Evaluation of Business Use Cases

D3.4

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About ReInvent

In 2030 and beyond, multiple energy vectors (electricity, gas, heat, green molecules) will play a role in an interconnected energy system. Increased electrification will support sector integration between end user segments. To benefit maximally from the advantages of sector coupling, a fundamental rethinking of market design, business models and financing models is needed. ReInvent will define a roadmap for sector coupling in Belgium. The ReInvent approach is based on **4 pillars** and is a combination of 1) conceptual analysis, 2) sound modelling, 3) proofing of concepts by relevant test cases, and 4) an ambitious impact assessment and replication strategy.

The **first pillar** will analyse the role of different energy vectors (gas, power, heat, green molecules…) in the Belgian energy mix. This includes the impact on infrastructure, market design and business models for different energy end user groups. Based on discussions with project partners and relevant stakeholders, different concepts for both supply-side and demand-side sector integration will be proposed. In addition to the operational implications of sector integration, the financial implications in terms of risk, return, and uncertainty will be analysed.

The **second pillar** will develop the ReInvent modelling and simulation. This multi-sectoral simulation environment will capture the different dynamics of different vectors in multiple timeframes, for multiple scenarios, for multiple market design options, for multiple services, including different end-use sectors and different layers of the physical networks and their interconnection. Innovations modelled in ReInvent aim at the overarching goal of augmenting and realizing the potential of sector coupling in providing key flexibility, balancing, and adequacy services to the multi-energy system and the electric grid.

The **third pillar** will look at a selection of reference test cases that represent main use cases of sector coupling/integration. These applications will provide real data that allow proofing of the developed models in the second pillar. In addition, the models of the second pillar will provide necessary insights to the test cases about the impact of the ReInvent solutions on the operational and financial stability of the presented solution. The ReInvent test cases address different vectors, end user segments and applications and are selected based on the technologies and applications that will play a central role in a future integrated system but still face barriers today that hinder their expected breakthrough.

The **fourth pillar** will define a roadmap for improved sector coupling and sector integration for Belgium. This includes an impact assessment of a wide roll-out of the solutions for the Belgian energy system, in particular the implications for security of supply and system balancing.

Table of Contents

1 Introduction 18

1.1 Objectives of the Work Reported in this Deliverable 18

1.2 Outline of the Deliverable 19

2 Evaluation of the ReInvent use cases 20

2.1 BUC 1a - 5GDHC network for sharing of heat and cooling in a business park 23

2.2 BUC 1b - 5GDHC network providing flexibility to the electricity system 34

2.3 BUC 2 - Integration of a Battery Energy Storage System in a REC 42

2.4 BUC 3 a/b - Social charging shared EVs 52

2.5 BUC 4 - Collective Offshore Wind Integration through Battery Storage 61

2.6 BUC 5a/b - Business Citizen Energy Community 72

2.7 BUC 6a - Green H2 for long haul trucks 87

2.8 BUC 6b - Green electricity for long haul trucks 108

2.9 BUC7 - The role of hydrogen in the Belgian and European energy system 127

2.10 BUC 8 - Integrated energy systems 138

2.11 BUC 9 - Flexibility provision with large-scale electrolyser 150

2.12 BUC 10 - Flexibility provision with a portfolio of EVs 166

2.13 BUC 11 - Smart billing solutions for large-scale EV fleet charging 189

2.14 BUC 12 - Smart billing solutions for collective EV charging 197

3 Conclusions 202

4 References 203

List of Figures

Figure 1-1: Flowchart of the task distribution within ReInvent, T3.4 is outlined in red. 18

Figure 2-1: Modelling concept of optimal dispatch of district heating and cooling 24

Figure 2-2: Integrated 5GDHC and ATES topology. 26

Figure 2-3: Per-building daily heat and cold balance over the operational year. 28

Figure 2-4: ATES seasonal dynamics. 29

Figure 2-5: Per-actor cost decomposition (if PV revenue shared between buildings) and Annual operational costs (if supplier centrally control all the PV) 29

Figure 2-6: Schematic diagram of the thermal system connected to the CIGRE MV power grid 36

Figure 2-7: Schematic diagram of the REC 42

Figure 2-8: Picture of the test case site 42

Figure 2-9: Overview of the optimization tool 43

Figure 2-10: Use case setup 44

Figure 2-11: Total curtailment volume for different scenarios 48

Figure 2-12: Variation of total cost for different scenarios 49

Figure 2-13: Diagram of the main energy flows within BUC 3. 52

Figure 2-14: Contractual relations between actors in the Shared Mobility Provision framework 53

Figure 2-15: Contractual relations in the joint model for the coordination of a SMO and a social REC. 54

Figure 2-16: Monthly distance travelled by the shared vehicles. 56

Figure 2-17: Electricity Import Tariff Mechanisms. 57

Figure 2-18: Modelling environment for optimal day-ahead bidding and battery use of the REC 62

Figure 2-19: The profiling and imbalance costs of the REC 63

Figure 2-20: Two options for leveraging the battery. 65

Figure 2-21: The annual profiling costs of all options for all scenarios 66

Figure 2-22: The annual imbalance costs of all options for all scenarios 67

Figure 2-23: The annual total costs of all options for all scenarios 68

Figure 2-24: The annual total cost saving by leveraging the battery 69

Figure 2-25: Schematic Representation of CEC's physical and economic flows. 73

Figure 2-26: Schematic of the two-step's optimisation process. 75
Figure 2-27: Local consumption and injection patterns (Winter Day). 81
Figure 2-28: Local consumption and injection patterns (Summer Day). 81
Figure 2-29: Schematics of the input and outputs of the optimisation model for BUC6 88
Figure 2-30: Interactions between energy vectors and technologies involved in BUC 6a 89
Figure 2-31: Monthly share of PV – WIND – GRID energy to produce hydrogen per year for Scenario (4). 100
Figure 2-32: Expected sourcing mix for hydrogen production for Scenario (4) 100
Figure 2-33: Expected cost breakdown of LCOH2 for Scenario (4), in [€/kg_h2] and [%]. 101
Figure 2-34: Electrolyser operation with electricity sourcing and refuelling events - typical spring day 102
Figure 2-35: Electrolyser operation with electricity sourcing and refuelling events - typical summer day 103
Figure 2-36: Electrolyser operation with electricity sourcing and refuelling events - typical autumn day 103
Figure 2-37: Electrolyser operation with electricity sourcing and refuelling events - typical winter day 103
Figure 2-38: Diagram of the main energy flows within BUC 6b 110
Figure 2-39: Interactions between energy vectors and technologies involved in BUC 6b 111
Figure 2-40: Monthly share of PV, WIND, GRID energy for charging energy supply per year for Scenario (4). 118
Figure 2-41: Expected sourcing mix for charging energy supply for Scenario (4) and Scenario (5). 118
Figure 2-42: Expected cost breakdown of LCOC for Scenario (4) and Scenario (5), in [€/MWh] and [%]. 119
Figure 2-43: Behaviour of battery with electricity sourcing and charging demand for Uniform scenario (4). 120
Figure 2-44: Behaviour of battery with electricity sourcing and charging demand for Batch scenario (5). 120
Figure 2-45: POMMES framework illustrative scheme 128
Figure 2-46: Hydrogen production, transiting through storage, and import volumes in 2050 in Europe 132
Figure 2-47: Dispatchable electricity production in 2050 in Europe for ISO, EHB and EHB+I scenarios 132
Figure 2-48: Total system costs in 2050 across infrastructure scenarios 133
Figure 2-49: Belgian hydrogen yearly dispatch and price in 2050 under different demands 134
Figure 2-50: Electricity system yearly dispatch in 2050 in Belgium under different hydrogen demand 135
Figure 2-51: Hydrogen system installed capacities in 2050 in Belgium under different hydrogen demand 135
Figure 2-52: NSIM topology for a given country 139
Figure 2-53: Geographical zones covered in NSIM. 140

Figure 2-54: Final demand (energy + feedstock) for the Distributed Energy scenario in 2050 142
Figure 2-55: RES and nuclear potential. 143
Figure 2-56: Electricity generation capacity and monthly balance for the 10 countries. 144
Figure 2-57: Electricity balance for offshore zones 144
Figure 2-58: Hydrogen balance for the 10 countries 145
Figure 2-59: Hydrogen monthly balances for the 10 countries 146
Figure 2-60: Hydrogen balances for the 10 countries 147
Figure 2-61: Average energy system cost versus import dependency for various scenarios. 148
Figure 2-62: Offshore wind capacity vs. offshore electrolysis capacity installed in various scenarios 148
Figure 2-63: Model formulation of the electrolyser MIQP optimisation (BUC9) 151
Figure 2-64: Hourly operation in Case A across a representative month (August). 156
Figure 2-65: Hourly operation in Case B across a representative aFRR-down activation episode. 158
Figure 2-66: Hourly operation in Case C-hourly across a representative period (January). 160
Figure 2-67: PPA contract sensitivity. 164
Figure 2-68: Optimization tool overview for BUC 10 167
Figure 2-69: BUC 10 model setup. 169
Figure 2-70: KPIs for BUC 10. 171
Figure 2-71: Cumulative hourly load (average +/- 1 standard deviation) 173
Figure 2-72: Temporal charging status of the considered EV fleet during the monitoring period 176
Figure 2-73: Temporal variation in SoC across the considered EV fleet during the monitoring period. 177
Figure 2-74: Distribution of daily driving distances for individual EVs during the monitoring period. 177
Figure 2-75: Distribution of charging times for the individual EVs during the monitoring period. 178
Figure 2-76: Average number of weekly charging sessions and average SoC increase per charging session. 179
Figure 2-77: Distribution of SoC values for the considered EVs during the monitoring period. 180
Figure 2-78: Percentage change in flexibility, consumer cost, and self-consumption 182
Figure 2-79: Hourly average aggregated household grid offtake for the considered EV charging scenarios 184
Figure 2-80: Hourly average aggregated household grid injection for the considered EV charging scenarios 184
Figure 2-81: Percentage change in upward flexibility, downward flexibility, and consumer cost 185

Figure 2-82: Hourly average aggregated household grid offtake for the considered EV charging scenarios.....187

Figure 2-83: Example of a charge session derived from EV IoT Data. 191

Figure 2-84: Otterbeek social housing district in Mechelen, Belgium. 198

List of Tables

Table 1-1: Main conclusions from the Business Use Cases 15

Table 2-1: Overview of ReInvent BUC 22

Table 2-2: Main input data of the BUC1a 27

Table 2-3: Daily KPI breakdown of the four pricing scenarios (day of year 39). 30

Table 2-4: Results on the main KPI of the BUC1a (centralized model) 32

Table 2-5: Key recommendations for BUC 1a 33

Table 2-6: Main input data for BUC1b 38

Table 2-7: Results on the main KPI of the BUC1b 40

Table 2-8: Key recommendations for BUC 1b 41

Table 2-9: Data inputs for BUC analysis 44

Table 2-10: Scenario description for BUC analysis 45

Table 2-11: Variation in cost with increasing number of hours with negative prices 50

Table 2-12 : BESS usage for Case-1 in scenarios S5 to S8 50

Table 2-13: Variation in costs for tolling provisions for scenario S6 51

Table 2-14: Key recommendations for BUC 2 51

Table 2-15: Main Data Inputs for BUC 3 a/b 55

Table 2-16: Scenarios considered for BUC3 a/b 57

Table 2-17: Grid Performance Indicators (kW) and Objective Functions (€) by Tariff Structure 58

Table 2-18: Key recommendations for BUC 3 60

Table 2-19: Main Data inputs for BUC 4 64

Table 2-20: The net cost saving of leveraging battery 69

Table 2-21: Key recommendations for BUC 4 71

Table 2-22: Data inputs for BUC 5a/b 76

Table 2-23: Investment scenarios description 77

Table 2-24: Benchmark performances 78

Table 2-25: Individual vs joint investment performance 80

Table 2-26: Flexibility impact assessment 82

Table 2-27: Minimum SCR impact assessment 83
Table 2-28: Peak import/export power performances with volumetric tariffs 84
Table 2-29: Peak import/export power performances with capacity tariffs 84
Table 2-30: Key recommendations for BUC 5 85
Table 2-31: Main Data inputs for BUC 6a 92
Table 2-32: Expected battery sizing, LCOH2, and share of grid electricity for each incremental scenario 96
Table 2-33 : Breakdown of annual electricity bill per year for Scenario (4). 98
Table 2-34: Breakdown of objective function per year for Scenario (4). 99
Table 2-35: Sensitivity analysis of the H2 selling price on the expected financial indicators for scenario (4) ... 104
Table 2-36 : Sensitivity analysis of the maximum allowed share of electricity import from the grid 105
Table 2-37: Main KPI results for BUC 6a 106
Table 2-38: Key recommendations for BUC 6a 107
Table 2-39: Main Data inputs for BUC 6b 113
Table 2-40: Expected CAPEX, battery capacity, LCOC, grid-electricity share and annual grid peak power 115
Table 2-41: Breakdown of annual electricity bill per year for Scenario (4) and Scenario (5). 116
Table 2-42: Breakdown of objective function per year for Scenario (4) and Scenario (5). 117
Table 2-43: Sensitivity analysis of the charging price on the expected financial indicators 121
Table 2-44: Sensitivity analysis of ma allowed share of electricity from grid on battery sizing and LCOC 122
Table 2-45: Main KPI results for BUC 6b 123
Table 2-46: Comparison fuel energy costs and NPV associated to selling prices for BUC 6a/b with an indicative reference cost for diesel transport. 125
Table 2-47: Key recommendations for BUC 6b 126
Table 2-48: Commodity prices for POMMES-EU in 2050 129
Table 2-49: Economic characteristics in POMMES-EU for electricity production technologies 129
Table 2-50: Economic characteristics in POMMES-EU for hydrogen production technologies 130
Table 2-51: POMMES-EU low-carbon energy potential for Belgium | except for biogas, ... 130
Table 2-52 : European hydrogen infrastructure scenarios 131
Table 2-53: Key recommendations for BUC 7 137
Table 2-54: Main Data inputs for BUC 8 141

Table 2-55: Key recommendations for BUC 8 149
Table 2-56: Main Data inputs for BUC 9 154
Table 2-57: Electrolyzer operating parameters and hydrogen delivery limits. 155
Table 2-58: Hydrogen offtake price ratio 155
Table 2-59: Modelling scenarios characteristics 156
Table 2-60: Case A cashflow breakdown 157
Table 2-61: Case A & B cashflow breakdown comparison 158
Table 2-62: Case C-monthly cashflow breakdown 159
Table 2-63: Case C-monthly & C-hourly cashflow breakdown comparison 161
Table 2-64: Case C-hourly& D cashflow breakdown comparison 162
Table 2-65: Cross scenario comparison 162
Table 2-66: Key recommendations for BUC 9 165
Table 2-67: Data inputs for analysis of EV flexibility potential in BUC10. 170
Table 2-68: Key recommendations for BUC 10 188
Table 2-69: Main Data for BUC 11 195
Table 2-70: Key recommendations for BUC 11 196
Table 2-71: Key recommendations for BUC 201

List of Abbreviations and Acronyms

Acronym	Meaning
5GDHC	5th Generation District Heating and Cooling
API	Application Programming Interface
ATES	Aquifer Thermal Energy Storage
BAUY	Business As Usual
BESS	Battery Energy Storage System
BRP	Balance Responsible Party
BUC	Business Use Case
CAPEX	Capital Expenditure
CB	Consumer benefit
CCGT	Combine Cycle Gas Turbine
CCS	Carbon Capture and Storage
CEC	Citizen Energy Community
CH4	Methane
CHP	Combined Heat and Power
CO2	Carbon Dioxide
CPO	Charge Point Operator
cVAR	Conditional Value-At-Risk
DA	Day Ahead
DER	Distributed Energy Resources
DHC	District Heating and Cooling
DLFM	Distribution Local Flexibility market
DNO	Distribution Network Operator
DRC	Direct Cooling
DSF	Demand-Side Flexibility
DSO	Distribution System Operator
ENTSO-E/G	European Network of Transmission System Operators (Electricity/Gas)
ETF	Energie Transitie Fonds
EV	Electric Vehicle
FSP	Flexibility Service Provider
GG	Gas Grid
GHG	Greenhouse Gas
GSCh	Ground Source Chiller
GSHP	Ground Source Heat Pump
H2	Hydrogen
H2O	Water
HC (H/C)	Heating and Cooling

HEC	Hybrid Energy Community
HEMRM	Harmonized Electricity Market Role Model
HP	Heat Pumps
HVDC	High Voltage Direct Current
ID	Intraday
IoT	Internet of Things
IRR	Internal Rate of Return
IT	Information Technology
KPI	Key Performance Indicator
MCR	Maximum Continuous Rating
MES	Multi-Energy System
MILP	Mixed-Integer Linear Programming
MIQP	Mixed Integer Quadratic Programming
MSOL	Minimum Stable Operation Load
MSP	Mobility Service Provider
NPO	Non-Profit Organization
NSIM	North Sea Integration Model
O2	Oxygen
OEM	Original Equipment Manufacturer
OPEX	Operational Expenditure
PPA	Power Purchase Agreements
PEM	Proton Exchange Membrane
PoC	Proof of Concept
PV	Photovoltaic
RAT	Revenue Adequate Tariff
REC	Renewable Energy Community
RES	Renewable Energy Sources
RFI	Request for Information
RLP	Real Load Profile
RF	Residue Factor
RFNBO	Renewable Fuel of Non-Biological Origin
SEC	Supplier Electricity Cost
SME	Subject Matter Expert
SMO	Shared Mobility Operator
SMR	Steam Methane Reforming
SoC	State of Charge
SP	Supplier Profit
SPV	Special Purpose Vehicle

SR	Supplier revenue
SW	Social Welfare
ToU	Time of Use
TPT	Two-Part Tariff
TSO	Transmission System Operator
TT	Tube Trailers
TYNDP	Ten-Year Network Development Plan
V2G	Vehicle to Grid
VE	Full Electric Vehicles
VH	Hydrogen Vehicles
WP	Work Package

Executive Summary

This deliverable presents the evaluation of the ReInvent Business Use Cases (BUCs). The assessment builds on the BUCs and Key Performance Indicators (KPIs) defined in Task 3.1 [1], the datasets developed in Task 3.2, and the modelling approaches developed within ReInvent [2]. The BUCs cover a broad range of sector-coupling applications covering electricity, heating and cooling, mobility, energy communities, battery storage, hydrogen and integrated energy systems.

The evaluations primarily assess the technical and economic performance of the proposed solutions, while also considering relevant environmental, societal and regulatory aspects. Most BUCs are evaluated through simulation and optimisation, complemented by Proof-of-Concept assessments for the smart-billing applications. The main conclusions from the individual BUC evaluations are summarised below.

Table 1-1: Main conclusions from the Business Use Cases

BUC	***Main conclusions***
BUC 1a/b – 5GDHC heat/cooling sharing	A 5GDHC network can enable efficient collective heating and cooling, while thermal storage and appropriate pricing and settlement mechanisms are important for balancing the system and distributing costs and benefits between actors. The thermal system provides several operational levers providing flexibility, although the value and availability of this flexibility depend on the underlying thermal and storage constraints.
BUC 2 – BESS in a renewable energy community	Battery storage can reduce renewable-energy curtailment and community energy costs; Optimisation at community level can provide better overall results than optimisation from the perspective of individual participants.
BUC 3a/b – Shared EVs in an energy community	Shared EV charging in an energy community can create mutual economic and grid benefits. The balance between mobility utilisation and the availability of EV flexibility needs to be considered carefully.
BUC 4 – Offshore wind and battery storage	Large-scale battery storage can help reduce the profiling and imbalance costs associated with integrating offshore wind, with coordinated optimisation improving the utilisation of the available battery flexibility.
BUC 5a/b – Business energy community	Combining complementary renewable generation, coordinated investment and flexibility can improve the economic and energy performance of business energy communities.

BUC	*Main conclusions*
BUC 6a – Hydrogen for heavy-duty transport	Locally produced renewable hydrogen can provide a flexible pathway for supplying heavy-duty mobility, while its economic performance remains strongly dependent on electricity sourcing and market conditions.
BUC 6b – Green electricity for heavy-duty transport	High shares of renewable electricity can be achieved for electric truck charging through local renewable generation and battery storage, but moving towards grid independence significantly increases storage requirements and costs.
BUC 7 – Hydrogen in the Belgian/European energy system	Hydrogen infrastructure is a key driver of system costs, competitiveness and domestic supply. Coordinated electricity and hydrogen planning is therefore essential as hydrogen demand grows.
BUC 8 – North Sea wind and offshore electrolysis	Offshore electrolysis can further support offshore wind integration by reducing curtailment and transmission constraints while providing flexibility to the electricity and hydrogen systems.
BUC 9 – Large-scale electrolyser flexibility	Large-scale electrolysers can create additional value through flexibility provision, but the available flexibility and associated profitability are strongly influenced by RFNBO requirements and participation in balancing markets.
BUC 10 – EV flexibility	EVs can provide significant flexibility, but the practically available potential depends strongly on user behaviour, vehicle availability and manufacturer constraints. Accounting for these factors is therefore important for realistic assessments of EV flexibility.
BUC 11 – Smart billing for EV fleets	Vehicle and charging data can technically support smart-billing solutions, while regulatory requirements regarding metering and settlement remain important conditions for practical implementation.
BUC 12 – Smart billing for collective EV charging	A blockchain-based smart billing solution can provide a neutral and transparent settlement layer for collective EV charging, combining automated billing and reward distribution with community governance.

Across the BUCs, the results demonstrate the potential of sector coupling to improve the alignment between energy production and consumption, increase the utilisation of renewable energy and unlock flexibility across different energy vectors. A recurring finding is that coordinated operation across technologies and actors can provide benefits compared with their isolated operation. This is visible across applications ranging from energy communities and EV charging to battery storage, thermal systems and hydrogen applications.

At the same time, the evaluations show a clear distinction between theoretical or technical flexibility potential and the flexibility that can practically and economically be realised. Operational constraints, user behaviour, infrastructure requirements, technology characteristics and market conditions can substantially affect the available flexibility and its value. In addition, maximising one objective, such as cost reduction or renewable-energy utilisation, does not necessarily maximise other objectives such as grid support, flexibility provision or emissions reduction.

Finally, the BUCs underline that technical feasibility alone is insufficient for successful implementation of sector-coupling solutions. Economic viability, allocation of costs and benefits between actors, access to suitable infrastructure, user acceptance, and enabling market and regulatory conditions all influence practical deployment. The results from D3.4 therefore provide not only evidence on the performance of individual sector-coupling solutions, but also the basis for assessing their wider scalability and replicability within the Belgian energy system in the next work package of the ReInvent project.

1 Introduction

By 2030 and beyond, multiple energy vectors (electricity, gas, heat, and green molecules) will play a crucial role in an interconnected energy system. Increased electrification will support sector integration across various end-user segments. To fully capitalize on the advantages of sector coupling, a fundamental rethinking of market design, business models, and financing models is required. ReInvent will define a roadmap for sector coupling in Belgium, based on advanced modelling and reference test cases selected based on the technologies and applications expected to play a central role in the future integrated system. This deliverable focuses on the evaluation of one or more Business Use Cases (BUCs) for each test case, assessing their performance and implications in relation to the corresponding research questions.

1.1 Objectives of the Work Reported in this Deliverable

The objective of Deliverable 3.4 is to evaluate the BUCs identified in Task 3.1 and quantify the associated KPIs, initially identified in Task 3.1 and further refined within WP3. The evaluation uses the datasets developed in Task 3.2 and integrates concepts from WP1, including market concepts, business models and financing models, with the modelling approaches developed in WP2. The resulting evaluation provides the basis for WP4 to assess the impacts of the BUCs and analyse their scalability and replicability potential.

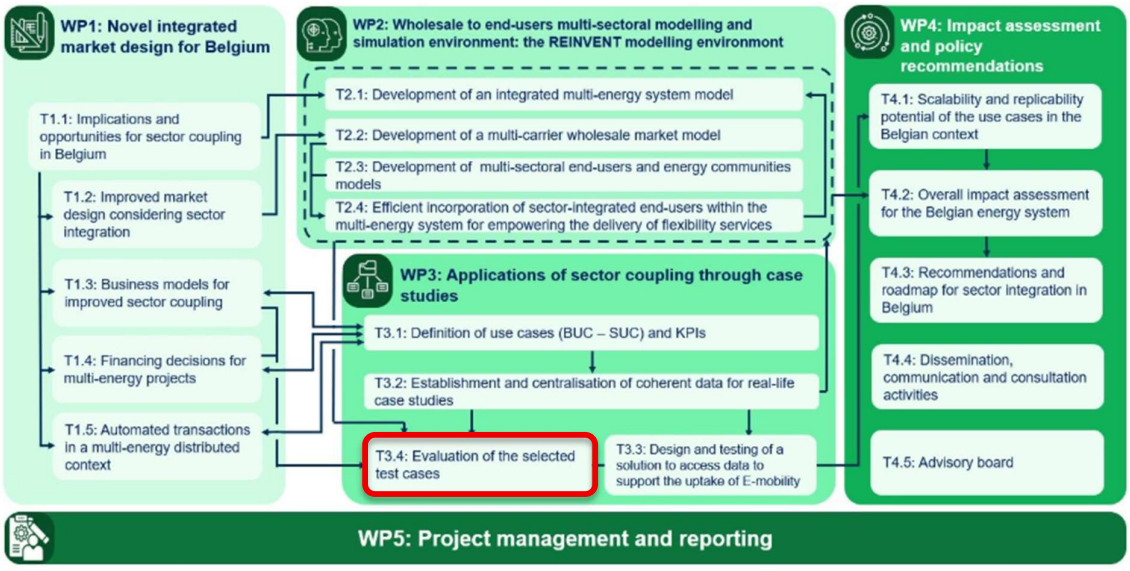


Figure 1-1: Flowchart of the task distribution within ReInvent, T3.4 is outlined in red.

1.2 Outline of the Deliverable

Following this introduction, the deliverable is structured into three chapters. Chapter 2 presents the evaluation results for the different BUCs, following a consistent structure. Finally, Chapter 3 concludes the deliverable with a high-level synthesis of the main findings across all BUCs.

To ensure consistency and comparability across the different use cases, a common reporting structure has been applied. Each use case is presented according to the following elements:

- **General information:** introduction to the use case, its objectives, and the research questions addressed.
- **Simulation tool:** brief description of the relevant sub-model within the ReInvent simulation environment.
- **Use case setup:** overview of the proposed concept, key technologies involved, stakeholders, and system boundaries.
- **General assumptions:** key assumptions underpinning the analysis and the boundaries of the assessment.
- **Main data inputs:** overview of the internal and external data sources used in the evaluation.
- **Modelling scenarios:** description of the analysed scenarios and their main distinguishing characteristics.
- **Results and analysis**: presentation and discussion of the main technical, economic, environmental, and societal outcomes based on the identified KPIs.
- **Conclusions:** interpretation of the results, identification of key success factors and limitations, and reflection on the transferability of the findings.
- **Recommendations**: recommendations derived from the use case results, covering technical, socio-economic, and regulatory aspects where relevant.

The level of detail provided for each section may vary across use cases depending on their objectives, number of scenarios and modelling approach. The last two BUCs present Proofs of Concept (PoCs) that were technically tested and evaluated, rather than assessed through separate simulation and analysis activities using the ReInvent simulation environment. For these two BUCs, a simplified structure was therefore followed: **General Information**, **Description PoC**, **Conclusions**, and **Recommendations.**

2 Evaluation of the ReInvent use cases

This chapter presents the evaluation of the ReInvent Business Use Cases (BUCs), as defined in detail in ReInvent Deliverable 3.1 [1]. The BUCs are analysed using the simulation environment described in ReInvent Deliverable 2.1 [2] to address the different research questions. The use cases constitute the practical application and validation layer of the ReInvent project. Building on the conceptual framework developed in Pillar 1 and the modelling environment presented in Pillar 2, they demonstrate how sector coupling solutions can be applied in real-world contexts and assessed under realistic technical, economic, and regulatory conditions.

The selected use cases cover a diverse range of applications across electricity, heating and cooling, mobility, energy communities, renewable gases, and industrial energy systems, reflecting the broad scope of sector integration addressed within ReInvent.

Between the initial definition of the business use cases (BUCs) in Task 3.1 and their subsequent evaluation in Task 3.4, several modifications were introduced to reflect methodological developments, updated project objectives, and changes in project implementation. To facilitate reporting within this deliverable, several use case scenarios originally defined separately in Task 3.1 were consolidated into a single use case report, thereby avoiding unnecessary repetition while preserving the completeness of the analysis. At the business use case level, four BUCs underwent significant modifications during the evaluation phase:

BUC 6 was slightly reoriented to better align with the simulation model and the updated business concept. More specifically, the use case was expanded to address both the need to secure hydrogen demand from the electrolyser and the grid congestion challenges affecting the business park and the *Wind to Trucks* project. Consequently, a gas engine dedicated to alleviating grid congestion within the business park was incorporated into the system design. During its operating hours, the engine is intended to operate using a predefined proportion of hydrogen in its fuel mix, thereby contributing simultaneously to grid flexibility, congestion management, and hydrogen utilisation.

For **BUC 7,** the modelling approach changed substantially between Task 3.1 and Task 3.4. In Task 3.1, the use case was intended to be evaluated using the Belgian TIMES model (TIMES-BE), with the objective of assessing the role and competitiveness of green hydrogen across Belgian end-use sectors, including transport, industry, feedstock, and buildings. During the course of the project, however, the evaluation framework was revised to use POMMES-EU, a pan-European electricity and hydrogen system model covering 27 countries with an hourly temporal resolution for a 2050-time horizon. This change was motivated by the broader geographical scope of POMMES-EU, which enabled the assessment of cross-border hydrogen infrastructure and market interactions that could not be captured by the national TIMES-BE model. Consequently, the scope of the use case evolved from a Belgium-specific assessment of hydrogen end-use allocation to an analysis of how European hydrogen infrastructure—including the hydrogen backbone, carbon capture and storage (CCS), and hydrogen imports—influences hydrogen production costs and competitiveness. This assessment is conducted through three

infrastructure scenarios (ISO, EHB, and EHB+I), while Belgium remains the focus of a detailed demand analysis. Consequently, the use case was renamed "The role of hydrogen in the Belgian and European energy system", replacing its original title, "From Wind to Trucks: Green Hydrogen for Heavy-Duty Vehicles."

BUC 9 also experienced substantial methodological changes. In Task 3.1, the evaluation was based on a qualitative three-step approach consisting of (i) characterising the flexibility potential, (ii) mapping this flexibility to relevant market segments, and (iii) assessing its profitability. The original scope also included the evaluation of hydrogen infrastructure requirements, such as pipeline sizing. In Task 3.4, this approach was replaced by a mixed-integer quadratic programming (MIQP) optimisation model that determines the optimal hourly operation of a 25 MW electrolyser. The flexibility assessment was narrowed to participation in the aFRR down-regulation market and day-ahead electricity market arbitrage. Furthermore, compliance with Renewable Fuels of Non-Biological Origin (RFNBO) requirements became a central component of the analysis, comparing monthly balancing against strict hourly matching obligations. Five operating scenarios (A, B, C-monthly, C-hourly, and D) were developed to isolate both the value of participation in the aFRR market and the economic impact of the RFNBO requirements. The infrastructure sizing objective initially proposed in Task 3.1 was therefore no longer retained.

Finally, **BUC 11**, which focused on smart billing solutions for electric vehicle charging, was affected by organisational changes. Specifically, re.alto, the business use case owner, left the project. As a result, the further development and evaluation of BUC 11 could not be pursued. Nevertheless, the work completed prior to the company's project exit is presented in this deliverable.

Table 2-1 provides an overview of the ReInvent use cases covered in the deliverable.

Table 2-1: Overview of ReInvent BUC

BUC #	*Name*	*Test case*	*Test case owner*
BUC1a	Collective, cross-sectoral business model for sharing of heat and cooling in a business park with a 5GDHC network	TC3	VITO
BUC1b	Collective, cross-sectoral business models for the provision of flexibility to the electricity system by a 5th generation DHC network	TC3	VITO
BUC2a	Collective, cross-sectoral business models for the integration of a BESS in a REC	TC4.1	CAMPINA
BUC2b	Collective, cross-sectoral business models for the provision of flexibility to the electricity system by BESS in a REC	TC4.1	CAMPINA
BUC3a	Collective, cross-sectoral business models for car sharing in an Energy Community consisting of social housing	TC4.2	KLIMAAN
BUC3b	Collective, cross-sectoral business models for flexibility enhanced car sharing in an Energy Community consisting of social housing	TC4.2	KLIMAAN
BUC4	Integration of collectively owned offshore wind energy production in the electricity grid, by means of demand side management at REC level and the use of a large-scale battery	TC4.3	SEACOOP
BUC5a	Collective, cross-sectoral business models for Business Renewable Energy Communities (without flexibility)	TC6	IDETA
BUC5b	Collective, cross-sectoral business models for Business Renewable Energy Communities with flexibility solutions	TC6	IDETA
BUC6a	Cross sectoral business models for long haul trucks on Hydrogen.	TC2	IDETA
BUC6b	Cross sectoral business models for long haul trucks mobility from local green power.	TC2	IDETA
BUC7	The role of hydrogen in the Belgian energy system	TC2	IDETA
BUC8	INTEGRATION extended to North Sea region: impact of North Sea wind potential and offshore electrolysis.	TC7	Fluxys
BUC9	Potential for flexibility provision with a large-scale electrolyser	TC5	Virya
BUC10	Potential for flexibility provision with a portfolio of EVs	TC1	Re.alto
BUC11	Smart billing solutions for EV charging (focus on a large fleet of EVs)	TC1	Re.alto
BUC12	Smart billing solutions for EV charging (focus on collective car sharing)	TC 4.2	KBC

2.1 BUC 1a - 5GDHC network for sharing of heat and cooling in a business park

2.1.1 General information

Test Case ID	*Name of Test Case*
3	CollecTHOR
Maturity of Test Case	
Developing, part of the network (buildings) is connected and operational.	

BUC ID	*Name of Business Use Case*
BUC 1a	Collective, cross-sectoral business model for sharing of heat and cooling in a business park with a 5GDHC network

Short description and objectives

This use case focuses on designing and testing business models for heating and cooling (H/C) exchange within Thor Park, a business park in Genk. The goal is to provide sustainable heating and cooling by combining shallow geothermal energy with energy sharing between buildings. In this setup, heating and cooling are delivered to end users as a service. Thor Park will be the first pilot site for deploying a 5th Generation District Heating and Cooling (5GDHC) network in Flanders. The network will supply heating and cooling to multiple buildings across the site. In the initial phase, four existing buildings, mainly offices, research laboratories, and other commercial spaces, will be connected.

The system will rely on aquifer thermal energy storage (ATES) to supply heating and cooling, supported by building-level heat pumps that provide the required temperature lift. These heat pumps will be powered by renewable electricity from photovoltaic (PV) installations and, when needed, electricity from the grid. ATES installations will enable long-term seasonal storage of heat and cold. The overall concept is modular, allowing the network to expand over time.

The use case will examine potential heating/cooling (H/C) sharing and pricing models that enable cost-efficient H/C delivery to the different buildings. Since the connected buildings can exchange H/C through the district heating and cooling (DHC) network, it is essential to optimize H/C supply at the level of the entire business park while also establishing a credible business model and fair settlement arrangements between building owners. We therefore foresee a two-step approach:

1. Cost-optimal operation of the H/C system: We will investigate how H/C can be generated, stored, and distributed to the different buildings at the lowest cost. This includes assessing the operational characteristics of the DHC network, the thermal demand profiles of the buildings, and the available thermal storage capacity within the network.
2. Pricing and settlement mechanisms: Based on the cost-optimal operation identified in step 1, we will propose pricing and energy-sharing mechanisms that (i) incentivize or reproduce cost-efficient H/C supply and (ii) ensure a fair allocation of costs and revenues across building owners. Different sharing and pricing approaches will be compared in terms of their feasibility and their implications for the business models of the involved actors.

2.1.2 Simulation tool

The simulation tool is a single-level mathematical optimization framework that schedules every prosumer and the central supplier over an annual hourly horizon. The primary optimization objective is **to minimize net electricity and gas costs, maximize excess photovoltaic (PV) energy exports to the power grid, and simultaneously ensure that the model identifies a schedule that balances the ATES system** over the scheduling horizon (see Figure 2-1). It captures building-level assets (water-source heat pumps, compression chillers, direct cooling (DRC), gas-boiler backup, PV), the bidirectional warm-and-cold-pipe network with soil losses and thermal dynamics, and the supplier-side energy hub with its ground-source heat pump, chiller, free-cooling exchanger, accumulator and warm-and-cold ATES doublet.

The optimization model uses three main groups of inputs:

1. **Time-series forecasts (hourly)** for each building, including space-heating and cooling demand, on-site PV generation, and electricity tariff profiles.
2. **Technology and storage parameters**, such as equipment capacities, conversion efficiencies, operational limits, self-discharge rates, and heat-loss coefficients for each device (including building-level TES).
3. **Aquifer and storage characteristics**, covering the physical properties and constraints of the hot and cold ATES wells as well as the thermal storage units connected to each building.

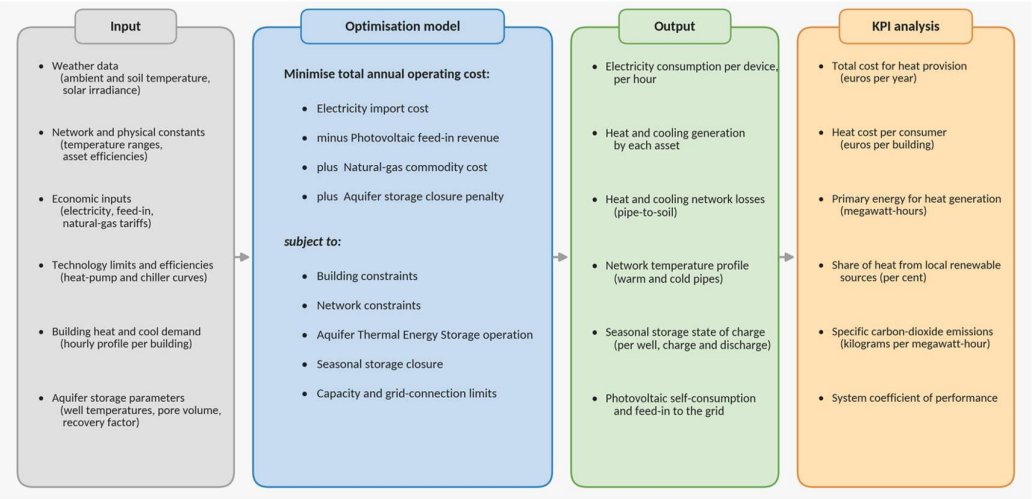


Figure 2-1: Modelling concept of optimal dispatch of district heating and cooling

Based on these inputs, the Mixed-Integer Linear Program (MILP) constructs a **network-wide energy balance** across three coupled subsystems:

- **Individual buildings** (demand, local production),
- **The bidirectional pipe network** (thermal exchange and temperature evolution), and
- **The central energy hub** (Ground Source Heat Pump (GSHP) / chiller operation and ATES charge/discharge behaviour).

The model produces detailed operational schedules as time-series outputs, including:

- **Electric power consumption** of every building-level heat pump and chiller, as well as the hub GSHP and chiller,
- **Charging and discharging decisions** for the hot and cold ATES wells (including state trajectories),
- **Electricity flows**, such as grid imports, PV self-consumption, and PV feed-in to the grid, and
- **Optimal warm and cold pipe temperature trajectories** that satisfy all heating and cooling loads at minimum cost while respecting network constraints.

2.1.3 Use case setup

The use case represents a 5GDHC network serving 4 buildings, mainly offices, labs, that are all connected through a bidirectional two-pipe network (one warm pipe and one cold pipe, see Figure 2-2). Each building is equipped with its own set of flexible devices, PV panels (distributed between buildings proportional to their floor area), a local heat pump (to upgrade low-temperature heat from network for space heating), a local chiller (to produce cooling) and a gas boiler (as an auxiliary backup heat source). Because the network is bidirectional, buildings can effectively share energy. For example, in heating mode, a building extracts heat from the warm pipe (as the heat pump source) and rejects cooler water into the cold pipe. In cooling mode, the building uses its chiller and reinjects the waste heat generated during cooling into the network, where it can serve as a useful heat source for other buildings' heating demands.

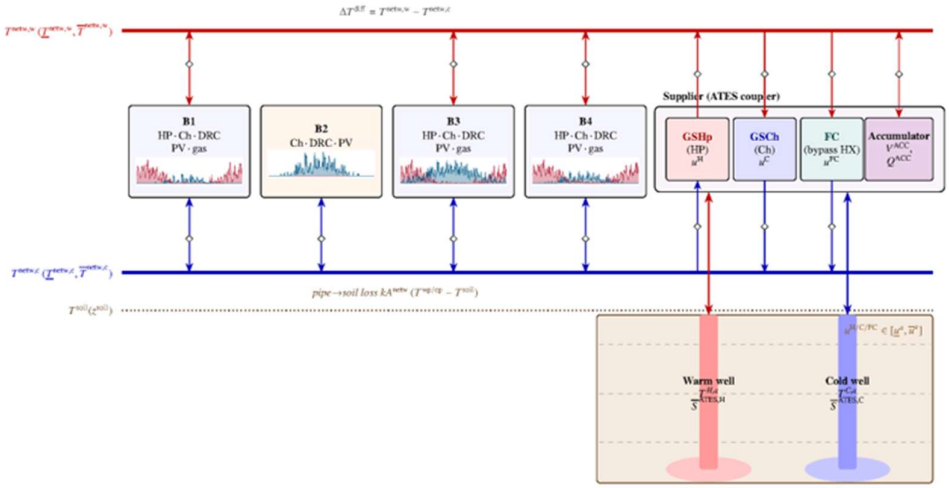


Figure 2-2: Integrated 5GDHC and ATES topology.

To ensure reliable operation when building-to-building exchange is not sufficient, the system includes a central energy hub. This hub comprises a GSHP, which raises the network temperature when additional heat is required; a chiller, which lowers the network temperature when excess heat accumulates; and an accumulator tank (ACC), which buffers thermal imbalances between the warm and cold sides of the network.

2.1.4 General assumptions

The following assumptions have been made to provide a trade-off between accuracy and computational complexity of the model:

- Perfect foresight on hourly demand, weather and PV generation, and on the electricity and gas price time-series. Electricity is priced with two-zone (peak/off-peak) retail price representative of a Flemish commercial contract, which sums up the energy component, network tariffs and levies. The only thermal demands are space heating and cooling with all the PV used for this purpose and the remaining is injected into the distribution grid. The buildings' non-thermal electrical loads are outside the model boundary.
- Ambient-loop thermodynamics with linear soil losses; no hydraulics.
- Single supplier ownership of the district hub and ATES doublet for pricing scenario.
- The system starts operating at the seasonal cooling peak (summer)

2.1.5 Main data inputs

Table 2-2: Main input data of the BUC1a

Name	*Description*	*Units*	*Value or time-series*	*Reference years*	*Data source*	*ReInvent Common data (Yes/No)*
Building data	Four prosumer buildings of the Thor Park CollecTHOR pilot (Thor Central, EnergyVille 1, EnergyVille 2, IncubaThor) demand profiles.	m^2, kW (electric), kW (thermal), kWh/h	8760-h demand time-series	-	CollecTHOR	No
ATES data	Closed warm/cold aquifer thermal-energy-storage specifications	m^3, MWh (thermal), m^3/h, °C	Parameters	-	Flemish region Analogues	No
Network data	Thermal network configuration and capacities.	kW/K, m^3, °C	Parameters	-	CollecTHOR	No
Economic data	Belgian commodity prices/tariffs: two-zone retail electricity (off-peak / peak), photovoltaic injection tariff, natural-gas commodity price	€/kWh (electric), €/kWh (gas, lower heating value)	hourly pricing profile with off-peak and peak behaviour; PV injection tariff	-	ENGIE (Vlaanderen)	No
Ambient data	Hourly outdoor temperature, solar irradiance, soil temperature at 1 m	°C, W/m^2, °C	Time-series (8760 h)	2024	Belgian Royal Meteorological Institute (RMI)	No
CO_2 emission factors	Grid-electricity emission factor	tCO_2/MWh	grid emission factor = 0.145; natural-gas emission factor = 0.202	2024	European Environment Agency country profile	No

2.1.6 Modelling scenarios

We considered different scenarios for two modelling studies:

- **Cost-optimal operation** (objective 1, central planner). Year-round dispatch of the system under centralized coordination.
- **Pricing mechanisms** (objective 2). Regulatory framework for heating and cooling pricing under monopoly supplier. We analysed this objective under following pricing scenarios:
    - Centralized, the centralized social-welfare planner;
    - Single-level social-welfare maximisation with a Revenue-Adequate Tariff (RAT, Supplier Profit = 0);

- Cap-based, supplier as strategic seller of thermal energy with a profit-maximising supplier subject to a cap price (maximum allowable charge); and
- The proposed Two-Part Tariff (TPT), in which supplier act again as a strategic seller of thermal energy, but we set prices compared to an alternative outside option baseline (an air-source heat pump backed up by a gas boiler, and an air source chiller).

2.1.7 Results and analysis

2.1.7.1 Annual optimal operation

Under current system model and announced data input, the dispatch shows three separated operational regimes, a winter heating period in which the warm well is discharged through the supplier heat pump, a summer cooling period in which condenser rejection and direct cooling charge the warm well, and a shoulder-season free-cooling regime in which the bypass exchanger handles the cooling duty without compressor activation.

Building thermal demand is served almost entirely by the prosumer water-source heat pumps drawing from the warm pipe (see Figure 2-3), Above zero, heat-pump supply with a residual gas-boiler share; below zero, chiller and direct-cooling (DRC) contributions. Net flow to the network in green, positive into the cold pipe, negative drawn from the warm pipe). gas boilers are mobilised only on cold-snap seasons. Cooling is dominated by the building direct-cooling exchangers. Under current sizing and operation, the supplier ground-source chiller is not activated, free cooling alone satisfies the cooling demand.

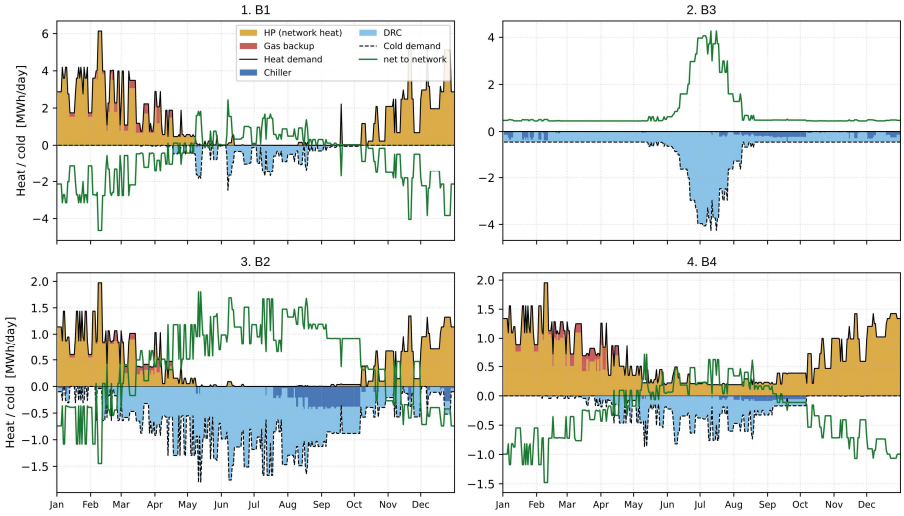


Figure 2-3: Per-building daily heat and cold balance over the operational year.

The aquifer doublet exhibits a clear full-amplitude seasonal cycle for energy and volume of water, the cold well drains through summer cooling and is recharged by winter free cooling, while the warm well charges through summer condenser rejection and drains under winter heating.

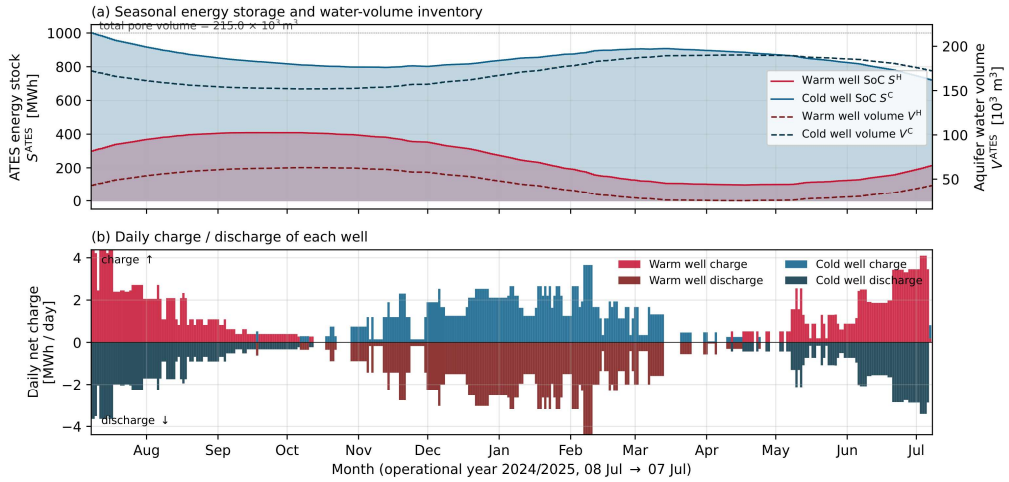


Figure 2-4: ATES seasonal dynamics.
(a) State-of-charge and water-volume inventory of the warm and cold wells.
(b) Daily aggregated thermal flux (charge / discharge) into each well.

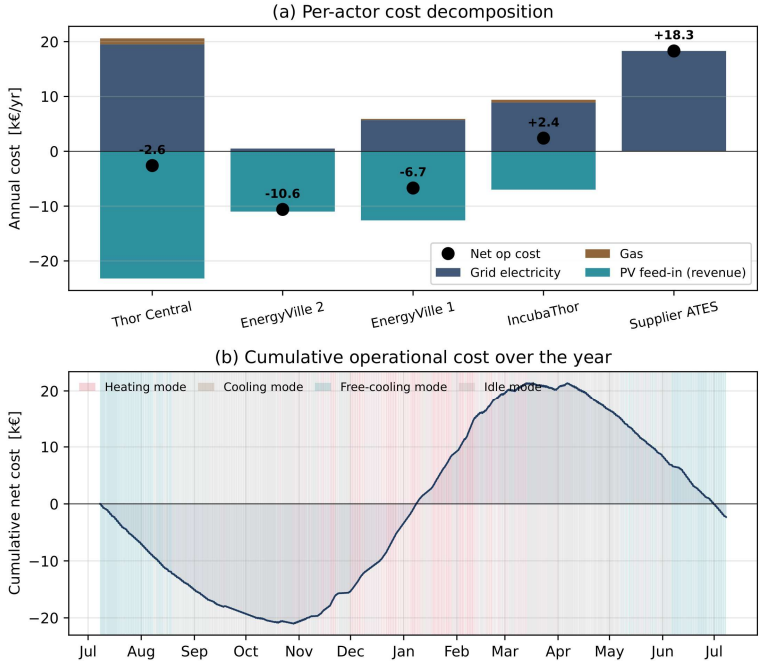


Figure 2-5: Per-actor cost decomposition (if PV revenue shared between buildings) and Annual operational costs (if supplier centrally control all the PV).

Figure 2-5a decomposes the year-end cash position of each actor into grid-electricity cost, gas cost and photovoltaic feed-in revenue. Three of the four prosumers (B1 at −2.6 k€/yr, B3 at −10.6 k€/yr, and B2 at −6.7 k€/yr) end the year as net sellers because their PV revenue exceeds their grid and gas costs, IncubaThor is the only prosumer net buyer (all buildings assumed to have 60-degree heat demand secondary side temperature). Figure 2-5b then traces the cumulative net campus cash flow over the operational year against supplier modes and reveals a clear seasonal arbitrage pattern. Cumulative costs decrease sharply during the summer cooling and free-cooling period (July to October), when PV export revenues dominate and the central supplier is largely idle. They then rise steeply during the winter heating period (November to March), when the supplier's ground-source heat pump is operating and PV generation is low, before partially recovering during the spring shoulder season. Together, the two panels show that the system operates cost-neutrally at the campus level under the Belgian 2024 tariff regime with photovoltaic-rich prosumers

2.1.7.2 Pricing scheme and scenarios

This subsection extends the BUC 1a operational benchmark by comparing three regulatory pricing designs for thermal exchanges on the 5GDHC network, each benchmarked against a centralized social-welfare planner. A distinctive feature of the setting is that the supplier controls not only the tariff but also the loop temperature, which sets every building's conversion efficiency and decides whether direct cooling from the cold pipe is available. All four designs therefore let the supplier choose the temperature bin; they differ only in how the per-unit price is constrained. The four cases are: (i) Centralized, the single-level social-welfare planner (benchmark), (ii) Ramsey, a social-welfare maximisation with a break-even constraint that holds supplier profit at zero; (iii) Cap-based pricing, a profit-maximising supplier subject to a regulatory cap on the per-unit charge, and (iv) the proposed Two-Part Tariff (TPT), a profit-maximising supplier whose per-unit price is unconstrained but its recoverable fee is regulated, per building and hour, to an audited outside alternative (an air-source heat pump backed up by a gas boiler for heat, and an air-source chiller for cooling), with a regulated share returning a tenth of each building's gain. Cases (iii) and (iv) are bilevel Stackelberg problems with the supplier as leader and the buildings as followers. Each mechanism is solved on the same CollecThor instance over the heating-extreme winter day.

Table 2-3: Daily KPI breakdown of the four pricing scenarios (day of year 39).

Scenario	*Social welfare (€)*	*Supplier profit (€)*	*Consumer bill (€)*	*Thermal price (c€/kWh)*	*CO_2 (kg)*
Centralised	−834.87	–	–	[3.3; 3.5] — shadow price, recovered ex post	528.06
RAT	−835.00	0.00	16.50	[3.9; 5.1]	527.59
Cap-based	−952.69	93.03	−194.22	4.97(flat at cap)	569.75
TPT (proposed)	−834.87	7.21	9.43	[3.3;3.5] Marginal price	528.06

Table 2-3 outlines the system performance metrics. Social Welfare (SW) represents the total economic benefit generated across the system. The Supplier Payoff combines revenue from thermal sales net of electricity cost with the fixed fees collected under the mechanism. The Buildings' Payoff gives the end-users' net position relative to that same standalone alternative, so a positive value means a building is better off connected. The Price metric reflects the range of the posted per-unit thermal price over the day, and the environmental impact is quantified by the daily operational CO_2 emissions.

Interpretation of the different pricing scenarios is as follows:

- **Centralized**, the benchmark for social welfare. The planner operates the loop at the efficient temperature and values heat at its marginal worth. It defines the maximum attainable surplus over standalone operation, against which the three regulated designs are measured.
- **Ramsey**. This is the "non-profit" case. The operator sets its announced price so as to break even, taking no profit and no loss, and the buildings keep the entire surplus. It reaches essentially first-best welfare and holds the efficient temperature, so it is efficient and financially neutral. The downside is that the operator earns nothing, which gives no return on the network and ATES investment and no margin on the days when the constraint binds.
- **Cap-based**. Here the operator may earn a profit, but a regulator caps the per-unit price it can charge. Capping the price does not exhaust its withholding power, because the temperature lever stays unregulated. The operator starves the loop down to its 5 °C floor and saves about a third of its plant electricity; the cold loop collapses the buildings' heat-pump efficiency, so their grid purchases rise by a third to deliver the same heat. The operator gains 93 €, the buildings lose 194 €, and the 118 € gap is deadweight, dissipated as electricity in the buildings' own equipment. That loss exceeds seven times the day's entire achievable surplus, leaves every building worse off than if the network had not operated, and raises carbon emissions by 7.9%.
- **Two-part tariff (TPT)**, the proposed mechanism. It reaches exactly the central-planner welfare, and the posted per-unit price coincides with the shadow price of the efficient dispatch, so the buildings never have a reason to distort their operation, and the efficient temperature is held. Profit is collected separately as a fixed fee, bounded per building and hour by that building's audited outside alternative. The operator retains 7.21 € and the buildings 9.43 €, so the supplier stays solvent while every building remains at or above its standalone cost. The sharing lever is a policy dial that moves this split linearly at no welfare cost and split the network generated surplus between buildings and supplier.

2.1.7.3 Results on main KPI's

Table 2-4: Results on the main KPI of the BUC1a (centralized model)

Name	Value - results	Unit
Total system cost (centralized planner)	The campus's gross operating bill (54.7 k€/yr, before PV-feed-in revenue) breaks down into near 58 €/MWh of heat and 5 €/MWh of cold delivered. Once the 53.8 k€/yr of PV feed-in revenue is accounted for, the net unit prices fall to almost 1 €/MWh_heat and 0.08 €/MWh cold respectively, the PV revenue stream effectively covers almost the entire campus heat-and-cold service (If PV only for space heating and cooling).	k€/yr
Primary energy used for heat generation	231 MWh/yr grid-electricity import + 86.7 MWh/yr PV self-consumption, delivering 878 MWh/yr useful heat and 709 MWh/yr useful cold (1587 MWh total thermal). Primary-energy equivalent on grid imports at primary-energy factor for electricity = 2.10, results in 485.9 MWh/yr. System SCOP (total thermal output / grid-electricity import) 6.86 (a typical 5GDHC network has SCOP of 3.5-5 and a high-performance temperature controlled one has SCOP of 6-10); heat-only SCOP approximately 3.79.	MWh/yr
Heat costs for the different consumers	B1 = 38.1; B2 = 10.9; B3 = 0.0 (cooling-only, no heat demand from the thermal network); B4= 18.6.	k€/yr
Share of heat produced by local RES	29% (PV-self-consumed =86 / Electricity consumed by heat assets = 290)	%
Operational CO_2 emissions	38 (34 grid electricity + 4 gas boiler)	t CO_2/yr

2.1.8 Conclusions

BUC1a focuses on the optimal operation and pricing mechanisms of a 5GDHC network. Using mathematical optimization, the proposed model provides insights into the cost-optimal operation of DHC networks, their associated challenges, and efficient pricing mechanisms. From an ATES balancing perspective, only around 21% of the campus heating and cooling demand overlaps on a day-to-day basis, which is well below the 40% threshold at which direct prosumer-to-prosumer heat sharing could independently balance the campus thermal system. As a result, some form of seasonal storage is a necessity in CollecThor. Over a full year the ATES doublet does not return to its initial state, for two independent reasons. First, the thermal recovery efficiency of the storage (about 28 %/yr loss), and second, the campus's heating and cooling loads are not symmetric to charge or discharge aquifer wells equally. The consequences of the thermal imbalance could be severe as similar failure already happened in Brussels, leading to costly drilling of a new ATES system. A gas-boiler backup is included and helps absorb part of this imbalance, but excessive reliance on gas would compromise compliance with the

EU Renewable Energy Directive III (Directive 2023/1791, Chapter V Article 26) [3], which defines an 'efficient district heating and cooling system' as one supplied by at least 50 % renewable energy, waste heat, or efficient cogeneration. International reference projects address the closure problem in different ways, UK low-temperature ATES installations use dedicated dry coolers as the balancing element, while Dutch installations are regulated under a five-year rolling balance rule rather than per calendar year.

Battery for self-consumption. The model self-consumes almost 10 % of its 858-MWh annual PV generation; the remaining 90 % (around 772 MWh) is exported at 0.07 €/kWh. Each kWh redirected from export to self-consumption is worth 0.228 − 0.07 = 0.158 €/kWh net. A modest battery shifting 50–100 MWh from export to self-consumption is worth near 8–16 k€/yr.

Pricing and settlement. Pricing scheme should preserve the supplier-side incentive to dispatch cost-optimally while ensuring prosumers see a reasonable and fair prices. The proposed baseline-based Two-part tariff guarantees the same total welfare as the central-planner allocation which is the maximum achievable welfare which shows that by implementing the right regulatory framework, a cooperative outcome can be achievable even under strategic profit-maximizing environment.

The PV injection tariff dominates the operational economics. The operational economics of the thermal network are heavily influenced by the PV injection tariff (for PV-heavy thermal system design). Specifically, the contract type between the thermal supplier and the electricity retailer governs the network's operational schedule. On the other hand, since prosumer network-tariff regimes differ between Flanders and Wallonia, the stability and duration of this contract are far more critical for securing project bankability and optimizing operations than the actual tariff rate itself.

2.1.9 Recommendations

Table 2-5: Key recommendations for BUC 1a

Recommendations	
Technical	A modest electric battery system allows shifting PV from export to self-consumption since most of the PV generations may not coincide with the thermal demand.
Socio-economic	Power grid PV feed-in price impacts the thermal network operation intensively. Hence, its stability and contract details become important for bankability and optimal operation across Flemish-to-Walloon different regulatory regimes.
Policy/regulatory	The Two-Part Tariff matches central-planner welfare while keeping the supplier cost-optimal and prosumers protected. The aquifer doublet cannot self-balance over a calendar year, so the operating strategy should rely on multi-year cumulative balancing or an external auxiliary (dry cooler or Air Source Heat Pump).

2.2 BUC 1b - 5GDHC network providing flexibility to the electricity system

2.2.1 General information

Test Case ID	*Name of Test Case*
3	CollecTHOR
Maturity of Test Case	
Developing, part of the network (buildings) is connected and operational.	

ID	*Name of Business Use Case*
BUC 1b	Collective, cross-sectoral business models for the provision of flexibility to the electricity system by a 5th generation DHC network
Short description and objectives	
Building on the previous thermal network model, this use case will also examine how the flexibility available in a 5th Generation District Heating and Cooling (5GDHC) network can be valorised in the electricity system, while maintaining cost-efficient H/C delivery. More precisely, this BUC addresses the question of how the aggregated electrical flexibility of a 5th-generation district heating and cooling (5GDHC) network with aquifer thermal energy storage (ATES) can be valorised in short-term electricity markets, while preserving cost-efficient thermal service to the connected prosumers. This flexibility assessment is structured in three steps: 1. Identification and characterization of flexibility potential: determine which resources can provide flexibility and quantify their characteristics (flexible capacity, and seasonal dependence). 2. Mapping to flexibility market requirements: evaluate which market segments and product can be targeted from a technical perspective to be provided by the thermal network. 3. Economic impact assessment: quantify how flexibility provision affects system operation and the distribution of costs and revenues.	

2.2.2 Simulation tool

A 5GDHC network with seasonal storage can in principle offer several distinct services to the electricity system. The analysis is confined to the local congestion (DLFM) segment. Participation in TSO-level balancing services would require aggregation into a flexibility service provider's portfolio, which is outside the scope of this use case. To address this congestion management problem, the simulation tool is designed as a single leader single follower bilevel programme. The upper level is the 5GDHC operator that co-decides the full physical dispatch of the supplier-side plant, the buildings, the ATES doublet and the in-line accumulator, together with the quantity-price flexibility offer it submits to the DSO-run distribution local flexibility market (DLFM). Bid prices in the model are treated asymmetrically by design. CollecThor's upward and downward bid prices are endogenous. They are decision variables of the upper level, optimised jointly with the physical dispatch and bounded only by an assumed regulatory cap of 0.20 €/kWh. The bilevel therefore returns CollecThor's profit-maximising bid given the DSO's least-cost clearing rule. The rival FSPs, by contrast, are exogenous competitors, meaning that their offers are fixed parameters, not outputs of a cost model. Their biding amounts are presented

in Table 2-6. The lower level is the DSO that clears the DLFM by least-cost merit-order procurement against four rival Flexibility Service Providers (FSP) and a transformer-cap constraint on the substation flow (the source of congestion). All the thermal network, building and ATES related inputs parameters are the same as the previous use case. The ATES doublet is anchored to the canonical year-round trajectory of BUC 1a, as the normal (no market) trajectory, and any deviation of the 24-hour slice from that seasonal target is penalised at a shadow price. This way, the DHC operator should decide between the price of charging or discharging the ATES and the profit that comes from the DLFM.

The horizon is 24 hours at hourly resolution. Three representative days summer peak (8 July, cooling-dominated, high PV export), mixed (15 April, balanced heat and cool with a substantial PV midday) and winter peak (15 January, heat-demand-dominated import). Each day's initial ATES state of charge and end-of-day target are the same as the BUC-1a year-round trajectory. This allows us to assess whether the participation of the district heating and cooling (DHC) system in the market alters the optimal operation of the ATES.

The output of the model are hourly profiles of every plant-side and prosumer-side device with and without DLFM participation; the resulting modification of the operator's net electricity withdrawal at the connection point; the cleared upward and downward awards split between the operator and the rivals; the operator's pay-as-bid revenue and the corresponding operator-side social welfare.

2.2.3 Use case setup

The four prosumer buildings of the ThorPark initial-deployment phase (Thor Central, EnergyVille 1, EnergyVille 2, IncubaThor) are connected through the bidirectional ambient-temperature thermal loop to the supplier-owned energy hub (the same DHC network), and to a MV feeder of the electricity network. For the MV feeder a standard medium-voltage (MV) distribution test feeder published by CIGRE Working Group in Technical Brochure 575 is used [4]. The European MV benchmark is a 20 kV, 50 Hz network representative of a European distribution grid; it has two feeders, and this analysis uses Feeder 1 in its base-case radial configuration, giving 11 nodes and 10 branches. The operator's energy hub is placed at node 11 (see Fig 3-6).

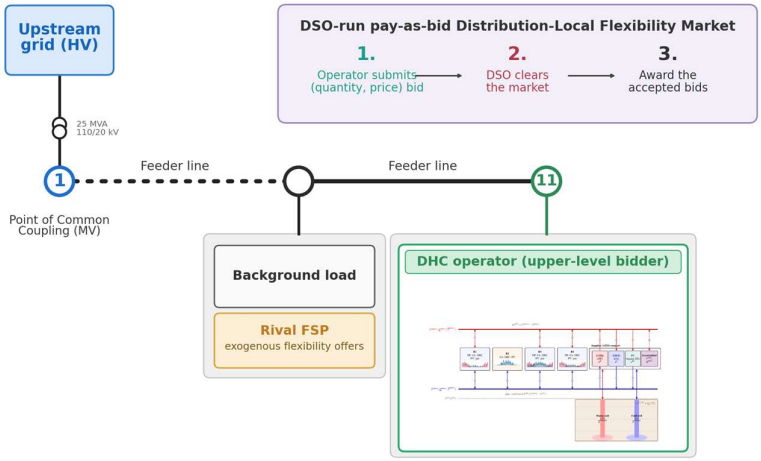


Figure 2-6: Schematic diagram of the thermal system connected to the CIGRE MV power grid

A 25 MVA transformer is never stressed by a 0.7 MW DHC at the use-case scale. Following standard practice with this benchmark, distributed PV and feeder loads are therefore rescaled so that the substation experiences realistic bidirectional congestion, midday PV export in the sunny seasons and evening heat-load import in winter. The distributed PV is driven by the day irradiance, so it naturally mimics seasonal patterns. The DSO congestion signal is a hard limit on the magnitude of the active-power flow at the substation root (node 1). The congested hours are relieved by procuring flexibility through a DSO-run market mechanism. Export-excess hours require downward flexibility (consume more or inject less), and import-excess hours require upward flexibility (consume less or inject more).

The operator competes with four rival FSPs located at nodes 4, 6, 8, and 9. Their aggregate flexibility capacity (approximately 760 kW in each direction) is deliberately sized to match the DHC's flexibility envelope (around 740 kW), thereby establishing a contestable market.

Although the building heat and cold demand and the photovoltaic generation are both held strictly fixed by the input time series, the operator's electricity consumption at any given hour is genuinely flexible. The same kilowatt-hour of delivered heating or cooling can be produced through several different channels, and the supplier-side plant can produce thermal energy more than the buildings demand and store it. We distinguish five complementary mechanisms:

- ***Building channel substitution for cooling.*** Each building's cooling load can be served either by its water-source compression chiller or by direct cooling through a heat exchanger on the cold pipe. The two channels deliver the same cooling but draw very different amounts of electricity, so re-routing the cooling between them changes the operator's grid offtake without changing the cold delivered.

- ***Building channel substitution for heating.*** Each building's heat load can be served either by its water-source heat pump or by an auxiliary gas boiler. Substituting heat pumps for the boiler raises electricity consumption (and lowers gas consumption) for the same heat delivered. The substitution is small on cooling-dominated days but is the dominant lever on heat-demand-dominated days.
- ***Supplier-side channel substitution.*** The central energy hub can run its ground-source heat pump, ground-source chiller and free-cooling channel independently to satisfy demand. Running the central chiller harder than the buildings need it is the largest single flexibility lever on cooling-dominated days, the excess cooling production is rejected into the warm aquifer well, charging the seasonal storage for later heating.
- ***Accumulator tank charging and discharging.*** The thermal accumulator tank can be charged or discharged at any chosen rate. Charging it requires the supplier plant or the building heat pumps to produce thermal energy beyond the demand. The stored energy is then released at a later hour, redistributing electricity consumption across the day.
- ***Photovoltaic self-consumption versus feed-in split.*** Photovoltaic generation can either offset the building's grid offtake (self-consumption) or be exported to the upstream grid at the grid tariff.

The bilevel optimisation chooses the cost-minimising combination of these five levers subject to the building thermal demand balances, the temperature-dependent coefficients of performance of the assets, the storage dynamics and the DSO market clearing.

2.2.4 General assumptions

The following assumptions have been made (along with the previous assumptions for the thermal network operation) to provide a trade-off between accuracy and the computational complexity of the model:

- 11-node radial medium-voltage feeder (CIGRE) with active-power (no reactive power) following LinDistFlow formulation.
- Aggregated operator-side capacity is below wholesale market access thresholds, and the analysis is therefore confined to the DLFM segment.

2.2.5 Main data inputs

Table 2-6: Main input data for BUC1b

Name	*Description*	*Units*	*Value or time-series*	*Reference years*	*Data source*	*ReInvent Common data (Yes/No)*
Network data	11-node CIGRE European MV benchmark	Ω/km	base-case radial data	-	CIGRE	NO
Flexibility market data	Competitive FSP bid shape; pay-as-bid clearing	€/kWh-kW	Down: 0.10/0.12/0.14/0.16, up: 0.11/0.13/0.15/0.17 €/kWh; caps 200/200/180/180 kW each direction	-	-	NO

2.2.6 Modelling scenarios

The following scenarios have been considered to have a clear view on the use case:

- Congestion at the 88th-percentile transformer cap, rival prices at their reference level.
    - Summer day (8 July). Peak-cooling day with strong midday PV, creating a high export mode for the power system, that the FSPs relieve with downward flexibility (consuming more).
    - Shoulder day (15 April). Balanced spring day with small two-directional congestion, served with a mix of up/down flexibility.
    - Winter day (15 January). Peak-heating day with little PV, creating an evening high import need that the FSPs relieve with upward flexibility (consuming less).

2.2.7 Results and analysis

This section presents the results of the simulation from two perspectives, operational and economic. Without a flexibility market, the operator schedules its plant and heat pumps purely to minimise its own energy bill, running them when electricity is cheap or when PV is plentiful and keeping the aquifer on its normal seasonal track. When it joins the DLFM, it shifts some of that operation to different hours, for example, running harder when the grid wants extra demand (downward flex, summer export hours), and softer when the grid wants relief (upward flex, winter import hours). The visible change is in the timing of the network's electricity use, not the total energy, and not the service to the buildings. The aquifer's state of charge drifts slightly from its normal track during the day but stays within its seasonal targets. The amount of the re-scheduling is modest, a small fraction of the day's operation, which is why it can be done without disturbing the core heat-and-cold business. Following are the analysis of each representative day operation.

On the summer day (8 July), midday solar surplus pushes power back toward the grid, and the DSO procures downward flexibility on the most-exporting hours. The DHC absorbs the surplus by running its chillers harder

(previously free cooling) to charge the warm aquifer well which leads also to the adverse effect of raising the CO2 emission. Also, this is the largest gross flexibility revenue (≈ €49/day). Most of the gross revenue is consumed by absorbing the export, since running the chillers harder forgoes PV feed-in.

The shoulder-season day (15 April) sits at the opposite extreme of the economic spectrum. Congestion is small and bidirectional, one import hour, two export hours, and the DHC handles it with intra-day levers (chiller and heat-pump re-routing and the accumulator) without changing the aquifer operation. Gross revenue is modest (≈ €15/day). The DHC covers almost the entire procurement need on its own which shows in the shoulders season the DHC can be a good source of flexibility for the power system.

On the winter day (15 January), the direction of flexibility needs changes. Evening heating demand strains the feeder in the import direction, and the DSO procures upward flexibility on the peak hours. The DHC eases off its heat pumps and draws on stored heat instead, supplying the upward award from accumulated thermal inventory and use gas boiler at some hours. Since the DHC provides upward flexibility, it consumes less electricity and its total thermal cost is slightly improved.

Taken together, the three days reveal that *gross* flexibility revenue scales with the size of the DSO's procurement need (largest in summer, smallest in shoulder), but *net* benefit is driven by whether the response can remain in the fast-lever envelope (no use of ATES), making the shoulder season the most profitable in margin terms, and the summer-peak day the most active but most expensive to serve (using ATES wells has a virtual price meaning the amount that it should drift from its optimal yearly operation to procure flexibility).

Table 2-7 summarizes the results on the main KPIs.

Table 2-7: Results on the main KPI of the BUC1b

Key Performance Indicator	Summer (8 Jul)		Shoulder (15 Apr)		Winter (15 Jan)	
	no-mkt	with mkt	no-mkt	with mkt	no-mkt	with mkt
Total cost for heat provision (€/day) (- net earner/+ net cost)	−248	−212 (36 worse)	−44	−39 (5 worse)	+119	+115 (4 better)
Primary energy, heat & cool (MWh/day)	0.32	0.52	1.79	1.86	1.66	1.67
Thermal cost per building TC·EV1·EV2·IncT (€/day)	−124/−48/−63/−30	−121/−42/−60/−29	−19/−52/−38/−2	−17/−51/−36/−1	+18/−12/+2/+25	+20/−12/+3/+26
Share of heat from local RES (%)	100	100	99.1	97.8	100	96.1
Available flex, offered & cleared (MWh/day)	0	0.29 (dn)	0	0.15 (mix)	0	0.10 (up)
Accepted flexibility (MWh/day)	0	0.29	0	0.15	0	0.10
Flexibility revenue (€/day)	0	49.4 (no gas used)	0	15.5 (without gas boiler = 10.1)	0	11.1 (without gas boiler = 7.1)
CO_2 emissions (kg/day)	21.9	35.9	128.8	141.0	114.7	128.1

2.2.8 Conclusions

BUC1b focuses on feasibility, identification, operation and economic assessment of participation of the 5GDHC network in a local flexibility market (LFM). Using mathematical optimization, the model provides insights in strategic bidding of a DHC network in an LFM. More precisely, the results show that from the operational perspective, on PV-export-dominated days, the downward-flexibility band is set by the ATES intra-day charge envelope and the accumulator rather than by device ratings (heat pumps or chiller). Expanding these storage systems would therefore widen the flexibility band. Whether a wider band translates into larger flexibility revenue, however, depends on the network congestion level and the market-clearing behaviour, which our results show is modest in net terms.

From an environmental perspective, although the flexibility market increases the DHC operator's revenue, it introduces a trade-off, as it can in some cases lead to higher CO_2 emissions by altering the operation of the thermal network. Whether by switching the chiller from free cooling to electric operation (thereby increasing electricity consumption) or by using gas boilers instead of heat pumps to provide upward flexibility, the result is a higher CO_2 KPI. Because the market compensates flexibility purely on the basis of volume shifted, the operator naturally selects the cheapest available lever, which can also be the most carbon intensive.

Economically, all representative days show positive revenue for the DHC operator, although the gains are small in some cases. However, an annual-scale revenue assessment, obtained by the representative-day analysis across a full calendar year (as done in BUC1a), would provide a clearer picture. The three-day framework used here serves as a building block chosen for computational tractability.

The results of BUC1b point to a natural next step. For a single campus, over three representative days and for one service, the flexibility of the 5GDHC network has a positive but modest market value, and the system design is fixed beforehand. Scaled to a large-scale district level thermal system, however, the network would exceed the minimum bid sizes of TSO balancing products and could stack revenues from local congestion management, balancing and wholesale markets. Since the main barrier to 5GDHC–ATES systems is their upfront investment rather than their operating cost, this raises a question worth investigating, that is, can the electricity system's need for flexibility finance part of that investment?

2.2.9 Recommendations

Table 2-8: Key recommendations for BUC 1b

Recommendations	
Technical	The accumulator tank size and the amount of water in the network extend the downward flexibility band during PV-export periods. This suggests a pathway toward district-scale thermal networks (e.g., at the neighbourhood level) and motivates further investigation of their flexibility revenue potential.
Socio-economic	It could be interesting to explore a mechanism that links flexibility remuneration to a carbon signal, so that the operator delivers flexibility using low-carbon sources rather than relying on its gas boiler.
Policy/regulatory	Given the demonstrated benefits of the thermal network across all scenarios, a new regulatory framework is needed to enable the participation of these energy systems (5GDHC) in flexibility markets.

2.3 BUC 2 - Integration of a Battery Energy Storage System in a REC

2.3.1 General Information

Test Case ID	*Name of Test Case*
4.1	Hybrid Energy Communities (Campina Energie)
Maturity of Test Case	
Realised in R&D	

ID	*Name of Business Use Case*
BUC 2	Collective, cross-sectoral business models for the integration of a Battery Energy Storage System (BESS) in a REC
Description and objectives - refer to Task 3.1	

Objective: To evaluate the effect of BESS on the risk and return of the portfolio of a Renewable Energy cooperative (REC).
Description: Campina Energie is a Belgian cooperative that owns renewable energy installations, e.g., PV systems in industrial, commercial, and governmental buildings (a school in this BUC). The business model of such RECs typically relies on pay-as-produced Power Purchase Agreements (PPAs) with local partners (schools) to maximise local renewable self-consumption and injection of the excess generations into the grid. In these arrangements, the REC is connected to the grid via its partner, which makes the partner responsible for any grid injection costs. With the current trend of increasingly low or even negative injection prices, grid injection can lead to financial losses for the REC's partner. While curtailing power output is a potential strategy to limit these costs, it undermines the REC's business model, which depends on continuous energy delivery under pay-as-produced PPAs. This BUC will therefore investigate whether using a BESS to minimise this curtailment by storing excess generation and to support financial returns through energy arbitrage can decrease risks and improve economic feasibility for the REC.

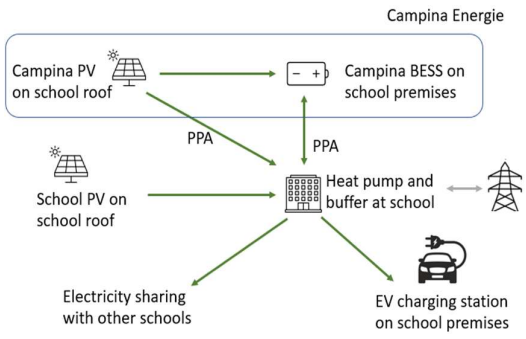


Figure 2-7: Schematic diagram of the REC



Figure 2-8: Picture of the test case site

2.3.2 Simulation tool

The simulation tool for the analysis is an optimisation framework which aims to minimise the community (or the individual member) electricity consumption costs over a rolling horizon, optimising daily energy usage over a 36-hour window with a resolution of fifteen minutes. The optimisation framework enables users to dynamically schedule energy offtake and injection to minimise daily electricity costs. The model runs iteratively for each day for a specific considered time horizon (e.g. one year).

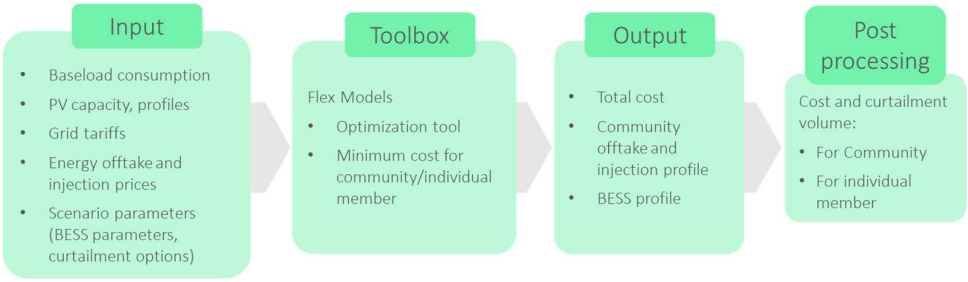


Figure 2-9: Overview of the optimization tool

The optimisation tool uses base load consumption data for community members, installed PV capacity and generation profiles, grid tariffs, retail prices for energy offtake and injection, and scenario-specific parameters such as the BESS parameters, PV curtailment options as input. The total cost over the considered period, the grid offtake schedule, the power exchange schedule within the community, and the BESS offtake and injection schedule are the output of the optimisation tool. In the post-processing phase, KPIs are calculated such as the total community cost, power curtailment levels, and BESS utilization.

The optimisation tool is formulated as a convex optimisation problem. It uses a linearised representation of the BESS (charge/discharge power, state-of-charge dynamics, and efficiency constraints) to maintain tractability while ensuring a convex solution space. This guarantees that the optimisation problem can be solved efficiently with standard solvers and that the solutions obtained are globally optimal.

2.3.3 Use case setup

The setup for the BUC analysis is shown in Figure 2-10. Campina Energie (the energy cooperative) owns a PV installation at the school premises and sells the power generation from this PV based on a pay-as-produced PPA. The school is connected to the grid and is responsible for power offtake from and injection into the grid. The school has its own PV installation as well.

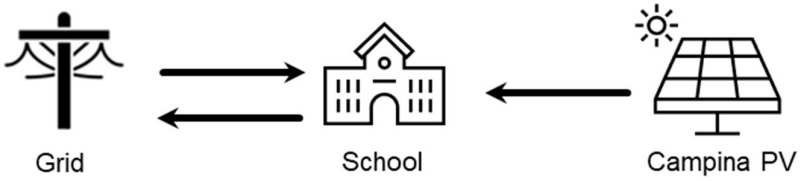


Figure 2-10: Use case setup

2.3.4 General assumptions

To assess the contribution of using a BESS to the financial stability of the considered energy cooperative the following assumptions are made:

- For the BUC, there is only one grid connection for the community, i.e., only the school is connected to the grid, and the TSO and DSO offtake and injection distribution grid tariffs are applicable for the net injection and offtake from the grid.
- A time-varying baseload profile derived from the historic consumption data is considered for the school.
- The community is subjected to time of use (ToU) prices for power offtake, and the injection prices are considered as dynamic (with consideration of day-ahead electricity market clearing prices for Belgium).
- The community PV generation follows the actual PV generation capacity factor for Belgium.
- The analysis is carried out for a time period from 10/11/2022 to 17/09/2024. For the considered time period, the injection prices (based on the day-ahead electricity prices) were negative for 5.98% of the time.

2.3.5 Main Data inputs

Table 2-9: Data inputs for BUC analysis

Data input	*Unit*	*Description and value*	*Source*
School power consumption profile	kWh	The actual time varying power consumption profile for school with 15 minutes time resolution.	Campina Energie
PV installed capacity	kWp	A peak capacity of 118kWp for PV at school and 117kWp for Campina Energie PV installation.	Campina Energie
Grid tariffs	€/kWh	The TSO and DSO power offtake and injection tariffs.	Campina Energie
	€/kWh/ month	The capacity tariff for monthly peak offtake from the grid.	Campina Energie
Electricity offtake retail price	€/kWh	The ToU electricity retail prices for power offtake from the grid.	Campina Energie
Grid injection retail price	€/kWh	The dynamic retail price for power injection into the grid.[1]	Campina Energie

[1] The grid injection prices are based on the day-ahead prices which are calculated with actual day-ahead prices in Belgium based on the formula provided by Campina Energie.

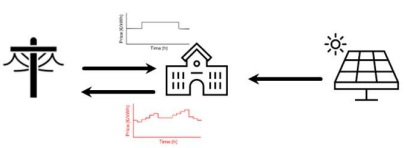
Community flow price	€/kWh	The price for power exchange amongst the community members	Campina Energie
BESS capacity	kWh	200kWh	Campina Energie
BESS efficiency	/	95%	Campina Energie
BESS charging /discharging rate	/	0,25	Campina Energie

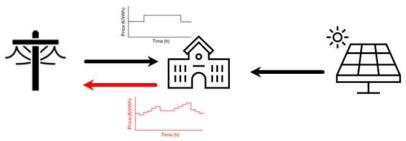
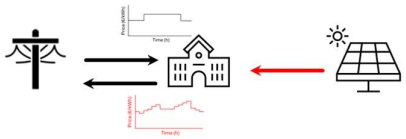
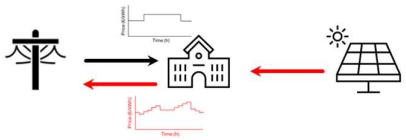
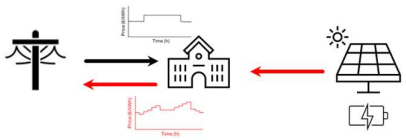
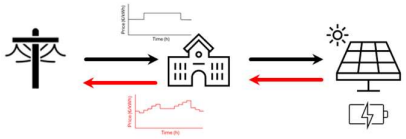
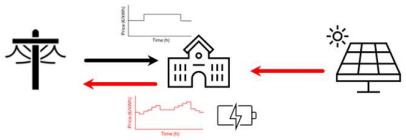
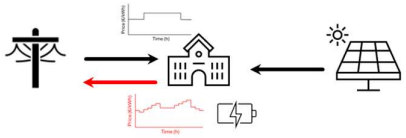
2.3.6 Modelling scenarios

In the considered community, various configurations for PV generation curtailment options and BESS ownership and operational control are possible. To ensure a comprehensive analysis, multiple scenarios encompassing these options are considered.

In the reference scenario (S1), it is assumed that the community does not curtail any power injections into the grid, regardless of the power injection prices. Scenario S2 considers the case where the school curtails its power injection based on electricity injection prices; however, it buys all the power generation from the energy cooperative. In Scenario S3, the school may choose not to take off power from the energy cooperative, leading the energy cooperative to curtail generation accordingly. Scenario S4 combines both options, allowing the school to curtail its own PV generation and to control offtake from the energy cooperative. Scenario S5 introduces a BESS operated by the energy cooperative, with curtailment allowed by both the energy cooperative and the school. However, the energy cooperative (and hence the BESS) is restricted from grid offtake and can only use the BESS to minimise its own curtailment. Scenario S6 extends this by permitting the school (and hence the BESS) to also offtake power from the grid. Thus, engaging in arbitrage via smart charging and discharging actions (which is also the case for scenarios S7 and S8). In Scenario S7, the BESS is operated by the school, and both the school and the energy cooperative may curtail power. Finally, in Scenario S8, the BESS is operated by the school, with the energy cooperative injecting power into the school as produced, without curtailment. Scenario S8 is considered to optimise the BESS operation and, at the same time, ensure that the energy cooperative does not face losses due to power curtailment. The overview of the considered scenarios is shown in Table 2-10. It should be noted here that power curtailment by the energy cooperative in the table below implies that the school does not buy the curtailed power from the energy cooperative.

Table 2-10: Scenario description for BUC analysis

Scenario Name	***Scenario Description***	***Diagram***
S1	The school buys all the power from the energy cooperative and always injects excess power into the grid i.e. there is no curtailment. This is the current setup and is considered as the **reference scenario.**	

Scenario Name	*Scenario Description*	*Diagram*
S2	The school buys all the power from the energy cooperative, however; injection of excess power into the grid is based on an optimization decision i.e. **the school can curtail**. The total curtailment by the school is the sum of its own PV generation curtailment and the curtailment of PV generation from the energy cooperative.	
S3	The **school does not purchase all the power from the energy cooperative** entailing power curtailment by the energy cooperative for the energy not purchased by the school. However, the school is not allowed to curtail its own PV generation.	
S4	The **school does not buy all the power from the energy cooperative** entailing power curtailment by the energy cooperative for the energy not purchased by the school. The **school can also curtail** its excess power generation from its **own PV installation**.	
S5	The **school does not buy all the power from the energy cooperative**, both the energy cooperative and the school can curtail. The **energy cooperative operates the BESS**; however, the energy cooperative cannot offtake from the grid and thus use the BESS for arbitrage.	
S6	The **school does not buy all the power from the energy cooperative**, both the energy cooperative and the school can curtail. The **energy cooperative operates the BESS and** can offtake from the grid and thus **use the BESS for arbitrage**.	
S7	The **school does not buy all the power from the energy cooperative**, both the energy cooperative and the school can curtail. The **school operates the BESS and** can offtake from the grid and thus **use the BESS for arbitrage.**	
S8	The **school buys all the power from the energy cooperative**, only the school can curtail. **The school operates the BESS** and can offtake from the grid and thus **use the BESS for arbitrage**.	

2.3.7 Results and analysis

In this section we will present the results of our BUC analysis. We first present an analysis of the potential of BESS on RES power curtailment and the total cost savings for the REC, comparing community-wide versus school-specific optimisation based on two main KPIs. Next, we examine the effects of payment provisions and negative prices on the BUC outcomes.

The impact of deploying the BESS on community financial returns is evaluated using a set of key performance indicators (KPIs). Each KPI is computed under two optimisation scopes: (i) community-level optimisation (referred to as **case-1** in the analysis below) and (ii) single-member optimisation (the school in this case and referred to as **case-2** in the analysis below). The following KPIs are considered: **RES power curtailment** and **Total cost savings**. In addition, for each KPI, we also show the percentage difference between the results of the considered scenario and the reference scenario (S1).

2.3.7.1 RES power curtailment

An increasing trend of negative electricity injection prices is expected in the coming years, meaning that (collective) consumers will have to pay to inject surplus renewable power into the grid. In such scenarios, power curtailment would be preferred. An alternative to power curtailment is to utilise a BESS to store the power which would otherwise be curtailed, hence reducing the RES power curtailment. In addition, a BESS can be deployed for price arbitrage, i.e. charging during periods of low electricity prices and discharging when the prices are high.

The analysis for the usefulness of BESS for the considered community in terms of RES power curtailment volume is shown as case-1 in Figure 2-11. As we move from S1 (reference scenario without any curtailment i.e. the current setting) to S4 (the curtailment decision is based on the economic gains), there is an increase in the volume of renewable power curtailed. These curtailment decisions reduce the cost for the school; however, they also lead to reduced revenue for the energy cooperative due to the pay-as-produced PPA. As we move to the scenarios with the availability of BESS, the curtailment volume decreases. It is observed that for S5, since no power offtake is allowed for the BESS operated by the energy cooperative, only the school experiences curtailment, with a volume similar to that of S4. As we move to S6, which allows the BESS to be used for power offtake (curtailed power from the school and from the grid), the curtailment volume further reduces. For S7, where the BESS is operated by the school, it can be seen that the energy cooperative curtails PV generation; however, the total curtailment volume is less than that of S6. Further, when the energy cooperative is not allowed to curtail in S8, the total curtailed volume is very small and is less than all of the previous scenarios with the curtailment option. The availability of BESS thus helps in reducing power curtailment.

The impact of the BESS operation by the school or the energy cooperative on the curtailment volume can also be seen in Figure 2-11. For case-1 and scenario S6, the BESS is operated by the energy cooperative, and curtailment is observed at the school. As there is a fixed cost for the community flow (equal for offtake and

injection), and at the same time, there is also a power loss due to BESS efficiency, it is not beneficial for the energy cooperative to charge the BESS with the excess power from the school, which results in curtailment at the school. Similarly, when the BESS is operated by the school in scenario S7, there is still some curtailment at the energy cooperative.

The scope of the optimisation also influences the curtailment volume as can be seen in Figure 2-11. Optimising for the school alone results in higher curtailment volumes for the energy cooperative; highlighting that the decisions optimised for one community participant might lead to adverse outcomes for the other community members. The findings also show that case-2 results in overall higher curtailment volumes (when curtailment is allowed for the energy cooperative) and as such optimisation for community will lead to lower overall RES power curtailment.

To quantify the percentage reduction in RES curtailment for case-1, the scenario S4, where both the school and the energy cooperative can curtail, is used as the reference scenario (since S1 allows no curtailment). With BESS, curtailment decreases by 68% in S5, 86% in S6, 97% in S7, and ≈100% in S8, relative to S4. These results indicate that deploying BESS substantially reduces the curtailment of RES generation (and, in S8, almost entirely). As such, scenario S8, when no curtailment is allowed at the energy cooperative, appears to be the most favourable scenario for minimising the power curtailment and maximising BESS utilisation.

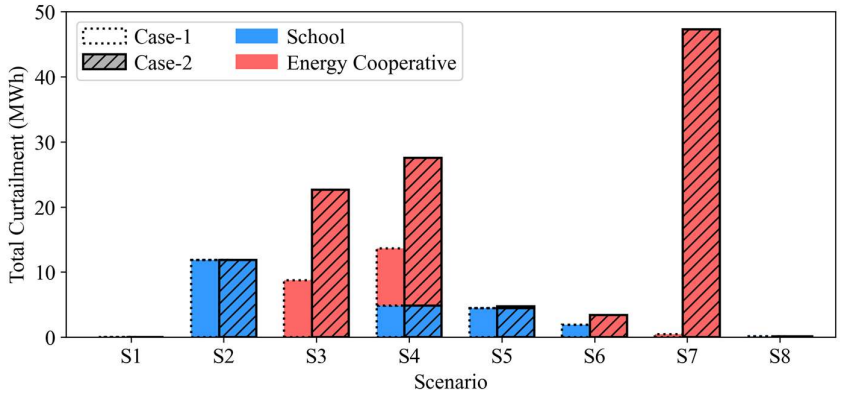


Figure 2-11: Total curtailment volume for different scenarios

2.3.7.2 Total cost savings

Figure 2-12 shows the variation in the net cost for the community for different scenarios. The availability of curtailment options (e.g. scenario S3 and S4) leads to a reduction in the school offtake cost and the net cost for the community. At the same time, the energy cooperative injection costs also decrease, implying a reduction in the energy cooperative's revenue. It can also be observed that for case-1 the availability of BESS, even without using it for arbitrage (i.e. no grid offtake), results in a substantial 8% (relative to S1) reduction in the net cost, as shown for S5 in Figure 2-12. Furthermore, using BESS for smart charging and discharging reduces the net cost by an additional 3%, as can be seen for scenario S6 in the figure. When the BESS is operated by the school in

scenario S7, the net cost reduces further by 12%. This reduction in the cost as compared to S6 is on account of a reduction in the curtailment volume (as shown in Figure 2-11) and the exclusion of BESS charging and discharging efficiency related costs. In S6, the BESS is operated by the energy cooperative so if the BESS is used for offtake from the grid or school (to minimize curtailment), the energy cooperative faces a net loss due to the difference in the BESS charging and discharging volume on account of BESS efficiency (the efficiency is 95%, hence there is a total loss of 10%) whereas this is not the case for S7 as the BESS is operated by the school. The scenario S8 leads to a marginal reduction in the total cost as compared to S7 as there is only a marginal increase in the power consumption from the energy cooperative installation.

There is very small difference in the net cost for case-2 and case-1 when the curtailment options are limited (as can be seen for scenarios S1 to S4 in Figure 2-12) and when the BESS is operated by the energy cooperative (in scenario S5 and S6). However, when the BESS is operated by the school (in scenario S7), there is a substantial difference in the net community cost between case-1 and case-2. This difference in the community cost arises from higher curtailment volumes for the energy cooperative (as shown in Figure 2-11) and hence lower revenue for the energy cooperative which hampers their business case and leads to underutilization of the produced renewable energy. Overall, for case-2, it is again seen that the use of BESS leads to a reduction in the net cost for power offtake for the community. A comparison of curtailment volume and net cost highlights the benefits of optimising for the school at the cost of a loss to the energy cooperative.

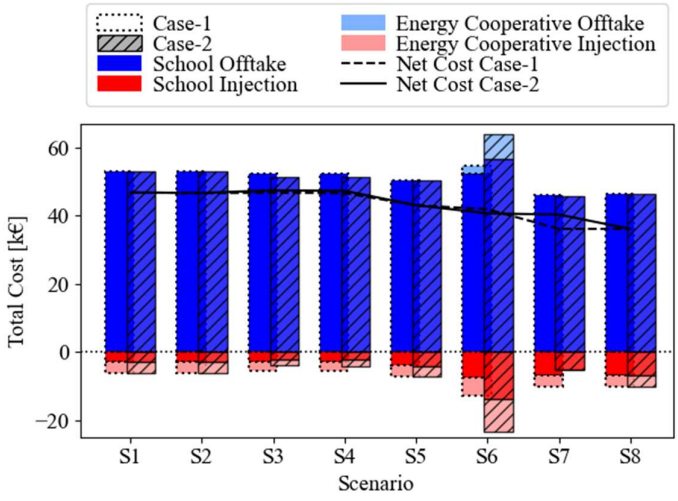


Figure 2-12: Variation of total cost for different scenarios

2.3.7.3 Supplementary analysis

In addition to the KPIs, the BUC study reports two supplementary analyses: (i) a sensitivity of total community cost to the number of hours with negative prices, with and without BESS, and (ii) the influence of payment provisions on net costs and the distribution of benefits among community members. The results are presented below.

2.3.7.3.1 Impact of negative prices

This section compares the expected cost of power injection into the grid for different levels of negative injection prices over a year. These results are based on an ex-post extrapolation. Table 2-11 presents grid power injection costs for the current setup (S1) and scenario S8 for case-1. For comparability, the S8 costs are calculated only for the time intervals in which grid injection incurred a cost to the community in S1. The results show that as the number of hours with negative prices increase the total cost of power injection into the grid also rises for S1. However, with the availability of BESS, this cost can be reduced as shown in Table 2-11 for scenario S8.

Table 2-11: Variation in cost with increasing number of hours with negative prices

	Hours with negative prices (%)			
	6	***10***	***15***	***20***
Scenario-S1 Cost [€]	979.89	1633.15	2449.72	3266.30
Scenario-S8 Cost [€]	12.63	21.05	31.57	42.10
Savings [€]	967.26	1612.10	2418.15	3224.20

2.3.7.3.2 Impact of payment provisions

In a tolling agreement, the asset owner (e.g., a power plant) grants a buyer or third party the right to control and operate the asset within the power system [5]. This concept is extended here to BESS operation in scenario S7, where the energy cooperative owns the BESS and the school operates it to minimise total community costs. A comparison of S6 and S7 shows that S7 lowers the community's total cost, indicating that a school-operated BESS can yield higher overall benefits. Moreover, as shown in Table 2-12 for scenarios S7 and S8, BESS utilisation increases when the school operates it. As such, in these cases, the tolling provisions enable a more efficient use of BESS capacity and can generate additional revenue for the BESS owner (subject to an agreement with the BESS operator). This aspect requires further investigation.

Table 2-12 : BESS usage for Case-1 in scenarios S5 to S8

Scenario	***S5***	***S6***	***S7***	***S8***
Total offtake (MWh)	35.44	68.5	132	132.88
Total injection (MWh)	31.98	61.82	119.13	119.93

Table 2-13 compares the impact of energy cooperative payment provisions for scenario S6. In the "grid tariff" case, the energy cooperative pays both grid offtake and injection tariffs for BESS smart charging and discharging. In the "no grid tariff" case, the cooperative pays only community-flow charges to the school, while the school bears the grid offtake and injection tariffs associated with BESS operations. As shown, the "no grid tariff" arrangement reduces net costs by 15.55% in Case-1 and 20.69% in Case-2 relative to "grid tariff" payment

provisions. This result highlights the need for a dedicated PPA for the smart charging and discharging of BESS in the S6 scenario setup to maximise community benefits and a fair distribution of benefits.

Table 2-13: Variation in costs for tolling provisions for scenario S6

Cost component [€]	Case – 1		Case – 2	
	Grid tariff	No grid tariff	Grid tariff	No grid tariff
School Offtake	50.09	52.22	51.69	56.72
School Injection	-2.35	-7.54	-3.33	-13.91
Energy cooperative Offtake	7.75	2.47	14.19	7.25
Energy cooperative Injection	-5.95	-5.32	-10.94	-9.43
Net Cost	49.53	41.83	51.61	40.63

2.3.8 Conclusions

The expected increase in negative electricity prices may incentivise (collective) consumers to curtail renewable energy generation, which could reduce the revenue of energy cooperatives, thereby weakening their business case and also leading to the underutilization of renewable energy. In such situations, the various stakeholders will likely seek to optimise their profits or minimise losses associated with power injection into the grid. The deployment of BESS can serve as a risk mitigation strategy against these anticipated curtailments and act as an effective countermeasure.

This study demonstrates the benefits of optimising energy management at the community level rather than for a single stakeholder (in this case, the school). Using actual load and PV generation profiles, it is shown that community-level optimisation yields better overall outcomes in terms of net costs and total curtailment volumes compared to school-specific optimisation. The study also examines the influence of the BESS operator (through a tolling arrangement) on BESS usage and overall system costs. The analysis further highlights the savings with the usage of BESS systems on account of an increase in the number of hours with negative electricity prices.

Overall, the analysis presented in this study concludes that BESS will play a crucial role in enabling the cost-optimal utilisation of renewable energy sources owned by energy cooperatives.

2.3.9 Recommendations

Table 2-14: Key recommendations for BUC 2

Recommendations	
Technical	A detailed optimization model considering the cyclical constraints of the BESS should be developed to ensure the accurate inclusion of BESS constraints.
Socio-economic	The use of BESS is recommended for a reduction in the power consumption costs and the optimal use of available RES generation.
Policy/regulatory	Further study focusing on the tolling model for BESS operations, examining its implications under different PPA structures is required.

2.4 BUC 3 a/b - Social charging shared EVs

2.4.1 General information

Test Case ID	*Name of Test Case*
4.2	Social charging shared EVs
Maturity of Test Case	
The solar installations are installed throughout the neighbourhood of Otterbeek and are thus in business operation. Setup of local shared EVs and charge infrastructure is realised in R&D.	

ID	*Name of Business Use Case*
BUC 3a/b	Collective, cross-sectoral business models for car sharing in an Energy Community consisting of social housing
Short description and objectives	

Klimaan has 741 kW of domestic solar PV installations in the Otterbeek social housing district in Mechelen, Belgium. A total of 197 households were equipped with solar PV systems, maximizing the use of available roof space and resulting in a significant amount of excess solar generation.
BUC 3A: This use case aims to optimize the local self-consumption of excess solar power by installing charging infrastructures and coupling it with shared EVs within an energy community. The intention is to increase the value of solar power production, optimise the OPEX of the EVs, and as such lower both the electricity and mobility costs for end-users in a specific social context.
BUC 3B: In addition, an extension of the use case aims to assess the potential of external services provision to other actors (e.g., Balancing Responsible Parties (BRPs), Transmission/Distribution System Operators (T/DSOs)). For example, dynamically charging the EVs based on local distribution network conditions and DSO pricing impulses could add additional value to this business use case, providing further benefits for the whole system (social housing, shared mobility provider/operator, DSO).

Objectives:

- To optimize the valorisation of excess PV production using a shared EV as a mobile storage device.
- To translate this optimized business model to an optimal social sharing tariff for EV charging.

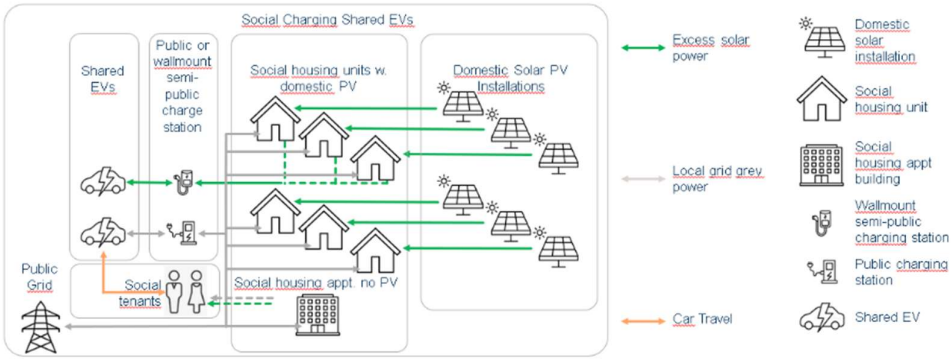


Figure 2-13: Diagram of the main energy flows within BUC 3.

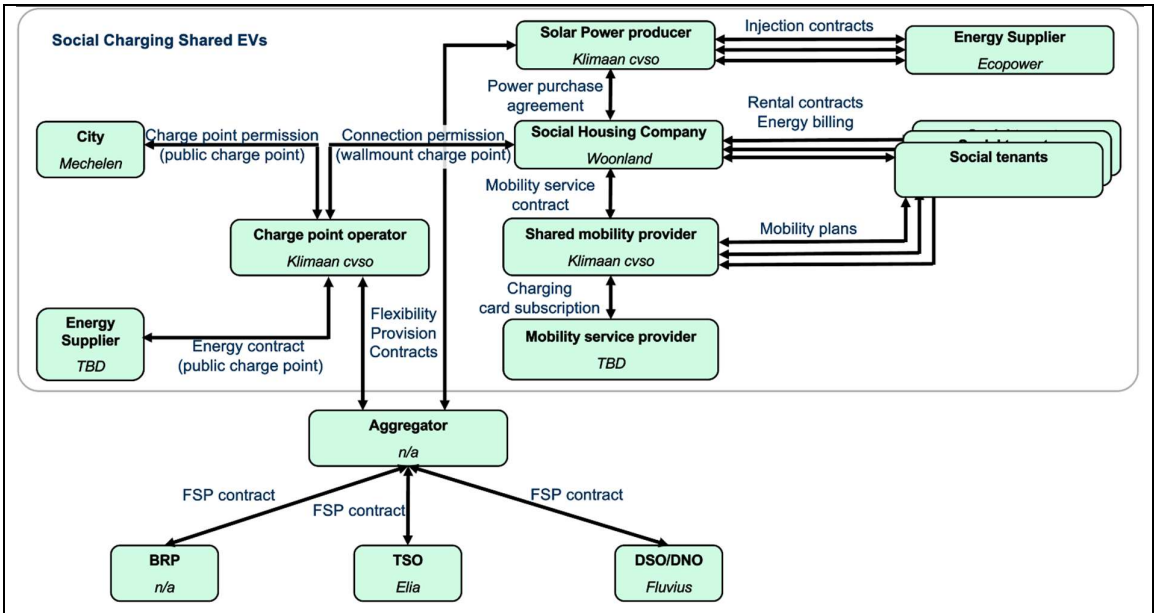


Figure 2-14: Contractual relations between actors in the Shared Mobility Provision framework

2.4.2 Simulation tool

The contractual relations depicted in Figure 2-14, are simplified within the modelling framework and presented in Figure 2-15. The considered framework models the coordination between a Shared Mobility Operator (SMO) and a Renewable Energy Community (REC), enabling the mobility operator to value the excess solar production of the community and thereby reduce EV charging costs. The REC is a residential community composed of social tenants, equipped with rooftop PV generation and connected to the distribution network through a single point of common coupling (PCC), through which electricity is imported from or exported to a common retailer. The SMO, representing Klimaan in this case, is a single entity encompassing three complementary roles: a Charge Point Operator responsible for the EV charging infrastructure, a Shared Mobility Provider managing the shared electric vehicle fleet, and a Mobility Service Provider offering charging access to EV users. For the sake of clarity and conciseness, these entities are aggregated and referred as the Shared Mobility Operator or SMO in this work. The fleet is charged through dedicated infrastructure located at the PCC, under the full operational responsibility of the SMO, making it a new electricity consumer whose charging decisions are directly impacting the community's energy balance. Finally, different peak tariff mechanisms can be applied by the DSO, which could further enhance the flexibility potential of the shared fleet, unlocking additional benefits for all actors involved.

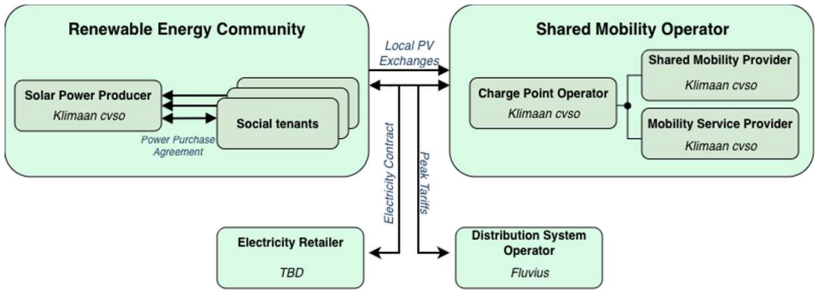


Figure 2-15: Contractual relations in the joint model for the coordination of a SMO and a social REC.

The simulation tool developed to assess the operational synergies between the REC and the SMO . consists in an original Mixed-Integer Linear Programming (MILP) optimization problem, which jointly minimises the total costs over a one-year horizon, considering a 15-minute timesteps and solved iteratively on a weekly basis. The optimization problem can be formulated, in general terms, as:

$$\min_{\Omega} C^{SMO} + C^{EC}$$

$$\begin{aligned} s.t. \quad & Power\ Balance\ and\ PV\ Constraints \\ & Ride - EV\ Assignment\ Constraints \\ & EV\ and\ CS\ Operational\ Constraints \end{aligned}$$

Specifically, the optimization problem minimises the sum of the costs associated to the REC, C^{EC}, and the SMO, C^{SMO}. The community bill is composed of the retailer electricity import costs and the PV export revenues. The SMO's bill captures the electricity purchase to charge the EV (at the local charging station or during the trip) and a virtual cost for unserved mobility request. Indeed, the SMO has the opportunity to not serve a mobility request when it is deemed not profitable, or if overlaps occur.

This optimization problem is subject to three categories of constraints: community-level *Power Balance* at PCC linking retailer exchanges and physical power flows, i.e., PV production (with curtailment allowed), EC loads, and EV charging power; *ride-EV assignment constraints* ensuring coherent EV assignment to the mobility demand; *EV and CS operational constraints* modelling state-of-charge dynamics and power limits of the fleet.

The model aims to determine the optimal decisions Ω, which includes retailer import and export flows, PV production, binary EV-ride assignment decisions, binary EV state (*i.e.,* either if the EV is at the charging station or on the road), EV charging profiles, EV state-of-charge, and energy charged during rides.

2.4.3 Use case setup

The setup for the BUC analysis is based on the Otterbeek social district case. Specifically, we consider 20 households among which 10 members have access to a total of 97 kW rooftop PV capacity. The aggregated yearly consumption of the social tenants is 55 MWh.

2.4.4 General Assumptions

To assess the operational synergies between EC and SMO, the following assumptions are made:

1. A perfect foresight regarding the members' load profiles and mobility demand requests;
2. The shared EV must be charged at least at 70% before serving a ride;
3. We don't consider battery degradation costs and losses for EV charging;
4. The SMO must bear the EV charging costs during a ride (0,45 €/kWh), which is 125% of the highest retailer import price;
5. A virtual opportunity cost is applied when a mobility request is not served (2 €/kWh);
6. The retailer electricity price for import and export is dynamic and equal for all members. The local PV exchange (PV surplus sold by the REC to the SMO) is set halfway between the retailer import and export prices (i.e., *0.5*(import+export)*). For all imported volumes an additional 0.099€/kWh is considered for the distribution and transportation cost.

2.4.5 Main Data inputs

Regarding the mobility demand, this study relies on a real historical dataset, provided by Klimaan. This dataset contains around 7600 recorded trips and 4500 charging events from a fleet of 35 shared EVs. Built on this dataset, scenarios of specific mobility demand of shared vehicles are obtained for the case study and further presented in 0. In addition, the following table (Table 2-15) details the main inputs required for the simulation.

Table 2-15: Main Data Inputs for BUC 3 a/b

Name	*Description*	*Units*	*Value or time-series*	*Reference years*	*Data source*	*ReInvent Common data (Yes/No)*
Fleet of EVs	EV technical parameters (maximum charging power and battery capacity).	kW, kWh	Set of values	2025	Klimaan	No
Charging Stations	Maximum power of charge.	kW	Set of values	2022	Klimaan	No
Mobility Demand	Associated requests of the concerned area. The mobility demand is a set of predefined requests, composed of departure/arrival times, and battery consumption for each trip.	Timestep, kWh	Time-series	2024-2025	Klimaan	No
Load and PV profiles	Power profiles for the social tenants' consumptions and PV production.	kW	Time-series	2025	Fluvius/ Klimaan/V ITO	No
Electricity Prices	Dynamic electricity prices (import and export).	€/kWh	Time-series	2025	Belpex	Yes

2.4.6 Modelling scenarios

To assess the benefits arising from the coordination between the SMO and the EC, the simulation tool is evaluated across a set of scenarios depending on the operational coordination of both actors, the level of EV integration, and the electricity tariff mechanism considered.

Regarding EV integration, two stages are considered to reflect the progressive adoption of shared mobility within the community: the **early stage** and the **maturity stage**. In the early stage, the EV usage is often sub-optimal as adoption still needs to grow. Once the SMO has gained sufficient visibility of the new mobility service, or that there is a shift in inhabitants' habits, it enters the maturity phase. In this study, two cars covering a two-year period (from July 2023 to July 2025) are extracted from the whole fleet. The first year represents the early stage and the second year the maturity stage. Figure 2-16 shows that the long-term adoption trend of those cars (in red) follows the general dynamic (in blue) with a lower travelled distance during the early stage and a slightly higher level in the maturity usage. In terms of technical properties, the extracted EV are a *Renault ZOE* and an *Opel Corsa*, with battery capacities of 50kWh. In addition, one deposit charging station is considered in this study with a maximum power charge (and discharge) of 11kW.

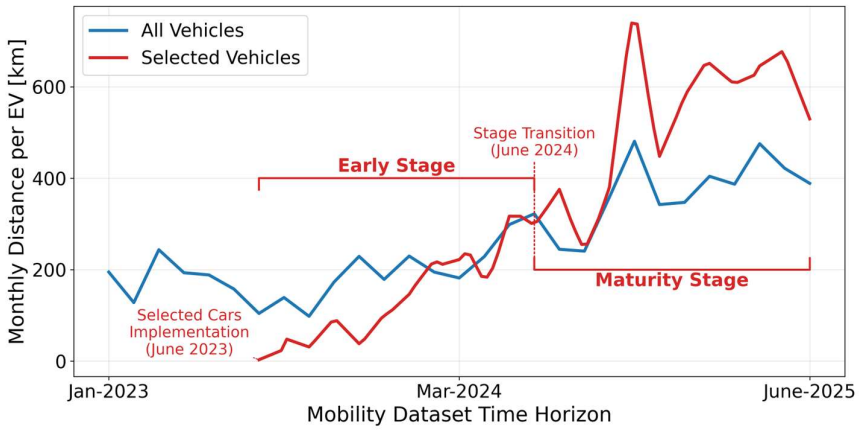


Figure 2-16: Monthly distance travelled by the shared vehicles.

Regarding coordination, two operational configurations are considered. In the standalone baseline, the EC and the SMO optimise their respective operations independently, without any collaboration: the EC minimises its electricity costs while the SMO minimises its mobility service costs. In the coordinated configuration, both actors are jointly optimised within the unified MILP framework, allowing the EV charging schedule to respond to the EC's load and PV production dynamics.

Finally, within the coordinated framework, three tariff mechanisms are further examined: a volumetric tariff without peak incentive, an individual capacity tariff penalising each actor's peak independently, and a collective capacity tariff penalising the aggregate community peak at the transformer substation. These mechanisms are presented in Figure 2-17.

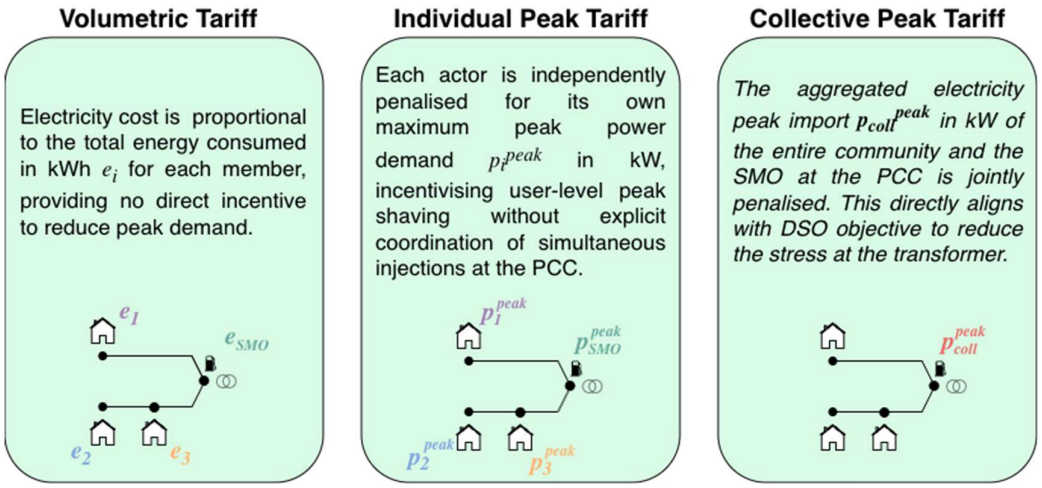


Figure 2-17: Electricity Import Tariff Mechanisms.

Considering both integration phases of the introduced EV, the ability of the SMO and the REC to collaborate, and the different tariff mechanisms, Table 2-16 summarizes all the scenarios considered in this work.

Table 2-16: Scenarios considered for BUC3 a/b depending on the EV integration phase, the coordination status between EC and SMO, and tariff mechanisms.

Scenarios	*EV Integration Phase*	*EC-SMO interactions*	*Tariff*
S1	Early Phase	Standalone	Volumetric
S2	Early Phase	Coordinated	Volumetric
S3	Maturity Phase	Standalone	Volumetric
S4	Maturity Phase	Coordinated	Volumetric
S5	Early Phase	Coordinated	Individual Peak
S6	Early Phase	Coordinated	Collective Peak
S7	Maturity Phase	Coordinated	Individual Peak
S8	Maturity Phase	Coordinated	Collective Peak

2.4.7 Results and analysis

This section summarizes the main results of this work and is divided into two aspects. While Section 2.4.7.1focuses on the economic performance of the REC-SMO coordination (Scenarios S1 to S4), Section 2.4.7.2 extends the analysis by quantifying technical impacts on the local network for S5 to S8 scenarios: with individual or collective DSO peak tariffs.

2.4.7.1 Coordination creates Economic Benefits

The REC-SMO coordination yields to mutual economic benefits. However, these benefits will progressively increase as the shared EVs are adopted by end-users. Indeed, in the early phase, the coordinated model achieves

a 7% reduction in the total costs (SMO and REC aggregated bills) compared to stand-alone configuration, decreasing the bill from 2,531€ to 2,354€. Then, when entering the maturity phase, the joint objective is 3,470€, representing a 15.66% reduction compared to the combined stand-alone costs, 4,115 €. These results highlight that cost reductions are driven by the increase in local self-consumption under the coordinated scheme which is directly linked to the mobility demand volume. This limits the coordination advantage in early stage with low mobility demand. The coordinated model bill reduction brings slight reduction of the average electricity price to cover EC members consumption and the average mobility service fee compared to stand-alone model, from 0.035 to 0.031 €/kWh, and from 0.10 to 0.072 €/km.

REC–SMO coordination reduces total system costs by 7% in the early stage and 15.6% at maturity integration compared to the standalone configurations. The complementarity benefits are driven by increased local PV self-consumption and thus limited by the shared mobility demand: the more the EV are used, the more the SMO can benefit from local electricity surplus and reduce its bill.

2.4.7.2 Technical Impacts of Peak Tariffs

This section evaluates the stress on the substation transformer considering that all 20 households and the SMO are connected behind the same substation. The analysis considers first the results obtained in the previous section with only volumetric DSO cost (S4 and S2). Subsequently, to reduce the degradation of the transformer at the substation, a DSO capacity tariff charged on the maximum power load is considered. The cost charged by the DSO is added to the global bill, with a peak power price of 59€/kW/year. In this case study different tariff options naturally arises when considering the REC-SMO coordination. In the REC framework, the DSO may either charge individual import peak power, or collective peak power, as already shown on Figure 2-17. Table 2-17 presents the active power import peaks for the SMO, the maximum peak over EC members, the aggregate peak observed at the PCC for the three tariff structures, and the total objective of the optimization program defined before, which represents the total costs of the SMO and the REC.

Table 2-17: Grid Performance Indicators (kW) and Objective Functions (€) by Tariff Structure.

	Early Stage				Maturity Stage			
	SMO Peak	User Peak	Agg. Peak	Obj.	SMO Peak	User Peak	Agg. Peak	Obj.
Volumetric	11	9.11	24.11	2353	11	9.11	26.92	3470
Individual	7.02	6.77	22.71	5775	11.00	6.77	26.74	7110
Collective	11.00	9.11	18.62	3205	11.00	9.12	18.62	4347

By leveraging the combined flexibility of the EVs and residential loads, the collective peak tariff reduces the aggregated peak power by 22.8% and 30.8% in early and maturity stages, respectively. The resulting peak cost

to achieve this grid relief are 826.74€ and 837.20€, representing 25.79% and 19.25% of the total objective. On the contrary, while offering lower individual peak but higher energy imports, the individual tariff charges a substantially higher peak cost of 3196.86€ and 3361.32€, reflecting the penalization of all 21 actors independently. Because the charge of the EV is low relative to the EC consumption, the individual tariff is the only mechanism able to reduce the peak at the CS through a direct constraint at the EV charge and not on the REC-SMO load aggregation. However, it decreases local energy exchanges by 2%.

To further increase the flexibility potential of the coordination scheme (and economic performances), other technologies were also assessed during the study: Vehicle-to-Grid (V2G) capability of the EVs and stationary Battery Energy Storage System (BESS). With the collective capacity tariff, these models further decrease the total objectives across both stages, driven primarily by their ability to absorb peak demand through storage rather than only load shifting. The early phase exhibits significantly higher flexibility potential compared to the maturity phase. In the latter, higher mobility demand reduces the EV availability, thus shrinking the windows where the EV can act as a stationary battery. While the BESS offers a lower objective, the V2G allows to reduce the stress at the transformer.

The collective peak tariff achieves the greatest stress relief on the substation transformer by jointly penalising aggregated REC-SMO import, while individual tariffs more effectively decrease EV charging peaks. The flexibility potential of the shared fleet is higher at the early stage of the EV integration since it is less limited by mobility usage, and the SMO has a larger window to charge the EVs.

2.4.8 Conclusions

This work demonstrates the economic and technical synergies arising from the coordinated operation of an EC and a SMO. Key findings show that these benefits depend on the EV integration stage: while early-stage deployment enables flexible grid support through longer station-connected periods, the maturity stage generates greater mutual economic benefit through higher local consumption charging volumes. These findings underscore the importance of jointly optimising operational decisions of both actors and point toward a natural extension: incorporating joint investment planning to capture long-term synergies in infrastructure sizing and tariff design. As the magnitude of the identified benefits remains highly sensitive to the local PV generation, load profiles, and mobility demand patterns, future work should assess the sensitivities of these synergies as well across a larger range of EC configurations.

2.4.9 Recommendations

Table 2-18: Key recommendations for BUC 3

Recommendations	
Technical	The shared vehicle fleet can provide flexibility to help DSOs reduce stress at the transformer, especially when a new EV is integrated and the mobility demand is low. Introducing EV with V2G capability can further improve the flexibility potential of the fleet and should be further incentivized.
Socio-economic	The coordination of REC and SMO generates mutual benefits. However, an important aspect to consider is the repartition of these profits, especially in the context of social tenants. Studies on fair benefit sharing mechanisms between community members and the mobility operator should be conducted.
	In addition, considering the social housing framework where tenants have limited capital and risk tolerance, co-investment schemes and incentives are needed to mitigate the investment costs of PV, charging infrastructures, etc. Without this, the identified synergies remain inaccessible to most vulnerable households.
Policy/regulatory	Despite the system-level benefits identified, per-member savings remain modest and may be offset by additional yearly fees for the user to participate in an EC (often charged by retailers), raising concerns about the fairness for smaller participants, and especially vulnerable customers.
	A key finding of this study is the better performance of the collective peak tariff from both a technical and social perspective: it achieves the lowest aggregate load peak, while simultaneously reducing the total bill.

2.5 BUC 4 - Collective Offshore Wind Integration through Battery Storage

2.5.1 General information

Test Case ID	*Name of Test Case*
4.3	Hybrid Energy Communities (SeaCoop)
Maturity of Test Case	
In business operation.	

ID	*Name of Business Use Case*
BUC 4	Integration of collectively owned offshore wind energy production in the electricity grid, by means of demand side management at the REC level and the **use of a large-scale battery**
Short description and objectives	
SeaCoop aims to connect the electricity production from an offshore wind farm with the electricity demand of many households in Belgium, united in a Renewable Energy Community (REC). In the supply chain, from sea to socket, profiling and balancing risks have to be tackled in a cost-effective way. **Profiling costs** arise from differences between the wind production forecast and the baseload profile, while **imbalance costs** occur when actual wind production deviates from the forecast, with both costs influenced by increased renewable energy in the grid and creating opportunities for flexibility providers. This BUC investigates the impact of adding a large-scale battery on reducing the profiling and imbalance costs associated with offshore wind production in relation to residential consumption profiles. The **overall objective** is thus to evaluate the business case of a large-scale battery at the REC-level to mitigate profiling and imbalance costs of offshore wind production	

2.5.2 Simulation tool

Figure 2-18 summarizes and depicts the simulation tool developed for this BUC. The tool is technically an optimization engine that simulates optimal day-ahead bidding and battery scheduling for an energy producer, assuming that the producer is a price taker in the day-ahead market, i.e., its bids do not influence cleared prices. This simulation tool requires the forecast and realization profiles of the renewable generation and the loads for a given simulation period. Similarly, cleared day-ahead market and imbalance prices for the simulated period are also needed as input. Additionally, this tool is capable of taking into account the risk aversion level of the energy producer. In this case, price scenarios must be generated and considered as additional input.

In the most general setting, the developed optimization engine solves a risk-aware optimization problem for simultaneously setting the bid quantity in the day-ahead market and the schedule of a battery. To this end, the profiling and imbalance cost functions are considered as the objective of the optimization problem, taking into account cleared day-ahead market and imbalance prices as parameters. Furthermore, the generation and load forecasts are used to determine balancing constraints for the day-ahead market bidding, and together with the generation and load realization profiles, they are used to define imbalance constraints. The battery dynamics

and operational constraints are also included in the optimization model, and thus, they allow for strategic bidding in the day-ahead market as well as adjustment of imbalances. The optimization engine can operate in two modes, namely deterministic and risk-aware. In the former, the day-ahead market and imbalance prices are assumed to be perfectly known. In the latter, imbalance prices are not known and are assumed to be uncertain. To cope with the uncertainties, stochastic optimization is used, where the objective functions are considered in expectation and require the generation of a set of (imbalance) price scenarios. Additionally, the risk appetite of the producer is also considered through the conditional value at risk, which quantifies the expected loss at the tail probability or worst-case scenarios. It is integrated as an additional objective function and constraints. This simulation tool is then run to compute daily optimal bidding strategies and battery schedules for the entire simulated period, resulting in optimal expected profiling and imbalance costs, as well as optimal battery schedules.

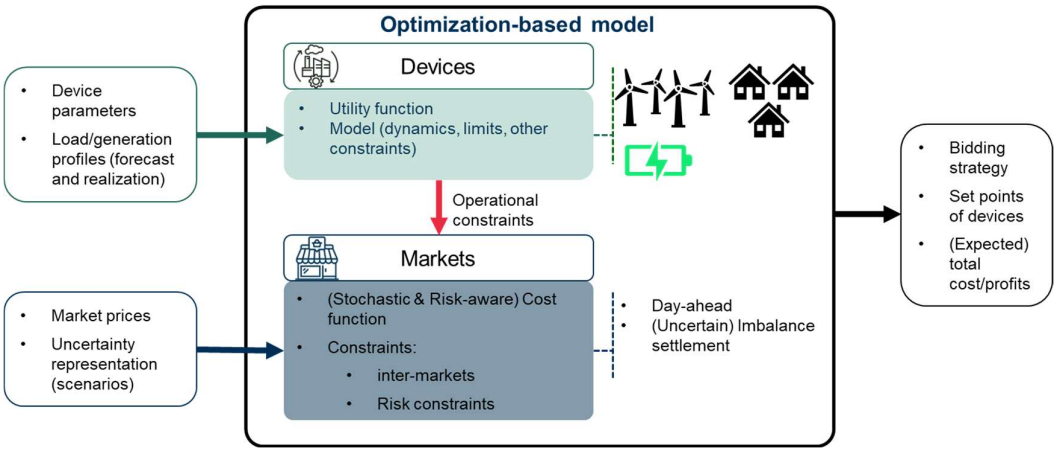


Figure 2-18: Modelling environment for optimal day-ahead bidding and battery use of the REC

2.5.3 Use case setup

This BUC considers a wind farm with a capacity of 70 MW. The total wind generation from this wind farm is 280 GWh annually. Thus, an equal amount of annual load is considered. Nevertheless, the generation and load profiles do not match; thus, the discrepancy in the day-ahead forecasts must be met from the day-ahead market (profiling cost), while the discrepancy between the forecasts and realization must be dealt with an imbalance settlement process. While this is considered business-as-usual (BAU), the wind-based producer also considers investing in batteries to deal with these profiling and imbalance costs. To assess the business case of integrating a large-scale battery, a quantitative analysis is conducted by using the developed simulation tool and comparing the BAU with cases where a battery is installed and can be used strategically. The simulations are carried out based on historical data of 2 years (2023-2024).

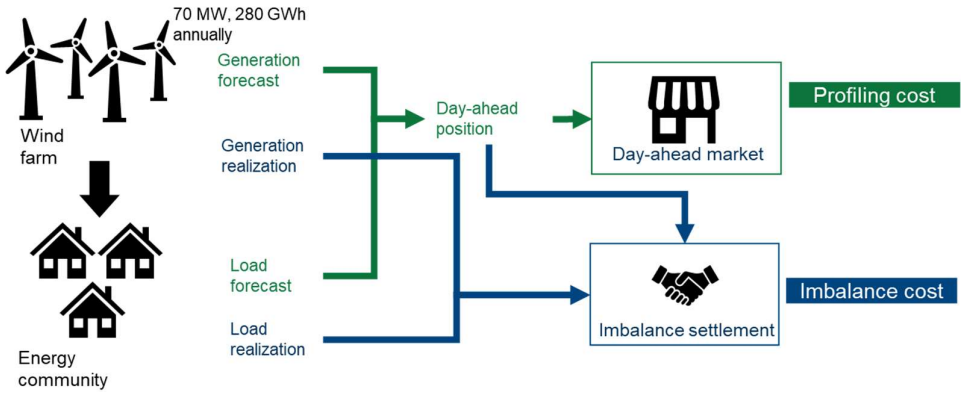


Figure 2-19*: The profiling and imbalance costs of the REC*

2.5.4 General Assumptions

The following assumptions are made:

- Historical day-ahead and imbalance price data are used for the BUC analysis. The optimization engine uses this data as parameters in the cost function, assuming complete information when optimizing the day-ahead bid and battery schedule. When the tool considers a risk aversion level, only the imbalance prices, which are more volatile than the day-ahead cleared prices, are assumed to be uncertain.
- Similarly, historical data of day-ahead forecasts and realizations of generation and load are used.
- The dynamics of the battery are modelled as a linear discrete-time system, which is widely acceptable for quarter-hourly operation settings. The battery is sized according to the daily load and generation, i.e., the capacity is 10 MWh with charging/discharging rate of 3 MW.
- The imbalance price scenarios used by the risk-aware optimization engine are obtained by fitting a student-t probability distribution function[2] for each time step of a day based on the historical imbalance price data and then generating the price scenario by sampling from these distributions.
- The CAPEX of the battery is 270 Euro/kWh and the OPEX of the battery is 2700 Euro/year. We assume that the battery has 15 years of lifetime.

[2] *As observed from the historical data and supported by [22], the student-t distribution function is a better option than a normal distribution function for this imbalance price modelling.*

2.5.5 Main Data inputs

Table 2-19: Main Data inputs for BUC 4

Name	*Description*	*Units*	*Value or time-series*	*Reference years*	*Data source*	*ReInvent Common data (Yes/No)*
Day-ahead prices	Cleared prices from the day-ahead market	Euro	Time series	2023-2024	EPEX	Yes
Imbalance prices	Imbalance prices	Euro	Time series	2023-2024	ELIA	Yes
Generation forecast profiles	Day-ahead forecast of normalized generation profiles	MW	Time series	2023-2024	SEACoop	No
Generation realization profiles	Normalized generation realization profiles	MW	Time series	2023-2024	SEACoop	No
Load forecast profiles	Day-ahead forecast of normalized load profiles	MW	Time series	2023-2024	SEACoop	No
Load realization profiles	Normalized load realization profiles	MW	Time series	2023-2024	SEACoop	No
Battery capacity	The capacity of the battery	MWh	Value	2024	SEACoop	No
Charging/discharging rate of battery	The rates of charging and discharging of the battery	MW	Value	2024	SEACoop	No
CAPEX of Battery	The capital expense of the battery	Euro	Value	2024	SEACoop	No
OPEX of Battery	The operational expense of the battery	Euro/year	Value	2024	SEACoop	No
Battery lifetime	The expected lifetime of the battery	years	Value	2024	SEACoop	No

2.5.6 Modelling scenarios

The analysis is conducted considering the BAU scenario and two options of using the battery, depicted in Figure 2-20, as follows:

1. **Option 1 (Imbalance only):** The battery is used only to optimize the imbalance costs. The day-ahead bids, which result in the profiling costs, are calculated based on the day-ahead forecasts of generation and load, as in the scenario BAU.
2. **Option 2 (DA & Imbalance):** The battery is used to simultaneously optimize the profiling and imbalance costs.

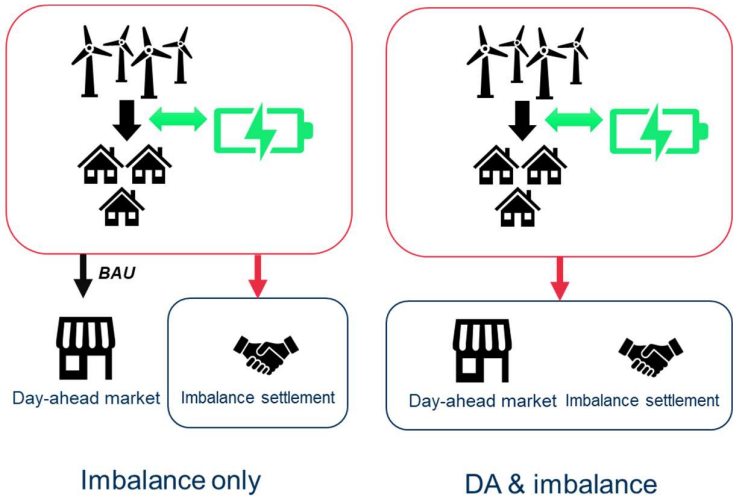


Figure 2-20: Two options for leveraging the battery.

In any of the options, on each day, the previously discussed optimization problem is solved to obtain an optimal bid for the day-ahead market as well as the battery schedule for that day. The time horizon of this daily optimization for computing the day-ahead bidding strategies and battery schedule is 36 hours, which allows for a battery schedule that anticipates the load and generation in the next day. Nevertheless, the rolling horizon principle is adopted, i.e., only the schedule of that day (the first 24 hours) is considered, while that of the remaining 12 hours is discarded, as another optimization problem that covers these hours will be solved at the beginning of the next day. Furthermore, regardless of the option, two price scenarios and a theoretical bound scenario are considered, namely:

1. **Theoretical bound scenario:** the perfect forecast scenario. Both day-ahead and imbalance prices are known parameters in the daily optimization problem. This scenario provides the theoretical bound of performance as it assumes perfect foresight of all prices, which is unrealistic in practice.
2. **Scenario 2:** the stochastic and *risk-neutral* scenario. The imbalance prices are not known and assumed to be stochastic. In this scenario, the expected imbalance cost function is minimized.
3. **Scenario 3:** the stochastic and *risk-averse* scenario. The imbalance prices are not known and assumed to be stochastic, as in scenario 2. However, a risk measure, namely the conditional value-at-risk (cVAR), is added to the objective of the daily optimization and is minimized.

2.5.7 Results and analysis

This section reports and critically discusses the outcomes of the numerical simulations. We first decompose the economic performance into (i) profiling costs (day-ahead positioning driven by forecast mismatches) and (ii) imbalance settlement costs (driven by deviations between forecast and realization). Results are presented for the BAU benchmark and for the two battery-operation options under the three price-information settings (risk-averse, risk-neutral, and theoretical bound). Finally, we translate the operational cost reductions into net annual savings by explicitly accounting for battery investment costs.

2.5.7.1 Costs analysis

Figure 2-21 compares the annual average profiling costs across BAU and the two battery-operation options for all scenarios. As expected, Option 1 (Imbalance only) reproduces the BAU profiling cost in every scenario because the day-ahead position is determined solely from the day-ahead forecasts of generation and load, without using the battery to reshape the day-ahead commitment. In contrast, Option 2 (DA & Imbalance) co-optimizes the day-ahead bid and the battery schedule; consequently, its profiling cost deviates from BAU. Notably, Option 2 yields higher profiling costs than BAU across all scenarios, with the theoretical-bound case exhibiting the largest increase. This apparent deterioration should not be interpreted in isolation as it reflects a deliberate reallocation of value between the profiling and imbalance costs (i.e., participation in the day-ahead market and the imbalance position), where accepting higher day-ahead profiling costs can enable more profitable imbalance outcomes. The net effect therefore becomes clear only when the imbalance and total costs are considered jointly (Figure 2-22 and Figure 2-23).

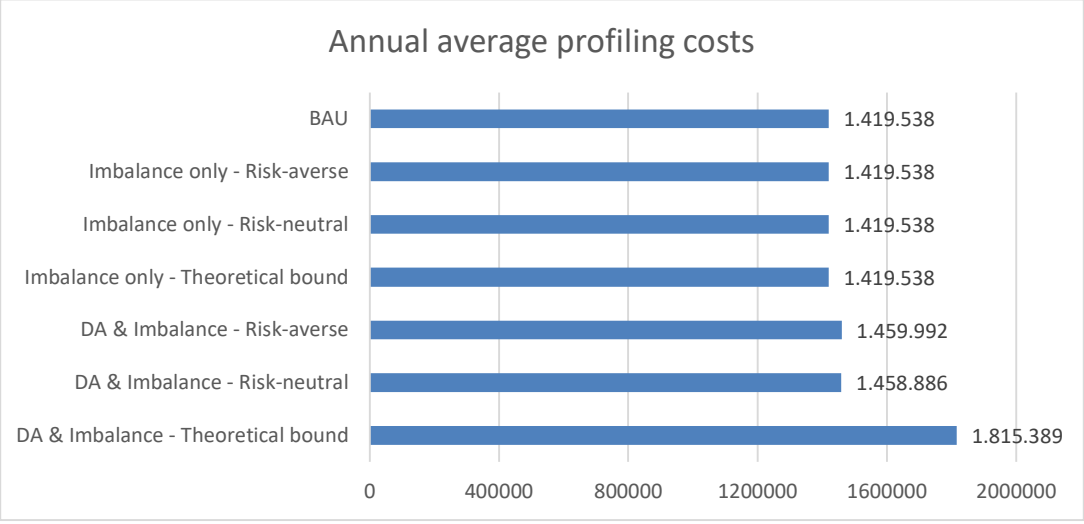


Figure 2-21: The annual profiling costs of all options for all scenarios

Figure 2-22 reports the annual imbalance settlement costs. Under BAU, imbalance settlement constitutes a net cost (positive values). Introducing the battery reverses this outcome: both options achieve negative annual imbalance costs, i.e., net revenues from imbalance settlement. Moreover, Option 2 (DA & Imbalance) consistently outperforms Option 1 (Imbalance only) in every scenario. In fact, the magnitude of the imbalance revenue under Option 2 exceeds that of Option 1 by more than a factor of two across all three settings. This result explains the higher profiling costs observed for Option 2 in Figure 2-21: the co-optimized day-ahead position and battery schedule strategically shift value from the day-ahead profiling component toward the (more lucrative) imbalance settlement component, leading to a favourable overall economic balance.

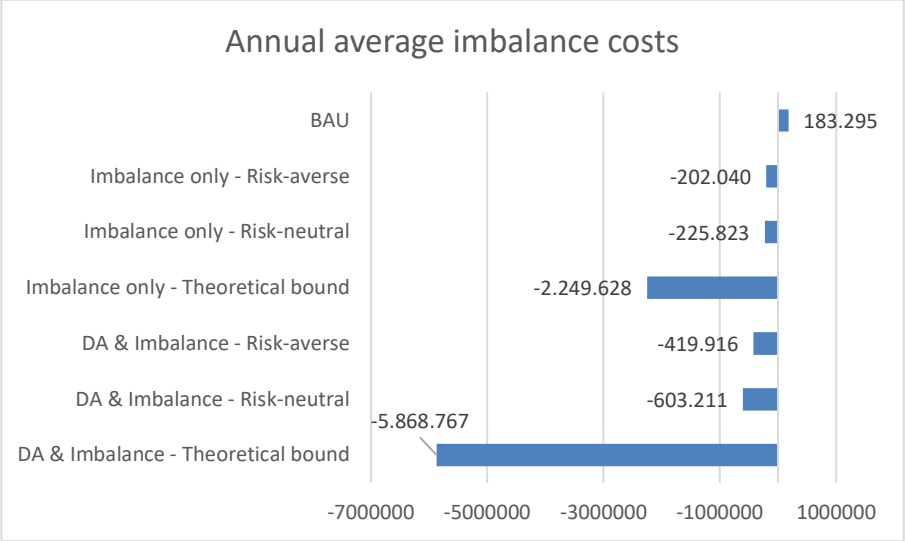


Figure 2-22: The annual imbalance costs of all options for all scenarios

The combined impact of profiling and imbalance settlement is summarized by the annual total costs in Figure 2-23 (profiling plus imbalance). The results show that deploying a battery reduces total costs relative to BAU in all scenarios considered. In addition, Option 2 is unambiguously superior to Option 1: co-optimizing day-ahead and imbalance decisions yields a lower total cost than using the battery for imbalance settlement alone, regardless of whether the operator is risk-neutral, risk-averse, or evaluated under the theoretical-bound setting. These findings indicate that the principal economic benefit of the battery is not limited to correcting forecast errors ex post (imbalance mitigation) but also arises from proactive shaping of the day-ahead position when the battery is integrated into the bidding decision.

The theoretical-bound cases represent an upper bound on attainable performance: they assume perfect ex-ante knowledge of prices in the daily optimization, which is not achievable in practice. Unsurprisingly, these cases deliver the largest cost reductions (and can even yield net revenues). When the most volatile component,

i.e., imbalance prices, is treated as uncertain and represented through probabilistic scenarios (risk-neutral and risk-averse settings), the achievable benefit decreases relative to this upper bound, providing a more realistic estimate of operational value. Finally, the comparison between risk attitudes is consistent with economic intuition: incorporating risk aversion via cVAR reduces exposure to adverse tail outcomes, but it also limits upside opportunities, resulting in smaller expected cost reductions than in the risk-neutral case.

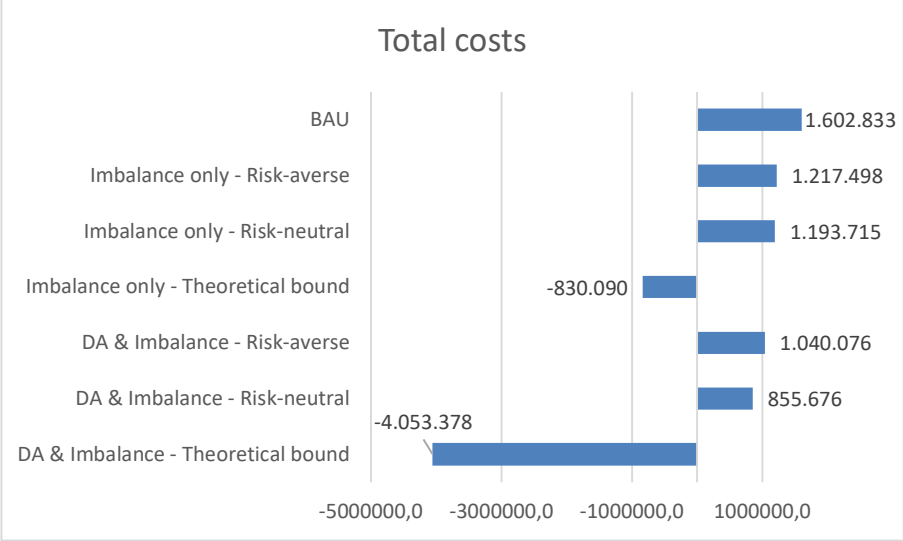


Figure 2-23: The annual total costs of all options for all scenarios

2.5.7.2 Revenue from leveraging battery

Based on the total costs, we compute the annual cost savings of deploying a large-scale battery as the reduction relative to BAU (Figure 2-24). To evaluate the investment attractiveness, these gross savings are converted into net annual savings by subtracting the annualized battery investment cost (CAPEX and OPEX). Using the stated assumptions (15-year lifetime), the corresponding annualized cost amounts to 18.27 euro/kWh. The resulting net annual cost savings are reported in Table 2-20. Two conclusions follow. First, net savings are positive for all combinations of option and scenario, indicating that the simulated operational benefits exceed the assumed investment cost under the studied conditions. Second, the ranking across strategies is robust: Option 2 (DA & Imbalance) yields higher net savings than Option 1 (Imbalance only) in every scenario, confirming that joint optimization of day-ahead positioning and imbalance settlement is economically preferable to using the battery solely for imbalance mitigation.

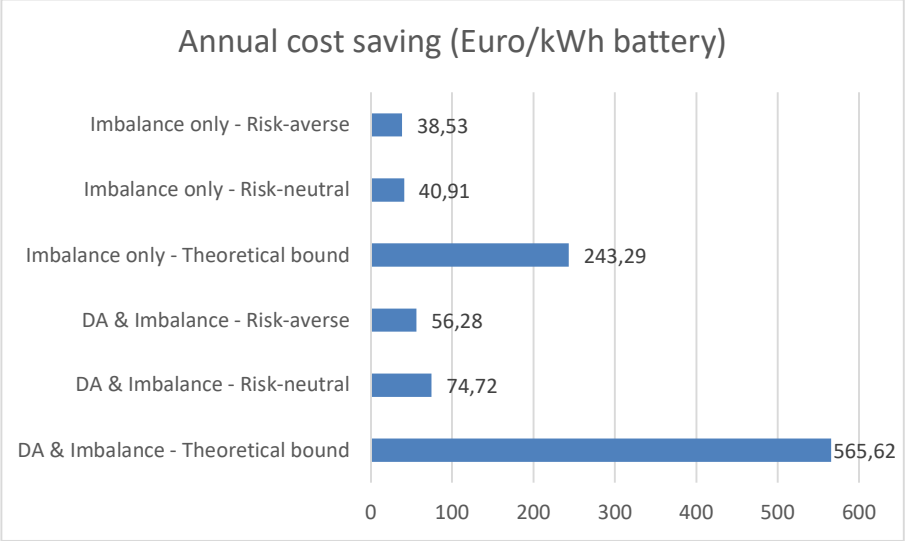


Figure 2-24: The annual total cost saving by leveraging the battery

Table 2-20: The net cost saving of leveraging battery

Option - Scenario	***Net annual cost saving (Euro/kWh battery)***
Imbalance only – Risk-averse	20.26
Imbalance only – Risk-neutral	22.64
Imbalance only – Theoretical bound	225.02
DA & Imbalance – Risk-averse	38.00
DA & Imbalance – Risk-neutral	56.44
DA & Imbalance – Theoretical bound	547.35

2.5.7.3 Key takeaways and interpretation.

The results highlight a systematic trade-off: Option 2 increases profiling costs yet delivers substantially larger imbalance revenues, so that total costs decrease and net savings improve. The theoretical-bound outcomes should be interpreted as performance limits rather than forecasts of realized profits, because perfect price knowledge is assumed. Consequently, the stochastic scenarios provide a more relevant estimate for decision-making, and they show that risk aversion reduces expected savings by prioritizing protection against adverse tail-price events. Finally, the analysis is conditional on the modelling assumptions (e.g., battery sizing and operational constraints, historical price patterns, and the availability of forecasts); deviations from these assumptions, such as forecast errors in day-ahead prices and generation/load profile realization, or additional degradation-related costs, would be expected to reduce the realized savings.

2.5.8 Conclusions

The simulation results indicate that integrating a large-scale battery at the renewable energy community level can reduce the combined profiling and imbalance settlement costs associated with offshore wind supply to residential demand. Cost reductions are achieved both when the battery is used solely for imbalance settlement (Option 1) and, more effectively, when the battery is jointly optimized with the day-ahead bidding decision (Option 2). Across all considered price-information settings, Option 2 yields the lowest annual total cost, reflecting a consistent shift from higher day-ahead profiling costs toward substantially larger imbalance revenues. When these operational benefits are compared against the assumed annualized battery investment cost, the resulting net savings remain positive for all evaluated scenarios, supporting the existence of a positive business case under the modelling assumptions.

These conclusions should be interpreted with appropriate caution. The theoretical-bound cases represent upper limits because they rely on perfect information for prices during the daily optimization, while practical implementations must rely on forecasts for both market prices and system conditions. Moreover, the optimal dispatch policies reported here assume that battery operation can be planned and executed without practical non-idealities (e.g., forecast errors, transaction costs, efficiency uncertainty, or degradation-related constraints beyond the modelled limits). In reality, such factors are expected to reduce the achievable savings relative to the simulated values.

Nevertheless, the qualitative ranking is robust: explicitly incorporating the battery into the day-ahead bidding decision together with portfolio balancing action remains economically preferable to using it only for imbalance mitigation, and risk-averse operation provides a principled way to trade expected savings against protection from adverse tail-price outcomes. Future work should therefore focus on evaluating performance under realistic forecasting errors, incorporating battery ageing costs, and assessing sensitivity to battery sizing and market-design parameters.

2.5.9 Recommendations

Table 2-21: Key recommendations for BUC 4

Recommendations	
Technical	Higher operational value can be unlocked when the battery is operated through co-optimization of day-ahead positioning and real-time imbalance management (rather than imbalance-only control). This requires (i) reliable short-term forecasts for net REC position and (where applicable) imbalance-price distributions, (ii) an optimization-based energy management system capable of rolling-horizon scheduling, and (iii) explicit incorporation of battery constraints (power/energy limits, efficiency, and ageing proxies) to ensure implementable dispatch. In practice, integrating forecast updating, uncertainty-aware scheduling (e.g., scenario-based optimization) and performance monitoring (KPIs for savings, constraint violations, cycle depth) is recommended to sustain benefits under non-ideal conditions
Socio-economic	A REC-scale battery can reduce exposure of citizen-owned offshore wind portfolios to profiling and imbalance cost volatility, supporting **more stable retail pricing** and improved affordability for members. Furthermore, social acceptance can be strengthened by communicating the dual value proposition, i.e., (i) enabling higher integration of renewables and (ii) generating measurable net savings, and using accessible KPIs (annual savings, avoided imbalance costs, emissions proxy).
Policy/regulatory	Regulatory measures that facilitate REC participation in wholesale and balancing arrangements would improve the scalability of the proposed approach. First, enable clear access pathways for RECs (directly or via an aggregator/BRP) to optimize across day-ahead and imbalance settlement, including unambiguous roles and responsibilities for metering, settlement, and data exchange. Second, support high-quality forecasting and dispatch by ensuring timely access to relevant data (e.g., near-real-time metering, standardized interfaces) while maintaining data protection obligations. Third, promote investment certainty through stable treatment of storage assets (permitting, connection procedures, and, where applicable, compatibility with long-term procurement instruments such as PPAs/CfDs (Contracts for Difference) used by community offshore wind participation). Finally, consider regulatory sandboxes or pilots for RECs to test advanced battery dispatch and risk-management approaches (e.g., cVAR-based bidding) under supervision, generating evidence for broader market-rule updates.

2.6 BUC 5a/b - Business Citizen Energy Community

2.6.1 General information

Test Case ID	*Name of Test Case*
6	Business Citizen Energy Community
Maturity of Test Case	
Currently in development (raising awareness among businesses, recruiting participants), starting feasibility study.	

ID	*Name of Business Use Case*
BUC 5a(**/b**)	Collective, cross-sectoral business models for Business Citizen Energy Communities (**with flexibility solutions)**
Short description and objectives	

Symco Energies (formerly Wapigreen) is a business citizen energy community (CEC) that brings together enterprises, public institutions, and hospitals across Picardy Wallonia. 50 consumption sites are currently under study, representing 36 enterprises. Energy sharing is expected to start in 2026, with the community expanding and evolving progressively over time. The primary objective is to reduce the electricity bill for the provision of electricity. To do so, the CEC aims to reduce its dependence on traditional suppliers by investing in RES and exchanging energy locally at more advantageous prices. In addition, the CEC seeks to maximize local consumption within the community and avoid large injections into the grid or exports outside the CEC. The challenge is to find the local RES mix that offers the best trade-off between cost reduction and self-consumption maximisation. The community is already equipped with 13,3 MWp of solar capacity and 1.8 MW of combined heat and power (CHP) contributed by its members. Besides that, four wind turbines of 2.35 MWp each (producing together around 9,000 MWh per year) might be integrated to the CEC.

Another lever of action considered in the BUC is the integration of flexibility solutions aimed at optimizing and improving the self-consumption and economic performance of CEC members. Several approaches are being considered, including adapting consumption patterns and adding additional storage capacity within the community. For industrial members, in practice flexibility measures include shifting consumption needs for energy-intensive processes such as cooling systems (e.g., refrigerators and freezers), water pumping operations (e.g., in rock quarries), and electric vehicle charging.

Objectives:

- Identify the optimal sizing of local renewable energy sources (RES – photovoltaic and wind) to ensure a cost-efficient collective electricity provision of the CEC member's load.
- Identify the optimal energy-sharing mechanism (i.e., distribution key model) and the optimal local pricing scheme (i.e., local market model) to guarantee fair distribution of benefits among members while accounting for all the interactions between the members and with the different stakeholders across the value chain (i.e., CEC/members ↔ suppliers, CEC/members ↔ DSO).
- Quantify the added value of unlocking industrial flexibility solutions within the CEC. This potential is evaluated from a technical and economic point of view, by observing improvements in self-consumption and reduction of energy costs.

2.6.2 Simulation tool

To address the objectives and identify the best business model for the CEC Symco Energies, an exact optimisation-based approach has been adopted. This method, first, gathers individual information of the members (i.e., quarter-hourly consumption profiles, electricity supplier tariffs, RES potential capacity, etc.) and standard/common technical and economic parameters (i.e., RES installation costs, market prices, etc.). Then, an optimisation problem is solved to find the size of RES units to be installed to cover the electricity needs of the CEC at minimum cost. Finally, a sensitivity analysis is conducted on the self-consumption target to observe the impact on the local RES mix, the flexibility needs and the associated economic performance. As presented in Figure 2-25: Schematic Representation of CEC's physical and economic flows., the model includes PV and wind technologies as RES, along with a collective battery energy storage system. The model also accounts for the different physical and virtual/economic flows within the community and with external stakeholders. The different components of the approach are presented in the following.

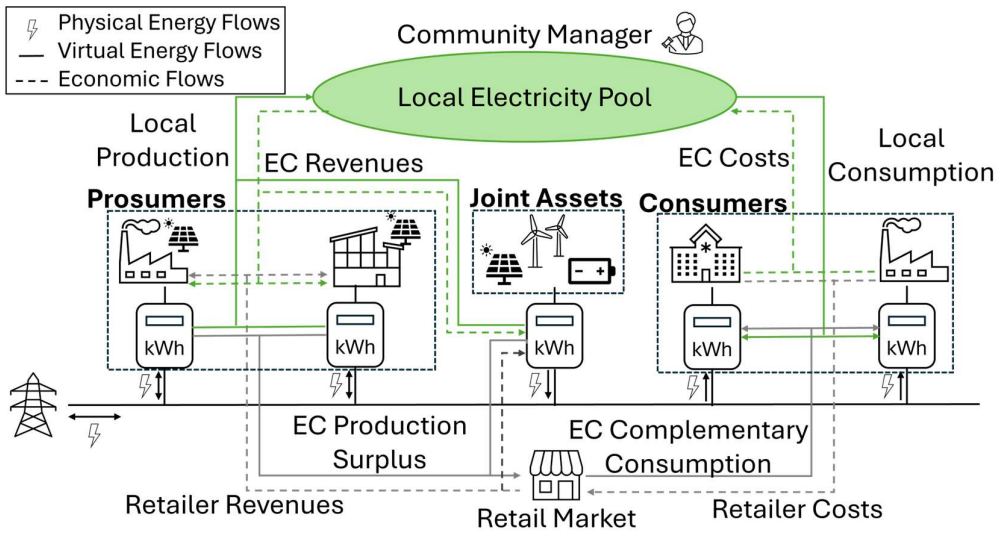


Figure 2-25: Schematic Representation of CEC's physical and economic flows.

More precisely, the first step is a REC specific generation expansion planning problem whose objective is to determine the optimal DERs capacity, location and ownership to minimise the total life-cycle cost of the REC entity (i.e., coordinated optimisation) while modelling local energy exchanges. The ownership decision is integrated into the REC framework, as this organisational structure allows participating end-users to make joint investments. Indeed, multiple members may decide to gather their equity to buy an asset that will be put at disposal of the whole community.

The proposed problem is formulated as a Mixed-Integer Linear Programming Problem that simultaneously embeds long-term and short-term decisions and constraints. Long-term decisions are the desired output of the model, namely DERs capacity, location and ownership. Long-term constraints are for example, budget constraints for individual and joint investment, maximum capacity constraints, etc.

On the other hand, short-term decisions are operational variables such as the energy traded with the retailer and/or the community, the storage system usage and the allocated energy (following a specific sharing principle). They are necessary to evaluate the short-term incomes of the community related to the investment made and validate the profitability of this investment. Operational/short-term constraints are the physical meter balance, local market balance, storage system usage but also the sharing rules selected by the community.

In some European states and regions such as France or Wallonia, sharing rules in the forms of Keys of Repartition are applied. They determine the share of the available local energy each member can benefit from. They are often formulated as fractions which may depend on several factors such as the number of members, their level of consumption, etc. Six typical rules are supported by the model. If no rule is selected, the objective function (minimise Total Life-Cycle Cost) will drive the local energy dispatch.

Then the second step distributes the benefits among members by computing the optimal price of local exchanges to maximise a fairness objective. Different fairness formulations can be adopted such as the maximisation of the minimum individual savings, the minimisation of individual savings variance or other indices defined in the literature. In this work, the minimisation of the savings spread (i.e., upper bound – lower bound) is considered. This problem only has three sets of decision variables: the local import price, the individual export price (for individual assets surplus shared in the community) and the collective export price (for joint assets production shared in the community). These variables are constrained by a yearly economic balance at the local level and can have different degrees of freedom.

Hence, we may play on three options in the simulations that are “price uniformity”, “price unicity” and “price dynamic”. “Price uniformity”, if selected, imposes that individual export prices are common to all members for each timestep. For the import price, this feature is set by default. “Price unicity”, if selected, imposes that all import, individual export and collective export prices are equal for each timestep. “Price dynamic”, if set to true, means that prices may vary at each timestep. If set to false, prices are assumed to be flat over the whole investment period. Multiple combinations of those variables can be chosen.

In addition, prior to the second step, an intermediate step is necessary to distribute the joint investment efforts among the participants and define their share in the investment based on their available equity.

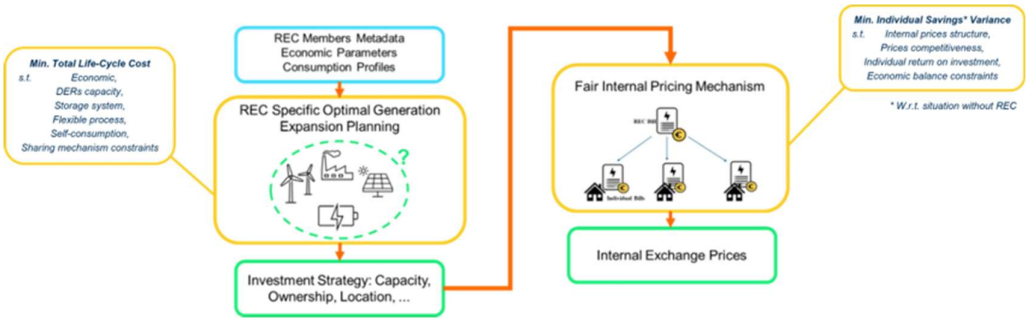


Figure 2-26: Schematic of the two-step's optimisation process

2.6.3 Use case setup

The simulated use case comprises 50 consumption sites, representing 36 enterprises for which quarter-hourly load data are available. Together, these sites account for an annual net electricity consumption of 65 GWh. In addition, several members already operate PV and CHP assets. The resulting surplus generation injected into the grid, which could potentially be valorised within the community, amounts to 2.8 GWh annually.

One of the key aspects of this BUC is the diversity of the end-users' profiles included in the energy sharing framework. They vary in size: 10 SMEs (i.e., Small and Medium-sized Enterprises) and 21 LSEs (Large-scale Enterprises) are included, along with 5 local authorities. The participating enterprises represent a diverse range of sectors, including construction, healthcare, and brewing. More importantly, they exhibit significant diversity in both electricity consumption levels (ranging from approximately 40 MWh to 70 MWh annually) and load profiles, reflecting their different operating schedules, which vary between one, two, and three 8-hour shifts per day.

2.6.4 General Assumptions

The following assumptions are common to all scenarios considered in this analysis:

- An investment period of 15 years is considered, assuming that all assets will stand without replacement during this period. This value is used for the computation of the total (actualized) life-cycle cost;
- One year of historical hourly load profiles and RES load factor profiles is sampled and used as such, assuming that these quantities won't evolve in time. Regarding the load specifically, the last year of available data was selected whatever it is, neglecting the correlation in demand patterns among members;
- Each yearly profile is further reduced to a set of 48 representative days (4 per months) to reduce the computational complexity;

- Three retail price options are included (i.e., single-rate, time of use and dynamic contracts) but a single retailer is considered. It means that all members with the same contract option have the same exact retail tariffs;
- The end-user's budget for further investment is computed based on the initial (from historical data) yearly net consumption with a rule of three. The maximum budget being set at 7.5 M€. This way the budget does not represent a bounding constraint for the investment, but the repartition of investment contributions is relative to the electricity needs;
- Individual storage assets are assumed to be used (i.e. discharged) exclusively to supply own load. However, they may be charged from any available source, including on-site generation, local generation, or the main grid.
- Joint investment contributions are computed by following a cascade principle meaning that all members with remaining budget after individual investment participates to the same magnitude. Once a member has reached its limit, the others share evenly the remaining portion of investment.

2.6.5 Main Data inputs

Table 2-22: Data inputs for BUC 5a/b

Name	*Description*	*Units*	*Value or time-series*	*Reference years*	*Data source*	*ReInvent Common data (Yes/No)*
Load Profiles	Historical quarter-hourly metered consumption	kWh	Time series	2024-2025	ORES/ Members	No
Production potential	PV and Wind load factors	kW/kWp	Time series	2025	ELIA	No
Retailer tariffs	Retailer contracts information	Euro/year, Euro/kWh	Set of Values	2025	ENGIE	No
Potential hosting capacity	Maximum installed power for PV, wind and batteries	kWp	Set of Values	-	Members	No
Day-ahead prices	Cleared prices from the day-ahead market	Euro	Time series	2023-2024	EPEX	Yes
Assets economic parameters	CapEx, Fixed Operation & Maintenance costs, Lifetime	Euro/kWp, Euro/kWp/year, years	Set of values	2025	ELIA	Yes

2.6.6 Modelling scenarios

In this Business Use Case, 11 scenarios have been simulated. First two benchmark scenarios are considered: 1) End-users operating alone with their existing assets & 2) End-users gathering to form an Energy Community but only relying on existing assets.

Then, starting from a baseline scenario with only individual investment in PV production assets, additional features are progressively explored such as joint investment in PV but also in wind assets, flexible technologies (batteries or load flexibility) or certain business models. The investment scenarios are specifically differentiated based on 5 criteria:

1. **Investment type**: Members can either invest individually, jointly or both at the same time.
2. **Asset type**: Members can invest in PV and/or wind and/or storage assets (batteries).
3. **Load flexibility**: Members can allow to unlock flexibility in their consumption habits with a certain daily shifted volume limit expressed with respect to the daily demand in %.
4. **Pricing options**: Prices can be uniform (or not), unique (or not), flat (or dynamic) as described earlier.
5. **Minimum self-consumption**: The REC may want to aim a minimum share of local energy that is consumed within the REC to avoid large injections and associated balancing responsibilities.

Regarding the sharing mechanism, i.e., the rules attributing the share of local production available to each member, no specific repartition scheme is selected. The virtual energy dispatch is driven by the objective function. A subsequent analysis could examine which regulatory-compliant rule yields the most similar allocation of electricity, but this falls outside the scope of the present study. The following table summarizes the characteristics of the 7 investment scenarios.

Table 2-23: Investment scenarios description

Scenarios	Investment Type	Assets Type	Load Flexibility	Pricing Options	Minimum Self-consumption
3	Individual	PV	No	Uniform and Flat	0
4	Individual	PV	No	Flat	0
5	Individual+Joint	PV+Wind	No	Flat	0
6	Individual+Joint	PV+Wind+Batteries	No	Flat	0
7	Individual+Joint	PV+Wind	Yes (5,15,25%)	Flat	0
8	Individual+Joint	PV+Wind+Batteries	Yes (5%)	Flat	0
9	Individual+Joint	PV+Wind+Batteries	Yes (5%)	Flat	90

In all the above-mentioned scenarios, only volumetric grid tariffs have been considered. In the last two scenarios (10 & 11), a peak tariff component is applied to both collective import and export power. From an investment point of view, Scenario 10 builds on Scenario 5 characteristics while Scenario 11 includes batteries and load shifting as in Scenario 8.

2.6.7 Results and analysis

In the following section, the results of the 11 scenarios are presented and compared following four main axes of discussion:

- How does the local pricing structure affect the individual incentive to join the community?
- To what extent can joint investment in onshore wind generation improve the balance between local generation and demand within a large-scale community?
- How can flexibility improve the economic (bill reduction) and energy-efficiency (improved self-consumption) performances of the community?
- How can a collective capacity tariff contribute to reducing grid stress (balancing needs, congestion, etc.)?

These questions are discussed using economic Key Performance Indicators (KPIs), i.e., individual and collective savings, but also energy-efficiency KPIs such as the collective self-consumption and the collective self-sufficiency. The collective self-consumption (SCR) is defined as the ratio between the total energy used within the community with respect to the total injected energy. It can be seen as the rate of local exchange. The collective self-sufficiency (SSR) is defined as the ratio between the total energy demand supplied from the community (e.g., to a traditional retailer) with respect to the total energy demand of the community.

0) Benchmark Cases

First the two benchmark scenarios are discussed. The total capacity of existing PV assets amounts to 13.3 MWp and the total cogeneration capacity is 1.8 MW.

The first benchmark corresponds to the actual performances of the different sites before joining the Energy Community. Some sites may benefit from direct self-consumption of electricity generated by their existing assets. However, any remaining demand is fully supplied by retailers, and excess generation is valorised solely through retailer feed-in tariffs.

The second benchmark integrates the principle of local energy sharing but the local electricity pool is only fed by surplus production from existing assets and dispatched among members in need.

The main economic, energy efficiency and grid stress performances are given in Table 2-24.

Table 2-24: Benchmark performances

Scenarios	Yearly Cost	EC SCR	EC SSR	Peak Import	Peak Export
1	15.6 M€	/	/	12.9 MW	1.5 MW
2	15.4 M€	97.7 %	4.6 %	12.9 MW	1.5 MW

One can observe that with existing assets only, members can save overall 260 k€ which only represents 1.66 % of the initial aggregated bill. This is mainly because the amount of energy to be shared is not sufficient with respect to the global need. Hence, we reach a local self-consumption of the individual surplus of 97.7 %, but this electricity only covers 4.6 % of the needs.

From a grid perspective, the aggregated peak at the substation transformer is unchanged when forming a REC (in both import and export direction). Indeed, in the second benchmark scenario physical flows are kept unchanged. The only difference is how energy is (economically) traded, leading only to improved economic performance.

1) Local Pricing Impact on Fair Savings Distribution

When it is assumed that community members may only invest individually in additional PV assets (Scenario 3 & 4) the optimal decision would be to install 11.2 MW of additional PV. Doing so, the community further increases the local demand-generation balance, thereby improving the community self-sufficiency to 10.4 %.

This investment would be around 7.5 M€, while the annualized yearly savings would amount to 1.3 M€ overall. The next question is how the resulting savings are allocated among community members. The answer depends on the selected internal tariff structure. Based on the price set for the purchase and sale of electricity within the community, everyone will perceive a smaller or a greater share of the benefits.

In the first configuration (Scenario 3), namely a uniform selling price and flat prices, the local electricity prices will not necessarily be advantageous for all community consumers (i.e., purchasing from the EC). Indeed, as the uniform selling price is set based on the highest price contracted by prosumers with their retailers, local import prices will also be high. In this case study, high selling prices can be observed with a maximum at 504 €/MWh when some members have dynamic contracts whose prices vary with the wholesale market conditions.

To ensure the local economic balance over the year, this price will also be set as the import price with this pricing structure. This pricing structure introduces a wide gap between individual members savings. Some may save up to 1.2 M€/year in this case while others may lose up to 492 k€/year, despite an average saving of 36.35 k€/year. This highlights the importance to select the pricing structure wisely. Especially, when the community targets a flat and common price to guarantee stability and equity among members the consideration of dynamic contracts must be carefully addressed. Also, this disparity can be explained by the lack of individual consideration when solving the sizing problem. Indeed, some members with high capital will be asked to significantly invest in production assets to feed the load of other members. However, because of the unconstrained local energy dispatch and the ex-post pricing, members may not really anticipate their individual retribution for these investments, making them not profitable.

In the second configuration (Scenario 4), when the price is kept flat, but the selling price uniformity is relaxed, the import price drops down to 145 €/MWh. On the other hand, each prosumer will have a specific feed-in tariff

profitable with respect to its own retailer contract. With such business model, we end up with 11 enterprises out of 36 with a net loss (instead of 16 in the former case) when joining the community and a reduced maximum loss of 0.17 k€/year mainly due to the administrative fee of the retailer when end-users join a community. Although this loss is reduced, the fact that it still exists will prevent those members from joining the community, consequently affecting the community performance and the savings of the other members.

This analysis emphasizes the complexity of building a unified business model which benefits all members exhibiting various characteristics in terms of local consumption potential, investment potential and retailer contracts. Future work may include the explicit integration of energy-sharing rules into the investment optimization problem (1st step) to drive the dispatch based on fairness indicators rather than global cost-optimality. The second option would be to solve both problems in one step with a parametric objective function making a trade-off between collective performances and individual savings repartition.

2) Wind Production Complementarity with Large-Scale Community Demand

When gathering end-users in a community, other investment strategies may be considered by members. Namely, joint investment allows members to collectively buy new generation or storage assets, with the resulting production shared among them. This can for instance allow one member with capital but no space for assets to still participate in the investment. Another advantage is the potential to acquire larger power facilities such as wind turbines.

Scenario 5 hence enables the members to invest individually in PV assets on their site but also to invest jointly in extra PV assets or in wind turbines (on one member site with remaining space or at a specific location). The result of this Scenario is presented in Table 2-25 and compared to the result of Scenario 4.

Table 2-25: Individual vs joint investment performance

Scenarios	Yearly Cost	EC SCR	EC SSR	Peak Import	Peak Export
4	14.3 M€	73.8 %	10.4 %	12.9 MW	8.4 MW
5	13 M€	73 %	36.7 %	12.3 MW	13.7 MW

By allowing to invest jointly, members could add 6.6 MW of collective PV installations to the 11.2 MW of individual PV investment and invest in 9.4 MW of wind turbines (all four 2.35 MW turbines). Doing so, they would double their economic performances by saving an extra 1.3 M€/year.

This significant improvement can naturally be attributed to the better complementarity of production and load patterns when the means of renewable generation are diversified. Indeed, many industrial members operate 24 hours a day (e.g., hospitality, logistics, etc.). Hence, as can be seen in Figure 2-27 and Figure 2-28, wind turbines will, for example, compensate during winter days with less solar potential (+90.65 % SSR with Scenario 5 vs Scenario 4 in Fig. 3-27). This improvement in local demand-production balance will also be observed in summer days (+40.87 % SSR in Fig. 3-28) as the wind turbines will produce during the night.

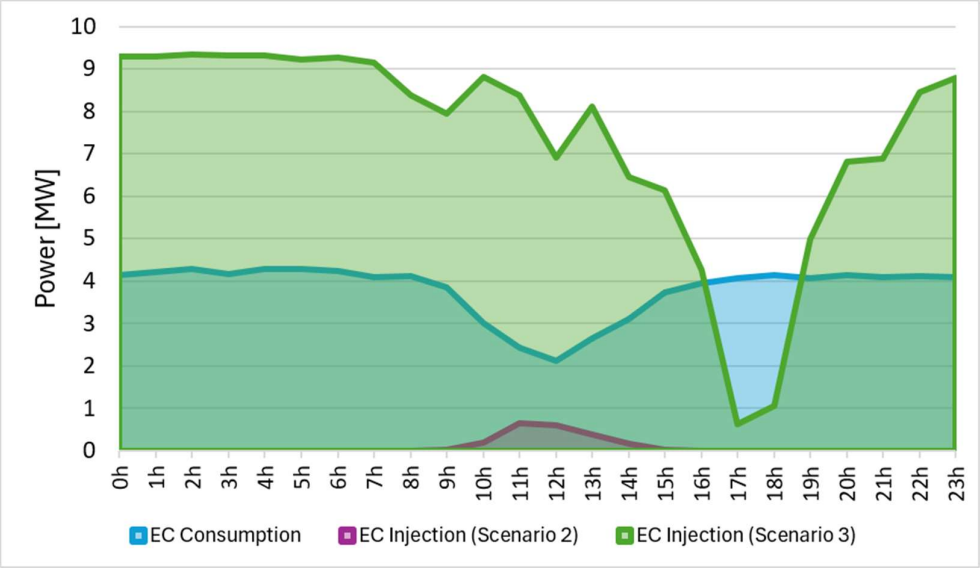


Figure 2-27: Local consumption and injection patterns (Winter Day).

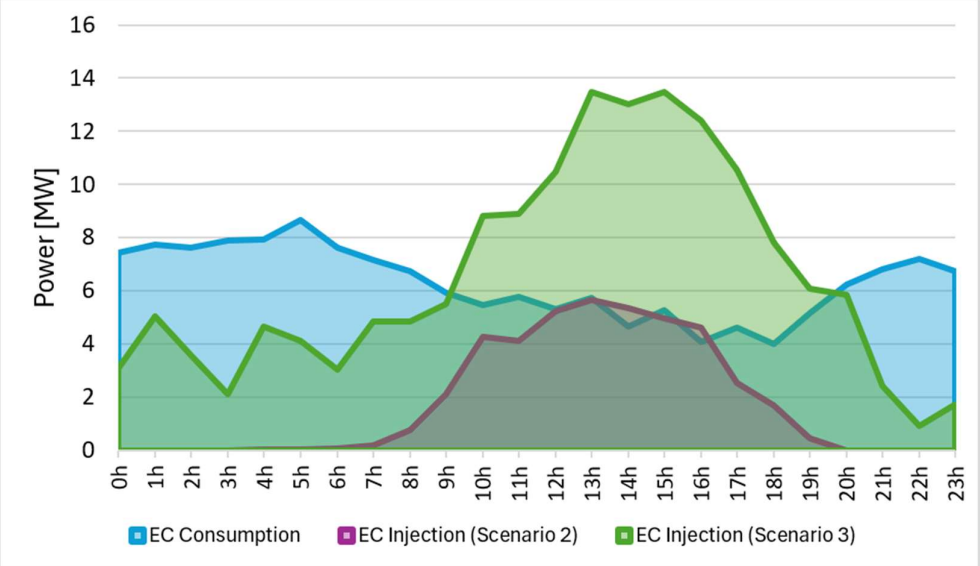


Figure 2-28: Local consumption and injection patterns (Summer Day).

3) Batteries and Load Flexibility as levers to improve Self-Consumption

There is one additional lever that may further improve the performance, i.e. the use of Flexibility. In this BUC, flexibility may arise from two sources: i) physical battery storage systems integrated in the community and ii) efforts of members to adapt their consumption patterns to match the generation profile. In the first case, an investment is required, leading to the need of finding a suitable trade-off to match the economic objective (i.e., minimizing the total cost of energy supply). In the second case, it may be assumed that no or only minor investments (e.g., EMS system) are required, but load shifting mainly leads to comfort losses. These losses can represent human discomfort or loss of revenue from the production stream. In the model, battery cost is explicitly considered on the contrary of comfort losses or other costs that are difficult to quantify. Therefore, for the scenarios with load flexibility, members of the community must, individually and independently, put in perspective the economic savings on their energy bill with respect to their estimated comfort losses or other costs.

In the first set of simulated scenarios including flexibility potential (6, 7 & 8), we aimed to observe the impact of each flexibility form (battery or load-shifting) independently and then assess their complementarity by integrating both at the same time. The results of these scenarios are presented in Table 2-26.

Table 2-26: Flexibility impact assessment

Scenarios	*Yearly Cost*	*EC SCR*	*EC SSR*	*PV Indiv*	*PV Coll*	*PV Tot*
5	13 M€	73 %	36.7 %	11.2 MW	6.6 MW	**17.8 MW**
6	12.9 M€	74.6 %	38.4 %	10.5 MW	9 MW	**19.5 MW**
7(5%)	12.6 M€	75.7 %	40.1 %	11.2 MW	8.8 MW	**20 MW**
7(15%)	12.1 M€	77.2 %	44.3 %	11.2 MW	12.2 MW	**23.4 MW**
7(25%)	11.9 M€	79.7 %	46.1 %	11.2 MW	12.7 MW	**23.9 MW**
8	12.5 M€	76.5 %	41.3 %	10.6 MW	10.7 MW	**21.3 MW**

We can observe that in Scenario 6, the cost-optimal investment in storage infrastructures only leads to 0.1 M€/year of savings. The optimal investment consists of a 2.8 MW battery with a storage duration of 2 hours. This system is rather used to push PV investment rather than storing the volumes produced obtained in Scenario 5 to use it in more suitable times. This is mainly because the performance of Scenario 5 in terms of SCR is already interesting, the battery CapEx may be too high and the fact that the model imposes a daily battery cycle (i.e., what is charged in one day must be used that same day). Hence, in the configuration without flexibility, we have days with self-consumption rates close to 90 % leaving less room for the battery to charge and other days with lower SCR but also less demand meaning that it would be interesting to have battery dynamics spanning several days (e.g., charging one day, discharging the next day).

On the other hand, integrating load-shifting behaviour of community members has a bigger impact on both the economic and energy efficiency performance. In Scenario 7, we tested different fractions of daily flexible consumption (i.e., the amount of energy that can be shifted each day) from 5 to 25 %. As expected, by shifting consumption to balance production without creating additional cost we can save up to 1.1 M€/year more (compared to Scenario 5) in the most optimistic scenario. This is translated into an increased SCR of 79.7 % and an increased SSR of 46.1 %. In this case, the SCR is improved even though the total production capacity also increases. Indeed, with load-shifting we may further invest in PV beyond the 9.4 MW of wind turbines that are consistently included in the community production assets.

Combining storage and load-shifting (Scenario 8) performs better than each solution alone. It highlights that there is no unique solution to improve community performance, but a combination of solutions should be envisaged (load-shifting, storage devices, sector-coupling, etc.).

Nevertheless, regarding the objective to avoid large injection/export outside of the CEC as surplus electricity would need to be traded on external markets, BUC members may not be fully satisfied with the SCR level. Therefore, in Scenario 9, we pushed the SCR requirement to 90 %.

Table 2-27: Minimum SCR impact assessment

Scenarios	Yearly Cost	EC SCR	EC SSR	PV Indiv	PV Coll	PV Tot
8	12.5 M€	76.5 %	41.3 %	10.6 MW	10.7 MW	**21.3 MW**
9	12.8 M€	90 %	35.5 %	10.5 MW	1.5 MW	**12 MW**

We can see in Table 2-27 that the main impact of this additional constraint is the reduction of the collective PV installation. The four wind turbines are still included in the mix, and the storage capacity is pushed to 3 MW with 2h storage duration. The economic loss amounts to 0.3 M€/year. This cost must be put in perspective with the equivalent cost of balancing responsibility for the BUC members to decide on their best investment strategy.

4) Collective Capacity Tariff for Grid Stress Reduction

A last important factor to consider when sizing the local mix of electricity is the interaction with the grid. Indeed, an energy community relies on the public transport and distribution network infrastructures. SCR and SSR indicators already reflect the electricity volume that will require balancing outside of the community on a yearly basis. The magnitude of community's power import and export at each time step is of particular importance. Indeed, consumption and injection peaks can significantly stress the electricity network and may contribute to congestion in some branches of the network.

Table 2-28: Peak import/export power performances with volumetric tariffs

Scenarios	Yearly Cost	EC SCR	EC SSR	Peak Import	Peak Export
2	15.4 M€	97.73 %	4.57 %	12.9 MW	1.5 MW
5	13 M€	73 %	36.7 %	12.3 MW	13.7 MW
8	12.5 M€	76.5 %	41.3 %	12.8 MW	14.6 MW

When considering only volumetric grid tariffs, we may observe that the investment decisions discard this peak power consideration. As shown in Table 2-28, while the peak import power is relatively constant, the export peak power significantly increases with the introduction of the four wind turbines of 2.35 MW each, the ~20 MW of PV panels and the storage system.

Scenarios 8 & 9 then investigate the addition of a capacity tariff (2 €/kW) charged on both import and export peak power of the community on the investment decisions and community performances. The corresponding results are depicted in Table 2-29.

Table 2-29: Peak import/export power performances with capacity tariffs

Scenarios	Yearly Cost	EC SCR	EC SSR	Peak Import	Peak Export
10	13 M€	74 %	36.3 %	12.3 MW	13.1 MW
11	12.6 M€	77 %	41.1 %	9.6 MW	11.7 MW

Without flexibility means (Scenario 8), the added tariff component only slightly affects the economic and energy efficiency performance of the community. The main difference with Scenario 3 is the reduction of PV installed capacity to slightly limit the peak export power to balance the peak power penalty and investment cost. The installed PV capacity is reduced to 17 MW overall (11.2 MW of individual and 5.8 MW of collective investment). In the second case, despite the addition of batteries and load-shifting possibilities (Scenario 9), the yearly savings are reduced by 0.1 M€/year with respect to Scenario 6. However, the installed PV capacity is kept at 20.8 MW total with a battery of 2.5 MW (2h). This enables to conserve the SSR performances while reducing both import (-3.2 MW) and export (-2.9 MW) peak power.

2.6.8 Conclusions

The objective of this Business Use CaBUCse was to study the techno-economic feasibility of the **Symco Energies** (formerly Wapigreen) business citizen energy community (CEC) that brings together enterprises, public institutions, and hospitals across Picardy Wallonia. The aim was to reduce the electricity bill for the provision of electricity by investing in renewable production assets and trading the output electricity locally at advantageous prices. To this end, a two steps investment optimisation framework has been used to identify the best investment strategy for the community and evaluate its economic and energy efficiency performance.

Based on the simulation of 11 scenarios differing in terms of investments, assets and flexibility potential, the following key messages emerged:

- Special attention should be paid to the organization of internal exchanges in terms of both energy sharing rules and local tariff structure. Indeed, despite the existence of collective benefits (i.e., at the REC scale), some members may be worse off than in their initial stand-alone situation. This is a major limitation to the engagement of end-users in the energy community and therefore requires precautious consideration.
- When gathering end-users with various profiles, the community must select the appropriate production assets. As the local energy exchange relies on quarter-hourly matching of demand and production, the selected technology should have a generation profile complementary to the demand pattern. For such large-scale business energy community, relying only on solar production is not sufficient. Hence, the introduction of wind turbines considerably improved the collective economic performance of the community.
- Finally, flexibility is key to enhance the performance of the local entity from an economic and energy efficiency point of view. This flexibility may come from physical storage devices or from demand-side flexibility. Nevertheless, the benefits offered by these solutions on the local energy supply cost must be put into perspective with the direct (e.g., investment cost for deploying the solution) and indirect (e.g., loss of productivity) cost to find the best trade-off. To better valorise this flexibility, and especially storage assets, the community may envisage to extend its usage beyond energy arbitrage between local and retailer supply. It may serve to participate in flexibility services such as grid balancing or congestion management.

2.6.9 Recommendations

Table 2-30: Key recommendations for BUC 5

Recommendations	
Technical	Currently, collective storage assets are not permitted within Renewable Energy Communities under the Walloon regulatory framework. However, shared storage could represent one of the most suitable and effective assets to develop collectively rather than individually. By maintaining records of both retailer transactions and local energy exchanges, it may be possible to accurately track renewable energy flows and ensure that no non-renewable electricity is exchanged through the battery within the Renewable Energy Community.
Socio-economic	Grouping end-users to form a community and collectively invest in renewable assets has shown to provide global economic and energy efficiency benefits. However, the repartition of such benefits among members is a key challenge. The market design of energy communities must be carefully developed to ensure that participation remains financially beneficial for all members. In this context, a broader range of sharing rule options should be considered, as the most appropriate allocation mechanism may be case-specific to ensure a positive outcome for each member.

Policy/regulatory	Consideration should be given to adapting grid tariff structures for Energy Communities, particularly regarding the way capacity-based charges are applied to end users. From a network perspective, the key driver of infrastructure needs is the coincident community peak demand rather than the individual peak demand of each member. In addition, the appropriateness of the administrative fees charged by suppliers to customers participating in Energy Communities warrants further discussion. These fees often reflect the increased complexity associated with current market arrangements. Regulators and policymakers could play an important role in facilitating dialogue and developing frameworks that reduce administrative burden while ensuring an equitable allocation of costs.

2.7 BUC 6a - Green H2 for long haul trucks

2.7.1 General information

Test Case ID	*Name of Test Case*
4.3	Green H2 for long haul trucks
Maturity of Test Case	
In development	

ID	*Name of Business Use Case*
BUC 6a	Cross sectoral business models for long haul trucks on Hydrogen.
Short description and objectives	
This business use case aims at defining a cost-efficient business model to locally operate a production, storage and distribution unit for green hydrogen mainly dedicated to heavy transport. Currently, the test case focuses on supplying hydrogen to long-haul trucks, but any surplus hydrogen production not consumed by the transport fleet would be valorised through hydrogen-based turbines or engines, contributing to grid congestion mitigation in IDETA business parks while simultaneously reducing their carbon footprint. H2 will be produced in a sustainable manner by electrolysis of water, and power will be supplied from an existing 2MW wind turbine and a complementary 1.78 MWp photovoltaic park to be built. The renewable energy production units are located on or next to the H2 station where a direct grid connection is possible. Electricity will be used primarily to supply trucks with hydrogen while extra generation will be injected into the grid. In the first stage of the pilot, the demand-side reflects the needs of a fleet of 10 hydrogen-powered trucks which corresponds to about 109 tons of H2 per year. Each truck is running about 136.500 km/year. The electrolyser and the compressed H2 storage (1.25 MW) has been dimensioned accordingly but the equipment can make the most of its capacity as it also includes, in addition to the trucks filling station, the possibility to sell excess hydrogen to 20–25 MW gas-fired power plants (industrial off-taker) located nearby via tube trailers. A storage capacity of high-pressure hydrogen (1057kg) is implemented to cover periods of low renewable energy production or high energy prices. In addition, investment in a battery is considered if daily arbitrage is deemed economically attractive. The project is modular in time; a second phase foresees the replacement of the existing wind turbine at its end of life (+/-2036) by a more powerful equipment that could meet a greater demand.	

2.7.2 Simulation tool

The BUC 6a hydrogen refuelling station is represented through the customer-centred techno-economic optimisation framework developed in WP2. The model is formulated as a two-stage stochastic linear programming problem, in which investment decisions are common to all considered years while operational decisions adapt to interrelated yearly renewable generation and electricity-market conditions. Historical time series for 2023, 2024 and 2025 are considered to capture interannual variability.

The optimisation minimises the expected annualised cost of supplying the hydrogen demand while determining the optimal system design and operation. In this BUC, the design configuration of the system is fixed except for the battery; investment variables therefore only include battery capacity, while the operation of the electrolyser, hydrogen storage, renewable generation and grid exchanges is jointly optimised according to the existing installed capacities. Dynamic electricity prices, grid tariffs and storage technologies provide the main sources of implicit operational flexibility.

The economic assessment combines annualised CAPEX, fixed and variable OPEX and electricity expenditures. Lifetime indicators, including Levelized Cost of Hydrogen ($LCOH_2$), NPV and payback period, are subsequently derived over the project horizon, accounting for component replacement, dismantling costs, discounting and the relevant hydrogen revenues and monetised CO_2 benefits.

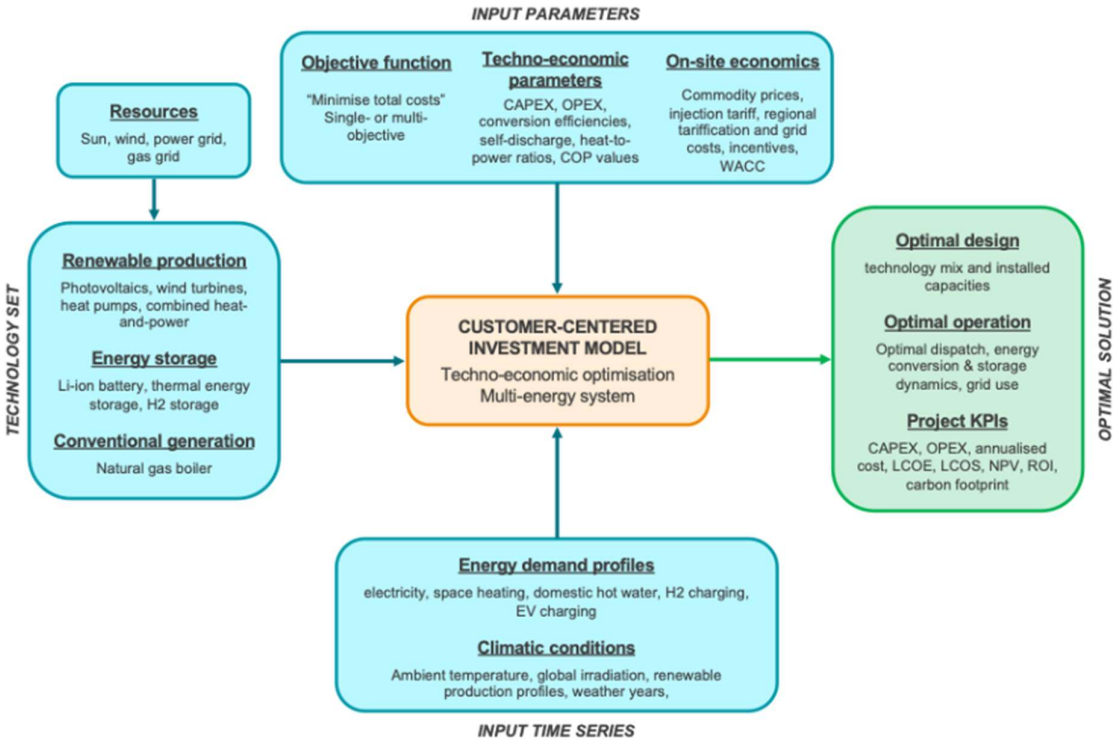


Figure 2-29: Schematics of the input and outputs of the optimisation model for BUC6

2.7.3 Use case setup

BUC 6a considers a decentralised hydrogen production and refuelling system supplying a fleet of ten long-haul trucks, corresponding to approximately 360 kg H_2/day. Hydrogen is produced by a grid-connected PEM (Proton Exchange Membrane) electrolyser supplied by local renewable generation and, when required, electricity imports from the public grid. The system further includes compressed hydrogen storage and may incorporate battery storage to increase operational flexibility.

The wind and solar power generation facilities are located adjacent to the hydrogen production and distribution plant, as well as to the industrial and transportation site. These assets are connected to the public electricity grid to allow the injection of surplus renewable energy. Hydrogen production is primarily powered by locally generated green electricity, while any additional demand can be met by drawing from the grid. Compressed hydrogen is stored on-site and supplied to long-haul trucks providing transport services to the industry, and excess can be sold to industry via tube trailers.

In this configuration, five distinct legal entities are involved through various contractual relationships. The electricity supplier and the asset owner have agreements covering both the purchase of grid electricity and a Power Purchase Agreement (PPA) for the sale of injected electricity and associated green certificates. The PPA also includes Balancing Responsible Party (BRP) services. The asset owner operates two Business Units (BUs) under an internal arrangement: one responsible for renewable power generation and the other for hydrogen production. The green power unit supplies electricity to the hydrogen plant while ensuring that its internal revenues remain comparable to a full-grid injection scenario. When renewable generation is insufficient, the hydrogen plant can draw additional electricity from the grid. The hydrogen produced is then made available to a retail entity for sale to transport and industrial clients.

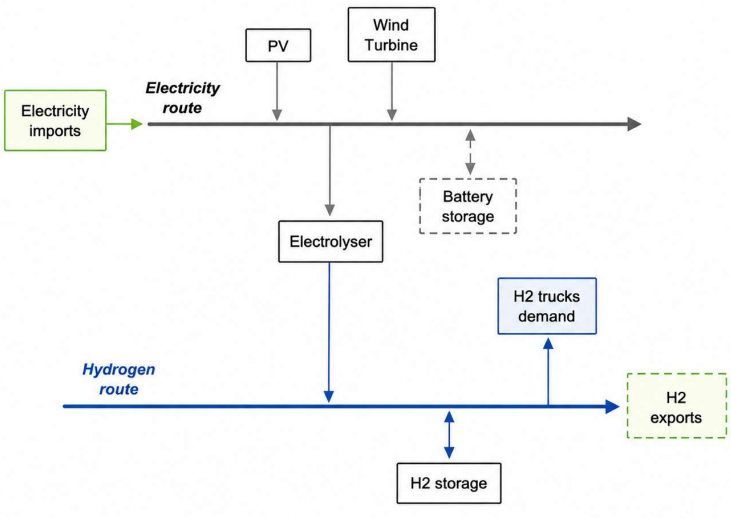


Figure 2-30: Interactions between energy vectors and technologies involved in BUC 6a

Figure 2-30 summarises the resulting energy flows: At each timestep *i*, the model enforces an energy balance for electricity, hydrogen, and heat vectors. Electricity produced by PV and wind units can either be 1) directly consumed by on-site components (electrolyser, compressors, auxiliaries), 2) stored in intermediate energy buffers (battery or H_2 storage), or 3) exported/imported from the grid depending on price signals and technical limits.

2.7.4 General Assumptions

First, several operational assumptions are adopted to simplify the representation of the refuelling process. Each heavy-duty truck is assumed to complete a 36 kg refuelling event within 15 minutes, consistent with current commercial hydrogen refuelling stations. In addition, the PEM electrolyser is assumed to exhibit negligible dynamic limitations, with ramping times below one second. Consequently, the electrolyser is considered perfectly responsive to variable renewable electricity generation and dynamic electricity prices within the selected 15-minute simulation time step.

The techno-economic assessment is performed from the perspective of the hydrogen refuelling station operator over the entire project lifetime. All investment costs are assumed to occur at the beginning of the project and are annualised using the Capital Recovery Factor (CRF), based on the selected project lifetime N and discount rate D. The total annualised investment cost therefore includes the capital expenditures associated with the hydrogen refuelling station (electrolyser, compressor, hydrogen storage, dispensing system and balance-of-plant), together with the investments in battery energy storage whenever selected by the optimisation.

Annual operating expenditures are divided into fixed and variable operating costs. Fixed operating costs are assumed proportional to the installed capacity of each technology and include preventive maintenance, insurance, land lease, overhead costs and routine servicing. Variable operating costs are assumed proportional to the annual energy processed by each technology. For the hydrogen refuelling station, these primarily include the electricity required for hydrogen compression and the pre-cooling unit, together with technology-specific operation and maintenance costs.

The annual electricity expenditure of the hydrogen refuelling station is calculated by accounting for all electricity supplied to the system. Electricity may originate from on-site photovoltaic generation, on-site wind generation, purchased including a Guarantee of Origin (GoO) premium, or direct electricity imports from the public grid. Electricity withdrawn from the grid is subject to a grid tariff consisting of a volumetric component per MWh and a capacity component based on the annual peak power.

The renewable generation assets are evaluated independently through their own annual cash flows. Their revenues are obtained from electricity sold internally to the hydrogen refuelling station or exported to the

electricity grid, while their expenditures include annualised capital costs together with fixed and variable operation and maintenance costs.

Several complementary economic indicators are subsequently derived to assess both the cost of hydrogen production and the profitability of the project. The Levelized Cost of Hydrogen (LCOH2) is evaluated by discounting the expected costs and hydrogen production over the complete project horizon, including electrolyser stack replacement after 10 years, and the dismantling cost at the end of its lifetime, while accounting for the assumed inflation and nominal WACC rates. The $LCOH_2$ is then obtained as the ratio between the present value of these lifetime net costs and the present value of the hydrogen supplied to the truck fleet, expressed in €/kg H_2.

Project profitability is evaluated separately by assigning a selling price to the hydrogen delivered to the truck fleet, thereby converting the annual hydrogen demand into an operating revenue. In the configurations where hydrogen export is enabled, the optimiser may additionally produce and sell surplus hydrogen to an industrial off-taker, provided that doing so improves the overall economic performance of the system.

The resulting Net Present Value (NPV) represents the discounted cumulative value generated by the project, while the Payback Period (PB) corresponds to the first year in which the cumulative discounted cash flow becomes positive. Since project profitability is inherently dependent on the assumed value of hydrogen, a dedicated sensitivity analysis is performed for H_2 selling prices ranging from the computed expected $LCOH_2$ to 17€/kg H2.

Finally, the economic assessment accounts for the monetisation of avoided CO_2 emissions using the ETS2 and ETS1 carbon prices for mobility and industry, respectively. For the truck fleet, avoided emissions are estimated against the reference diesel pathway (~10 $kgCO_2/kgH_2$), while industrial exports are assumed to substitute natural gas in a gas turbine on an equivalent energy basis (~6.7 $kgCO_2/kgH_2$). Assuming carbon prices of 45 €/tCO_2 for ETS2 and 79 €/tCO_2 for ETS1, the resulting decarbonisation benefits amount to approximately 0.45 €/kgH_2 for mobility and 0.53 €/kgH_2 for industrial use and are included as monetary revenues in the economic assessment.

Renewable generation and electricity-market conditions are represented using interrelated historical yearly time series for 2023, 2024, and 2025. Perfect foresight is assumed within each yearly scenario, while interannual uncertainty is captured through the stochastic formulation. Hydrogen demand must be satisfied at every time step, either through direct production or hydrogen previously stored.

All investment decisions are made at the beginning of the project and evaluated over the common project lifetime using the assumed nominal weighted average cost of capital (WACC) rates. Technology CAPEX and variable OPEX, conversion efficiencies, storage losses and other techno-economic parameters are provided in the input dataset presented in Table 2-31.

2.7.5 Main Data inputs

Table 2-31: Main Data inputs for BUC 6a

Name	Description	Units	Value or time-series	Reference years	Data source	ReInvent Common data (Yes/No)
Nominal discount rate	Set as the nominal WACC of the project, includes inflation	%	val	2023-2025	NREL	no
Day ahead Wholesale prices	Day ahead prices used to implement dynamic pricing	Eur/kWh	T-S	2023-2025	ENTSO-E	yes
Feed-in tariff for PV	Remuneration rate for injection of PV energy to the grid.	Eur/kWh	T-S	2023-2025	IDETA	no
Wind Turbine production profile	Historical hourly wind energy production from IDETA's WT10.	kWh	T-S	2023-2025	IDETA	no
Solar PV production profile	Normalized PV energy production from ENTSO-E transparency platform, hourly resolution	kWh	T-S	2023-2025	ENTSO-E	no
H2 demand profile	Hourly compressed hydrogen demand profile. Theoretical profile ideally distributed over the day	kWh	T-S	2023-2025	IDETA	no
Nominal operating pressure	Nominal operating pressure of compressor and H2 storage unit	bar	val	2026	IDETA	no
PV installed capacity	Available on-site solar PV capacity	kWp	val	2026	IDETA	no
PV inverter capacity	Power rating of the AC/DC conversion unit for solar power	kVA	val	2026	IDETA	no
PV inverter conversion efficiency	Conversion efficiency from solar DC to grid AC	%	val	2026	IDETA	no
Electrolyser capacity	1,25kW, PEM technology, production rate = 22.7kgH2/h	kW	val	2026	IDETA	no
H2 storage capacity	Available on-site compressed hydrogen capacity	kg	val	2026	IDETA	no
Electrolyser's Specific energy consumption	Expected energy required to produce 1 kg H2 @ nominal operation, @30bar	kWh/kg H2	val	2026	IDETA	no
Electrolyser's minimum load	Minimum output power of the electrolysis unit	% nom.	val	2026	IDETA	no
Electrolyser's hourly production rate	Expected H2 production rate @ nominal operation	kg/h	val	2026	IDETA	no
Compressor hourly compression rate	Expected H2 compression rate @ nominal operation	kg/h	val	2026	IDETA	no
Fixed O&M Electrolyser + compressor	Fixed annual component of operation of maintenance costs of electrolysis unit	EUR/y	val	2026	IDETA	no
Variable O&M Wind Turbine	Variable component of operation of maintenance costs of electrolysis unit	EUR/kWh.y	val	2026	IDETA	no

Name	Description	Units	Value or time-series	Reference years	Data source	ReInvent Common data (Yes/No)
Fixed O&M Wind Turbine	Fixed annual component of operation of maintenance costs of wind turbine	EUR/y	val	2026	IDETA	no
Fixed O&M PV	Fixed annual component of operation of maintenance costs of solar PV installation	EUR/y	val	2026	IDETA	no
Variable O&M PV	Variable component of operation of maintenance costs of solar PV field	EUR/kWh.y	val	2026	IDETA	no
Electrolyser's stack replacement cost	Replacement of electrolyser's stack at the end of their lifetime	EUR	val	2026	IDETA	no
Decommissioning cost H2 equipment	Decommissioning cost H2 equipment at the end of the project	EUR	val	2026	IDETA	no
Electrolyser's deionised water price	Unit price of deionised water required for electrolysis process	EUR/kg	val	2026	IDETA	no
H2 Compression energy	Energy required to compress H2 for 700 bar refuelling	kWh/kg H2	val	2026	NREL	no
H2 pre-cooling energy	Cooling energy required to maintain h2 to -40°C during dispensing	kWh/kg H2	val	2026	SHENSHI	no
GoO price	GoO bought by the H2 business unit from the wind (and solar) business units	EUR/MWh	val	2026	IDETA	no
Carbon prices	Estimated ETS 1&2 trade values for CO2 valuation (resp. for industry and mobility)	EUR/kgCO2	val	2026	European Commission	No

2.7.6 Modelling scenarios

To isolate the respective contributions of the main implicit flexibility mechanisms, six incremental scenarios are defined. Starting from a constrained reference case, dynamic electricity prices, battery storage, and changes in the temporal structure of hydrogen demand are progressively introduced. Each scenario is additionally evaluated with and without the electricity capacity tariff.

The resulting incremental scenarios are defined as follows:

- **Scenario (1) – Average electricity price, no battery, uniform demand:** baseline configuration in which the electrolyser is not exposed to short-term electricity price variations and no electrical storage flexibility is available.

- **Scenario (2) – Average electricity price, battery, uniform demand:** battery investment is enabled while the electricity price remains constant throughout each year, allowing the intrinsic value of electrical storage in the absence of dynamic price signals to be assessed.
- **Scenario (3) – Dynamic electricity prices, no battery, uniform demand:** quarter-hourly electricity prices are introduced, enabling the electrolyser to respond directly to electricity-market conditions without support from a BESS.
- **Scenario (4) – Dynamic electricity prices, battery, uniform demand:** both dynamic electricity prices and battery storage are enabled, representing the reference configuration with the full set of implicit electrical flexibility mechanisms considered in this study.
- **Scenario (5) – Dynamic electricity prices, battery, batch demand:** the more constrained batch-refuelling profile is introduced while maintaining dynamic prices and battery investment, thereby assessing whether electrical storage can mitigate the operational consequences of reduced hydrogen-demand flexibility.
- **Scenario (6) – Dynamic electricity prices, no battery, batch demand:** the same batch-refuelling constraint is considered without battery storage, providing the counterfactual required to isolate the actual contribution of the BESS under the constrained refuelling profile.

For each of these six configurations, the optimisation is performed both with and without the capacity tariff, resulting in a total of twelve configurations and enabling the effect of the tariff to be distinguished from the other flexibility mechanisms. Particular attention is given to its impact on the annual grid peak.

The comparison focuses primarily on the resulting $LCOH_2$, optimal battery capacity, share of grid electricity in the electrolyser electricity supply, and annual peak power imported from the grid. Together, these indicators make it possible to assess not only whether additional flexibility reduces hydrogen production costs, but also whether it leads to a more grid-friendly operation of the hydrogen production system.

As explained, two H2 demand profiles are considered to assess the impact of the temporal distribution of truck refuelling on the operation of the overall system, with the objective to provide a controlled basis for assessing whether the production system benefits from a coordinated and distributed refuelling strategy, and whether complementary flexibility assets, such as the BESS, can mitigate the operational constraints introduced by batch refuelling :

- The uniform profile assumes that the refuelling of the ten trucks is evenly distributed throughout the operating day, representing a coordinated and relatively favourable use of the Hydrogen Refuelling Station (HRS).

- In contrast, the batch profile represents a deliberately more constrained case in which the fleet is refuelled during only two major daily sessions, around noon and 18:00, with five trucks associated with each session.

While the total hydrogen demand remains unchanged, concentrating refuelling into these two time windows creates substantially larger instantaneous H2 withdrawals and can potentially reduce the temporal flexibility available to the production and storage system. These profiles also directly impact the operation of the HRS compressor and pre-cooling system, whose electricity consumption is modelled as synchronized with the refuelling sessions. It is indeed expected that the power required to supply H2 for 5 trucks in a row for the batch profile will be significantly larger than for the uniform profile.

Finally, in addition to the incremental flexibility scenarios, two sensitivity analyses are performed on the retained system configuration (scenario 4). First, the H2 selling price is varied between the determined $LCOH_2$ up to 17€/kg H_2, while allowing surplus hydrogen production to be exported to an industrial off-taker. This analysis evaluates how the hydrogen selling price affects the profitability of the project, notably in terms of NPV, payback period and industrial H2 exports.

A second sensitivity analysis investigates the possibility of reducing the system's dependence on grid electricity by progressively constraining the maximum grid share in the electricity supplied to the H2 production system. Grid shares of 25%, 20%, 15%, 10%, and 5% are imposed successively. This analysis assesses both the technical feasibility and economic consequences of producing hydrogen with an increasingly renewable electricity mix, particularly through its impact on battery sizing, electricity costs and $LCOH_2$.

2.7.7 Results and analysis

Let's recall the initial BUC 6 system design consists of an existing 2 MW wind turbine complemented by a 1.78 MWp PV plant, supplying a 1.25 MW electrolyser and a 1057 kg compressed hydrogen storage unit to meet the annual hydrogen demand of a fleet of 10 long-haul trucks, while allowing surplus hydrogen production to be valorised by nearby industrial off-takers. Note that sales of surplus hydrogen production are only considered in the sensitivity analysis on the H_2 selling price. Consequently, the first part of the study focuses on minimising the cost of energy required to supply the H_2 fleet.

2.7.7.1 Unlocking implicit flexibility through incremental scenarios

The results are analysed by progressively comparing the incremental scenarios defined above, with the objective of isolating the contribution of each implicit flexibility mechanism to system economics and grid interaction. Particular attention is given to the effects of dynamic electricity prices, battery storage, hydrogen demand patterns and the capacity tariff on the $LCOH_2$, grid-electricity dependence and peak power imports.

To this means, Table 2-32 progressively unlocks different sources of implicit flexibility in order to identify their respective contribution to the operation and economics of the hydrogen production system. Each scenario is optimised with and without the capacity tariff to observe its impact on the expected battery sizing, $LCOH_2$, and share of grid electricity.

Table 2-32: Expected battery sizing, LCOH2, and share of grid electricity for each incremental scenario

Scenario	Battery Size [MWh]		LCOH2 [€/kg_h2]		Share grid electricity [%]		Annual peak power from grid [MW]	
	Capacity tariff	No capacity tariff	Capacity tariff	No capacity tariff	Capacity tariff	No capacity tariff	Capacity tariff	No capacity tariff
(1) No dynamic prices – No battery – Uniform	-	-	13.82	13.45	21.92	21.92	0.48	1.37
(2) No dynamic prices – Battery – Uniform	0	0	13.82	13.45	21.92	21.92	0.48	1.37
(3) Dynamic prices – No battery – Uniform	-	-	12.80	12.11	23.06	23.81	0.63	1.37
(4) Dynamic prices – Battery – Uniform	0.19	0.23	12.78	12.08	22.68	23.44	0.64	1.48
(5) Dynamic prices – Battery – BATCH	0.26	0.38	12.85	12.14	22.84	23.60	0.64	1.80
(6) Dynamic prices – No Battery – BATCH	-	-	12.87	12.19	23.33	24.08	0.64	1.69

Scenario (1) exhibits no implicit flexibility signals, with annual-average rather than dynamic electricity prices and no battery, while Scenario (2) introduces the possibility of investing in a battery without yet exposing the system to dynamic price variations. The identical results obtained for these two scenarios, together with a zero optimal battery capacity in Scenario (2), demonstrate that storage provides no economic value in the absence of a dynamic electricity-price signal; at least considering the actual initial configuration of the system (fixed capacities for electrolyser and H_2 storage units).

Scenario (3) subsequently introduces dynamic EPEX prices while excluding battery storage. This alone reduces the $LCOH_2$ from 13.82€/kg to 12.80€/kg with the capacity tariff, and from 13.45€/kg to 12.11€/kg without it, demonstrating that flexible electrolyser operation in response to hourly electricity prices represents a major source of economic value.

Scenario (4) additionally allows investment in battery storage. The optimizer selects only a quite limited capacity of 0.19–0.23 MWh, resulting in a quite marginal further $LCOH_2$ reduction of 0.02€/kg and 0.03€/kg,

respectively. This indicates that most of the available temporal flexibility can already be captured directly through the flexible operation of the electrolyser and H_2 storage, leaving relatively little additional value for electrical storage to reduce the total system costs.

Finally, Scenario (5) replaces the uniform H2 demand with the more constrained batch-refuelling profile defined earlier, while retaining dynamic prices and battery investment. The optimizer responds by increasing the battery capacity to 0.26–0.38 MWh, thereby partially buffering the additional temporal constraints imposed by batch refuelling and limiting the resulting increase in $LCOH_2$ to only 0.06–0.07€/kg compared with Scenario (4). However, Scenarios (5) and (6) isolate the actual contribution of battery storage under the more constrained batch-refuelling demand profile. Scenario (6) considers dynamic electricity prices and batch H_2 demand without battery storage, whereas Scenario (5) allows the optimizer to invest in a battery under otherwise identical conditions. The comparison shows that the economic benefit of the battery remains relatively limited. With the capacity tariff, the optimizer installs 0.26 MWh of battery capacity, reducing the $LCOH_2$ only marginally from 12.87€/kg in Scenario (6) to 12.85€/kg in Scenario (5). Without the capacity tariff, a larger 0.38 MWh battery is selected and the $LCOH_2$ decreases from 12.19€/kg to 12.14€/kg, representing a slightly larger, but still modest, benefit of 0.05€/kg H_2. Battery storage also slightly reduces the dependence on grid electricity, with the grid share decreasing from 23.33% to 22.84% under the capacity tariff and from 24.08% to 23.60% without it. Battery storage has a similarly limited impact on grid peak power: the peak remains unchanged at 0.64 MW under the capacity tariff, while without the tariff it actually increases from 1.69 MW to 1.80 MW when the battery is introduced. Overall, although the batch demand profile increases the optimal battery capacity compared with the uniform-demand case, Scenarios (5) and (6) demonstrate that this additional storage provides only marginal economic and grid-sourcing benefits.

The comparison also reveals the important role played by the capacity tariff in shaping grid-friendly operation. Across all scenarios, introducing the capacity tariff dramatically reduces the expected annual grid peak: from 1.37 to 0.48 MW in Scenarios (1) and (2), from 1.37 to 0.63 MW in Scenario (3), and from 1.48–1.80 MW to approximately 0.64 MW once battery flexibility is available. Remarkably, this substantial peak reduction is achieved at a comparatively limited $LCOH_2$ penalty of approximately 0.37–0.71€/kg. The capacity tariff therefore provides a strong economic incentive for the electrolyser and, when available, the battery to avoid concentrated grid withdrawals, illustrating how tariff design can translate system-level grid constraints into economically rational asset operation. However, it has little influence on the total amount of grid electricity consumed: grid shares remain broadly within 22–24% across all ten configurations. The tariff therefore primarily modifies when electricity is withdrawn from the grid rather than how much grid electricity is ultimately required.

Overall, the incremental analysis suggests a clear hierarchy between the available flexibility mechanisms. Flexible electrolyser operation is the primary flexibility asset, with dynamic electricity prices unlocking considerably more economic value than battery storage. This limited role of the BESS under the baseline

configuration may also indicate that the installed electrolyser capacity already provides sufficient operational headroom to shift hydrogen production in time, reducing the need for an additional electrical buffer. Conversely, the capacity tariff primarily delivers grid-oriented flexibility, strongly suppressing peak imports while only moderately affecting hydrogen production costs. Taken together, these results show that implicit flexibility does not necessarily require substantial additional storage capacity: a significant part of its value can already be captured through appropriate exposure of a sufficiently flexible electrolyser to electricity-market and grid-tariff signals.

The use of a constant annual electricity price provides no temporal market signal, such that electrolyser operation is primarily driven by local VRES availability and the need to satisfy hydrogen demand. In Scenario (4), the introduction of dynamic electricity prices, together with the capacity tariff and battery storage, noticeably reshapes the operating schedule: the electrolyser is incentivised to consume electricity when price signals are favourable, while avoiding or reducing consumption during expensive periods. Importantly, low-price periods frequently reflect conditions of abundant electricity supply, often associated with high renewable generation, meaning that this price-responsive behaviour also tends to shift hydrogen production towards periods that are less constraining for the power system. The resulting dispatch is therefore not only more economically responsive, but also inherently more grid-friendly, as the electrolyser adapts its consumption to both local renewable availability and broader electricity-system conditions.

2.7.7.2 Costs breakdown and techno-economic evaluation

Following the incremental scenario analysis, the remainder of the study focuses on Scenario (4), which combines uniform hydrogen demand, dynamic electricity prices, the capacity tariff, and a 190 kWh battery, and is retained as the reference configuration for the subsequent analyses.

Table 2-33 : Breakdown of annual electricity bill per year for Scenario (4).

Year uniform demand	*Grid electricity [k€]*	*Volumetric grid costs [k€]*	*Capacity tariff [k€]*	*Wind electricity [k€]*	*PV electricity [k€]*	*GoO [k€]*	*Total [k€]*
2023	175.21	32.45	47.17	249.84	129.3	18.62	652.65
2024	143.17	48.78	43.24	176.75	60.39	16.85	489.19
2025	211.37	55.60	49.70	188.11	66.23	16.01	587.03
Expected value	176.59	45.61	46.70	204.89	85.33	17.16	576.29

Table 2-33 decomposes the electricity bill and highlights the respective contributions of grid purchases, local renewable electricity and network charges. The expected annual electricity bill amounts to 576.29k€, with wind electricity representing its largest component (204.89k€/year), followed by grid electricity purchases

(176.59k€/year) and PV electricity (85.33k€/year). Grid-related volumetric and capacity charges add respectively 45.61k€ and 46.70k€/year, illustrating that grid dependence affects the system economics beyond the wholesale electricity price alone. Significant interannual variability is also observed, with the total electricity bill ranging from 489.19k€ in 2024 to 652.65k€ in 2023, reflecting the combined influence of renewable availability and electricity-market conditions.

Table 2-34: Breakdown of objective function per year for Scenario (4).

Year uniform demand	Annualised CAPEX H2 [k€]	OPEX H2 [k€]	Electricity bill [k€]	Fleet CO2 valorisation [k€]	H2 exports [k€]	Industry CO2 valorisation [k€]	Total annual cost [k€]
2023	554.38	189.67	652.65	-49.09	0	0	1247.63
2024	554.38	189.70	489.19	-49.25	0	0	1184.41
2025	554.38	189.69	587.03	-49.09	0	0	1282.02
Expected value	554.38	189.69	576.29	-49.14	0	0	1271.23

Table 2-34 provides the economic overview of the optimised hydrogen production system by decomposing the objective function across the three representative years. The expected annual system cost amounts to €1.27 million, of which the annualised CAPEX (554.38k€) and electricity bill (576.29k€) represent the dominant contributions, followed by approximately 189.69k€ of hydrogen-system OPEX. While the investment-related costs remain identical across the three scenarios, the electricity bill exhibits substantial interannual variability, ranging from 489.19k€ in 2024 to 652.65k€ in 2023, and therefore constitutes the main source of variation in the annual cost of hydrogen production. The valuation of avoided fleet CO_2 emissions provides a relatively limited but consistent benefit of approximately 49k€/year. Since industrial H_2 exports are disabled at this stage, neither export revenues nor the associated industrial CO_2 valorisation contribute to the objective function. These results already highlight the central role of electricity-market and renewable-generation conditions in determining the economics of the hydrogen production system, which is further investigated in the following analyses.

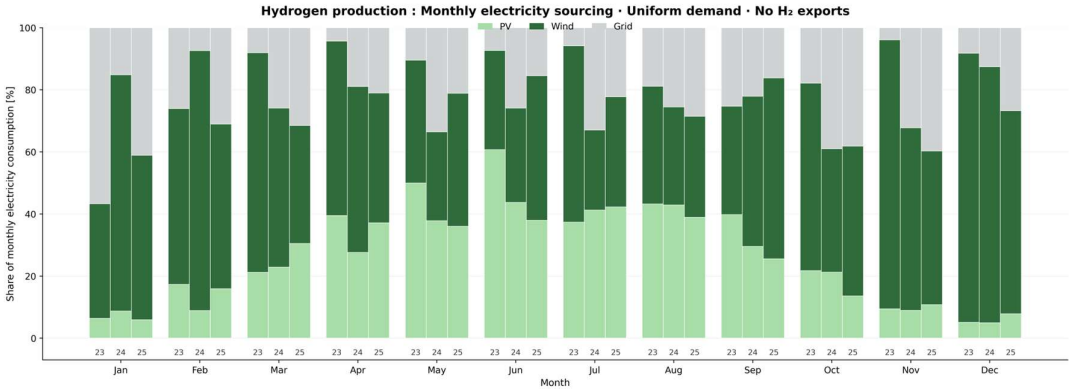


Figure 2-31: Monthly share of PV – WIND – GRID energy to produce hydrogen per year for Scenario (4).

In Figure 2-31, it is observed that the electricity mix used for hydrogen production remains strongly dependent on local renewable generation conditions, with grid electricity acting as a complementary source whenever PV and wind production are insufficient. A seasonal pattern can be observed, although it differs quite substantially between years due to the interannual variability of renewable generation. In 2023, for instance, the grid contribution falls below 10% during several spring and summer months, while reaching 57% in January. By contrast, grid dependence remains considerably higher throughout much of 2024 and 2025, reaching respectively 39% and 40% during some autumn months. Wind power provides a particularly important contribution during winter, partly compensating for the seasonal reduction in PV generation, while solar electricity becomes increasingly significant during spring and summer. Note that enabling additional hydrogen exports of the industrial off-taker will likely impact the monthly mix of electricity sourcing.

Figure 2-32 summarizes the expected electricity sourcing mix for hydrogen production across the three representative years, showing that local wind and PV generation respectively supply 50.9% and 26.4% of the electricity demand, while the remaining 22.7% is supplied by the grid.

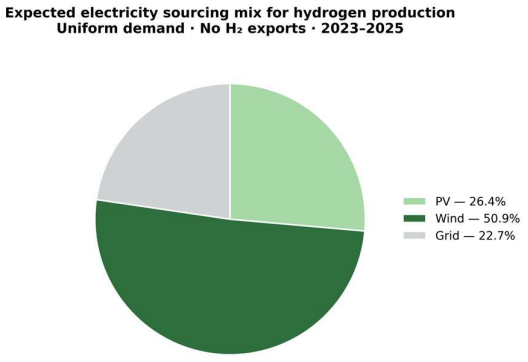


Figure 2-32: Expected sourcing mix for hydrogen production for Scenario (4).

Overall, these results show that the existing local VRES resources alone cannot consistently supply the electricity required for hydrogen production throughout the year. Moreover, given the lower cost of locally produced PV and wind electricity compared with electricity from the grid, it is expected that the optimiser already exploits most available renewable generation to minimise the annual electricity bill. This is further confirmed with the sensitivity analysis conducted in Table 2-36 on the maximum allowed share of electricity from grid in the sourcing mix, where infeasibility is observed when this constraint is below 20% share; therefore, explaining that most VRES energy is already exploited by the optimiser without even constraining the grid share.

This residual reliance on grid electricity finally raises an important issue regarding the ability of the resulting hydrogen to comply with the requirements to be defined as "clean" hydrogen, therefore decreasing the valuation of CO2 removal from mobility and industry sectors discussed earlier.

Figure 2-33 provides a detailed breakdown of the expected $LCOH_2$, estimated at 12.78€/kg for the uniform-demand scenario without industrial H_2 exports. Electricity sourcing constitutes the largest cost component, contributing 6.05€/kg H_2 (43.78%), followed by the annualised system CAPEX at €5.08/kg H_2 (36.76%) and electrolyser OPEX, including water consumption, at 1.99€/kg H_2 (14.38%). Together, these three components therefore dominate the hydrogen production cost, while battery costs, stack replacement and end-of-life dismantling have comparatively limited contributions. The valorisation of avoided fleet CO_2 emissions reduces the $LCOH_2$ by approximately 0.52€/kg H_2. Overall, the breakdown highlights electricity sourcing as the primary economic lever of the system and confirms that achieving competitive hydrogen production costs will largely depend on securing sufficiently low-cost electricity while maintaining adequate electrolyser utilisation.

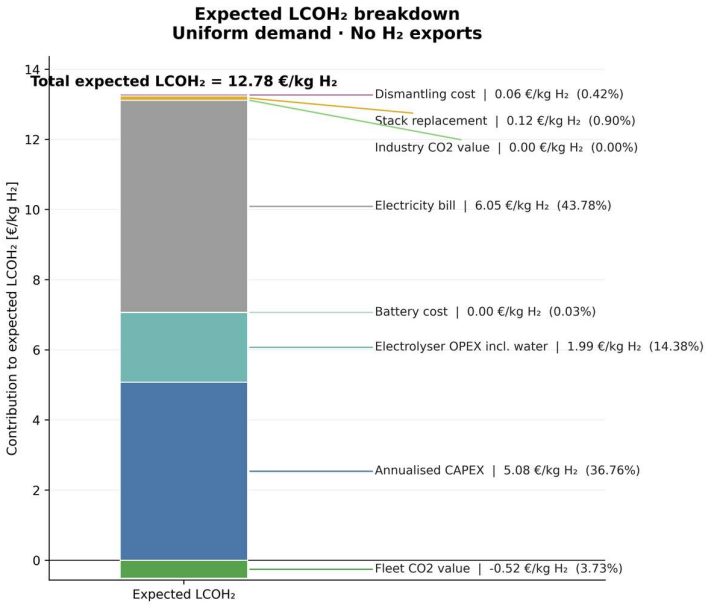


Figure 2-33: Expected cost breakdown of LCOH2 for Scenario (4), in [€/kg_h2] and [%].

Note that this expected $LCOH_2$ is evaluated without allowing sales of surplus H_2 for industrial purposes, therefore meaning that this is the marginal cost of H_2 supply for the heavy-duty transport fleet considering the nominal WACC and the lifetime of the project (and stack replacement & dismantling costs). In terms of NPV evaluation, it is translated as the minimum required H_2 selling price to the H_2 fleet to achieve NPV = 0 at the end of the project (and the associated payback period is equal to the last year of the project). Any H_2 sold to industry, or H_2 sold at price higher than the $LCOH_2$ will therefore generate additional cash flows increasing the NPV above 0 (and decreasing the payback period accordingly) as it will be observed later in Table 2-35.

Going further, the four representative seasonal days presented in Figure 2-34 to Figure 2-37 illustrate the flexible operation of the electrolyser in response to renewable availability and electricity-market conditions. The figures simultaneously display the electrolyser power consumption (blue), available VRES production combining PV and wind (green), grid electricity imports (brown), H_2 storage level (purple), hourly H_2 refuelling events (orange), EPEX spot electricity price (grey dotted line), as well as battery charging (cyan dotted line) and discharging power (red dotted line), thereby providing an integrated view of the interactions between electricity sourcing, H_2 production, storage operation and market conditions throughout each typical day.

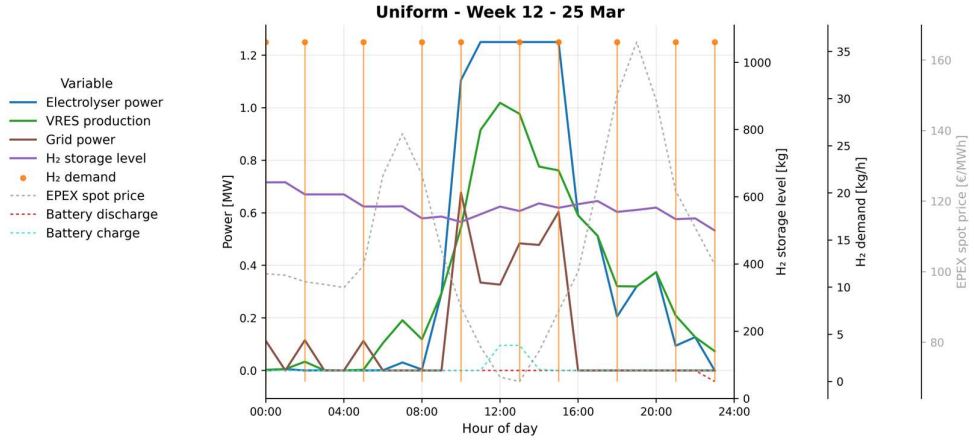


Figure 2-34: Electrolyser operation with electricity sourcing and refuelling events - typical spring day

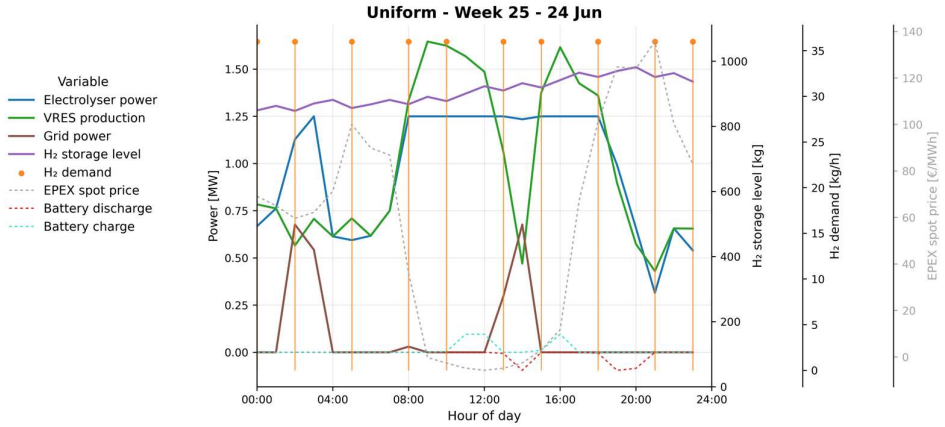


Figure 2-35: Electrolyser operation with electricity sourcing and refuelling events - typical summer day

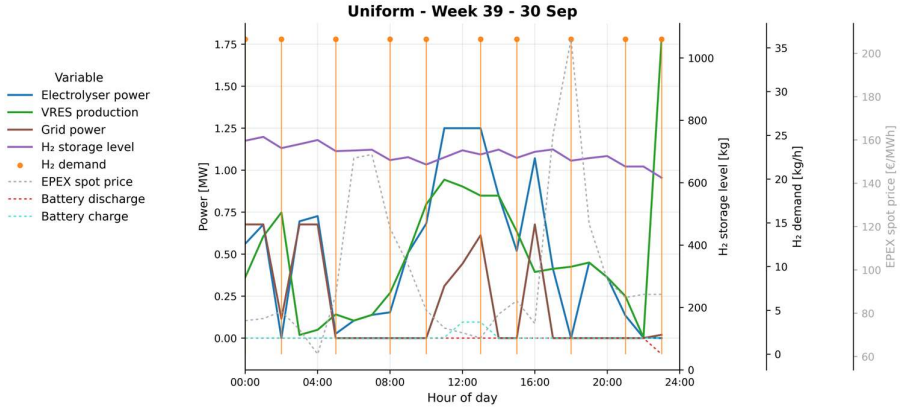


Figure 2-36: Electrolyser operation with electricity sourcing and refuelling events - typical autumn day

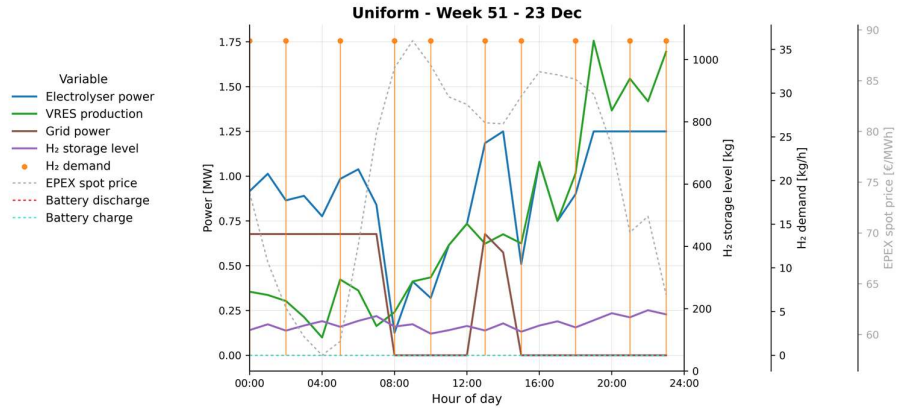


Figure 2-37: Electrolyser operation with electricity sourcing and refuelling events - typical winter day

In spring, the electrolyser remains almost inactive during the first part of the day before increasing rapidly towards its nominal operating level as VRES production becomes available, with grid electricity complementing local generation when required. This behaviour becomes even more pronounced in summer, when abundant

renewable generation allows the electrolyser to operate close to full load for several consecutive hours while relying comparatively little on grid imports. In autumn, the lower and more irregular VRES availability results in a substantially more fragmented electrolyser schedule, with production alternating between periods supplied predominantly by local renewables and periods requiring significant grid support. Winter conditions similarly require a more opportunistic operating strategy, with the electrolyser adapting its production to the available renewable resource and electricity-market conditions. Despite these pronounced variations in electrolyser operation, the H_2 storage level evolves comparatively smoothly, demonstrating its role in decoupling hydrogen production from the refuelling schedule.

By contrast, the battery remains only marginally used throughout the four seasons. Charging and discharging events are short and of limited magnitude compared with the electricity flows handled directly by the electrolyser. The optimizer therefore predominantly exploits the inherent operational flexibility of hydrogen production itself, adjusting electrolyser consumption in time rather than systematically storing electricity in the battery. This suggests that, under the baseline economic conditions, converting electricity directly into hydrogen and using the H_2 storage as the main temporal buffer is generally more cost-effective than performing electricity arbitrage through the BESS. The battery consequently acts as a secondary short-term balancing asset, whereas the combination of flexible electrolyser operation and hydrogen storage provides the dominant source of temporal flexibility.

Next, Table 2-35 and Table 2-36 present the sensitivity analyses performed, respectively studying the respective impacts of the H2 selling price on financial KPIs, and the maximum allowed share of electricity from the grid forcing a progressively greener electricity sourcing for hydrogen production.

Table 2-35: Sensitivity analysis of the H2 selling price on the expected financial indicators for scenario (4) with H2 exports enabled for the industrial off-taker.

H2 selling price [€/kg_h2]	*Size Battery [MWh]*	*Annual Revenues [M€/y]*	*NPV H2 unit [M€]*	*Discounted Payback year [y]*	*Grid electricity share [%]*	*H2 exports [ton/y]*
13	2.29	0.36	2.41	9	48.0	69.85
14	2.58	0.55	4.11	7	49.0	76.77
15	2.84	0.74	5.86	6	51.2	81.92
16	1.40	0.91	7.42	5	52.3	83.79
17	1.46	1.07	8.92	4	53.2	86.09

Table 2-35 highlights the strong influence of the hydrogen selling price on both the financial performance and optimal operation of the system. Increasing the selling price from 13€/kg to 17€/kg raises the expected annual revenues from 0.36€ million to 1.07€ million, resulting in a substantial increase in NPV from 2.41 million € to 8.92 million € and reducing the discounted payback period from approximately 9 to 4 years. This improvement in profitability is primarily driven by the direct price effect, as each kilogram of hydrogen supplied to both the truck fleet and industrial off-takers generates greater revenue. However, the higher hydrogen value also modifies the optimal operating strategy and creates an additional volume effect: industrial H_2 exports increase from 69.85 to 86.09 tonnes per year, while the grid electricity share rises from 48.0% to 53.2%. The optimizer therefore finds it economically attractive to purchase additional grid electricity to produce and sell more hydrogen as its market value increases.

Table 2-36 : Sensitivity analysis of the maximum allowed share of electricity import from the grid on battery sizing and LCOH2 for the "uniform demand" scenario

Grid share	*Expected electricity bill [k€/y]*	*Expected LCOH2 [€/kg_h2]*	*Battery sizing [MWh]*
25%	562.61	12.83	0.80
20%	492.74	30.48	60.12
15%	INFEAS.	INFEAS.	INFEAS.

The grid-share sensitivity analysis highlights a clear techno-economic limit to further reducing grid dependence. Tightening the maximum grid electricity share from 25% to 20% reduces the expected annual electricity bill from 562.61k€ to 492.74k€ but requires the optimal battery sizing to increase dramatically from 0.80 to 60.12. This excessive storage requirement causes the expected $LCOH_2$ to rise from 12.83€/kg to 30.48€/kg, making the solution economically unattractive despite its lower reliance on grid electricity (or the maximisation of the self-consumption of local renewable energy). Moreover, grid-share constraints of 15% and below lead to infeasible solutions. These results indicate that the locally available PV and wind generation is already extensively exploited, and that further reductions in grid dependence can only be achieved through disproportionate storage investments or, ultimately, additional renewable generation capacity. As the model does not allow investment in additional renewable energy capacity, the problem becomes infeasible.

2.7.7.3 Results on main KPI's

Table 2-37: Main KPI results for BUC 6a

Name	Value - results	Unit
Fuel net cost price	12.78	€/kg H_2
Fuel net sales price	Sensitivity range investigated: 13–17	€/kg H_2
Share of electricity sources in H_2 production (with H_2 exports to industry)	*Depends on H_2 selling price:* Share Wind = 34.9–31.4 for 13–17€/kg H_2 Share PV = 17.1–15.4 for 13–17€/kg H_2 Share Grid = 48.0–53.2 for 13–17€/kg H_2	%
Quantity of self-consumed electricity per year	*Depends on H_2 selling price :* Wind: 3.53-3.45 for 13–17€/kg H_2 PV: 1.72-1.70 for 13–17€/kg H_2	GWh/y
Quantity of injected electricity per year	*Depend on H_2 selling price :* Wind: 0.29-0.45 for 13–17€/kg H_2 PV: 0.06-0.09 for 13–17€/kg H_2	GWh/y
Investment profitability H_2 unit	*Depends on H_2 selling price :* NPV = 2.41–8.92 for 13–17€/kg H_2	M€
Total CAPEX (with battery)	4.3	M€
CO_2 valuation	Avoided fleet CO_2 emissions valued at ≈ 49.1	k€/year
Volume sold to industry (extra demand)	69.85–86.09 depending on H_2 selling price	t/year
Annual sales PV-WIND business units	Wind: 223.44 (sales to H_2 unit) + 11.65 (revenues from injection) = 235.09 / PV: 86.75 (sales to H_2 unit) - 1.08 (revenues from injection) = 85.67	k€/year
Opportunity cost of self-consumed electricity	Wind: 148.96 / PV: 52.83	k€/year
Transport cost price (only fuel cost component)	Depends on *H_2 selling price :* *104-136*	€/100 km

2.7.8 Conclusions

The BUC 6a analysis demonstrates that locally produced renewable hydrogen can provide a flexible pathway for supplying heavy-duty mobility, while its economic performance remains strongly dependent on electricity sourcing and market conditions. Dynamic electricity prices constitute the main source of implicit flexibility: exposing the electrolyser to hourly price signals significantly reduces the $LCOH_2$ by allowing hydrogen production to be shifted towards favourable periods.

The electrolyser itself, combined with H_2 storage, provides most of the required temporal flexibility. Battery storage therefore remains a complementary asset under the investigated configuration, with relatively limited additional economic benefits. Conversely, the capacity tariff strongly reduces peak grid withdrawals and demonstrates how appropriate tariff signals can incentivise more grid-friendly operation without fundamentally changing total grid electricity consumption.

Local PV and wind generation provide approximately 77% of the expected electricity mix for hydrogen production to supply the H2 fleet, but complete independence from the grid is neither technically nor economically optimal with the existing generation capacities. Further reducing the grid share requires rapidly increasing storage capacities, with a 20% grid-share constraint already increasing the $LCOH_2$ to approximately 30.5€/kg H_2. Enabling H2 exports for industry further deteriorate this ratio as the share of grid electricity in the H2 production mix increase up to 53% in the scenario with H2 selling price at 30.5€/kg H_2

Finally, the substantial interannual variation in electricity costs confirms the importance of considering correlated renewable-generation and electricity-price conditions when assessing long-term hydrogen economics.

2.7.9 Recommendations

Table 2-38: Key recommendations for BUC 6a

Recommendations	
Technical	Flexible operation of electrolysers and adequate H_2 storage should be prioritised before adding electrical battery capacity. Electrolysers should be operated in response to local VRES availability and dynamic electricity prices. Refuelling demand patterns should be as uniform as possible and required energy for high pressure compression and pre-cooling should not be neglected. Flexible operation of compressors is a must.
Socio-economic	Hydrogen projects should be assessed using several representative climatic and electricity-market years rather than a single deterministic year. Electricity sourcing is the dominant economic lever, while project profitability remains highly sensitive to the achievable H_2 selling price and access to additional off-takers. Industrial H_2 demand can therefore improve asset utilisation and project revenues when economically and technically feasible. On-site solar and/or attractive PPA contracts are a must to cut the electricity bill. Only minimising costs as primary objective will not produce “clean” H_2 ; if required, grid energy share should be constrained / multi-objective analysis should be performed.
Policy/regulatory	Dynamic electricity pricing and appropriately designed capacity tariffs encourage flexible hydrogen production and grid friendly behaviour. Dynamic prices provide an economic signal to shift electrolysis towards favourable system conditions, while capacity-based network tariffs effectively limit peak grid withdrawals. Regulatory frameworks for renewable hydrogen should nevertheless account for the practical need for residual grid electricity, as imposing excessively restrictive grid-share requirements can lead to disproportionate storage investments and strongly increase hydrogen production costs.

2.8 BUC 6b - Green electricity for long haul trucks

2.8.1 General information

Test Case ID	*Name of Test Case*
2	Green H2 for long haul trucks
Maturity of Test Case	
In development	

ID	*Name of Business Use Case*
BUC 6b	Cross sectoral business models for long haul trucks mobility from local green power.
Short description and objectives	

This business use case aims to identify the most cost-efficient and sustainable energy model for operating long-haul trucks powered by locally produced green energy. The initial pilot focuses on converting renewable electricity from wind and solar sources into hydrogen to supply a transport company. Given the rapid advancements in electric truck technologies and their increasing driving range, the study will also compare the optimal hydrogen-based configuration with a fully electric alternative, assessing both as viable low-carbon mobility solutions.

Accordingly, the primary objectives are to:

- Provide a comparative analysis between the optimized hydrogen fuel production solution defined in BUC 6a and an equivalent fully electric alternative.
- Extend the comparative assessment beyond the fuel production stage to include all parameters, benefits, and costs associated with transport operations, in order to determine the most advantageous solution from the end-user's perspective.

In the baseline scenario (BUC 6a), hydrogen is produced sustainably via electrolysis powered by renewable energy. The electricity is supplied by an existing 2 MW wind turbine complemented by a new photovoltaic installation. Both generation assets are located on or near the hydrogen refuelling station, which also has a direct grid connection. The renewable electricity is primarily used to produce hydrogen for truck refuelling, while any surplus generation is exported to the grid.
On the demand side, the project involves a fleet of ten hydrogen-powered trucks, representing an annual consumption of approximately 109 tons of hydrogen. Each truck operates around 136.500 km per year. The electrolyser, rated at 1.25 MW, is sized accordingly. In addition to supplying the truck refuelling station, surplus hydrogen can be transported via tube trailers and supplied to 20–25 MW gas-fired power plants located nearby. A high-pressure hydrogen storage system is integrated to balance production and demand during periods of low renewable generation.
In the electric alternative scenario of BUC 6b, the 2 MW wind turbine and the photovoltaic park directly supply electricity to a battery energy storage system (BESS), which ensures continuity of supply during periods of low renewable generation. The stored energy is then delivered to truck charging stations, powering ten electric trucks with performance comparable to hydrogen trucks, each covering approximately 136.500 km per year. In addition to the heavy-duty charging infrastructure, supplementary EV charging points for passenger vehicles could be installed to make use of surplus renewable electricity.
Both scenarios are designed to be modular and scalable over time. A second phase foresees the replacement of the existing wind turbine at the end of its lifetime (around 2036) with a higher-capacity model capable of meeting increased future demand.

2.8.2 Simulation tool

Building upon the results obtained in BUC6a, this variant investigates an alternative pathway for the decarbonisation of heavy-duty road transport based exclusively on battery-electric vehicles (BEVs). Rather than supplying hydrogen to fuel-cell trucks, the locally generated renewable electricity is directly used to charge a fleet of battery-electric trucks through dedicated high-power charging infrastructure.

The objective of this use case is to compare the technical and economic performance of the wind-to-hydrogen-to-vehicle (VH_2) and wind-to-vehicle (VE) pathways under identical boundary conditions. Using the optimised renewable generation capacities determined in BUC6a as a common starting point, the analysis evaluates how the direct electrification of heavy-duty transport affects renewable energy utilisation, electricity procurement, infrastructure investments, operational costs and overall system economics.

BUC 6b relies on the same stochastic optimisation framework and the same 2023–2025 input datasets as BUC 6a, thereby accounting for the interannual variability of renewable generation and electricity-market conditions. The objective remains to minimise the expected annual cost of energy supply, with investment-related expenditures annualised through a capital recovery factor using the same WACC, inflation and financial assumptions. The avoided-CO_2 valuation and subsequent techno-economic assessment also follow the same methodology, including the calculation of NPV, payback period and the other economic KPIs based on a selling price greater than the LCOE (or LCOC, levelized cost of charging). However, a difference lies in the revenue structure: no surplus energy can be valorised through an external industrial off-taker in BUC 6b, cash flows are solely generated by the sales to the truck-fleet operator.

Finally, similarly to the hydrogen case, different charging strategies are investigated in order to assess the influence of fleet operation on the utilisation of local renewable generation and electricity market opportunities. The optimisation therefore determines the most cost-effective charging schedule while ensuring that the energy requirements of the electric truck fleet are always satisfied. The resulting techno-economic indicators provide a direct comparison between both transport pathways and highlight the conditions under which battery-electric or hydrogen-powered heavy-duty transport constitutes the most attractive solution.

2.8.3 Use case setup

The wind and solar power generation facilities are located adjacent to the electric truck charging station and the associated industrial and transportation site. These assets are connected to the public electricity grid, allowing surplus renewable electricity to be injected into the grid, while additional electricity can be imported whenever local generation is insufficient to meet the charging demand. A BESS can be installed on-site to temporally decouple electricity supply from truck charging requirements, increase the utilisation of locally generated renewable electricity and limit grid withdrawals during unfavourable periods. Electricity is ultimately

supplied through two 400 kW DC fast chargers to long-haul electric trucks providing transport services to the industry.

The comparative scenario for low carbon fuel (full electric) case BUC 6a is represented in Figure 2-38.

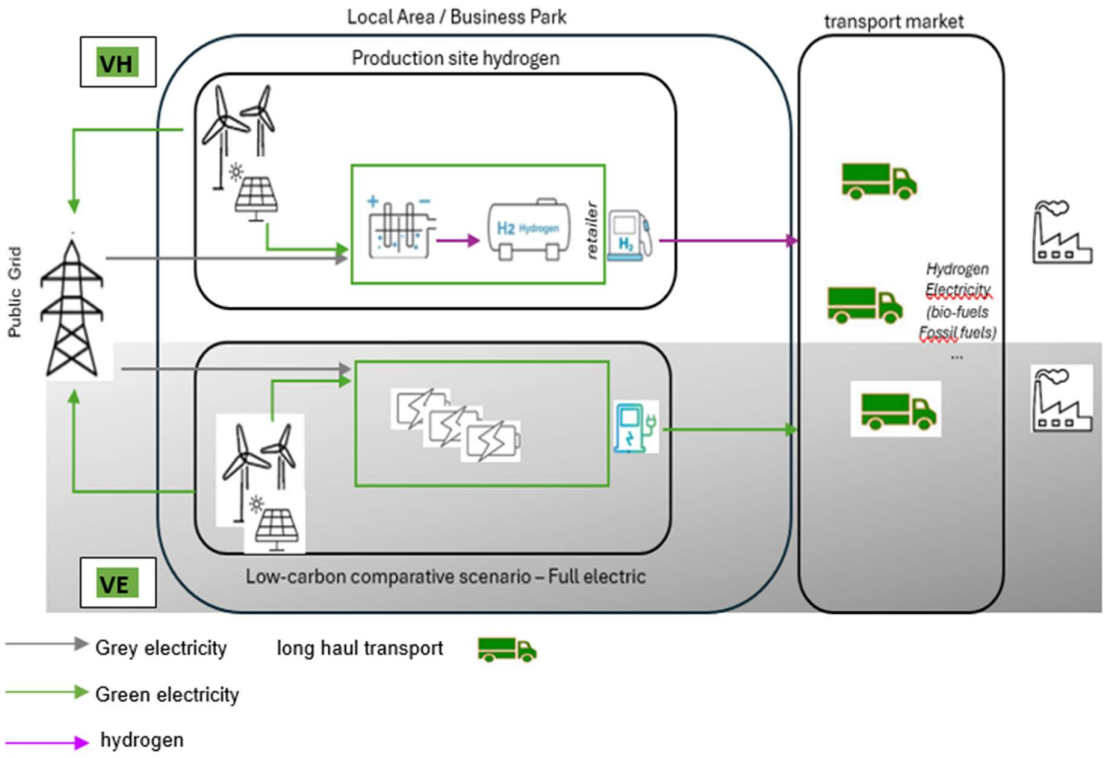


Figure 2-38: Diagram of the main energy flows within BUC 6b

In this configuration, the contractual structure is simplified compared with BUC 6a, as the hydrogen production, storage and retail chain is replaced by the direct supply of electricity to the fleet operator. The electricity supplier and asset owner maintain agreements covering the purchase of electricity from the grid, the sale of surplus electricity injected into the grid, and the associated Guarantees of Origin (GoOs).

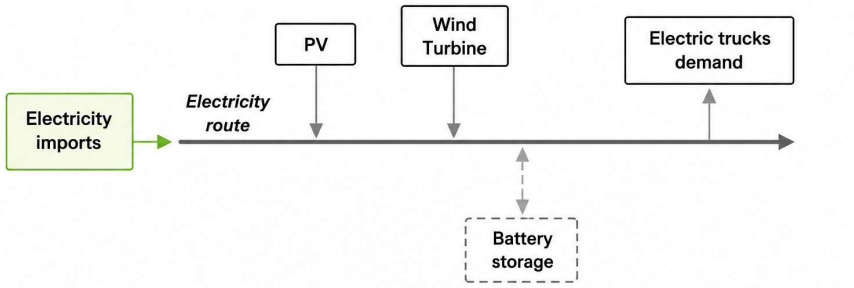


Figure 2-39: Interactions between energy vectors and technologies involved in BUC 6b

Figure 2-39 presents the schematic representation of BUC 6b, where the electric truck charging demand is supplied through a combination of local PV and wind generation and grid imports. Battery storage can additionally be deployed to increase operational flexibility and optimise electricity supply to the charging infrastructure. In this setup, the BESS is expected to become the primary source of operational flexibility. Unlike BUC 6a, where hydrogen storage decouples hydrogen production from refuelling demand and the electrolyser itself provides flexibility, battery storage is here the main asset available to temporally decouple electricity supply from truck charging requirements and facilitate the grid-friendly integration of the end-user.

2.8.4 General Assumptions

The charging-infrastructure CAPEX accounts for both the two HVDC 400kW charging units and the associated infrastructure, including site preparation, charging platform and electrical cabin. It should be noted that potential upstream grid reinforcement or distribution network adaptation costs are not included in this study and could result in substantial additional investment costs.

While a specific energy consumption term was accounted per kg of dispensed H_2 in BUC 6a, the electrical consumption of the charger balance-of-plant and auxiliary systems, including power conversion and cooling requirements, is implicitly included in the 90% overall charging efficiency for BUC 6b.

Annual O&M costs cover regular onsite expenses (land lease, insurance, overhead, cleaning, etc.) as well as specific maintenance costs for the charging equipment, including periodic servicing and the replacement of components such as liquid-cooled charging cables and connectors, as well as coolant replacement. Beyond these recurring maintenance activities, the limited lifetime of the charging equipment is represented through a life-extension and replacement cost, accounting for ageing components such as power electronics. Finally, dismantling costs are included for the decommissioning and removal of the charging equipment at the end of the lifetime.

Regarding EV charging conditions, according to technical specifications, the eActros 600 can be recharged from 20 % to 80 % state of charge in approximately 60 minutes using a CCS charger rated at up to 400 kW and 500 A under standardised ISO/SAE 12906 charging conditions. Although Mercedes-Benz qualitatively describes the charging process as consisting of an extended constant-power phase close to the maximum charging rate followed by a progressive power reduction as the battery approaches 80 % SoC, no public manufacturer data providing the exact charging power as a function of battery state of charge are currently available. Consequently, each charging session is represented in this work by an equivalent one-hour charging event delivering 360 kWh, which preserves both the manufacturer-reported charging duration and the transferred energy, charging efficiency accounted.

Additionally, to ensure a fair comparison between the hydrogen and battery electric scenarios, the charging demand considered in BUC 6b was not based on an identical number of service events, but rather on an equivalent transport service. In BUC 6a, each hydrogen refuelling event delivers approximately 36 kg of hydrogen, providing an estimated motorway driving range of around 450 km considering a hydrogen consumption ratio of 8kg per 100km. Conversely, the fully electric scenario considers Mercedes-Benz eActros 600 trucks charged between 20 % and 80 % state of charge (SoC), corresponding to approximately 360 kWh transferred to the battery during each charging session. This operating window was selected to reflect common fleet management practices aimed at limiting battery degradation while maintaining high vehicle availability. Under typical motorway operating conditions (estimated consumption of 119kWh/100km), such a charging session provides an estimated driving range of approximately 300 km. Consequently, a single battery charging session only delivers around 66,67 % of the transport service provided by one hydrogen refuelling event. An equivalent transport demand would therefore require approximately 1.5 charging sessions for each hydrogen refuelling event. As a result, the battery electric scenario assumes 5 more charging sessions as the hydrogen case to preserve the same overall fleet utilisation for comparison.

For BUC 6b, avoided CO_2 emissions are estimated relative to the reference diesel truck, resulting in approximately 0.68 kg CO_2 avoided per kWh supplied. Assuming an ETS2 carbon price of 45€/tCO_2, this corresponds to a decarbonisation benefit of approximately 30.5€/MWh.

Similarly to BUC 6a, two charging strategies are subsequently investigated. The first distributes the charging sessions uniformly over the day, whereas the second adopts a batch charging strategy in which vehicles are recharged during two concentrated charging windows, one in the morning and one in the evening, reflecting typical fleet operating schedules.

A notable distinction from BUC 6a is the different fiscal excise regime. Electricity supplied to the charging stations is subject to the Belgian excise regime applicable to professional consumers, including electricity supplied from local production. An average effective rate of 13.07€/MWh is assumed, based on the progressive excise rates effective from 1 August 2026 under the Programme Law. By contrast, electricity directly used for electrolysis in

BUC 6a is assumed to be exempt from excise duties, subject to the relevant administrative authorisation. For electricity drawn from the grid, proportional and capacity tariffs follow the same modelling approach as in BUC 6a.

2.8.5 Main Data inputs

Table 2-39: Main Data inputs for BUC 6b

Name	Description	Units	Value or time-series	Reference years	Data source	ReInvent Common data (Yes/No)
Nominal discount rate	Set as the nominal WACC of the project, includes inflation rate	%	val	2023-2025	NREL	No
Day ahead Wholesale prices	Day ahead prices used to implement dynamic pricing	EUR/kWh	T-S	2023-2025	ENTSO-E	No
Feed-in tariff for PV	Remuneration rate for injection of PV energy to the grid.	EUR/kWh	T-S	2023-2025	IDETA	No
Wind Turbine production profile	Historical hourly wind energy production from IDETA's WT10.	kWh	T-S	2023-2025	IDETA	No
Solar PV production profile	Normalized PV energy production from ENTSO-E transparency platform, hourly resolution	kWh	T-S	2023-2025	ENTSO-E	No
Charging demand profiles	Hourly 400kW EV charging demand profiles. "uniform' and "batch" versions.	kWh	T-S	2023-2025	IDETA	No
PV installed capacity	Available on-site solar PV capacity	kWp	val	2023-2025	IDETA	No
PV inverter capacity	Power rating of the AC/DC conversion unit for solar power	kVA	val	2023-2025	IDETA	No
PV inverter conversion efficiency	Conversion efficiency from solar DC to grid AC	%	val	2026	IDETA	No
400kW charger efficiency	Charging efficiency including cooling energy.	%	val	2026	IDETA	No
Fixed O&M 400kW charging station	Fixed annual component of operation of maintenance costs of EV charging station	EUR/y	val	2026	IDETA	No
Variable O&M Wind Turbine	Variable component of operation of maintenance costs of electrolysis unit	EUR/kWh.y	val	2026	IDETA	No
Fixed O&M Wind Turbine	Fixed annual component of operation of maintenance costs of wind turbine	EUR/y	val	2026	IDETA	No
Fixed O&M PV	Fixed annual component of operation of maintenance costs of solar PV installation	EUR/y	val	2026	IDETA	No
Variable O&M PV	Variable component of operation of maintenance costs of solar PV field	EUR/kWh.y	val	2026	IDETA	No
Life extension costs of charging station	Life-extension and replacement cost, accounting for ageing	EUR	val	2026	ULB	No

Name	Description	Units	Value or time-series	Reference years	Data source	ReInvent Common data (Yes/No)
	components such as power electronics					
Decommissioning costs of EV chargers	Decommissioning costs of EV chargers at the end of the project.	EUR	val	2026	ULB	
EV consumption	Electricity consumption of Mercedes-Benz eActros600	kWh/100km	val	2026	Mercedes-Benz	No
EV battery usable capacity range	Usable capacity of Mercedes-Benz eActros600 battery (20%-80% range)	kWh	val	2026	Mercedes-Benz	No
Carbon price	Estimated ETS 2 trade value for CO2 valuation	kWh/kgCO2	val	2026	European Commission	No
GoO price	GoO bought by the H2 business unit from the wind (and solar) business units	EUR/MWh	val	2026	IDETA	No

2.8.6 Modelling scenarios

BUC 6b follows the same incremental scenario-based methodology as BUC 6a to isolate the contribution of the main implicit flexibility mechanisms. The six scenarios therefore retain the same structure, progressively combining dynamic electricity prices, battery storage and the temporal distribution of the truck energy demand, while each configuration is again evaluated both with and without the electricity capacity tariff. The main difference is that hydrogen refuelling demand is replaced by the corresponding electric-truck charging demand, using uniform and batch charging profiles to assess the impact of coordinated versus concentrated fleet charging on the electricity supply system. Particular attention is given to the role of the BESS, which represents the main asset available to temporally decouple electricity supply from the charging demand in the absence of the flexibility previously provided by the electrolyser and hydrogen storage.

Similarly, sensitivity analyses are performed on the retained configuration (Scenario 4). The charging price paid by the fleet operator is varied to assess its impact on project profitability, particularly NPV and payback period. Contrary to BUC 6a, this sensitivity does not affect system operation, as no surplus energy is sold to an external off-taker; the charging-price sensitivity is therefore evaluated directly from the optimised baseline cash flows. Finally, the maximum grid-electricity share is progressively constrained following the same methodology as in BUC 6a (this time for the uniform and the batch scenarios) to quantify the technical and economic implications of supplying the fleet with an increasingly renewable electricity mix.

2.8.7 Results and analysis

The incremental scenario analysis is first used to quantify the individual and combined contributions of the different flexibility mechanisms available to the charging station. Starting from the constrained reference configuration, battery storage, dynamic electricity prices and alternative charging patterns are progressively introduced, while the impact of the capacity tariff is assessed independently for each configuration. The resulting techno-economic and grid-related indicators are summarised in Table 2-40.

Table 2-40: Expected CAPEX, battery capacity, LCOC, grid-electricity share and annual grid peak power for each scenario for incremental scenarios to highlight impact of unlocking implicit flexibility

Scenario	Total CAPEX [M€]		Battery capacity [MWh]		LCOC [€/MWh]		Share grid electricity [%]		Annual peak power from grid [MW]	
	Capacity tariff	No capacity tariff	Capacity tariff	No capacity tariff	Capacity tariff	No capacity tariff	Capacity tariff	No capacity tariff	Capacity tariff	No capacity tariff
(1) No dynamic prices – No battery – Uniform	0.61	0.61	-	-	233.63	196.61	38.22	38.22	0.76	0.76
(2) No dynamic prices – Battery – Uniform	0.92	0.80	1.07	0.66	199.05	186.17	12.59	18.12	0.22	0.76
(3) Dynamic prices – No battery – Uniform	0.61	0.61	-	-	241.89	204.87	38.78	38.78	0.76	0.76
(4) Dynamic prices – Battery – Uniform	1.00	1.00	1.34	1.33	185.77	172.43	11.17	12.47	0.20	1.42
(5) Dynamic prices – Battery – BATCH	1.31	1.26	2.43	2.25	212.03	197.42	12.03	14.78	0.23	1.85
(6) Dynamic prices – No battery – BATCH	0.61	0.61	-	-	287.55	250.53	48.99	48.99	0.76	0.76

The results first highlight the central role of battery storage in BUC 6b. Under uniform charging demand and the capacity tariff, enabling battery investment reduces the levelized charging cost from 233.63 €/MWh in Scenario (1) to 199.05 €/MWh in Scenario (2), while the share of grid electricity decreases from 38.22% to 12.59% and the annual grid peak from 0.76 MW to 0.22 MW. This improvement is obtained with a 1.07 MWh BESS, demonstrating that electrical storage provides substantial value even in the absence of dynamic electricity-price signals.

Interestingly, dynamic electricity prices alone provide virtually no flexibility benefit. Moving from Scenario (1) to Scenario (3) without a battery leaves the grid share and peak power essentially unchanged, while the levelized charging cost even increases from 233.63 to 241.89 €/MWh under the capacity tariff. Unlike the electrolyser in BUC 6a, the truck charging demand cannot freely shift its electricity consumption in response to market prices. Consequently, a dynamic price signal only becomes exploitable when an intermediate flexibility asset is available.

This complementarity becomes apparent in Scenario (4), where dynamic prices and battery storage are combined. The optimizer increases the battery capacity to 1.34 MWh, thereby reducing the levelized charging

cost to 185.77€/MWh, the share of electricity supplied by the grid to 11.17%, and the annual grid peak to just 0.20 MW when the capacity tariff is applied. Scenario (4) therefore provides the most favourable configuration under the uniform charging profile and confirms that, in BUC 6b, dynamic electricity prices primarily create value through their interaction with the BESS rather than through direct demand-side flexibility.

The Batch profile further reinforces this conclusion. Concentrating truck charging into more constrained time windows requires a substantially larger battery, reaching 2.43 MWh in Scenario (5), while the levelized charging cost increases to 212.03 €/MWh. Nevertheless, the BESS still limits the grid share to 12.03% and the annual grid peak to 0.23 MW. Without battery storage, Scenario (6) deteriorates sharply, with the levelized charging cost reaching 287.55 €/MWh and the grid share increasing to 48.99%. The comparison therefore demonstrates both the economic value of coordinating truck charging and the ability of battery storage to mitigate the additional constraints introduced by batch charging.

2.8.7.1 Costs breakdown and techno-economic evaluation

Following the incremental scenario analysis, the remainder of the study focuses on Scenario 4, which combines uniform charging demand, dynamic electricity prices, the capacity tariff, and a 1.34 MWh battery, and is retained as the reference configuration for the subsequent analyses. When relevant for assessing the impact of the charging profile, the results for Scenario 5 (batch profile) are explicitly presented and discussed.

Table 2-41: Breakdown of annual electricity bill per year for Scenario (4) and Scenario (5).

Charging profile / Year	Grid electricity [k€]	Prop. grid costs [k€]	Capacity tariff [k€]	PV electricity [k€]	Wind electricity [k€]	GOO [k€]	Excise [k€]	Total [k€]
Uniform								
2023	33.05	5.52	13.20	53.16	64.38	5.65	22.51	197.48
2024	31.98	7.88	15.30	25.99	41.32	5.39	22.51	150.37
2025	34.83	7.61	16.20	28.51	49.28	5.42	22.51	164.37
Expected value	**33.29**	**7.00**	**14.90**	**35.89**	**51.66**	**5.48**	**22.51**	**170.74**
Batch								
2023	37.02	6.18	16.51	43.34	71.67	5.65	22.51	202.88
2024	35.27	8.43	16.68	21.57	45.85	5.39	22.51	155.69
2025	38.38	8.02	16.79	23.28	56.98	5.44	22.51	171.41
Expected value	**36.89**	**7.55**	**16.66**	**29.40**	**58.17**	**5.49**	**22.51**	**176.66**

Table 2-41 presents the annual electricity-bill breakdown for the retained configuration under the Uniform and Batch charging profiles. Despite identical annual charging requirements, the temporal distribution of the truck demand affects both the sourcing and cost of electricity. The Batch profile systematically results in a higher

expected electricity bill, increasing from 170.74k€/year to 176.66k€/year, mainly due to higher grid-electricity purchases, wind-energy procurement and capacity-tariff costs. Conversely, PV procurement decreases, reflecting the lower temporal coincidence between concentrated charging events and local PV availability. The results also highlight significant interannual variability, with total electricity costs ranging from 150.37k€ to 197.48k€/year for the Uniform profile and from 155.69k€ to 202.88k€/year for the Batch profile. This variability is primarily driven by changes in renewable availability and electricity-market conditions across the 2023–2025 scenarios, whereas the electricity excise remains constant as it is directly determined by the fixed annual charging demand.

Table 2-42 further decomposes the annual objective function into its main economic components for both charging profiles. The results confirm the economic advantage of the Uniform charging strategy, with an expected annual cost of 292.06k€/year, compared with 336.13k€/year for the Batch profile.

Table 2-42: Breakdown of objective function per year for Scenario (4) and Scenario (5).

Charging profile / Year	OPEX [k€]	Electricity bill [k€]	Annualised CAPEX [k€]	Fleet CO_2 valorisation [k€]	Total annual cost [k€]
Uniform					
2023	59.32	197.48	114.55	-52.53	318.82
2024	59.29	150.37	114.55	-52.53	271.67
2025	59.29	164.37	114.55	-52.53	285.68
Expected value	**59.30**	**170.74**	**114.55**	**-52.53**	**292.06**
Batch					
2023	61.38	202.88	150.71	-52.53	362.43
2024	61.21	155.69	150.71	-52.53	315.08
2025	61.29	171.41	150.71	-52.53	330.87
Expected value	**61.29**	**176.66**	**150.71**	**-52.53**	**336.13**

This reflects the larger BESS required to accommodate the more concentrated charging demand and highlights the additional infrastructure cost associated with reduced temporal flexibility. OPEX is only moderately affected, increasing from **59.30k€ to 61.29k€/year**, while the fleet CO_2 valorisation remains identical at **52.53k€/year**, since both profiles supply the same annual transport energy demand. Overall, the comparison shows that the economic penalty of Batch charging primarily results from the additional storage capacity required to reconcile concentrated charging events with renewable availability and grid constraints, rather than from a substantial increase in annual operating expenditure.

Moreover, Figure 2-40 illustrates the monthly electricity-supply mix of the charging station under the Uniform charging profile for the three representative years. Local renewable generation supplies the dominant

share of the charging demand throughout most of the year, although its composition varies markedly across seasons and climatic years. As expected, PV contributes most strongly during spring and summer, while wind generation becomes increasingly important during the winter months, illustrating the seasonal complementarity between both renewable sources.

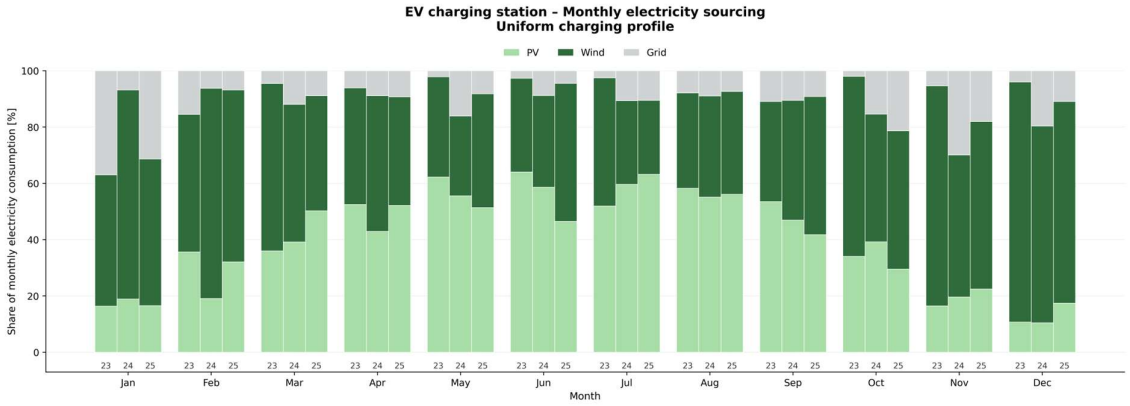


Figure 2-40: Monthly share of PV, WIND, GRID energy for charging energy supply per year for Scenario (4).

Grid dependence consequently remains relatively limited during periods of favourable renewable availability but increases substantially during less favourable months, particularly in winter. The differences observed between 2023, 2024 and 2025 further highlight the impact of interannual climatic variability: for an identical charging profile and system design, the monthly contribution of individual energy sources can change considerably. This variability reinforces the relevance of the multi-year stochastic formulation, which avoids designing and evaluating the charging infrastructure based on a single climatic year.

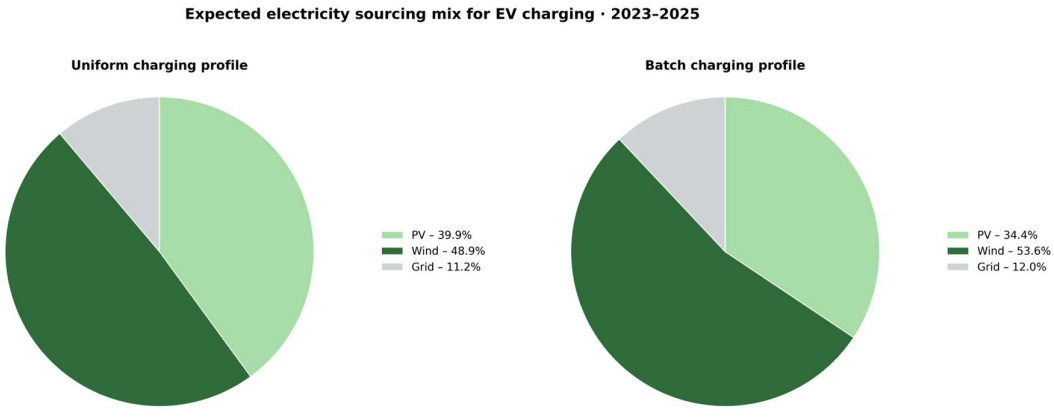


Figure 2-41: Expected sourcing mix for charging energy supply for Scenario (4) and Scenario (5).

Compared with BUC 6a, the electricity sourcing of BUC 6b is substantially more renewable, with local PV and wind generation jointly supplying approximately 89% of the annual charging demand under the Uniform profile and 88% under the Batch profile, as illustrated in Figure 2-41. This considerably lower grid dependence reflects the central role of the BESS in BUC 6b, which temporally decouples renewable generation from truck charging demand and allows a larger fraction of locally available renewable electricity to be effectively valorised. The slightly less favourable renewable sourcing observed under the Batch profile further illustrates the impact of concentrating charging demand into more constrained time windows, which reduces the temporal alignment with local renewable availability despite the larger battery capacity.

Now focusing on the breakdown of LCOC per contribution, Figure 2-42 presents the expected LCOC breakdown for the Uniform and Batch charging profiles. Electricity supply remains the largest cost component in both cases, contributing 113.6 €/MWh and 117.5 €/MWh, respectively. However, the main driver of the difference between the two profiles is CAPEX, which increases substantially from 66.5 €/MWh under Uniform charging to 87.5 €/MWh under Batch charging, due to the larger battery capacity for scenario (5) required to accommodate the more concentrated charging demand. Overall, the results confirm that concentrating charging into restricted time windows primarily penalises the system through increased storage requirements and associated investment costs, rather than through a major increase in electricity procurement costs.

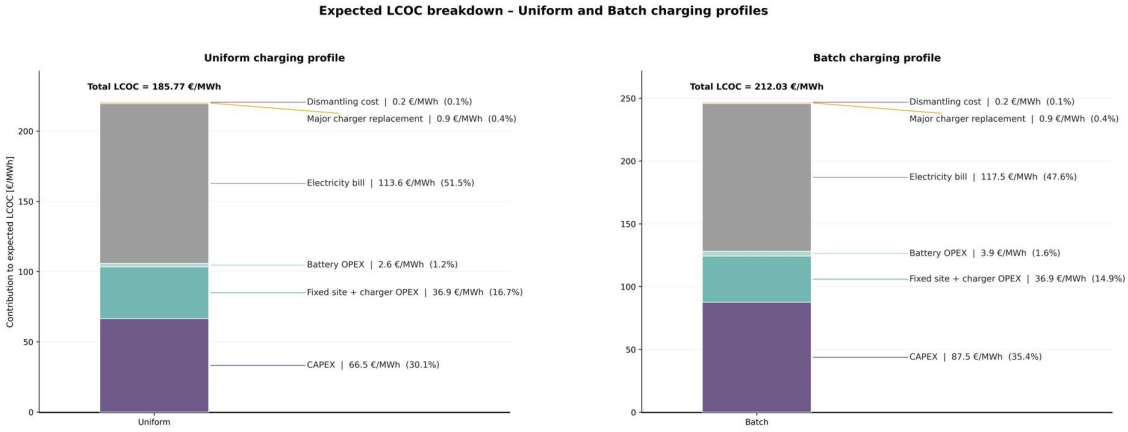


Figure 2-42: Expected cost breakdown of LCOC for Scenario (4) and Scenario (5), in [€/MWh] and [%].

Going further, Figure 2-43 and Figure 2-44 illustrate the hourly electricity balance for representative seasonal Tuesdays under the Uniform and Batch charging profiles, respectively. In both cases, the BESS acts as the main temporal flexibility asset, charging during periods of renewable surplus and/or favourable electricity prices and discharging when truck charging demand occurs under less favourable supply conditions.

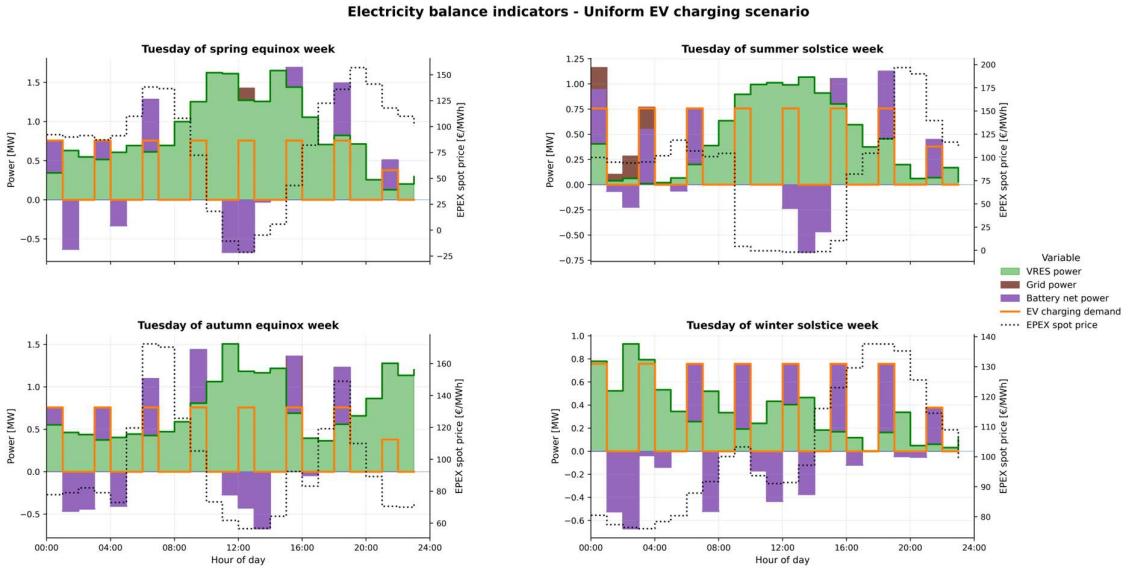


Figure 2-43: Behaviour of battery with electricity sourcing and charging demand for Uniform scenario (4). One typical day per season.

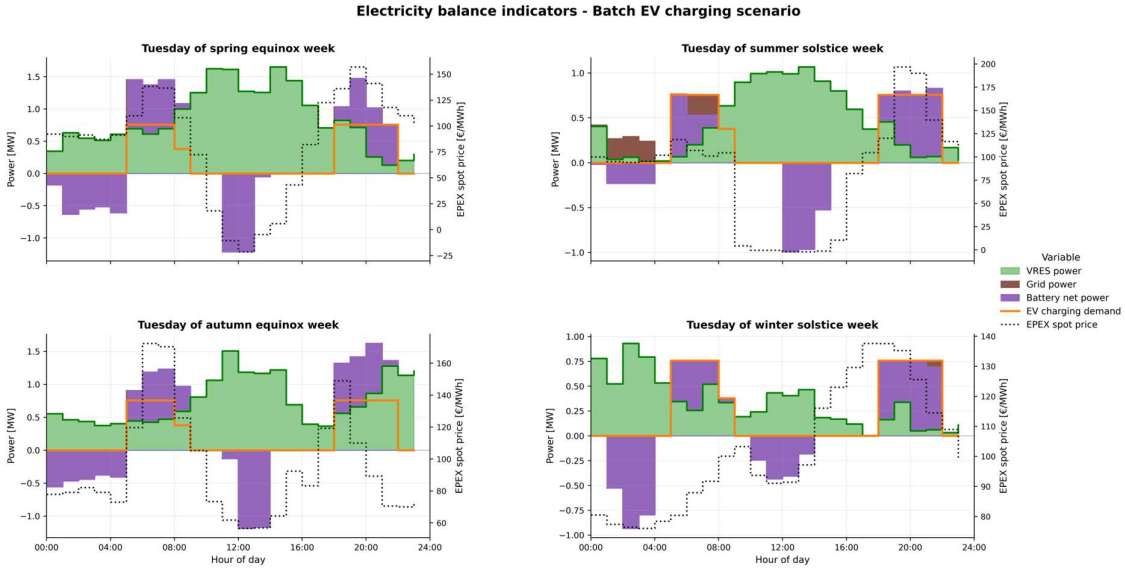


Figure 2-44: Behaviour of battery with electricity sourcing and charging demand for Batch scenario (5). One typical day per season.

This behaviour is particularly visible around midday, when high renewable availability and generally lower spot prices frequently lead to battery charging, followed by discharge during subsequent charging events. Under the Uniform profile, the more distributed charging sessions provide frequent opportunities to directly match EV demand with local renewable generation, thereby limiting the required battery shifting. In contrast, the Batch profile concentrates demand into two larger charging windows, requiring substantially stronger battery

intervention to decouple these events from instantaneous renewable availability. The larger charge and discharge cycles observed under Batch charging are consistent with the higher optimal BESS capacity identified previously (2.43 MWh versus 1.34 MWh for Uniform charging). Overall, the seasonal profiles confirm that the BESS effectively transforms an otherwise inflexible EV charging demand into a more grid-responsive load, allowing the station to exploit both renewable availability and dynamic electricity-price signals while limiting reliance on grid imports.

Table 2-43: Sensitivity analysis of the charging price on the expected financial indicators for scenario (4) and Scenario (5).

Charging profile	Charging price [€/MWh]	Charging revenue [M€/year]	NPV [M€]	Discounted payback [years]	Grid electricity share [%]
Batch	300	0.52	1.31	5.42	12.03
Batch	400	0.69	2.81	3.19	12.03
Batch	600	1.03	5.80	1.77	12.03
Batch	800	1.38	8.80	1.23	12.03
Batch	1000	1.72	11.79	0.94	12.03
Uniform	250	0.43	0.96	5.42	11.17
Uniform	400	0.69	3.20	2.29	11.17
Uniform	600	1.03	6.20	1.31	11.17
Uniform	800	1.38	9.19	0.91	11.17
Uniform	1000	1.72	12.18	0.71	11.17

Having characterised the optimal system design and operation, the analysis is now extended through a series of sensitivity studies to assess the robustness of the techno-economic results against key external assumptions. The first sensitivity focuses on the charging price paid by the fleet operator, which directly determines project revenues without affecting the previously optimised system design or dispatch, since the annual charging demand remains fixed. Table 2-43 summarises the resulting economic performance for both Uniform and Batch charging profiles. As expected, project profitability increases strongly with the charging price: under the Uniform profile, NPV rises from €0.96 million at 250 €/MWh to €12.18 million at 1,000 €/MWh, while the discounted payback period decreases from 5.42 to 0.71 years. A similar trend is observed for the Batch profile, although its higher investment and operating requirements systematically reduce profitability, with NPV reaching €11.79 million at 1,000 €/MWh. At the common charging-price points, the Uniform configuration therefore consistently outperforms Batch charging; for example, at 400 €/MWh, NPV reaches €3.20 million versus €2.81 million, with discounted payback periods of 2.29 and 3.19 years, respectively. As the charging price only modifies fleet revenues, the electricity sourcing remains unchanged across the sensitivity, with grid shares fixed at 11.17% and 12.03% for the Uniform and Batch profiles, respectively.

Note that whereas the hydrogen selling price in BUC 6a could also influence the optimal operation through the valorisation of surplus hydrogen to industrial off-takers, the charging-price sensitivity in BUC 6b is purely economic: it affects project revenues without modifying the optimal system design, dispatch or electricity sourcing.

The analysis is now extended to a technical constraint directly affecting system design and operation : the maximum share of electricity supplied by the grid; that is progressively reduced to evaluate the additional

flexibility and investment required to achieve increasingly renewable electricity sourcing. Table 2-44 summarises the resulting system design and techno-economic performance for both charging profiles.

Table 2-44: Sensitivity analysis of ma allowed share of electricity from grid on battery sizing and LCOC for Scenario (4) and Scenario (5).

Charging profile	Maximum grid share [%]	Actual grid share [%]	Battery capacity [MWh]	Total CAPEX [M€]	Electricity bill [k€/year]	LCOC [€/MWh]	Annual peak power from grid [MW]
Batch	10	9.27	2.84	1.43	164.61	212.31	0.21
Batch	5	4.73	4.35	1.87	139.49	226.88	0.17
Batch	3	3.00	6.11	2.38	133.54	270.81	0.16
Batch	1	1.00	15.04	4.97	203.36	558.72	0.22
Uniform	10	9.11	1.58	1.07	163.63	185.90	0.20
Uniform	5	4.68	3.01	1.48	139.19	198.32	0.17
Uniform	3	3.00	4.99	2.06	135.15	250.47	0.16
Uniform	1	1.00	14.01	4.67	201.56	537.41	0.23

The results reveal a clear non-linear cost associated with reducing grid dependence. Tightening the maximum grid share from 10% to 5% remains relatively manageable, although it already requires battery capacity to increase from 1.58 to 3.01 MWh for Uniform charging and from 2.84 to 4.35 MWh for Batch charging. Further reducing the grid contribution to 3% significantly increases storage requirements and LCOC, while the 1% constraint marks a sharp economic penalty, requiring approximately 14 MWh and 15 MWh of battery capacity and increasing LCOC to 537 and 559 €/MWh for Uniform and Batch charging, respectively. Interestingly, the electricity bill initially decreases as grid dependence is reduced, but rises again under the 1% constraint, indicating that the system becomes increasingly oversized and relies on substantially more costly renewable-energy shifting to satisfy the charging demand. The Uniform profile consistently remains less capital-intensive and achieves a lower LCOC than the Batch profile, confirming that a more distributed charging demand facilitates very high renewable penetration. Overall, the results suggest that very high renewable shares can be achieved at moderate additional cost, whereas approaching complete grid independence becomes disproportionately expensive and requires substantial battery oversizing.

2.8.7.2 Results on main KPI's

Table 2-45: Main KPI results for BUC 6b

Name	Value - results	Unit
Fuel net cost price	Depends on charging demand profile: 185.77 (Uniform) - 212.03 (Batch)	€/MWh
Share of electricity sources in charging	Depends on charging demand profile: PV: 39.9 (Uniform) - 34.4 (Batch) Wind 48.9 (Uniform) - 53.6 (Batch) Grid: 11.2 (Uniform) - 12.0 (Batch)	%
Battery storage capacity	Depends on charging demand profile : 1.34 (Uniform) - 2.43 (Batch)	MWh
Quantity of self-consumed electricity per year	Depends on charging demand profile: Wind: 0.86 (Uniform) - 0.95 (Batch) PV: 0.61 (Uniform) - 0.70 (Batch)	GWh/y
Quantity of injected electricity per year	Depends on charging demand profile: Wind: 3.04 (Uniform) - 2.95 (Batch) PV: 1.08 (Uniform) - 1.17 (Batch)	GWh/y
Investment profitability charging station	*Depend on selling price:* NPV(Uniform) = 0.96–12.18 for €250–1000/MWh NPV(Batch) = 1.31–11.79 for €300–1000/MWh	M€
Total CAPEX	Depends on charging demand profiles: PV: 1 (Uniform) - 1.31 (Batch)	M€
CO_2 valuation	Avoided fleet CO_2 emissions valued at ≈ 49.1	k€/year
Annual sales PV-WIND business units	*Depends on selling price :* Uniform : Wind: 51.66 (sales) + 117.21 (injection) = 168.87 PV: 35.89 (sales) - 30.53 (injection) = 85.67 Batch : Wind: 58.17 (sales) + 113.22 (injection) = 171.39 PV: 29.40 (sales) - 34.56 (injection) = 63.96	k€/year
Opportunity cost of self-consumed electricity	Wind: 148.96 / PV: 52.83	k€/year
Transport cost price (only fuel cost component)	Depends on charging demand profiles and selling price: 29.8-119	€/100 km

2.8.8 Conclusions

First, BUC 6b demonstrates that a high-power electric-truck charging station can be supplied with a predominantly local renewable electricity mix while maintaining attractive techno-economic performance. Unlike BUC 6a, where the electrolyser and hydrogen storage already provide substantial operational flexibility, the BESS plays a key role to provide flexibility in the BUC 6b configuration. Indeed, dynamic electricity prices and capacity tariff alone provide little operational value when charging demand is inflexible, but become effectively exploitable when combined with battery storage, which enables peak shaving and daily energy arbitrage. Coordinated charging (i.e. enabling flexibility in demand) may provide additional inherent flexibility, for example through dynamic charging prices.

The charging strategy consequently has a significant influence on optimal system design. A uniform demand throughout the day reduces substantially the required storage capacity and the annual peak power drawn from

the grid. Indeed, under the retained configuration, the Uniform profile requires a 1.34 MWh BESS and achieves an LCOC of 185.77 €/MWh, compared with 2.43 MWh and 212.03 €/MWh for Batch charging. Nevertheless, both configurations achieve a particularly renewable electricity supply, with local PV and wind jointly covering approximately 89% and 88% of annual demand, respectively. The multi-year analysis further demonstrates that the respective contributions of PV, wind and grid electricity can vary considerably between climatic years, confirming the relevance of the stochastic formulation.

The sensitivity analyses confirm the robustness of these conclusions while highlighting the main economic trade-offs. Project profitability increases strongly with the charging price, with the Uniform configuration consistently outperforming Batch charging due to its lower investment requirements. Conversely, progressively restricting grid imports reveals a strong non-linear cost of increasing renewable self-sufficiency. Grid shares of approximately 5–10% can still be achieved with moderate additional storage capacity, whereas approaching complete grid independence requires substantial battery oversizing and leads to a sharp increase in LCOC.

Comparison of BUC 6a and BUC 6b

The comparison between BUC 6a and BUC 6b is performed on an equivalent transport-service basis by converting the respective levelized energy production costs into €/100 km. With an H_2 consumption of 8 kg/100 km, the BUC 6a $LCOH_2$ of €12.78/kg corresponds to 102.2€/100 km. For the eActros 600 consumption of 119 kWh/100 km, the BUC 6b LCOC corresponds to only 22.1€/100 km under Uniform charging and 25.2€/100 km under Batch charging. For comparison, a diesel truck consuming 26 L/100 km represents approximately €44.2–54.6/100 km for diesel (selling) prices of €1.70–2.10/L. Direct electrification therefore presents a substantial energy production cost advantage under the investigated assumptions.

The main identified barrier for the hydrogen pathway is the need for substantial reductions in CAPEX of H_2 infrastructure to become competitive on fuel cost alone. The conversion efficiency of the electrolyser is also affecting the economic performances, as a significant amount of energy is lost in fatal heat; however, valorisation of recoverable heat from the electrolysis process can positively impact efficiency and economic KPIs if local heat demand is included in such projects. In the case of BUC 6a, the heat recovery amounts to a total of 1.75 GWh per year, corresponding to an annual production of approximately 33.5 kt of water undergoing a 45 °C temperature rise.

Table 2-46 puts these levelized production costs into perspective by comparing them with the selling prices and associated NPV ranges of the H_2/charging station business units and with the revenues generated by the VRES business unit, providing an integrated comparison of the different pathways across business units.

Table 2-46: Comparison fuel energy costs and NPV associated to selling prices for BUC 6a/b with an indicative reference cost for diesel transport.

KPI	BUC 6a	BUC 6b (Uniform)	BUC 6b (Batch)	Diesel (Reference case)
Production cost [€/100km]	102.2	22.1	25.2	-
Selling price range [€/100km]	104-136	29.8-119	37.5-119	44.2-54.6
Associated NPV range [M€]	2.41-8.92	0.96-12.18	1.31-11.79	-
Annual revenues VRES unit [k€/y]	320.8	254.6	245.4	-

The comparison also differs from the perspective of the individual business units. For the VRES producer, BUC 6a provides a stronger captive demand for locally generated electricity, resulting in annual revenues of approximately €320.8k/year, compared with €254.6k/year and €245.4k/year for Uniform and Batch electric charging, respectively. BUC 6b consumes substantially less local electricity, leaving a larger fraction injected to the grid at the feed-in tariff. Hydrogen production can therefore provide a particularly valuable long-term local off-taker for renewable generators, despite its lower overall energy efficiency.

For the refuelling/charging infrastructure owner, both pathways can generate attractive returns, but through different value propositions. BUC 6a benefits from the possibility of selling surplus H_2 to an industrial off-taker, whereas BUC 6b benefits from substantially lower CAPEX and energy production costs. This leaves greater room between the charging production cost and the price paid by the fleet while maintaining attractive project profitability. From the fleet-owner perspective, this translates into the strongest advantage for direct electrification, whose underlying energy cost remains below both the hydrogen and diesel references.

The preferred pathway might therefore depend not only on overall system cost, but also on how costs, revenues and flexibility value are distributed between the VRES producer, infrastructure operator and fleet owner. Coordinated electric charging appears particularly attractive from the overall system perspective, while hydrogen retains potential value where operational constraints favour rapid refuelling, extended range or additional industrial H_2 valorisation.

Note that these results remain limited to the energy-supply infrastructure and should not be interpreted as a complete Transport Cost of Ownership comparison, which would additionally require vehicle CAPEX, payload, range, downtime and other operational constraints to be considered.

2.8.9 Recommendations

Table 2-47: Key recommendations for BUC 6b

Recommendations (max 250 words)	
Technical	High-power charging infrastructure should be designed as an integrated charging–BESS–renewable energy system, rather than as a passive electrical load. The BESS is essential to decouple charging requirements from instantaneous grid conditions and limits the impact of the capacity tariff. Charging coordination should be prioritised wherever possible, as uniform demand reduces the required BESS capacity, limits grid peaks and improves renewable-energy utilisation. Imposing a limited grid contribution provides disproportionate battery oversizing.
Socio-economic	Multi-year renewable and electricity-price datasets should also be used for system sizing to account for interannual variability. Fleet operators should prioritize adapting charging schedules uniformly, as coordinated charging can reduce the infrastructure required and ultimately lower the cost of fleet electrification. Appropriate incentives or flexible charging contracts could reward users for providing this temporal flexibility.
Policy/regulatory	Dynamic electricity prices and capacity-based network tariffs can provide effective signals when charging stations have access to flexibility assets such as BESS. Capacity tariffs can contribute to this objective when combined with controllable assets such as BESS and smart charging. Policy support should prioritise coordinated charging, renewable integration and network flexibility rather than grid independence, encouraging charging stations to become active flexibility resources (directly or through aggregators) instead of additional inflexible peak loads.

2.9 BUC7 - The role of hydrogen in the Belgian and European energy system

2.9.1 General information

Test Case ID	*Name of Test Case*
2	The role of hydrogen in the Belgian and European energy system
Maturity of Test Case	
In development	

ID	*Name of Business Use Case*
BUC 7	The role of hydrogen in the Belgian and European energy system
Short description and objectives *- refer to Task 3.**1***	

By 2050, the production cost of hydrogen will become highly dependent on electricity prices as well as available infrastructure (production mix, storage, transport, etc.). In this BUC, we assess how capacity expansion for hydrogen production (and its impact on prices & competitiveness) is affected by the available backbone infrastructure.

In line with the revised scope of this BUC, the analysis addresses the following research questions:

1. Under what infrastructure conditions can hydrogen be supplied to Belgium at competitive cost?
2. How do European hydrogen infrastructure choices — the hydrogen backbone, CO2 transport and storage, and extra-European imports — shape hydrogen production costs and the supply mix ?
3. How do hydrogen infrastructure choices propagate into the Belgian electricity system?
4. To what extent can Belgium remain self-sufficient in hydrogen without sacrificing cost-competitiveness, and what does reliance on imports imply for energy sovereignty?

These questions replace the formulation used in D3.1, which was framed around the allocation of hydrogen between end-use applications. That allocation was an output of TIMES-BE, in which applications compete for a scarce carrier. In POMMES-EU, hydrogen demand is an exogenous input that is met in full, so the model cannot produce such an allocation. Demand uncertainty is instead addressed by scaling the reference demand across the infrastructure scenarios.

2.9.2 Simulation tool

POMMES is the acronym of a recent Python framework [3] called Planning and Operation Model for Multi-Energy Systems. It was designed for multi-horizon modelling of energy systems, with the primary objective of cost minimisation, as illustrated in Figure 2-45.

[3] https://github.com/qraillard/pommes-kuleuven

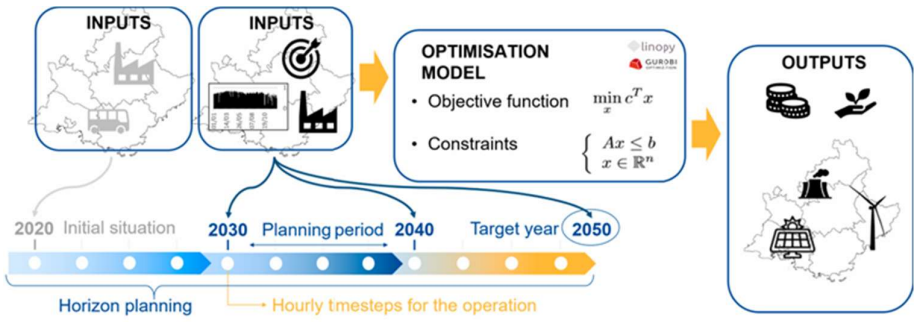


Figure 2-45: POMMES framework illustrative scheme

POMMES is highly modular and can be used to model both big multi-energy systems [6] [7] as well as small regional systems [7] with varying operation temporal granularity.

Combining ERAA2024 (for the 2030-2035 period) and TYNDP2024 (for the 2040-2050 period) data, a European electricity and hydrogen system model, using POMMES, was developed. Although we use a single horizon (2050) for this BUC, POMMES-EU comprises 4 investment horizons (2030-2035-2040-2050) with between each other 3 operation years (representing each a different weather scenario).

2.9.3 Use case setup

For this analysis, we implement POMMES-EU as a single-horizon optimisation with target year 2050 and a chronological representation of an entire climate year with an hourly resolution. The geographical scope covers 27 countries[4] [5], which allows cross-border electricity and hydrogen exchanges to be captured at a pan-European scale.

2.9.4 General assumptions

Capacity expansion in the power sector is constrained by technology-specific upper bounds. Renewable energy investments are limited by potentials from TYNDP2024, and nuclear capacity is upper bounded using PEMMDB2 and TYNDP2024 assumptions. By contrast, other dispatchable technologies and battery energy storage (BES) can expand without explicit potential limits. On the demand side, we allow for load shifting of electric vehicles and heat pumps, consistent with the flexibility assumed in ERAA2024. Remaining imbalances can be resolved through load shedding, which is limited in both power and energy and activated at certain price levels (see TYNDP2024).

Hydrogen-sector expansion follows similar principles. Electrolyser investment is capped using PEMMDB2 estimates for 2030, reflecting deployment limits. Underground hydrogen storage in salt caverns is bounded

[4] EU Member States (excl. Malta, Cyprus and Croatia), Switzerland, Norway and the United Kingdom
[5] Those countries were selected to properly model a potential future European hydrogen backbone while focus on Belgium in the analysis

using TYNDP2024 potentials. By default, reforming-based hydrogen production (Steam Methane Reforming (SMR) with and without CCS) is not subject to explicit capacity potentials and may expand freely when cost-effective. Together, these constraints define the feasible space in which we evaluate alternative hydrogen infrastructure and flexibility configurations.

It should be noted that electricity and hydrogen demand as well as renewable energy potential were readjusted to match PATHS2050 for Belgium.

2.9.5 Main data inputs

The techno-economic assumptions and data used by POMMES-EU are described in Table 2-48 to Table 2-50.

Table 2-48: Commodity prices for POMMES-EU in 2050

Commodity	Price	Source
Uranium	2.2€/MWh_{th}	TYNDP2026
Natural Gas	35.5€/MWh_{th}	TYNDP2026
Biomethane	50.0€/MWh_{th}	TYNDP2026
CO_2 price	502.7€/tCO_2	TYNDP2026

Table 2-49: Economic characteristics in POMMES-EU for electricity production technologies

Technology	Efficiency	CAPEX [€/kW]	Fixed OPEX [€/kW/yr]	Variable cost [€/MWh][6]	Lifetime [yr]	Source
Wind Onshore		1090	1.4% CAPEX	1.85	30	DAE
Wind Offshore		1990	1.4% CAPEX	2.78	30	DAE
Solar PV		290	2.5% CAPEX		40	DAE
LTO Nuclear		/	319[7]	8	20	RTE_BP2050/ERAA2024
New Nuclear	33%	4945	100	8	60	RTE_BP2050/ERAA2024
Hydro[8]		/	130[7]		50	RTE_BP2050
OCGT/CCGT	40%/60%	522/889	20.8/33.8	2.4	25	ERAA2024
OCGT/CCGT-H_2	40%/60%	600/978	23.9/37.2	2.5	25	ERAA2024

[6] Does not include fuel cost.
[7] Includes CAPEX
[8] Pumped hydro not included

Table 2-50: Economic characteristics in POMMES-EU for hydrogen production technologies

Technology	Unit	CAPEX [€/unit]	Fixed OPEX [€/unit/yr]	Variable cost [€/MWh_{H2}]	Lifetime [yr]	Source
Electrolyser	kW_e	910	36.4		20	TYNDP2026
SMR (legacy)	kW_{H2}		198		25	[6]
eSMR	kW_{H2}	850	144		25	[6]
SMR+CCS (90% capture)	kW_{H2}	1600	108	3.1[9]	25	[6]

For the specific case of biomethane, while prices and available volumes are fixed exogenously, POMMES-EU optimises the distribution between the electricity and hydrogen system. The TYNDP 2024 relies on the ENSPRESO database to estimate the biomass potential, although the methodology for allocating this potential across sectors remains unspecified. For both the TYNDP 2024 and TYNDP 2026, biogas production is assumed to mainly come from manure. Consequently, the MINBIOGAS1 commodity from the ENSPRESO database is used as the reference. Given the relatively low-price assumptions for biomethane in the TYNDP 2026, it is further assumed that biogas is also intended for industrial applications. To reflect this, a volume equivalent to the ENS_Med scenario is allocated. Eventually, for Belgium, the low-carbon energy potential considered in POMMES-EU is described in Table 2-51.

Table 2-51: POMMES-EU low-carbon energy potential for Belgium | except for biogas, derived from ENSPRESO, the other potentials are taken from PATHS2050 assumptions

Solar PV	Wind Onshore	Wind Offshore	Nuclear (new)	Biogas
104 GW	20 GW	8 GW	8 GW	10.7 TWh

[9] For CO_2 transport & storage

2.9.6 Modelling scenarios

Three European scenarios were defined, varying the hydrogen infrastructure setting, for this use case:

Table 2-52 : European hydrogen infrastructure scenarios

Scenario	Common assumptions	European hydrogen backbone	Extra-EU H_2 imports	Carbon capture cap
ISO	+ Legacy SMR capacity capped from existing units + Biogas limitation from ENSPRESO database	No (thus, no underground storage)	No	SMR+CCS limited with TYNDP2024 assumptions[10]
EHB		Yes	No	No
EHB+I		Yes	Yes[11], volumes and capacities optimised by POMMES	No

2.9.7 Results and analysis

2.9.7.1 European impact

Figure 2-46 illustrates capacity expansion and yearly dispatch results for the European hydrogen system across the three scenarios describe in Table 2-52. In all cases, domestic electrolysis accounts for 56-67% of hydrogen supply. Under the ISO scenario (characterized by the absence of a hydrogen backbone and limited SMR+CCS potential) a substantial share of the remaining production relies on unabated SMR, resulting in significant grey hydrogen output. When SMR+CCS deployment is less constrained, blue hydrogen progressively displaces grey hydrogen production.

The combination of underground storage, hydrogen backbone infrastructure, and expanded CCS access (EHB scenario) reduces total system cost by 11% relative to the ISO scenario, as shown in Figure 2-48. Allowing extra-European hydrogen imports (EHB+I scenario) yields further cost reductions, with imports largely substituting domestic blue hydrogen production. This comes however at the expense of a European energy sovereignty, since imports ultimately account for 25% of total hydrogen supply in that scenario. Would natural gas not come from Norway, that figure would technically increase even more.

[10] The underlying assumption is that if there is no hydrogen transport network, there is no CO_2 network either. Thus, carbon capture units are supposed to be located close to potential CO_2 offtakes (close to the sea for ship transport). Eventually the cap is of 1.95GW_{H2} for Belgium

[11] Based on TYNDP2024/2026: Blue hydrogen from Norway and Ukraine, green hydrogen from Northern African and ammonia ships in ports. Import blue hydrogen prices from TYNDP2024 were readjusted to match natural gas assumption increase between TYNDP2024 and TYNDP2026.

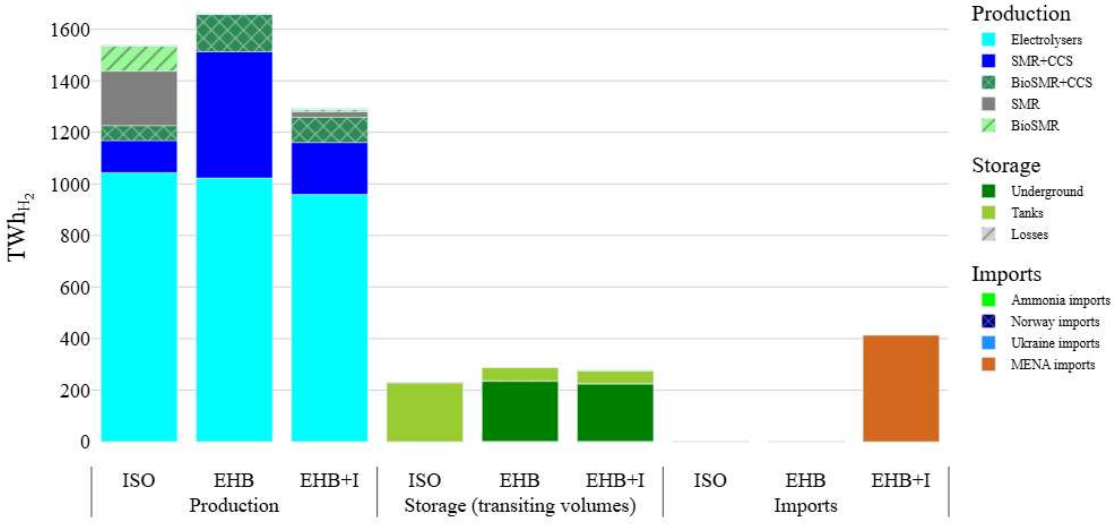


Figure 2-46: Hydrogen production, transiting through storage, and import volumes in 2050 in Europe

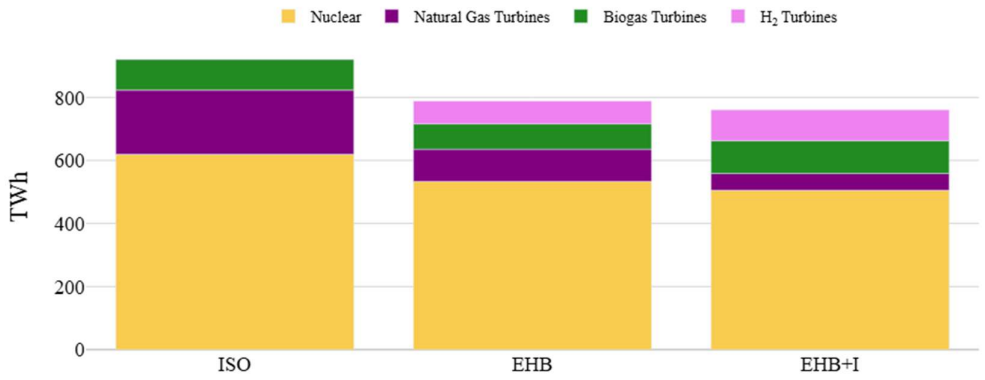


Figure 2-47: Dispatchable electricity production in 2050 in Europe for ISO, EHB and EHB+I scenarios

Figure 2-48 also reveals that the ISO scenario entails substantially higher emissions from both the electricity and hydrogen systems. Two mechanisms explain this. First, the absence of a hydrogen network and CO_2 infrastructure forces greater reliance on electrolytic hydrogen, increasing electricity demand. Second, the higher share of unabated SMR raises methane consumption. Additionally, while hydrogen turbines contribute 1–1.5% of electricity generation in the EHB and EHB+I scenarios, the higher cost of hydrogen under the ISO scenario causes H_2 turbines to be displaced by CH_4 turbines (Figure 2-47). This increases pressure on biogas availability, which must simultaneously serve SMR units (with or without CCS) and CH_4-fired power generation.

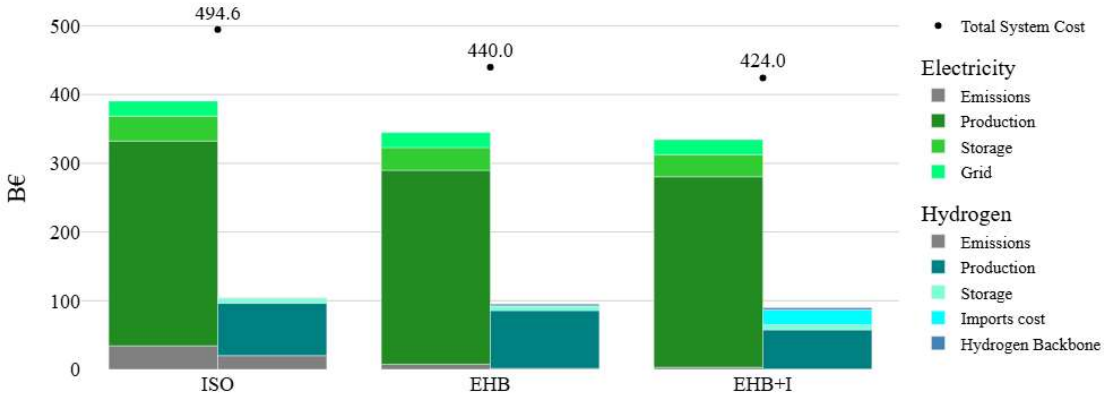


Figure 2-48: Total system costs in 2050 across infrastructure scenarios

This dynamic highlights two broader findings. Bioenergy availability is a critical system constraint whose implications propagate across both the power and hydrogen sectors. More generally, cross-sector synergies, enabled by shared infrastructure such as hydrogen pipelines and CO_2 networks, play a decisive role in shaping both cost and emission outcomes, and should be explicitly accounted for in scenario design and policy assessment.

2.9.7.2 Focus on Belgium

Hydrogen demand in Belgium is subject to considerable uncertainty. While demand, derived from PATHS2050, is set at 32 TWh in 2050 (used here as the reference), the TYNDP2024 assumes demand as high as 98 TWh (Distributed Energy scenario). To assess the implications of this uncertainty, the reference demand was progressively scaled (×2 and ×3) across the three infrastructure scenarios. It should be noted that these Belgian-level variations have negligible impact on European-wide results and were therefore not included in the preceding section. Also worth noting, compared to the TYNDP2024 assumptions, this exercise allows for nuclear energy in Belgium in 2050 and sets a larger renewable potential, which somewhat eases the domestic supply challenge.

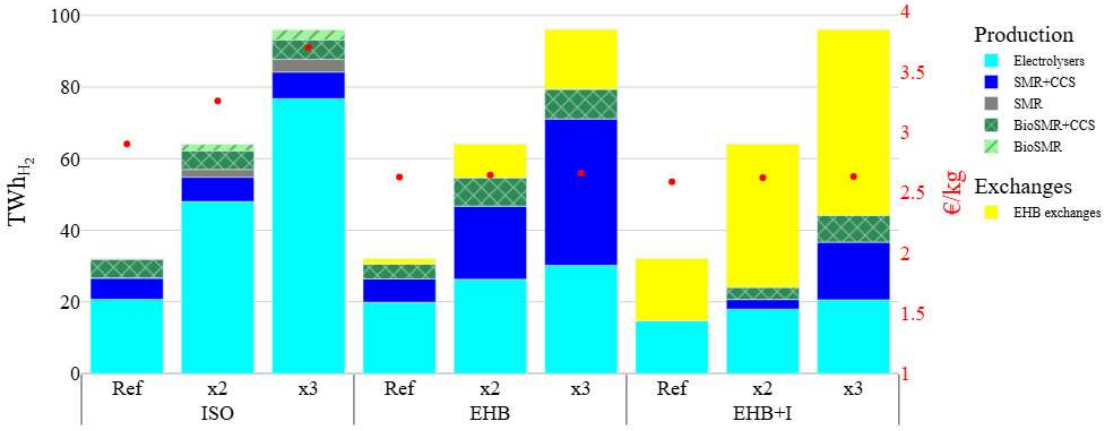


Figure 2-49: Belgian hydrogen yearly dispatch and price in 2050 under different demands

Under the ISO scenario, where no hydrogen backbone and limited CCS infrastructure are available, any increase in hydrogen demand is almost exclusively met by additional electrolysis capacity (Figure 2-49). This has direct and significant consequences for the electricity system: as shown in Figure 2-50, the incremental electricity demand is absorbed by reaching the solar PV potential cap and by increasing electricity imports, which together drive electricity prices upward, from around 75 €/MWh at reference demand to nearly 95 €/MWh at ×3. Since electrolytic hydrogen production costs are tightly coupled to electricity prices, hydrogen prices follow the same upward trajectory, rising from approximately 2.9 €/kg to 3.7 €/kg. These price levels would render hydrogen-based decarbonisation highly uncompetitive for several Belgian industrial sectors relative to European neighbours with better access to low-cost hydrogen supply routes. Notably, Figure 2-49 also reveals that under the ISO ×3 case, unabated SMR capacity is mobilised alongside electrolysis, suggesting that when electrolytic hydrogen becomes too expensive, grey hydrogen re-enters the mix as a cost relief valve, which is a detrimental outcome from an emissions standpoint.

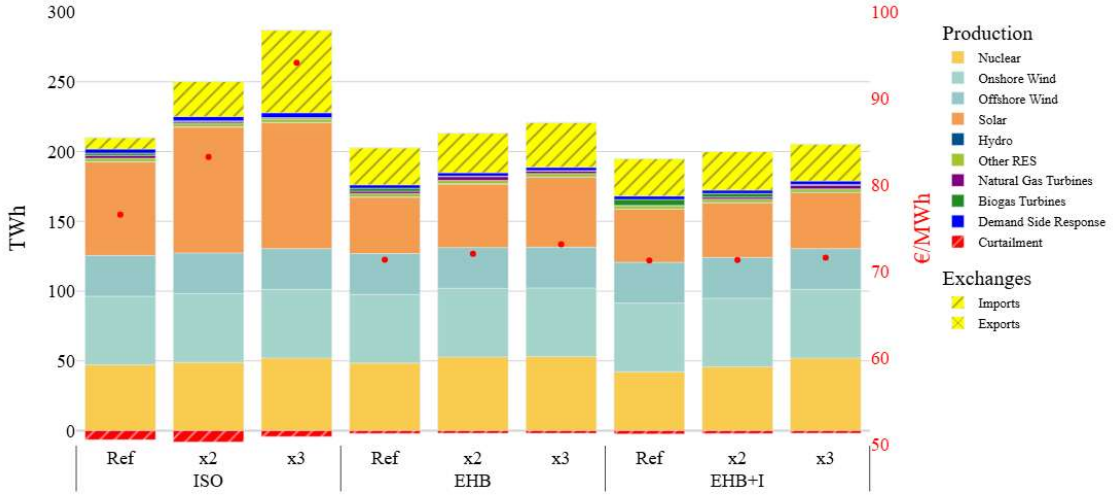


Figure 2-50: Electricity system yearly dispatch in 2050 in Belgium under different hydrogen demand

The storage implications are equally significant. As illustrated in Figure 2-51, the absence of a hydrogen backbone in the ISO scenario forces heavy reliance on tank storage, whose capacity scales almost proportionally with electrolyser capacity. This confirms an intuitive but important result: in an electricity-centric hydrogen supply model, seasonal and operational balancing must be handled domestically, generating substantial infrastructure costs that are not captured in the hydrogen price alone.

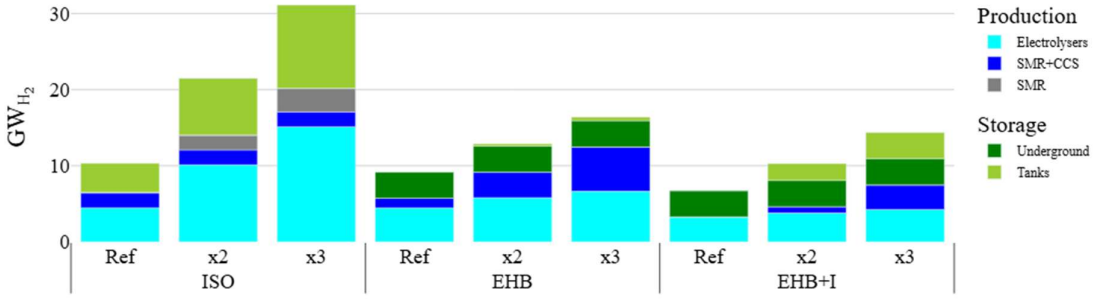


Figure 2-51: Hydrogen system installed capacities in 2050 in Belgium under different hydrogen demand

The picture changes markedly when hydrogen network infrastructure and CCS access are made available (EHB scenario). Hydrogen prices remain far more stable as demand increases, hovering around 2.5 €/kg across

all demand levels, because incremental demand is largely absorbed by SMR+CCS and European network imports rather than by additional electrolysis. The burden on the electricity system is consequently reduced, with electricity prices remaining broadly flat across the ×1 to ×3 range (Figure 2-50). Underground storage, accessible under the EHB scenario, also contributes to system flexibility and partially substitutes for the large tank storage requirements seen under ISO. A particularly noteworthy result is that under the reference demand (32 TWh), Belgium can achieve over 95% domestic hydrogen self-sufficiency in the EHB scenario at prices that are nearly as competitive as the import-heavy cases, suggesting that domestic sufficiency and cost-competitiveness are not mutually exclusive at moderate demand levels.

Even under the EHB+I scenario, which allows for cheap Northern African imports (to Spain & Italy), a non-negligible share of domestic production, primarily electrolysis and SMR+CCS, remains competitive and is retained in the optimal solution (Figure 2-49). This indicates that Belgian domestic production assets are not simply crowded out by cheap imports, but rather coexist with them, providing a foundation for energy sovereignty even in an open hydrogen market context. However, as demand scales up under EHB+I, imports increasingly dominate the supply mix, underscoring the tension between cost optimisation and strategic autonomy.

2.9.8 Conclusions

This analysis examines the European hydrogen system and its Belgian specificities under contrasting infrastructure and demand scenarios. At the European level, the results confirm that hydrogen backbone deployment, CCS access, and underground storage are collectively decisive in reducing total system costs, by up to 11% between the ISO and EHB scenarios, while also curtailing residual emissions from both the electricity and hydrogen sectors. The interdependence between the two systems is central: infrastructure choices in the hydrogen sector propagate into the electricity dispatch through electrolyser load, gas turbine utilisation, and biogas allocation, underscoring the importance of co-optimised, multi-energy planning. Extra-European imports offer further cost reductions but introduce energy sovereignty concerns, as they ultimately account for a quarter of hydrogen supply in the EHB+I scenario.

At the Belgian level, infrastructure availability similarly emerges as the primary determinant of cost outcomes and system interactions. Without a hydrogen backbone or CCS access, domestic self-sufficiency is technically achievable but increasingly costly as demand grows, with hydrogen prices reaching up to 3.7 €/kg, driven by the tight coupling between electrolysis expansion and electricity prices. Access to H_2 network infrastructure and CCS stabilises hydrogen prices around 2.5 €/kg even at high demand levels, relieves pressure on the electricity system, and enables near-full domestic self-sufficiency at the reference demand level. Even when cheap extra-European imports are available, domestic Belgian production retains a competitive foothold. Taken together, these findings draw infrastructure deployment as the decisive lever for both the European and Belgian hydrogen transitions, with demand growth ambitions needing to be sequenced accordingly.

2.9.9 Recommendations

Table 2-53: Key recommendations for BUC 7

Recommendations	
Technical	Accelerate CO_2 transport and storage infrastructure development, as steam methane reforming with carbon capture has quite a role to play, and pursue early integration into a European Hydrogen Backbone. Develop underground hydrogen storage in parallel, as its system value is contingent on network connectivity. Ensure electricity system planning accounts explicitly for hydrogen demand growth scenarios to prevent price spillovers onto broader electricity consumers.
Socio-economic	Avoid high hydrogen demand roadmaps for industrial decarbonisation without secured infrastructure milestones, as high hydrogen prices risk making Belgian industry uncompetitive relative to European neighbours. Assess distributional impacts of electricity price increases on households and non-hydrogen sectors under high-demand trajectories. Support domestic electrolyser and SMR+CCS industrial clusters, particularly around Antwerp and the North Sea corridor, as Belgium's role as a hydrogen producer and transit hub carries strategic value beyond pure cost optimisation.
Policy/regulatory	Condition sectoral hydrogen demand targets on infrastructure deployment milestones rather than treating them as exogenous inputs. Frame import strategy as complementary to, not a substitute for, domestic production capacity. Given that even cheap Northern African imports do not fully crowd out domestic production, regulate hydrogen import agreements with energy sovereignty and supply security safeguards.

2.10 BUC 8 - Integrated energy systems

2.10.1 General information

Test Case ID	*Name of Test Case*
7	Integrated energy system using Fluxys model (“North Sea Integration Model”)
Maturity of Test Case	
In development - extension of functionalities of the pilot model developed under the framework of ETF project “INTEGRATION”.	

ID	*Name of Business Use Case*
BUC 8	Fluxys model (“North Sea Integration Model”) extended to the North Sea region: focus on offshore electrolysis.
Short description and objectives	

The goal of this BUC is to develop and use Fluxys’ “North Sea Integration Model” (NSIM) to answer the following research questions:

1. What is the optimal way to transport the offshore wind energy potential towards the continent?
2. Can offshore electrolysis facilitate the deployment of offshore wind by reducing energy curtailment and/or lowering total system costs (by adding a dispatchable electricity demand for hydrogen production, located offshore)?

The initial version of Fluxys’ NSIM model has been built for Belgium by ULiège & Fluxys during the former ETF ‘INTEGRATION’ project. Its goal was to look at the interactions between electricity, methane (CH4), “hydrogen & derivatives” and CO2 to identify the optimal, carbon-neutral multi-energy system for Belgium. Fluxys further developed this initial model into what is now known as the Fluxys NSIM model, incorporating the following improvements:

- Geographical scope extended to 10 countries in North-West Europe (the countries bordering Belgium and the North Sea)
- A specific “North Sea Cluster” has been added to represent the offshore area located more than 24 nautical miles from the coastline
- New energy carriers (heat, coal & oil derivatives) were added to cover the complete energy system
- Overseas export hubs for green molecules were implemented

Following improvements are targeted within the ETF REINVENT project:

- The “Hydrogen & derivatives” carrier will be split in gaseous hydrogen (H2), ammonia (NH3) and methanol (MeOH)
- The “North Sea Cluster” will be split in several sub-zones to better reflect the distances between offshore wind farm locations and the coast
- All electrolysis technologies will be implemented: Proton-Exchange Membranes (PEM) & Solid-Oxyde Eletrolytic Cells (SOEC) on top of the current alkaline technology.

2.10.2 Simulation tool

Fluxys' extension of the ETF INTEGRATION model, known as Fluxys' "North Sea Integration Model" (NSIM), will be used. It is a linear optimization model that co-optimizes investments and operations in a multi-carrier energy system.

The model needs final energy demand for heating, industry and transport to be fixed ex-ante, together with renewable potentials and techno-economic assumptions. The model will find the optimal investments and dispatch allowing to supply this final energy demand while respecting CO_2 neutrality.

Fluxys has extended the initial ETF INTEGRATION model to the 10 countries around Belgium and the North Sea: Austria, Belgium, Denmark, France, Germany, Ireland, Luxembourg, the Netherlands, Norway and UK. A specific "North Sea Cluster" has also been added to represent all offshore zones farther than 24 nautical miles of any coastline. A description of the model can be found in [8].

Since then, more energy carriers have been added to the model (heat, coal & oil derivatives) to model the whole energy system, together with related technologies. Remote renewable energy hubs for green molecules, located overseas, were also added to better reflect the trade-off between local production and imports.

For the purpose of the ETF REINVENT project, two main developments were undertaken. First, the former "hydrogen & derivatives" carrier has been split in gaseous hydrogen (H_2), ammonia (NH_3) and methanol (MeOH). The resulting topology for each country is shown in Figure 2-52.

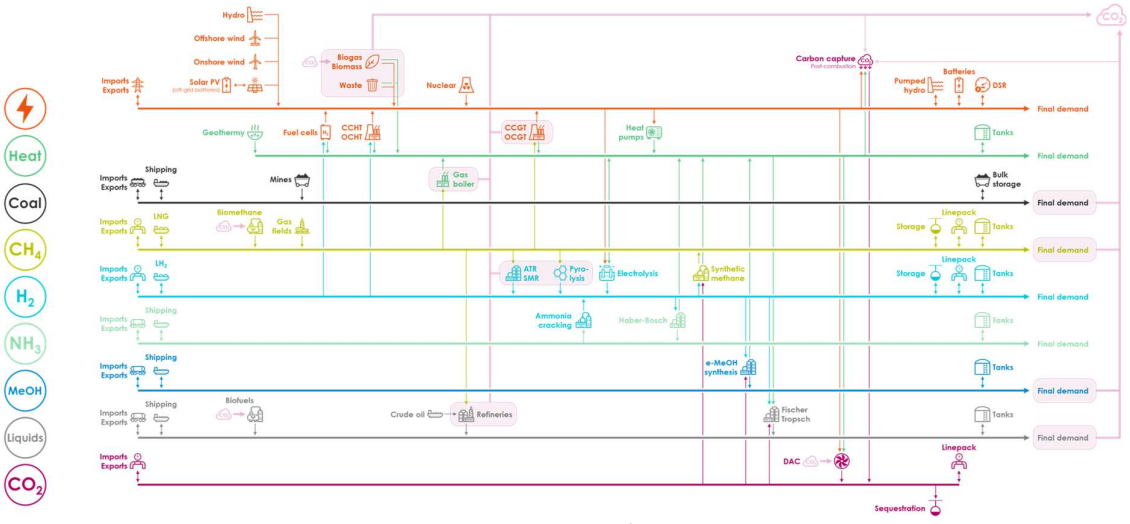


Figure 2-52: NSIM topology for a given country.

Second, based on the "North Sea Wind Power Hub" study [9], the existing "North Sea cluster" has been split in several subzones to better reflect the effect of distances between the main regions where offshore wind can be deployed, as shown in Figure 2-53.

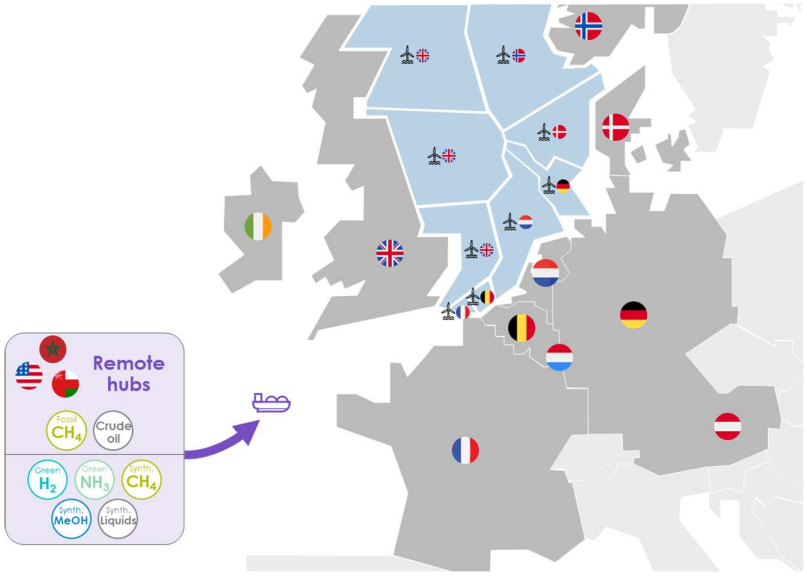


Figure 2-53: Geographical zones covered in NSIM.

2.10.3 Use case setup

The model simulates a fully decarbonized (net-zero) energy system in 2050, based on the Distributed Energy scenario from ENTSO-E and ENTSOG's Ten-Year Network Development Plan (TYNDP) of 2024. Key characteristics:

- Year modelled: 2050 only (no pathway)
- Climatic year used: 2009
- Time resolution: hourly over the whole year (8760 time steps)
- Carbon neutrality for the 10 countries by 2050
- Planning paradigm: centralized optimization + co-optimization of investments and technology usage (dispatch)
- Perfect foresight assumption (no uncertainty)

A scenario-based approach, with sensitivity analyses, is used to quantify the following aspects:

- Deployment of offshore electrolyzers (presence or absence)
- Level of import dependency
- CO_2 sequestration capacity
- Capital and operational costs of electrolyzers and/or HVDC lines

2.10.4 General Assumptions

Final energy & feedstock demand in 2050 for heating, industry and transport, together with the maximal potentials for renewables, biomethane & nuclear production capacity, are assumed upfront, based on the

Distributed Energy scenario from the TYNDP 2024.Techno-economic parameters for all technologies are mainly based on data from the Danish Energy Agency.

A perfect foresight assumption is adopted, meaning that all future demand, prices, and technology developments are known in advance.

2.10.5 Main Data inputs

Table 2-54: Main Data inputs for BUC 8

Name	Description	Unit	Value or time-series	Reference year	Data source	ReInvent Common data (Yes/No)
Final demand	Yearly value 2050, split per country, sector and carrier	TWh/y	Value	2050	TYNDP2024 NESO (UK) S&P (Norway)	No
Demand profiles	Hourly values (normalized)		Time-series	2009	TYNDP2024 Renewable ninja	No
RES potential	Maximum capacities that can be deployed	GW	Value	2050	TYNDP2024	No
RES profiles	Hourly production (normalized)		Time-series	2009	Renewable ninja	No
Nuclear potential	Maximum capacities that can be deployed	GW	Value	2050	TYNDP2024 4 GW for Belgium	No
Biomethane potential	Maximum capacities that can be deployed	TWh/y	Value	2050	TYNDP2024	No
Offshore wind zones	Subzones, depths and distances from shore	GW	Value	2050	NSWPH study	No
Pre-installed capacities	Capacities still existing in 2050	GW	Value	2050	Eurostat IRENA	No
Cost data	CapEx, OpEx, lifetime	EUR_{2023}	Value	2050	Mainly Danish Energy Agency and Concawe, DNV, Fluxys, IPCC, JRC, NREL, S&P and academic papers	No
WACC	7%	%	Value	2050	Fluxys	No
Technical data	Efficiencies, losses, emissions factors, ramping curves…	Various	Value	2050	Mainly Danish Energy Agency and Concawe, DNV, Fluxys, IPCC, JRC, NREL, S&P and	No

Name	Description	Unit	Value or time-series	Reference year	Data source	ReInvent Common data (Yes/No)
					academic papers	
Biomass cost	15-35 €$_{2023}$ /MWh$_{LHV}$	€/MWh	Value	2050	Fluxys	No
Coal cost	7.7 €$_{2023}$ /MWh$_{LHV}$	€/MWh	Value	2050	TYNDP2024	No
Uranium cost	3.5 €$_{2023}$/MWh$_{LHV}$	€/MWh	Value	2050	NREL	No
Waste cost	10 €$_{2023}$ /MWh$_{LHV}$	€/MWh	Value	2050	Fluxys	No

2.10.6 Modelling scenarios

The model simulates a fully decarbonized energy system in 2050, based on the Distributed Energy scenario from the TYNDP 2024. Some assumptions are made for splitting the "H_2 and derivatives" demand from the TYNDP into separate demands for H_2, NH_3 and MeOH, while also accounting for the endogenous representation of refineries in the Fluxys model. This results in the final demand depicted in Figure 2-54.

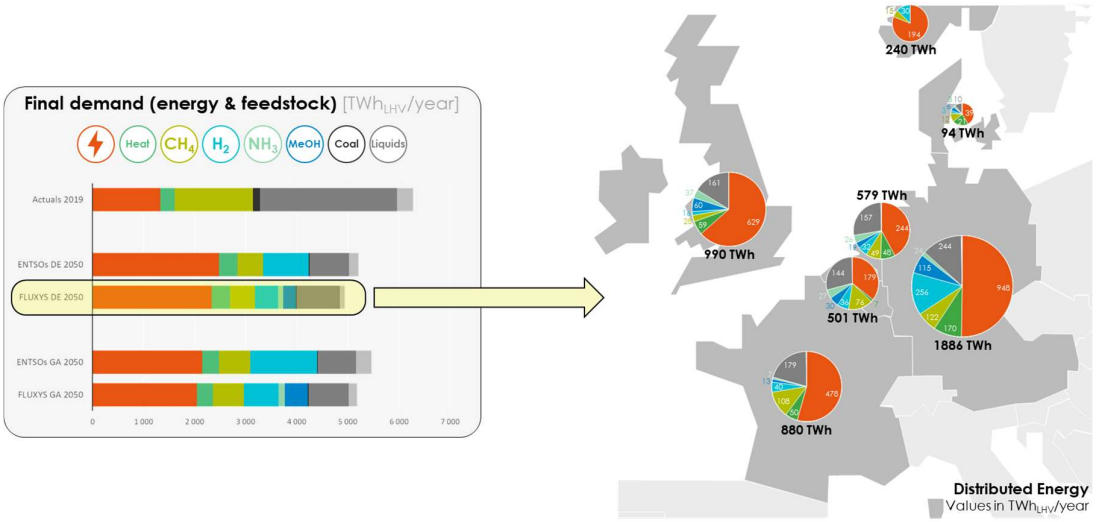


Figure 2-54: Final demand (energy + feedstock) for the Distributed Energy scenario in 2050 based on original data from TYNDP2024 and Fluxys' assumptions for the allocation of demand across H_2, NH_3 and MeOH.

Figure 2-55 shows the potential for renewable electricity and nuclear capacities, also based on data from the TYNDP 2024. The repartition for offshore wind potential in the North Sea is based on the NSWPH study [9].

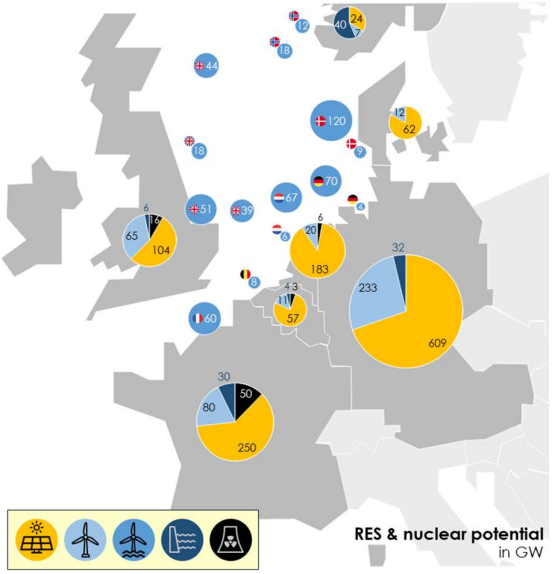


Figure 2-55: RES and nuclear potential.

2.10.7 Results and analysis

2.10.7.1 Base Case – Electricity system

Figure 2-56 shows the electricity system (capacities and monthly balance) for the 10 countries included in the model. Renewables dominate electricity production, with massive deployment of wind and solar close to their technical potential and producing most of the electricity needs. Gas turbines remain necessary during the winter, especially during periods with no sun nor wind.

In Belgium, renewable potential is limited and cannot supply more than 50% of the final electricity demand. Renewable generation is complemented by nuclear power and electricity imports from France and the North Sea.

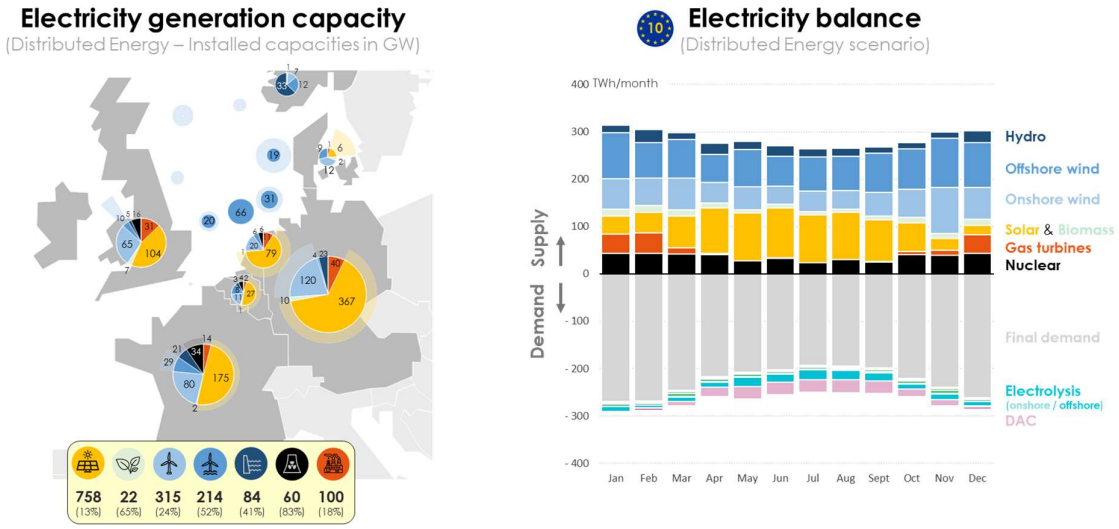


Figure 2-56: Electricity generation capacity and monthly balance for the 10 countries.
(electricity supplied as positive values, electricity demand as negative values)

Offshore electrolysis converts excess offshore wind production into hydrogen, reducing curtailment and enabling higher wind deployment (Figure 2-57). This does not occur in near-shore zones, highlighting the distance effect and the higher cost of HVDC lines over hydrogen transport. Total offshore electricity production reaches 967 TWh, demonstrating the strategic importance of offshore hubs.

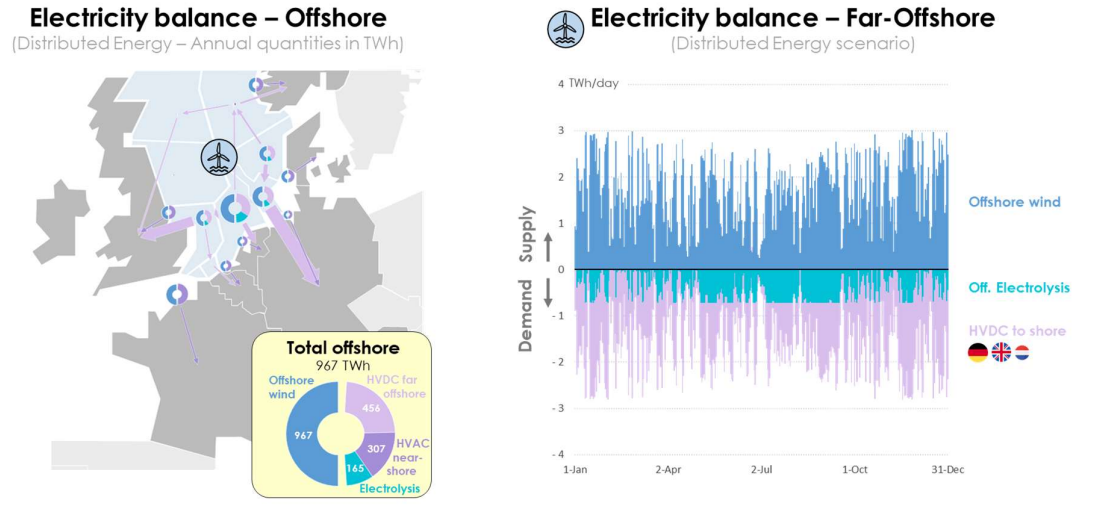


Figure 2-57: Electricity balance for offshore zones
(left: yearly quantities and flows – right: aggregated balance at daily resolution)

2.10.7.2 Base Case – Hydrogen system

Figure 2-58 shows that gaseous hydrogen is fully produced within Europe from methane (autothermal reforming with CCS) and from electricity (electrolysis). Hydrogen is not imported nor converted from imported ammonia or methanol: these solutions are possible but more expensive to deploy. Offshore electrolysis accounts for approximately 20% of total hydrogen production by valorising excess renewable electricity, especially during the summer. Hydrogen storages (underground salt caverns) provide seasonal flexibility – while batteries mainly provide intraday flexibility, linked to the intermittent electricity generation from PV.

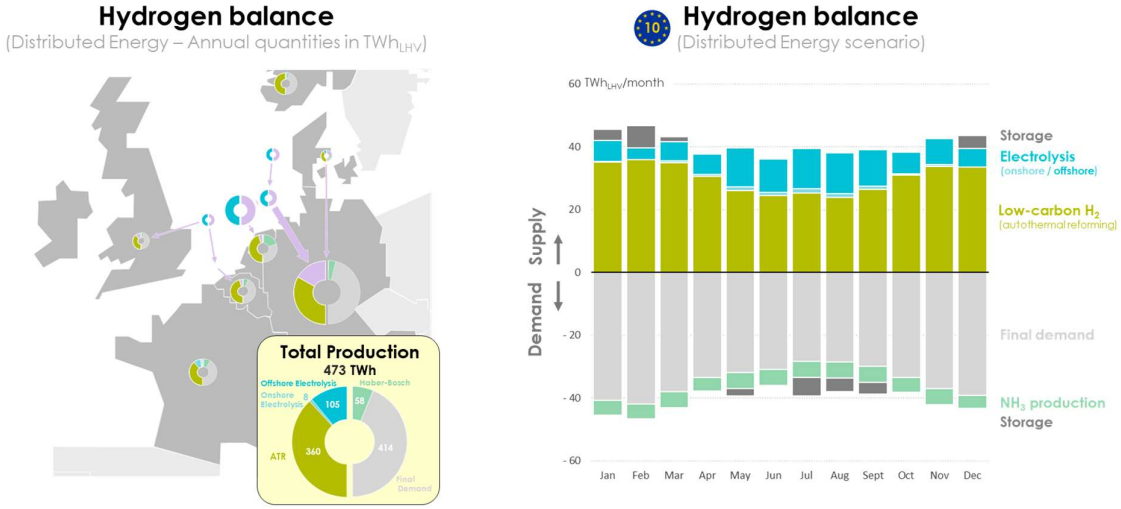


Figure 2-58: Hydrogen balance for the 10 countries
(left: yearly quantities and flows – right: aggregated balance at monthly resolution)

2.10.7.3 Base Case – CO_2 air balance

The model shows that carbon neutrality is optimally achieved through a combination of carbon capture and storage (373 $MtCO_2$ of CCS), the use of bioenergy, and imports of synthetic fuels. This solution gives an average system cost around 120 €/MWh and a marginal CO_2 abatement cost around 255 €/tCO_2.

2.10.7.4 Import dependency

When imports of methane, crude oil, oil derivatives or hydrogen derivatives by ships from overseas countries are restricted or eliminated, the optimal energy system changes significantly as shown in Figure 2-59:

- massive increase in domestic RES deployment: offshore wind deployment more than doubles in a no-imports scenario
- strong expansion of electrolysis, mainly offshore but also onshore
- shift away from imported energy carriers (mainly crude oil), replaced by local e-fuel production
- much higher average system cost: from 120 €/MWh up to 147 €/MWh (+22%) if no imports are allowed

Therefore, the hydrogen system strongly grows to produce hydrogen for synthetic fuels and ammonia domestically, enhancing strongly the beneficial role of offshore electrolysis. Indeed, if offshore electrolysis is forbidden, the electrolyzers move onshore, with much more HVDC capacity needed and a significant impact on system cost: the average cost increases by around 5 €/MWh up to 152 €/MWh with no imports and no offshore electrolysis.



Figure 2-59: Hydrogen monthly balances for the 10 countries
(left: optimal case with imports – centre: extreme case without imports – right: extreme case without imports and without offshore electrolysis)

2.10.7.5 Sensitivity: CCS potential

When carbon sequestration is forbidden, the optimal energy system also changes significantly as shown in Figure 2-60:

- CCS is mainly replaced by green molecules imported from overseas, but not by CCU in Europe
- autothermal reforming disappears, and is replaced by electrolysis and pyrolysis
- significant increase in offshore wind turbines deployment (+50 GW)
- significant average system cost increase: from 120 €/MWh up to 129 €/MWh (+7%)

The energy system is significantly impacted, but less than in the 'no imports' sensitivity. Without CCS in Europe, the model shifts to green molecules imports from overseas. In addition, if offshore electrolysis is forbidden, electrolyzers move onshore with a higher system cost (+2 €/MWh up to 131 €/MWh).



Figure 2-60: Hydrogen balances for the 10 countries
(left: optimal case with CCS – centre: extreme case without CCS – right: extreme case without CCS and without offshore electrolysis)

2.10.7.6 Results on main KPIs

Figure 2-61 shows an overview of the tested scenarios, highlighting the trade-off between the energy system cost and imports dependency. It also shows that CCS can facilitate the energy transition by decreasing the average energy system cost without significant impact on imports.

The role for offshore electrolysis is highlighted in the most extreme scenarios:

- compared with the Base Case, not allowing offshore electrolysis has almost no impact on the average energy system cost: 0.1% cost increase, slightly more imports;
- the impact becomes more significant if CCS is restricted: up to 1% of average energy system cost increase without offshore electrolysis;
- the most significant impact arises when no energy imports are allowed: up to 4% of average energy system cost increase without offshore electrolysis.

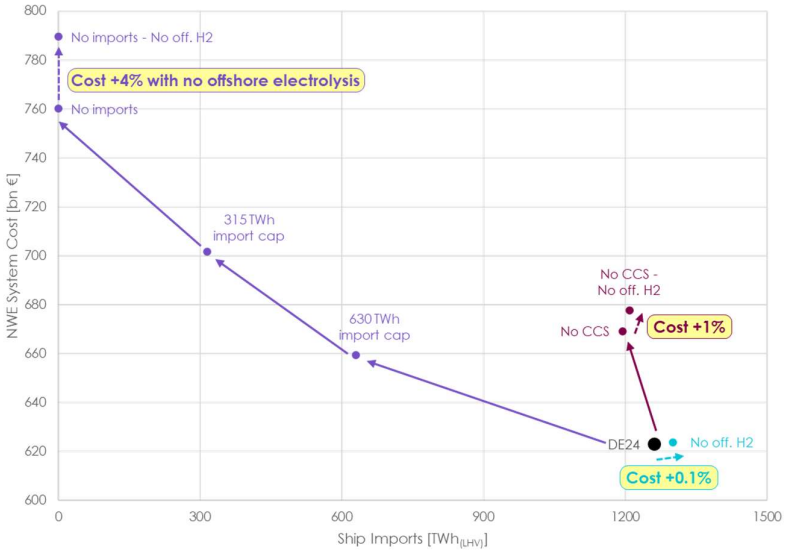


Figure 2-61: Average energy system cost versus import dependency for various scenarios.

Simulation results also show a strong coupling between offshore wind deployment and offshore electrolysis. Figure 2-62 compiles all modelled scenario results and reveals a strong correlation between the two variables:

- 184 GW of offshore wind is always deployed, without offshore electrolysis;
- any additional GW of offshore wind is deployed together with 0.6 GW(H_2), equivalent to 0.9 GWe, of offshore electrolysis, allowing the energy system to minimize curtailments and average system cost.

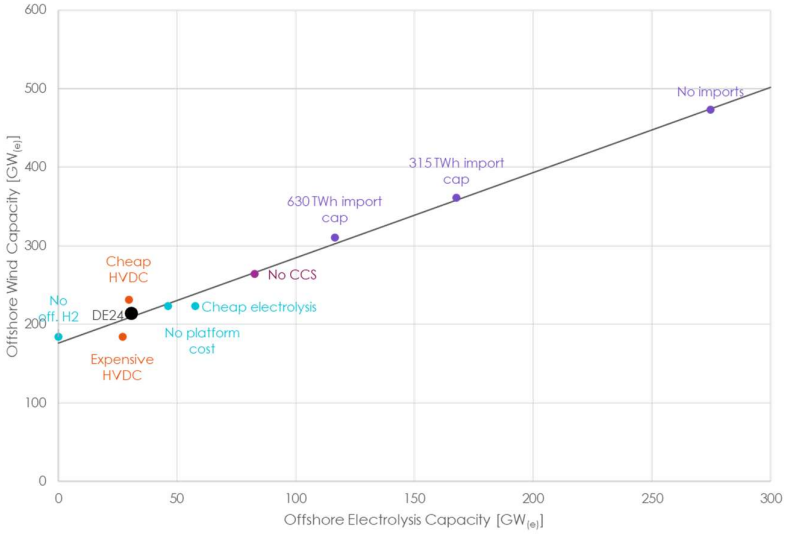


Figure 2-62: Offshore wind capacity vs. offshore electrolysis capacity installed in various scenarios

2.10.8 Conclusions

The simulation results highlight several key findings:

- a carbon-neutral energy system is feasible by 2050, but requires strong sector coupling
- renewables provide the bulk of electricity, but flexibility solutions are essential
- energy imports remain important, especially for hydrogen derivatives and crude oil
- CCS significantly reduces costs and system complexity
- offshore wind energy is delivered to the continent through a balanced combination of direct electricity transmission (via HVDC interconnections) and hydrogen transport (via offshore electrolysis and pipeline)

Offshore electrolysis emerges as a key enabler of the energy transition:

- it enables higher offshore wind deployment
- it reduces curtailment of renewable electricity
- it provides flexibility to both the electricity and hydrogen systems
- it facilitates local hydrogen production near offshore electricity production sites, thereby reducing transmission constraints and costs

2.10.9 Recommendations

Table 2-55: Key recommendations for BUC 8

Recommendations	
Technical	Support the deployment of offshore energy hubs integrating wind, electrolysis and interconnectors, enabling flexible conversion between electricity and hydrogen. Prioritise investment in system flexibility solutions (large-scale storage, demand response, electrolysis) to reduce curtailment and optimise renewable integration.
Socio-economic	Develop targeted financing mechanisms to de-risk early-stage offshore electrolysis and cross-border infrastructure. Ensure fair cost allocation and benefit sharing across countries and stakeholders, particularly for offshore grid investments. Promote skills development and workforce transition programmes to support emerging hydrogen and offshore infrastructure value chains.
Policy/regulatory	Establish a coordinated EU-wide framework for offshore energy planning, including joint infrastructure planning and cost-sharing rules. Clarify the regulatory status of offshore hydrogen production (market design, tariffs, ownership models). Implement robust carbon pricing and CCS frameworks to maintain competitiveness of low-carbon molecules. Enable long-term visibility on imports strategy (hydrogen and e-fuels) to guide investment decisions and avoid stranded assets.

2.11 BUC 9 - Flexibility provision with large-scale electrolyser

2.11.1 General information

Test Case ID	*Name of Test Case*
7	Large scale electrolysers
Maturity of Test	
A 25MW electrolyser plant is being built in Zeebrugge to be operational beginning of 2027.	

ID	*Name of Business Use Case*
BUC 9	Potential for flexibility provision with a large-scale electrolyser
Short description and objectives	
This use case aims to investigate whether the profitability of the installation can be increased by participating in specific electricity markets or by providing ancillary services from the electrolyser to the power system. The BUC will therefore analyse whether the electrolyser's operation can be optimized through flexible operation, while considering technical constraints, existing contracts for the procurement and sale of the involved vectors, the hydrogen demand and agreements with hydrogen customers, and the additional revenue streams generated from this flexibility. Various market opportunities may be explored, such as optimizing based on wholesale market prices or offering balancing services to the TSO.	

2.11.2 Simulation tool

The model is a **non-convex Mixed-Integer Quadratic Programme (MIQP)**, implemented in Python using the Pyomo modelling framework and solved with a commercial MILP/MIQP solver (Gurobi, with SCIP available as an open-source fallback). It optimises the hourly operation of an electrolyser that simultaneously produces green or grey hydrogen, sells excess renewable electricity on the day-ahead market, and offers **aFRR down-regulation capacity** to the Belgian TSO (Elia), all while maintaining compliance with the **RFNBO** (Renewable Fuels of Non-Biological Origin) regulation.

The optimisation horizon can span one or more calendar months. Because no state variable crosses a month boundary, the problem decomposes naturally month by month: one MIQP is built and solved per calendar month, and results are concatenated to form the full time series. The model outputs a CSV file with one row per hour covering all decision variable values, revenue and cost components, RFNBO certification details, and hydrogen routing.

2.11.3 Use case setup

The modelling setup considers the Virya electrolyser facility in Zeebrugge. The electrolyser can source electricity from two channels: a Power Purchase Agreement (PPA) tied to an offshore wind asset, providing low-cost renewable power at variable output, and the day-ahead market (grid electricity at a price that includes a fixed network tariff). Hydrogen can be delivered via two routes: tube trailers (TT) serving industrial customers, and direct injection into the gas grid (GG). The electrolyser can additionally offer aFRR down-regulation capacity to Elia, earning capacity and activation revenues.

The model maximises total profit over the simulation horizon, defined as hydrogen revenues from both delivery routes (with a green price premium for RFNBO-certified production), revenues from selling surplus PPA electricity on the day-ahead market, and aFRR activation revenues, minus grid electricity costs. The key structural elements of the formulation are described below.

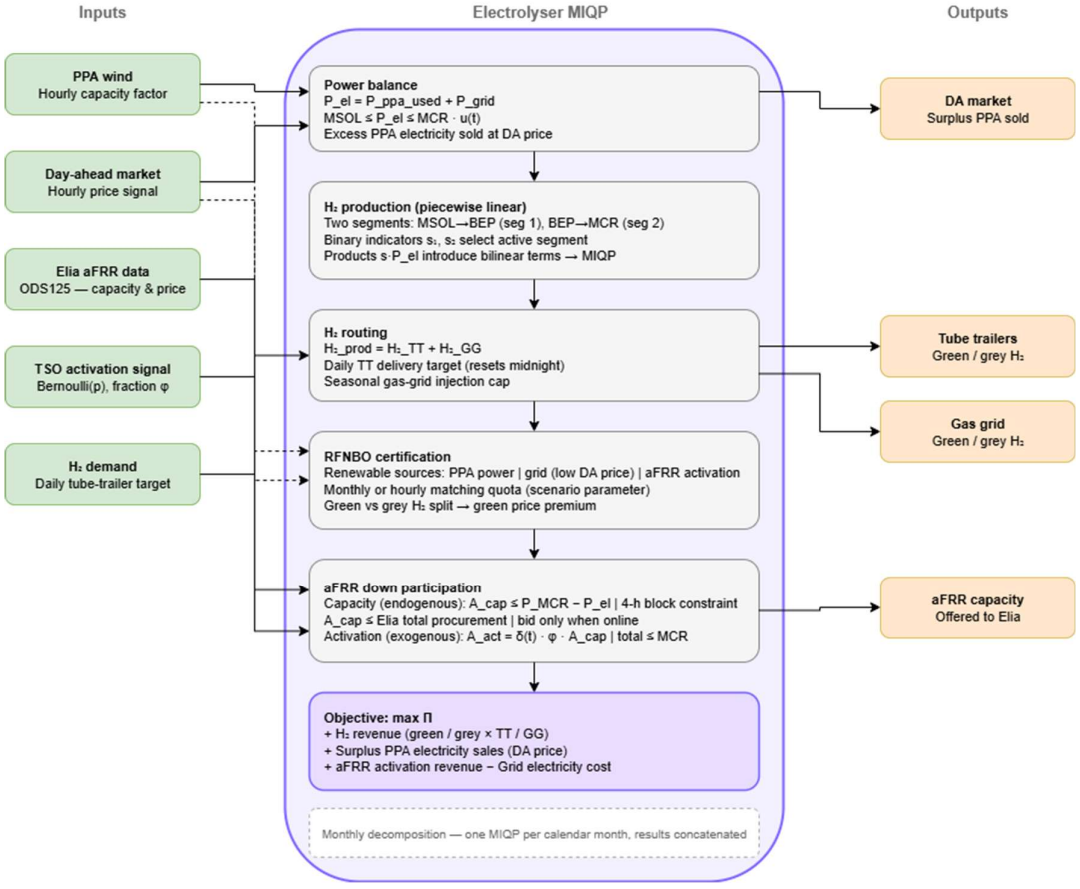


Figure 2-63: Model formulation of the electrolyser MIQP optimisation (BUC9)

2.11.3.1 Piecewise linear H_2 production

The piecewise linear hydrogen production approach uses data points from actual electrolyzer performance curves to create accurate production relationships between power input and hydrogen output. The model divides the operating range into two distinct segments. Segment one spans the MSOL (Minimum Stable Operation Load) to the BEP (Best Efficiency Point) and captures the lower efficiency region. Segment two covers the BEP to MCR (Maximum Continuous Rating) and reflects the high efficiency plateau. The model selects the appropriate segment through binary variables that activate based on the instantaneous power consumption level, ensuring accurate hydrogen production calculations across the entire operating range.

2.11.3.2 Tube trailer filling

The dynamic routing and arrival times of the tube trailers is not considered. Instead, a constant hydrogen daily demand is set. The model keeps track of the TT demand fulfilment throughout each 24-hour period. Once the daily TT demand is met, the spillover is injected in the GG. Since delivery in TT gets compensated at a higher H2 price, the model ensures that the higher-value tube trailer market is always served first while maintaining operational flexibility to utilize the gas grid as an outlet when contractual obligations are satisfied or when production exceeds TT capacity (either during normal operation times or during aFRR down activation periods).

2.11.3.3 aFRR down market representation

The aFRR market is modelled in two parts. The capacity dimension is endogenously optimised: the model decides how much down-regulation headroom to offer to Elia in each hour, subject to the physical headroom between the current operating point and MCR, the total aFRR down capacity procured by Elia (from Elia's ODS125 dataset), and a **4-hour block constraint** reflecting the actual Belgian market rule under which bids must be constant within each procurement slot. The electrolyser can only bid when it is online and above MSOL.

The activation dimension is exogenous: it is not a decision variable, but an input signal imposed by the TSO. Activation timing is drawn from a Bernoulli process with a configurable probability parameter, and activation magnitude is set as a fixed fraction of the offered capacity. When activated, the electrolyser ramps up consumption toward MCR, producing additional hydrogen that is routed according to the delivery logic described above. Total power during activation is capped at MCR. The two-part revenue structure - capacity payments per MW for availability, and activation payments per MWh for actual delivery - reflects the real Belgian aFRR payment mechanism, though the capacity revenue term can be toggled independently in the scenario configuration.

2.11.4 General assumptions

The following assumptions are made related to PPA cost treatment and aFRR assumptions:

- **PPA strike is intentionally outside the objective.** At the operational stage the PPA fee is sunk: the wind energy under contract is paid for whether or not the electrolyzer consumes it, so the strike price has no influence on hour-by-hour dispatch. What does drive that decision is the *opportunity cost* of using a PPA MWh on-site versus reselling it to the day-ahead market - and that opportunity cost is exactly the prevailing day-ahead price, which is already in the model. As a result, the optimizer's hourly dispatch is independent of the PPA strike, and the reported margins are best read as "contribution above the PPA contract". To get a bottom-line Profit & Loss (P&L), subtract the (case-independent) PPA strike × contracted volume - it shifts every case by the same constant and does not affect the ranking.
- **aFRR-down capacity payments are not currently monetised.** The capacity-remuneration term in the objective is multiplied by zero. This is a defensible choice given that capacity is cleared pay-as-bid and the resulting payments are highly uncertain - but it understates the true value of aFRR participation, particularly under hourly RFNBO.
- **Perfect foresight over activation prices — results are an upper bound.** The model solves the full year deterministically and treats the aFRR-down activation price series as a known input. The price the operator pays or receives for each activated MWh is the *clearing* activation price (an exogenous parameter), not a bid the operator submits. In reality the operator would have to bid in advance - the natural bid being its opportunity cost of consuming an extra MWh, i.e. the marginal hydrogen revenue net of any incremental cost - and would only be activated when its bid clears. Because the model both sees activation prices ahead of time *and* is paid the clearing price rather than its own bid, the aFRR-down activation revenue (and the corresponding profit uplift in Cases B and D, see below) should be read as an **upper bound** on what a real operator could realise. The achievable value will be lower once forecast error and bidding strategy are taken into account.

2.11.5 Main Data inputs

The data inputs for BUC 9 are summarized in this section. Table 2-56 provides an overview of the main data inputs used in the model.

Table 2-56: Main Data inputs for BUC 9

Parameter	Description	Units
P_{MSOL}, η_{MSOL}	Minimum stable operating point (power and efficiency)	(MW, %)
P_{BEP}, η_{BEP}	Best efficiency point (power and efficiency)	(MW, %)
P_{MCR}, η_{MCR}	Maximum continuous rating (power and efficiency)	(MW, %)
$H_2(P)$	Hydrogen production rate as a function of power input	(Nm^3/h)
$InjRateLimit_{GG}$	Maximum allowed H_2 injection rate into the gas grid (seasonal)	(Nm^3/h)
$R_{aFRR,cap}\ (t)$	Revenue per MW from supplying aFRR down capacity	(€/MW/h)
$P_{aFRR,cap,awarded}(t)$	Total aFRR down capacity awarded by Elia across all market participants	(MW)
$\beta_{aFRR,cap}(t)$	Binary flag indicating whether Elia has procured aFRR down capacity in a given hour	(–)
$R_{aFRR,act}(t)$	Revenue per MWh from aFRR down activation	(€/MWh)
p_{act}	Bernoulli probability governing the frequency of TSO activation	(–)
φ	Fraction of offered capacity activated by the TSO in each activated hour	(–)
$\pi_{DA}(t)$	Hourly day-ahead electricity price	(€/MWh)
$c_{network}$	Fixed network tariff add-on to the grid price	(€/MWh)
$CF_{wind}(t)$	Hourly wind capacity factor from the PPA asset	(–)
$E_{PPA,month}$	Monthly renewable energy quota derived from the annual H_2 target and average electrolyser efficiency	(MWh/month)
α_{RFNBO}	Minimum renewable electricity share required for H_2 to qualify as RFNBO-compliant	(%)
$D_{TT,day}$	Daily hydrogen delivery target to tube trailers	(kg/day)
π_{H_2} (green/grey × TT/GG)	Hydrogen selling prices by quality (green/grey) and delivery route (tube trailer/gas grid)	(€/kg)

Electricity market data (day-ahead prices and aFRR capacity/activation data) are sourced from Elia's open data platform (ODS125 dataset). Wind capacity factors are taken from an offshore wind profile representative of the Zeebrugge site. Electrolyser technical parameters are derived from the manufacturer's performance curves for the Virya unit. Hydrogen prices, the RFNBO renewable share threshold (α), and the network tariff are set as scenario parameters.

The asset is a 25 MW PEM electrolyzer connected to the public electricity grid and supplied with renewable electricity under a Belgian onshore wind PPA. Hydrogen is delivered through two outlets: tube trailers (TT) at a premium green-certified price, and the natural-gas grid (GG) at a substantially lower price that acts as a flexibility valve when the TT daily delivery quota is met. Operating limits used in all considered cases are summarised below.

Table 2-57: Electrolyzer operating parameters and hydrogen delivery limits.

Parameter	Value	Comment
Electrolyzer capacity (MCR)	24.10 MW	Maximum continuous rate
Minimum stable load (MSOL)	4.92 MW	Always-on operation
Annual H_2 target	650 t / year	Floor; the optimizer routinely exceeds it
Tube-trailer daily cap	2 t / day	= 730 t / year hard limit

Hydrogen pricing has four tiers depending on whether the hydrogen qualifies as RFNBO-certified (green) or not (grey), and on the delivery channel. The relative spread is what matters for the within-case routing decisions.

Table 2-58: Hydrogen offtake price ratio

Hydrogen tier	Channel	Price ratio (green-TT =1.00)
Green (RFNBO)	Tube trailers	1.00
Grey	Tube trailers	0.80
Green (RFNBO)	Gas grid	0.385
Grey	Gas grid	0.185

Two features matter for the remainder of this section. First, the green premium is much larger on the gas-grid channel than on the tube-trailer channel, so the regulatory regime affects revenue the most through the GG channel. Second, the absolute spread between green-TT and grey-GG is more than fivefold, which is what gives the optimizer such a strong incentive to (i) keep TT loaded to its daily cap before sending anything to GG, and (ii) stay RFNBO-compliant whenever physically feasible.

2.11.6 Modelling scenarios

Five cases are compared, with gradually increasing regulatory and market complexity. Cases A and B are unconstrained references that treat all hydrogen as green by construction: A is the day-ahead + PPA baseline, B adds aFRR-down participation to isolate its marginal value. Cases C and D add RFNBO compliance: C-monthly applies the looser monthly correlation rule, C-hourly enforces strict hourly matching, and D is the realistic regulator-compatible mode (hourly RFNBO with aFRR). Every case is solved deterministically at the reference PPA size, where its total yearly volume is able to cover its yearly hydrogen demand (this is equivalent to 14 MW baseload).

Table 2-59: Modelling scenarios characteristics

Case	RFNBO	aFRR-down	Role
A	—	no	Baseline (day-ahead + PPA only)
B	—	yes	Value of aFRR (vs A)
C-monthly	monthly netting	no	Cost of RFNBO under monthly rule
C-hourly	hourly matching	no	Cost of moving to hourly matching
D	hourly matching	yes	Realistic regulator-compatible mode

2.11.7 Results and analysis

2.11.7.1 Case A — Day-ahead + PPA, no aFRR (the baseline)

Case A is the baseline against which every subsequent case is compared. The electrolyzer is allowed to buy from the day-ahead market and to use the PPA but does not participate in any balancing market. This represents an idealised "all-green" world in which the electrolyzer's only economic question is whether to produce more or less hydrogen given the prevailing electricity prices.

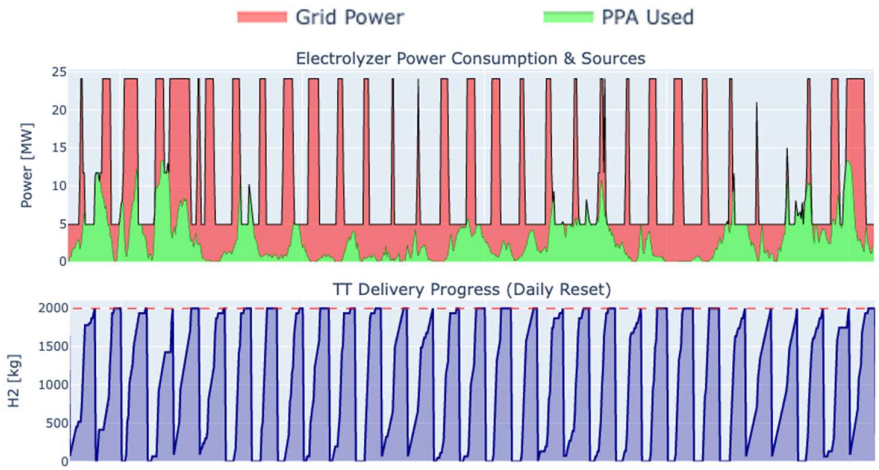


Figure 2-64: Hourly operation in Case A across a representative month (August). Top panel: electrolyzer power split between PPA-supplied (green) and grid-supplied (red) energy. Bottom panel: cumulative tube-trailer hydrogen with daily reset against the 2 t/day cap.

2.11.7.1.1 Operational pattern

With no compliance constraint and no aFRR, the optimizer behaves like a textbook arbitrageur: it runs at least at MSOL and increases production when DA prices are favourable, it balances the value of using PPA energy on-site against reselling it. At the reference PPA size (≈ 14 MW base), the operator consumes only **7.1 GWh** of PPA on-site and resells **34.8 GWh** to the day-ahead market - most of the wind volume is monetised externally because the model is indifferent to its source for compliance purposes.

Hydrogen output in Case A reaches **1671 t/year**, more than 2.5 × the contractual 650 t target. This excess is sent to the gas-grid outlet whenever the daily TT cap is met. Because all of it is classified as green by construction, every kg is monetised at the upper-tier prices.

2.11.7.1.2 Cash-flow breakdown

Table 2-60: Case A cashflow breakdown

Line	*% of revenue before costs*	*Note*
H_2 tube-trailer (all green)	55.3%	Saturated at 2 t/day cap
H_2 gas-grid (all green)	27.4%	Excess production
PPA surplus sold on day-ahead	17.3%	Most of PPA volume is resold
Total cashflow before costs	100%	Revenue before costs
Day-ahead grid electricity	-37.1%	All grid imports at DA price
Net margin	62.9%	On gross revenue (above the PPA contract)

The procurement of electricity from the grid dominates costs (about 37% of gross revenue) because Case A draws nearly 94 GWh from the grid over the year. The PPA contributes much more as a revenue stream (≈ 17%) than as on-site energy. The within-case margin lands at **62.9%**, and this profit forms the index reference (= 100) for all subsequent cases.

2.11.7.2 Case B — A + aFRR-down participation (the value of flexibility)

2.11.7.2.1 What aFRR-down does to operations

Two operational changes follow from adding aFRR. First, the optimizer accepts activation in **3,676 hours** out of 8,760, absorbing **60.3 GWh** of activation energy. Second, total grid intake **falls** from 93.7 GWh in Case A to 66.2 GWh in Case B, a decrease of about 28 GWh, even though the electrolyzer produces about **728 t more hydrogen**. The combination is intuitive once unpacked: activation hours typically coincide with low day-ahead prices (system over-supply), and the optimizer uses these activation MWh as cheap inputs that displace what would otherwise be more expensive day-ahead purchases at other times. Cumulatively, the energy mix shifts from "buy at day-ahead price" toward "absorb at lower combined cost during activation events".



Figure 2-65: Hourly operation in Case B across a representative aFRR-down activation episode. Purple shading shows aFRR activation power, green is PPA, red is day-ahead grid, blue is hydrogen production. Activation events appear as upward steps in absorbed power coinciding with downward TSO signals.

2.11.7.2.2 What aFRR-down does to profit

Indexed to Case A, Case B's profit is **117.3**, i.e., aFRR-down participation lifts profit by about **17.3 percentage points** above the no-aFRR baseline. The reason is straightforward: extra hydrogen production from aFRR activation adds about 13 percentage points to the H_2 revenue lines, the day-ahead grid bill shrinks by about 14 percentage points (because some of the energy that would have been bought at DA is now absorbed via activation), and the activation-charge line subtracts about 16 percentage points. The net is a positive ≈ 17-point lift indexed to A.

Table 2-61: Case A & B cashflow breakdown comparison

Line	*Case A*	*Case B*	*Delta (B-A)*
H_2 green-TT	55.3%	45.6%	-9.7 pp
H_2 green-GG	27.4%	40.1%	12.7 pp
PPA surplus sold	17.3%	14.3%	-3.0 pp
Day-ahead grid	-37.1%	-22.8%	14.3 pp
aFRR-down activation	—	-16.4%	—

Note that the within-case margin in Case B is slightly *lower* than in Case A (61% vs 63%). This is because the activation-charge line is a real cost that did not exist in A. Absolute profit is nonetheless higher because the gross-revenue base has expanded much more than the cost base. This is a recurring theme in the case comparison: the right way to read it is *absolute profit*, not *margin*.

2.11.7.3 Case C-monthly — RFNBO under monthly correlation

2.11.7.3.1 What "monthly RFNBO" means in this model

Under monthly RFNBO, the renewable certificates earned from PPA wind production over the calendar month can be netted against grid consumption over the same month. Concretely, the operator can sell PPA energy to the day-ahead market in the hours it is generated - keeping the corresponding green certificates - and separately buy grid electricity to power the electrolyzer in other hours, classifying the resulting hydrogen as green up to the volume of certificates available. The energy and the certificate need not co-exist hour-for-hour.

2.11.7.3.2 Operational pattern

At the reference PPA size, the optimizer in Case C-monthly converges to a clean corner solution: **100% of the PPA volume is sold to the day-ahead market** (41.9 GWh) and **100% of the electrolyzer's energy comes from grid imports** (77.0 GWh). The hourly renewable-fraction time series is zero in every single hour, yet the year-end accounting still classifies **67.5%** of the produced hydrogen as green - exclusively via the certificate-netting mechanism. It means the electrolyzer is run on grid electricity at whatever the prevailing day-ahead price is, while the wind farm independently monetises its production at the day-ahead price.

2.11.7.3.3 Cash-flow breakdown

Table 2-62: Case C-monthly cashflow breakdown

Line	*% of revenue before costs*	*Note*
H_2 green-TT	50.4%	TT cap; green via monthly netting
H_2 grey-TT	11.0%	TT volume above netted green allowance
H_2 green-GG	8.4%	Excess production; green when netting permits
H_2 grey-GG	3.9%	Excess grey production
PPA surplus sold on day-ahead	26.3%	Highest PPA-resale share of any case
Day-ahead grid	-36.5%	Largest grid bill of any case
Within-case margin	63.5%	
Profit index (A = 100)	87.0	

Although the energy is entirely grid-sourced and the grid bill is the largest of any case, profit indexed to Case A still reaches **87.0**. The 33-percentage-point loss in green-TT revenue (relative to A's 55%) is partly compensated by 11 percentage points of grey-TT and a strong PPA-resale line (26%). What is not recovered is the green-GG revenue: under RFNBO, the optimizer does not push much production toward the GG outlet because the grey-GG price (0.185 ×) is too low to justify additional grid energy spent in non-PPA hours.

2.11.7.4 Case C-hourly — RFNBO under strict hourly matching

Case C-hourly applies the same configuration as C-monthly except that RFNBO compliance is enforced at hourly resolution: in any given hour the certified-green power consumed by the electrolyzer cannot exceed the PPA wind power available in that same hour. This is the strictest interpretation and the one most consistent with the EU's hourly-matching expectation under the RED III delegated act [10].

2.11.7.4.1 Operational pattern

Hourly matching is much stricter and influences the operational pattern. PPA energy is now valuable as direct on-site fuel, using it locally in a wind hour produces a green kg of hydrogen, whereas reselling it does not contribute to RFNBO compliance. The result at the reference PPA size: **30.2 GWh** of PPA energy is consumed on-site (vs. zero in C-monthly), and only **11.7 GWh** is resold. Total grid intake falls from 77.0 GWh in C-monthly to 48.4 GWh in C-hourly, about 37% lower.

In hours where PPA is unavailable or insufficient, the electrolyzer is still required to run by the always-on baseload constraint, so additional grid energy is imported at the day-ahead price, and the resulting hydrogen is grey. The annual outcome is a **50.4% green share**, substantially below the 67.5% achieved in C-monthly, despite consuming all PPA on-site.



Figure 2-66: Hourly operation in Case C-hourly across a representative period (January). Top panel: electrolyzer power split between PPA-supplied (green) and grid-supplied (red) energy. Bottom panel: hydrogen production by tier (green-TT, green-GG, grey-TT, grey-GG). PPA energy is consumed on-site whenever available; grid imports fill the gaps and produce the visible grey slivers.

2.11.7.4.2 Cash-flow breakdown and comparison to C-monthly

Table 2-63: Case C-monthly & C-hourly cashflow breakdown comparison

Line	*Case C-monthly*	*Case C-hourly*	*Delta*
H_2 green-TT	50.4%	39.0%	-11.4 pp
H_2 grey-TT	11.0%	33.7%	22.7 pp
H_2 green-GG	8.4%	12.1%	3.7 pp
H_2 grey-GG	3.9%	5.0%	1.1 pp
PPA surplus sold	26.3%	10.2%	-16.1 pp
Day-ahead grid	-36.5%	-24.9%	11.6 pp
Within-case margin	63.5%	75.1%	11.6 pp
Profit index (A = 100)	87.0	81.3	-5.7

Two things are striking. First, even though C-hourly has a much higher within-case margin (75% vs 64%), its absolute profit is *lower* than C-monthly's. The reason is that C-monthly's expanded gross revenue base (driven by the large PPA-resale line at day-ahead prices) outweighs the higher cost share. Second, the structure of the H_2 revenue mix shifts dramatically: green-TT shrinks by 11 points, grey-TT expands by 23 points, and the GG outlets see a small expansion of grey-GG. This is the cost of strict hourly matching expressed in revenue terms - the same physical hydrogen output, but a much larger share of it falls into the lower price tiers.

2.11.7.5 Case D — Hourly RFNBO with aFRR-down (regulator-compatible operating mode)

Case D combines the strictest RFNBO regime (hourly matching) with the operational flexibility of aFRR-down participation. It is the closest representation of how the asset would actually operate in 2030+ Belgium under EU RED III rules. The comparison of interest is Case D vs Case C-hourly: the same RFNBO regime, with aFRR added.

2.11.7.5.1 Operational pattern

The optimizer accepts activation in **2,828 hours** - about 32% of the year and substantially fewer than the 3,676 hours in Case B. The hourly RFNBO constraint acts as a brake on activation: each activation MWh consumed outside a PPA-coincident hour produces grey hydrogen, so the model self-limits to activation events where the combined economics still pencil out. Total activation energy absorbed in Case D is **20.8 GWh**, roughly one third of Case B's 60.3 GWh.

Hydrogen output reaches **1476 t / year** (vs. 1255 t in C-hourly), and the green share falls to **43.9%** - about 6.5 percentage points lower than in C-hourly. The pattern is consistent: activation MWh expand the grey output, while the green base remains essentially anchored to PPA-coincident hours.

2.11.7.5.2 Cash-flow breakdown and comparison to C-hourly

Table 2-64: Case C-hourly& D cashflow breakdown comparison

Line	Case C-hourly	Case D	Delta
H_2 green-TT	39.0%	34.8%	-4.2 pp
H_2 grey-TT	33.7%	34.7%	1.0 pp
H_2 green-GG	12.1%	13.3%	1.2 pp
H_2 grey-GG	5.0%	8.4%	3.4 pp
PPA surplus sold	10.2%	8.8%	-1.4 pp
aFRR-down activation	—	-1.6%	new line
Day-ahead grid	-24.9%	-19.6%	5.3 pp
Within-case margin	75.1%	78.7%	3.6 pp
Profit index (A = 100)	81.3	88.5	+7.2

Adding aFRR participation lifts profit indexed to A from 81.3 to 88.5 - an uplift of about **7.2 percentage points** relative to A. That is materially smaller than the 17.3-point uplift Case B saw on the unconstrained side, which quantifies the regulatory cost of hourly RFNBO when stacked with balancing-market participation: roughly half the standalone aFRR uplift is forgone because activation MWh cannot easily be paired with PPA hours.

2.11.7.6 Cross-case comparison

The five cases share the same physical asset, the same PPA contract, the same hydrogen price tiers and the same aFRR-down market data. The only differences are (i) whether aFRR participation is enabled, and (ii) which RFNBO regime applies. The comparison summary at the reference PPA size is below.

Table 2-65: Cross scenario comparison

Metric	Case A	Case B	Case C-monthly	Case C-hourly	Case D
RFNBO regime	—	—	monthly	hourly	hourly
aFRR-down participation	no	yes	no	no	yes
H_2 output (t / year)	1671	2399	1217	1255	1476
Green H_2 share	100%	100%	68%	50%	44%
Grid intake (GWh / year)	93.7	66.2	77.0	48.4	37.9
PPA used on-site (GWh / yr)	7.1	7.1	0.0	30.2	29.7
PPA resold (GWh / yr)	34.8	34.8	41.9	11.7	12.2
aFRR activation hours	0	3,676	0	0	2,828
aFRR activation energy (GWh/yr)	0.0	60.3	0.0	0.0	20.8
Profit index (A = 100)	100	117.3	87.0	81.3	88.5

- **By absolute profit at the reference PPA size: B > A > D > C-monthly > C-hourly.** aFRR participation always helps; RFNBO compliance always hurts; hourly matching hurts more than monthly netting.

- **By H_2 output: B > A > D > C-hourly > C-monthly.** The all-green configurations (A, B) produce the most because the optimizer faces no regulatory friction in routing extra MWh through the GG outlet at green prices.
- **By green-H_2 share: A = B = 100% > C-monthly 67% > C-hourly 50% > D 44%.** Adding aFRR to hourly RFNBO reduces the green share by another ~7 percentage points because activation is often not PPA-coincident.

2.11.7.7 Sensitivity to PPA size

Each case was simulated across PPA sourcing fractions from 0.0 to about 4.0 (i.e., from no PPA to roughly 56 MW base capacity). The headline patterns differ qualitatively between the unconstrained cases (A, B) and the RFNBO-compliant cases (C, D).

2.11.7.7.1 Cases A and B — operationally PPA-independent

In Cases A and B the operational picture (hydrogen output, grid intake, electrolyzer load profile) is essentially flat across the entire PPA sweep. Hydrogen output changes by less than 0.3% from PPA frac = 0 to PPA frac = 2.0 in both cases. What does change is the PPA-resale revenue line, which scales linearly with PPA size. As a result, profit grows almost perfectly linearly with PPA size - by about 3 M EUR per unit of fraction in both A and B. This is unsurprising once you recognise that A and B treat all hydrogen as green by construction, so PPA size cannot influence the H_2 revenue mix. The only effect of bigger PPA is more wind volume to resell at the day-ahead price.

2.11.7.7.2 Cases C-monthly, C-hourly and D — the RFNBO regime shapes the curve

Once RFNBO compliance is enforced, PPA size becomes an operational variable, not just a financial one. Larger PPA means more hours where the hourly-matching constraint is satisfied (or more wind volume to net under monthly accounting), which directly shifts hydrogen output between green and grey tiers. The three RFNBO cases all show the same qualitative pattern - profit grows more slowly than linearly with PPA size, and the marginal value of an additional MW falls as PPA grows.

Two specific patterns emerge from the data: (i) green-H_2 share rises monotonically with PPA size in both C-hourly and D, but never reaches 100% even at frac = 4.0, because the always-on baseload constraint forces a minimum draw during low-wind hours that necessarily produces grey output; and (ii) the relative ranking of C-monthly vs C-hourly switches at very large PPA sizes - under hourly matching, large PPA is more valuable, because under monthly netting any additional PPA above the consumption volume is just resold at the day-ahead price rather than improving compliance.

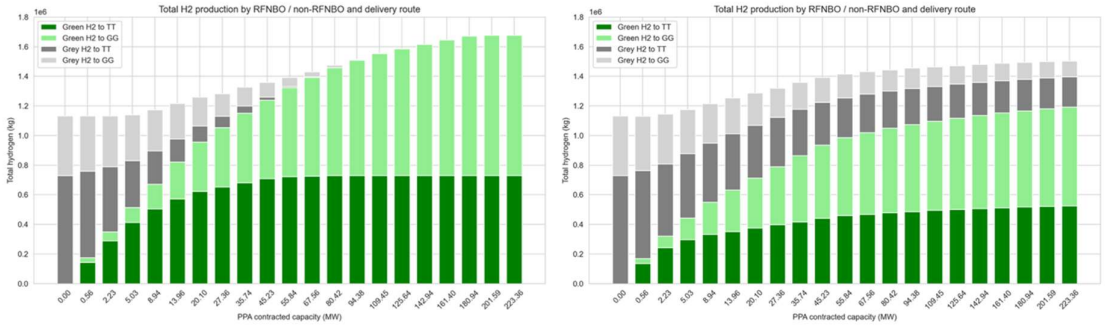


Figure 2-67: PPA contract sensitivity.
Left panel: monthly correlation (Case C-monthly). Right panel: hourly correlation (Case C-hourly). Each panel shows profit and the green hydrogen share as a function of contracted PPA size. Under monthly netting, RFNBO production is easier to obtain

2.11.8 Conclusions

- **aFRR participation can add value — but the value is bounded by the RFNBO certification rules.** Without RFNBO compliance, aFRR participation lifts profit by about 17 percentage points indexed to the no-aFRR baseline (Case B vs A). Once hourly RFNBO is enforced, the benefit shrinks to about 7 points (Case D vs Case C-hourly), because activation MWh cannot always be matched to PPA hours and so often produce grey hydrogen.
- **Hourly RFNBO reduces profit, oversizing the PPA can increase RFNBO production.** Comparing Case C- (with monthly correlation) to Case C-hourly (strict hourly matching) shows that the certification regime alone moves profit from 87% of A to 81% of A. The PPA size sweep (Section 2.11.7.7) further confirms that the marginal value of an extra MW of PPA is much smaller under hourly matching, because some hours are structurally unmatchable.

2.11.9 Recommendations

Table 2-66: Key recommendations for BUC 9

Recommendations	
Technical	The continuously operating baseload demand poses a limitation in the results. Because this demand must be met even during low-wind periods, the system is forced to rely on grid imports and consequently grey hydrogen production, preventing the green hydrogen share from approaching 100% under hourly RFNBO constraints, even at high PPA capacities. We therefore recommend assessing alternative asset configurations with lower minimum-load requirements or true cold-standby operation, as well as quantify the stack degradation associated with the strongly cyclic, PPA-following operating profiles observed in Cases C-hourly and D.
Socio-economic	The results reveal a clear trade-off. RFNBO requirements, and hourly matching in particular, substantially reduce electrolyser flexibility: participation in aFRR-down markets falls to roughly one third of the level observed in the absence of the RFNBO rules, while profits decline by approximately 19 percentage points relative to the baseline. At the same time, the societal value of these constraints lies precisely in their ability to couple hydrogen demand to additional renewable deployment, thereby ensuring that electrolytic hydrogen contributes to genuine emission reductions.
Policy/regulatory	The results quantify a direct trade-off between RFNBO strictness and the social value of grid flexibility: hourly matching nearly halves the aFRR-down uplift that the same asset delivers under no RFNBO. We recommend regulators (i) preserve some form of intra-month flexibility within the hourly matching regime to keep electrolyzers active in down-regulation hours, or (ii) exempt aFRR activation at low prices from additionality, so flexible RFNBO assets are not penalised for offering balancing services they are physically well-placed to provide.

2.12 BUC 10 - Flexibility provision with a portfolio of EVs

2.12.1 General information

Test Case ID	*Name of Test Case*
1	Large scale E-mobility uptake B2C
Maturity of Test Case	
The test case is representative of emerging business practices, as similar concepts have been demonstrated in medium- to large-scale projects and the adoption of EV flexibility within FSP / BRP portfolios is steadily progressing.	

ID	*Name of Business Use Case*
BUC 10	Potential for flexibility provision with a portfolio of EVs
Short description and objectives	
The flexibility of electric vehicles (EVs) can significantly contribute to balancing the energy system. This BUC focuses on analysing and evaluating the flexibility potential of EVs, as well as the profitability of leveraging them for grid services - whether through implicit or explicit participation by EV owners. With the increasing penetration of EVs, their aggregated flexibility is expected to play an important role in maintaining system balance. Thus, an accurate estimation of this flexibility potential is essential for planning and operational decision-making to ensure reliable grid performance. The technical constraints of the EVs (e.g., charging rate and minimum/maximum State-of-Charge (SoC) of the EV battery), behavioural constraints imposed by the user's behaviour and preferences (such as preferred SoC before starting a journey, preferred time of charging, charging location etc.) as well as the manufacturer's recommended usage (recommended minimum and maximum EV battery SoC) should be considered for this estimation of EV flexibility potential. Ignoring these constraints and limitations can lead to inaccurate assessments of EV flexibility, either underestimating or overestimating the available capacity and, at the same time, influencing the utilisation of other flexible assets (such as heat pumps (HPs)). This BUC aims to quantify the flexibility potential of EVs while accounting for technical, user behavioural, and manufacturer constraints. It also highlights the impact of incorporating these constraints on the total cost of users' households, the self-consumption of household PV generation, and the impact on the grid in terms of peak consumption due to simultaneous EV charging.	

2.12.2 Simulation tool

An optimisation framework referred to as the residential flexibility model has been used to quantify the flexibility potential associated with EVs. This optimisation framework determines the optimal electricity consumption and injection schedule at an hourly or quarter-hourly resolution over a predefined analysis horizon (e.g., a full year). The optimisation is executed on a daily basis using a rolling-horizon procedure, whereby each day is optimised over a 36-hour interval. The model accounts for household baseline electricity demand, household PV generation, and the technical, operational, and behavioural constraints of flexible assets such as EVs.

Within this framework, consumers are allowed to adjust their power offtake and injection across different time periods with the objective of minimising their total energy cost or maximising revenues arising from net injections. The resulting cost signals are determined by the applicable retail electricity tariffs, which may include dynamic price components linked to wholesale market variations [11]. Time-varying network tariffs (e.g., time-of-use structures in the Walloon region [12] and upcoming in the Brussels Capital region [13]) and tariff schemes with volumetric (kWh-based) and capacity (kW-based) components (as implemented in Flanders [14] [15]) are also incorporated. The optimisation is performed iteratively for each day of the analysis period, enabling a consistent assessment of flexibility provision under operational and tariff-related constraints.

In the post-processing phase, the flexibility potential (KPIs) is defined as the difference in its electricity consumption profile when exposed to fixed retail prices versus dynamic pricing schemes (and, where applicable, capacity-based network tariffs or other tariff schemes). This flexibility potential can be quantified directly using the proposed optimisation model by evaluating and comparing the optimal consumption schedules obtained under the respective tariff structures. An overview of the model is presented in Figure 2-68.

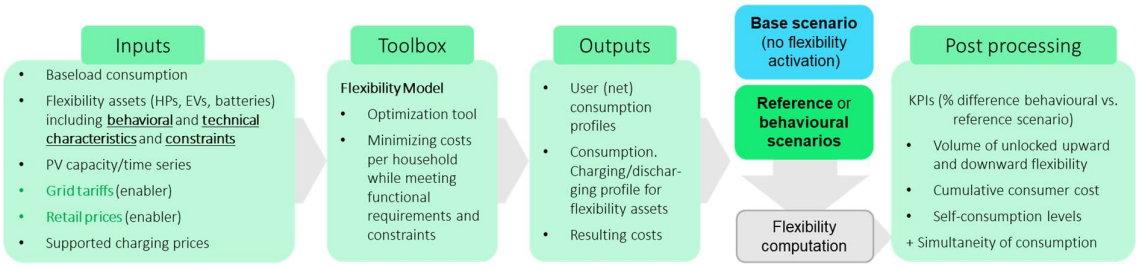


Figure 2-68: Optimization tool overview for BUC 10

In practice, the flexibility of residential EVs is shaped by numerous factors related to *user behaviour* and *manufacturer specifications*, which influence both the availability of the EV and the extent to which its charging (and discharging, in the case of V2G) can be adapted. The EV may not always be present at the residence or plugged in when available and may also charge at other locations potentially at subsidised rates and thus affecting its SoC upon returning home. Driving behaviour determines the EV's energy consumption and daily charging needs, while user preferences and manufacturer recommendations impose constraints on allowable SoC ranges to preserve battery life. Collectively, these elements substantially affect the flexible capacity that can be supplied by residential EVs.

To capture these aspects, the following key behavioural and technical factors have been integrated into the model:

- **Expected consumption**: anticipated daily energy requirements based on expected driving patterns.
- **Charging session**: expected time window during which the EV is at home and plugged in. This is derived from users' leaving, returning, and commuting times.
- **Target SoC**: desired SoC at the end of the charging session (e.g., before departure).
- **Expected SoC at arrival**: projected SoC when returning home, accounting for potential charging at work or other locations.
- **Preferred SoC range**: acceptable SoC band (e.g., 20–80%) based on user preferences or due to manufacturer's recommendations.
- **V2G capability**: indicator of whether bidirectional charging is technically supported.
- **Minimum SoC threshold**: SoC level below which the EV automatically charges at maximum power.

These parameters, combined with core technical characteristics such as maximum charging power (as specified by the EV and/or the charging station), battery capacity, and charging/discharging efficiencies, which are part of the optimisation framework, enable characterizing the flexibility feasibility space of the EV. This is significantly different setting in which the EV is assumed to always be at home and always plugged in (enabling full smart charging or V2G availability for the entire time period).

The instantiation of these parameters, together with household demand profiles, PV generation time series, and applicable electricity prices and network tariffs, constitutes the complete numerical environment in which the residential EV flexibility potential is evaluated in the subsequent case study. Two case studies are presented in the following section. The first is based on theoretical EV parameters, including predefined SoC requirements and driving profiles, and is primarily used to validate the modelling framework and tool implementation. The second case study is based on observed EV data and is used to assess residential EV flexibility under more realistic EV and user-specific operating constraints.

2.12.3 Case Study 1: Model Validation Using Theoretical EV Parameters

2.12.3.1 Use case setup

The analysis considers a set of residential consumers in Flanders with a time varying power consumption based on open-source consumption profiles from the Fluvius database [16]. The consumption data is from 2022, and the analysis focuses on households that did not at the time have an EV or PV installed. To assess self-consumption potential, the 20 households with the highest peak demand are selected, and households equipped with an EV are assumed to also have a residential PV installation. A schematic representation of the considered setup is shown in Figure 2-69.

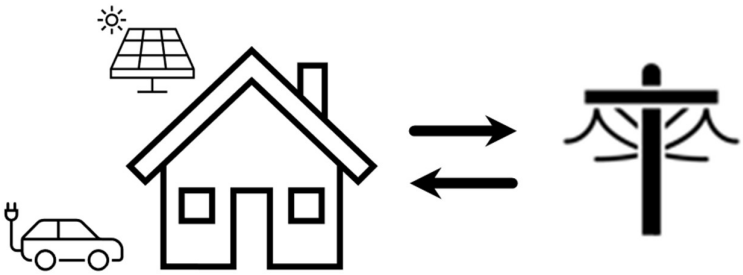


Figure 2-69: BUC 10 model setup.

2.12.3.2 General assumptions

To assess the household EV flexibility potential for the following assumptions are made:

- The average daily driving requires 10kWh energy [17].
- The driving time is drawn from a uniform distribution between 6–9 AM for leaving home and 4–7 PM for returning home. It is also assumed that users follow a consistent daily driving profile.
- It is considered that 50% of users have access to charging facilities away from home at a lower or no cost to assess the impact of having the possibility of charging away from home at significantly reduced rates on total EV flexibility potential at the home connection level (i.e., impacting the net household consumption profile).
- The SoC preferred limits are set to 20% and 80%, for the minimum and maximum limits, respectively.
- A target SoC is considered when charging elsewhere of 80%, and a minimum SoC preference of 30% before leaving home.
- A battery capacity of 62 kWh [17], a maximum power rating of 11 kW, and an efficiency of 90% is considered.

2.12.3.3 Main Data inputs

The optimisation model relies on the following input data for the BUC analysis:

Table 2-67: Data inputs for analysis of EV flexibility potential in BUC10.

Data input	Unit	Description and value	Source
Household power consumption profile	kWh	The actual time varying power consumption profile for school with 15 minutes time resolution.	Fluvius open-source database [16]
PV installed capacity	kWp	A peak capacity of 3-5kW for household PV installation.	
PV generation	kWh	The actual PV generation capacity factor for Belgium.	Elia open-source database [18]
Grid tariffs	€/kWh	The TSO and DSO power offtake and injection tariffs.	Prices from open-source information for a typical energy supplier in Flanders
	€/kWh/ month	The capacity tariff for monthly peak offtake from the grid.	
Electricity offtake retail price	€/kWh	The ToU electricity retail prices for power offtake from the grid (peak and off-peak).	
Grid injection retail price	€/kWh	The dynamic retail price for power injection into the grid[12].	
Daily EV energy requirement	kWh	The energy requirement for daily driving.	Considered from the information in [17]

2.12.3.4 Modelling scenarios

EV flexibility behaviour is shaped by two broad dimensions in our study namely, user behaviour (e.g., driving patterns, charging preferences, and availability of the vehicle at home) and manufacturer-imposed technical constraints (e.g., battery degradation limits, maximum charging rates, and preferred state-of-charge ranges). To systematically evaluate their impact, three distinct modelling scenarios are defined.

- **Baseload Scenario**: In this scenario, EV users are assumed to ignore dynamic electricity price signals, both in terms of time-varying network tariffs and retail price variations. EV charging is driven based solely on user convenience, typically starting immediately upon arrival at home and continuing until the battery reaches the desired level. As a result, no flexibility is exercised and the charging profile reflects uncontrolled behaviour, providing a benchmark against which the flexibility benefits in other scenarios can be compared.
- **Reference Scenario**: In this scenario, EV users actively respond to dynamic tariffs and retail prices. Charging is optimised to minimise electricity costs by shifting consumption to lower-priced hours. However, this scenario does not incorporate real-world behavioural patterns or technical limitations that affect charging availability and flexibility. The EV is implicitly assumed to be always

[12] The grid injection prices are based on the day-ahead prices which are calculated with actual day-ahead prices in Belgium based on the formula provided in [15].

plugged in when at home, with unrestricted charging flexibility aside from the imposed price signals. This provides a theoretical upper bound on flexibility under perfect consumer responsiveness and idealised technical conditions.

- **Behavioural Scenario**: This scenario extends the reference case by explicitly incorporating the behavioural and technical constraints. These include limited plug-in availability based on travel schedules, expected energy needs, preferred state-of-charge ranges, V2G capability, charging power constraints, and manufacturer recommendations aimed at preserving battery health. Consequently, the flexibility potential becomes more realistic, reflecting the actual temporal availability and operational limits of EVs in residential settings.

2.12.3.5 Results and analysis

In this section we will present the results of our BUC analysis. The impact of consideration of behavioural and manufacturers' constraints on the EV flexibility potential is evaluated using the following KPIs: **Volume of unlocked upward and downward flexibility, Cumulative consumer cost** and **Self-consumption levels**. The KPIs are calculated based on the consumer net offtake and injection for reference and behavioural scenarios.

The **volume of unlocked upward and downward flexibility** is the cumulative volume of upward and downward flexibility provided by the EV during the considered time horizon.

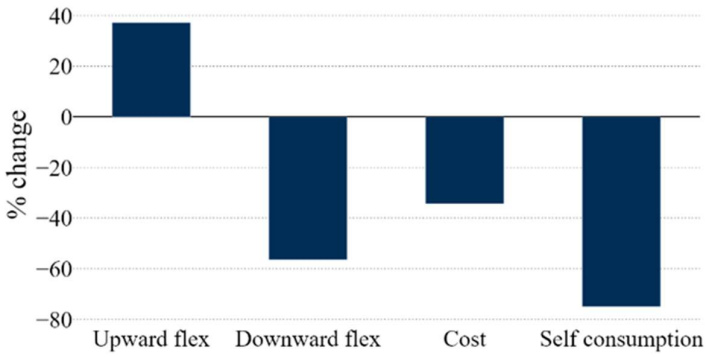


Figure 2-70: KPIs for BUC 10.

As illustrated in Figure 2-70, the introduction of behavioural considerations into the EV flexibility model results in a 37.18% increase in upward flexibility provision from residential EVs. This effect is primarily driven by the assumption that EV users have access to alternative charging locations most notably workplace charging and often at reduced tariffs. Because part of the charging demand is shifted away from the household, the residential base load decreases substantially, thereby expanding the headroom available for upward flexibility provisions (i.e., reducing consumption relative to baseline power consumption). Although this shift simultaneously

increases electricity demand at the external charging location, the present analysis focuses solely on the residential perspective, as it aims to quantify flexibility that can be delivered by the household itself. An extension of this work would be to analyse multi-location charging flexibility, integrating home, workplace, and public charging infrastructures to obtain a system-wide estimate of EV flexibility potential.

Conversely, Figure 2-70 also shows that downward flexibility decreases by 56.5% when behavioural and technical constraints are accounted for. This decline is explained by the reduced availability of EVs at the household location during large parts of the day, combined with the fact that many users return home with a higher SoC due to cheaper charging opportunities elsewhere. As a result, the additional charging volume that could be flexibly scheduled, particularly in response to low or negative prices is significantly constrained. Moreover, when cheaper charging alternatives exist outside the home, EV users have limited economic incentive to charge at higher household tariffs, further diminishing the potential to increase consumption at times beneficial to the system. Overall, these behavioural insights demonstrate that flexibility estimates that ignore realistic charging habits and user preferences can substantially overestimate the flexibility available at the residential level.

The introduction of behavioural and technical considerations has a pronounced effect on the charging costs incurred by EV users. As shown in Figure 2-70, under the behavioural scenario, the **total cost of charging** decreases by 34.38% compared to the reference setting. This reduction is primarily driven by the flexibility users have to charge their vehicles at alternative locations, most notably at workplaces or public charging points where tariffs may be lower or subsidised. As users strategically shift their charging away from the household to take advantage of more favourable price conditions, the overall expenditure on electricity for EV charging diminishes. This behaviour highlights the strong interaction between tariff design, user incentives, and charging infrastructure availability. These results again illustrate that the residential electricity cost alone may no longer reflect the full charging cost picture, emphasizing the need for system-wide analysis when assessing the economic benefits of flexible charging behaviour.

While the behavioural scenario reduces costs, it also significantly affects the degree to which households utilise their self-generated solar energy. As shown in Figure 2-70, self-consumption drops by 75%, reflecting a substantial decline in the ability of EVs to consume self-generated PV energy. This reduction is largely attributable to the fact that, under realistic behavioural patterns, EVs are not parked at home during the hours when PV production typically peaks. Consequently, the EV charging profile does not align with the solar generation profile, and households are unable to make effective use of their own renewable electricity. This mismatch forces a larger portion of PV output to be injected into the grid, reducing the direct economic value of self-generation and potentially leading to increased curtailment if grid export constraints are present. The findings underscore the importance of assessing complementary flexibility assets such as shiftable household loads or residential battery systems that can better synchronize consumption with local generation. The analysis

again highlights the broader system implications of mobility patterns, demonstrating that EV flexibility cannot be fully captured without acknowledging realistic user behaviour and charging availability constraints.

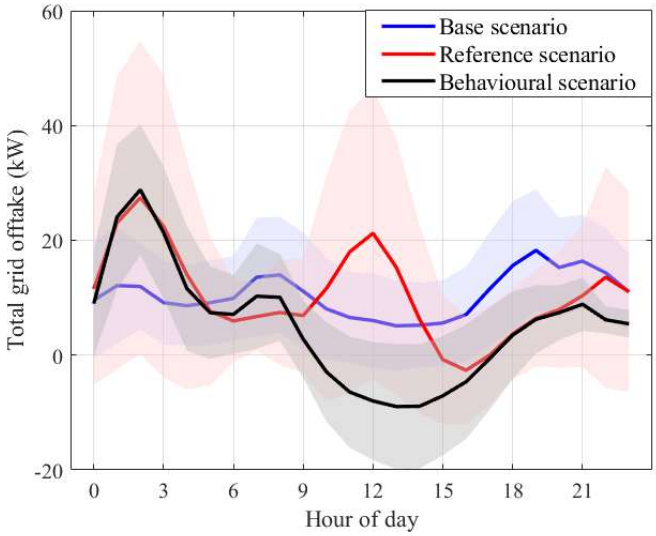


Figure 2-71: Cumulative hourly load (average +/- 1 standard deviation).

The interaction between dynamic price signals and the associated behavioural and technical constraints substantially influences both individual consumption patterns and the simultaneity of consumption across users. This effect is illustrated in Figure 2-71, which depicts the average cumulative household load for each hour of the day over the full study year, together with a shaded band representing one standard deviation above and below the mean. The results indicate that, under the reference scenario, load peaks become more pronounced relative to the baseline, as users collectively shift their demand towards hours with lower electricity prices. In contrast, the behavioural scenario produces a notable reduction in peak load and even lowers overall cumulative consumption compared to the base scenario. This outcome arises because users increasingly rely on external charging locations, which reduces household load, and because the limited availability of EVs at home restricts their ability to exploit low price periods for downward flexibility.

The flexibility potential of EVs is expected to play an essential role in meeting the growing need for power system flexibility and supporting network planning efforts. This case study demonstrates the importance of incorporating behavioural and technical considerations when evaluating the flexibility potential of residential electric vehicles. The case study highlights the extent to which these factors can influence the magnitude of available upward and downward flexibility, the costs faced by users, the achievable level of self-consumption, and the resulting cumulative peak demand. A natural continuation of this work involves two directions: first, extending the analysis to the full Belgian context, and second, including additional flexible assets such as heat pumps and household battery systems.

2.12.4 Case Study 2: Data-Driven EV Flexibility Assessment Using Realto Data

The behavioural and technical constraints are parameterized using an anonymized dataset of 63 EVs obtained from Realto within the ReInvent project. The dataset combines vehicle-specific technical characteristics with historical charging, SoC, and driving observations. As a result, key flexibility parameters, including charging availability, mobility requirements, driving-energy demand, SoC ranges, battery capacities, and maximum charging powers, are derived from observed behaviour.

2.12.4.1 Use case setup

The use case is defined by combining the EV-specific data with household base load consumption profiles, PV generation time series, and the applicable electricity prices and network tariffs. Together, these inputs define the technical and economic conditions under which the residential EV flexibility potential is evaluated. A set of residential consumers in Flanders is analysed using household electricity consumption data from 2024 (as data from 2025 is not available yet), as provided in Fluvius open-source database [16]. The analysis focuses on households without EV or PV system installations during the observation period. The 56 households with the highest peak demand are selected from the available dataset.

For each household, two cases are analysed to isolate the effect of PV availability on EV charging behaviour and household electricity demand. In the first case, the household is assumed not to have a PV system. EV charging demand is supplied entirely from the grid, and charging decisions are influenced primarily by mobility requirements, vehicle availability, and electricity prices. This case establishes a baseline for assessing the additional load introduced by EV charging and its impact on household peak demand and grid electricity consumption.

In the second case, the household is assumed to have a PV system. Local PV generation can influence both the timing and source of electricity used for EV charging. When the EV is connected at home during periods of PV generation, charging may be shifted to daytime hours to maximize the use of locally generated electricity. This increases PV self-consumption, reduces electricity imports from the grid, and limits the export of surplus PV generation to the network. The presence of PV thus provides an incentive for users or energy-management systems to coordinate EV charging with local generation. Household PV generation is modelled using the Belgian PV generation profile for the relevant period.

Comparison of the two cases enables quantification of the effect of PV availability on household net-load profile, grid dependence, peak demand, and EV flexibility. It also allows assessment of the extent to which EV charging can support local use of renewable generation without compromising user mobility requirements. The EV characteristics such as charging times, driving times and the energy requirements are considered as per the actual EV profiles and are presented in next section.

2.12.4.2 General assumptions for EVs

It is assumed that all the households have the possibility to charge the EVs at home with a maximum power rating of 11 kW. The optimization model schedules household power consumption at 15-minute intervals. As described in Section 2.12.2, optimization is performed daily using a rolling-horizon approach. An analysis of the actual EV data is presented in the following to extract EV characteristics required for the simulations.

An anonymized dataset comprising 63 EVs from Realto, collected within the ReInvent project, forms the basis for the analyses presented in this case study. The dataset combines vehicle-specific technical characteristics with historical operational data. Technical attributes include manufacturer, model, battery capacity, and maximum charging power. Operational data encompass time-series measurements of battery SoC, charging session records (plug-in time, charging start and end times, charging duration, charged energy), and driving information such as trip timing and distance travelled. The dataset facilitates the characterization of charging and driving behaviour, identification of differences in vehicle utilization, and evaluation of the fleet's flexibility potential under diverse charging strategies and electricity market participation scenarios. Observed charging times, driving patterns, daily driving energy requirements, SoC operating ranges, battery capacities, and maximum charging powers inform the behavioural and technical parameters of individual EVs. Data are available for all vehicles from May 2025 to November 2025. The principal characteristics and observed patterns are discussed below.

Figure 2-72 displays the temporal charging status of individual EVs during the monitoring period. Most data points represent non-charging periods, whereas charging events are generally brief and irregularly distributed. Several EVs exhibit longer and more continuous charging periods. These patterns indicate substantial differences across the fleet in charging frequency, duration, and timing. Missing observations for certain vehicles may arise from communication interruptions, unavailable measurements, or incomplete records. These instances are addressed separately from confirmed non-charging periods in subsequent analyses.

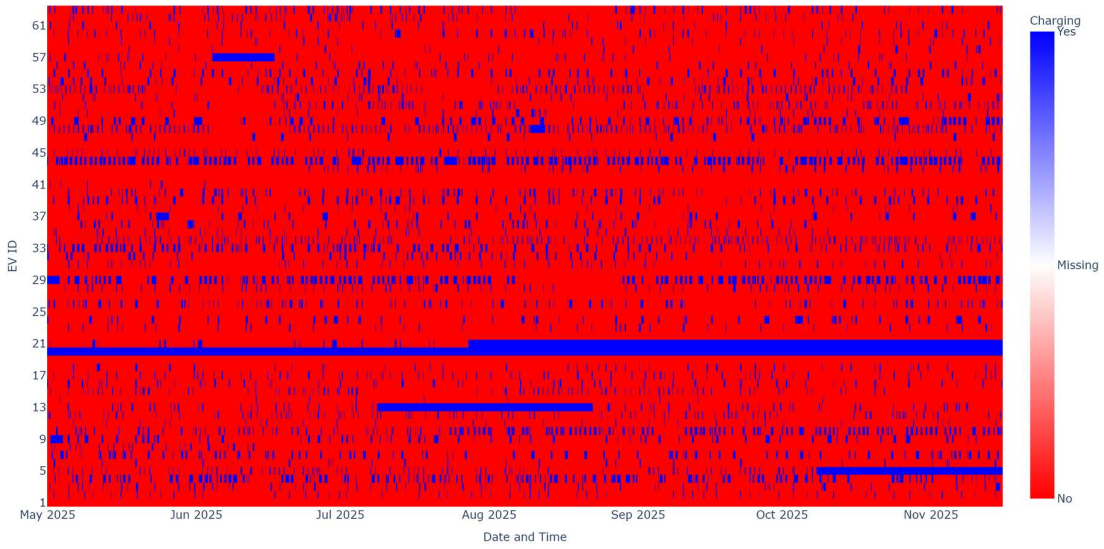


Figure 2-72: Temporal charging status of the considered EV fleet during the monitoring period.

Figure 2-73 shows the temporal variation in SoC for individual EVs during the monitoring period. Significant variability is observed both across vehicles and over time. Several EVs demonstrate frequent changes in SoC, reflecting repeated charging and driving activity, while others maintain stable values for extended periods. Some vehicles operate predominantly at high SoC levels, whereas others experience recurring periods of low or moderate SoC. Extended intervals with limited variation may indicate prolonged inactivity, stable operating conditions, or unchanged measurements. These findings underscore the heterogeneous utilization and charging patterns within the fleet.

Figure 2-74 illustrates a high degree of variation in daily driving requirements across the considered EVs. Differences are observed both in typical daily mileage and in the spread of the distributions. Some EVs exhibit relatively low and consistent daily driving distances, whereas others show substantially higher and more variable travel requirements. The results highlight the importance of representing mobility at the individual-vehicle level. Daily driving distance determines the energy withdrawn from the battery and, consequently, the amount of charging required to restore the desired SoC. Vehicles with higher or more variable daily mileage may therefore offer less charging flexibility, as a larger share of their available charging window is required to satisfy mobility needs.

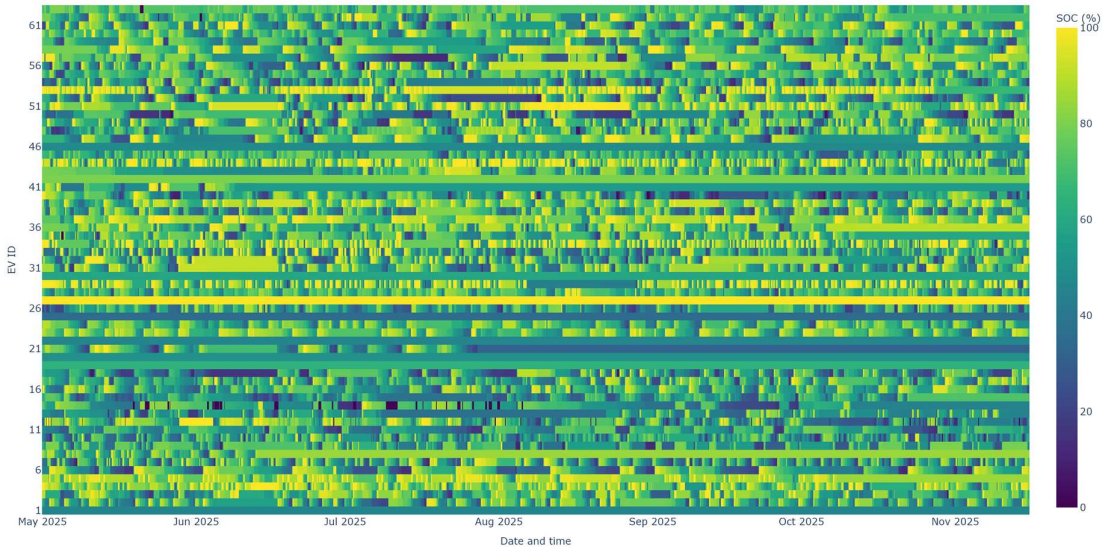


Figure 2-73: Temporal variation in SoC across the considered EV fleet during the monitoring period.

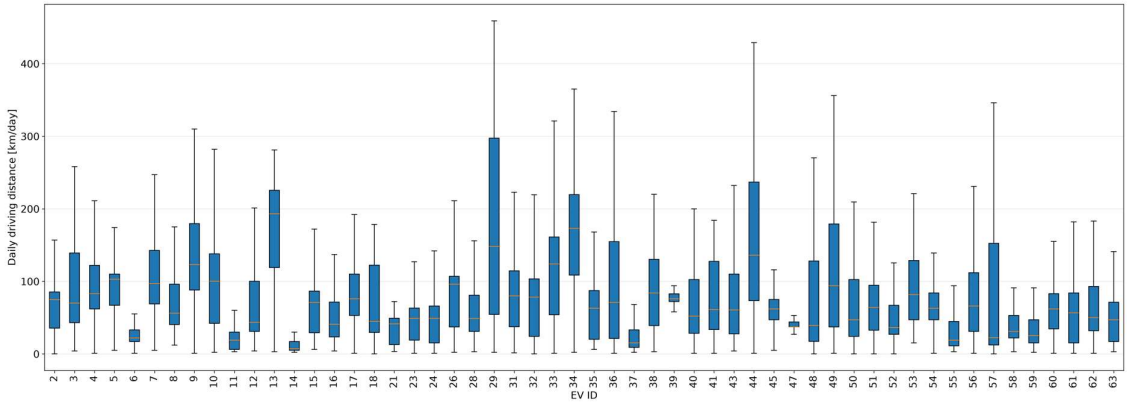


Figure 2-74: Distribution of daily driving distances for individual EVs during the monitoring period.

Figure 2-75 presents the distribution of charging times for individual EVs during the monitoring period. Substantial variation is observed both within and across vehicles. For several EVs, charging events are distributed across a wide range of hours, indicating that charging may occur at various times of the day depending on vehicle availability, mobility requirements, and user preferences. Other EVs display more concentrated charging-time distributions, suggesting more consistent charging habits. Typical charging times differ considerably among vehicles. Some EVs are charged primarily during morning or daytime hours, while others exhibit a stronger tendency toward evening charging. Several vehicles also display charging events near midnight or during early morning hours, indicating overnight charging behaviour. The broad distributions observed for certain EVs further

demonstrate the non-uniformity of charging behaviour across the fleet. Overall, the figure emphasizes the heterogeneity of user charging patterns and establishes a foundation for deriving vehicle-specific charging-time preferences and availability windows for flexibility simulations.

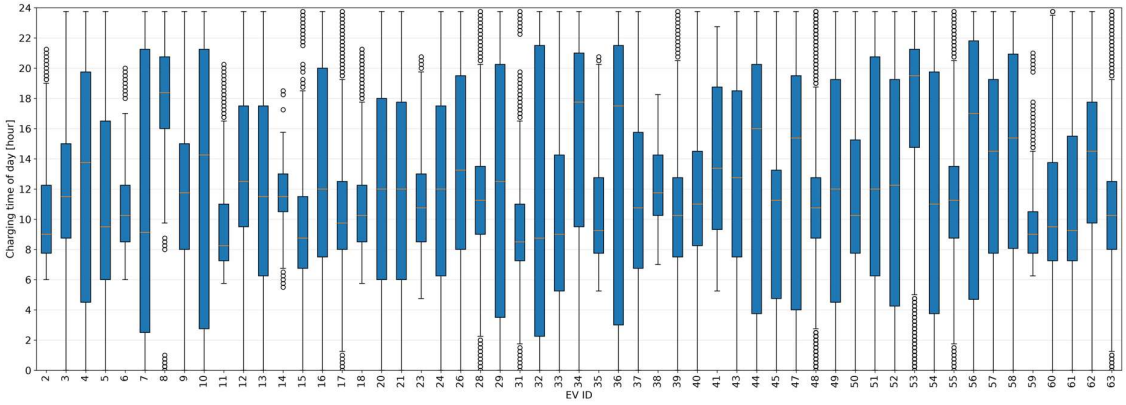


Figure 2-75: Distribution of charging times for the individual EVs during the monitoring period.

Figure 2-76 compares the average number of weekly charging sessions with the average SoC increase per charging session for each EV. Significant variation is observed across the fleet in both charging frequency and the amount of energy replenished per session. Most EVs are charged one to four times per week, with average SoC increases ranging from 20% to 60%. This suggests that many users charge infrequently but replenish a substantial portion of the battery during each session.

A smaller subset of EVs demonstrates more frequent charging, with six to nine sessions per week. These vehicles typically exhibit lower average SoC increases per session, indicating a preference for shorter and more frequent charging events. Conversely, several EVs with fewer weekly charging sessions display relatively high SoC increases, reflecting deeper charging cycles and longer intervals between sessions.

Overall, the figure indicates an inverse relationship between charging frequency and average SoC increase per session, although considerable vehicle-specific variation persists. These differences reflect heterogeneous user charging habits and are pertinent for defining representative charging profiles and evaluating the flexibility potential of the fleet.

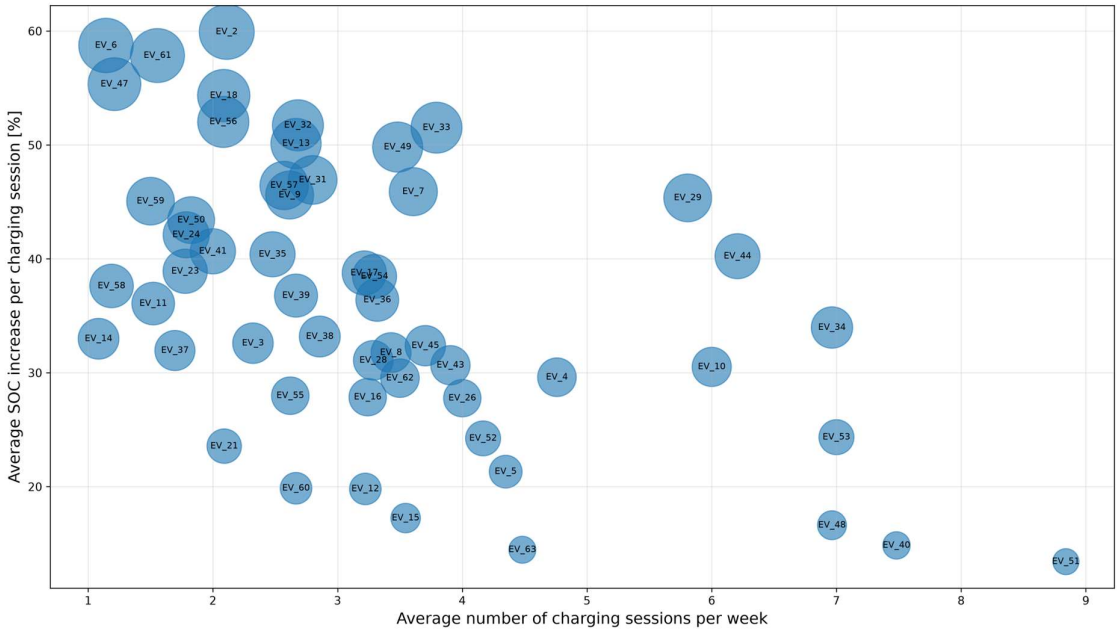


Figure 2-76: Average number of weekly charging sessions and average SoC increase per charging session. For the individual EVs - Bubble size represents the relative charging activity of each EV over the monitoring period.

Figure 2-77 summarizes the distribution of SoC values for each EV during the monitoring period. Significant differences are observed across the fleet in typical SoC levels, variability, and operating range. Some EVs remain predominantly at high SoC levels with limited variation, while others operate across a broader range. Several vehicles exhibit frequent low-SoC observations, which may indicate recurring periods of extensive battery use or longer intervals between charging events. These differences underscore the diversity of vehicle utilization and charging behaviour within the analysed fleet. The figure also provides insight into user preferences regarding minimum and maximum SoC levels at which EVs are typically operated. For some EVs, specifically EV 1, EV 19, EV 20, EV 22, EV 25, EV 27, EV 30, EV 42, and EV 46, the SoC remains constant over extended periods, as shown in Figure 2-77. This behaviour is likely attributable to data-collection or processing issues rather than actual vehicle operation. Similarly, Figure 2-72 shows that some EVs are recorded as continuously charging throughout the monitoring period. To avoid introducing bias or unrealistic behaviour into the analysis, these EVs are excluded from the simulations.

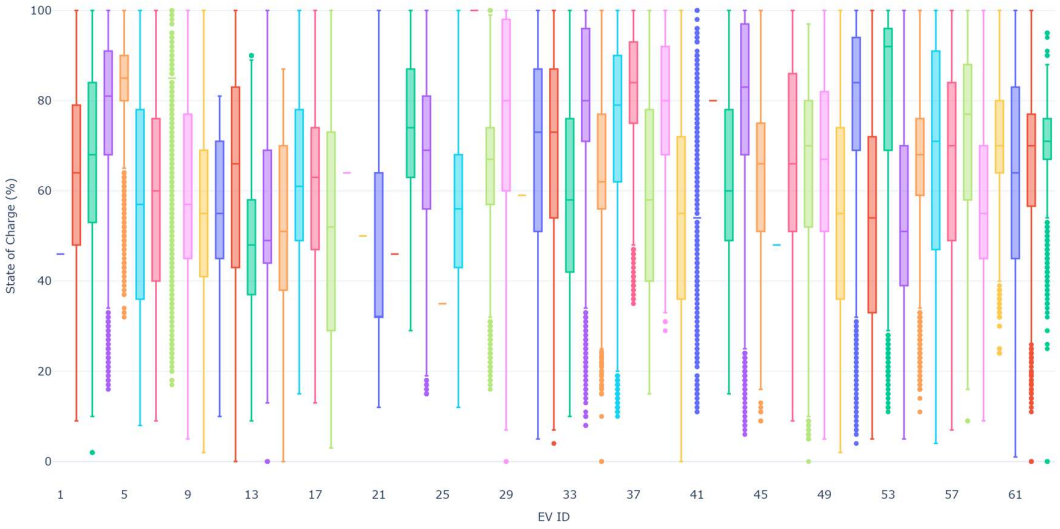


Figure 2-77: Distribution of SoC values for the considered EVs during the monitoring period.

For the remaining EVs, two methods are employed to represent user preferences regarding minimum and maximum SoC limits. The first method uses the observed minimum and maximum SoC values during the monitoring period as the lower and upper limits for charging sessions. The second method defines these limits using the 20^{th} and 80^{th} percentiles of the observed SoC data for each EV. The percentile-based approach mitigates the influence of isolated extreme values and yields a more representative estimate of the typical SoC range for each vehicle.

Figure 2-76 shows that EVs in the dataset have heterogeneous charging behaviour. For some vehicles, charging sessions occur only once every few days. Because optimization is performed independently each day, missing charging sessions over several days may lead to insufficient energy replenishment and infeasible EV SoC trajectories. To address this, the charging dataset is supplemented with additional sessions. If no charging session is available for a given day, the largest session from the previous day is replicated. If the EV is driving during that time, an alternative session from 22:30 to 24:00 is added. This ensures each EV has at least one feasible charging opportunity per day and reduces the risk of infeasible SoC values in the rolling-horizon optimization. Some charging sessions deliver a large amount of energy in a short period, typically 15 to 30 minutes. These rates are not representative of conventional home charging. Such sessions are classified as charging-away-from-home and are excluded from residential charging opportunities.

2.12.4.3 Main Data inputs

The BUC analysis uses same data assumption as those presented in Section 2.12.3.3 for household electricity consumption, installed PV capacity, PV generation, grid offtake and injection tariffs, and electricity retail prices. The daily energy requirement for EV use is derived from actual EV consumption data.

2.12.4.4 Modelling scenarios

EV flexibility depends on user behaviour, vehicle characteristics, electricity prices, and manufacturer-imposed technical constraints. To evaluate these factors, four scenarios are defined: reference, base, manufacturer-constrained, and behavioural.

- **Base Scenario:** In the base scenario, charging is optimized based on electricity prices. The EV is available for charging whenever it is not in use, allowing scheduling during the lowest-price periods. User-specific behavioural and manufacturer-imposed technical constraints are not enforced. This scenario represents the theoretical flexibility under ideal price-responsive charging.
- **Reference Scenario:** The reference scenario uses historical EV charging profiles from the input dataset. No additional optimization is performed, so charging follows observed behaviour. This scenario serves as the baseline for evaluating alternative charging strategies.
- **Manufacturer-Constrained Scenario:** The manufacturer-constrained scenario builds on the base scenario by applying battery SoC limits specified by each vehicle's manufacturer. These limits vary by model and restrict the range for charging optimization. This scenario estimates flexibility when vehicle-specific technical restrictions are considered.
- **Behavioural Scenario:** The behavioural scenario extends the manufacturer-constrained scenario by adding user-specific behavioural constraints from the EV dataset. Battery capacities and maximum charging powers are taken from technical data. Charging availability and timing are based on observed plug-in, start, and end times, as well as charging durations. Daily driving-energy needs and mobility patterns are estimated from trip timing, distance travelled, and changes in SoC. Minimum and maximum user-preferred SoC limits are derived from each EV's observed SoC distribution. Two sets of behavioural results are presented: one uses the observed minimum and maximum SoC values as limits, while the other uses the 20th and 80th percentiles of the observed SoC distribution as lower and upper limits.

As a result, the behavioural scenario captures the heterogeneity of the fleet instead of relying on a single representative EV profile. Each EV is defined by its own charging availability, daily driving-energy requirement, mobility pattern, SoC operating range, battery capacity, and maximum charging power. Charging efficiency is included in the model.

2.12.4.5 Results and analysis

This section presents and discusses the case study results for households with and without PV systems. The analysis examines the impact of manufacturer and user constraints on **cumulative EV flexibility**, **consumer cost**, **self-consumption**, and the **resulting household grid offtake and grid injection profiles**.

2.12.4.5.1 Household Flexibility Potential with PV

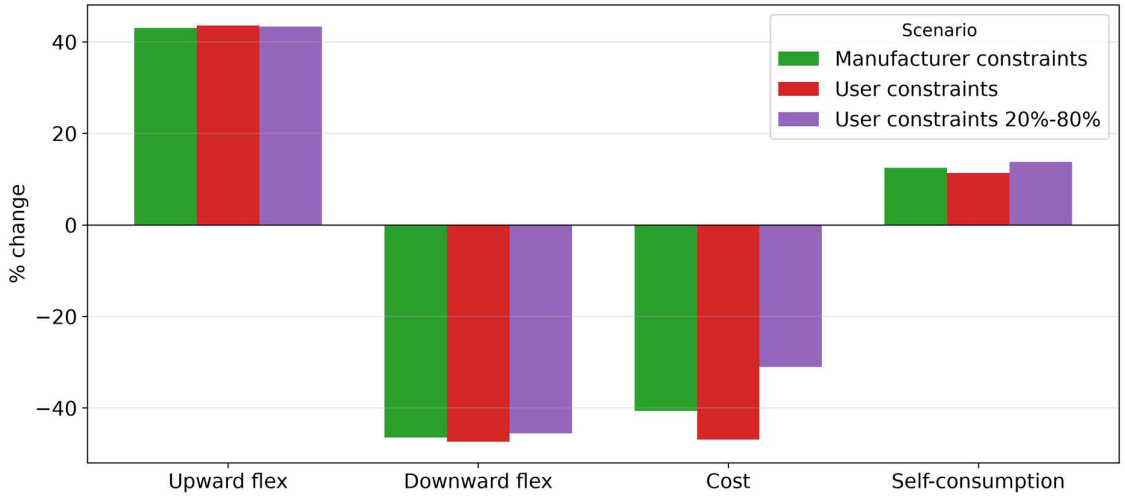


Figure 2-78: Percentage change in flexibility, consumer cost, and self-consumption for constrained scenarios relative to the reference scenario for users with PV.

Figure 2-78 presents the percentage change in the considered KPIs for the manufacturer-constrained and user-constrained scenarios relative to the reference scenario. Positive values represent an increase compared with the reference case, while negative values represent a decrease.

Upward flexibility increases by approximately 43–44% across the different constrained scenarios. This increase results from changes in EV charging behaviour induced by the technical and behavioural constraints, which alter the grid-offtake profile relative to the reference scenario. A comparison of the two user-constrained cases shows that the considered SoC range influences the amount of flexibility that can be provided by the EVs. The scenario based on the 20th–80th percentile SoC limits provides slightly less upward flexibility than the case using the observed minimum and maximum SoC values over the considered period. This indicates that a wider admissible SoC range provides greater freedom to shift charging demand and therefore increases the available upward flexibility.

In contrast, downward flexibility decreases by approximately 46–48% across the constrained scenarios. This reduction is mainly associated with a greater concentration of EV charging during lower-price periods, which leaves less unused charging capacity available to increase grid offtake at other times. The reduction is slightly

smaller in the scenario based on the 20th–80th percentile SoC limits. In this case, the more restrictive upper SoC limit reduces the amount of charging that can occur within individual charging sessions, leaving a slightly larger residual charging capacity available for downward flexibility.

The total consumer cost decreases relative to the reference scenario in all constrained cases. The reduction is approximately 39% for the manufacturer-constrained scenario and 46% for the user-constrained scenario, while the 20th–80th percentile SoC case results in a smaller reduction of approximately 30%. These savings are mainly driven by optimized charging schedules that shift EV charging towards lower-price periods. The comparison between the two user-constrained cases further shows that a narrower SoC operating range limits the ability to shift charging towards the most favourable price periods and therefore reduces the achievable cost savings.

The constrained scenarios also result in a clear increase in PV self-consumption relative to the reference scenario. The improvement ranges from approximately 11% to 14%, with the largest increase observed for the 20th–80th percentile SoC case. This indicates that optimized charging schedules improve the temporal alignment between EV charging demand and PV generation. Consequently, a larger share of locally generated PV electricity is consumed by household and EV demand, reducing the amount of surplus generation exported to the grid. The differences among the constrained scenarios further indicate that the representation of EV availability and SoC operating limits affect the extent to which charging can be aligned with periods of PV generation.

Overall, the results show that behavioural and technical constraints have a stronger influence on EV flexibility and consumer cost than on PV self-consumption. They also highlight the importance of accurately representing charging availability, mobility requirements, charging location, and user-preferred SoC ranges when estimating residential EV flexibility.

Figure 2-79 and Figure 2-80 further illustrate how the different charging scenarios affect the aggregated interaction of households with the grid. The solid lines represent the hourly average profiles over the considered period, while the shaded regions indicate the corresponding ± one-standard-deviation ranges.

As shown in Figure 2-79, the reference scenario produces a relatively smooth grid-offtake profile because EV charging follows the observed charging behaviour. In contrast, the base scenario permits charging at all times except when the vehicle is in use, allowing greater responsiveness to electricity-price signals. This results in a pronounced midday peak as multiple users shift their charging demand towards the same low-price periods. These results demonstrate that price-responsive charging can increase demand simultaneity and create new aggregate demand peaks.

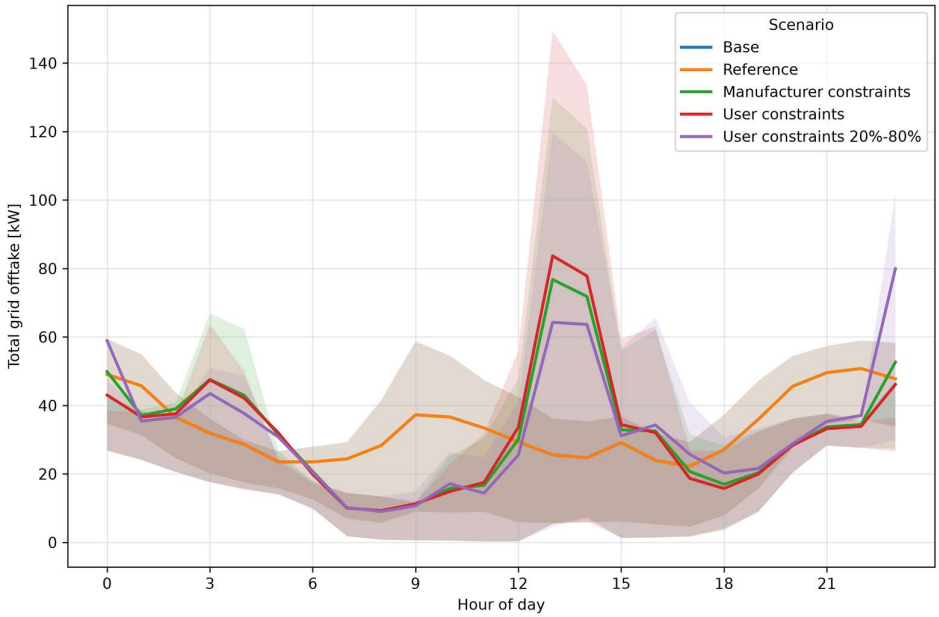


Figure 2-79: Hourly average aggregated household grid offtake for the considered EV charging scenarios for users with PV.

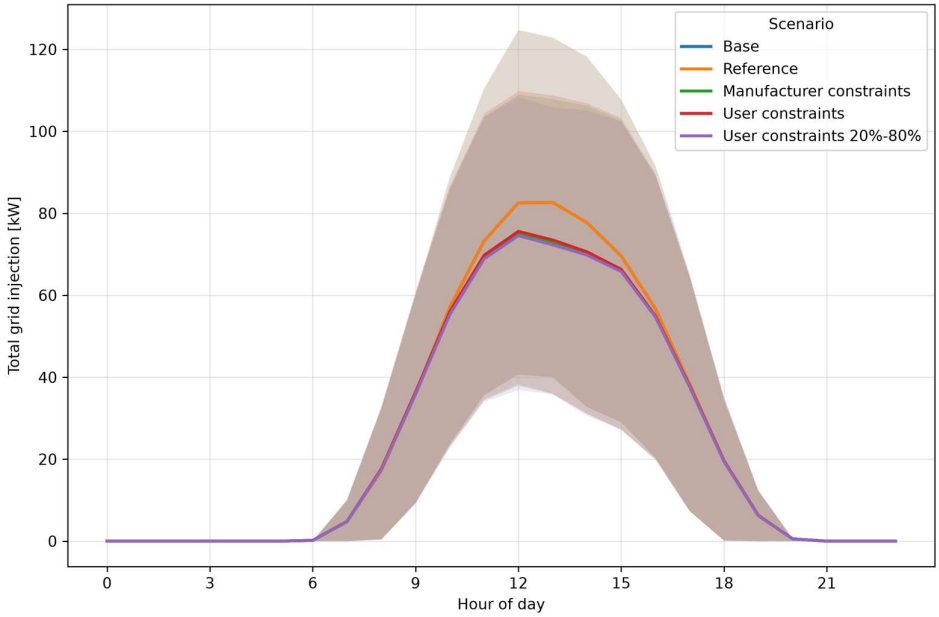


Figure 2-80: Hourly average aggregated household grid injection for the considered EV charging scenarios for users with PV.

The inclusion of manufacturer constraints moderates the midday peak by restricting the technically feasible charging range. The user-constrained scenarios reduce the peak further because charging schedules must also satisfy vehicle-availability patterns, mobility requirements, and user-preferred SoC limits. The 20th–80th

percentile SoC scenario shifts a larger share of charging demand away from the midday period and towards later hours, reflecting the more restrictive SoC operating range.

Figure 2-80 shows that grid injection broadly follows the daily PV-generation profile and is concentrated between the morning and early evening. The reference scenario results in the highest midday injection because the observed EV charging schedules are not systematically coordinated with PV generation. The base scenario produces the lowest injection by shifting a larger share of EV charging towards periods that coincide with local PV production, thereby increasing the local use of generated electricity.

The constrained scenarios retain part of this benefit but generally result in higher grid injection than the base scenario. Their lower ability to shift charging demand towards PV-generation periods reflects the restrictions imposed by manufacturer limits, vehicle availability, mobility requirements, and user SoC preferences. The relatively small differences between the two user-constrained injection profiles suggest that the selected representation of SoC preferences has a stronger effect on the timing of grid offtake than on the average daytime injection profile.

Taken together, Figure 2-79 and Figure 2-80 highlight a trade-off between economic responsiveness, peak-demand formation, and local PV utilization. Increased charging flexibility enhances the ability to exploit favourable price and PV-generation periods, but it may also lead to greater charging simultaneity. Behavioural and technical constraints reduce this theoretical flexibility and provide a more realistic representation of household interaction with the grid.

2.12.4.5.2 Household Flexibility Potential without PV

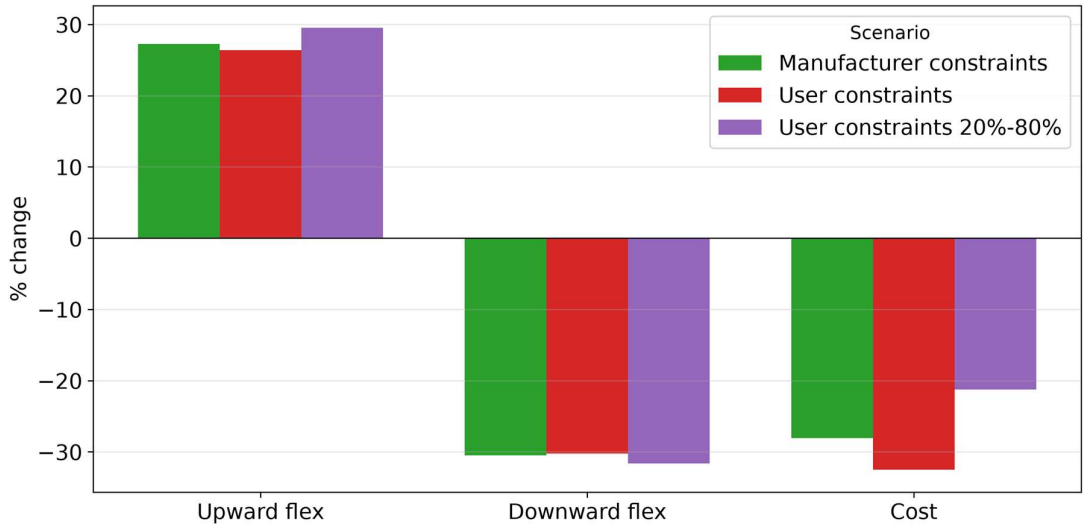


Figure 2-81: Percentage change in upward flexibility, downward flexibility, and consumer cost for the constrained scenarios relative to the reference scenario for users without PV.

Figure 2-81 presents the percentage change in the considered KPIs for households without PV. In this case, the self-consumption KPI is not applicable. As before, positive values indicate an increase relative to the reference scenario, whereas negative values indicate a decrease.

Upward flexibility increases by approximately 26–30% across the constrained scenarios. The scenario based on the 20^{th}–80^{th} percentile SoC limits results in the largest increase, while the manufacturer-constrained and user-constrained scenarios show slightly lower but comparable values. This confirms that the definition of the admissible SoC range affects the amount of charging demand that can be reduced or shifted when upward flexibility is required.

Downward flexibility decreases by approximately 30–32% across all constrained scenarios. As in the PV case, this reduction is primarily driven by the concentration of charging during economically favourable periods, which reduces the remaining charging capacity available to increase grid offtake at other times. The differences among the constrained scenarios are relatively small, although the 20^{th}–80^{th} percentile SoC scenario exhibits the largest reduction.

Consumer cost also decreases in all constrained scenarios. The reduction is approximately 28% for the manufacturer-constrained scenario, 32% for the user-constrained scenario, and 21% for the 20^{th}–80^{th} percentile SoC scenario. These savings result from shifting EV charging towards lower-price periods. The smaller cost reduction in the percentile-based case reflects the more restrictive SoC range, which limits the ability to exploit the lowest-price periods.

Overall, the results for households without PV are consistent with those observed for households with PV. The inclusion of technical and behavioural constraints increases upward flexibility relative to the reference scenario while reducing downward flexibility. At the same time, all constrained scenarios lead to lower consumer costs, although the magnitude of the savings depends on the assumed SoC limits and behavioural constraints.

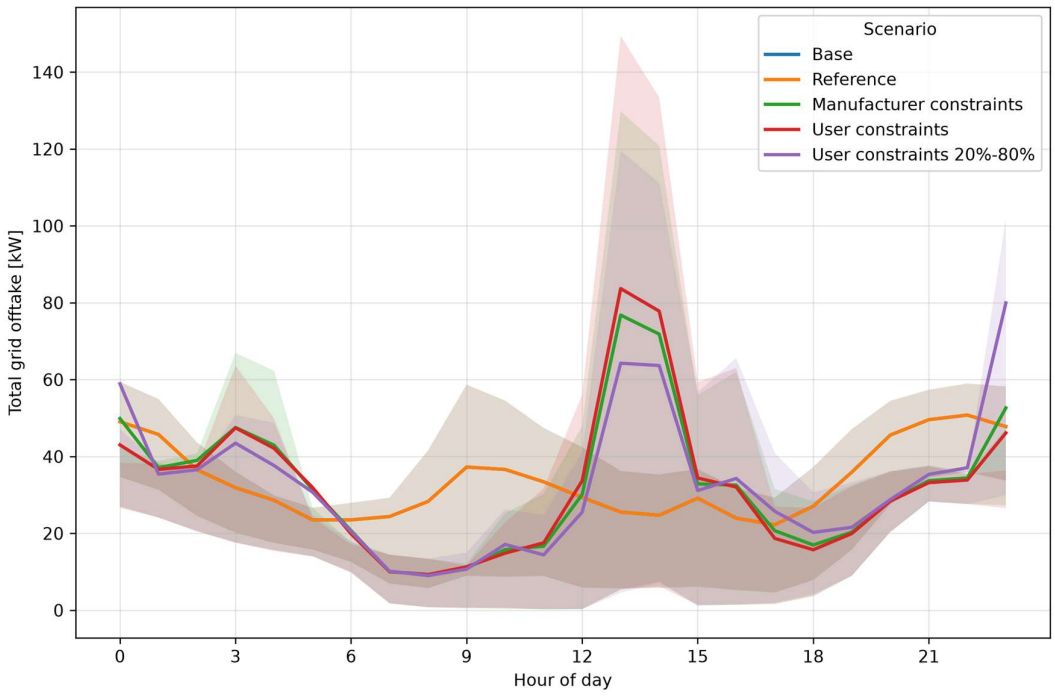


Figure 2-82: Hourly average aggregated household grid offtake for the considered EV charging scenarios for users without PV.

As shown in Figure 2-82, the reference scenario exhibits a comparatively smooth grid-offtake profile, with higher demand during the evening and lower demand during the early morning and midday periods. In contrast, the optimized constrained scenarios show a pronounced increase in grid offtake between approximately 12:00 and 14:00, indicating that a substantial share of EV charging is shifted towards economically favourable periods.

The magnitude of the midday peak differs across the constrained scenarios. The user-constrained scenario produces the highest average peak, followed by the manufacturer-constrained scenario, whereas the 20th–80th percentile SoC scenario results in a lower midday peak. The more restrictive SoC range limits the amount of charging that can be concentrated within the low-price period and redistributes part of the charging demand to other hours. This effect is particularly visible towards the end of the day, where the percentile-based scenario shows a pronounced increase in grid offtake.

These results demonstrate that introducing behavioural and technical constraints does not necessarily reduce household peak demand. Instead, the resulting demand profile depends on the interaction between electricity-price signals, EV availability, mobility requirements, and SoC limits. In particular, uniform price signals can induce synchronized charging and create new demand peaks, even when charging is individually cost-

optimal. This highlights the importance of considering aggregate charging behaviour and distribution-network conditions when designing price-responsive EV charging strategies.

2.12.5 Conclusions

EV flexibility is expected to play an increasingly important role in future power-system operation and network planning. This study demonstrates that the flexibility available from residential EVs is strongly influenced by user behaviour, vehicle characteristics, and manufacturer-imposed technical constraints. Consequently, assessments based on idealized assumptions of unrestricted vehicle availability and charging may differ substantially from the flexibility that can be achieved in practice at the residential connection.

The results show that charging availability, driving-energy requirements, SoC preferences, battery characteristics, and charging away from home significantly influence both upward and downward flexibility. More restrictive SoC limits further reduce the feasible charging range and alter the timing and volume of flexibility that can be provided. At the same time, price-responsive charging can shift EV demand away from conventional peak periods towards lower-price hours and periods of higher PV generation. However, when many users respond to the same price signals, charging may become synchronized and create new aggregate demand peaks. This highlights an important distinction between household-level cost minimization and system-level operation.

The interaction between EV charging and residential PV generation is also relevant. Flexible charging can increase PV self-consumption when vehicles are available during periods of local generation, although the achievable benefit depends on mobility requirements, charging availability, user preferences, and the possibility of charging away from home. Overall, the findings confirm that realistic behavioural and technical representations are essential for estimating the practically achievable flexibility of residential EVs.

2.12.6 Recommendations

Table 2-68: Key recommendations for BUC 10

Recommendations	
Technical	A realistic estimation of flexibility potential and avoidance of systematic overestimation require the development of an integrated optimisation framework that includes EVs, heat pumps, and household batteries, while explicitly modelling behavioural and technical constraints.
Socio-economic	Optimisation models that incorporate users' charging preferences and comfort constraints better reflect actual flexibility availability and provide consumers with guidance and incentives to reduce costs without compromising comfort or battery health.
Policy/regulatory	Accounting for user behaviour and manufacturer constraints allows for a more realistic assessment of EV charging behaviour and the resulting potential for flexibility provision, while providing policy-relevant insights into the effects of dynamic tariffs and pricing and the accounting of flexibility contributions across multiple charging locations.

2.13 BUC 11 - Smart billing solutions for large-scale EV fleet charging

2.13.1 General information

Test Case ID	*Name of Test Case*
1	Large scale E-mobility uptake B2C
Maturity of Test Case	
The test case is close to real business operations across its different approaches, as the concepts have been demonstrated in medium- to large-scale projects and could be further scaled. However, two concepts: vehicle data-based billing and volume-split mechanisms, are currently prevented from progressing to commercial operation. The main barriers are regulatory, in particular those related to the European regulations on measuring instruments and their national implementations, as well as the absence of an appropriate supply-split or equivalent mechanism.	

ID	*Name of Business Use Case*
BUC 11	Smart billing solutions for EV charging (focus on a large fleet of EVs)
Short description and objectives	

Most electric vehicles (EVs) currently deployed on the road are used as company cars. Company car schemes are characterized by a separation between the driver, who decides when and how the vehicle is charged, and the employer, who ultimately pays for the electricity consumed. Initial field observations indicate that drivers operating under such schemes exhibit heterogeneous charging behaviours. This use case aims to identify and categorize these different behaviours.

In addition, a smart billing solution will be developed to inform both the driver and the fleet manager of the (near) real-time cost of charging sessions. When combined with household electricity bills, this information can be used to define user-specific incentives designed to better align driver behaviour with broader system needs.

The objectives of BUC 11 are twofold: (i) to identify distinct charging patterns associated with company cars charging at home, and (ii) to develop a smart billing solution that informs drivers in real time about charging costs or enables them to provide flexibility services. As a key requirement, the smart billing solution will rely on vehicle IoT technologies, which can be deployed without additional hardware and are more cost-effective than solutions based on connected charging infrastructure. For the smart billing solution, two approaches have been developed and tested:

- The EV IoT charging cost monitoring involving cost calculations of charging sessions using the users' actual electricity contract data.
- Volume-split billing, based on vehicle data acquisition by the electricity supplier at the household meter level, with subsequent reinvoicing of charging volumes to the employer.

2.13.2 Description PoC

Whereas the other use cases relied on simulation-based analyses, BUC 11 drew on evidence from medium- to large-scale proof-of-concept (PoC) deployments via the re.alto platform. These PoCs involved approximately 120 electric vehicles (EVs) deployed across multiple fleets, enabling the assessment of the solutions under conditions close to real operational environments.

2.13.2.1 Considered approaches

Monitoring the cost of residential EV charging remains a technical and operational challenge, primarily due to the widespread reliance on connected charging infrastructure. Most existing solutions depend on smart charging points to measure charging volumes and support reimbursement mechanisms. Such devices entail significant upfront costs, require on-site installation, and are often tightly coupled to specific reimbursement or mobility service providers. Consequently, switching providers may require the replacement of existing hardware, resulting in additional costs and reduced user acceptance.

Accurate charging cost calculation further requires detailed knowledge of the driver's electricity supply contract, including the structure of fixed charges, variable energy prices, and time-dependent tariffs. In the absence of direct access to contract-specific information, reimbursement may rely on standardised reference prices, such as the CREG-based rate used in Belgium for the reimbursement of home charging of company cars [19]. As this rate is based on average regional electricity prices rather than the user's individual supply contract, the resulting reimbursement may differ from the actual charging cost. This simplification introduces systematic inaccuracies in cost estimation and limits transparency for both drivers and fleet managers.

The first approach, the EV IoT charging cost monitoring solution, addresses these limitations by leveraging direct vehicle connectivity and a dedicated electricity tariff database. Charging energy consumption is retrieved via vehicle IoT APIs (every 3 to 5 minutes) and are transformed into charge data records (see the following figure) through a specific algorithm developed by re.alto. The electricity costs are calculated using inputs provided by the user through a user interface to identify the contract-specific tariff parameters in the database. This approach eliminates the need for dedicated metering hardware at the household level and enables more precise and transparent cost allocation for home charging sessions.

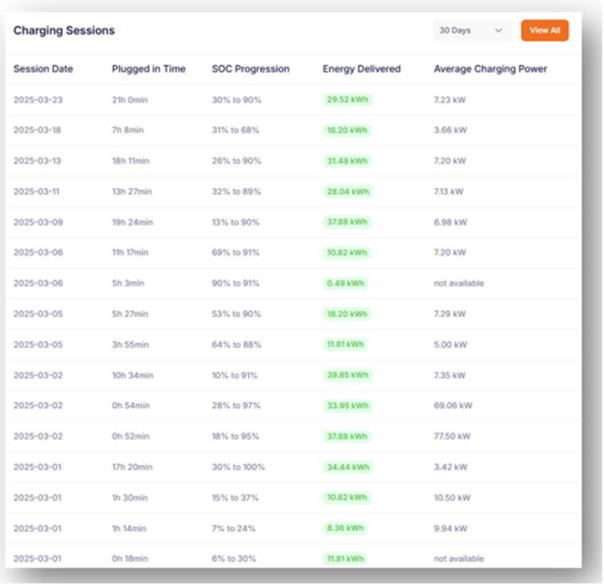


Figure 2-83: Example of a charge session derived from EV IoT Data.

From the perspective of mobility and fleet service providers serving the Fleet managers, the solution enables centralized access to vehicle-level consumption data and historical records, such as odometer readings. These data support automated reimbursement processes and monthly settlement workflows, while reducing operational complexity and infrastructure dependency.

Beyond charging cost monitoring and reimbursement, the re.alto platform is designed to support the progressive activation of additional functionalities, such as smart charging and flexibility services. These features can be enabled through software-based configurations, without requiring further hardware installation, allowing the solution to evolve in line with user requirements and system-level objectives.

The second approach called the volume split approach has been directly developed and tested in a pilot led by Elia Transmission Belgium. It is a market and settlement mechanism designed to enable accurate reimbursement of residential EV charging for company cars while preserving the existing electricity supply relationship of the household. It aims to separate, within the same physical connection point (the home meter), the portion of electricity consumption attributable to EV charging performed for professional use, so that this portion can be billed and reimbursed through a dedicated process without requiring a second physical meter or a change of supplier for the household.

Summarised, the volume split consists of (i) identifying EV charging events at home thanks to the re.alto platform, (ii) estimating the associated energy volumes with sufficient confidence by analysing IoT EV data, and (iii) allocating these volumes to a distinct settlement stream, typically linking the cost of those volumes to the

employer's reimbursement obligations, while the remainder of household consumption continues to be handled under the normal retail supply contract. The latter must be performed by the home supplier.

This design is motivated by the operational reality that home charging is where a large share of fleet EV energy is consumed, but it is also where reimbursement is most complex and currently relies on equipment such as expensive connected chargers and provider dependent solutions.

A central research motivation for volume split pursued by re.alto and Elia is that it can lower the friction to deploy smart charging at scale in fleet home-charging contexts dominated currently by company cars. By embedding reimbursement into a robust settlement logic, it may enable suppliers (or other orchestrators) to apply optimization strategies (e.g., portfolio cost optimization, grid-tariff response) without requiring end users to manage reimbursement workflows manually. At the same time, the adoption of such mechanism will be shaped by incentives: suppliers may perceive the mechanism as too complex.

The two approaches were demonstrated using the re.alto platform, a cloud-based, auto-scalable system providing connectivity, real-time data streaming, data storage, transformation, and permission management. The platform is fully controllable through APIs and designed to support machine-to-machine interactions across heterogeneous distributed energy resources (DERs).

The platform is built on the Apache Kafka framework, is fully containerized, and operates on a unified internal data model. In practice, each DER category (e.g. photovoltaic systems, electric vehicles, heat pumps) and each brand relies on its own connectivity technologies and proprietary data models. To address this heterogeneity, the re.alto team has developed a set of dedicated connectors (typically one per brand) that abstract both the underlying connectivity mechanisms and the native data models, exposing harmonized data and control interfaces.

Using a single, consistent API set, a re.alto platform user can:

- Connect to more than 30 DER brands;
- Access real-time DER telemetry;
- Retrieve historical data over configurable time periods and resolutions, using aggregation mechanisms where required;
- Generate charging session records for electric vehicles, including session start and end timestamps and total energy consumed per session;
- Send control commands (e.g. start/stop or set-points), subject to brand-specific capabilities;
- Geotag vehicles using either precise geolocation data (with explicit user consent) or semantic location labels (e.g. "Home", "Office") to support smart charging use cases;
- Aggregate multiple DERs into portfolios for unified monitoring or control actions;

- Manage data access permissions across multiple users and, where relevant, across different organizations.

For the first smart billing approach, a dedicated database of residential electricity contracts was procured from Wsave and integrated into the platform. Several additional functionalities were developed to enable charging cost calculation:

- A user interface allowing end users to input electricity contract information;
- A contract identification mechanism capable of selecting the closest matching contract parameters based on partial or incomplete user inputs;
- A charging cost calculation module combining contract parameters with individual charging sessions. This module supports:
    - Dynamic pricing schemes, including day-ahead prices and price changes occurring during a charging session;
    - Capacity-based tariff components.

Together, these functionalities enable the re.alto platform to calculate the precise cost of residential EV charging and support accurate reimbursement flows between fleet managers and drivers.

The volume-split approach relies on three tightly coupled building blocks.

- First, **data connectivity** is required to identify and quantify EV charging at home. This typically depends on connectivity either to the vehicle itself (via OEM interfaces or third-party intermediaries) and/or to the charging point operator (CPO) back-end. The re.alto platform provides the necessary machine-to-machine connectivity layer, capable of operating across heterogeneous EVs and charging ecosystems while managing access rights and permissions among multiple suppliers, intermediaries, and fleet managers.
- Second, **a "volume split" process** is needed to allocate EV charging volumes within total household electricity consumption. This split is not merely a technical identification of charging energy; it constitutes an allocation rule that underpins settlement. A key motivation for this approach is that it avoids issuing multiple supplier invoices for a single metering point, which would conflict with standard market arrangements. Instead, it preserves the household supplier perimeter while enabling a separate accounting of EV charging volumes. In this context, the re.alto platform provides a distinct and structured data flow directly to the supplier responsible for the main household meter.
- Third, **settlement and invoicing mechanisms** are required to link the allocated charging volumes to reimbursement processes. The approach is designed to allow employers to reimburse employees based on actual charging costs (or a defined cost proxy) without requiring dedicated charging hardware tied to a single reimbursement provider. Depending on the configuration, invoicing and

consolidation functions may be performed by a specialized many-to-many intermediary or, in some cases, by incumbent actors such as CPOs, mobility service providers, or leasing companies. This layer also raises competitive and governance challenges related to information sharing. This settlement component was not implemented during the volume-split tests conducted on the re.alto platform.

To demonstrate both approaches, re.alto engaged several fleet managers as intermediaries to obtain driver consent for participation in the ReInvent project. By Q2 2025, slightly more than 120 electric vehicles from four different fleet managers were connected to the platform and used for testing purposes.

2.13.2.2 Key considerations and open questions

From a research perspective, the two approaches raise several open questions.

For the EV IoT–based smart billing approach, key issues include:

- whether EV-side IoT data can be recognized as a valid and auditable source for determining charging volumes;
- how systematic deviations between vehicle-reported energy and charging-point measurements can be identified and corrected, in particular losses occurring in the charging cable and the vehicle's power electronics;
- the level of accuracy that can be achieved when approximating electricity contract parameters, given that end users are often unable to fully specify their exact contract conditions; and
- whether the resulting deviations are acceptable to both fleet managers and drivers, especially when compared to existing reimbursement approaches based on regulated reference prices (e.g. CREG-based tariffs), which themselves rely on approximations.

The volume-split approach raises a different but related set of research questions, including:

- what constitutes acceptable and trusted evidence for charging volumes (e.g. vehicle-side data versus charger-side metering);
- how shared connectivity layers should be governed if they evolve into essential infrastructure components for settlement and billing; and
- the long-term transition pathway from volume-split mechanisms toward more structurally separated supply arrangements, often referred to as "supply split" models.

Some of these questions have already been partially addressed during the first two years of the project, either through regulatory developments or through feedback collected from fleet managers and energy suppliers. Intermediate results from the business use cases (BUCs) related to these conditions are discussed in more detail in section 2.13.3.

2.13.2.3 Data collection

Table 2-69 summarizes the data available through the Re.alto platform.

Table 2-69: Main Data for BUC 11

Name	Description	Units	Value or time-series	Reference years	Data source	ReInvent Common data (Yes/No)
EV IoT data	Near real time EV data collected through the OEM official interface or enode containing the State of Charge, the range, the power when charging, the odometer, a flag is the car is charging and or plugged, the geolocation	Soc: % Range: km Power: W Odometer: km Geoloc: °,',”	Time series formed by near real time data with a granularity of 3 to 7 min.	Real time data collected over 2024 and 2025	OEM official apis	No but can be used by other partners
User input on the electricity contract	To identify the electricity contract in use on the main meter, the users is asked to provide, if possible, the name of the contract, the date of signature and the date of starting.	None	None	Depending on the contract	User	No
Electricity contract data base	A database of all the electricity contract formulas and their parameters linked to the different contracts offered since 2020 by suppliers in Belgium.	Euros	None	Depending on the contract	Wsave	No

2.13.3 Conclusions

Under the EU Measuring Instruments Directive (2014/32/EU), only data originating from certified metering instruments (MID-compliant meters) can be used for legally relevant measurements, including billing, reimbursement, and other financial settlement mechanisms. Current EU legal metrology rules and their national implementation therefore prevent IoT-derived measurements from serving as the legally binding basis for commercial energy transactions.

In this context, IoT-based measurements cannot be used for EV charging-related billing, reimbursement, or flexibility settlement where financial transactions depend on measured energy volumes. This interpretation was confirmed by the competent cabinet, which clarified that IoT data is not admissible for EV-related financial settlement under the current regulatory framework.

As a result, the original business use case could not be implemented as initially envisaged. The work was therefore reoriented towards other mechanisms enabling flexibility form EV such as the volume-split approach.

A first implementation involving 60 electric vehicles, including 10 vehicles actively participating in imbalance-price-based flexibility, demonstrated the technical feasibility of allocating energy volumes based on vehicle data. However, the approach didn't encounter the necessary traction on the supplier side to ensure a possible future scalability.

Consequently, a supply-split approach was also investigated. This option, framed by EU regulation, would rely on separate supply contracts at a single site, potentially allowing different tariff structures (e.g. flat and dynamic tariffs), but would require either the installation of an additional certified meter or access to validated data from an existing certified metering system.

Overall, the work demonstrated the technical feasibility and cost efficiency of IoT based EV data for mechanisms enabling fleets and personal cars to deliver flexibility. However, their large-scale deployment remains constrained by regulatory uncertainty on the acceptance of IoT based data and limited market maturity regarding flexibility provision from electric vehicle. Further investigation and development of BUC11 were ultimately discontinued following the decision of Re.alto's shareholders to cease operations as of 25 June 2025 and the company's subsequent liquidation in 2026, thereby preventing any further exploration of the proposed solutions.

2.13.4 Recommendations

Table 2-70: Key recommendations for BUC 11

Recommendations	
Technical	Continue the development of interoperable EV data platforms and software-based solutions that reduce dependence on dedicated charging hardware. Priority should be given to improving data quality, interoperability, and the integration of EV-derived data with smart charging and flexibility services, while ensuring compatibility with future settlement and reimbursement mechanisms.
Socio-economic	Promote user-centric reimbursement and billing mechanisms that lower the administrative burden for drivers, fleet managers, and employers. Simplifying reimbursement processes and reducing hardware-related costs can improve user acceptance and help unlock larger-scale participation of EV fleets in smart charging and flexibility services.
Policy/regulatory	Clarify the regulatory framework governing the use of EV-derived IoT data for billing, reimbursement, and flexibility-related settlement. Regulatory certainty on acceptable measurement and settlement approaches, including pathways for volume-split or supply-split mechanisms, is essential to enable commercial deployment and attract market participants.

2.14 BUC 12 - Smart billing solutions for collective EV charging

2.14.1 General information

Test Case ID	*Name of Test Case*
4.2	Social charging shared EVs
Maturity of Test Case	
Demo site is in business operation, but the solution is still in demonstration.	

ID	*Name of Business Use Case*
BUC 12	Smart billing solutions for EV charging (focus on collective car sharing)
Short description and objectives	

The experiment on "Social charging shared EVs" investigates the operational and economic synergies between a Renewable Energy Community (REC) and a Shared Mobility Operator (SMO) in the context of a social housing estate, with the aim of increasing the local utilisation of surplus photovoltaic generation through the coordinated deployment of shared electric vehicles and charging infrastructure. The case study is set in the Otterbeek neighbourhood in Mechelen, where 741 kW of residential PV capacity has already been installed across 197 social housing units. Despite this significant decentralised generation, local self-consumption remains limited for the time being, meaning that a large proportion of the solar energy is fed into the grid at a relatively low value. The experiment therefore starts from the hypothesis that shared EVs can function as a flexible, mobile source of electricity demand that can better absorb these local surpluses and thus reduce both energy and mobility costs for vulnerable households.

Within the experiment, two interconnected business use cases are distinguished. **BUC 3a** focuses on increasing local self-consumption of surplus PV generation by linking charging infrastructure to shared EVs within the energy community. **BUC 3b** extends this logic to the potential provision of external flexibility services to third parties.

This BUC focuses on a smart billing solution for EV charging. The solution should be understood as a digital settlement and accounting layer that automatically allocates charging costs, local energy value, incentives, and redemption rights across multiple actors, including the energy community, the shared mobility operator, residents, charging infrastructure operators, and potentially external users. In the Otterbeek-type configuration, the underlying challenge is not merely to meter electricity consumption, but to determine who created system value, when that value was created, and how it should be redistributed fairly within a socially sensitive community setting. This is particularly relevant where rooftop PV generation, shared EV charging, and community mobility services are jointly coordinated to increase self-consumption and lower both energy and mobility costs.

2.14.2 Description PoC

2.14.2.1 PoC setup

The empirical case on which this experiment is based concerns a subset of 20 households, 10 of which have a combined PV capacity of 97 kW, with an aggregate annual electricity consumption of 55 MWh. For the mobility component, a historical dataset of approximately 7,600 journeys and 4,500 charging events from a fleet of 35 shared EVs, provided by Klimaan, is used. Representative demand scenarios are constructed on the basis of this data. In the specific modelling for BUC 3, two vehicles are selected - a Renault ZOE and an Opel Corsa, each with a battery capacity of 50 kWh - and linked to a single depot charging point with a maximum charging and discharging capacity of 11 kW. This setup allows for the simulation of both the early adoption phase and a more mature phase of shared mobility.

The demo site is located in Mechelen, a city of approximately 88,000 residents strategically situated between Brussels and Antwerp. The project focuses on the Otterbeek district, a social housing neighbourhood originally developed in the 1950s.



Figure 2-84: Otterbeek social housing district in Mechelen, Belgium.

2.14.2.2 Proposed solution architecture

From a technical point of view, a blockchain-enabled smart billing solution for collective car sharing is best designed as a hybrid architecture composed of three layers:(i) a data acquisition layer, (ii) an off-chain calculation and control layer, and (iii) an on-chain settlement layer.

In the Otterbeek logic, the **data layer** collects certified or trusted information from distributed assets: PV inverters, smart meters, charging stations, booking applications, and shared mobility records. The proposal explicitly assumes that charging sessions are recorded through certified charging infrastructure using OCPI-compatible charge data records, while the broader EV charging ecosystem commonly relies on OCPP for charger-to-back-office communication and OCPI for interoperability across charging networks and service providers. This

combination is critical because blockchain does not measure energy by itself; it depends on trusted upstream metering and protocol-based data exchange.

The **off-chain layer** performs the computationally intensive part of the billing logic. In a collective car-sharing setting, this includes identifying which charging sessions belong to community members versus public users; determining whether a shared EV was charged during periods of local PV surplus; calculating how much local renewable energy was effectively absorbed by the shared fleet; and translating this into tariffs, credits, or rewards. In other words, the billing engine must not only compute an electricity invoice but also implement a value-sharing rule between community actors. In the Otterbeek concept, this rule is intentionally kept off-chain because it depends on fine-grained and privacy-sensitive data, such as household-level production and consumption patterns, trip timing, and charging windows. Keeping the computation off-chain also preserves flexibility, allowing tariff or reward rules to be refined without rewriting the core blockchain layer.

The **on-chain layer** then acts as the settlement engine. Rather than storing all raw measurements on a ledger, the blockchain records only the commercially relevant state transitions: the issuance of a reward token, the transfer of credits to an eligible household wallet, or the redemption of those credits against community mobility services. Technically, this can be implemented through smart contracts that define wallet whitelists, minting rules, redemption constraints, and token transfer permissions. In a collective car-sharing setting, this means that once the off-chain engine confirms that a shared charging session increased local self-consumption, the corresponding billing consequence can be executed automatically: for example, the user receives energy credits, discounted mobility access, or an internal community token. This architecture transforms billing from a periodic invoicing exercise into a programmable settlement workflow.

2.14.2.3 Rationale for the blockchain-based approach

A blockchain-based approach is especially attractive when **multiple organizations maintain separate ledgers and incentives**. In collective car sharing, a single charging session may involve a resident, a shared mobility operator, a charge point operator, the community energy manager, and potentially a supplier or grid-facing market counterparty. Without a shared settlement layer, each actor maintains its own accounting logic, which creates reconciliation delays, disputes over session attribution, and administrative overhead. Blockchain is chosen here because it provides a single, immutable, time-stamped record of settlement outcomes that all authorized parties can trust without relying on one actor's internal database as the canonical source. This is one of the central reasons repeatedly cited in the blockchain-for-EV-charging literature: the technology reduces reconciliation complexity, improves transparency, and enables automated multi-party payment or credit allocation.

A second reason for choosing blockchain is that collective car sharing often requires **micro-settlement of small, frequent transactions**. Charging events, mobility rewards, dynamic tariff differentials, and flexibility-related incentives may all occur at relatively small monetary value but at high frequency. Traditional billing

systems are poorly adapted to such fragmented, multi-party settlement because the administrative cost per transaction can become disproportionate. Smart contracts, by contrast, can automate these transfers at machine speed and with low marginal cost, especially when deployed on a permissioned ledger or a low-cost Layer 2/EVM-based environment. The Otterbeek proposal explicitly emphasizes this requirement, noting that unpredictable public-chain fees can destroy viability in small-scale community settings and that the blockchain should therefore be limited to low-cost minting and transfer events.

A third reason is **programmable governance**. In a collective car-sharing model, the objective is usually not to create a freely tradable energy token, but to keep value circulating inside the community. Blockchain is technically useful because smart contracts can encode this rule directly: only whitelisted community wallets may receive or redeem the token; non-members may pay conventional charging tariffs but are excluded from the community reward mechanism; and transfers to external or secondary markets can be blocked by design. This is particularly relevant in social-housing and community-mobility contexts, where the policy objective is to ensure that locally generated value remains socially embedded rather than being extracted by third parties.

A fourth reason is **auditability and compliance**. Smart billing in collective car sharing may eventually interact with subsidy frameworks, social tariffs, local flexibility incentives, or reporting obligations toward public authorities and financiers. Blockchain offers an auditable record of the execution of billing rules without exposing all underlying personal data. Importantly, the most credible architectures do not place detailed behavioural data on-chain. Instead, they combine blockchain with an off-chain privacy layer: household identifiers are abstracted, raw charging and mobility traces remain outside the ledger, and only the final settlement event is anchored immutably. This is why, from a research and implementation perspective, the most robust design is not a “blockchain-everything” model, but a minimal blockchain settlement layer on top of certified off-chain metering and analytics.

From a systems perspective, the blockchain choice is therefore justified not by ideological decentralization, but by a set of concrete technical and organizational requirements: shared trust across actors, automated multi-party settlement, low-cost execution of frequent micro-transactions, programmable community governance, and auditable billing outcomes. In collective car sharing, these requirements are amplified because the business case depends on aligning two infrastructures that are usually separate: local renewable energy and shared mobility. Smart billing becomes the digital mechanism through which these infrastructures are coupled. Blockchain is selected precisely because it can encode that coupling into an operational settlement logic: charging with local solar can be rewarded automatically, charging outside preferred windows can be billed differently, and community benefits can be redistributed transparently.

2.14.3 Conclusions

In conclusion, a blockchain-based smart billing solution for EV charging in collective car sharing should be conceptualized as a community settlement infrastructure, not merely as a payment tool. Its technical role is to

connect trusted charging and energy data with automated tariff execution, reward distribution, and controlled community value circulation. Blockchain is chosen because it enables a neutral and immutable settlement layer in a fragmented ecosystem, while smart contracts make the billing logic programmable and enforceable. However, the most viable designs are hybrid: **data collection, optimisation, and billing calculation remain off-chain; settlement, token lifecycle management, and auditability are implemented on-chain**. This hybrid model is particularly appropriate for social energy communities such as Otterbeek, where economic efficiency, privacy protection, and community governance must be achieved simultaneously.

2.14.4 Recommendations

Table 2-71: Key recommendations for BUC

Recommendations	
Technical	Prioritise the development of interoperable hybrid architectures that combine trusted metering and data acquisition off-chain with automated settlement and auditability on-chain. Future demonstrations should validate the scalability, cybersecurity, privacy protection, and interoperability of such architectures across energy communities, mobility operators, charging providers, and other market actors.
Socio-economic	Smart billing mechanisms should be designed to ensure that the value created through local renewable generation, and shared mobility is redistributed transparently and fairly among community members. Particular attention should be given to vulnerable households, ensuring that settlement mechanisms remain understandable, accessible, and capable of reducing both mobility and energy costs.
Policy/regulatory	Policymakers should establish clear governance frameworks for community-based settlement mechanisms, including rules on data sharing, digital identities, tokenized reward schemes, and consumer protection. Regulatory clarity on how community incentives, local energy sharing arrangements, and blockchain-enabled settlement solutions interact with existing energy market, and mobility regulations would reduce uncertainty and support wider deployment.

3 Conclusions

Building on the KPIs identified in Task 3.1 and quantified through the ReInvent simulation models developed in WP2, the simulations performed in Task 3.4 enabled each Business Use Case (BUC) to be evaluated primarily in terms of its technical and economic feasibility.

Overall, the simulations demonstrated the value of the ReInvent modelling framework in assessing a diverse range of sector coupling solutions under realistic technical, economic, and regulatory conditions. While the results confirm that many of the proposed solutions are technically feasible, they also highlight that their performance and viability strongly depend on local energy demand profiles, renewable resource availability, infrastructure, market conditions, and the prevailing regulatory framework. As such, the outcomes of Task 3.4 not only validate the analysed Business Use Cases but also provide an evidence base for identifying best practices, informing future investments, and supporting policy recommendations for the wider deployment of integrated energy solutions.

These findings form the basis for the scalability and replicability assessment carried out in Task 4.1, where the Business Use Cases are analysed to identify the technical, economic, regulatory, and stakeholder-related boundary conditions that enable or constrain their successful transfer and wider deployment.

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