pump area [m2]	120	140	160
Heat pump specific demand for area [kWh/m2]	90	100	110
Change of uncontrollable loads [%]	0	2.5	5

3.3.5 Electrification scenario with PV without BESS (PV + EV + HP, without BESS)

This scenario combines distributed generation and electrified demand without storage, allowing interaction effects between PV generation and load growth to be assessed without storage mitigation.

Table 7: Electrification scenario (EV + HP + PV, without BESS)

Parameter	Low-stress	Balanced	High-stress
Number of PVs [#]	200	400	600
Installed PV power [kW]	$0.8*P_{conn}$	$0.8*P_{conn}$	$0.8*P_{conn}$
Number of EVs [#]	200	600	1200
Number of heat pumps [#]	100	300	600
Heat pump area [m2]	120	140	160

Heat pump specific demand for area [kWh/m2]	90	100	110
Change of uncontrollable loads [%]	0	2.5	5

3.3.6 Combined scenario (PV + BESS + EV + HP)

This scenario represents the integration of all considered asset types and inputs, combining PV, EVs, HPs, and BESS deployed one-to-one with PV installations. It corresponds to the most advanced electrification case, in which both generation and demand increase simultaneously, allowing assessment of combined effects and the role of flexibility in managing overall network impacts.

Table 8: Combined scenario (PV + BESS + EV + HP)

Parameter	Low-stress	Balanced	High-stress
Number of PVs [#]	200	400	600
Installed PV power [kW]	$0.8*P_{conn}$	$0.8*P_{conn}$	$0.8*P_{conn}$
BESS power per unit [kW]	$0.8*P_{conn}$	$0.8*P_{conn}$	$0.8*P_{conn}$
BESS energy capacity per unit [kWh]	$1.6*P_{conn}$	$1.6*P_{conn}$	$1.6*P_{conn}$
Number of EVs [#]	200	600	1200
Number of heat pumps [#]	100	300	600
Heat pump area [m2]	120	140	160
Heat pump specific demand for area [kWh/m2]	90	100	110
Change of uncontrollable loads [%]	0	2.5	5

3.4 RESULTS

This chapter presents the results obtained with the scenario analysis. The analysis was based on four representative seasonal weeks, each week was scaled to represent its full season of approximately 13 weeks, so that the four weeks together represent a complete year. For each scenario, the required network reinforcements were first determined without flexibility and then reassessed after activating the available demand-side flexibility and PV curtailment. The economic comparison was performed over a 20-year assessment period. Reinforcement investments were treated as upfront capital expenditures, whereas recurring flexibility costs were discounted to their net present value. This provides a consistent basis for evaluating whether flexibility can technically reduce or defer network reinforcement and whether it represents an economically preferable alternative over the selected planning horizon.

The available measurements describe the net active-power exchange at each smart metering point and therefore already include the combined effect of existing consumption and behind-the-meter technologies. Consequently, the individual contributions of existing photovoltaic systems, heat pumps, electric vehicles, battery storage systems, and other devices cannot be identified separately. The technologies introduced in the analysed scenarios should therefore be interpreted as additional installations superimposed on the observed net-load baseline.

Network reinforcement was evaluated using a planning loading threshold of 90% for both lines and transformers. Any element exceeding this threshold during the analysed period was considered a candidate for reinforcement: lines were reinforced by increasing their parallel capacity, while transformers are replaced by a unit with a higher rated power.

A total of 16 scenarios were analysed: one baseline scenario and 15 future scenarios covering photovoltaic generation, photovoltaic generation combined with battery storage, electrification through electric vehicles and heat pumps, electrification combined with photovoltaics, and a fully combined technology case. Each scenario group was evaluated under low, balanced, and high-stress assumptions that vary the number of installed units and change of uncontrollable loads (CoUL). The scenarios providing the most relevant insights into network loading, reinforcement requirements, and the value of flexibility are presented in the following sections. As an illustration, Figure 2 shows the technology deployment across the network for the combined high-stress scenario. Table 9 presents the overview of scenarios analysed within sPLAN.

Table 9: Technology deployment and background load growth assumptions for the analysed scenarios

Scenario	PV	BESS	EV	HP	CoUL [%]
Baseline	-	-	-	-	0.0
PV – low	X	-	-	-	0.0
PV – balanced	X	-	-	-	2.5
PV – high	X	-	-	-	5.0
PV + BESS – low	X	X	-	-	0.0
PV + BESS – balanced	X	X	-	-	2.5
PV + BESS – high	X	X	-	-	5.0
Electrification – low	-	-	X	X	0.0
Electrification – balanced	-	-	X	X	2.5
Electrification – high	-	-	X	X	5.0
Electrification + PV – low	X	-	X	X	0.0
Electrification + PV – balanced	X	-	X	X	2.5
Electrification + PV – high	X	-	X	X	5.0
Combined – low	X	X	X	X	0.0
Combined – balanced	X	X	X	X	2.5
Combined – high	X	X	X	X	5.0

The economic assessment assumes a flexibility activation price of 100 €/MWh, while the cost of PV curtailment is set to 0 €/MWh. The zero-cost assumption reflects a future-oriented system perspective in which increasing PV penetration is expected to create more frequent periods of local generation surplus and network congestion. During such periods, the marginal PV energy cannot be accommodated or usefully consumed and may even increase reverse power flows, voltage deviations, and reinforcement requirements. Consequently, this energy is assumed not to receive compensation when its injection would provide no system benefit or adversely affect network operation. The assumption applies only to the marginal energy curtailed during constrained intervals and does not imply that PV generation has no value under normal operating conditions. It should also be recognised as an optimistic regulatory and market assumption, since alternative arrangements involving compensation for lost production would increase the cost of curtailment and reduce the calculated economic benefit of flexibility. The 100 €/MWh flexibility-activation price is consistent with currently observed flexibility prices.

As the purpose of the tool is to compare flexibility with conventional reinforcement under realistic present-day conditions, instead of forecasting the future market prices, this price level is applied consistently across the entire assessment period.

Table 10 presents the Grid Investment Savings Ratio (GISR), which expresses the relative reduction in grid-related costs achieved through flexibility compared with conventional network reinforcement. The results show that PV curtailment can fully avoid the identified reinforcement costs in the balanced and high-stress PV and PV + BESS scenarios, resulting in a GISR of 100 %, this however is heavily influenced by the assumed cost of PV curtailment. In the electrification scenarios, GISR generally decreases as network stress increases, since a larger share of the required reinforcement cannot be replaced by flexibility. The combined scenario nevertheless retains substantial savings, with GISR values of 97.40% and 64.31% under balanced and high-stress conditions, respectively.

Table 10: GISR

Scenario	Low-stress	Balanced	High-stress
PV	0 %	100 %	100 %
PV + BESS	0 %	100 %	100 %
Electrification	97.67 %	89.16 %	43.23 %
Electrification + PV	0 %	86.64 %	39.84 %
Combined	0 %	97.40 %	64.31 %

Table 11 complements Table 10 by presenting the break-even flexibility price, i.e. the maximum activation price at which flexibility remains economically preferable to the avoided reinforcement. Higher values therefore indicate greater economic robustness. The break-even price ranges from 493.82 €/MWh for the high-stress electrification + PV scenario to 4,299.49 €/MWh for the low-stress electrification scenario. No break-even value is reported where demand-side flexibility was not activated or where no reinforcement cost was avoided, as the calculation is not applicable in these cases. The break-even price does not vary monotonically with network stress, because it expresses the avoided reinforcement cost relative to the volume of activated flexibility rather than the absolute value of either. The balanced electrification case therefore shows a lower break-even price than the low- and high-stress cases, as it activates the largest volume of flexibility relative to the reinforcement cost it avoids.

Table 11: Break-even price of flexibility

Scenario	Low-stress [€/MWh]	Balanced [€/MWh]	High-stress [€/MWh]
PV	-	-	-
PV + BESS	-	-	-
Electrification	4,299.49	922.69	2,513.43
Electrification + PV	-	748.34	493.82
Combined	-	3,847.96	1,034.65

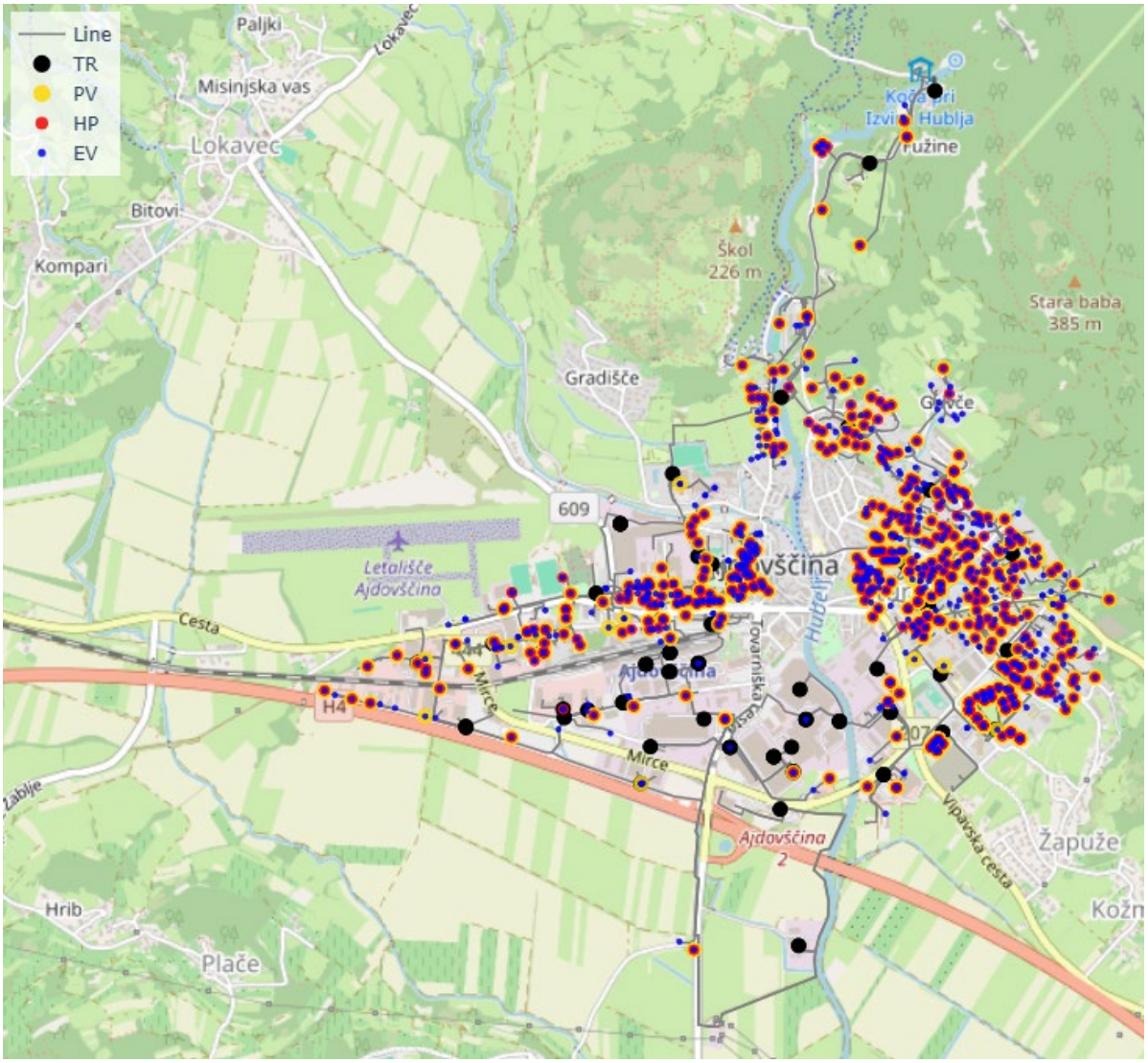


Figure 2: Combined high stress scenario technology deployment (TR: Transformer Station, PV: Photovoltaic, HP: Heat Pump, EV: Electric Vehicle)

Table 12 summarises the annual activation of EV and HP flexibility together with the amount of curtailed PV generation across all analysed scenarios. No flexibility or PV curtailment is required in the baseline and most low-stress scenarios, indicating that the existing network can accommodate these levels of additional technology deployment. Demand-side flexibility becomes more relevant under balanced and high-stress electrification conditions, reaching its highest value of 19.21 MWh/year in the high-stress electrification + PV scenario. Nevertheless, the activated energy remains below 0.5% of the total annual EV and HP consumption in all scenarios, since flexibility is required only during a limited number of critical intervals. PV curtailment is most pronounced in the high-stress PV scenario, where 220.02 MWh/year, or 1.15% of potential PV generation, is curtailed. The addition of battery storage and flexible demand reduces the required curtailment, demonstrating that coordinated consumption and storage can absorb part of the local PV surplus and mitigate network constraints.

Table 12: Annual activated demand-side flexibility and PV curtailment across the analysed scenarios

	Flexibility		Activated energy		PV curtailment	
Scenario	EV [MWh/a]	HP [MWh/a]	Total flexibility [MWh/a]	Share of EV+HP [%]	Absolute [MWh/a]	Share [%]
Baseline	-	-	-	-	-	-
PV – low	-	-	-	-	-	-
PV – balanced	-	-	-	-	15.79	0.148
PV – high	-	-	-	-	220.02	1.152
PV + BESS – low	-	-	-	-	-	-
PV + BESS – balanced	-	-	-	-	15.67	0.147
PV + BESS – high	-	-	-	-	196.22	1.028
Electrification – low	0.38	0.09	0.47	0.070	-	-
Electrification – balanced	5.64	2.62	8.26	0.354	-	-
Electrification – high	2.70	1.38	4.08	0.076	-	-
Electrification + PV – low	-	-	-	-	-	-
Electrification + PV – balanced	6.42	3.60	10.02	0.429	10.24	0.096
Electrification + PV – high	12.18	7.03	19.21	0.358	4.77	0.025
Combined – low	-	-	-	-	-	-
Combined – balanced	0.96	0.40	1.37	0.058	10.23	0.096
Combined – high	6.71	3.75	10.46	0.195	6.44	0.034

Table 13 compares the number of lines and transformers requiring reinforcement before and after flexibility activation, based on the adopted 90% planning threshold. No reinforcement is required in the baseline and most low-stress scenarios. Before flexibility, the largest reinforcement requirement occurs in the high-stress electrification scenario, with 28 lines and five transformers, followed by the high-stress electrification + PV and combined scenarios. Flexibility eliminates all additional reinforcement requirements in the balanced scenarios and substantially reduces them under high-stress conditions. In the high-stress electrification scenario, the requirement decreases from 33 to 15 elements, while in the high-stress electrification + PV scenario it decreases from 28 to seven elements. The strongest reduction is observed in the high-stress combined scenario, where the requirement decreases from 22 elements to only two transformers, demonstrating the complementary contribution of demand-side flexibility, PV curtailment, and battery storage.

Table 13: Network elements requiring reinforcement before and after flexibility

Scenario	Lines		Transformers	
	Before flexibility [no.]	After flexibility [no.]	Before flexibility [no.]	After flexibility [no.]
Baseline	-	-	-	-
PV – low	-	-	-	-
PV – balanced	-	-	1	-
PV – high	2	-	2	-
PV + BESS – low	-	-	-	-
PV + BESS – balanced	-	-	1	-
PV + BESS – high	2	-	2	-
Electrification – low	-	-	1	-
Electrification – balanced	6	-	2	-
Electrification – high	28	13	5	2
Electrification + PV – low	-	-	-	-
Electrification + PV – balanced	2	-	3	-
Electrification + PV – high	24	4	4	3
Combined – low	-	-	-	-
Combined – balanced	1	-	2	-
Combined – high	19	-	3	2

Table 14 compares the upfront reinforcement cost required without flexibility with the total 20-year net present cost after flexibility activation. The latter includes both the remaining reinforcement investments and the recurring cost of demand-side flexibility at the assumed price of 100 €/MWh, while PV curtailment is valued at 0 €/MWh. No additional costs occur in the baseline or most low-stress scenarios. In the balanced and high-stress PV and PV + BESS scenarios, targeted curtailment eliminates all additional reinforcement costs. Flexibility also avoids most costs in the balanced electrification scenarios, reducing them from 95,034 € to 10,300 € for electrification, from 93,407 € to 12,482 € for electrification + PV, and from 65,478 € to 1,702 € for the combined scenario. Under high-stress conditions, substantial residual costs remain, particularly for electrification, although flexibility still reduces the total cost from 283,779 € to 161,114 €. The greatest relative saving among the high-stress electrification cases is achieved in the combined scenario, where the cost decreases from 189,465 € to 67,626 €.

Table 14: Reinforcement costs before flexibility and total costs after flexibility

Scenario	Reinforcement cost before flexibility [€]	Total 20-year NPV after flexibility [€]
Baseline	-	-
PV – low	-	-
PV – balanced	25,040	-
PV – high	71,757	-
PV + BESS – low	-	-
PV + BESS – balanced	25,040	-
PV + BESS – high	71,757	-
Electrification – low	25,040	582
Electrification – balanced	95,034	10,300
Electrification – high	283,779	161,114
Electrification + PV – low	-	-
Electrification + PV – balanced	93,407	12,482
Electrification + PV – high	236,613	142,345
Combined – low	-	-
Combined – balanced	65,478	1,702
Combined – high	189,465	67,626

3.4.1 Baseline scenario

As defined in the Baseline scenario description, no additional PV, battery storage, electric vehicles, heat pumps or background load growth are introduced. The baseline therefore requires no reinforcement and no flexibility activation and serves as the reference case against which the introduction of new technologies is assessed. Sections below highlight only a couple of scenarios, due to their similar insights they provide, to retain the clarity of the deliverable.

3.4.2 PV and PV + BESS scenarios (all stress levels)

The PV and PV + BESS scenarios examine the effect of increasing distributed PV penetration and the extent to which behind-the-meter battery storage changes its impact on the distribution network. Under low-stress conditions, neither scenario creates additional reinforcement requirements nor requires PV curtailment. In the balanced case, both scenarios initially require the reinforcement of one transformer, which can be fully avoided through limited PV curtailment. The curtailed energy amounts to 15.79 MWh/year in the PV scenario and 15.67 MWh/year in the PV + BESS scenario, corresponding to approximately 0.15% of potential annual PV generation.

Table 15: Network elements requiring reinforcement before and after flexibility – PV and PV + BESS high stress scenarios

Overloaded element	Reinforcement	Flexibility and reinforcement
Lines	2	-
Transformers	2	-

In the high-stress case, the PV and PV + BESS scenarios result in the same reinforcement requirement before curtailment: two additional lines and two transformers. Table 15 presents the change in required element upgrades. This result indicates that the installed battery systems do not materially reduce the critical network loading that determines the required reinforcement. Although the batteries reduce the curtailed PV energy from 220.02 to 196.22 MWh/year, the reduction is insufficient to impact grid reinforcement. Following targeted PV curtailment, all additional reinforcement requirements are avoided in both scenarios. Figure 3 translates the required reinforcement into costs and compares it to the scenario that includes flexibility measures. The curtailed energy represents 1.15% of potential PV generation in the PV scenario and 1.03% in the PV + BESS scenario. Figure 3 presents the difference in 20-year NPV cost for the scenario.

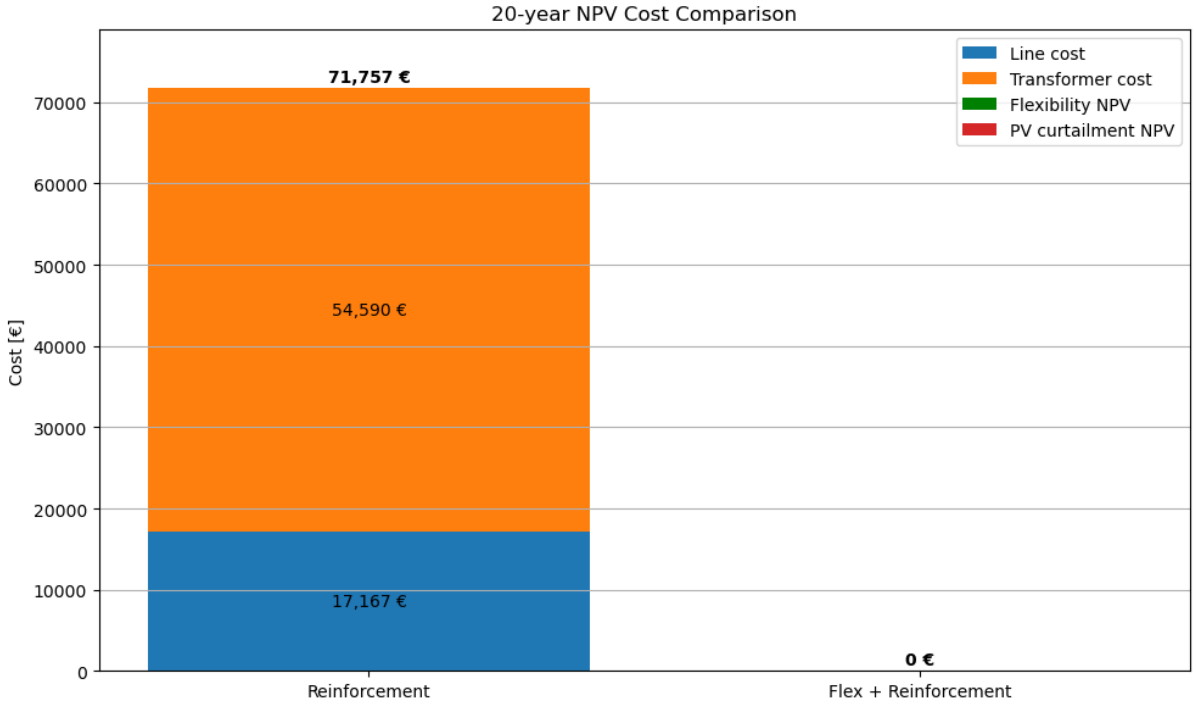


Figure 3: Required reinforcement before and after flexibility - PV and PV + BESS high stress scenario

The similar reinforcement requirements arise primarily from the assumed battery-control strategy. All installed battery systems are modelled as behind-the-meter self-consumption batteries, whose main purpose is to store locally generated PV surplus and subsequently increase household self-consumption. Their charging and discharging schedules are therefore determined by local consumption and generation profiles. As presented in Table 16, in the high-stress scenario, the effect of self-consumption BESS is reflected primarily in a **10.8% reduction in the required PV curtailment**, from 220.02 to 196.22 MWh/year, rather than in a reduction in the number of network elements requiring reinforcement. Although this operating mode reduces the total energy exported to the network, it does not explicitly target the locations and time intervals responsible for critical line or transformer loading.

Table 16: Annual activated demand-side flexibility and PV curtailment – PV and PV + BESS high stress scenario

Scenario	EV flexibility [MWh/a]	HP flexibility [MWh/a]	Total activated flexibility [MWh/a]	Activated share of EV+HP energy [%]	PV curtailment [MWh/a]	PV curtailment share [%]
PV – high	-	-	-	-	220.02	1.152
PV + BESS – high	-	-	-	-	196.22	1.028

These results emphasise that battery capacity alone does not determine its value to the distribution network. The battery type, location, availability, and particularly its operating strategy are equally important.

3.4.3 Electrification scenario (high-stress)

Table 17 presents the high-stress electrification scenario, the most demanding load-driven case, with the simultaneous large-scale deployment of electric vehicles and heat pumps. Before flexibility activation, 28 lines and five transformers require reinforcement. The concentration of EV charging and heat-pump demand during high-load periods creates network constraints, particularly during the winter season.

Table 17: Network elements requiring reinforcement before and after flexibility – Electrification high stress scenario

Overloaded element	Reinforcement	Flexibility and reinforcement
Lines	28	13
Transformers	5	2

Flexibility is less successful in avoiding reinforcement in this scenario than in the other electrification-related scenarios. After flexibility activation, 13 lines and two transformers still require reinforcement. Flexibility therefore avoids the reinforcement of 15 lines and three transformers, reducing the total requirement from 33 to 15 elements, or by approximately 54.5%. Figure 4 translates the required reinforcement into costs and compares it to the scenario that includes flexibility measures. The remaining reinforcement requirement is the highest among all analysed scenarios. This indicates that the magnitude and duration of the additional demand exceed the relief that can be achieved solely by shifting EV and HP consumption.

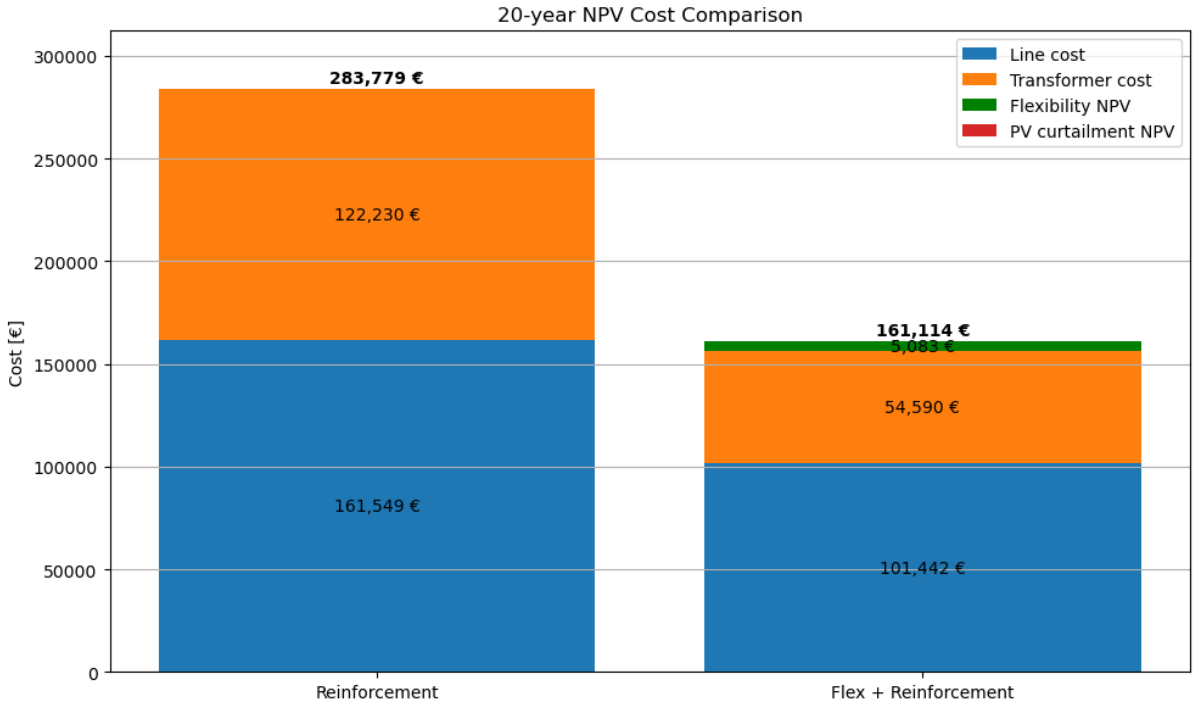


Figure 4: Required reinforcement before and after flexibility - Electrification high stress scenario

A total of 4.08 MWh/year of demand-side flexibility is activated, comprising 2.70 MWh/year from EV charging and 1.38 MWh/year from heat pumps. This represents only 0.076% of their combined annual electricity consumption. The relatively low activation volume does not indicate an absence of flexible demand. The reinforcement-aware approach activates flexibility only where shifting consumption can technically and economically change a reinforcement decision. Under severe electrification, many constraints are persistent or occur across several connected network elements, meaning that shifting demand to another interval may relocate the loading problem rather than eliminate it.

Table 18: Annual activated demand-side flexibility and PV curtailment – Electrification high stress scenario

Scenario	EV flexibility [MWh/a]	HP flexibility [MWh/a]	Total activated flexibility [MWh/a]	Activated share of EV+HP energy [%]	PV curtailment [MWh/a]	PV curtailment share [%]
Electrification – high	2.70	1.38	4.08	0.076	-	-

The results demonstrate that demand-side flexibility can delay or reduce individual investments but cannot fully substitute conventional reinforcement under very high electrification. A combination of coordinated charging, improved controllability of heat pumps, longer shifting windows, BESS, and targeted grid reinforcement would therefore be required to accommodate this level of additional demand reliably. Despite the remaining reinforcement needs, the scenario achieves a GISR of 43.23%, while the break-even flexibility price reaches 2,513.43 €/MWh, showing that the achieved reduction in reinforcement remains economically significant.

3.4.4 Combined scenario (high-stress)

The high-stress combined scenario represents the simultaneous large-scale deployment of PV systems, self-consumption battery storage, electric vehicles, and heat pumps. Table 19 presents the required reinforcements in both scenarios (reinforcement only vs flexibility and reinforcement). Before flexibility activation, 19 lines and 3 transformers required reinforcement. Although this remains a substantial requirement, it is lower than in the high-stress electrification scenario, where 28 lines and five transformers require reinforcement. The difference indicates that local PV generation and battery storage partly offset the additional electricity demand and reduce loading during some critical intervals.

Table 19: Network elements requiring reinforcement before and after flexibility – Combined high stress scenario

Overloaded element	Reinforcement	Flexibility and reinforcement
Lines	19	-
Transformers	3	2

The coordinated use of demand-side flexibility and PV curtailment is highly effective in this scenario. After flexibility activation, no additional lines and only two transformers still require reinforcement. The total reinforcement requirement therefore decreases from 22 to 2 elements, corresponding to a reduction of approximately 90.9 %. Figure 5 translates the required reinforcement into costs and compares it to the scenario that includes flexibility measures. The complete elimination of additional line reinforcement indicates that relatively small changes in power flows are sufficient to bring most line loadings below the 90% planning threshold. The two remaining transformer constraints are associated with load-dominated periods that cannot be fully addressed through the available shifting and curtailment options.

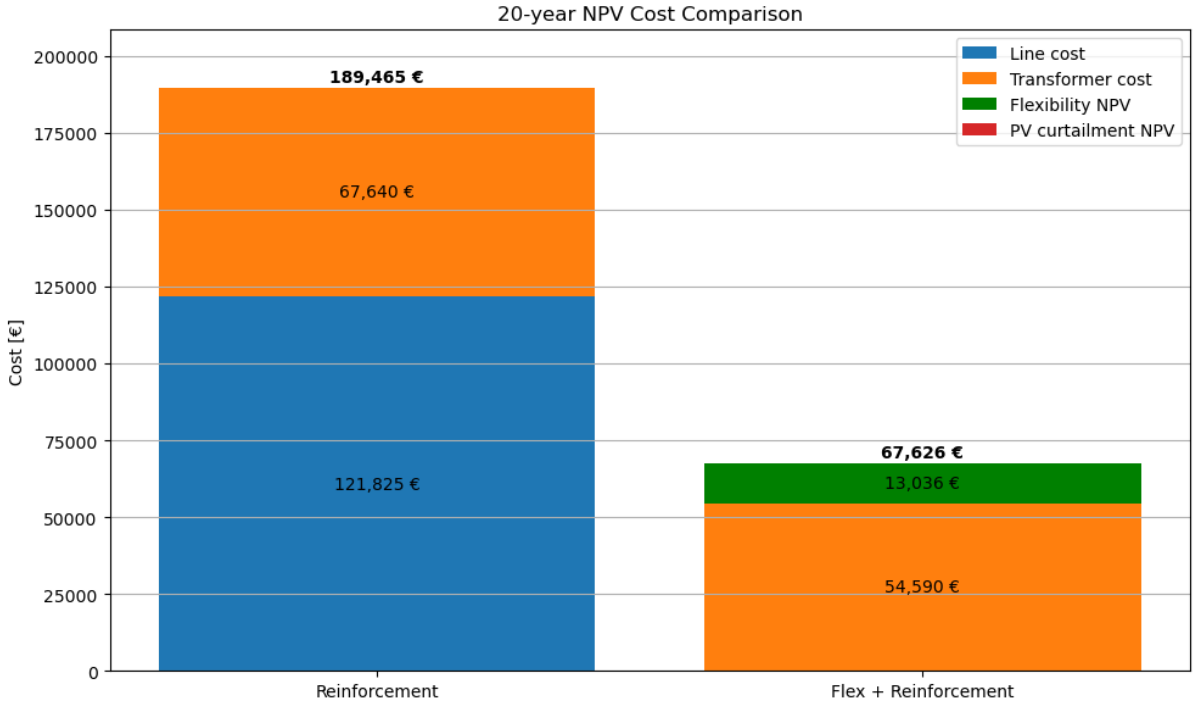


Figure 5: Required reinforcement before and after flexibility - Combined high stress scenario

As depicted in Table 20, a total of 10.46 MWh/year of demand-side flexibility is activated, comprising 6.71 MWh/year from EV charging and 3.75 MWh/year from heat pumps. This corresponds to approximately 0.195% of their combined annual electricity consumption. In addition, 6.44 MWh/year of PV generation is curtailed, representing only 0.034% of potential annual PV production. The limited curtailment requirement demonstrates that most network constraints can be resolved through demand shifting, while PV curtailment is used only during a small number of critical generation intervals. Self-consumption batteries additionally reduce local PV export, although their operation is not explicitly coordinated with network conditions. Notably, the combined scenario curtails slightly more PV than the electrification + PV scenario, despite the additional battery storage. This follows from the zero assumed curtailment cost: because curtailment is treated as cost-free, the tool applies it in preference to reinforcement wherever it can resolve a constraint, so the combined scenario relies on marginally more curtailment and less reinforcement to reach a lower overall cost.

Table 20: Annual activated demand-side flexibility and PV curtailment – Combined high stress scenario

Scenario	EV flexibility [MWh/a]	HP flexibility [MWh/a]	Total activated flexibility [MWh/a]	Activated share of EV+HP energy [%]	PV curtailment [MWh/a]	PV curtailment share [%]
Combined – high	6.71	3.75	10.46	0.195	6.44	0.034

The results demonstrate the value of combining complementary flexibility resources. PV generation and self-consumption batteries reduce part of the additional demand locally, EV and HP flexibility address load-driven peaks, and targeted PV curtailment mitigates short-duration reverse-power-flow constraints. The scenario achieves a GISR of 64.31% and a break-even flexibility price of 1,034.65 €/MWh. These results indicate that, even under high-stress conditions, coordinated flexibility can avoid most line reinforcement and retain substantial economic value, although targeted transformer upgrades remain necessary.

3.5 SENSITIVITY TO PV CURTAILMENT PRICE

The previous results assume a PV-curtailment price of 0 €/MWh, meaning that reducing PV generation does not impose a direct economic cost. While the assumption is aligned with the long-term projections of PV-curtailment value, it does not provide insights into the operation of the grid and value of flexibility in such case.

Therefore, the sensitivity to an alternative curtailment price of 30 €/MWh was also assessed. The price affects eight scenarios in which PV curtailment is activated under the zero-cost assumption. In the electrification + PV and combined scenarios, its effect on GISR remains limited, ranging from approximately 0 to 6 percentage points. In these cases, the primary source of network relief is EV and HP flexibility, while the additional demand also increases local PV consumption and reduces net export. In the combined cases, self-consumption BESS provides a further reduction in PV surplus, so that curtailment represents only a supplementary measure and its cost is small relative to the avoided reinforcement cost. In contrast, the impact is substantial in the PV-only and PV + BESS scenarios, where PV curtailment is the main flexibility resource available to resolve export-related network constraints.

Introducing a curtailment price reduces GISR by approximately 20 to 80 percentage points, depending on the stress level. The effect of alternative curtailment price on GISR is presented in Table 23.

Table 21: Effect of alternative PV curtailment prices on the GISR

Scenario	GISR at 0 €/MWh [%]	GISR at 30 €/MWh [%]	Change [%]
PV – reference	100.00	76.42	**–23.58**
PV – high	100.00	19.81	**–80.19**
PV + BESS – reference	100.00	76.60	**–23.40**
PV + BESS – high	100.00	19.83	**–80.17**
Electrification + PV – reference	86.64	83.07	–3.57
Electrification + PV – high	39.84	39.09	–0.75
Combined – reference	97.40	91.56	–5.84
Combined – high	64.31	63.00	–1.31

The PV-high and PV + BESS-high scenarios are therefore examined in greater detail below.

3.5.1 Impact of PV Curtailment Pricing in High Stress PV Scenarios

Under the alternative PV-curtailment price of 30 €/MWh, the PV-high and PV + BESS-high stress scenarios show that PV curtailment remains an effective measure for resolving most line constraints, while transformer upgrades generally remain necessary. Line overloads are typically local and occur during a limited number of high-export intervals and therefore, a relatively small and targeted reduction in PV injection can avoid the associated reinforcement. In contrast, transformer constraints reflect the aggregated PV surplus of a larger network area. Avoiding these upgrades would require curtailing substantially larger energy volumes over recurring periods, resulting in a 20-year curtailment cost higher than the cost of transformer reinforcement. The economic screening therefore retains transformer upgrades and applies curtailment primarily where it offers a lower-cost alternative.

Table 22 compares the annual volume of curtailed PV generation in the PV-high and PV + BESS-high scenarios under zero and alternative curtailment prices. At a price of 0 €/MWh, PV curtailment is applied extensively to avoid both line and transformer reinforcements, although it represents only around 1% of total annual PV generation. When a price of 30 €/MWh is introduced, the activated curtailment volume decreases substantially (PV curtailment column in Table 22). This reduction does not indicate lower technical PV-surplus condition, but it reflects the economic value, which retains the remaining transformer reinforcements where the long-term cost of curtailing a large amount of energy would exceed the reinforcement cost.

Table 22: Annual PV Curtailment in High-PV Scenarios at Alternative Curtailment Prices

Scenario	PV curtailment price [€/MWh]	PV curtailment [MWh/year]	PV curtailment share of annual PV generation [%]
PV – high	0	220.02	1.15
	30	3.17	0.02
PV + BESS – high	0	196.22	1.03
	30	7.85	0.04

Figure 6 depicts the NPV cost comparison in the PV high stress scenario. Compared to Figure 3, where all of the grid reinforcement could be avoided due to the curtailment price of 0 €/MWh, the situation is impacted by the changed curtailment price. The PV curtailment decreases from 220.02 MWh/year to 3.17 MWh/year and the GISR decreases to 19.81 %.

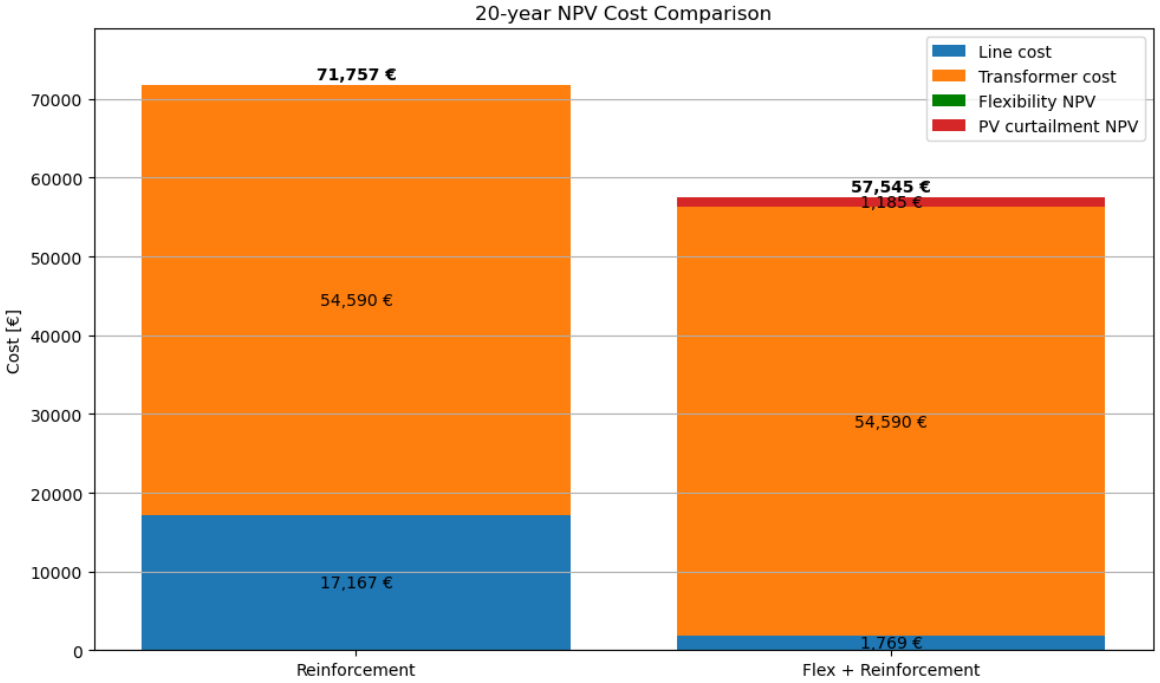


Figure 6: Required reinforcement before and after flexibility - PV high stress scenario with alternative PV curtailment price

Although self-consumption BESS reduces the required PV curtailment, its operation is not sufficient to change this conclusion, as the batteries are not controlled specifically for transformer peak relief as evident in Figure 7.

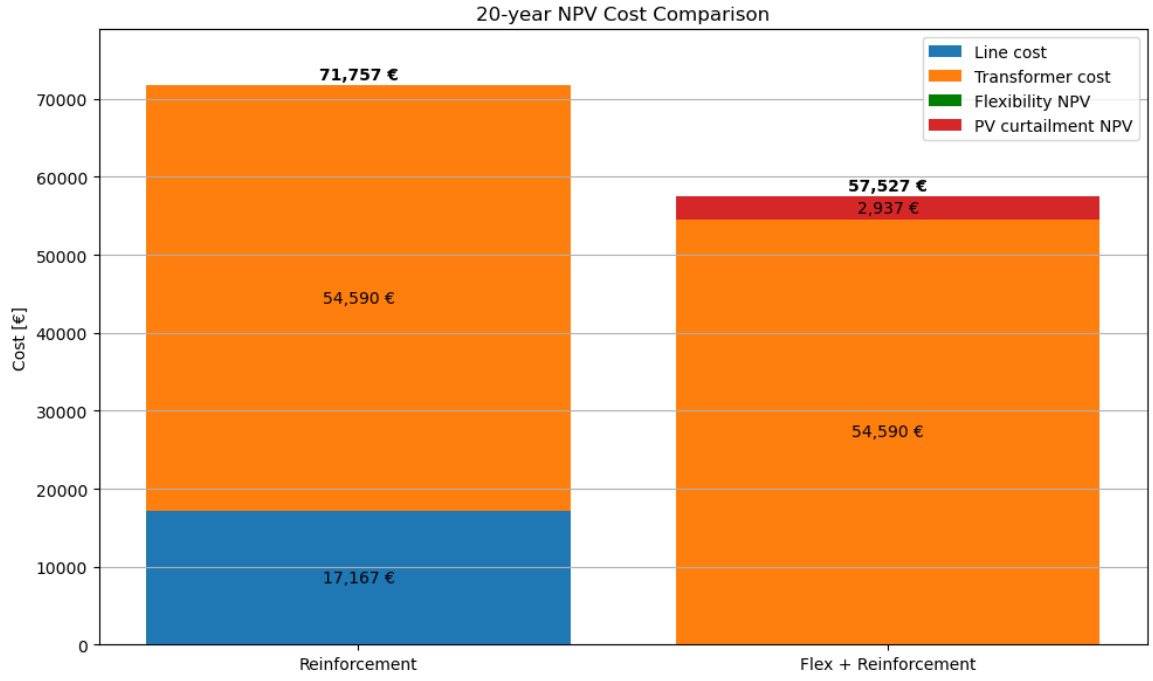


Figure 7: Required reinforcement before and after flexibility – PV + BESS high stress scenario with alternative PV curtailment price

3.6 CONCLUSIONS

This study assessed the impact of flexibility on the operation and reinforcement requirements of a low-voltage distribution network. A total of 16 scenarios were analysed, comprising a baseline case and different combinations of PV systems, battery energy storage systems, electric vehicles, and heat pumps under low, balanced, and high-stress conditions. The annual assessment was based on four representative seasonal weeks, while the economic comparison considered a 20-year period and expressed recurring flexibility costs as their net present value.

The results demonstrate that flexibility can eliminate or substantially reduce the need for conventional grid reinforcement. In balanced scenarios, the additional reinforcement requirements were generally avoided entirely through a combination of demand shifting and targeted PV curtailment. Flexibility also remained effective under high-stress conditions, although it could not fully replace physical reinforcement in every case. The high-stress electrification scenario retained the greatest need for reinforcement, with 13 lines and two transformers remaining after flexibility activation. By contrast, the high-stress combined scenario reduced the requirement from 19 lines and three transformers to only two transformers. This shows that the combination of complementary resources is more effective than relying on a single flexibility source.

Only a relatively small proportion of annual energy had to be controlled to achieve these effects. Activated EV and heat-pump flexibility remained below 0.5% of their combined annual consumption in all scenarios, while PV curtailment represented at most approximately 1.15% of potential annual PV generation. Flexibility therefore derives much of its value from being activated at the correct location and during a limited number of critical intervals. The results also confirm that the network value of battery storage depends strongly on its operating strategy. Self-consumption batteries reduced the required PV curtailment but did not change the reinforcement requirement in the high-stress PV scenario because their operation was not coordinated with network conditions.

The findings support the use of flexibility as a technically and economically viable component of future distribution-system planning and operation. Regulation will play a decisive role in enabling this transition. The regulatory framework should recognise flexibility as an eligible alternative to conventional grid investment and allow DSOs to recover justified flexibility-procurement and digitalisation costs. It should also provide clear rules for market participation, compensation, activation priority, data exchange, and coordination between DSOs, aggregators, suppliers, and customers.

The study therefore demonstrates the potential value of flexibility for the analysed network and scenarios rather than proving that reinforcement can always be avoided. In the most demanding cases, the appropriate solution is likely to be a coordinated combination of demand-side flexibility, PV curtailment, grid-oriented storage, and targeted physical reinforcement.

4 ECONOMIC IMPACT ASSESSMENT

The economic impact assessment builds upon the previously defined business models introduced in D2.3 Business model structuring for each pilot. These business model canvases were updated according to recent project insights and additional business cases were defined.

A CBA has been carried out for different business cases of the pilot sites (see Chapter 2, Table 1). CBAs were carried out for the main actors (DSOs, aggregators, CPOs, EV owners, asset owners) of the pilots. For each business case, the relevant costs and benefits were identified and quantified over the chosen assessment period, following the European Commission's Guide for conducting a Cost-Benefit Analysis of Smart Grid Projects [1]. The CBA evaluated the economic feasibility according to net present value (NPV), internal rate of return (IRR) and the pay-back period (PBP). The economic assessment was strengthened through a sensitivity analysis of the most uncertain parameters.

4.1 BUSINESS CASE SELECTION

The business cases were assessed from the perspectives of the relevant actors. To quantify the value of flexibility, each case is compared with a baseline scenario, typically representing operation without flexibility. Alternatively, the analysis compares the use of flexibility with conventional grid reinforcement to address grid congestion.

Each business case specifies the actor, for whom value is created, the baseline scenario, and the common boundary over which the comparison is made. The boundary covers the relevant asset or portfolio, the assessment period and the cash flows included. Costs, revenues and savings are assigned to the actor that bears or receives them. This approach follows the JRC sequence of establishing a baseline, identifying costs and benefits and their beneficiaries, and then comparing the alternatives [1]. When one organisation performs more than one role, the roles are kept separate in the calculation, for example, DSO and aggregator are not merged.

4.2 INPUT PARAMETERS

Input data for the CBA are specific to the individual pilot sites and draw on pilot data, as presented in previous deliverables [2, 3, 4, 5, 6, 7], simulations, partner estimations and market data. For each input parameter, the tested value/range and source is presented.

Costs vary across business cases but can generally be grouped into capital expenditures (CAPEX) and operational expenditures (OPEX). CAPEX includes costs related to development, set-up, system integration, installation, metering equipment, and sensors which occur in year 0, while OPEX includes recurring costs, such as licence fees of STREAM tools, software subscriptions, maintenance and operational support throughout the assessment period. Revenue relates to market remuneration or savings. Moreover, technical parameters such as portfolio size, available flexibility, activation, utilisation or bid acceptance as well as economic variables such as market prices or the discount rate are considered. Parameters are not necessarily considered constant over the assessment period but could be subject to a learning curve or estimated changes.

The assessment period was chosen based on the useful life of the installed assets and therefore the timeframe over which costs and benefits can be meaningfully evaluated, which varies between business cases and pilot sites. For input parameters with a high uncertainty a sensitivity analysis was conducted.

4.3 OUTPUT PARAMETERS

As indicators for the economic feasibility the NPV, the IRR and the PBP are calculated. A representative discount rate for the respective country is chosen to calculate the NPV of the business cases.

Equation 1 presents the calculation method of the NPV. R is the net cash flow in period t, i is the discount rate and n is the final period of the assessment. For the Spanish pilot, this formula is applied, however, only associated costs and no revenues are considered in the assessment as the aim is to compare the costs of grid reinforcement to the costs of flexibility and is therefore referred to as present-value cost (PVC).

$$NPV = \sum_{t=0}^{n} \frac{R_t}{(1+i)^t}$$

Equation 1: NPV calculation

NPV: net present value of the cash-flow series over the assessment period

- R_t : net cash inflow or outflow in period t,
- t : period index, running from 0 to n.
- n : final period of the assessment period.
- i : discount rate applied per period.

The IRR is obtained by finding the discount rate that makes the NPV equal to zero, as shown in Equation 2.

$$0 = \sum_{t=0}^{n} \frac{R_t}{(1+IRR)^t}$$

Equation 2: IRR calculation

- IRR : internal rate of return
- R_t : net cash inflow or outflow in period t
- t : period index, running from 0 to n.
- n : final period of the assessment period.

The PBP is calculated from the undiscounted cumulative net cash flow. t is the last complete year for which cumulative cash flow is negative, and the net cash flow in the following year is used to interpolate the fractional year (Equation 3).

$$PBP = t + \frac{-\sum_{k=0}^{t} R_k}{R_{t+1}}$$

Equation 3: payback period calculation

- PBP : payback period
- t : last complete year for which the cumulative undiscounted net cash flow is negative
- k : summation index for cash flows from period 0 through period t
- R_k : net cash inflow or outflow in period k
- $R_{(t+1)}$: net cash inflow or outflow in the period immediately following t, used to interpolate the fractional payback year

4.4 SENSITIVITY ANALYSIS

The economic impact assessment was strengthened through a sensitivity analysis of the most uncertain parameters that have a significant impact on the results. The sensitivity analysis evaluates the impact of varying these parameters across a defined range. The tested parameters differ by pilot. The Finnish model tests portfolio scale, bid acceptance and customer revenue sharing. The Italian business case of using flexibility for DAM optimisation examines the effect of the daily electricity-price spread and therefore the change in revenue. The Slovenian industrial case tests activation revenue and the revenue split between the aggregator and the asset owners. The Spanish analysis tests the information and communication technology (ICT) replacement costs, flexibility procurement prices and volumes, and the allocation of aggregator platform/service costs and participant revenue sharing. Sensitivity results are reported though the same indicator used by the underlying case, such as NPV and IRR.

5 STREAM QUANTITATIVE BUSINESS MODELS

5.1 FINNISH PILOT SITE

The Finnish pilot uses residential and holiday-resort buildings managed by OptiWatti (OPT) to test explicit demand response from electric radiators and electric floor heating. Room-level controls and customer settings are used to estimate and aggregate available heating flexibility while maintaining acceptable indoor conditions. The demonstrated service is Frequency Containment Reserve for Disturbances (FCR-D), with both upward and downward regulation achieved by rapidly reducing or increasing heating load in response to grid-frequency deviations. The pilot therefore evaluates how aggregated residential demand can support TSO frequency stability alongside existing energy-management and spot-price optimisation functions. The Finnish analysis distinguishes between the technical demonstration scale and the portfolios used for the economic assessment. The FCR-D demonstration used limited real residential loads together with simulated aggregated loads of up to approximately 1 MW to validate the flexibility-management and activation process. For the economic assessment, a 25 MW business-scale portfolio is considered, corresponding to approximately 2,500 participating apartments based on the portfolio's average installed flexible power per apartment as this represents the estimated business case by OPT. A 100 MW scenario, representing a fourfold upscale of this portfolio to approximately 10,000 apartments, is also assessed.

5.1.1 Scenarios and assumptions

The Finnish economic assessment covers explicit residential-heating flexibility for FCR-D up and FCR-D down. OPT is assessed as the aggregator, while building owners and tenants are the participating customers. Existing spot-price optimisation is retained within the baseline heating-management service and is therefore not assigned an additional revenue stream.

The baseline assumes that the existing heating-control service continues without incremental FCR-D revenue, additional metering expenditure, reserve-specific operating expenditure, or FCR-D activation energy effects (Table 23). Under the STREAM case, OPT invests in commercial demand-response functionality and metering, aggregates controllable heating loads, prepares FCR-D bids and receives reserve remuneration. Customers provide controllability subject to their room-level settings and availability constraints. For the baseline calculation, direct customer cash compensation from FCR revenue is set to 0%. Alternative revenue-sharing percentages are assessed separately in the sensitivity analysis.

Table 24 presents the parameters used in the Finnish pilot. Both scenarios use five operating years after Year-0 investment and a 2.25% annual discount rate. Average 2025 FCR-D prices of 11.54 €/MWh for up and 10.81 €/MWh for down are used. Revenue also reflects the seasonal heating-load envelope, a 50% active-pool ramp in Year 1, a 90% bid-acceptance assumption and a 3% revenue correction. Minimum bid size is 1MW. Both scenarios have fixed upfront CAPEX of €822k in Year 0, plus a variable investment cost of €65 per apartment. Consequently, the total CAPEX differs between the two portfolios according to their respective number of households.

Usable residential flexibility is constrained by spot-price scheduling, customer settings, an initial aggregator safety margin and an estimated capacity-reduction factor. Their product gives a 51.03% capacity-chain factor.

Table 23: Assessed scenarios in the Finnish pilot

Scenario	Actor perspective(s)	Description
Baseline: existing heating management	OPT, building owners / tenants	Reference case with no FCR-D revenue or FCR-D-specific cost
25 MW	OPT, 2,508 participating apartments	FCR-D cash flows
100 MW	OPT, 10,032 participating apartments	Upscaled scenario with FCR-D cash flow

Table 24: Parameters in the Finnish pilot

Parameter	Value / range and unit	Evidence type
Assessment period and discounting	Year 0 CAPEX + Years 1-5 operation, 2.25%/year	Reviewed project value
Portfolio scale	25 MW / 2,508 apartments 100 MW / 10,032 apartments	Reviewed/scaled project values
Installed flexible heating power	9.968 kW/apartment	Measured / reviewed project value
Capacity-chain factors	0.90 spot × 0.90 customer × 0.70 aggregator × 0.90 TSO capacity factor = 51.03%	Partner estimates plus project method
Seasonal FCR capacity at 25 MW	Up: 2 MW (Sep/Oct/Mar/Apr), 3 MW (Nov-Feb), 0 MW (May-Aug) Down: 10 MW (May-Sep), 8 MW (Oct-Feb), 9 MW (Mar-Apr)	2025 heating-load based calculation
FCR bid acceptance	90% base 0-100% sensitivity	Partner estimate / analytical sensitivity
FCR-D price reference	Up 11.54 €/MWh Down 10.81 €/MWh	2025 hourly averages, fixed reference, not forecast
Revenue integration correction	97%	Reviewed project value
Participation ramp	50% in Year 1 100% in Years 2-5	Partner assumption
Minimum bid size	1 MW	Current market rule used as model gate
Fixed development CAPEX	822 k€ at Year 0	Reviewed project estimate

Metering and installation	65 €/apartment	Reviewed partner value
Operating cost	Fixed 135.4 k€ in Year 1, 58.76 k€/year in Years 2-5, plus 14.40 €/meter/year	Reviewed/derived project values
Customer activation energy effect	+4.43 €/year FCR-D-up saving, -16.03 €/year FCR-D-down cost, -11.59 €/active apartment-year	Reviewed calculation, pilot evidence used for validation
End user revenue share	0% base 0-100% sensitivity	Reviewed base, analytical sensitivity

5.1.2 Results and sensitivity analysis

Both scenarios create a positive NPV for OPT. The 25 MW scenario produces annual FCR revenue of 0.879 million euros (M€), a 5-year NPV of 2.288 M€, IRR of 54.3% and a PBP of 1.85 years. The 100 MW case produces 3.516 M€ annual revenue a 5-year NPV of 12.667 M€, IRR of 154.1% and payback of 0.92 years. The higher return at a larger scale results from fixed development and operating costs being spread across more capacity.

The customer result is different. At the 0% cash-sharing base case as assumed in the pilot, FCR-D-up reduces electricity cost by 4.43 €/active apartment annually while FCR-D-down adds 16.03 €/active apartment-year, yielding a monetary effect of -11.59 €/active apartment-year. Over the 5 years this equals -130.8 k€ for the 25 MW portfolio and -523.3 k€ for the 100 MW portfolio (Table 25).

Table 25: Results for the Finnish pilot

Scenario	Actor	Result
25 MW	OPT	NPV: **2.288** M€ IRR: **54.3%** PBP: **1.85 y**
100 MW	OPT	NPV: **12.667** M€ IRR: **154.1%** PBP: **0.92 y**
25 MW	Building owners / tenants	**-11.59** €/active apartment/year, **-130.8** k€
100 MW	Building owners / tenants	**-11.59** €/active apartment/year, **-523.3** k€

The high IRRs result from the relationship between the initial investment and the recurring FCR-D revenues. In the 25 MW case, the initial CAPEX is 0.985 M€, while the annual cash flow reaches about 0.806 M€. This effect becomes stronger at 100 MW because a large part of the development and operating costs is fixed: increasing the portfolio from 25 MW to 100 MW increases FCR-D revenue from 0.879 M€ to 3.516 M€, while initial CAPEX increases only from 0.985 M€ to 1.474 M€. The results are also influenced by the scenarios boundary, as the FCR-D service builds on the existing OptiWatti home-automation and control infrastructure.

The scenarios therefore include the incremental costs required for the flexibility service rather than the full cost of deploying a new building control system. Also, in the scenarios, it is assumed that OPT retains all FCR-D revenues and that no revenue is transferred to end-users. Revenue sharing with customers is assessed separately in the sensitivity analysis.

Figure 8 presents the sensitivity analysis based on the number of apartments. The first positive NPV occurs at 927 apartments (9.240 MW). The NPV does not increase linearly because FCR-D revenues are only counted once the aggregated flexible capacity is large enough to meet the market's minimum bid requirement of 1MW. As more apartments participate, the available flexibility therefore increases smoothly, but some seasonal capacity becomes eligible for market participation only after these thresholds are crossed.

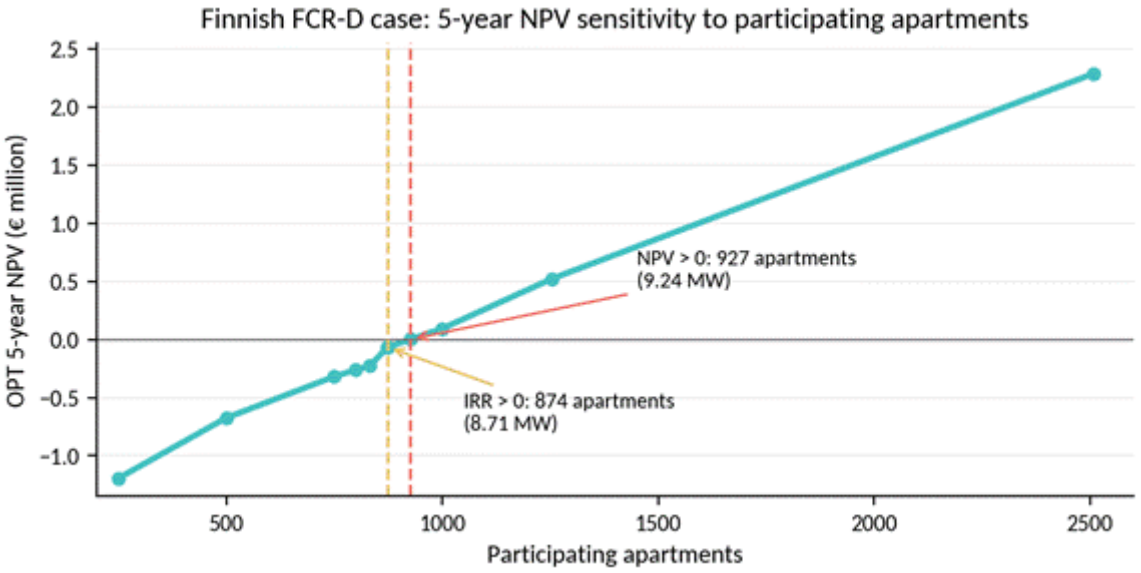


Figure 8: Finland: Sensitivity on participating apartments

Figure 9 presents the sensitivity analysis for the bid acceptance rate. Starting from the 90% base assumption, in the 25 MW scenario, the NPV falls to zero at a 34.10% acceptance rate. The 100 MW scenario reaches a positive NPV at a 12.62% acceptance rate.

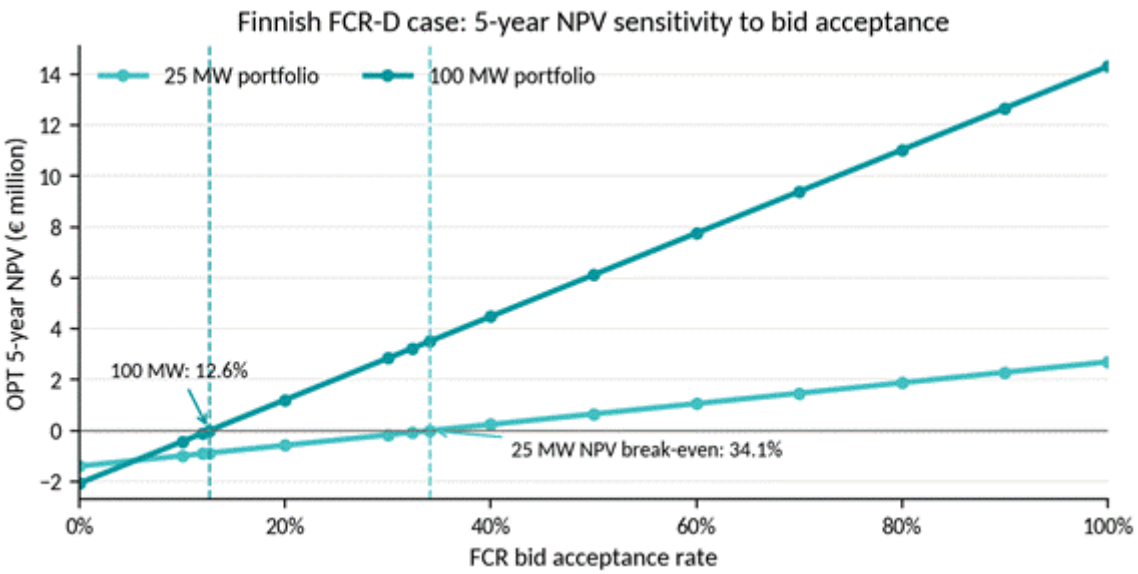


Figure 9: Finland: Sensitivity on bid acceptance rate

The sensitivity analysis on revenue sharing demonstrates the trade-off between aggregator return and customer participation (Figure 10). In the 25 MW scenario, OPT reaches a positive NPV when 62.12% of FCR revenue is transferred to customers. The corresponding 100 MW thresholds are 85.98%. A 10% revenue share changes the customer annual revenue from -11.59 €/active apartment/year to 23.45 €/active apartment/year while leaving OPT NPV positive at approximately 1.919 M€ (25 MW) and 11.193 M€ (100 MW). The customer annual revenues per apartment are identical in the 25 MW and 100 MW cases for a given revenue-sharing percentage because FCR revenue is in direct proportion to apartment count. Portfolio size therefore changes the aggregated value, not the per-apartment customer result.

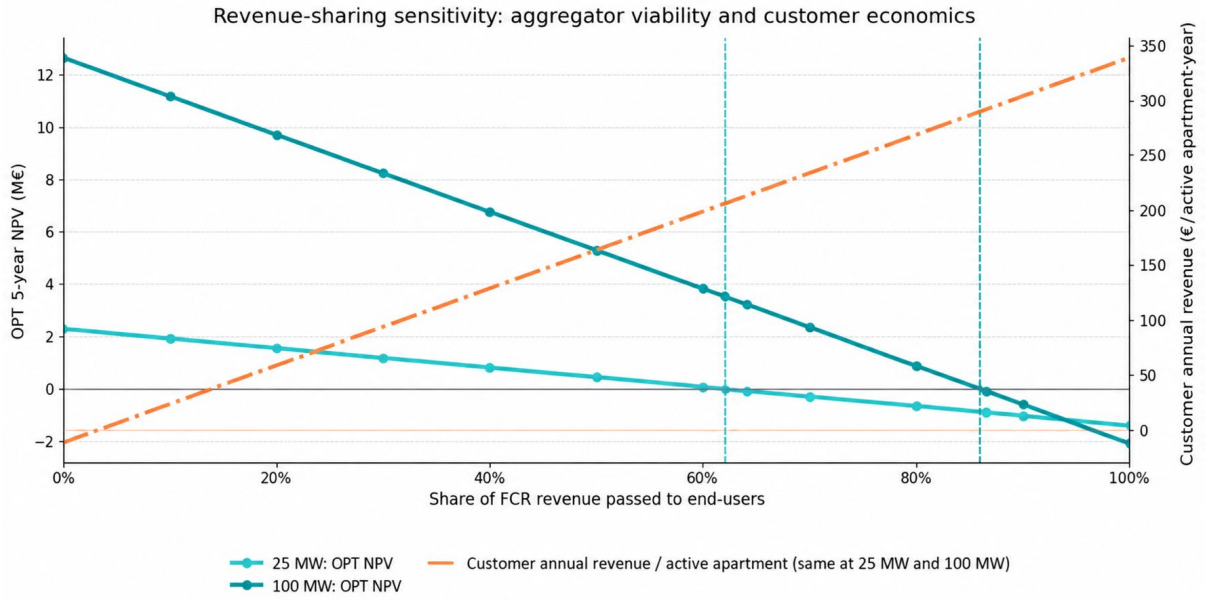


Figure 10: Finland: Sensitivity on revenue sharing

5.1.3 Conclusion

Over 5 years, the residential-heating flexibility business case is economically positive for OPT at both 25 MW and 100 MW under the reviewed base assumptions. The 25 MW scenarios returns a NPV of 2.288 M€ and an IRR of 54.3%, while the 100 MW benchmark returns a NPV of 12.667 M€ and an IRR of 154.1%. 927 apartments or 9.240 MW are the break even for a positive NPV.

For participating customers, the scenarios do not generate a monetary incentive: the activation-energy effect is -11.59 €/active apartment-year when no reserve revenue is shared. Revenue sharing can reverse the customer result - a 10% share gives 23.45 €/active apartment-year – while also creating a positive NPV in the 25MW and the 100 MW scenario.

The 25 MW and 100 MW financial results depend on scaled portfolios, a partly simulated market interface and fixed economic assumptions. The remaining evidence gaps are live cleared/accepted bid data, commercial prequalification and availability performance, verified flexible capacity at scale, a final customer-remuneration contract, a forward treatment of FCR prices and validated commercial operating requirements.

5.2 ITALIAN PILOT SITE

The Italian pilot is located in Terni, central Italy, and is operated by ASM Terni, a multi-utility company. ASM Terni provides a broad range of essential services, including electricity generation and distribution, gas network management, water supply and wastewater treatment, and environmental services. It examines the coordinated use of flexible loads from the water distribution system as well as from the EV charging infrastructure. This enables an analysis of cross-sector flexibility and interactions among the electricity, water, and electric-mobility sectors. Two business cases are assessed:

- Flexibility from the water pumping system for DAM price optimisation
- Flexibility from EV charging: Offering flexibility to the DSO but passing revenues along to EV owners to increase customer attractiveness

The non-monetary value creation mechanisms, including the P2P marketplace concept, were initially included in the proposal. However, following changes in the consortium and the development of the pilot activities, the P2P marketplace use case was removed from the scope of the Italian pilot.

5.2.1 Flexibility from the water pumping system for DAM price optimisation

This section assesses the business case for ASM for shifting water-pumping load in response to DAM prices.

5.2.1.1 Scenarios and assumptions

Table 26 presents the two assessed scenarios. The baseline scenario represents the reference case without DAM optimisation, while Scenario 1 assesses the effect of DAM optimisation based on simulation done by COM and extrapolated to calculate the savings over the year 2025. The simulation is based on the rated power of the pumps, the monthly demand profiles for the pumps and the zonal DAM electricity prices for Central-northern Italy for the year 2025 [8]. First, the model calculates the electricity consumption and cost of the baseline pumping schedule.

It then identifies the lowest-price intervals within the defined flexibility window and reallocates pump operation to these periods, while maintaining the required daily water volume. Both business cases are assessed from the perspective of ASM.

Table 26: Italy: Scenarios for DAM price optimisation

Scenario	Actor perspective	Description
Baseline	ASM	Reference case without DAM optimisation
Scenario 1 – DAM optimisation	ASM	Reduced electricity costs due to DAM optimisation

Table 27 presents the parameters for the DAM price optimisation. Costs for the business model relate to the use of the software for the DAM price optimisation which relate to sDATA (set-up fee 10,000 € at year 0, a fee per asset of 12€/year and a licence fee of 6,000 €/year) and sENC (8,000€ set-up fee at year 0 and a SaaS subscription of 8,000). Moreover, an additional sensor for the water pumping session is needed. Savings relate to reduced electricity costs due to DAM optimisation adding up to 19,718 €/year and are kept constant over the assessment period. The lifetime for the sensors is 15 years. The discount rate is 5%, and the economic assessment period is ten years.

Table 27: Italy: Parameters for DAM price optimisation

Parameter	Value	Evidence type
Set-up fee for sDATA [€]	10,000	Partner estimation
Licence fee sDATA [€/year]	6,000	Partner estimation
Fee per asset sDATA [€/asset/year]	12	Partner estimation
Sensors for water pumping [€]	1,160	Commercial costs
Number of assets [#]	1	Project value
Lifetime sensors [years}	15	Commercial estimation
Lifetime software [years]	10	Partner estimation
Savings due to DAM optimisation [€/year]	19,718	Simulation/market data
Set-up fee SENC – COM [€]	8,000	Partner estimation
SaaS Subscription sENC	8,000	Partner estimation
Assessment period	10 years	Commercial estimation
Discount rate [%]	5%	Partner estimation

5.2.1.2 Results and sensitivity analysis

The simulations show a clear seasonal pattern regarding the electricity cost savings per month (Figure 11).

May delivers the highest savings with 16.2% in comparison to the baseline without optimisation, driven by midday price dip due to PV generation, whereas December and February show the lowest savings, at approximately 6–7% compared to the baseline, because daily price variations are less pronounced.

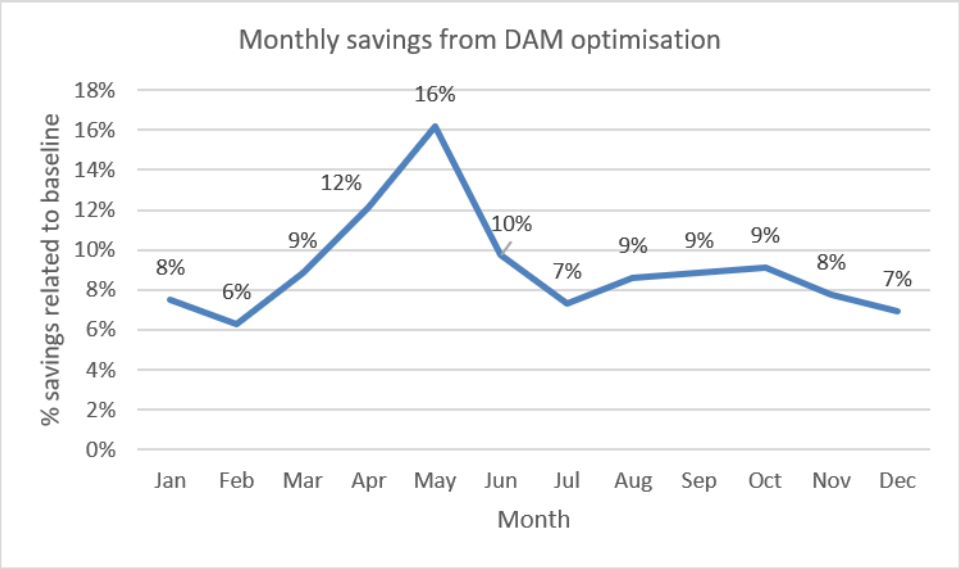


Figure 11: DAM optimisation % savings per month

The business case achieves an NPV of €25,138 and an IRR of 27.1%, indicating that it is economically feasible (Table 28). This result is primarily driven by high theoretical potential for energy-cost savings. It should be noted that the simulation was conducted ex post. In practice, deviations in weather forecasts, or operational conditions may reduce the savings that can be achieved. These uncertainties will be examined further through the sensitivity analysis.

Table 28: Italy: Results for DAM price optimisation

Scenario	Perspective	Result
Scenario 1 – DAM optimisation	ASM	NPV: 25,138€ IRR: 27.1%

Figure 12 presents the sensitivity analysis for changes in the savings achieved through DAM price optimisation. The results show that annual savings could decrease to approximately €16,465 per year (-16.5% of the base value), while still generating a positive NPV.

Even when a more conservative monthly saving rate of 7.5% to the baseline costs over the full year, the investment would still achieve a positive NPV, confirming the economic feasibility of the business case

Even under a more conservative scenario, in which the monthly saving rate observed in January (7.5% in comparison to 8.9% in the baseline scenario) is applied consistently across the full year, annual savings would amount to approximately €16,646, which would still generate a positive NPV, indicating that the business case remains economically feasible. A negative NPV would arise only if the lower saving rates observed in February, July, or December were applied across the entire year.

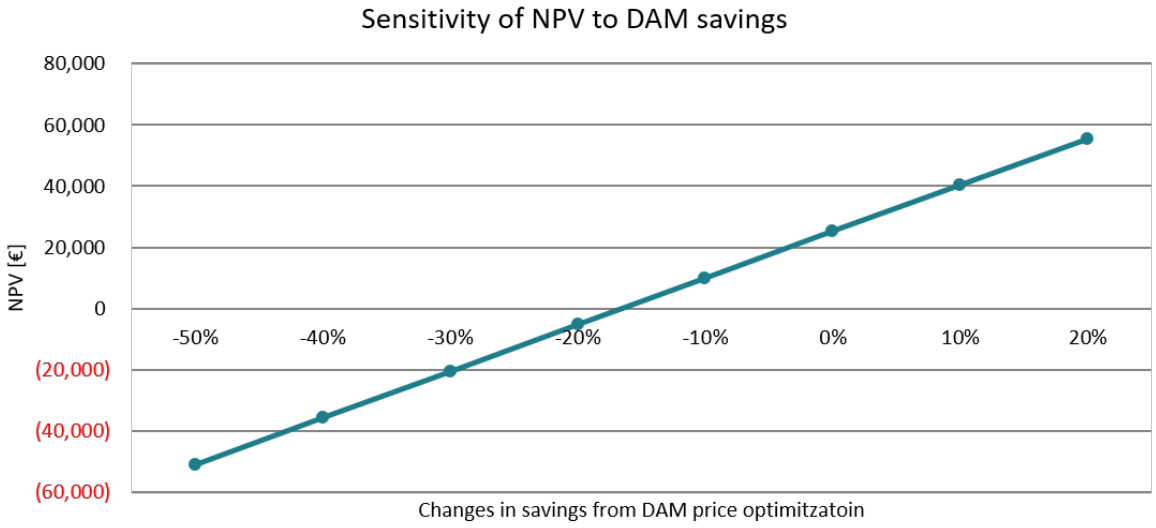


Figure 12: Sensitivity to change in DAM optimisation savings

5.2.1.3 Conclusion

Under the model assumptions, DAM-based pumping optimisation can reduce ASM's electricity costs by shifting pumping activity to lower-price periods while maintaining the required daily water supply. This flexibility creates significant potential to reduce energy costs and results in a positive NPV even under conservative savings assumptions. This is because the required investment costs are relatively low and the pumping system offers substantial operational flexibility to shift electricity consumption to lower priced periods.

However, the achievable savings are highly dependent on the daily spread in day-ahead electricity prices. As these price spreads are strongly influenced by weather conditions actual savings may vary substantially between days, months, and years. It should also be noted that the analysis was conducted ex post, using past market prices and operational data. Therefore, actual savings may be lower in practice due to forecasting errors, or operational constraints.

5.2.2 Flexibility from EV charging to increase customer attraction

EMOT as the CPO focuses on increasing customer attractiveness rather than generating direct revenues. Flexibility from EV charging stations is aggregated and offered to ASM, the DSO via an LFM platform. Revenues from the DSO are passed on to participating EV users as a discount on charging sessions, in exchange for charging constraints (Figure 13). The constraints mainly concern the charging schedule rather than the charging power. Users communicate their charging preferences, such as the desired departure time and required state of charge, through the EMOT app. Based on these preferences, the charging process can be shifted in time to provide flexibility services while still ensuring that the user's charging requirements are met. The participation conditions are accepted by the user through the app.

EMOT benefits from increased customer acquisition and retention. EV users save approximately €0.06/kWh, resulting in savings of around €2.60 per full recharge, assuming a 44 kWh battery capacity. The €0.06/kWh reflects the value that the DSO (ASM) is willing to pay for the right to control flexible assets through the market platform.

Considering that the average cost per kWh for charging an EV in Italy is 0.45 €, this means that the incentive is equal to a 13% discount on the charging tariff. The business model involves only moderate risk, as it requires no significant investment or maintenance costs, as all charging stations are up to date and can directly be used to offer flexibility. The main risk is that revenues from providing flexibility may not be sufficient to offset the reduced charging prices. For this reason, the economic incentive for individual end users is kept small. While the economic benefits for individual private EV users are quite small, flexibility programmes are more attractive for fleet operators, where the savings can be aggregated across many charging sessions and vehicles, resulting in a more significant overall economic benefit.

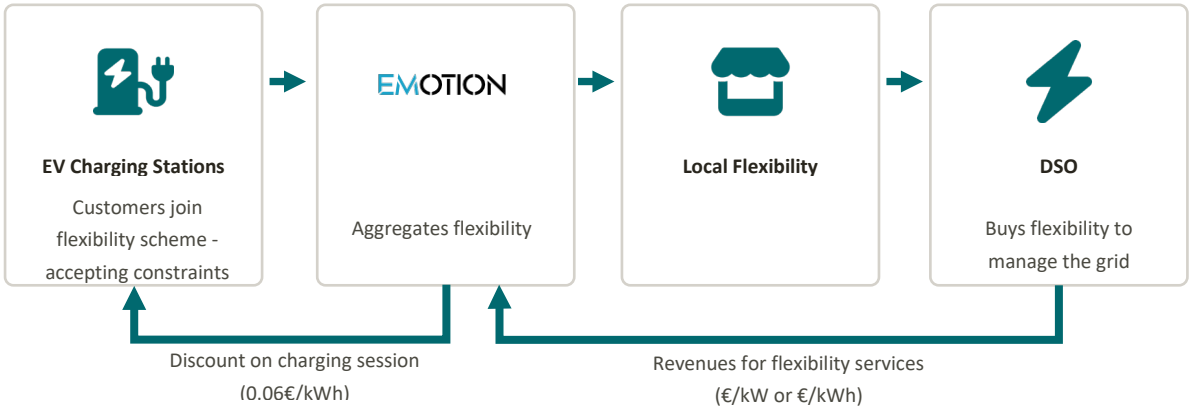


Figure 13: EMOT value chain

5.3 SLOVENIAN PILOT SITE

The Slovenian pilot is located in the industrial zone of Ajdovščina in southwest Slovenia, an area characterised by a mix of small, medium-sized and large industrial consumers. Industrial development has led to increasing electricity demand, requiring the local DSO, Elektro Primorska, to regularly adapt and reinforce the distribution network. The site was therefore selected to assess how flexibility can support distribution network planning. Flexibility is provided by the cold storage room of Incom Leone, the Mlinotest Mill and EV charging stations operated by AVANTCAR and are aggregated and offered within KOLEKTOR sETups portfolio. Three business cases are assessed for the Slovenian pilot.

- **Industrial flexibility for mFRR/LFM service provision:** Flexibility is offered to the mFRR market and LFM, assessed from the perspectives of both the aggregator and participating asset owners.
- **EV charging optimisation for mFRR service provision:** Flexibility is offered to mFRR from the optimised charging of AVA charging stations. Financial benefits are assessed for AVA and EV owners.
- **Grid-reinforcement deferral:** The DSO uses flexibility to manage local network constraints and defer or reduce investment in conventional grid reinforcement.

5.3.1 Industrial flexibility for mFRR/LFM service provision

This section describes the business model for offering flexibility on the mFRR market and LFM from the perspective of the aggregator KOLEKTOR sETup, while also considering the revenues generated for Incom Leone cold storage room and the Mlinotest mill.

5.3.1.1 Scenarios and assumptions

Table 29 defines three scenarios for assessing the economic value for this business case. The baseline scenario describes the case, in which asset owners do not provide flexibility and therefore receive no additional revenue. Scenario 1 assesses participation in the mFRR market from the perspectives of KOLEKTOR sETup, as the aggregator, and industrial companies. Scenario 2 evaluates revenues from the participation on an LFM. The financial parameters used for the economic evaluation are the NPV and the IRR for KOLEKTOR sETup, while for the asset owners the yearly savings are presented, as no investment costs occur.

Table 29: Slovenia: Scenario definition for mFRR/LFM service provision

Scenario	Actor perspective	Description
Baseline	Asset owners	Reference case without flexibility provision
Scenario 1 – mFRR market	KOLEKTOR SetUP, Incom Leone, Mlinotest mill	Revenue from mFRR market
Scenario 2– local market	KOLEKTOR SetUP, Incom Leone, Mlinotest mill	Revenue from local market

Table 30 summarises the input parameters for the business model calculation. Flexibility includes flexibility from the cold storage room of Incom Leone (1 MW flexibility) as well as of the Mlinotest mill (0.5 MW flexibility), adding up to 1.5 MW. It is assumed that flexibility from the Mlinotest mill can be offered 5 days per week, while flexibility from the cold storage room can be offered the entire week. To consider this a 71% availability factor for the Mlinotest mill is used. Due to the technical set up, the flexibility from the mill is used to make offers on the capacity and energy market while the flexibility from the cold storage room is offered on the energy market only. Costs are divided into implementation costs (CAPEX) for KOLEKTOR sETup, which arise for every additional MW added to the portfolio, and operating costs, which cover the maintenance of the baseline and forecasting algorithms and are assumed to remain constant over time. With total development costs of €500,000 for an initial rollout of 5 MW in the first year, a proportionate share of €100,000 is allocated to the approximately 1 MW of flexibility offered by the two companies. Revenues refer to revenues from capacity as well as activated energy from the mFRR market and are estimated with 20,000 €/MW for capacity and 20,000 €/MW for energy expressed as an annualised revenue per available MW per year. For the LFM, revenues are assumed to be 80% of those on the mFRR market. The share between the aggregator and the asset owners is assumed to be 50% for the aggregator and 50% for the asset owners. The business model is assessed over a ten-year time horizon. No investment costs for asset owners are included.

Table 30: Slovenia: Parameters for mFRR/LFM service provision

Parameter	Value	Evidence type
Cumulated Flexibility [MW]	1.5 MW	Project values
IT technician costs [€/day]	400	Partner estimation
Implementation costs [person days/MW]	15	Partner estimation

OPEX [person days/MW/year]	6	Partner estimation
Flexibility platform (sFLEX module as part of STREAM) [€]	100,000	Partner estimation
Lifetime of platform [years]	10	Partner estimation
Revenues from activation on the mFRR market [€/MW/year]	20,000	Partner estimation
Revenues from reservation on the mFRR market [€/MW/year]	20,000	Partner estimation
Revenues from activation on the LFM [€/MW/year]	16,000	Partner estimation
Revenues from reservation on the LFM [€/MW/year]	16,000	Partner estimation
Flexibility from Mill [days/week]	5 days	Project value
Flexibility from cold storage room [days a week]	7 days	Project value
Availability factor Mlinotest mill [%]	71%	Calculation
% of revenues to asset owner	50%	Assumption
Assessment period [years]	10 years	Partner estimation
Discount rate	5%	Partner estimation

5.3.1.2 Results and sensitivity analysis

Table 31 presents the financial results for the two scenarios. Scenario 1, participation in the mFRR market, falls short of economic viability, as reflected by KOLEKTOR SetUP, NPV of €-4,426 and an IRR of 4.2%. It also provides annual revenues of €10,000 for Incom Leone and €7,143 for the Mlinotest mill. Scenario 2, participation in an LFM generates lower returns because revenues are assumed to be lower than in the mFRR market. KOLEKTOR SetUP achieves an NPV of € -30,900 and an IRR of –1.34% which is not financially viable, while annual revenues amount to €8,000 for Incom Leone and €5,714 for the Mlinotest mill. However, this is based on the assumption that revenues in the LFM are lower than those in existing markets, which needs to be validated once actual market data for LFMs is available. The negative NPV for KOLEKTOR sETup is mainly driven by the relatively high revenue share (50%) allocated to Incom Leone and the Mlinotest mill and is therefore further explored in the sensitivity analysis

Table 31: Slovenia: Results for mFRR/LFM service provision

Scenario	Perspective	Result
Scenario 1 – mFRR market	KOLEKTOR SetUP	NPV: € -4,426 IRR: 4.2%
	Incom Leone	Revenues: 10,000 €/year
	Mlinotest mill	Revenues: 7,143 €/year
Scenario 2– local market	KOLEKTOR SetUP	NPV: € -30,900 IRR: -1.34%

Incom Leone	Revenues: 8,000 €/year
Mlinotest mill	Revenues: 5,714 €/year

A sensitivity analysis is conducted regarding the revenues from activation (0%-200% of the revenues from 20,000 €/MW/year), as actual activations are hard to predict and regarding the split between the asset owners and the aggregator (0%-100%) as the actual market split is confidential.

Figure 14 presents the sensitivity analysis regarding the energy market revenue. Scenario 1 – mFRR market becomes profitable at around €21,338/MW/year for activation, which slightly higher than the estimated revenues. Scenario 2 - LFM reaches a positive NPV at approximately €31,672/MW/year for activation. This highlights that revenues must at least increase slightly to ensure economic viability for Scenario 1 and must increase significantly for Scenario 2. This is particularly relevant because actual revenues from LFMs are still uncertain, as no such market is currently operating in Slovenia. The results can therefore provide an indication of the price levels that would be required in LFMs to establish a viable business case.

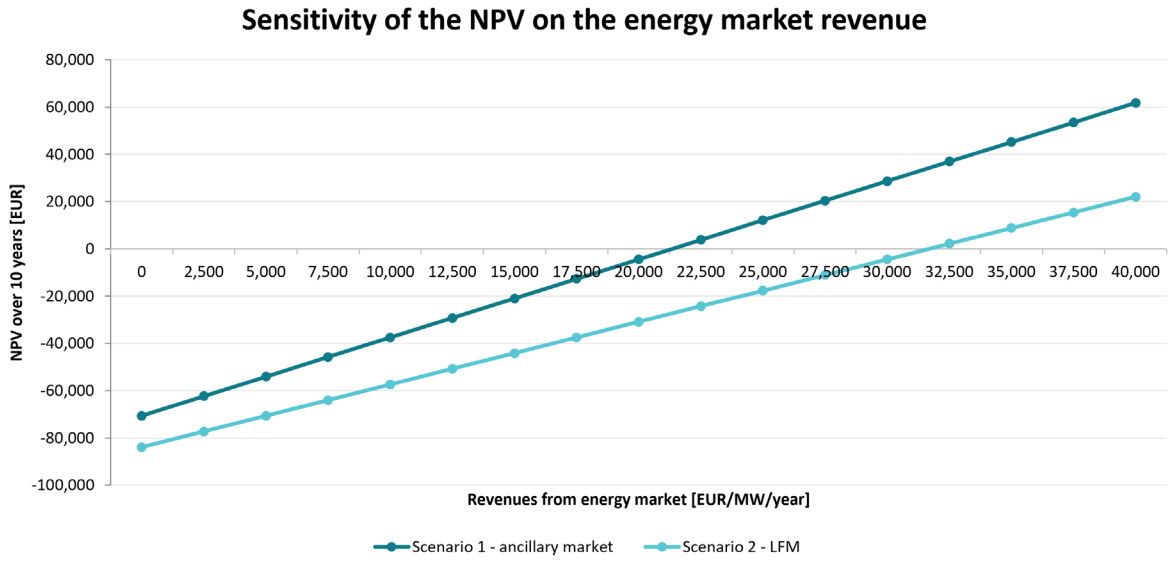


Figure 14: Slovenia: Sensitivity to energy market revenue

Figure 15 presents the sensitivity analysis related to the share of revenues allocated to asset owners. As this share increases, the aggregator's NPV decreases accordingly. This highlights the trade-off between attracting users and keeping the business case viable. Scenario 1 – mFRR market remains profitable for the aggregator up to a 48% revenue share, whereas Scenario 2 - LFM, reaches a zero NPV at an asset owner share of 35%. At a 48% revenue share in Scenario 1, annual revenues for asset owners amount to €9,600 for Incom Leone and €6,857 for the Mlinotest mill. Under Scenario 2, at a 35% share, the corresponding annual revenues are €5,600 for Incom Leone and €4,000 for the Mlinotest mill.

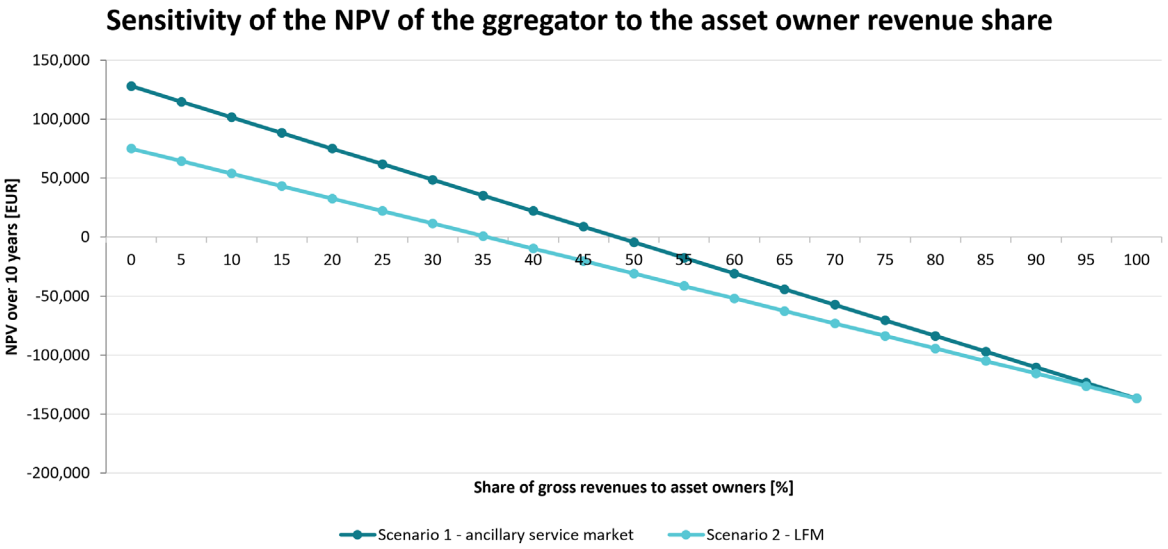


Figure 15: Slovenia: Sensitivity to revenue sharing between the aggregator and the asset owner

5.3.1.3 Conclusion

This business case indicates that providing flexibility in the mFRR market is close to economic viability, with the aggregator achieving a slightly negative NPV. At the same time, the scenario results underline how much the outcome depends on market prices and activations, which are both unknown for LFMs in Slovenia as they are currently non-existent and increases the uncertainty for the aggregator. In addition, it remains unclear whether activation volumes and frequencies in an LFM would be comparable to those in the mFRR market and therefore represents a source of uncertainty for the business case.

It should also be noted that the pilot focuses on industrial companies. If smaller assets were used for flexibility provision instead, costs are expected to rise, which would weaken the economic case.

The revenue share allocated to customers should be sufficient to incentivise their participation in the flexibility scheme. If participation remains lower than expected, this share could be increased to improve the attractiveness of the offer and encourage additional customers to join while also granting economic feasibility for the aggregator.

5.3.2 EV charging optimisation for mFRR provision

This section describes the business case of offering flexibility on the mFRR (downward) market from the AVA charging stations. Financial benefits are assessed for AVA and EV owners.

5.3.2.1 Scenarios and assumptions

AVA's business model aggregates flexibility from EV chargers at homes, public areas, and fleet locations, optimising when vehicles charge without compromising drivers' mobility needs. Rather than charging continuously whenever a car is plugged in, the platform uses expected parking and departure times to identify a suitable charging window. For the business model, different types of charging stations are considered, which come with different characteristics:

- **Private/residential charging stations** usually offer flexibility overnight, as this is the time when private EVs are plugged in (e.g. 20:00-06:00).
- **EV fleet charging stations** could offer flexibility from 11:00-16:00 and 21:00-06:00 when cars are not used.
- **Public charging stations** are used for shorter and less predictable stays. Available flexibility is therefore more limited and depends strongly on user behaviour (06:00-20:00).
- **High-power charging stations** provide rapid charging. These stations offer less scope for flexibility, as charging availability and user convenience are the main priorities and are therefore disregarded in this analysis.

For this analysis, a representative EV with a battery capacity of 60 kWh is assumed. Daily energy consumption is set at 40% of the battery capacity, corresponding to 24 kWh per day. As the AVA charging stations provide a charging power of 11 kW, one charging session requires approximately 2 hours. For the revenue calculation, only hours in which flexibility is available, as indicated above, are considered for the different charging types.

To ensure the reliable provision of flexibility, the number of charging stations required to deliver 11 kW of flexibility is adjusted for each type. This adjustment accounts for differences in charging behaviour and the predictability of charger availability. For an EV fleet, two charging points are assumed to be sufficient to provide 11 kW of flexibility, as AVA can coordinate and optimally allocate vehicles across the available charging stations. For private charging stations, 7 charging points are required as usually only one car is charged per station. For public charging stations, four charging points are required, reflecting the greater uncertainty associated with arrival times, parking durations, and charging demand.

Combining different types of charging stations can increase the overall availability of flexibility. Nevertheless, the available flexibility remains difficult to predict over longer time horizons due to uncertainty in charging behaviour and connection patterns. Therefore, flexibility is assumed to be offered only in energy markets, rather than capacity markets, which require more reliable and longer-term availability commitments.

As part of the STREAM project two public charging stations and two charging stations for corporate fleets were established. Actual flexibility provision is only feasible if more chargers are included and therefore assumed that the number and type of chargers are upscaled according to AVA portfolio.

Table 32 presents the baseline scenario without flexibility provision, and Scenario 1, which includes participation in the mFRR market. Economic benefits are considered from the perspective of AVA and the EV owners.

Table 32: Scenario definition EV charging optimisation, Slovenian pilot

Scenario	Actor perspective	Description
Baseline	AVA, EV owners	Reference case without flexibility provision
Scenario 1 – mFRR market	AVA, EV owners	Revenue from mFRR market

Table 33 presents the parameters used for the calculation of the business model. Revenues are split between the aggregator, the charging-point operator (as part of STREAM AVA), and the EV owner. CAPEX refers to the costs for the development of the platform. OPEX include technology costs for charger connectivity and personnel costs. The discount rate is 5%. Public and EV-fleet charging stations can provide flexibility for 14 hours per day, while private charging stations are available for 10 hours, mainly during overnight charging periods. In the upscaled scenario, the portfolio consists of 100 public charging station, 300 EV fleet charging stations and 200 private charging stations, but are expected to increase over the 5 year time horizon. Only revenues from the mFRR energy market were considered, as committing a fixed reserve volume reliably in advance, as required on the capacity marker, is difficult from EV charging station. These revenues are given as annualised revenue/MW offered for each hour of the year. This number is scaled down to include the assumptions regarding the hours of available flexibility by each charging station type. The share to the EV owner is 20% for private charging points and 10% for public charging points, as more coordination is needed. The revenues are based on assumptions from KOL, while all other values are based on estimations by the AVA.

Table 33: Parameters for the Slovenian EV charging optimisation

Parameter		Value
Total revenues from mFRR energy market [€/MW/year]		20,000
Charging power [kW]		11
Investment costs platform [€]		50,000
Lifetime platform [years]		5
Technology costs (connectivity) [€/charger/month]		0.5
Personnel costs [€/charger/month]		0.5
Share to aggregator [%]		40%
Share to AVA (%)		Public: 50%, Private:40%, EV fleet: 60%
Share to EV owner [%]		Public: 10%, Private: 20%
Required number of charging stations to provide 11 kW [#]	Public charging station	4
	Private charging station	7
	EV fleet charging station	2
Hours where flexibility is available [number of daily hours]	Public charging station	14
	Private charging station	10
	EV fleet charging station	14
	Public charging station	100;200;350;700;1,000

Upscaled scenario [number of charging stations per year]	Private charging station	200;500;1,000;2,000;3,000
	EV fleet charging station	300;500;750;1,000;1,250
Discount rate [%]		5%
Assessment period [years]		5

5.3.2.2 Results and sensitivity analysis

The annual revenue generated per charger type for 11kW of flexibility amounts to €92 Euro for private charging points (10 hours of flexibility) and €128.33 for public and EV fleet charging points (14 hours of flexibility). This value is distributed among the three main actors in the value chain, as indicated in Table 34. The costs differ due to the different number of charging stations needed to provide 11 kW of flexibility. The aggregator receives 40% of the revenue, reflecting its role in pooling flexible charging capacity, accessing flexibility markets, optimising dispatch and managing commercial and operational processes, while AVA receives between 60% and 40% of the revenues depending on the share paid to the EV owners (20% for private chargers and 10% for public chargers, 0% for EV fleet chargers). The aggregator receives between €37 and 51€. AVA receives between €37 and €77 per year. The EV owner receives between €13 for public charging stations and €18 for private charging stations per year as an incentive to participate and allow their charging process to be controlled within agreed limits. Moreover, the respective costs for each type of charging station for the provision of 11 kW of flexibility is given. For both private charging points, the annual operating costs exceed the annual revenue generated from flexibility services for AVA. This is because a private charging station typically serves only one vehicle overnight. As a result, a large number of charge points must be aggregated to provide 11 kW of reliable flexibility over a 10-hour window.

Table 34: Annual revenue for 11kW of flexibility

	Revenue CPO (AVA)	Revenue aggregator	Revenue EV owner	Costs for CPO
Fleet [€/year]	77	51	0	24
Public [€/year]	64	51	13	48
Private [€/year]	37	37	18	84

Table 35 presents the results for the upscaled scenario. The upscaled AVA portfolio is estimated to provide 1.3 MW of flexibility in the first year and increasing according to the uptake of charging station taking part in the flexibility scheme. This value is derived by aggregating the 11 kW charging capacity of the relevant charging stations, while accounting for the number of stations required to provide a reliable 11 kW flexibility block and the hours during which flexibility is assumed to be available. This scenario is financially viable under the assessed assumptions, generating a positive NPV of €5,132 and an IRR of 8%. Revenues from EV fleets and public charging stations offset the losses associated with private charging stations.

Table 35: Slovenia: Results for EV charging optimisation

Scenario	Perspective	Result
Upscaled scenario – AVA portfolio	AVA	NPV: € 5,132 IRR: 8%

The results of the sensitivity analysis show that the most influential parameters are the revenue share retained by the aggregator and the number and mix of the charging type in the portfolio. If only public chargers are considered, the NPV is negative at -€42,166. However, increasing the total number of public chargers seven times per year would result in a positive economic case. A portfolio consisting only of EV-fleet chargers is profitable, with an NPV of €34,514. Increasing the aggregator's revenue share for EV-fleet charging to 56% would still generate a positive business case. In contrast, private chargers do not achieve a positive business case under any of the assessed scenarios, as costs consistently exceed revenues. For private charging stations alone, energy-market revenues would need to more than double, reaching approximately €46,000/MW/year, for revenues to exceed costs. This is mainly because each private charger provides only a small and less predictable amount of flexibility, so many chargers need to be combined before the service becomes financially worthwhile.

5.3.2.3 Conclusion

With the upscaled AVA portfolio the business model is economically feasible. Focusing on EV fleets is the most promising option, as it entails low risks regarding charging behaviour and avoids the need to share revenues with individual EV owners. Upscaling is essential, meaning that the model is primarily relevant for larger CPOs with sufficiently large charging portfolios. A larger portfolio increases the available flexibility volume, reduces the impact of individual charging behaviour, and improves the ability to participate reliably in flexibility markets. Commercial viability will depend on the mix of charging station types, the flexibility market revenues that can realistically be achieved, and the costs of operating the aggregation platform. For private charging, the business case remains challenging because each charger provides only limited and less predictable flexibility but costs remain the same per charging station. At present, the expected EV owner incentive of approximately €13–18 per year is likely too low to create a strong motivation to participate. Economic feasibility can be strengthened by focusing on EV fleet charging stations, increasing the portfolio size and potential value stacking on different flexibility markets or vehicle to grid charging in the future. This could also create scope for more attractive incentives for asset owners.

5.3.3 Flexibility to defer grid reinforcement

On the basis of a single case study, this chapter aims analyses whether flexibility is capable of creating economic value for the local DSO, Elektro Primorska, by deferring grid reinforcement.

5.3.3.1 Scenarios and assumptions

For the case study presented in this section, the MV/LV transformer with the highest utilisation was selected to be investigated. Three scenarios were examined via UL's sPLAN, based on expectations about future developments of electricity demand, with EVs as well as heat pump (HP) developments modelled tool explicitly. There is a *conservative/expected* scenario, one *high-stress* scenario and one *extra-conservative* scenario. They differ in the assumed annual growth of uncontrollable loads, the annual growth of user connection power (P+) and the time required to reach full technology adoption

(EVs, HPs). Uncontrollable loads are assumed to increase due to electrification (apart from EV's and HP's), population growth and a continuous rise in energy demand (Table 36).

Table 36: Technical scenario inputs

Parameter	Extra Conservative	Conservative	High Stress
Growth of uncontrollable loads [%]	0.5	1	5
P+ [%]	0.5	2	5
Adoption [years]	50	40	30

To identify the value of the use of flexibility, a baseline scenario with conventional grid reinforcement practices is compared to a flexibility scenario in which flexibility is used to defer grid reinforcement for at least one year. The NPV of the difference between these scenarios over the entire time horizon T = 30 years is considered the value of flexibility. The time horizon is defined by the depreciation time of a transformer.

To create a realistic investment decision-scenario, the analysis starts in the year 0 in which the decision either in favour or against investing in the availability of flexibility in year 1 has to be made. Year 2 then marks the first year in which flexibility services are applied in the flexibility scenario. This means the different time spans that it takes in the scenarios to even exceed the planning limit are disregarded. In the benchmark scenario, the grid reinforcement investment happens also in year 1.

The planning limit was used to determine the flexibility energy needed each year to defer grid reinforcement by another year. It is derived from the asset's operational limit, which is defined as its rated apparent power, but is set one year earlier, based on the asset's projected installation timeline. The planning limit is calculated by applying a predefined security factor to the maximum loading observed in the planning year. For each time step, the maximum allowable active power is then derived from the planning limit and the corresponding reactive power. Whenever the expected active power exceeds this limit, the difference represents the required flexibility power.

In the absence of LFMs in Slovenia, plausible estimates for both reservation and activation prices were determined based on weighted average prices for all registered LFMs on the NODES trading platform throughout 2025 [9]. To correct for the different price level in Slovenia compared to the countries where these LFMs are located, a correction factor based on the average electricity wholesale spot prices was applied. The results were 0.0595€/kWh for the reservation price and 1.1945€/kWh for the activation price. These prices were assumed to remain constant in real terms.

It is assumed that all flexibilities are first reserved and then part of them is also activated. The activated flexibility equals the required flexibility power. To account for the risk of non-delivery, a risk compensation factor of 2.0 was introduced which doubles the reserved flexibilities purchased. Finally, it is assumed that there is sufficient supply of flexibilities to meet demand at all times.

As creating the opportunity to integrate flexibilities into the electricity system is mandated by European law, the initial investment costs for establishing the flexibility market and trading platform are fixed costs and should therefore not be considered for the investment decision.

However, what is considered is the development of a network simulation model platform and algorithm for calculating and monitoring flexibility as well as communication and control system for flexibility activations. According to the DSO, these investments amount to 12.77 million € excluding 780,000€ for operation and maintenance per year. As flexibilities will be used for many cases these numbers are scaled down to the respective grid segment, by voltage level and equipment type. For the transformer, the investment and OPEX costs were divided by 31, the number of transformers in the respective grid segment. This resulted in 264€ one-time flexibility investment and 14€ flexibility OPEX. Please note that this calculation implicitly assumes that flexibility can and will be used for any grid element currently in place which might be a strong assumption leading to a potential underestimation of the true costs per element.

The DSO also provided the CAPEX for the transformer reinforcement (€42,377) and the estimated annual OPEX for the transformer (€192/year). The reinforcement costs are assumed to be independent of how long the existing transformer had been in use. The transformer's remaining value at the end of the time horizon is accounted for. Discounting is based on the DSO's approximate WACC in 2025, which was 5.15%.

The assumptions as well as the input variables for the calculation of the value of flexibility are summarized in Table 37.

Table 37: Slovenia: Parameters for comparing flexibility to grid reinforcement

Parameter	Value	Evidence type
Assessment period [years]	30	Assumption
Lifetime of the asset [years]	30	Partner information
CAPEX Transformer [€]	42,377	Partner estimation
OPEX Transformer [€/year]	192	Partner estimation
Share of CAPEX Flexibility platform [€]	264	Partner estimation
Share of OPEX Flexibility platform [€/year]	14	Partner estimation
WACC/Discount rate [%]	5.15	Partner estimation
Risk compensation factor	2.0	Assumption
Flexibility reservation price [€/kWh]	0.0595	Assumption
Flexibility activation price [€/kWh]	1.1945	Assumption

5.3.3.2 Results and sensitivity analysis

The technical result of the different scenarios was a rising flexibility demand throughout the years. The expected flexibility demand per scenario is summarized in Figure 19. While in the high-stress scenario flexibility was already needed in four years from now, the planning limit was exceeded in year 15 in the conservative scenario and in year 25 for the extra-conservative scenario. What is most relevant, however, is the development of the necessary flexibilities after the first year in which flexibility is needed.

Notably, the flexibility demand of the extra-conservative scenario is even slightly higher than in the conservative scenario until the 6th year in which flexibility is needed. This can be explained by the S-shaped technology adoption trajectory for EVs and HPs, reflecting the assumption that adoption is initially slow, accelerates during the middle of the transition period and slows again as market saturation is approached.

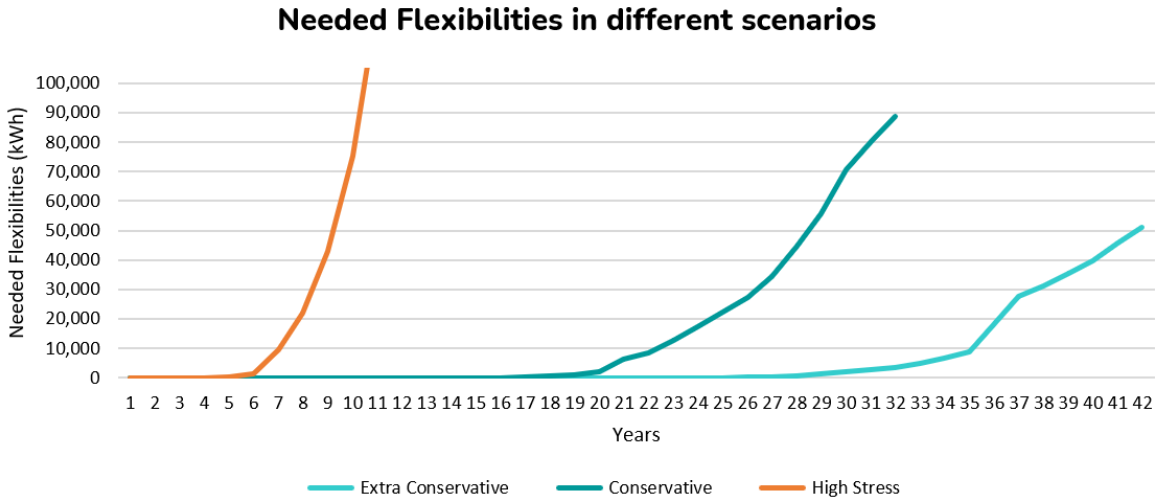


Figure 16: Needed flexibilities in the three different scenarios

The results show that flexibility is more valuable in the conservative and the extra conservative scenario i. e. can defer reinforcement for longer and creates more value the slower the demand for flexibility is rising. In the conservative scenario, flexibility defers reinforcement by 5 years and creates a benefit of 8,673€ in NPV for the DSO compared to grid reinforcement (Table 38). Similarly, in the extra conservative scenario, flexibility defers reinforcement by 6 years and creates a benefit of 8,017€ in NPV. Due to the fast-rising demand in the high-stress scenario, the scenario represents an atypical case for the deployment of flexibilities to defer grid reinforcement. In the fourth year the planning limit is exceeded, flexibility demand in this scenario already exceeds 20,000kWh. However, even for this high-stress scenario, flexibility can defer grid reinforcement by two years and shows a benefit of the NPV of 2,574€. Figure 20 presents the change in NPV across the three scenarios, depending on the number of years by which grid reinforcement is deferred.

Table 38: Slovenia: Results of flexibility to defer grid reinforcement

Scenario	Grid reinforcement	Use of flexibility	Difference in NPV
Extra conservative	NPV: 42,718	NPV: 34,700	NPV: 8,017€
Conservative	NPV: 42,718	NPV: 34,045	NPV: 8,673€
High stress	NPV: 42,718	NPV: 40,144	NPV: 2,574

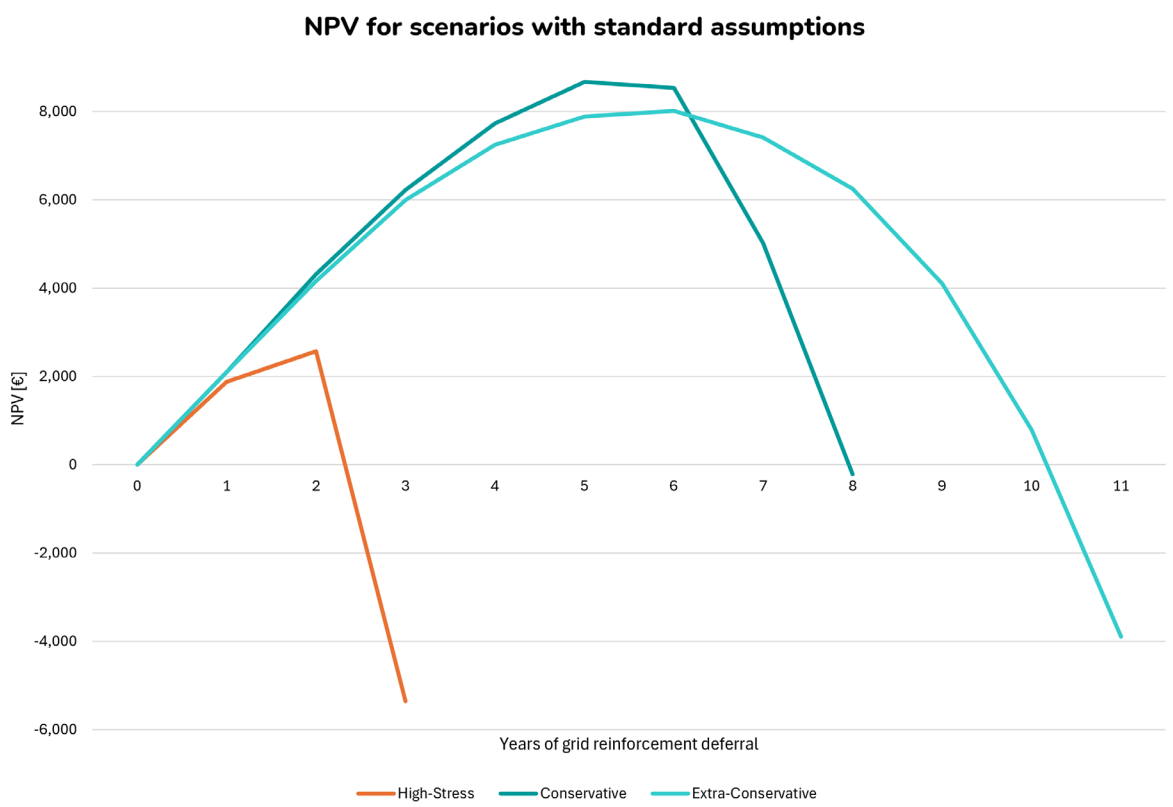


Figure 17: Change in NPV for the three scenarios, depending on the years of grid reinforcement deferral

The sensitivity analysis conducted investigated reservation and activation prices (together), the CAPEX for transformer reinforcement, and the risk compensation factor. The results regarding optimal deferral period and potential profit appeared most sensitive to the CAPEX of the grid reinforcement Doubling the CAPEX led to one more year of grid deferral in the conservative scenario (5 to 6) and two more years of deferral in the extra conservative scenario (6 to 8). In all three scenarios, the NPV benefits by the deferrals rise (8,673€ to 21,197€, 8,017€ to 22,432€, and 2,574€ to 7,186€). The effect is similar but opposite when reducing the CAPEX by 50%.

Reducing both, activation and reservation prices by 50% moves the optimal deferral period from 5 to 6 years in the conservative scenario, in the extra-conservative scenario from 6 to 8 years. The economic gains increase from 8,673€ to 10,440€, and from 8,017€ to 11,048€ in NPV respectively. In the high-stress scenario, the optimum deferral period does not change, economic gains increase from 2,574€ to 3,455€. The risk compensation factor had an even smaller quantitative influence. This can be explained by the risk compensation factor only influencing reserved flexibilities but not of activated flexibilities. As the activation price dominates the cost for flexibilities (about 20 times higher than the reservation price), this risk compensation factor only plays a limited role.

Figure 21 presents the change in the years if deferral as well as the change in NPV in relation to the conservative scenario, which assumes a five-year grid-reinforcement deferral and an NPV of €8,673. Halving prices or doubling CAPEX increases the optimal deferral period by one year, while doubling prices or halving CAPEX reduces it by one year. CAPEX assumptions have the strongest impact on NPV, with doubled CAPEX increasing NPV by €12,520 and halved CAPEX reducing it by €5,360.

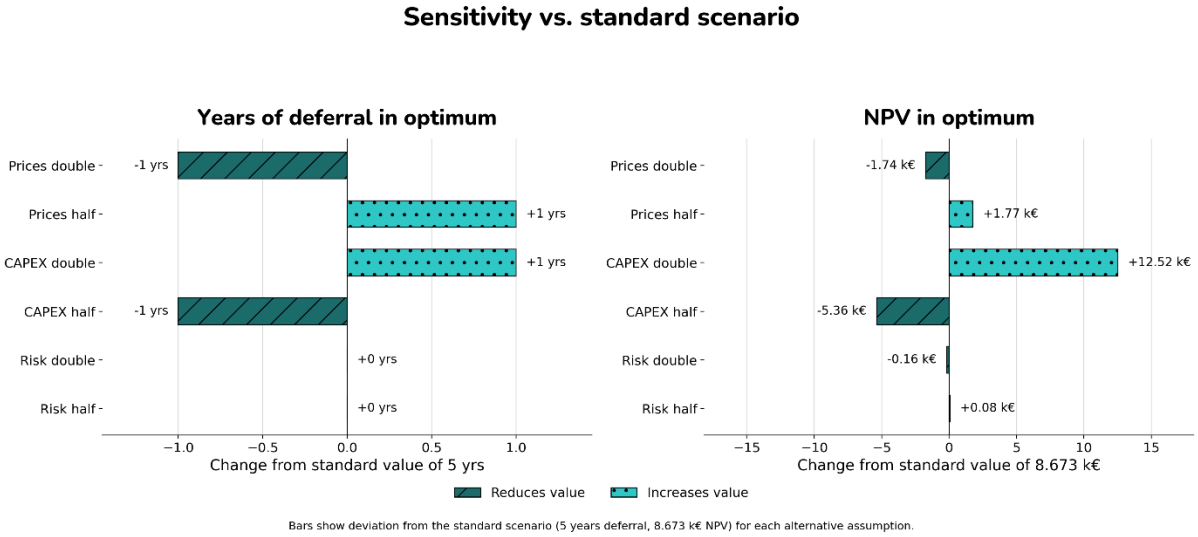


Figure 18: Change in years of deferral and NPV in the sensitivity analysis

5.3.3.3 Conclusion

In conclusion, this case study shows that there are cases where flexibility can defer grid reinforcement and create economic value. The most important factor determining the economic viability of flexibility is the overall development of flexibility demand. The lower the demand, the more effective is the deployment of flexibility compared to conventional grid reinforcement. This suggests that flexibility is most valuable where demand only marginally exceeds planned capacity limits, or where demand is expected to stabilise or decline in the future.

Other factors strongly influencing the economic viability of flexibility deployment are the size of the investment – the larger the necessary capital investment for reinforcement, the more viable flexibility is. Naturally, lower flexibility prices make it also a more attractive alternative to conventional grid reinforcement.

Finally, the analysis shows that compensation for the risk of non-delivery appears to be economically feasible and not influential on the effectiveness or the viability of flexibilities.

However, the results of this analysis have to be treated with care for several reasons. On the one hand, this is only a case study and different grid components in different countries with different regulatory and market conditions could yield different results. Furthermore, a substantial weakness of the case study is that the analysis is based on an isolated grid component, meaning upstream and downstream components of the power grid were not considered.

As mentioned above, this case study does not represent a perfect case for the deployment of flexibilities but rather the most relevant case for the DSO based on utilization. This leads to a potential underestimation of the economic potential of flexibilities.

Finally, the assumption that there is sufficient supply of flexibilities to meet demand at all times can be a strong assumption for some regions – especially in the early phase of the establishment of LFMs.

5.4 SPANISH PILOT SITE

The Spanish pilot in Crevillent combines an energy community with ENER in the distinct roles of the DSO and the aggregator, OMIE as the LFM operator, and ETRA's technology solutions. The pilot demonstrated the workflow for registering and qualifying resources, forecasting grid needs, submitting flexibility requirements and bids, clearing market sessions and activating community assets.

5.4.1 Scenarios and assumptions

The business case for the DSO compares two ways of providing the required network service. The reference is grid reinforcement comprising a 350 m medium-voltage line and a 630 kVA transformer/substation with associated equipment. The alternative uses flexibility procurement together with the cost for sGRID (a planning tool for DSOs developed as part of STREAM) (Table 39). Based on assumption by ENER, the needed flexibility to avoid grid reinforcement is 33.6 MWh/year of availability plus 33.6 MWh/year of activation.

The comparison was done over a 40-year horizon, applying a 6.58% real discount rate, initial investment at t=0 and OPEX. Because the alternatives (grid reinforcement and use of flexibility) are cost streams rather than investments that generate revenue for the DSO, the present value of costs (PVC) is used to compare the two options. Therefore, a higher PVC actual reflects higher costs.

Table 39: Assessed scenarios in the Spanish pilot

Scenario	Actor perspective(s)	Description
Grid reinforcement scenario	ENER as DSO	Immediate 350 m medium voltage line + 630 kVA transformer/substation reinforcement
Long term flexibility scenario	ENER as DSO ENER as aggregator	Flexibility plus enabling sGRID costs compared with the reinforcement
Flexibility scenarios with activation payments only	ENER as DSO	Tests the cost effect of removing the reservation component while holding activation quantity and price at base values

Table 40 summarises the main economic assumptions used for the Spanish assessment, including investment costs, annual operating costs and flexibility procurement costs. The costs for sGRID have to be paid every five years, due to the assumed lifetime of the tool. In the long-term flexibility scenario, each future replacement becomes cheaper as technology costs decline, while the stress case assumes that the real replacement cost remains unchanged. The platform costs and participant revenue shares are tested as separate sensitivity cases.

Table 40: Parameters in the Spanish pilot

Parameter	Value / range and unit	Source
Assessment period	40 years	Partner-validated convention
Real discount rate	6.58% real	Partner-validated input
Grid reinforcement	246,450 € CAPEX at t=0, 40-year life	Partner/engineering input
Grid OPEX	5,000 €/year	Partner input

Parameter	Value / range and unit	Source
sGRID cost	22,795 € initial allocation, 5-year replacement interval	Partner/model allocation
sGRID OPEX	6,000 €/year	Partner input
Availability procurement	33.6 MWh/year × 60 €/MWh = 2,016 €/year	Partner-validated scenario input
Activation procurement	33.6 MWh/year × 180 €/MWh = 6,048 €/year	Partner-validated scenario input
Total base procurement	8,064 €/year	Calculated from the two remuneration components
Technology replacement sensitivity	Base: 5-year replacement cost declines to ~71.5% at year 5 and ~51.1% from year 10, Stress: no real decline	Model sensitivity assumption
Aggregator operating cost	5,000 €/year	Partner input
Platform/service-cost alternatives	sFLEX Base: 3,000 € setup + 12,000 €/year, sFLEX Premium: 5,350 € + 19,000 €/year, sENC: 2,575.5 € + 20,115 €/year	Partner commercial inputs
Participant revenue share	0%, 25%, 50%, 75%, 100% tested	Scenario sensitivity

The long-term product structure is consistent with the STREAM Spanish market design. The DSO can procure availability in advance and activate contracted flexibility when required, whereas short-term procurement focuses on activation at shorter notice [3, 4, 5, 7].

The sGRID costs used in this assessment differ from those reported in D7.4. In D7.4, the costs refer to the use of sGRID for the whole distribution grid. In D6.2, only part of the grid was considered for the financial comparison between flexibility and grid reinforcement. Therefore, the sGRID costs were scaled to match the part of the grid included in this analysis.

5.4.2 Results and sensitivity analysis

The flexibility alternative has a PVC of 250.9 k€, compared with 316.5 k€ for grid reinforcement. The resulting 65.6 k€ savings is equivalent to about 4.68 k€ in annualised savings. Flexibility therefore costs about 79.3% compared to grid reinforcement. The aggregator's NPV in the flexibility scenario is –40.1k€, indicating that the business case is unprofitable under the applied assumptions (Table 41).

Table 41: Results for the Spanish pilot

Scenario	Actor	Result / comparison
Grid reinforcement scenario	ENER as DSO	PVC: 316.5 k€
Long-term flexibility scenario	ENER as DSO	PVC: 250.9 k€, 65.6 k€ lower cost
	ENER as aggregator	NPV: -40.1 k€
Activation revenue only	ENER as DSO	PVC: 222.7 k€, 93.8 k€ lower cost

The first robustness test removes the assumed real decline in ICT replacement cost (Figure 22). Even when every sGRID replacement is held at its initial real cost, the PVC for the flexibility alternative rises to 274.0 k€ but remains 42.5 k€ below the reinforcement scenario. The economic preference for flexibility is therefore not dependent on the favourable technology-cost trajectory used in the base case.

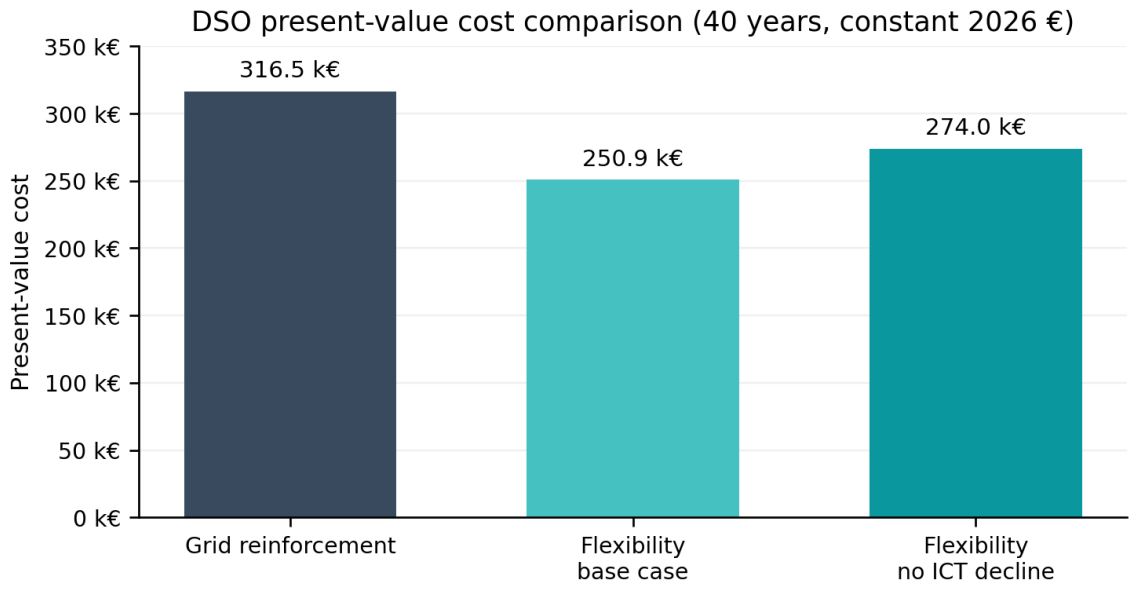


Figure 19: Cost comparison for the ENER DSO

Flexibility remuneration is the dominant parameter for profitability (Figure 23). With all other assumptions unchanged, break even for the DSO occurs when annual costs (availability and activation) reach 12,745 €/year, compared with 8,064 €/year in the base case. This shows that revenues can rise 58% compared to the base case before grid reinforcement becomes the cheaper option for the DSO. Holding one component at its base value gives a break-even activation price of 319.33 €/MWh or an availability price of 199.33 €/MWh.

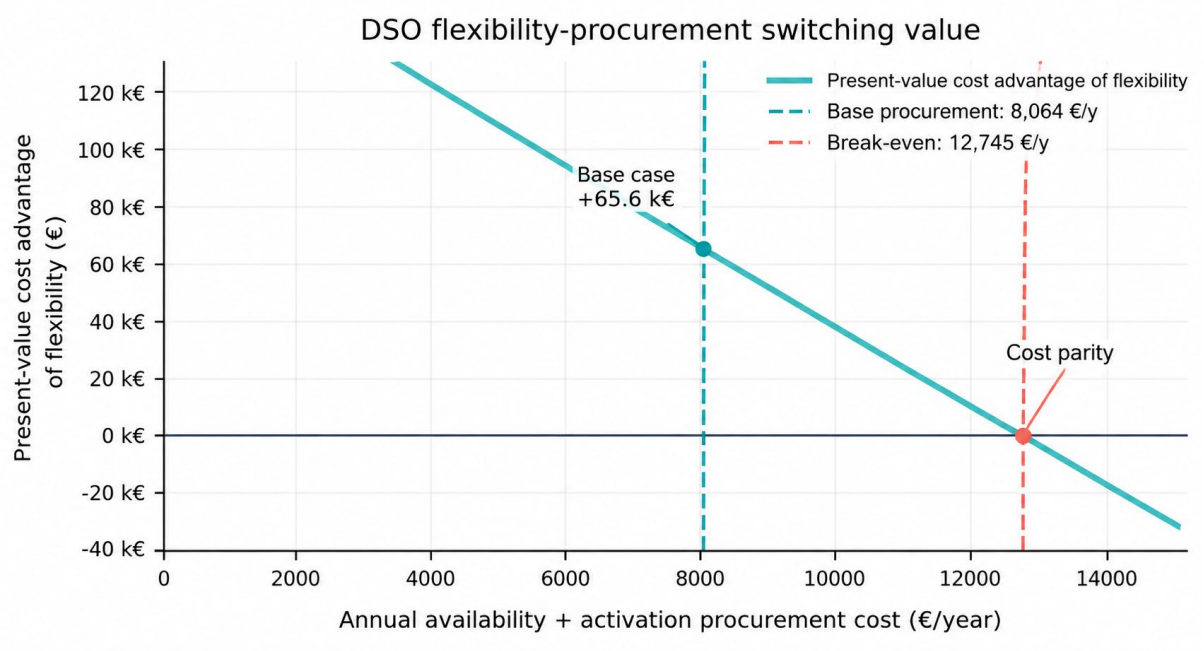


Figure 20: DSO annual flexibility-procurement cost

Product structure also matters. Holding the base activation quantity and price while removing the availability payment, reduces the PVC of the flexibility alternative to 222.7 k€ and increases the potential savings to 93.8 k€.

The business case for the aggregator leads to a different conclusion when the platform costs are fully attributed to this single flexibility service (Figure 24). At revenue of 8,064 €/year, the most favourable case—flexibility management platform (Base), 5,000 €/year aggregator operating cost and 0% participant revenue share—still produces an annual margin of −8,936 €/year.

It requires 17,000 €/year of revenue to break even. That required revenue exceeds the maximum of 12,745 €/year, under which the DSO would break even. Higher participant sharing or a different flexibility management platform (Premium) and energy community platform (monitoring) cost alternatives widen the gap. Consequently, there is no overlap between DSO affordability and aggregator recurring break-even in the analysed scenario.

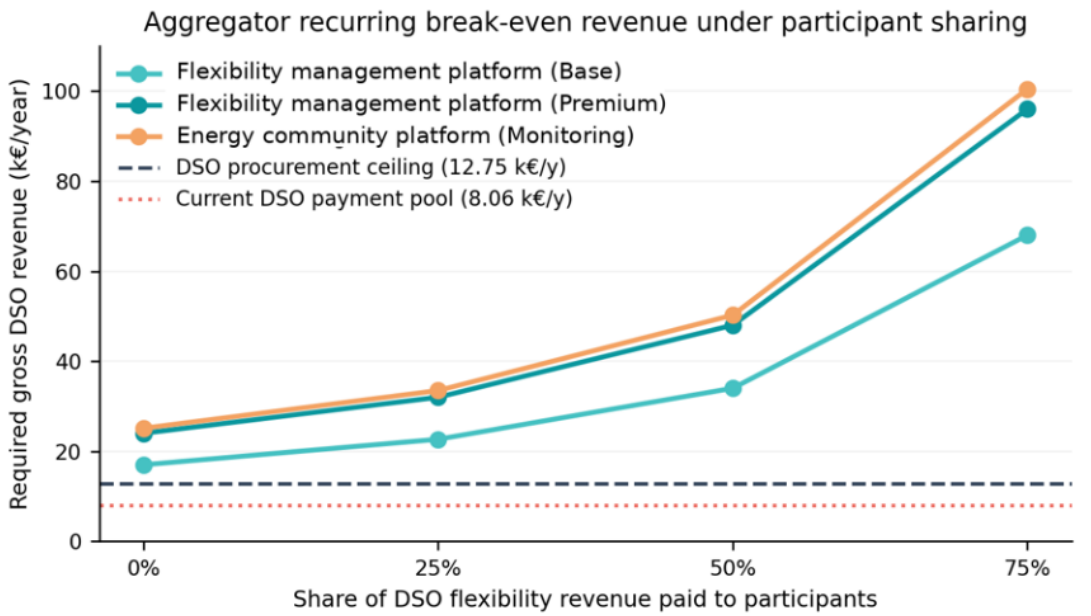


Figure 21: Aggregator break-even revenue under alternative platform costs and participant revenue sharing

5.4.3 Conclusion

Under the current assumption the flexibility alternative proves to be lower in costs than grid reinforcement. When no real decline in ICT replacement cost is assumed, the flexibility alternative reduces the PVC by 42.5 k€. The DSO breaks even at 12,745 €/year of flexibility cost, compared with 8,064 €/year in the scenarios.

For ENER as the DSO a positive business case is reached, while ENER's as the aggregator does not reach break-even when the tested platform costs are fully attributed to this single service. Even in the most favourable case, the business model requires annual DSO revenues of €17,000, exceeding the maximum amount the DSO can pay while still achieving a positive NPV. However, the calculations for ENER as the aggregator did not consider possible additional revenues from using the flexibility management platform and the energy community platform, such as the optimisation of the EnC self-consumption assets, peak shaving, and participation in a P2P market without the involvement of a DSO. These additional revenue streams can contribute to making the aggregator business case economically viable.

The finding is specific to this grid section under the presented assumption. The current analysis does not quantify a specific reinforcement-deferral period or production-scale market liquidity. In addition, the pilot's congestion and activation evidence and therefore need for flexibility includes controlled or simulated conditions and asset-availability limitations.

While the assessment is intentionally focused on the economic comparison between flexibility and reinforcement, the final DSO decision may also reflect considerations beyond the resulting cost indicators. In particular, differences in the operational and risk characteristics of the two alternatives, such as the firmness and availability of flexibility, dependence on market participation, and the ability to respond to evolving network conditions, may influence the value attributed to each option. Conversely, flexibility may also provide strategic value by allowing investment decisions to adapt progressively as network needs evolve. These aspects do not alter the economic results presented here but provide additional context for their use in broader DSO planning and investment decisions.

6 MACROECONOMIC ASSESSMENT OF DSF IN THE EU USING INPUT-OUTPUT MODELLING

6.1 BACKGROUND

Input-Output (IO) modelling is a widely used method in economic analysis, focusing on the interdependencies among industries across the entire economy [10]. Originally developed by Wassily W. Leontief in 1936, the model has since been extended to incorporate employment metrics, interregional flows of goods and services (via Multi-Regional IO, MRIO, tables), and environmental impacts such as pollution and energy flows associated with production [11].

While IO models can be constructed from simple fundamental definitions, this section omits their detailed derivation. Readers seeking foundational explanations are referred to the standard textbook by [11]. Like all economic models, IO models rely on simplifying assumptions to abstract from reality. A comprehensive summary of these assumptions is provided by [10].

The concept of the technical coefficient in IO modelling is central to understanding the translation of electricity-efficiency improvements into the IO model. A technical coefficient measures the amount of input from one sector required to produce one unit of output in another sector. Reducing it therefore represents an improvement in the input efficiency, holding its output constant. This means that lowering the technical coefficient is equivalent to increasing input-efficiency as the quantity of input required to produce the same amount of output becomes smaller [11].

Given its capacity to capture interlinked, second-order economic effects, IO modelling is a suitable framework for analysing the macroeconomic implications of a full EU-wide roll-out of demand side flexibility (DSF). The model uses the EXIOBASE MRIO input-output database [12] of the year 2022. The table includes employment data as well as environmental accounts. The disaggregation of the electricity-production sector into electricity production by source (geothermal, biomass and waste, hydro, solar photovoltaic, solar thermal, tide, wave and ocean, wind, coal, gas, oil, nuclear and others) as well as the availability of the “Transmission of electricity” and “Distribution and trade of electricity” sectors are particularly useful to distinguish between renewable and fossil-fuelled electricity sources as well as to target cost reductions in the electricity grid more accurately than in other IO databases.

6.2 METHODOLOGY

The shock quantities to implement into the IO model were based on a study from DNV for smarten [13]. The study uses the fit for 55 objectives and the goals within the REPowerEU plan for its scenario-building to calculate necessary DSF-capacities within these policies. It explores two scenarios: one that assumes no-DSF and one that assumes full-DSF according to the two mentioned policy packages. The first assumption can be regarded unrealistic as DSF already plays a significant role. Therefore, the benefit-quantities of the model must be read having in mind that limitation [13].

As the current report only deals with the effects of an upscaling of DSF throughout the economy, ceteris paribus, 2022 data and 2030 shock-quantities stemming from the DNV model were applied. This means that the DSF is scaled up according to the level of the DNV-study scenario, whereas the rest of the economy remains as it is in 2022. This is a limitation that is hard to avoid given the fact that there are no IO table forecasts publicly available with a sectoral detail comparable to EXIOBASE.

The model by DNV estimates a total of 164 GW upward and 130 GW of downward flexible power by the year 2030. This leads to multiple benefits regarding the technical efficiency of the electricity grid as well as the functioning of electricity markets stemming from the possibility of load shifting and the associated price decreases for all consumers. This is implemented through four different channels.

- E*fficiency-Grid channel*

Benefit: €4.6 billion in savings due to lower cost to generate electricity [13]

The Efficiency-*Grid channel* relates to efficiency improvements in the electricity grid following an increase in DSF. This relates to lower costs to produce electricity due to lower fuel, variable and maintenance, start and shutdown, emission costs, and penalties [13]. As a shock in the IO framework, this is translated to a reduction in the technical coefficients of all electricity producing sectors similar to [14]. This is implemented across EU-regions as a percentage reduction equal to the ratio of the national and total electricity production output in the EU.

- *Curtailment-Avoidance channel*

Benefit: 15.5 TWh (61%) less renewable energy curtailment [13].

The second channel stems from a reduction in curtailment of renewable energy due to economic or interconnector congestion considerations [13].The avoidance of curtailment is translated to a reduction of fossil fuel technical coefficients and an increase in renewable electricity technical coefficients. Quantity of reductions and increases in this case relates to the ratio of total production of fossil fuel electricity (for the reduction) and the total production of renewable electricity (for the increase).

- *Balancing-Market-Efficiency* channel

Benefit: DSF technologies save €262-690 million on European balancing markets [13]

The SmartEn report states calculations for the balancing potential of different DSF technologies given their roll-out in 2030 and related potential savings on energy-balancing markets [13]. This is implemented in the IO model again by lowering technical coefficients in the electricity transmission sector. Again, national savings are related to the ratio of national production in the transmission sector to total production in the transmission sector in the EU.

- *Avoided-Grid-Capacity channel*

Benefits:

- **Serving demand all year saves €9 billion by avoiding lost loads**
- **60 GW of DSF saves €2.7 billion compared to installing peak generation capacity**
- **€11.1-29.1 billion saved in investment needs in low- and medium voltage distribution grids to integrate new loads and renewable energy supply capacity**
- **Reinvestment of the operational savings of the *Efficiency-Grid and Balancing-Market-Efficiency channels*** [13]

This can be interpreted as “the other side” of the efficiency improvements described in the channels above. When we increase input-efficiency in the system by lowering technical coefficients, in an IO model this leads to a decrease in output, stemming from a decrease in demand from industries that have become more efficient. This reflects the demand-driven nature of IO models.

In reality, this also leads to an increase in free capacities on the supply side that are implemented by the following 4 benefits computed by the model in the DNV study:

- As DSOs are obliged to pass on cost-reductions to the consumers [14], this is a positive demand shock for the household final demand vector as well as the Gross Fixed Capital Formation final demand vector indicating an increase of income for households and investment of the industrial sectors.
- The second benefit implementation is similar to the first but the negative demand shock targets different sectors concerned with the construction of electricity distribution infrastructure, from here on referred to as the construction sector.
- Cost reductions stemming from efficiency improvements are passed on to consumers like the shocks above.
- Redistribution of cost savings due to efficiency gains in producing electricity on the balancing markets through a roll-out of DSF.

Distribution of the savings are conducted according to Eurostat electricity consumption statistics [15] that state a 60% consumption of the private sector translating to the “Gross Fixed Capital Formation”, 30% for the household sector, translating to the “Final consumption expenditure by households” as well as 10% for the government sector that is captured by the “Final consumption expenditure by government” in the IO.

6.3 RESULTS

6.3.1 EU-level results

The following section deals with the results of the IO analysis. Figure 25 presents the change in gross domestic product (GDP) and employment for each of the EU-27 countries. The full table with regional results can be found in Annex B.

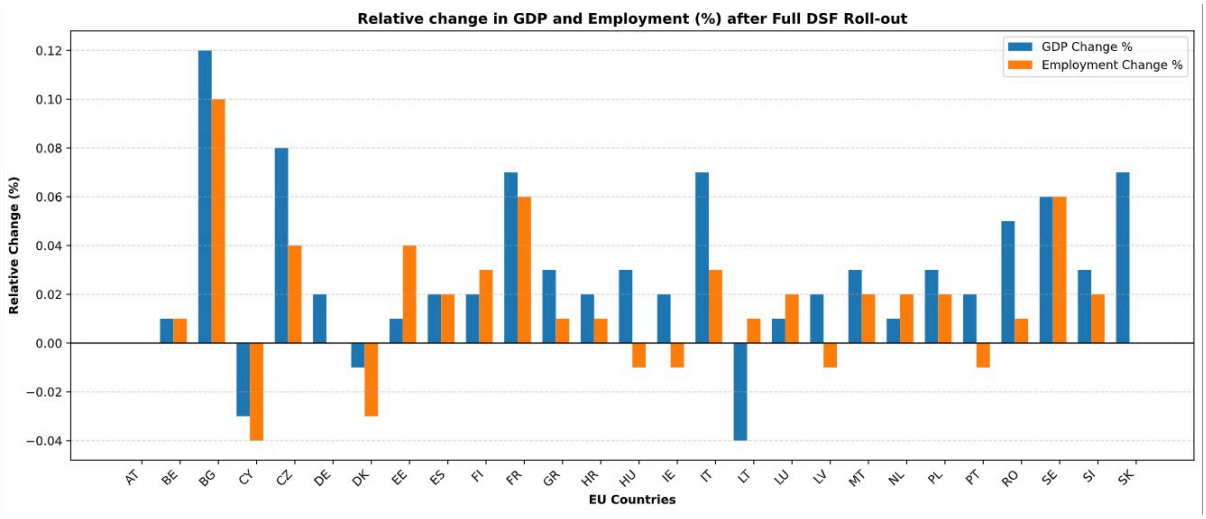


Figure 22: Relative change in GDP and employment after full DSF roll-out

Results between EU countries differ profoundly. Overall, GDP increases for most countries but there are considerable losses in GDP for example for Denmark, Cyprus or Lithuania.

In Cyprus this is mainly driven due to increased input-efficiency whereas in Lithuania this stems primarily from a decrease in the construction sector entailing reduced investment in the private sector investment. It is worth noting that for Cyprus the decrease in output is also followed by a decrease in the number of jobs. By contrast, the number of jobs in Lithuania increases despite the decrease in output. This can be explained by a shift in household and government spending towards more labour intense sectors. This means that the same amount of economic output can create more jobs in different sectors than in construction. Denmark also experiences a decline in private investment from the construction sector which is regionally only partially compensated by an increase in household demand resulting in a decrease in GDP.

Countries that benefit are for example Bulgaria, Czech Republic and Sweden. Bulgaria also experiences losses in GDP in the electricity sectors due to an increase in efficiency but is able to compensate by a rise in demand by households, companies and the public sector alike. The private sector, for example, shifts its investment towards the transport and educational sectors, offsetting its losses in the production of electricity by nuclear, gas, oil and coal as well as coal mining. Furthermore, Bulgaria's construction sector is not as important for the countries' economy and the losses in GDP are relatively small.

In the Czech Republic, the construction sector experiences a GDP reduction of 0.8% equivalent to €110 million driven by private sector decrease in investment which is drastically bigger than in Bulgaria. Similar to Bulgaria, the coal, gas and nuclear electricity producing sectors experience reductions in value-added which stems from input-efficiency related demand reductions. Compared to Bulgaria, several sectors experience moderate increases in value-added, such as the tech sectors, sectors in the domain of agriculture as well as in the manufacture of vehicles, machinery and plastic products so that their sum outweighs the reductions in the negatively affected sectors.

Another winner with a furthermore structurally different economic system is Sweden. Its increase in GDP mainly stems from increases in demand of the private and government sector whereas private investment decreases. The largest sectoral decline in Sweden comes from the electricity producing sectors (nuclear, gas, oil and biomass) and the construction sector. Sectoral gains are widespread where the biggest increase in value-added is experienced interestingly by sectors for mining copper and precious metals.

6.3.2 Pilot-level results

The following section deals with the reallocation of jobs in the pilot countries. Sankey plots are used to illustrate changes in the labour markets in a visualized way, as an Input-Output model cannot track the exact movements of workers.

6.3.2.1 Spain

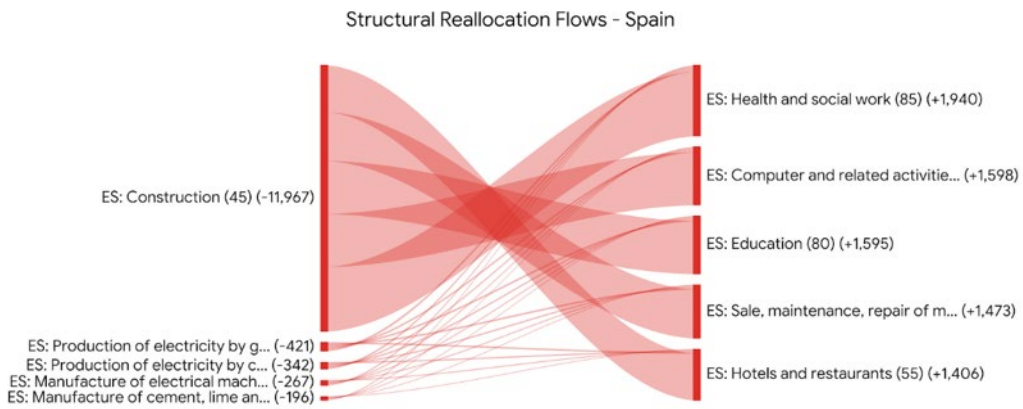


Figure 23: Structural reallocation flows - Spain

Results for Spain show a decrease in output which is not associated with a loss in employment. On the contrary, the shift from the construction sector towards more labour-intense sectors leads to the creation of around 4,000 jobs in Spain as apparent from the table in the Annex B. Figure 26 highlights that jobs decrease in the construction sector and increase in the healthcare, IT and education sector indicating changes in consumer spending as well as implying a shift in the investment behaviour of companies.

6.3.2.2 Finland

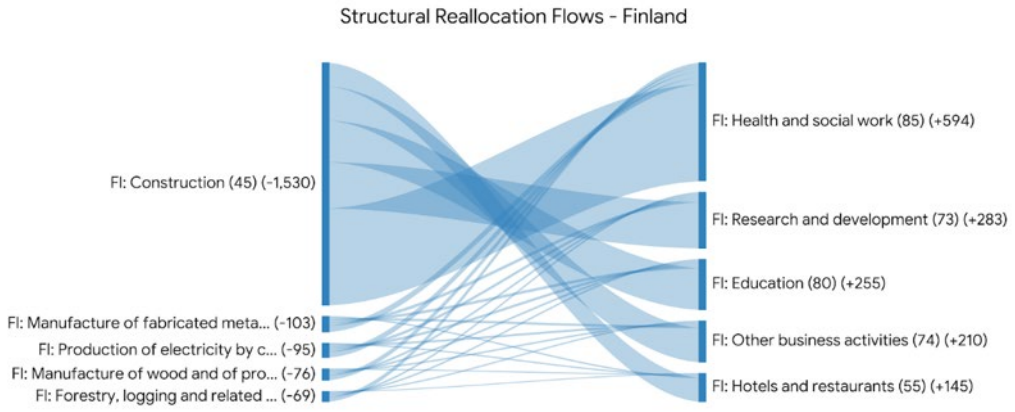


Figure 24: Structural reallocation flows - Finland

The results for Finland are similar to the Spanish results except a particular increase in jobs in the research sector (Figure 27). This shift is of interest as it signals a shift in the economy towards high skilled activities originating from energy-efficiency increases in the grid which would not have become apparent if second-order economic effects (redistribution of savings) were not included in the analysis of these policies.

6.3.2.3 Slovenia

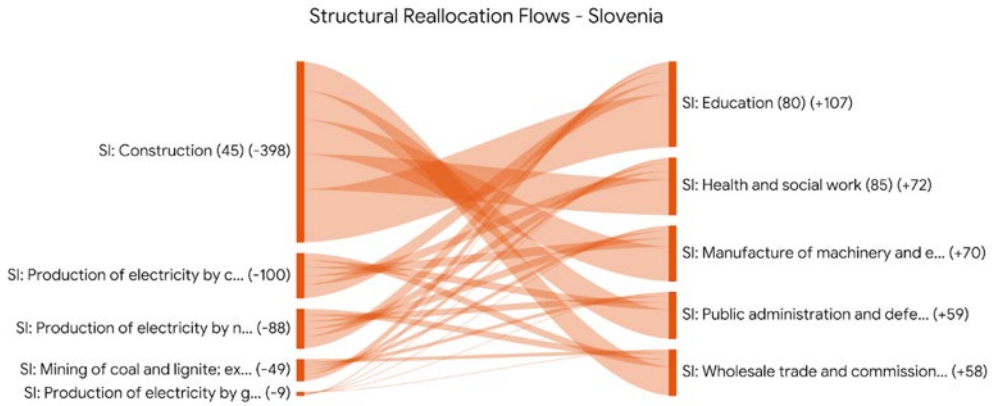


Figure 25: Structural reallocation flows - Slovenia

Slovenia's structural shift is insofar interesting as the biggest job-related losses include losses in the construction, the production of electricity and the coal mining sector (Figure 28). It can therefore be concluded that an EU-wide roll out of DSF would mean a decrease in fossil-fuel-related economic activities in Slovenia. Overall, the shift of jobs away from construction and electricity production to more labour intense jobs such as education, health and social work and manufacture of machinery lead to an overall increase in jobs.

6.3.2.4 Italy

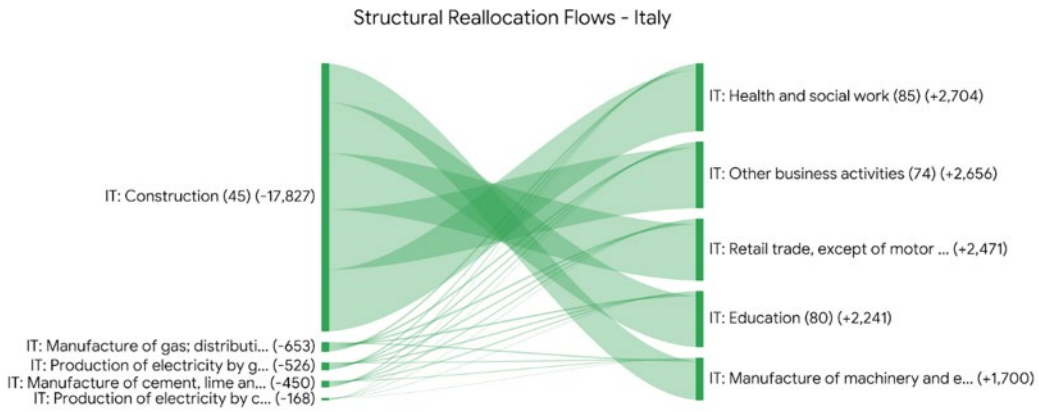


Figure 26: Structural reallocation flows - Italy

The construction sector in Italy is particularly affected by the decrease in demand due to lower spending on construction work to upgrade the grid (Figure 29). More than 17,000 jobs are lost in the Italian construction sector. They are replaced mainly by jobs in the healthcare and educational sectors as well as by increase in jobs related to specialized professional disciplines related to the Other business activities sector - including graphic design, commercial photography or translation, leading to an overall increase in jobs.

6.4 CONCLUSIONS OF THE MACROECONOMIC ASSESSMENT

The input-output model maps the economic effects of full-scale demand-side flexibility activation both in the EU level as well as for the pilot countries at high sectoral resolution, capturing the second-order economic effects of efficiency improvements as they disseminate through the interconnected European economies. Cost savings realized in the grid are redistributed to companies, households, and the public sector in proportion to their respective shares of electricity consumption, triggering structural shifts that vary considerably across countries.

At the aggregate level, the results point to a positive net effect: EU-27 GDP and employment both increases. Beneath this aggregate picture, however, regional and sectoral outcomes diverge substantially. A consistent pattern across regions is a decline in private investment, which in most cases is offset by increased spending from households and the public sector as savings are redirected into consumption and government expenditure. This reallocation of spending, from capital investment toward consumption, is the primary driver of the sectoral shifts observed across the EU-27.

For the pilot countries, this shift reflects job losses in the construction sector across all countries, paired with job gains in health and education. This pattern is a direct consequence of the underlying spending reallocation: as gross fixed capital investment formation-linked investment (which supports construction-heavy capital goods) falls and household/government consumption rises, employment intensity shifts toward the labour-intensive service sectors, health and education.

It is important to note a methodological limitation here: input-output models capture *net* sectoral employment changes but cannot trace the movement of individual workers between sectors. Job losses in construction and job gains in health and education are independent outputs of the model, not a modelled transition path — the framework offers no information on whether, or how, workers displaced from one sector might move into the other.

The main change is a move away from construction jobs towards more labour-intensive but often also high skilled sectors. Based on the jobs-per-output factors from the EXIOBASE MRIO database, this means that the same amount of economic output can create more jobs in services than in construction. As a result, fewer jobs in construction may be balanced by additional jobs in other sectors. One limitation is that the projection for the DSF scenario in 2030 assumes that the economic structure and the number of jobs needed per unit of output remain similar to today.

7 DISCUSSION AND CONCLUSIONS

Across the STREAM pilot sites, the results highlight that the economic viability of flexibility business models depends strongly on the actor, portfolio characteristics, and available value streams. In Finland, offering flexibility on ancillary markets was economically feasible under the scaled deployment assumptions. Larger portfolios perform better because fixed costs are spread across more participating assets. Viability remains conditional on accepted capacity, market remuneration and customer participation. In the analysed case, end users received no revenue. Revenue sharing can improve the profitability for asset owners but reduces the aggregator margin, so the commercial arrangement must balance participation incentives and aggregator viability. In the Italian pilot, offering flexibility on a theoretical LFMs, lead to lower charging costs, while EMOT also benefits indirectly through improved customer attractiveness, demonstrating the relevance of non-monetary value creation. In addition, DAM based pumping optimisation allows ASM to shift pumping activity to lower price periods while maintaining daily water supply requirements, resulting in considerable electricity cost savings and a positive NPV even under conservative assumptions, supported by low investment costs and the system's high operational flexibility. In Slovenia, the business case for the KOL was close to economic feasibility but remained highly sensitive to the revenue share allocated to asset owners and to uncertainty regarding actual flexibility activation. The business case for the AVA was dependent on the size and composition of the charging portfolio, including the type and utilisation of charging stations, with EV fleets and public charging stations providing profitable cases. Moreover, only limited revenues for participating EV owners were generated. The business case comparing flexibility to defer grid reinforcement proved to be economically feasible for the analysed Slovenian grid segment. However, these findings should be interpreted cautiously given the single-component, case-specific analysis and the assumption of adequate flexibility supply. In Spain, flexibility was economically preferable to grid reinforcement for the DSO. The business case for the aggregator did not reach break-even when the tested platform costs were fully attributed to this service.

The assessment of the sPLAN tool for the Slovenian low-voltage network validates and reinforces the finding that flexibility works best as a targeted complement to conventional reinforcement. Across 16 scenarios, coordinated demand-side flexibility and PV curtailment removed all additional reinforcement in the balanced stress cases and avoided most of it under high stress, most strongly in the combined scenario (from 22 network elements to two transformers and GISR 64 %). Under severe electrification, however, the tool could not fully substitute reinforcement, 13 lines and two transformers remained in the high-stress electrification case, because persistent, spatially correlated constraints limit what demand shifting can resolve. A further insight is that self-consumption batteries lowered PV curtailment but did not reduce the number of reinforced elements, underlining that the network value of storage depends on its operating strategy and grid-awareness, not on installed capacity alone. These results are consistent with the Slovenian grid-reinforcement-deferral business case (Chapter 5), which likewise found flexibility most valuable where loading exceeds limits only occasionally or by small margins.

DSO perspective

The assessment of the Spanish and Slovenian STREAM pilots shows that flexibility can provide a valuable alternative to conventional grid reinforcement. For DSOs, flexibility can allow them to defer grid investments by multiple years and in some cases even until the end of the lifetime of the grid element (essentially replacing reinforcement). How effective the use of flexibility is compared to reinforcement depends largely on the (expected) load development.

Flexibility appears to be particularly effective in cases where grid capacity limits are exceeded only occasionally or by relatively small margins. Where loading is expected to increase fast and continuously, flexibility offer only small economic gains or might not be able to postpone reinforcement at all. Other factors influencing this aside from the activation and reservation prices are particularly the OPEX of flexibility and the risk assessment. The latter is not trivial as the risk of non-delivery connected to the use of flexibility generally increases the risks for the DSO. However, the versatility of flexibility can also help to decrease risks. For instance, if the exceedance of a grid element's capacity in the forecasts falls within the margin of error, grid expansion is in any case an excessive measure, but it can also be a complete malinvestment if it turns out that the load on the grid element remains permanently below its capacity limits after all. Flexibility measures can eliminate this risk and can be reserved and activated depending on actual load.

An implication for DSOs is therefore the need for a practical decision process that compares the expected lifetime cost of flexibility procurement with the cost, timing, and technical benefits of grid reinforcement. Such an assessment should account for a long planning horizon as well as uncertainty regarding future electricity demand, distributed generation, flexibility availability, risk of non-delivery and market prices.

The analysis also highlights the need for functioning LFM. In the absence of established local market prices, it remains difficult to estimate the actual cost of flexibility, compare it consistently with grid reinforcement, and adequately account for delivery and price risks.

Aggregator perspective

For aggregators, economic viability depends on establishing a sufficiently large and reliable portfolio of flexible assets, securing adequate remuneration for the services provided and the share of revenues attributed to the asset owners. This share must be sufficiently attractive to encourage participation while still allowing the aggregator to maintain a viable business case. The aggregator business case could potentially be improved through revenue stacking across different markets and value streams, however, such combinations were outside the scope of this project.

Asset owners' perspective

For asset owners, participation in flexibility schemes requires a predictable and sufficiently attractive share of the generated revenues. Since individual payments are often relatively small, they must be perceived as adequate compensation for potential reductions in comfort, convenience, or autonomy.

Macroeconomic perspective

At the macroeconomic level, the results suggest that a broader deployment of demand-side flexibility may generate economic effects beyond the energy sector. These effects are likely to involve shifts in expenditure and employment between sectors, for example from conventional grid construction towards more labour-intensive sectors. The magnitude and direction of these effects are strongly country-specific, reflecting national industrial structures, energy-system characteristics and import dependencies.

Limitations

The results should be interpreted in light of several limitations. Data availability and quality varied across the pilot sites, requiring assumptions in the definition and quantification of business cases. Moreover, some economic results rely on scaled, modelled or simulated conditions rather than fully demonstrated commercial operation.

In addition, the absence of LFMs meant that actual market prices for local flexibility services were generally not available, introducing uncertainty into the revenue assumptions. Comparing the value of flexibility with conventional grid reinforcement also proved challenging due to limited information on reinforcement costs for specific grid sections, the lack of knowledge on the costs of flexibility, and the lack of knowledge regarding the risk of non-delivery. Furthermore, the assessment of grid reinforcement in comparison to the use of flexibility focused on a specific network section and does not represent a comprehensive assessment of the wider distribution network. Finally, the long-term results remain sensitive to uncertain developments in electricity demand, distributed generation, technology costs, market prices, and asset owner participation.

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8.2 ACRONYMS

BESS	Battery Energy Storage System
CAPEX	Capital Expenditure
CBA	Cost-Benefit Analysis
CoUL	Change of uncontrollable loads
CPO	Charging Point Operator
DAM	Day-Ahead Market
DSF	Demand-Side Flexibility
DSO	Distribution System Operator
EV	Electric Vehicle
FCR	Frequency Containment Reserve
FCR-D	Frequency Containment Reserve for Disturbances
GDP	Gross Domestic Product
GISR	Grid Investment Savings Ratio
HP	Heat Pump
ICT	Information and Communication Technology
IO	Input-Output
IRR	Internal Rate of Return
LFM	Local Flexibility Market
LV	Low voltage
mFRR	Manual Frequency Restoration Reserve
MRIO	Multi-Regional Input-Output
NPV	Net present value
OPEX	Operating Expenditure
PBP	Payback Period
PV	Photovoltaic
PVC	Present-Value Cost
TSO	Transmission System Operator
WACC	Weighted Average Cost of Capital
M€	Million euros

ANNEX A – FLEXIBILITY NEED IN THE THREE SCENARIOS

This table presents the underlying data for Figure 19, showing the needed flexibility for the three scenarios for each year for the analysed grid section of the Slovenian pilot.

Table 42: Flexibility need in the three scenarios

Years after zero years	Conservative	High Stress	Extra Conservative
Zero Years	0-14	0-4	0-24
1	1	183	2
2	30	1,380	153
3	209	9,474	291
4	533	21,822	781
5	1,055	42,975	1,375
6	2,211	75,382	1,920
7	6,163	125,769	2,786
8	8,509	193,025	3,508
9	12,740	283,477	4,897
10	17,168	390,955	6,652
11	22,450	520,403	8,883
12	27,325	686,746	18,334
13	34,310	857,897	27,460
14	44,737	1,032,409	31,026
15	55,667	-	35,606
16	70,587	-	39,669
17	80,040	-	45,791
18	88,764	-	51,014

ANNEX B – DETAILED RESULTS OF THE IO MODEL

Table 43 and Table 44 present the country specific results of the input/output model regarding the change in GDP and employment, broken down into the technical and demand effects.

Table 43: Country-specific results of the input/output model regarding GDP

Country	Total Output Absolute M€	Relative GDP %	GDP Total	GDP Tech Effect	GDP Demand Effect	GDP Demand Effect Household	GDP Demand Effect Gross fixed capital formation	GDP Demand Effect Government
Austria	-253.66	0	15.66	-98.71	114.37	253.32	-224.93	85.91
Belgium	-277.45	0.01	73.64	-79.78	153.42	257.49	-213.83	109.79
Bulgaria	185.69	0.12	88.97	-68.71	157.68	65.63	69.29	22.82
Cyprus	-28.2	-0.03	-8.11	-10.18	2.07	14.68	-17.64	5.08
Czech Republic	439.42	0.08	186.72	-84.19	270.91	153.73	65.98	51.15
Germany	-504.43	0.02	580.12	-644.22	1224.34	1,821.11	-1287.8	691
Denmark	-117.57	-0.01	-30.49	-20.48	-10.01	174.4	-244.21	59.79
Estonia	5.59	0.01	3.33	-15.81	19.14	14.65	0.59	3.85
Spain	-187.59	0.02	275.27	-192.83	468.1	772.35	-564.07	259.83
Finland	-11.74	0.02	63.52	-33.67	97.19	199.19	-164.39	62.34
France	2,081.42	0.07	1739.77	-582.84	2,322.6	1,715.85	-4.78	611.48
Greece	73.69	0.03	56.77	-25.55	82.32	68.49	-6.48	20.25
Croatia	-11.16	0.02	15.27	-14.07	29.34	45.12	-29.15	13.36
Hungary	46.43	0.03	40.44	-32.9	73.34	107.16	-68.25	34.41
Ireland	107.5	0.02	101.11	-49.95	151.06	144.07	-41.21	48.25
Italy	1,214.59	0.07	1,245.62	-356.98	1602.6	1,324.49	-204.52	482.62
Lithuania	-125.02	-0.04	-24.98	-5.91	-19.07	32	-62.81	11.72
Luxembourg	34.77	0.01	9.32	-8.23	17.55	25.69	-13.85	5.69
Lativa	-7.13	0.02	8.16	-4.69	12.85	19.24	-11.88	5.5
Malta	9.39	0.03	5.11	-1.81	6.92	4.91	0.08	1.89
Netherlands	-147.46	0.01	61.34	-112.19	173.53	381.94	-355.55	147.11
Poland	87.19	0.03	201.71	-182.59	384.3	398.62	-151.98	137.59
Portugal	-127.43	0.02	39.64	-48.99	88.63	155.66	-121.28	54.36
Romania	28.11	0.05	125.68	-66.32	192	173.85	-38.45	56.53
Rest of the World	4,991.75	0	2,096.11	-895.66	2,991.7	2,024.82	685.07	281.77
Sweden	598,41	0,06	356,41	-101,47	457,88	373,72	-53,9	138,01
Slovenia	29,72	0,03	17,18	-13,48	30,66	29,6	-8,25	9,22
Slovakia	171,3	0,07	65,8	-25,05	90,85	51,23	22,62	16,99
EU27 Total	3314,38	0,04	5312,98	-2881,6	8194,58	8778,19	-3730,65	3146,54

Table 44: Country-specific results of the input/output model regarding employment

Country	Employment Total	Employment %	Employment Tech Effect	Employment Demand Effect	Employment Demand Effect Household	Employment Demand Effect GFCF	Employment Demand Effect Government
Austria	-201	0	-633	432	2,434	-2,880	872
Belgium	464	0.01	-788	1,252	2,069	-2,362	1,535
Bulgaria	3,054	0,1	-2,447	5,501	2,923	1,723	871
Cyprus	-272	-0.04	-358	86	400	-531	217
Czech Republic	1,975	0.04	-1,776	3,751	3,026	-842	1560
Germany	-405	0	-8,190	7,785	18,432	-21,962	11,311
Denmark	-900	-0.03	-216	-684	1,294	-2,800	824
Estonia	289	0.04	-94	383	295	-20	110
Spain	3,929	0.02	-2,395	6,324	11,345	-10,382	5,197
Finland	723	0.03	-323	1,046	1,633	-1,497	892
France	16,380	0.06	-3,042	19,422	17,003	-6,331	8,742
Greece	478	0.01	-1,050	1,528	1,711	-530	341
Croatia	90	0.01	-450	540	929	-820	436
Hungary	-525	-0.01	-955	430	2,757	-3,696	1,374
Ireland	-321	-0.01	-391	70	778	-909	197
Italy	7,720	0.03	-4,557	12,277	14,918	-9,559	6,923
Lithuania	136	0.01	-98	234	830	-1,046	449
Luxembourg	56	0.02	-19	75	85	-44	30
Lativa	-54	-0.01	-53	-1	466	-659	181
Malta	55	0.02	-18	73	59	-16	19
Netherlands	1,569	0.02	-589	2,158	3,582	-3,603	2,171
Poland	3,077	0.02	-6,343	9,420	10,550	-6,556	5,423
Portugal	-495	-0.01	-1,016	521	2,913	-3,905	1497
Romania	646	0.01	-2,768	3414	5,899	-4,620	2,149
Rest of the World	133,289	0	-26,893	160,182	107,491	40,549	12,126
Sweden	3,316	0.06	-373	3,689	2,779	-1,054	1,957
Slovenia	208	0.02	-386	594	496	-144	230
Slovakia	94	0	-720	814	1,189	-1,071	692
EU27 Total	41,086	0.02	-40,048	81,134	110,795	-86,116	56,200