Scalability and replicability potential of the test cases in the Belgian context and overall impact assessment for the Belgian energy system

D4.1

Authors:

Pieter Valkering, Andrea Moglianesi, Jacob Mason, Kris Kessels, Lina Silva Rodriguez (VITO)

Joffrey Hardy (IDETA)

Quentin Raillard--Cazanove (KUL)

Bram Van Dun (CAMPINA Energy)

Ghislain Detienne (Fluxys)

Thomas Heylen (Klimaan)

Tom Willems (SeaCoop)

Tom Engels (Virya Energy)

Responsible Partner	VITO, IDETA
Checked by WP leader	Anton Gerits, 09/10/2026
Approved by Project Coordinator	Kris Kessels, 09/10/2026
Dissemination level	Public

This project has received funding from Energy Transition Fund 2023 FPS Economy, SMEs, Self-employed and Energy.

Issue Record

Planned delivery date	30/09/2026
Actual date of delivery	09/10/2026
Status and version	Final

Version	Date	Author(s)	Notes
1.0	30/09/2026	All authors	Draft final version
1.1	09/10/2026	All authors	Final version

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 14

1.1 Objectives of the Work Reported in this Deliverable 14

1.2 Outline of the Deliverable 16

2 Sector coupling from a use case perspective 17

2.1 Approach scalability and replicability analysis 17

2.1.1 Methodology 17

2.1.2 Concepts and definitions 18

2.1.3 Types of boundary conditions 18

2.2 Scalability and replicability potential of the BUC 20

2.2.1 BUC 1 - 5GDHC network with H/C sharing and flexibility provision 20

2.2.2 BUC 2 - Integration of a Battery Energy Storage System in a REC 23

2.2.3 BUC 3 - Social charging shared EVs 27

2.2.4 BUC 4 - Collective Offshore Wind Integration through Battery Storage 30

2.2.5 BUC 5 - Business Citizen Energy Communities 33

2.2.6 BUC 6 – Green H2 vs Electricity for Long Haul Trucks 36

2.2.7 BUC 9 - Flexibility provision with large-scale electrolyser 39

2.2.8 BUC 10 - Flexibility provision with a portfolio of EVs 43

2.3 Main insights on scaling and replicability potential 46

2.3.1 Electrification and demand-side flexibility (DSF) 46

2.3.2 Collective energy sharing 48

2.3.3 Clean molecules and Power2X 50

3 Sector-coupling from the system perspective 54

3.1 Analyzing future energy demands and flexibility options 54

3.1.1 Flexibility in EV Charging and Heating Demand 55

3.1.2 Uptake of demand-side flexibility 57

3.1.3 System Cost Savings 58

3.2 Analysing the role of Power2X and import 60

3.2.1 What drives hydrogen demand? 60

3.2.2 Representation of energy supply chains and infrastructures 62

3.2.3 Impact of European hydrogen infrastructure on the Belgian energy system 64

3.3 Modelling Integrated Multi-Energy Market Designs 67

3.3.1 Model description 68

3.3.2 Simulation framework 69

3.3.3 Impact on profits 72
3.3.4 Impact on system flexibility 80
3.3.5 Discussion 81
4 Combined model analysis of sector-coupling 86
4.1 Relevance and approach 86
4.2 Updated reference scenarios 87
4.2.1 Updated results from Fluxys North Sea Integration Model (NSIM) 87
4.2.2 Updated results TIMES-BE 91
4.3 Sector coupling scenario results 93
4.3.1 Scenario design 93
4.3.2 Results and discussion 95
4.4 Benefits and challenges of a combined model analysis 98
5 Conclusion: main impacts of sector-coupling 100
References 103

List of Figures

Figure 2-1: Impact of boundary conditions on scalability for BUC 1 21
Figure 2-2: Impact of boundary conditions on replicability for BUC 1 23
Figure 2-3: Impact of boundary conditions on scalability for BUC 2 25
Figure 2-4 : Impact of boundary conditions on replicability for BUC 2 26
Figure 2-5: Impact of boundary conditions on scalability for BUC 3 28
Figure 2-6: Impact of boundary conditions on replicability for BUC 3 29
Figure 2-7: Impact of boundary conditions on scalability for BUC 4 31
Figure 2-8: Impact of boundary conditions on replicability for BUC 4 32
Figure 2-9: Impact of boundary conditions on scalability for BUC 5 34
Figure 2-10: Impact of boundary conditions on replicability for BUC 5 35
Figure 2-11: Impact of boundary conditions on scalability for BUC 6 37
Figure 2-12: Impact of boundary conditions on replicability for BUC 6 39
Figure 2-13: Impact of boundary conditions on scalability for BUC 9 41
Figure 2-14: Impact of boundary conditions on replicability for BUC 9 42
Figure 2-15: Impact of boundary conditions on scalability for BUC 10 44
Figure 2-16: Impact of boundary conditions on replicability for BUC 10 45
Figure 3-1: Design of the charging infrastructure in TIMES-BE for passenger cars [8] 56
Figure 3-2: Design of the structure for heating flexibility in TIMES-BE 57
Figure 3-3: Undiscounted annualized savings for heat flexibility 59
Figure 3-4: Undiscounted annualized savings for EV flexibility 59
Figure 3-5:Categorization of (Clean) Molecules [10] 60
Figure 3-6: Molecules flows (TWh) from supply sources to end-use demand in 2050 62
Figure 3-7: Schematic representation of the NSIM modelling framework 63
Figure 3-8: Hydrogen demand (inc. ammonia and methanol) by sector in Belgium in 2050 65
Figure 3-9: Hydrogen system yearly dispatch, hydrogen price and backbone exchanges in 2050 in Belgium 65
Figure 3-10: Electricity system yearly dispatch in 2050 in Belgium, for the ISO, EHB and EHB+I scenarios 66
Figure 3-11 Overview of the market optimization and simulation framework. 72

Figure 3-12 Annual GFPP profit across gas-market designs and market participation combinations..... 73
Figure 3-13 GFPP annual profit range across gas-market designs and market participation combinations..... 74
Figure 3-14 Maximum improvement in GFPP annual profit from gas-day reform..... 75
Figure 3-15 Annual CHP profit across gas-market designs and market participation combinations. 76
Figure 3-16 Electrolyzer profit by hydrogen-market design and market participation combination..... 78
Figure 3-17 Maximum improvement in electrolyzer annual profit from hydrogen-market reform 79
Figure 3-18: Upward and downward aFRR activation across market combinations and scenarios..... 84
Figure 3-19: Upward and downward aFRR reservation across market combinations and scenarios. 85
Figure 4-1: terative TIMES-BE–North Sea model linkage for sector-coupling assessment 86
Figure 4-2: Comparison of Belgian final energy and feedstock demand assumptions used in NSIM 88
Figure 4-3: Comparison of Belgian annual energy balances obtained with NSIM..... 89
Figure 4-4: Example of hourly electricity imports and associated marginal prices derived from NSIM..... 89
Figure 4-5: Example of hourly hydrogen imports and associated marginal prices..... 90
Figure 4-6: Modelled production and transport costs for molecules imported from overseas hubs 90
Figure 4-7: Average import fuel and electricity prices comparison across scenarios (2050) 91
Figure 4-8: Comparison of a) hydrogen demand, b) hydrogen supply, and c) other clean molecules import..... 92
Figure 4-9: Maximum uptake of flexible EV chargers for different scenario choices..... 93
Figure 4-10: Electrolyzer cost per type and scenario choice option..... 94
Figure 4-11: System cost savings and additional expenditure of sector-coupling scenarios 96
Figure 4-12: Hydrogen supply for all sector-coupling scenarios (year 2050) 97
Figure 4-13: Hydrogen demand for all sector-coupling scenarios (year 2050) 97
Figure 4-14: Hydrogen tank storage capacity by scenario..... 98

List of Tables

Table 1-1: Overview of BUCs and how these link to the main topics covered by ReInvent 15

Table 2-1: Types and categories of boundary conditions for scalability and replicability analysis 19

Table 3-1: Main assumptions underlying PATHS2050 storylines [7] 55

Table 3-2: Uptake of demand side flexibility technologies for space and water heating 58

Table 3-3: Uptake of demand side flexibility technologies for EV charging 58

Table 3-4 Main technical characteristics of the technologies considered in the market-model simulations. 68

Table 3-5 Market configurations considered for each technology 71

Table 3-6 Decomposition of the GFPP annual-profit improvement 75

Table 3-7 Decomposition of the CHP annual-profit improvement 77

Table 3-8 Decomposition of the electrolyzer annual-profit improvement 80

Table 4-1: Extreme scenario cases ranging from weak to strong sector-coupling 94

List of Abbreviations and Acronyms

Acronym	Meaning
5GDHC	5th Generation District Heating and Cooling
aFRR	automatic Frequency Restoration Reserve
ATES	Aquifer Thermal Energy Storage
ATR	Autothermal Reforming
BESS	Battery Energy Storage System
BRP	Balance Responsible Party
BUC	Business Use Case
CAPEX	Capital Expenditure
CCGT	Combined Cycle Gas Turbine
CCS	Carbon Capture and Storage
CCUS	Carbon Capture, Utilisation and Storage
CEC	Citizen Energy Community
CHP	Combined Heat and Power
DA	Day-Ahead
DSF	Demand-Side Flexibility
DSO	Distribution System Operator
EEX	European Energy Exchange
EGSI	European Gas Spot Index
EHB	European Hydrogen Backbone
EMS	Energy Management System
ENTSO-E	European Network of Transmission System Operators for Electricity
EV	Electric Vehicle
GFPP	Gas-Fired Power Plant
H/C	Heating and Cooling
HP	Heat Pump
NSIM	North Sea Integration Model
OEM	Original Equipment Manufacturer
OPEX	Operating Expenditure
P2X	Power-to-X
PEM	Proton Exchange Membrane
PoC	Proof of Concept
PPA	Power Purchase Agreement
PV	Photovoltaic
REC	Renewable Energy Community
RFNBO	Renewable Fuel of Non-Biological Origin
SRA	Scalability and Replicability Analysis
SMR	Steam Methane Reforming

SoC	State of Charge
SOE	Solid Oxide Electrolyser
TSO	Transmission System Operator
TYNDP	Ten-Year Network Development Plan
VRE	Variable Renewable Energy
V2G	Vehicle-to-Grid
V2H	Vehicle-to-Home
V2H/B/G	Vehicle-to-Home/Building/Grid
WDRP	Within-Day Reference Price

Executive Summary

Sector coupling is generally recognized as an important enabler for the energy transition towards climate neutrality. In this report, sector-coupling is analysed from a system-level perspective, addressing the scalability and replicability potential of the ReInvent test cases in the Belgian context and overall impact assessment for the Belgian energy system. We do so for three main aspects of sector coupling: electrification and demand-side flexibility, clean molecules and Power2X, and collective energy sharing. The system level perspective provides a complementary focus compared to the local-level analyses, by analysing how the test cases could become mainstream across Belgium, and the role that sector coupling could play in supporting the broader energy transition. These insights are important to understand the system benefits of sector-coupling and envision pathways how those benefits could materialize over the medium to long-term.

The first part of this deliverable (Chapter 2) examines the scalability and replicability potential of the different business use cases deployed under ReInvent to understand how local-level sector-coupling initiatives can generate impacts beyond the pilot and simulation phases. The analysis shows that sector-coupling solutions generally have potential for wider deployment, but that scaling and replication depend on the alignment of technical, economic, regulatory and stakeholder-related boundary conditions. Scalability and replicability should therefore not be understood as straightforward expansion or duplication of successful pilots. While many of the underlying technologies and operational principles are transferable, deployment at larger scale or in new contexts typically requires adaptation to local infrastructure, market conditions, regulation and stakeholder needs.

For electrification and demand-side flexibility, the growing deployment of EVs, heat pumps, batteries and other controllable electrical assets creates an expanding flexibility potential. Realising this potential at scale, however, requires effective coordination of increasingly diverse and distributed resources, and sufficient economic incentives for users to participate. Replication across regions and customer groups appears feasible because the underlying flexibility principles are broadly transferable, but implementation needs to account for differences in asset availability, interoperability, tariffs and flexibility mechanisms, regulation and user preferences.

For collective energy sharing, modularity and economies of scale can support wider deployment by spreading fixed costs across more participants and improving opportunities to match local generation and demand. At the same time, expansion can increase governance and administrative complexity and may encounter local infrastructure constraints. Replication is particularly dependent on the regulatory and market context, as well as on locally appropriate governance, contractual and benefit-sharing arrangements. The analysis therefore points to a balance between standardisation and local adaptation: common technical and organisational solutions can reduce replication efforts, but each project still needs to fit local conditions and provide a transparent and credible value proposition for participating stakeholders.

For clean molecules and Power2X, scalability and replicability are more strongly conditioned by the surrounding infrastructure and market ecosystem. Although technologies such as electrolysers are modular and increasingly standardised, scaling requires sufficient renewable electricity and grid capacity, suitable hydrogen transport and storage infrastructure, and stable demand from industrial or mobility off-takers. Economic viability remains closely linked to high utilisation and sufficiently competitive hydrogen production, while permitting and renewable hydrogen requirements can further influence project development. Replication is therefore less a matter of reproducing a standard technical configuration than of finding locations where the necessary infrastructure, demand, regulatory conditions and stakeholder commitments can be brought together.

The second part of this deliverable (Chapter 3) evaluates the impact and value of sector-coupling, particularly for electrification and demand-side flexibility, for Power2X in relation to clean molecules import, and for multi-energy market design. We generally find significant system benefits from sector-coupling technologies and market designs. Demand side flexibility technologies are largely 'no-regret' from a techno-economic perspective, since they provide high value to the system at low cost. Water heating buffers and flexible EV charging, for example, prove highly attractive from a system optimization perspective, reaching the full utilization of their maximum potential in every scenario where they are enabled. Other flexibility options, like thermal inertia in buildings and the uptake of two-way flexible charging (vehicle to home, building or grid) are exploited more moderately up to respectively some 20% and 35% of their maximum potential. Overall, the monetary system-level benefits from demand side flexibility are significant, and can be attributed to having more VRE integration, lesser imports of power and molecules, lesser battery investment, and more efficient heating systems.

Besides electrification, hydrogen and other clean molecules are found to have an important role in a climate-neutral Belgian energy system, although significant uncertainty applies. There is considerable uncertainty on the drivers of hydrogen demand, such as access to affordable electricity, deployment of CO_2 storage, regulatory requirements on renewable hydrogen supply. As a result, hydrogen demand scenarios for Belgium developed with TIMES-BE indicate a broad range from some 11 to 30 TWh (out which some 6 TWh being supplied as a byproduct, mainly from refineries). Furthermore, there is uncertainty on cost-optimal hydrogen supply routes, with different results among the different cases and models (TIMES-BE, NSIM, POMMES). For example, the models TIMES-BE and POMMES differ on the cost-optimal domestic supply routes, with notably higher levels of electrolysis in POMMES compared to TIMES-BE. To fully appreciate these model differences, further research is needed to further analyse differences in electricity prices, commodity prices, weather data and other factors affecting competitive domestic production. Overall, first estimates of the value of Power2X for Belgium indicate significant system-levels savings from enabling Power2X, albeit smaller to those of demand side flexibility. These savings could materialize over a long-term timeframe (2050) and are primarily attributed to enhanced PV integration, with reduced needs for imported clean molecules and power.

More coordinated energy market designs can be an important enabler for sector coupling. The Belgian electricity, gas, hydrogen and heat markets are already physically interconnected through technologies that convert energy between carriers. However, these physical interactions are not yet fully reflected in market organisation. Differences in trading products, temporal granularity and market arrangements can limit the ability of multi-carrier technologies to respond efficiently to signals across energy markets. The results indicate that temporal granularity and temporal alignment represent two distinct dimensions of market coordination. Greater market granularity, more specifically through shorter day-ahead gas or hydrogen products, consistently improves the ability of flexible technologies to respond to changing market conditions and is the main driver of the observed profitability gains. Temporal alignment has a smaller effect on annual profitability but can substantially influence how flexibility is made available to the balancing market. The magnitude and direction of both effects depend strongly on the technology and the combination of markets in which the technology participates. These findings therefore support a coordinated approach to market design, in which changes to gas, hydrogen, electricity and balancing-market structures are considered jointly rather than independently.

A methodological objective, finally, was to explore how different system level models can work together in a complementary way through a combined model analysis (Chapter 4). An iterative soft-linking procedure was tested between the more integrated energy system model TIMES-BE and the more supply-oriented model NSIM, covering one iteration of a two-way data exchange. This modelling exercise was valuable as it forces modelling teams to critically reflect on modelling assumptions that - in light of uncertainty - may be chosen differently between different models. Yet, the exercise is also challenging, first since model coupling is a time-intensive process, and second as it remains difficult to arrive at fully consistent model set-ups. Further combined model analysis, therefore, could also consider stand-alone model application structured around common research questions. Careful analysis of the explanatory factors of differences in model results would reveal critical uncertain factors underlying different viewpoints on energy system planning, as a valuable input for further scenario analysis and robust policy-making.

1 Introduction

Sector coupling is generally recognized as an important enabler for the energy transition towards climate neutrality. In ReInvent, sector coupling is interpreted as a concept to promote the integration of large-scale renewable electricity by increasing its direct use or indirect application through transformation into a suitable energy carrier, such as heat, gas, and liquids [1]. We consequently highlight three aspects of sector coupling as central to the project: electrification and demand-side flexibility, clean molecules and Power2X, and collective energy sharing.

Sector-coupling can be analysed from a local, bottom-up perspective and from a system-level, top-down perspective. From the bottom-up perspective, a suite of sector-coupling test cases have been analysed under ReInvent, ranging from flexible heating and cooling networks in business parks, to battery operation in energy communities, to flexibility provision with a large-scale electrolyser [2]. Main focus points for these analyses include optimal design and operation and the viability of business cases. The system level perspective provides a complementary focus by analysing how the test cases could become mainstream across Belgium, and the role that sector coupling could play in supporting the broader energy transition. These insights are important to understand the system benefits of sector-coupling and envision pathways how those benefits could materialize over the medium to long-term.

1.1 Objectives of the Work Reported in this Deliverable

This deliverable takes a system level perspective, reporting on Tasks 4.1 and 4.2 of the ReInvent project. These tasks respectively cover the scalability and replicability potential of the test cases in the Belgian context, and the overall impact assessment for the Belgian energy system.

For each real-life test case, ReInvent defined one or more Business Use Cases (BUCs), which capture the specific applications and solutions to be evaluated for their potential wider deployment. The **first aim** of this deliverable is to examine how these BUCs can generate impacts beyond the pilot and simulation phases through wider deployment and replication. This requires an understanding of the boundary conditions for scalability and replicability of the different BUCs, and how these conditions could be met. For the Scalability and Replicability Analysis (SRA), the analysis focuses on a subset of the BUCs evaluated within ReInvent [2]. BUC7 and BUC8 are excluded as they focus on wider energy-system impacts related to hydrogen, rather than on individual solutions to be scaled or replicated. In addition, BUC11 and BUC12 are excluded as they primarily concern proof-of-concept (PoC) solutions for smart billing for EV charging. The SRA therefore focuses on the remaining BUCs for which scalability and replicability are most relevant. Although the BUCs addressed in ReInvent are diverse, they can be clustered under the three main themes as shown in Table 1-1.

Table 1-1: Overview of BUCs and how these link to the main topics covered by ReInvent

BUC	Test Case	Description	Sectors	Vectors	Electrification & demand-side flexibility	Collective energy sharing	Clean molecules & Power2X
1	CollecThor	Sharing of H/C and providing flexibility to the electricity system in a business park with a 5GDHC network	Commercial	Heat Electricity	X	X	
2	Hybrid Energy Communities (Campina)	Integration of a BESS in a REC to provide flexibility to the electricity system	Residential	Electricity	X	X	
3	Social charging shared EVs	Flexibility enhanced car sharing in an EC consisting of social housing	Residential	Electricity	X	X	
4	Hybrid Energy Communities (SeaCoop)	Integration of collectively owned offshore considering DSF/BESS	Residential Renewable power	Electricity	X	X	X
5	Business Citizen Energy Communities	Business Citizen Energy Community with flexibility solutions	Commercial	Electricity	X	X	
6	Wind to truck	Local green power to long haul trucks	Transport Renewable power	Clean molecules Electricity	X		X
9	Large scale electrolyzers	Potential for flexibility provision with a large-scale electrolyser	Residential Renewable power	Clean molecules Electricity	X		X
10	Large scale e-mobility uptake B2C	Potential for flexibility provision with a portfolio of EVs	Transport	Electricity	X		

A **second aim** is to evaluate the impact and value of sector-coupling, particularly for electrification and demand-side flexibility, for Power2X in relation to clean molecules import, and for multi-energy market design.

A **methodological objective**, finally, is to explore how different system level models can work together in a complementary way through a combined model analysis.

1.2 Outline of the Deliverable

Following this introduction, the deliverable is structured into four main chapters. Chapter 2 analyses the scalability and replicability potential of the ReInvent Business Use Cases, identifying the main technical, economic, regulatory and acceptance-related boundary conditions for wider deployment. Chapter 3 assesses the system-level impact and value of sector coupling, focusing on demand-side flexibility, Power2X and clean molecules, and improved coordination of multi-energy markets. Chapter 4 explores the complementary use of different energy-system models through a combined model analysis. Finally, Chapter 5 brings together the main findings and conclusions.

2 Sector coupling from a use case perspective

This chapter analyses the scalability and replicability potential of the ReInvent Business Use Cases (BUCs), examining how they can generate impacts beyond the pilot and simulation phases through wider deployment and replication.

2.1 Approach scalability and replicability analysis

2.1.1 Methodology

The assessment builds upon the business use cases defined in ReInvent D3.1 and incorporates insights from Reinvent D1.2 (Business models for improved sector coupling) [3]and Deliverable D3.4 (Evaluation of Test Cases) [2]. These inputs were used to identify the boundary conditions influencing the scalability and replicability of each BUC. To ensure consistency with the assessment framework adopted in D3.4 [2], business use cases comprising multiple variants, including flexibility scenarios, were consolidated into a single business use case for the purpose of this analysis.

The boundary conditions were initially identified based on information provided by the BUC owners and feedback gathered from relevant stakeholders. This information was further complemented by findings from scientific literature to ensure a comprehensive assessment. Each identified boundary condition was subsequently assigned to a specific category. Where relevant, the boundary conditions also specify the geographical region and/or the particular BUC scenario to which they apply. The categorization framework was inspired by methodologies applied in comparable European energy projects that have conducted scalability and replicability assessments.

Once identified and categorised, the boundary conditions were analysed collectively within their respective categories. Rather than evaluating each condition independently and calculating an average score, the assessment considered the overall influence of each category by examining how the individual conditions interact, whether they originate from common underlying causes, and the extent to which they reinforce or complement one another.

Each category was then assessed using a four-level scale ranging from 0 to 3 according to the following criteria:

- **0 – Not relevant:** The category has no or negligible influence on the scalability or replicability of the BUC.
- **1 – Low importance:** The category has a limited influence on the scalability and replicability of the business use case.
- **2 – Moderate to high importance:** The category has a substantial influence on the scalability and replicability of the business use case.

- **3 – Critical importance:** The category plays a decisive role in determining the scalability and replicability of the business use case.

For each assigned score, a justification was provided. The rationale focused not on explaining the selected score in absolute terms, but rather on demonstrating why it was considered more appropriate than the alternative scoring options.

The resulting category scores were subsequently visualised using spider diagrams to facilitate comparison and interpretation. Finally, a consolidated summary of the boundary conditions was developed for each business use case, providing an overview of the key factors influencing its scalability and replicability potential, which will be presented in this chapter.

2.1.2 Concepts and definitions

The following definitions are used for the scalability and replicability analysis:

- **Scalability:** Scalability in this deliverable refers to the ability of the proposed solutions and results to be expanded in scope, size, or operational load in order to meet growing volumes of demand.
- **Replicability:** Replicability means the capacity of the project's methods or models to be duplicated at another location (e.g. other region) or another sector, enabling effective knowledge and solution transfer.
- **Boundary conditions**: Boundary conditions in this scalability and replicability analysis are the set of technical, economic, regulatory and stakeholder related factors that define as both the **constraints** that limit expansion or transferability (such as grid capacity, regulations, tariff structures, or resource availability) and the **enablers** that make scaling or replication possible (such as supportive policies, market demand, interoperable technologies, or available infrastructure).

2.1.3 Types of boundary conditions

Boundary conditions were grouped into three main types: technical, economic, and regulatory and acceptance-related conditions. Each type comprises several categories designed to capture specific constraints and influencing factors. The categories of boundary conditions were inspired by and adapted from other European energy projects to ensure comprehensive coverage of the diverse business use cases considered, as well as the various boundary conditions associated with them [4] [5] [6]. The types and categories of boundary conditions considered in this study are presented in the table below.

Table 2-1: Types and categories of boundary conditions for scalability and replicability analysis

Dimension	*Type*	*Category*	*Description*
Scalability	Technical	Modularity	Ability to divide the solution into interconnected modules and add new elements.
		Technological evolution	Capability of the technology to support scaling.
		Control and communication interface	Management of interactions between components (centralized or decentralized).
		Software tools	Performance of models, databases, and simulations when scaling up.
		Infrastructure compatibility	Consistency of the technical framework and interactions with the external ecosystem.
	Economic	Economies of scale	Cost evolution when expanding.
		Profitability	Growth of profits with scaling.
	Regulatory & Acceptance	Regulation	Legal and institutional framework influencing the size and scope of the project.
		Acceptance	Degree of stakeholder buy-in (regulators, decision-makers, users).
Replicability	Technical	Standardization	Compliance with standards or ability to become standardized.
		Interoperability	Compatibility and plug-and-play functioning between solutions and components.
		Integration and customization (network configuration)	Dependence on existing resources and infrastructure.
	Economic	Business model	Viability of the solution in different contexts.
		Profitability	Sensitivity to macroeconomic variables (discount rate, inflation, etc.).
		Market design	Dependence on the design of the market in which the solution operates.
	Regulatory & Acceptance	Regulation	Alignment with national or local frameworks and identification of potential barriers.
		Acceptance	Degree of stakeholder buy-in.

2.2 Scalability and replicability potential of the BUC

2.2.1 BUC 1 - 5GDHC network with H/C sharing and flexibility provision

2.2.1.1 General Information

ID	*Name of Business Use Case(s)*
BUC 1A	Collective, cross-sectoral business model for sharing of heat and cooling in a business park with a 5th generation district heating and cooling (5GDHC) network
BUC 1B	Collective, cross-sectoral business models for the provision of flexibility to the electricity system by a 5GDHC network
Short description	
CollecThor covers two closely linked applications of a 5th generation district heating and cooling (5GDHC) network at Thor Park business park: sharing heat and cooling between buildings, and an extension of the first where the connected heat pumps as well as other assets are considered as flexible electrical assets. The network is based on aquifer thermal energy storage (ATES) for thermal storage, building-level heat pumps for temperature step-ups, and a shared-service model where heating and cooling costs and revenues must be allocated fairly among the participating building owners.	

2.2.1.2 Impact of boundary conditions on scalability

The scale-up potential is defined first by the geography and physics of the network rather than by the modular concept alone. Adding buildings only improves the system where those buildings can realistically be connected to the 5GDHC architecture, have sufficient heating and cooling demand, and are close enough to justify the thermal link. Distance can be partly offset by higher demand, but not eliminated as a constraint. Building compatibility also matters: integration is easier where the building can work with low-temperature heat exchange and building-level heat pumps, while hybrid or partially upgraded buildings introduce higher costs and more uncertainty in future demand.

The storage layer places an additional boundary around growth. Because ATES relies on suitable local aquifers, expansion depends on subsurface capacity as much as on above-ground demand. Environmental limits on water use, groundwater levels, and temperature change can define the practical size of the network before pricing or contractual questions become decisive. Environmental regulation therefore primarily affects scalability through the requirements and permitting conditions associated with the selected storage technology. The heat-sharing concept itself is not presented as heavily restricted, but the environmental permitting conditions attached to underground storage can directly shape how far the network can be extended.

The modular design still provides an important advantage. Unlike a highly centralized thermal system, later connections do not necessarily face a fundamentally different cost structure from early participants, provided the network is planned for staged growth. A minimum initial size remains necessary, and that threshold depends

on storage technology, building proximity, and expected CAPEX, but the concept can grow gradually where physical conditions align. This makes modularity an enabler rather than a guarantee.

A larger network also needs stronger operational and settlement capabilities. As more buildings join, optimization tools must continue to support low-cost heating and cooling supply while preserving a fair allocation of costs and revenues. The challenge is not only calculating efficient thermal flows, but maintaining pricing and energy-sharing rules that participants can understand and trust. If settlement becomes opaque or if some buildings perceive that the allocation no longer reflects their use of the system, expansion can slow even where connection remains technically feasible.

The flexibility-oriented extension adds a separate layer of complexity. Using heat pumps and other assets as flexible electricity assets means that thermal operation, building comfort, network balancing, and aggregator requirements all need to be coordinated. This is not the main barrier for expanding the basic heating and cooling network, but it becomes more important as the number of buildings and controllable devices grows. The more the network is expected to deliver dependable electricity-system services, the more control rules and communication interfaces become part of the scale-up risk.

Participation ultimately connects these constraints. New building owners and users must accept a shared-service model, common settlement rules, and the operational coordination that comes with the network. Each additional building brings its own demand profile, technical constraints, and expectations. Growth is therefore most plausible where compatible buildings, suitable storage conditions, manageable permitting, and trusted governance are present together.

Figure 2-1 summarizes how the different boundary conditions influence the scalability potential.

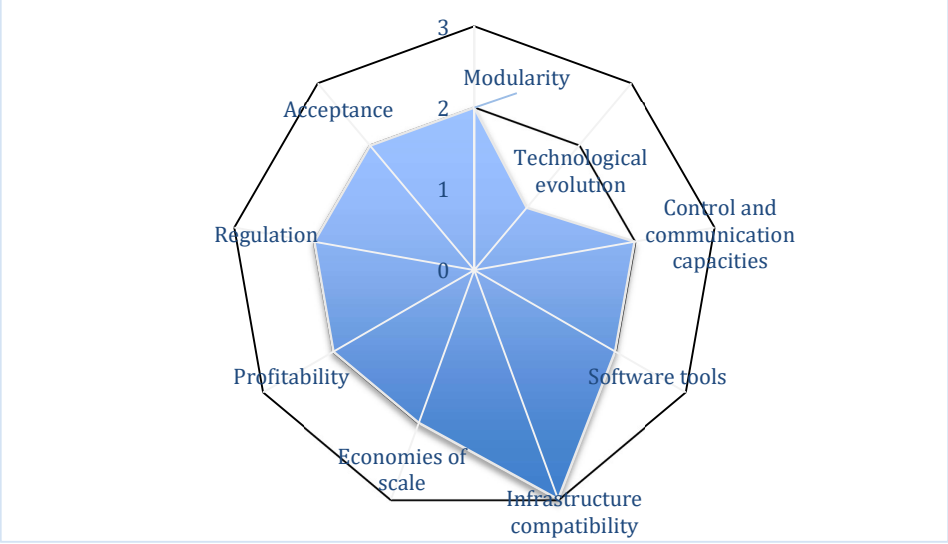


Figure 2-1: Impact of boundary conditions on scalability for BUC 1

2.2.1.3 Impact of boundary conditions on replicability

A new deployment cannot be assessed as a simple transfer of the Thor Park design. The most decisive question is whether the local conditions can support the same storage concept and thermal exchange logic. For an ATES-based 5GDHC network, this means suitable aquifers, sufficient capacity, proximity to demand, and the ability to accommodate future expansion. The design can be adapted, but only within the limits set by local geology and the chosen storage technology.

Environmental regulation follows from this dependency. Underground thermal storage may be constrained by rules on groundwater abstraction, water-level changes, and permissible temperature impacts, especially near protected natural areas. A site may have a promising demand profile and still be difficult to develop if the storage operation is not acceptable from an environmental perspective. Conversely, policy pressure to move away from gas-based heating can improve the attractiveness of low-temperature shared thermal networks, provided the site-specific permitting conditions can be met.

The contractual model also needs to be rebuilt around the local participant mix. A replicated network may include offices, laboratories, commercial users, housing, public buildings, or industrial consumers, each with different thermal profiles and expectations. Previous contracts and settlement templates can reduce effort, but they cannot remove the need for site-specific allocation rules, actor roles, responsibilities for future expansion, and service-quality agreements. Where flexibility services are included, contracts must also define control rights, aggregator involvement, transparency requirements, and the distribution of any flexibility-related impacts or revenues.

Profitability depends on the balance and density of demand more than on the novelty of the technology. A location with complementary heating and cooling needs, sufficient demand volume, and suitable storage conditions is more likely to support cost-efficient operation. If demand is dispersed, too small, or poorly balanced, the economics weaken even when the technical components can be installed.

The technical transfer barriers are not negligible, but they are not the dominant limitation. Design standards, contracting experience, and repeated deployment can make future projects easier, and the basic interaction between thermal networks, heat pumps, and building systems can be reproduced. The flexibility extension is less straightforward, because the thermal system, controllable heat pumps, building systems, and intermediary route to electricity-system services must all align in the new context.

Replication therefore depends on more than engineering feasibility. Stakeholders must trust the shared operation, pricing logic, settlement method, and allocation of responsibilities. Even where geology, demand, and permitting are favourable, the model will not transfer well if building owners or users do not believe that the costs, benefits, and control rights are fairly distributed.

Figure 2-2 summarizes how the different boundary conditions influence the replicability potential.

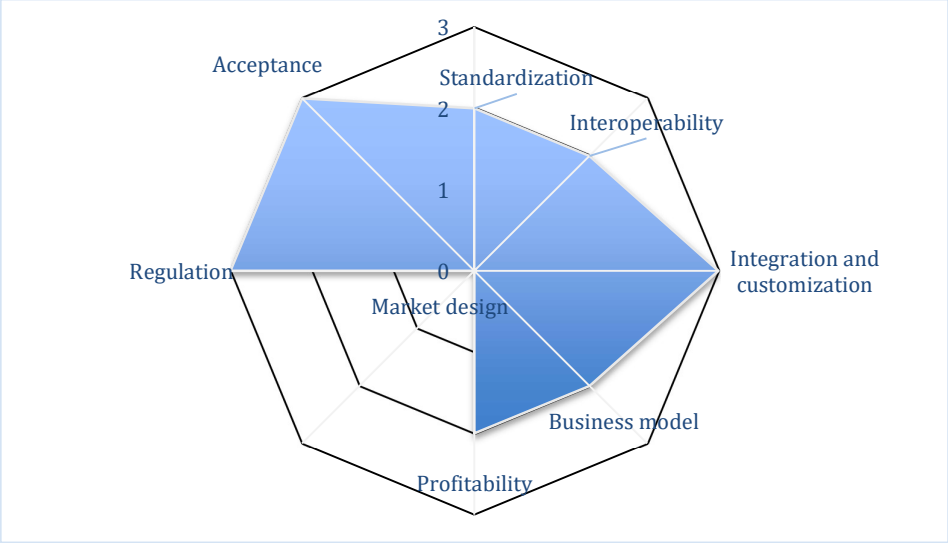


Figure 2-2: Impact of boundary conditions on replicability for BUC 1

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

2.2.2.1 General Information

ID	*Name of Business Use Case(s)*
BUC 2A	Collective, cross-sectoral business models for the integration of a BESS in a REC
BUC 2B	Collective, cross-sectoral business models for the provision of flexibility to the electricity system by BESS in a REC
Short description	
The analysis examines how a renewable energy cooperative can integrate a Battery Energy Storage System (BESS) with behind-the-meter PV installations at customer sites, such as schools. The cooperative owns and operates renewable generation and sells the produced electricity to the host customer through a PPA. When PV production exceeds on-site demand, surplus electricity is injected into the grid, but increasing hours with low or negative electricity prices can reduce or even reverse the value of this injection. Curtailment can protect the host from negative-price exposure, but it reduces compensation for the cooperative and wastes renewable generation. A BESS can reduce this problem by storing surplus PV production, increasing self-consumption, limiting curtailment, and potentially enabling energy arbitrage. The BUC analysis compares community-level and host-level optimisation to understand how different operating strategies affect total costs and curtailment. It also considers who should operate the BESS, how benefits and costs should be shared, and whether tolling arrangements could improve the business model. Overall, the objective is to assess whether BESS can strengthen the cooperative PV business case while improving local use of renewable electricity in the Belgian context.	

2.2.2.2 Impact of boundary conditions on scalability

Growth is most naturally organized as a portfolio of site-level projects. Each host location functions as its own RES and BESS configuration, with a specific production profile, load pattern, grid connection, metering setup, storage size, and operating arrangement. This modular structure allows the cooperative to reuse engineering experience, contract templates, optimisation workflows, and settlement logic across projects, rather than treating every deployment as entirely new.

The limitation is that each module is still constrained by its own physical conditions. PV production cannot simply be increased where roof space is already saturated, and the useful battery size depends on the amount of surplus PV that can be stored or shifted. Local demand matters just as much. A battery only adds value if stored energy can later be used, if curtailment can be avoided, or if market conditions make arbitrage worthwhile. A stronger grid connection may expand the range of possible operating strategies, but it can also require DSO approval and introduce costs that materially affect the business case.

Regulation and tariffs determine what “good operation” means. Capacity charges, network costs, injection compensation, negative-price exposure, and price spreads influence whether the BESS is mainly used for curtailment reduction, peak avoidance, arbitrage, or broader value stacking. The same battery can therefore have different value depending on the applicable tariff structure and on how the resulting benefits are allocated between the host and the cooperative.

This allocation issue is central to both profitability and acceptance. Curtailment protects the host from negative-price exposure but reduces the cooperative’s compensated PV generation. Storage can reduce that conflict by absorbing surplus production, but only if the rules for dispatch, cost sharing, and revenue sharing are clear. The host must see that battery operation will not impose unfair costs or restrict its choices, while the cooperative and its shareholders need evidence that the BESS protects PV value, improves local renewable use, reduces emissions, and delivers an acceptable return.

As the portfolio grows, decision-making also becomes more data- and model-intensive. A single site can be analysed through a manageable set of scenarios, but multiple sites multiply the combinations of battery size, tariff assumptions, operator models, curtailment logic, arbitrage strategies, and settlement designs. Software tools therefore become important not because the equipment is difficult to coordinate, but because the cooperative needs a practical way to compare projects and decide where the next investment is justified.

Control issues are more institutional than technical. PV systems, batteries, meters, and energy management systems can generally be coordinated. The more sensitive question is who controls the battery and according to which priorities. Scale-up is easier where dispatch rights, operational objectives, and settlement consequences are agreed in advance, so that storage does not become a source of tension between the host and the cooperative.

Figure 2-3 summarizes how the different boundary conditions influence the scalability potential.

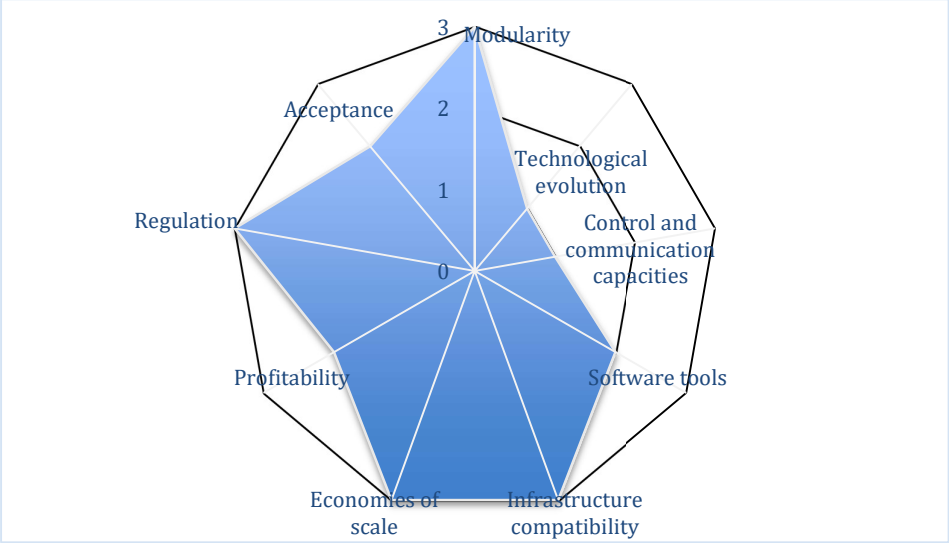


Figure 2-3: Impact of boundary conditions on scalability for BUC 2

2.2.2.3 Impact of boundary conditions on replicability

Transfer to new settings depends less on whether PV and BESS can be combined and more on whether the cooperative business model remains credible. The current structure is closely tied to cooperative-owned PV, a host customer, and PPA-based settlement. Similar schools or public buildings are likely to be the easiest replication targets because demand patterns, governance, and curtailment exposure may remain comparable. Moving to industrial sites, municipal buildings, care facilities, or other environments changes the assumptions behind the model.

The hardware is comparatively transferable. PV, batteries, metering, and energy management systems are familiar technologies, and each deployment can be adapted through normal project design: battery sizing, metering configuration, EMS integration, and tariff-signal handling. These tasks require engineering work, but they are not the main reason replication may fail.

The more difficult transfer question is whether energy flows and financial outcomes can be measured and attributed convincingly. A new site must allow behind-the-meter PV generation, host consumption, grid injection, and battery charge and discharge to be traced in a way that supports settlement between the host and the cooperative. If data quality or metering resolution is weaker, the allocation of costs and benefits becomes harder to defend. If the host load profile differs substantially, the operating logic may also shift from curtailment reduction toward arbitrage, or toward a combination that changes the value proposition.

Profitability and market design remain uncertain because practical implementation evidence is still limited. Negative-price exposure, injection compensation, tariff treatment, network charges, financing conditions, and

value-stacking opportunities will all influence future deployments. At this stage, they are better treated as factors requiring validation rather than as fully demonstrated barriers or enablers.

Regulation is not expected to block the basic PV and BESS concept, but it can alter the settlement structure and the economic attractiveness of a project. Rules around injection, curtailment, behind-the-meter arrangements, tariff application, and metering configuration may require adaptation when the model is moved to another site.

The final condition is trust in the investment logic. Cooperative shareholders need to understand why storage belongs in a renewable energy project even though it does not generate renewable electricity itself. Host organizations need a transparent explanation of how battery operation affects their costs, revenues, and operational flexibility. Replication is most plausible where the technical setup is familiar, the host profile is similar enough for the business model to transfer, and the value of storage can be explained in terms of avoided curtailment, better PV use, CO2 reduction, and fair benefit sharing.

Figure 2-4 summarizes how the different boundary conditions influence the replicability potential.

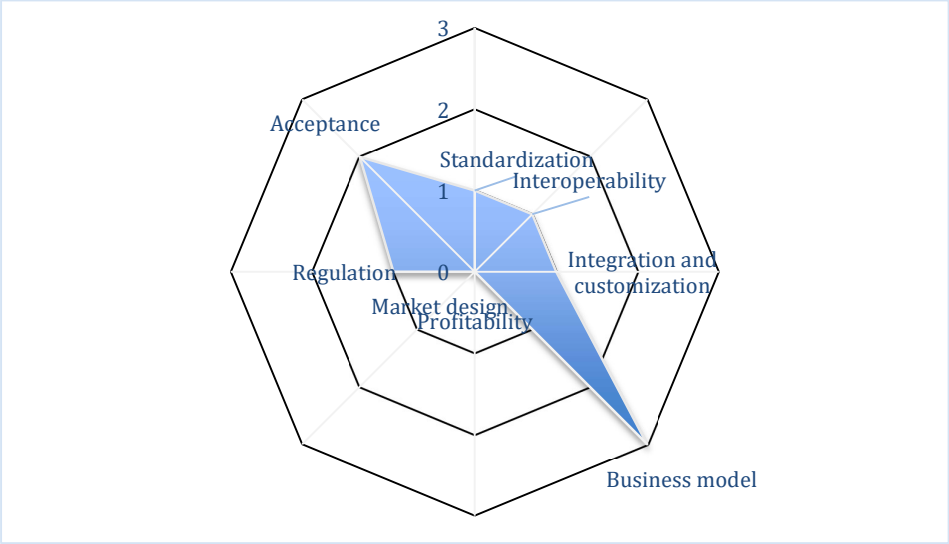


Figure 2-4 : Impact of boundary conditions on replicability for BUC 2

2.2.3 BUC 3 - Social charging shared EVs

2.2.3.1 General Information

ID	*Name of Business Use Case(s)*
BUC 3A	Collective, cross-sectoral business models for car sharing in an Energy Community consisting of social housing
BUC 3B	Collective, cross-sectoral business models for flexibility enhanced car sharing in an Energy Community consisting of social housing
Short description	
Klimaan has 197 domestic solar PV installations in the Otterbeek social housing district in Mechelen. Solar power was installed with maximal roof area usage to maximize solar production, resulting in a significant amount of excess solar power. 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 thereby lower the costs specifically for end-users in a social context. BUC 3B: Dynamically charging the EVs based on pricing impulses and local distribution network conditions could add additional value to this business use case.	

2.2.3.2 Impact of boundary conditions on scalability

The model can grow only if the physical expansion of shared charging is matched by an operational framework capable of managing community energy flows. Adding EVs and charging points is not the most difficult step on its own. The larger challenge is coordinating local PV, shared mobility demand, member participation, charging behaviour, and energy allocation in a way that remains workable as the number of tenants and transactions increases.

There is a strong economies-of-scale argument. Governance, booking platforms, charging-point operation, insurance, simulation tools, and community management all include fixed or semi-fixed costs. Higher utilization spreads these costs across more kilometres driven and more shared energy, creating the possibility of a lower social charging tariff. That affordability objective is central: the model becomes more attractive as utilization improves, but utilization only improves if the offer is accessible and trusted by tenants.

The current energy-sharing framework makes this harder. Collective self-consumption requires allocation keys, member management, metering data, and market-data processes that are still relatively rigid in Flanders. At present, Fluvius relies primarily on predefined allocation keys, with limited support for dynamic management of energy communities through automated APIs. In addition, energy sharing is not yet established as a standard market process within the Atrias framework. As a result, administrative workarounds that may be manageable at small scale can become a bottleneck as the number of tenants, vehicles, charging points, and energy flows increases.

Regulation introduces further misalignment. Public charging infrastructure is often organized through tenders with large operators, so community-oriented charging may require specific municipal support or exemptions. The individual capacity tariff creates another challenge: charging EVs during high local PV production may be optimal for collective self-consumption, but it can still create a cost-relevant peak at the individual connection. The model therefore depends not only on whether shared charging and solar production can be combined, but on whether the tariff and infrastructure framework rewards the behaviour the community is trying to encourage.

User adoption is the practical test of the whole design. Tenants are being asked to shift toward digitally booked shared EVs and variable per-use pricing. That involves trust in shared assets, comfort with the booking platform, digital literacy, perceived convenience, and confidence that the service is genuinely affordable. The economic case becomes stronger with higher utilization, but higher utilization will not appear unless the service first feels reliable and socially appropriate. Scale-up therefore depends on a feedback loop between affordability, trust, and participation.

Figure 2-5 summarizes how the different boundary conditions influence the scalability potential.

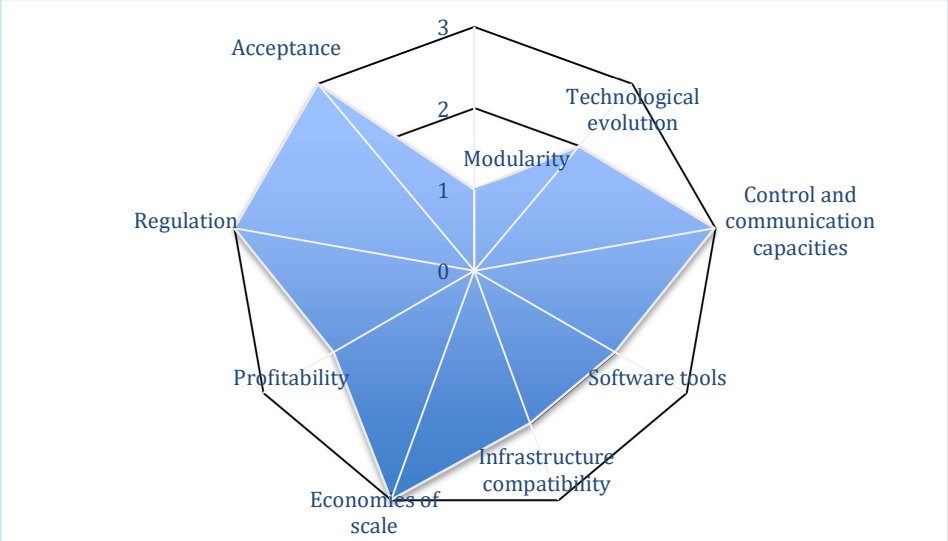


Figure 2-5: Impact of boundary conditions on scalability for BUC 3

2.2.3.3 Impact of boundary conditions on replicability

A new district may be able to install PV, chargers, and shared EVs, but that does not mean the Otterbeek model transfers automatically. The value proposition depends on a specific combination of solar surplus, household demand, mobility needs, smart-meter availability, charging locations, tenant engagement, and local institutional support. A technically similar site can still require a different tariff model, cost-sharing approach, or operating structure.

The most binding transfer issue is market design. Small, distributed energy-sharing volumes are vulnerable to supplier administrative fees, which can erode the financial benefit before the mobility service has enough scale to compensate. This is especially problematic in social housing, where individual savings may already be modest. For the flexibility-enhanced variant, the absence of a mature local DSO flexibility market creates a second gap: dynamic charging may help the grid technically, but without a clear route to monetize local flexibility, that value remains difficult to include in a replicated business case.

Regulatory conditions make transfer even more context-specific. Flemish restrictions on selling shared energy, tariff barriers for neighbourhood batteries behind charging points, limited discounts for local energy sharing, and the immature V2G framework all affect how the model can be structured. Moving beyond Flanders adds further variation in smart-meter rollout, DSO practices, and tariff treatment. The same concept may therefore require substantial redesign before it fits another regional framework.

Institutional acceptance is not a secondary concern. Each new district needs support from the social housing organization that controls rooftop access and tenant engagement, as well as from the municipality that influences public-space charging and any exceptions to charging tenders. These actors have their own priorities, political timelines, and risk perceptions. Otterbeek can serve as a reference, but it cannot substitute for local agreement. As such, replication is strongest where the social and institutional conditions are as convincing as the technical ones. The model needs a setting where tenants are willing to participate, local partners actively support the arrangement, and the financial structure makes the social value of shared electric mobility visible rather than abstract.

Figure 2-6 summarizes how the different boundary conditions influence the replicability potential.

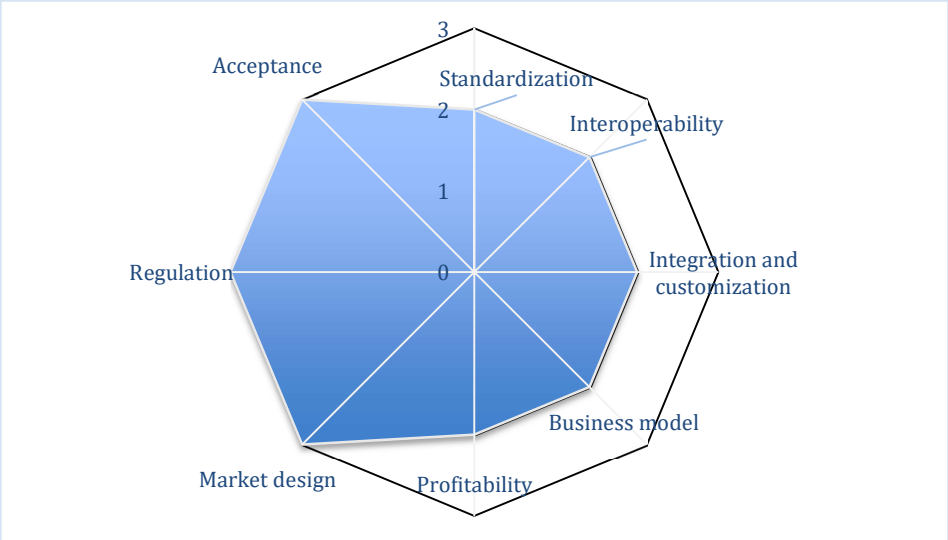


Figure 2-6: Impact of boundary conditions on replicability for BUC 3

2.2.4 BUC 4 - Collective Offshore Wind Integration through Battery Storage

2.2.4.1 General Information

ID	Name of Business Use Case(s)
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	
Sea2Socket 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 assesses the impact of integrating a large-scale battery to reduce the profiling and imbalance costs associated with offshore wind generation when serving residential consumption profiles.	

2.2.4.2 Impact of boundary conditions on scalability

For BUC4, scalability is primarily constrained by grid infrastructure and connection availability. Physical grid congestion and limited connection capacity can restrict the deployment of additional assets alongside offshore wind turbines, such as batteries, solar PV, and, more importantly, onshore wind turbines. These constraints may therefore limit the extent to which additional renewable generation and flexibility assets can be integrated into the system.

Regulatory evolution is the second key constraint. The removal of citizen participation criteria in offshore wind concessions has weakened the position of cooperative models, which now compete in tenders driven mainly by price, speed, financial strength, and technical capability. This increases pressure for consolidation within SeaCoop and limits access to new offshore developments, shifting expansion toward acquisitions of existing assets and diversification into onshore wind and solar PV. At the same time, permitting complexity continues to slow onshore wind deployment.

Investment governance and financial risk appetite form an equally important constraint. Despite a large membership base and significant capital mobilisation, large-scale investments, particularly BESS and offshore wind, depend on collective approval within cooperative structures. Revenue uncertainty in BESS projects reduces willingness to invest, while territorial anchoring of local cooperatives can limit support for projects outside their traditional areas.

In contrast, technical scalability and EMS architecture are enabling factors rather than limitations. Assets can be aggregated without structural changes to the EMS, with storage typically modelled as a virtual battery. While scaling increases optimisation complexity, it does not affect feasibility, instead requiring more advanced control, forecasting, and dispatch strategies as market participation expands.

Modularity and economies of scale further support gradual expansion by enabling incremental capacity additions and improved operational efficiency, including the progressive insourcing of functions such as balancing and maintenance. However, these benefits remain conditional on grid access, regulatory feasibility, and member approval.

In conclusion, BUC4 is technically scalable, but practical expansion is primarily governed by grid constraints, regulatory conditions, and cooperative investment dynamics. While modularity and optimisation capabilities support growth, the actual pace and scale of deployment depend on grid access, permitting, territorial acceptance and risk acceptance to invest in capital-intensive assets.

Figure 2-7 summarizes how the different boundary conditions influence the scalability potential.

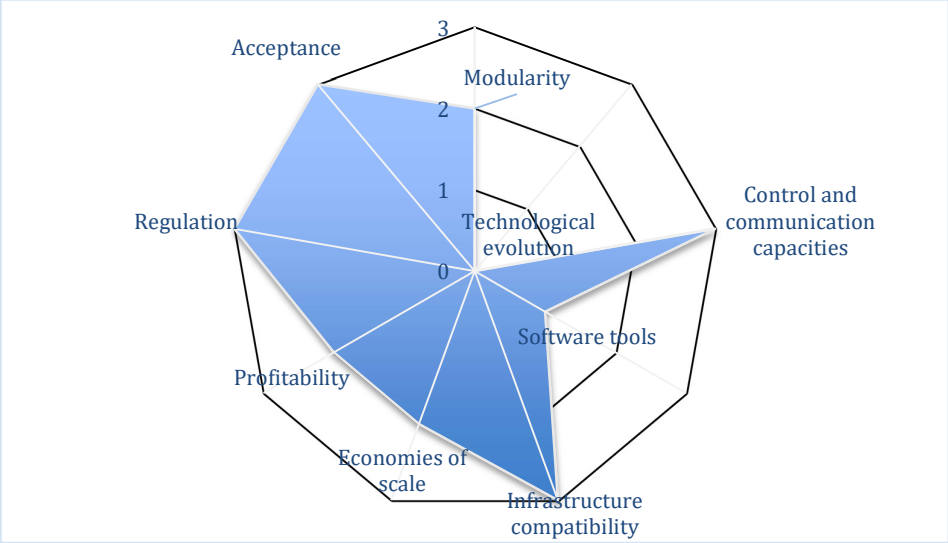


Figure 2-7: Impact of boundary conditions on scalability for BUC 4

2.2.4.3 *Impact of boundary conditions on replicability*

For BUC4, regulatory changes in offshore wind concessions constitute the first major barrier to replication. The removal of explicit citizen participation criteria has created a highly competitive allocation framework based primarily on price, speed, financial strength, and technical capability as explained above. This structurally disadvantages cooperative models and limits standardisation, as citizen participation must now be negotiated on a case-by-case basis. Consequently, transaction costs increase, timelines lengthen, and uncertainty rises, reducing the ability to replicate a consistent “Sea to Socket” framework.

Second, when offshore wind development is not feasible for regulatory reasons, transferability shifts toward other technologies, but is constrained by grid capacity and permitting availability, particularly for onshore wind. This redirects investment toward less constrained assets such as solar photovoltaics and battery storage, or

toward offshore wind projects in neighbouring countries. However, such a shift moves away from the original purpose of the use case.

Third, financial constraints represent a key limitation. Replicating the model requires substantial capital mobilisation from a large base of citizens, particularly for offshore wind projects with high upfront costs and long development horizons. Although SeaCoop aggregates a broad membership base, securing sufficient additional investment across multiple cooperatives remains both time-consuming and uncertain.

Overall, the replicability of the Sea to Socket model is limited by the combined effect of regulatory, technical, and financial barriers. Regulatory uncertainty in concession design strongly reduces the ability to standardise cooperative participation, while grid and permitting constraints restrict alternative domestic deployment pathways. As a result, expansion tends to be redirected toward less constrained technologies or cross-border offshore investments, diluting the original model's integrated value chain ambition. Together with the challenges of mobilising sufficient citizen capital at scale, these factors significantly constrain the replicability and consistent deployment of the Sea to Socket framework across projects.

Figure 2-8 summarizes how the different boundary conditions influence the replicability potential.

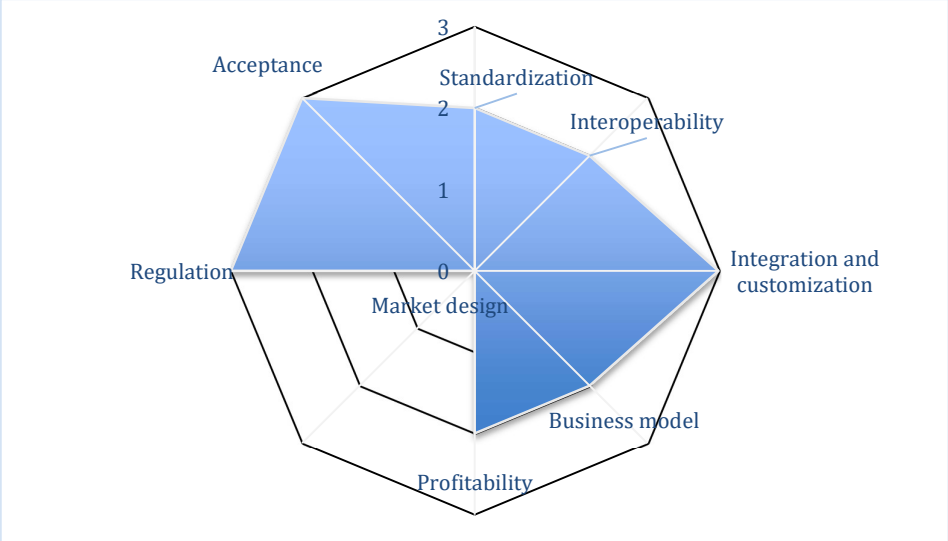


Figure 2-8: Impact of boundary conditions on replicability for BUC 4

2.2.5 BUC 5 - Business Citizen Energy Communities

2.2.5.1 General Information

ID	*Name of Business Use Case(s)*
BUC 5A	Collective, cross-sectoral business models for Business Renewable Energy Communities (without flexibility)
BUC 5B	Collective, cross-sectoral business models for Business Renewable Energy Communities with flexibility solutions
Short description	
Symco Energies is a business citizen energy community (CEC) powered by two wind turbines of 2,35MWp producing around 9,000 MWh per year, complemented by 13 MWp of solar capacity and 1.8 MW of combined heat and power (CHP) contributed by its members. 50 consumption sites were studied, representing 36 enterprises. These entities include public authorities, industrial firms, service-sector companies, and hospitals. This Business Use Case also integrates flexibility solutions aimed at optimizing and increasing the self-consumption of CEC members. Several approaches are being considered, including adapting consumption patterns and adding additional storage capacity within the community.	

2.2.5.2 Impact of boundary conditions on scalability

When considering scalability, economic boundary conditions, more specifically economies of scale and profitability, constitute the primary factors influencing the expansion of citizen energy communities. At small scale, fixed costs borne by community members, such as annual membership fees, supplier contract adaptation fees, and potential penalties, are often disproportionately high compared with the expected benefits. This can effectively offset the advantages of participation and create a significant entry barrier for low-consumption actors such as households and SMEs. A similar effect applies at the level of the energy community itself, where the initial costs associated with its establishment and operation remain high relative to the limited exchanged energy volumes from which the community derives revenues or management fees.

As the scale of energy exchanges increases, two reinforcing effects emerge. First, a cost dilution effect benefits both community members and community managers by spreading fixed operational costs over larger exchanged volumes. Second, an energy value amplification effect linked to modularity arises: a greater diversity of load profiles, if appropriately selected through prior simulations, increases internal matching opportunities and improves self-consumption rates.

Nevertheless, the practical benefits of economies of scale remain limited by governance and organizational constraints. As the number of participants grows, coordination requirements, decision-making procedures, and quorum obligations become increasingly complex and increase administrative burdens, thereby indirectly limiting the maximum size of the community.

Beyond economic and organizational considerations, scaling will only be possible if energy communities succeed in convincing risk-averse companies to participate and support their development despite limited awareness, perceived complexity, financial uncertainty, and organizational constraints.

In conclusion, citizen energy communities can scale effectively, as their scalability is primarily driven by economic viability rather than technical limitations. Reaching a minimum critical size is almost a prerequisite, as it enables the dilution of fixed costs and improves profitability through higher energy exchange volumes and better matching of diversified load profiles. However, beyond an optimal intermediate scale in terms of number of members, governance complexity, coordination requirements, and administrative burdens progressively limit further expansion. Consequently, organizational efficiency, economic attractiveness, and participant acceptance remain the main determinants of scalability.

Figure 2-9 summarizes how the different boundary conditions influence the scalability potential.

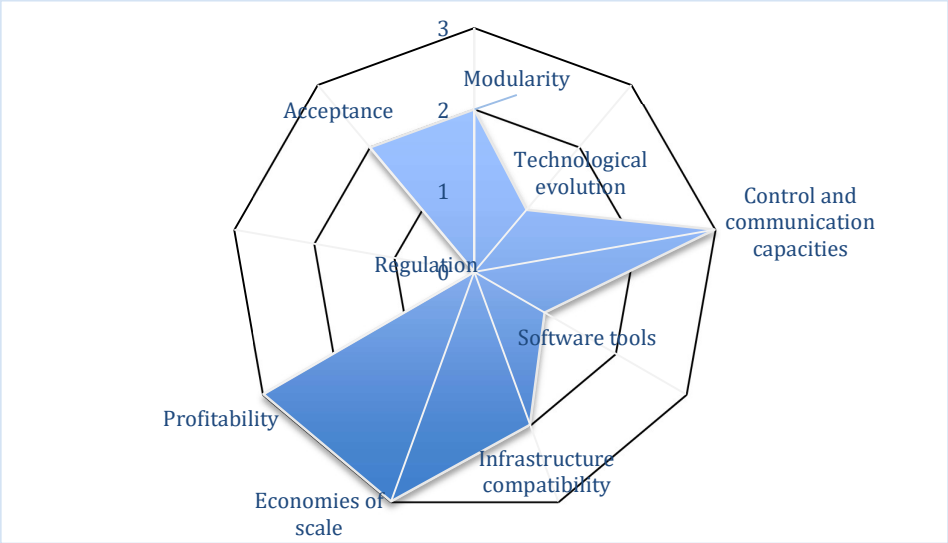


Figure 2-9: Impact of boundary conditions on scalability for BUC 5

2.2.5.3 Impact of boundary conditions on replicability

The business model of energy communities is currently structured in such a way that projects face a significant cumulative burden of non-physical setup costs. These include legal structuring, administrative procedures, contractual arrangements related to regulatory boundary conditions, as well as simulation and EMS development costs linked to interoperability and standardisation. Since these elements must largely be recreated for each new project, they are highly time-consuming and significantly hinder replicability.

As such, each category of boundary condition constrains replicability in its own way without necessarily having a critical impact individually. However, when combined, these constraints create substantial complexity

for the deployment of new projects. In addition, alternative use-case scenarios involving collective batteries are currently not feasible in Wallonia due to concerns related to grid stability and uncoordinated operation, thereby limiting certain advanced community configurations (e.g., BUC 5b).

Finally, from the perspective of community members, profitability and economies of scale play an important role. Large companies, due to their high levels of energy consumption and/or production, are better able to dilute the costs associated with participation in an energy community, thereby improving the economic attractiveness of such schemes. However, existing regulatory frameworks restrict their level of control, reducing the overall attractiveness and operational flexibility of these arrangements for large companies.

Overall, the replicability of energy communities remains entirely feasible, except at present for configurations involving collective batteries, provided that sufficiently high volumes of exchanged energy can dilute the various costs associated with establishing and joining the community.

Figure 2-10 summarizes how the different boundary conditions influence the replicability potential.

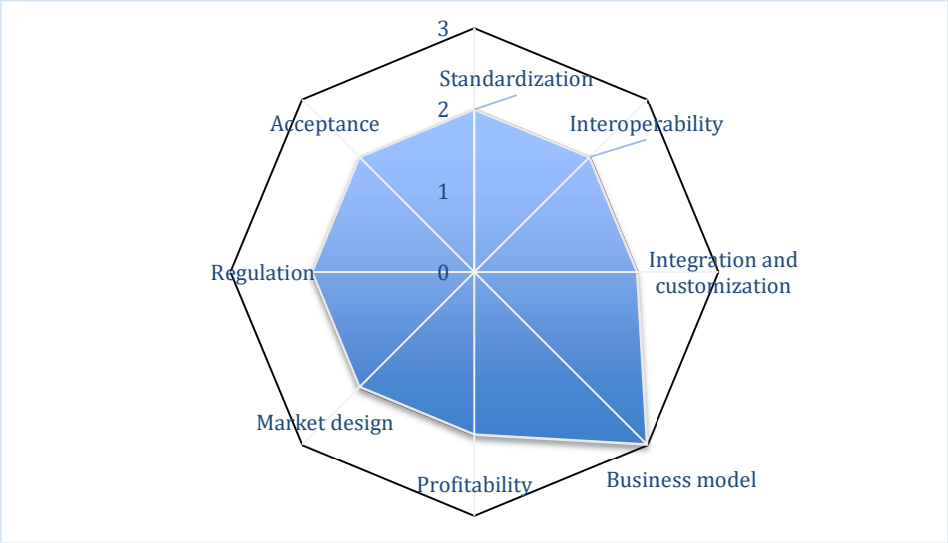


Figure 2-10: Impact of boundary conditions on replicability for BUC 5

2.2.6 BUC 6 – Green H2 vs Electricity for Long Haul Trucks

2.2.6.1 General Information

ID	*Name of Business Use Case(s)*
BUC 6A	Cross sectoral business models for long haul trucks on Hydrogen.
BUC 6B	Cross sectoral business models for long haul trucks mobility from local green power.
Short description	
In the baseline scenario of this BUC (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 1,78 MWp photovoltaic installation to be built. 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 a fleet of ten hydrogen-powered trucks, representing an annual consumption of approximately 80–85 tons of hydrogen. The electrolyser, rated at 1.25 MW, is sized 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 high-pressure hydrogen storage system (1057kg) 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 110,000 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.	

2.2.6.2 Impact of boundary conditions on scalability

Wind-to-Trucks faces several important boundary conditions that constrain its scalability, with the main limitations arising from infrastructure, regulation, stakeholder engagement, and spatial constraints.

Firstly, a major infrastructural barrier is the absence of dedicated hydrogen transport infrastructure. As a result, hydrogen production must remain closely connected to local demand, since transport via tube trailers rapidly becomes uneconomic over longer distances. Consequently, scalability depends heavily on the presence of nearby industrial or mobility offtakers willing to adopt green hydrogen solutions.

Even where additional demand exists, further expansion requires additional renewable electricity generation capacity, preferably through local wind or photovoltaic assets. This, however, depends on the availability of suitable land, grid access, permitting conditions, and environmental constraints.

These limitations are further reinforced by regulatory boundary conditions. In particular, increasing hydrogen storage capacity may trigger classification under the Seveso III Directive, notably at hydrogen thresholds of 5 and 50 tonnes. Such classification entails substantially stricter permitting procedures, extensive safety and risk assessments, reinforced inspection obligations, additional land-use planning constraints, higher

compliance costs, and longer project development timelines. Together, these requirements reduce the attractiveness and feasibility of large-scale expansion.

Stakeholder acceptance also constitutes a significant scalability barrier. Due to the lack of hydrogen pipeline infrastructure, projects remain highly dependent on local actors adopting relatively expensive green hydrogen solutions. This dependence slows demand formation, increases market uncertainty, and limits replication potential across regions.

As a consequence, the economies of scale that could theoretically improve project economics are often constrained by the combined effects of limited access to low-cost renewable electricity, land scarcity, storage requirements, regulatory obligations, and insufficient local hydrogen demand. Therefore, even where physical scaling remains technically feasible, these constraints are likely to offset expected cost reductions and may even result in underutilised assets, thereby weakening an already fragile profitability.

Figure 2-11 summarizes how the different boundary conditions influence the scalability potential of.

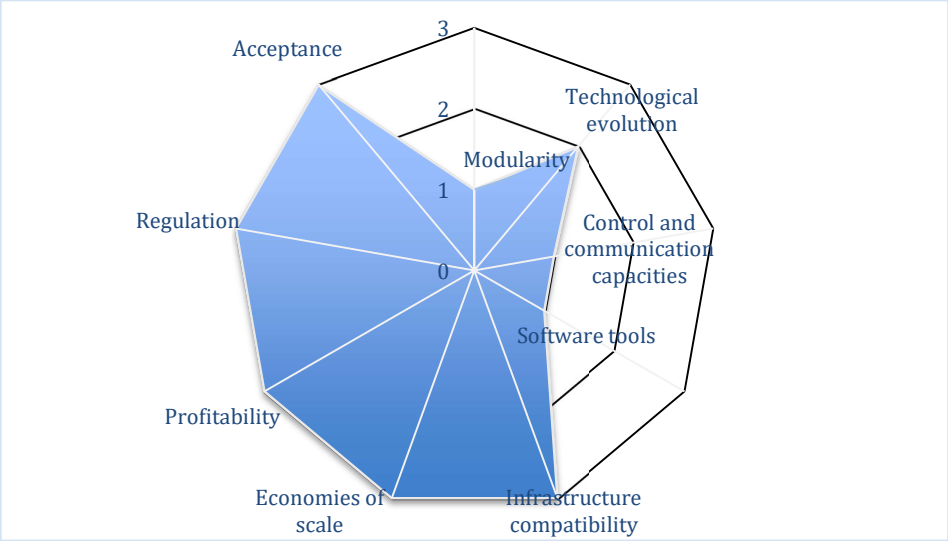


Figure 2-11: Impact of boundary conditions on scalability for BUC 6

2.2.6.3 Impact of boundary conditions on replicability

The Wind-to-Trucks project faces several structural constraints that significantly limit its replication potential. One of the main challenges is its strong dependence on the development of stable local hydrogen demand, particularly from transport companies and industrial users. However, the uptake of hydrogen/electric trucks remains limited due to their high investment costs, technological uncertainties, and more importantly their lower competitiveness compared to diesel trucks, which continue to benefit from mature supply chains, extensive refuelling infrastructure, and a reduced effective fuel cost for professional users through the Belgian excise-duty reimbursement scheme. In the absence of hydrogen pipeline infrastructure, the project relies almost

entirely on local consumption, making long-term stakeholder commitment and demand stability essential. Under real market conditions, maintaining such stakeholder engagement remains particularly challenging given the fragility and limited competitiveness of the current business model.

This structural fragility is further amplified by the limited profitability of the current Wind-to-Trucks configuration, with production costs generally significantly higher than alternative pathways. Such weak economic performance reduces both the attractiveness and the bankability of potential replication projects. Furthermore, the business model is highly dependent on obtaining renewable hydrogen certification and accessing associated subsidies or market premiums. The RFNBO regulatory framework imposes stringent requirements that reduce operational flexibility, increase compliance costs, and create regulatory uncertainty, potentially compromising certification eligibility.

In addition, regulatory and permitting constraints further restrict replication opportunities. Land-use and permitting regulations limit the geographical areas suitable for deploying such infrastructure, while additional regulatory constraints restrict the use of hydrogen trucks for the transport of dangerous goods. Together, these factors reduce both land availability and potential local demand, thereby further constraining the large-scale deployment and replication of the Wind-to-Trucks concept.

In conclusion, the replication of the Wind-to-Trucks concept remains constrained by a combination of economic, regulatory, and market-related challenges. The project's dependence on stable local hydrogen demand, coupled with the limited competitiveness of hydrogen mobility solutions and the absence of hydrogen transport infrastructure, creates significant uncertainty regarding its long-term viability. These challenges are further reinforced by weak profitability, high hydrogen production costs, and the complexity of complying with renewable hydrogen certification requirements. At the same time, regulatory and permitting constraints further limit deployment opportunities and market accessibility, thereby reducing the replication potential of the Wind-to-Trucks model.

Figure 2-12 summarizes how the different boundary conditions influence the replicability potential.

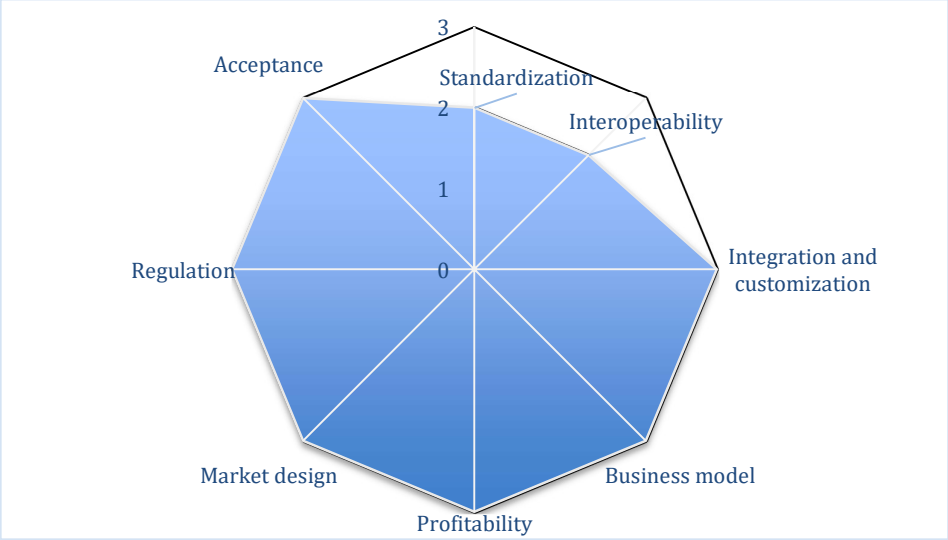


Figure 2-12: Impact of boundary conditions on replic*ability for BUC 6*

2.2.7 BUC 9 - Flexibility provision with large-scale electrolyser

2.2.7.1 General Information

ID	*Name of Business Use Case(s)*
BUC 9	Potential for flexibility provision with a large-scale electrolyser
Short description	
BUC 9 examines whether the profitability of a large-scale electrolyser can be improved by operating it flexibly and providing services to the power system, rather than running it at a constant load. The modelling setup considers a 25 MW PEM electrolyser at the Virya facility in Zeebrugge, which sources electricity from an offshore-wind Power Purchase Agreement (PPA) and from the day-ahead market, and delivers hydrogen through two outlets: tube trailers serving industrial customers at a green-certified premium, and injection into the gas grid as a lower-value flexibility outlet. On top of hydrogen sales and surplus-electricity arbitrage, the electrolyser offers aFRR down-regulation capacity to the Belgian transmission system operator (Elia). The use case assesses how much additional value this flexibility can generate, and how the RFNBO (Renewable Fuels of Non-Biological Origin) certification rules constrain it.	

2.2.7.2 Impact of boundary conditions on scalability

For BUC 9, scalability is constrained most strongly by infrastructure compatibility and by profitability, with the remaining boundary conditions - modularity, economies of scale, technological evolution, control and communication, software tools, regulation and acceptance - playing meaningful but secondary roles. Because the concept creates value through flexible operation rather than sheer size, scaling depends less on the technology itself than on whether the surrounding grid, demand and economic conditions allow that flexibility to be expanded profitably.

Infrastructure compatibility is the binding constraint. Although electrolysis is modular and the Zeebrugge site (part of the HyOffWind project) benefits from available industrial land, the grid connection capacity caps how much additional electrolyser power can be installed and operated at high load factors. On the demand side, the evacuation routes are equally limited: the Fluxys gas grid offers only a low-value injection outlet, constrained to roughly 2% blending, and no dedicated hydrogen backbone yet exists for large-volume transport. Both the supply-side connection and the demand-side offtake must therefore be secured before capacity can grow.

Profitability is the second decisive constraint. Flexible operation does improve project economics - aFRR participation lifts profit by about 17 percentage points in the unconstrained case and around 7 points under hourly RFNBO - but this value is expected to erode as more flexible assets enter the balancing market. More fundamentally, overall profitability remains low even when a green premium is applied: the difficulty of competing with fossil-based hydrogen keeps the business case fragile, so additional capacity only pays off where high load factors and bankable premium offtake are assured.

Modularity and economies of scale shape the scaling pathway but cannot override these limits. Electrolysis can be expanded in stack increments rather than as a single large investment, and shared balance-of-plant, engineering and procurement allow some CAPEX dilution as modules are added. However, these gains are demand-validated rather than supply-driven and exhibit diminishing returns: without sustained high utilisation backed by local offtake, additional capacity erodes rather than improves unit economics.

The remaining conditions act as moderate enablers or frictions. Regulation tightens as the asset grows - RFNBO hourly temporal correlation and additionality make PPA structuring progressively more complex, with the move from monthly netting to strict hourly matching lowering the modelled profit index from 87 to 81 - but the rules remain workable. Control-and-communication interfaces and advanced optimisation and EMS software become more important as hourly dispatch across PPA wind, day-ahead trading and aFRR bidding grows in complexity, yet those interfaces are already standardised in Belgium and better tools cannot remove the underlying grid or RFNBO constraints. Continued technological progress in efficiency, stack lifetime and module cost will gradually improve unit economics, while acceptance from nearby industrial and mobility offtakers - still constrained by hydrogen's cost gap - remains a real but easing demand-side condition.

In conclusion, BUC 9 is technically scalable thanks to the modular nature of electrolysis, but the practical limits are set by grid connection capacity and by weak profitability rather than by the technology itself. Expansion is only attractive where additional grid capacity can be contracted and where sufficient high-value hydrogen demand exists to keep load factors and margins high; regulation, control, software and acceptance shape the pathway but are not, on their own, the binding constraints.

Figure 2-13 summarizes how the different boundary conditions influence the scalability potential.

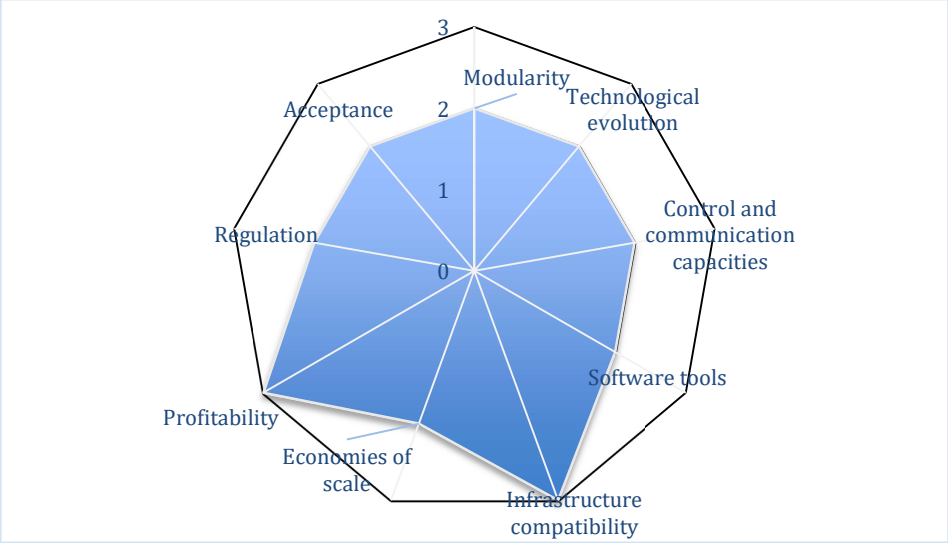


Figure 2-13: Impact of boundary conditions on scalability for BUC 9

2.2.7.3 Impact of boundary conditions on replicability

For replicability, BUC 9 is supported by a high degree of standardisation and interoperability but constrained most by integration and customisation, with business-model design, profitability, regulation, market design and acceptance all playing moderate roles. The concept is conceptually transferable, but it is not a plug-and-play solution.

At the technology and market-interface level, replication is straightforward. PEM electrolysers are built around standardised stack and balance-of-plant modules, and the dispatch optimisation logic is portable to any similar asset. Likewise, the interfaces with the Belgian power markets (day-ahead market and aFRR) and with the Fluxys gas grid follow established protocols common to any electrolyser site in the country. Standardisation and interoperability are therefore essentially solved problems and pose little friction to replication.

The decisive constraint is integration and customisation. Although the individual components are standard, each new site requires substantial site-specific engineering: securing a PPA structured for hourly RFNBO compliance, sizing the grid connection against local congestion, arranging gas-grid injection within blending limits. This combination has to be re-engineered for every location, which is what prevents the concept from being a simple copy-and-paste exercise.

The commercial dimensions reinforce this site-dependence. The business model rests on a specific combination of PPA wind, premium tube-trailer offtake, the gas-grid valve and aFRR participation, and must be rebuilt around local PPA terms, offtake anchors and grid tariffs at each site. Profitability is sensitive to local conditions so two otherwise identical Belgian sites can yield materially different business cases. Market design itself is largely uniform across sites and neither helps nor blocks replication strongly.

Finally, regulation and acceptance condition replication without prohibiting it. RFNBO compliance under RED III applies equally to every Belgian site, but its bite runs through PPA availability: finding a site with a direct renewable connection to obtain exemption from the rules is difficult, PPA offerings are limited. Securing long-term offtake from local industrial or mobility users remains the binding demand-side condition, given hydrogen's persistent cost gap and the absence of a wider pipeline network. Overall, BUC 9 is replicable wherever a well-matched PPA, adequate grid capacity and a credible anchor offtaker can be brought together - the technology transfers easily, but the surrounding integration and commercial conditions determine whether a replicated project is viable.

Figure 2-14 summarizes how the different boundary conditions influence the replicability potential.

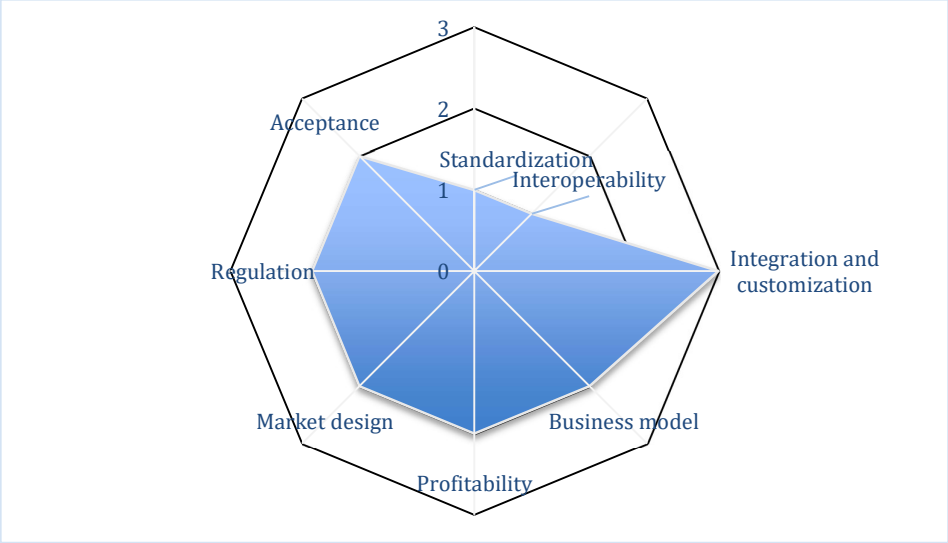


Figure 2-14: Impact of boundary conditions on replicability for BUC 9

2.2.8 BUC 10 - Flexibility provision with a portfolio of EVs

2.2.8.1 General Information

ID	*Name of Business Use Case(s)*
BUC 10	Potential for flexibility provision with a portfolio of EVs
Short description	
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.	

2.2.8.2 Impact of boundary conditions on scalability

The scalability of BUC 10 should be assessed as the growth of a usable EV flexibility portfolio, not as the expansion of a specific data platform. More connected vehicles increase the potential pool of assets, but usable flexibility only exists when charging demand can be shifted without compromising mobility needs. Availability windows, state of charge, driving-energy requirements, preferred state of charge (SoC) ranges, and charging location all determine the real resource. This makes fleet composition a practical scaling constraint. A portfolio with many low-consumption users may expand quickly while adding only limited controllable energy. Vehicles charged away from home, connected briefly, or kept within narrow SoC limits can also contribute less than their number suggests.

Control reliability then determines whether that flexibility can be trusted. Schedules and control actions need timely information on plug-in status, SoC, availability, and user constraints. At small scale, poor data or failed commands may remain isolated issues. At portfolio scale, they can weaken delivery reliability or create synchronized charging patterns that introduce new peaks instead of relieving system stress. Software tools must therefore represent real users and real vehicles. Larger portfolios contain different battery sizes, telemetry quality, charging habits, tariff exposure, and manufacturer constraints. Treating EVs as generic grid-connected

batteries risks overstating flexibility. ReInvent Deliverable 3.4 results show that behavioural and technical constraints materially affect upward flexibility, downward flexibility, consumer costs, and grid interaction [2].

The economic case remains strongest where digital access avoids repeated hardware-heavy smart-charging installations. Once onboarding, data collection, optimization, dispatch, and validation are in place, additional users can be integrated at lower marginal cost. Still, scale only creates value if enough users have shiftable energy and see a benefit from participation. Acceptance is therefore part of the scaling mechanism. Drivers need to understand the offer, agree to share data, accept some charging control, and trust that their mobility needs remain protected. Without sustained consent, the technically available fleet cannot become a dependable flexibility resource. Belgian tariff differences also prevent a single national scale-up logic. Flanders, Brussels, and Wallonia expose users to different tariff structures and regulatory timelines, so dispatch objectives, savings calculations, and user communication need to be adapted regionally.

Figure 2-15 summarizes how the different boundary conditions influence the scalability potential.

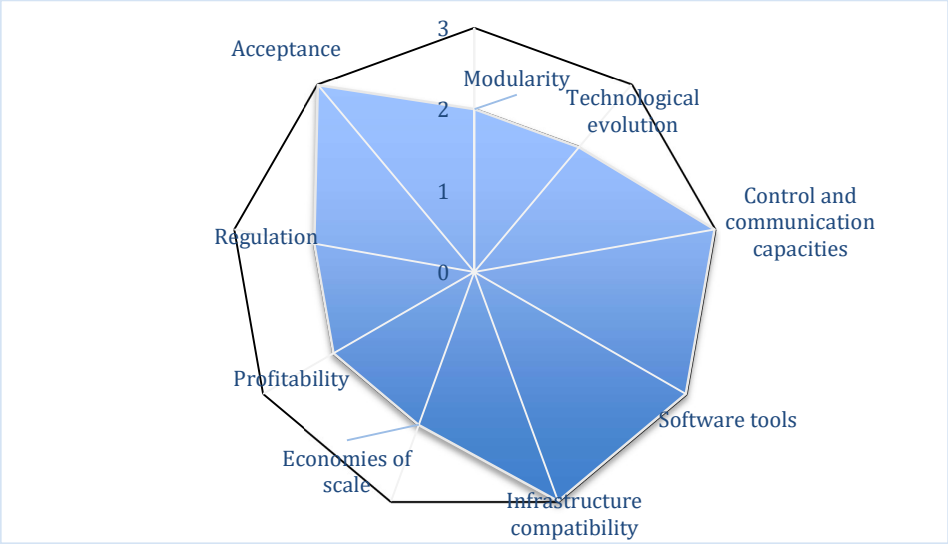


Figure 2-15: Impact of boundary conditions on scalability for BUC 10

2.2.8.3 Impact of boundary conditions on replicability

Replication depends on whether the EV flexibility concept can be reproduced in another fleet, region, or customer segment. The transferable function is the ability to observe charging behaviour, estimate flexibility realistically, control charging where appropriate, validate delivery, and assign value to the result.

The most immediate technical transfer issue is the vehicle interface layer. The original equipment manufacturers (OEMs) differ in exposed data, telemetry quality, update frequency, permissions, and remote-control functionality. A new brand mix can therefore change both integration effort and confidence in the resulting flexibility. Stable and standardized access routes support replication; bespoke connectors or

incomplete OEM support increase operational risk. The commercial arrangement must also be rebuilt around the target context. EV flexibility can involve drivers, fleet managers, employers, electricity suppliers, BRPs, aggregators, charge point operators, and flexibility service providers. The responsibilities for aggregation, imbalance exposure, settlement, market access, and user compensation may shift between deployments. A contract model that works in one setting cannot be assumed to transfer unchanged. Profitability requires the same re-check. Managed charging can reduce consumer costs and improve alignment with PV production, but the benefit depends on charging behaviour, PV availability, tariffs, and available flexibility products. A portfolio with weak price signals or little shiftable demand may not support participation, even if the technical setup works.

Market design and regulation determine which value routes are open. Dynamic tariffs, distribution-grid signals, explicit flexibility products, aggregation rules, baselining, settlement, and multi-location accounting can differ by region or customer segment. Within Belgium, the same controlled charging behaviour may produce different economic outcomes in Flanders, Brussels, and Wallonia.

User acceptance remains the final condition. A replicated portfolio only becomes useful if participants share data, allow managed charging, and stay enrolled long enough for the service provider to rely on the fleet. Replication is strongest where data access is standardized, the vehicle mix provides meaningful shiftable load, market rules create a clear value signal, and users experience managed charging as a practical benefit rather than a loss of control.

Figure 2-16 summarizes how the different boundary conditions influence the replicability potential.

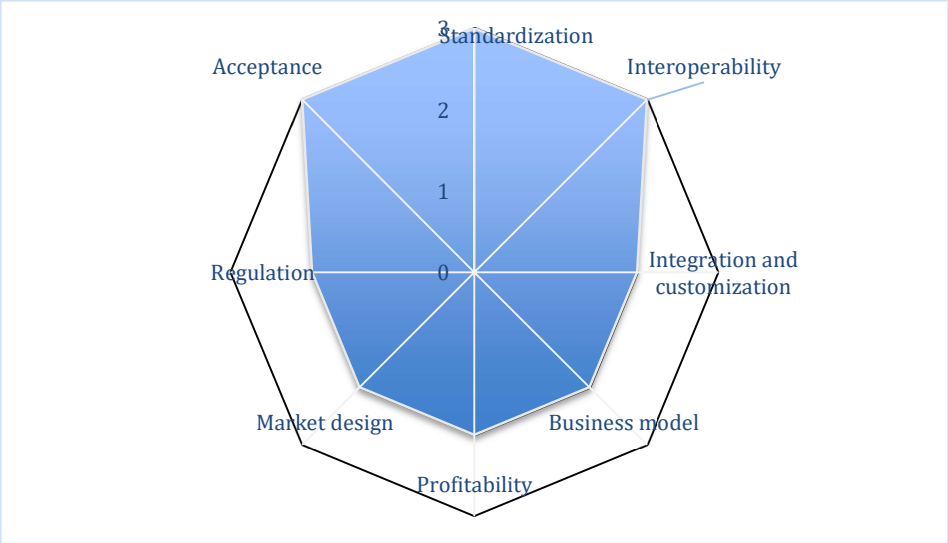


Figure 2-16: Impact of boundary conditions on replicability for BUC 10

2.3 Main insights on scaling and replicability potential

This subsection summarises the main insights from the SRA according to the three key sector-coupling themes addressed in ReInvent: electrification and demand-side flexibility, Power2X (power to gas, liquids and heat), and community energy.

2.3.1 Electrification and demand-side flexibility (DSF)

1.1.1.1 Scalability

Electrification changes the scalability question because it turns everyday end-use demand into a potential system resource. As transport, heating, and distributed storage become increasingly electric, a growing share of consumption can in principle be shifted, coordinated, or temporarily buffered. This creates a broad potential for demand-side flexibility: the resource is not limited to a few large assets, but can emerge from many smaller devices distributed across households, fleets, buildings, and communities.

The first condition for scale is therefore the size and composition of the electrified asset base. More EVs, heat pumps, electric heating systems, and batteries increase the number of possible flexibility sources, but different assets contribute in different ways. EV charging is closely linked to mobility routines and charging location. Heating flexibility is shaped by building characteristics, thermal inertia, buffer capacity, and comfort limits. Battery operation depends on sizing, metering, and the role the battery plays within the local use case. The combined flexibility potential grows when these assets become common, but the contribution of each asset category is shaped by its own physical and operational logic.

A second scaling condition is coordination. At small scale, flexible operation can be optimized around individual benefit, such as lower charging costs, improved PV self-consumption, or reduced exposure to peak tariffs. At larger scale, those individual optimizations interact. If many users respond to the same price signal, EV charging can become synchronized and create new aggregate peaks. If heating flexibility is used beyond appropriate levels, savings may be offset by thermal losses or comfort concerns. Demand-side flexibility therefore becomes more valuable, but also more complex, as it scales and relies on more distributed resources. The relevant question is not only whether devices can respond, but whether their combined response improves system operation.

This increases the importance of realistic modelling and digital control. Flexibility potential can be overstated when assets are treated as generic controllable loads. In practice, charging availability, state-of-charge preferences, mobility needs, building heat demand, comfort requirements, manufacturer limits, data quality, and control reliability all affect what can be delivered. Scalable flexibility requires tools that can capture this diversity, estimate the available resource realistically, and coordinate dispatch without creating unwanted rebound effects.

The economic scaling logic is strongest where flexibility can be enabled through existing device connectivity, smart charging, energy management systems, or software-based coordination rather than repeated hardware-heavy upgrades. Once the main processes for onboarding, data collection, optimization, dispatch, validation, and settlement are in place, additional users or devices can often be added at lower marginal cost. However, this only supports sustained scale-up if the resulting value is visible and sufficiently shared. System-level savings do not automatically translate into user-level willingness to participate.

Overall, electrification creates a large and expanding flexibility pool, while demand-side coordination determines how much of that pool becomes usable. The strongest scalability potential is found where the asset base is broad, the flexible operation is technically reliable, the response is coordinated at portfolio or system level, and the economic benefits are strong enough to support continued participation.

2.3.1.1 Replicability

The replicability of electrification and demand-side flexibility is best understood as a question of translation rather than duplication. The underlying principle can be reused widely: electrified demand can be shifted toward moments that are cheaper, cleaner, or more useful for the electricity system. The exact implementation, however, must be rebuilt around each new setting. A solution designed around one fleet, building stock, tariff structure, or energy community cannot simply be copied elsewhere without checking whether the same sources of flexibility, conditions and value are present.

This makes local context the starting point for replication. A mobility-focused application must account for vehicle model mix, charging locations, driver routines, data availability, and control permissions. A heating-focused application depends more strongly on insulation levels, installed heating technologies, thermal inertia, available buffers, and comfort expectations. A community or portfolio application adds questions around ownership, metering, settlement, and benefit-sharing. These contextual differences shape the amount of flexibility that can be offered and the practical effort needed to make it operational.

Some elements are highly transferable. The logic of using time-varying signals, optimizing controllable demand, protecting user constraints, and validating delivered flexibility can be applied across many use cases. Interoperable data access, stable control interfaces, standardized communication protocols, and common settlement methods can further reduce the work required at each new deployment. Where these elements are present, replication becomes closer to adapting a proven model.

Where they are absent, replication becomes more bespoke. Fragmented data access, inconsistent device control, immature flexibility markets at regional and system level, and regional tariff differences can all change the business case. The same EV, heat pump, or battery may be technically flexible in several locations, but the value of operating it flexibly depends on the surrounding market design. Dynamic retail pricing, capacity tariffs,

supplier or BRP optimization, balancing markets, local flexibility mechanisms, and collective energy arrangements each create different incentives and different operational priorities.

The social dimension also changes from place to place. Users may accept flexible operation for different reasons: lower charging costs, improved use of local PV, comfort-preserving heating optimization, lower community energy costs, or contribution to grid stability. A replicated solution therefore needs a locally credible value proposition, not only a technical control strategy. It must explain what is controlled, what remains protected, who receives the benefit, and how risks are managed.

The conclusion for replicability is therefore positive but conditional. Electrification and demand-side flexibility can be reproduced across many regions and customer groups because the core principle is general. The implementation must still be adapted to local asset characteristics, interoperability conditions, tariff structures, market access, data availability, settlement rules, and user motivations. Replication is strongest where these local conditions allow the flexibility principle to be transferred without rebuilding the entire technical and commercial framework from the ground up.

2.3.2 Collective energy sharing

2.3.2.1 Scalability

When analysing energy sharing use cases, several common boundary conditions influencing scalability can be identified.

Energy sharing activities can benefit from economies of scale, which improve their economic performance as the number of participants and assets increases. Indeed, energy sharing schemes often involve significant fixed costs related to contractual arrangements, regulatory compliance, administrative processes, and technical coordination. Expanding the community allows these costs to be distributed among a larger number of participants, improving overall profitability and reducing the cost per member. At the same time, a larger community increases opportunities to match local generation with demand, thereby enhancing self-consumption and maximizing the value of shared energy.

Furthermore, energy sharing activities are generally highly modular, allowing communities to grow progressively through the integration of additional members, consumers, and energy assets. Digital infrastructure, such as Energy Management Systems (EMS), can facilitate this expansion by enabling the integration of new participants and assets without requiring a complete redesign of the system.

Despite these enablers, several factors may limit the scalability of energy sharing activities. First, the expansion of energy communities can lead to increased governance complexity. As the number of participants grows, coordination, communication, and collective decision-making processes become more challenging,

potentially increasing administrative burdens and slowing down decision-making processes. This may limit the optimal size of a community.

Moreover, technical infrastructure constraints can restrict further growth. The integration of additional renewable generation assets may be limited by available grid capacity, while thermal energy sharing schemes may face constraints related to network capacity or available storage flexibility.

Finally, even when the existing infrastructure can accommodate further expansion, scaling through joint investment in additional assets depends on the willingness and financial capacity of participants. The development of larger renewable generation and storage assets requires sufficient investment capacity and acceptance from existing and potential members, which may become a limiting factor as the scale and complexity of projects increase.

Overall, the scalability of energy sharing activities is primarily determined by their ability to combine economic viability, modular system design, efficient governance, stakeholder engagement, and compatible technical infrastructure. While these activities are inherently well suited to gradual expansion, their long-term growth ultimately depends on balancing increasing operational complexity with the economic benefits generated by larger communities.

2.3.2.2 Replicability

When analysing the replicability of energy sharing activities, similarly to scalability, we can recognize that they are governed by a common set of boundary conditions, although their relative importance varies depending on the specific application. The most influential boundary condition is the regulatory and market framework. The successful transfer of an energy sharing concept to a new location/region depends on the compatibility of energy sharing regulations, tariff structures, permitting procedures and market rules. Differences in these frameworks often require substantial adaptations of the business model and may significantly affect its economic viability.

Beyond regulation, technical and site-specific conditions play a fundamental role in determining whether a project can be successfully replicated. Suitable grid capacity, demand characteristics and storage opportunities are essential prerequisites for deployment.

The replicability of energy sharing schemes further relies on the ability to adapt governance structures and contractual arrangements to the local context. Ownership models, participant roles, settlement mechanisms, and benefit-sharing rules must be tailored to the characteristics and expectations of local stakeholders, ensuring a transparent and equitable distribution of costs, revenues, and responsibilities.

Similarly, stakeholder acceptance and trust emerge as critical enablers of replicability across all Business Use Cases. Successful deployment requires the support of companies, citizens or municipalities who must perceive the business model as fair, understandable, and beneficial.

The analysis also highlights that economic viability remains a prerequisite for replication. The business model must remain profitable under local market conditions, with sufficient energy exchange volumes to offset the fixed costs associated with project development, operation, and administration. Variations in tariffs and revenue streams may therefore substantially influence the feasibility of replication.

Taken together, the replicability of energy sharing activities depends on the capacity to balance standardization and local adaptation. While common enabling conditions, such as supportive regulatory frameworks, digital infrastructures, economic viability, and stakeholder engagement, are essential across different contexts, successful replication requires tailoring the business model to local technical, economic, and organizational realities. Therefore, replicability should not be understood as a direct transfer of an existing model, but rather as an adaptive process in which core principles are maintained while implementation approaches are adjusted to the specific conditions of each new context.

2.3.3 Clean molecules and Power2X

2.3.3.1 Scalability

The scalability of hydrogen value chains is influenced by the interaction between technical, economic and systemic factors. While individual projects may face different constraints depending on their configuration and target market, several recurring boundary conditions can be identified across use cases. These conditions determine both the potential for expansion and the long-term viability of larger-scale hydrogen deployment.

Infrastructure compatibility represents the most influential boundary condition. Scaling hydrogen systems requires sufficient renewable electricity generation, adequate grid connection capacity, hydrogen transport and storage infrastructure, and access to reliable local demand. Since hydrogen transport remains expensive in the absence of dedicated pipeline networks, projects generally need to be located close to industrial or mobility off-takers. Consequently, the availability of suitable infrastructure often determines the maximum feasible scale of deployment.

Closely linked to infrastructure is profitability, which ultimately governs whether additional capacity can be economically justified. Although larger installations can benefit from economies of scale through shared engineering, balance-of-plant equipment and procurement, these benefits only materialise when high utilisation rates and stable hydrogen demand can be maintained. Otherwise, increasing capacity may lead to underutilised assets and deteriorating project economics rather than improved competitiveness.

The regulatory framework also becomes increasingly important as projects expand. Permitting procedures, renewable hydrogen certification requirements, safety regulations and storage obligations generally become more complex with increasing project size, resulting in longer development timelines, higher compliance costs and greater investment uncertainty. Although these regulations do not necessarily prevent scaling, they can significantly slow down project development.

Stakeholder acceptance and market maturity constitute another important boundary condition. The scalability of hydrogen projects depends on industries, transport operators and other consumers being willing to adopt green hydrogen despite its current cost premium compared with fossil-based alternatives. Without sufficient market uptake, the additional production capacity required for larger projects cannot be economically sustained.

Finally, technological evolution and digital optimisation act primarily as scalability enablers. Continuous improvements in electrolyser efficiency, durability and manufacturing costs progressively strengthen the business case over time. Likewise, advanced energy management systems, optimisation software and communication platforms facilitate the increasingly complex coordination of renewable electricity, hydrogen production and electricity market participation as projects grow. However, these technological improvements cannot compensate for insufficient infrastructure, limited demand or weak project economics.

To conclude, the scalability of hydrogen systems depends on the alignment of multiple conditions rather than on the availability of the technology alone. Expanding these systems requires the simultaneous development of adequate renewable electricity supply, hydrogen infrastructure, viable business models, supportive regulatory frameworks and sufficient market uptake. While technological progress and digital optimisation can improve operational performance, large-scale deployment will ultimately depend on the creation of an ecosystem capable of supporting reliable hydrogen production, distribution and consumption. In the transition period towards the development of a mature hydrogen value chain, project design strategies that limit exposure to uncertainty can facilitate deployment. For instance, adopting modular expansion approaches, as demonstrated in BUC 9, can enable capacity additions to be aligned progressively with infrastructure availability and market demand.

2.3.3.2 Replicability

Replicating hydrogen-based projects across different locations requires more than the transfer of technical solutions. Each project results from a specific combination of energy resources, infrastructure availability, market opportunities, regulatory conditions and stakeholder commitments. Analysing replicability therefore requires identifying which elements can be standardised and reproduced, and which elements need to be redesigned to match local circumstances.

A first key boundary condition is infrastructure compatibility and integration. While core technologies such as electrolysers, renewable generation assets and associated control systems are increasingly standardised, their deployment depends on site-specific conditions. Each new project requires the alignment of renewable electricity availability, grid connection capacity, hydrogen storage and transport options, and proximity to suitable off-takers. In particular, the absence of hydrogen pipelines means that many projects remain strongly dependent on local demand and require a close match between production capacity and consumption opportunities. Consequently, replication cannot be achieved through a simple duplication of an existing project but requires significant integration and customization for each location.

The economic viability and business model represent another critical boundary condition. Although technical solutions can often be transferred between locations, profitability depends strongly on local parameters, including renewable electricity costs, grid tariffs, hydrogen certification opportunities and the presence of reliable long-term off-takers. The current cost gap between green hydrogen and fossil alternatives remains a major challenge, reducing the attractiveness and bankability of replicated projects. As a result, successful replication requires the reconstruction of a viable business model adapted to local market conditions rather than the direct transfer of an existing approach.

Regulatory conditions also strongly influence replication potential. Renewable hydrogen certification requirements, permitting procedures, safety regulations and land-use constraints can significantly affect project feasibility and development timelines. While regulatory frameworks such as RFNBO (renewable fuel of non-biological origin) requirements provide a common basis for deployment, their practical implications depend on project configuration, renewable electricity sourcing and operational choices. Therefore, compliance strategies must generally be reassessed for each new location.

Market acceptance and stakeholder engagement constitute an additional common boundary condition. Replication requires the presence of committed hydrogen consumers, such as industrial users or transport operators, willing to adopt hydrogen despite its current cost disadvantage and the limited maturity of associated markets. Securing long-term demand is particularly challenging in applications where users face high investment costs, technological uncertainty or competition from more established alternatives. Without strong local stakeholders and anchor off-takers, replicated projects face significant risks of low utilization and weak economic performance.

Finally, standardization, interoperability and technological progress facilitate replication by reducing technical complexity. Standardized components, established market interfaces and improved optimization rftools can accelerate project development and reduce engineering efforts. However, these elements mainly act as enablers rather than decisive factors, as they cannot overcome fundamental limitations related to infrastructure availability, profitability or market maturity.

In practice, hydrogen projects are unlikely to be replicated through a fully standardised model. Instead, future deployments will most likely rely on the reuse of proven technological components, operational approaches and organisational models, combined with significant local adaptation. The replication potential of these projects will therefore depend on the ability to identify suitable locations where the required technical, economic and institutional conditions can be assembled.

3 Sector-coupling from the system perspective

Various energy and market models have been further developed in the ReInvent project. Each model addresses sector-coupling from a specific scope. Together, they provide complementary insights on the impact of sector-coupling for the Belgian energy system. This chapter zooms in on these complementary insights from different modelling tools, addressing different aspects of sector-coupling. The first section analyses the value of sector-coupling in providing demand side flexibility to the power system, comparing heat demand flexibility in buildings to EV charging flexibility. Second, main insights are summarized on the role of power2X and clean molecules import. Third, an assessment is provided on improved temporal coordination of multi-energy markets to facilitate the economic utilization of cross-carrier flexibility.

3.1 Analyzing future energy demands and flexibility options

Main Model: TIMES-BE

TIMES-BE is a bottom-up, technology-rich optimization model of the Belgian energy system, built on the TIMES (The Integrated MARKAL-EFOM System) modelling framework. It determines the least-cost configuration of the energy system over a multi-decade horizon by simultaneously optimizing investment and dispatch decisions across the full value chain, from primary resource supply to final energy service demand, subject to technical, policy, and resource constraints. A distinctive advantage of TIMES lies in its ability to optimize simultaneously across multiple milestone years rather than a single snapshot in time. This intertemporal optimization allows the model to identify the entire cost-optimal pathway of investment and technology deployment needed to reach a given environmental goal, such as climate neutrality, capturing how early decisions constrain or enable later ones, and ensuring that near-term choices remain consistent with long-term targets. A further key strength of TIMES-BE lies in its sectoral granularity: final energy demand is not treated as a single aggregate, but is disaggregated by sector (residential, commercial, industry, and transport) and, within each sector, further broken down by end-use and characterized in energy service demand terms, making the final energy consumption an output of the model rather than an assumption on the input side.

TIMES-BE is recurrently applied[1] under PATHS2050: a VITO/EnergyVille energy-system modelling initiative engaging main Belgian energy intensive companies to explore how Belgium can become climate-neutral by 2050 while keeping the transition affordable and economically resilient [7]. Recent analyses thereby consider three main storylines, differing in the level of offshore wind potential, biomass availability, nuclear investment possibilities, CCUS potential and energy commodity import costs (Table 3-1).

[1] Note that a development branch of TIMES-BE version has been applied in ReInvent, given the project focus on methodological development. This can result in discrepancies with the TIMES-BE main results reported on the PATHS2050 website.

Table 3-1: Main assumptions underlying PATHS2050 storylines [7]

	ROTORS	REACTORS	IMPORTS
Offshore wind potential: *inside* Belgian territorial waters	8 GW	8 GW	8 GW
Offshore wind potential: *outside* Belgian territorial waters	16 GW	6 GW	6 GW
Onshore wind potential	20 GW	10 GW	10 GW
Biomass, - gas and – methane availability	43 TWh/a by 2050	29 TWh/a by 2050	43 TWh/a by 2050
Nuclear investment	20-year extension of 2GW up to 2045 SMR investment max. 4GW from 2045 onwards	20-year extension of 2GW up to 2045 1,6 GW Gen III+ capacity fixed from 2040 onwards SMR investment from 2045 onwards, with max. 8 GW total new capacity	10-year extension of 2GW up to 2035
CCUS availability	Available from 2030 onwards Access limited to 10Mt/a	Available from 2030 onwards Unlimited access	Available from 2030 onwards Unlimited access
Clean molecules import price[2]	Default: hydrogen import at 135 €/MWh (~4 €/kg) by 2050	Default: hydrogen import at 135 €/MWh (~4 €/kg) by 2050	Low: hydrogen import at 80 €/MWh (~2.4 €/kg) by 2050

3.1.1 Flexibility in EV Charging and Heating Demand

Demand-side flexibility is one of the key sources of sector coupling, since it determines how and when different end-use sectors interact with the power system rather than drawing from it independently. Building on its granular demand representation, this modelling track focuses on two major sources of demand-side flexibility already present, or newly introduced, in TIMES-BE: **flexible EV charging** and **heat flexibility in buildings**.

For transport, the representation of flexible EV charging and discharging profiles was already relatively mature in TIMES-BE [8]. The model explicitly represents the charging infrastructure available to passenger cars,

[2] For all clean molecules prices, see https://perspective2050.energyville.be/results/main-edition-2025/assumptions

including Smart Chargers and Vehicle-to-Home/Building/Grid (V2H/B/G) solutions, allowing flexible charging to reduce peak power demand, lower stationary storage needs, and support renewable integration (Figure 3-1).

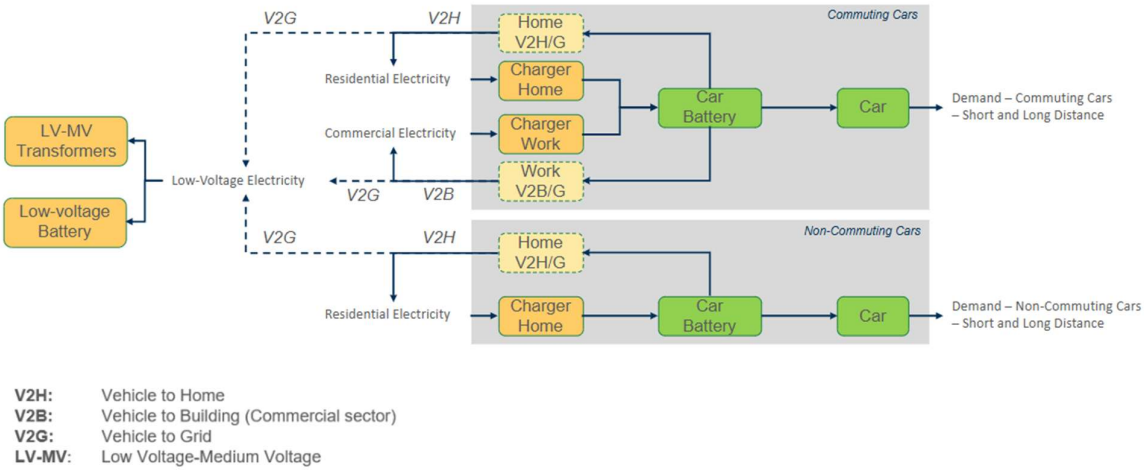


Figure 3-1: Design of the charging infrastructure in TIMES-BE for passenger cars [8]

Heating demand flexibility in buildings was added under ReInvent (see [9] for details). The space and water heating structures in TIMES-BE have been revised to explicitly represent flexibility for technologies relying on time-varying commodities, namely heat pumps, electric heaters, and district heating. For space heating, thermal inertia of the building envelope was represented as a storage technology, introducing a new commodity 'intermediate heat' (Figure 3-2). This explicit buffer-inertia link allows the model to shift space heating load across the day while respecting comfort constraints, using either storage or the building's own thermal mass as flexibility sources. The water heating structure follows a similar logic but omits the thermal inertia component, since hot water demand has no equivalent building-envelope storage effect; instead, it relies solely on an intraday, building type-specific buffer.

To support this new flexibility structure, the underlying space heating demand profiles have also been revised, to better isolate heating service demand from the thermal inertia effects of the building envelope. To this end, the original gas-consumption-based approach was updated towards one based on weather and building statistics available on Renewables.ninja[3]. This resulted in heating demand profiles that are smoother and less peaked than the ones based on gas consumption data.

[3] https://www.renewables.ninja/

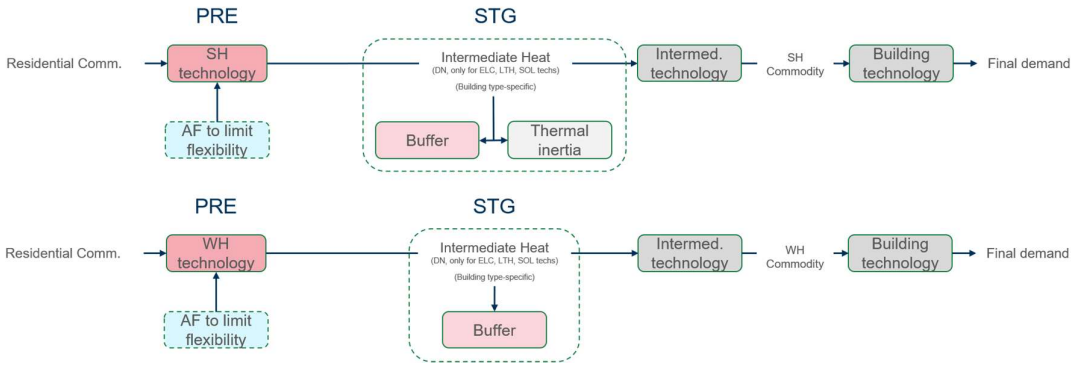


Figure 3-2: Design of the structure for heating flexibility in TIMES-BE

3.1.2 Uptake of demand-side flexibility

The revised modelling structure produces differentiated results on how flexibility technologies are adopted once made available in the model. We distinguish three flexibility levels as follows:

- Full flexibility: all flexibility options enabled[4]
- No flexibility: all flexibility options disabled
- Partial flexibility: only specific flexibility options enabled, i.e. water heating buffers for heating flexibility and flexible charging (without V2H/B/G) for EV charging flexibility

Demand side flexibility technologies are largely 'no-regret' from a techno-economic perspective, since they provide high value to the system at low cost. This implies technology uptake is often close to the maximum potential as specified in the model (Table 3-2 and Table 3-3). Water heating buffers, for example, prove highly attractive, reaching the full utilization of their maximum potential in every scenario where they are enabled. Similarly, the uptake of flexible EV charging reaches close to full utilization once enabled, as the surplus cost of charging assets is easily outweighed by the system cost reductions for other technologies (e.g. batteries).

Yet, techno-economic uptake barriers do apply. Thermal inertia in buildings, for example, is exploited moderately, at around one third of its full potential, as using thermal-inertia flexibility goes to the cost of increased thermal losses. Space heating buffers are generally not selected in any scenario, since space heating buffers remain too costly to compete. These adoption patterns also interact with building insulation choices: optimal insulation levels are found to be significantly lower when space-heating flexibility is available, since the ability to shift demand during critical hours reduces overall heating costs and weakens the economic case for additional envelope investment. Similarly, the uptake of two-way flexible charging (vehicle to home, building or

[4] Under full heating flexibility, heating technologies can operate in a flexible manner, but within a range of plus 50% and minus 50% of the baseline heating demand.

grid) is not exploited to the full extent. An uptake level of roughly 20% would be cost-optimal; the point at which system benefits saturate in comparison to the additional cost of compatible charging infrastructure.

Table 3-2: Uptake of demand side flexibility technologies for space and water heating (WH = water heating, SH = space heating) under the full sensitivity range from no to full flexibility potential. All scenarios based on the ROTORS story

	Heating Techs [GW]		Insul. [Mm2]	Heat Flex Technologies [GW]			Heat Flex [%]		
	Total (WH)	Total (SH)	Total (SH)	Buffers (WH)	Thermal Inertia	Buffers (SH)	Buffers (WH)	Thermal Inertia	Buffers (SH)
Full flexibility	9.0	46.6	316.5	8.8	15.7	0.0	98%	34%	0%
Partial flexibility	8.8	62.2	666.0	8.7	0.0	0.0	99%	0%	0%
No flexibility	8.1	64.1	641.4	0.0	0.0	0.0	0%	0%	0%

Table 3-3: Uptake of demand side flexibility technologies for EV charging under the full sensitivity range from no to full flexibility potential. All scenarios based on the ROTORS story

	EV chargers capacity [GW]				EV Flex [%]	
	Unflex	Flex	Flex + V2H/B/G	Total	Flex	Flex + V2H/B/G
Full flexibility	0.1	13.8	3.3	17.2	100%	19%
Partial flexibility	0.2	11.0	0.0	11.3	98%	0%
No flexibility	11.3	0.0	0.0	11.3	0%	0%

3.1.3 System Cost Savings

Beyond technology adoption patterns, flexibility also delivers measurable system-wide cost savings. Regarding heat flexibility, Figure 3-3 compares the fully flexible scenario (i.e. full flexibility on both space and water heating) against the no-flexibility scenario for each PATHS2050 storyline in terms of undiscounted annualized system costs. The comparison shows that heat flexibility – under the relaxed flexibility constraints chosen in the model - could unlock savings ranging from 2.5 to 5 B€/year across the milestone years analysed, growing from roughly 1.8-2.3 B€/year in 2030, to 3.2-3.8 B€/year in 2040, and reaching 5.3-6 B€/year by 2050, or close to 1% of Belgian GDP. Most of these savings stem from lower investment needs in insulation and heating technologies, as flexible operation may lower the energy costs for heating buildings by shifting to periods of low electricity prices. This, in turn, could lower the cost-optimal level of building insulation. In 2030 and 2050, however, roughly half of the savings also originate from the supply side. Supply-side system-cost savings are driven by reduced imports of fossil fuels and clean molecules ('Other Import/Export' in Figure 3-3), and – mostly under the IMPORTS and REACTORS storylines - lower requirements for dispatchable capacity and grid investments.

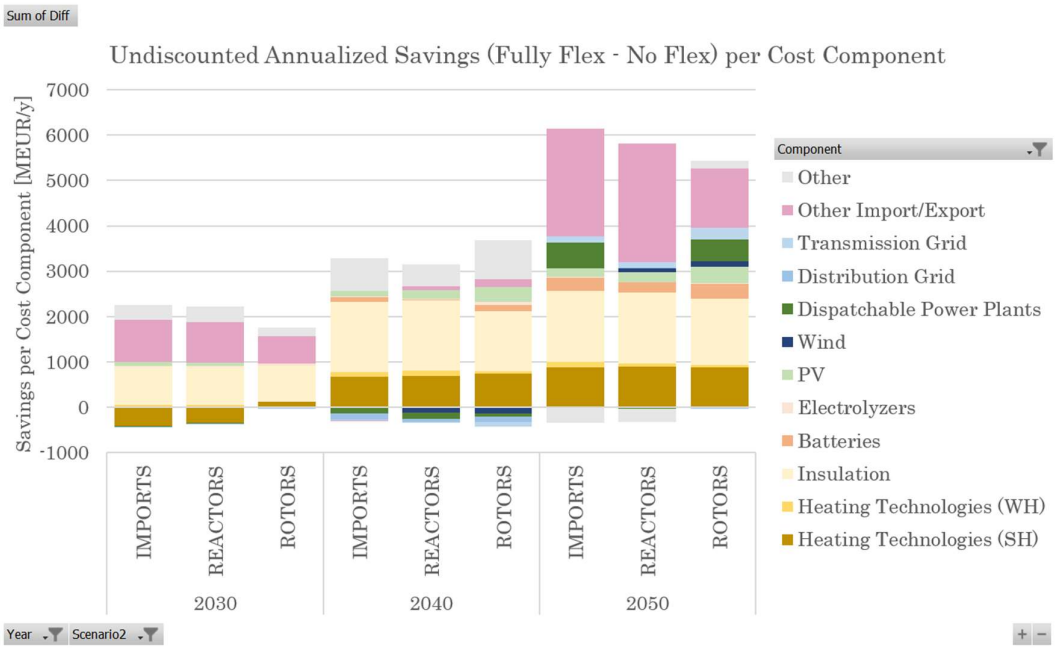


Figure 3-3: Undiscounted annualized savings for heat flexibility (system cost difference between fully flexible scenario, and no flex one, for each storyline), by cost component

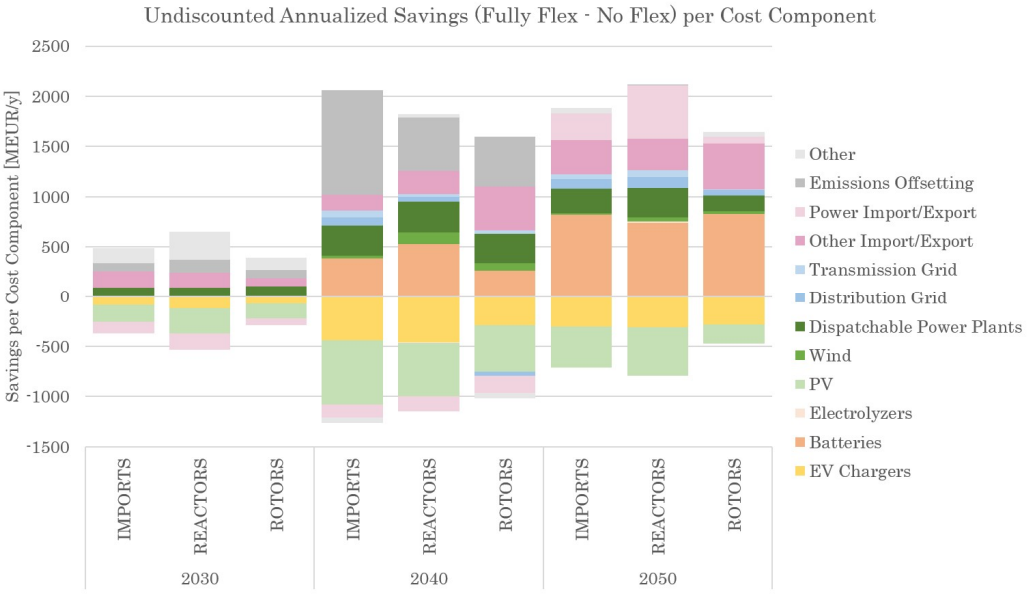


Figure 3-4: Undiscounted annualized savings for EV flexibility (system cost difference between fully flexible scenario, and no flex one, for each storyline), by cost component [8].

In comparison with EV flexibility (Figure 3-4), we find the total net heat flexibility saving potential to be significantly higher, and for different cost components. Whereas savings from EV flexibility are attributed mostly to reduced battery investment, heating flexibility contributes strongly to a more efficient heating system, with at the same time less insulation needs and lower heating costs. Moreover, EV charging flexibility enables PV integration, while with space heating flexibility less PV investment is needed. This suggests EV charging flex is better suited to shift charging loads to day-time periods (e.g. with flexible office charging), while space heating flexibility offers a more general shift to periods of low electricity prices, including during night-time periods.

3.2 Analysing the role of Power2X and import

3.2.1 What drives hydrogen demand?

Main Model: TIMES-BE

In PATHS2050 [7], electrification is considered the backbone of the energy transition, particularly for transport, buildings and other low-temperature heating needs that are relatively easy to electrify. Yet, clean molecules are essential for a climate-neutral Belgian energy system, to fill the 'hard-to-electrify' gap. Hydrogen and derivatives such as ammonia, methanol, e-methane and e-kerosene are particularly important for high-temperature industry, chemical feedstocks, aviation and shipping. In the recent PATHS2050 deep-dive on Molecules [10], a distinction is made between different types of Clean Molecules (Figure 3-5). Clean molecules first encompass the renewable molecules, biofuels and biogases on the one hand, and Renewable Fuels of Non-Biological Origin (RFNBOs) on the other. The latter typically includes green hydrogen produced via renewable electricity and electrolysis, and its derivatives (e.g. ammonia, kerosene, methane, methanol). Not renewable, yet low-carbon molecules include hydrogen (and its derivatives) based on nuclear electricity ('pink') and natural gas with CCS ('blue'). The distinction is relevant since from a cost-optimization perspective – and in a country like Belgium – domestic production of low carbon molecules is more viable than the production of RFNBOs.

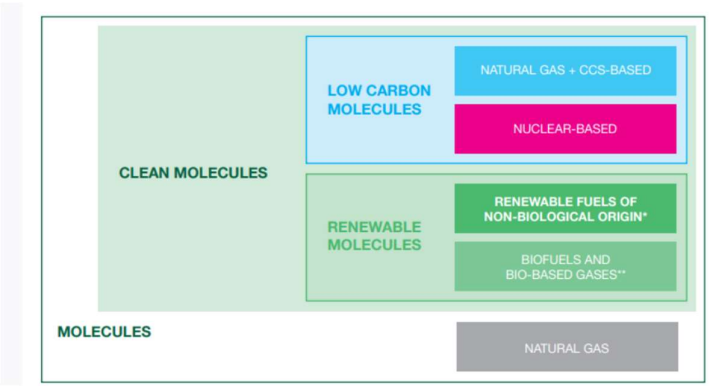


Figure 3-5:Categorization of (Clean) Molecules [10]

Belgium's supply of clean molecules is expected to rely heavily on imports, more than power-to-X, particularly to meet the growing demand for decarbonized international transport fuels. Domestic production of green hydrogen via electrolysis powered by renewable energy is expected to be small, due to limited cost competitiveness. However, under certain conditions domestic production can become attractive. In the PATHS ROTORS scenario, for example, domestic hydrogen production plays a relatively large role with some 5 TWh[5] of electrolysis-based hydrogen in 2050 (Figure 3-6). Main drivers include ample access to affordable electricity and a limit on CO_2 storage (max 10 Mta, Table 3-1). The latter drives a significant yearly hydrogen demand of some 11 TWh for methanol synthesis, which in turn is used as a feedstock for plastics and for international transport. Yet, the largest share of hydrogen demand above is covered by pipeline import, as a more cost-effective option.

A further potentially significant driver is relaxing the regulatory constraints on green hydrogen supply that – under current EU regulation – requires that 60% of hydrogen used in industry, at Member-State level, be supplied as RFNBOs by 2035. This requirement de facto constrains domestic hydrogen production, as it needs to compete with green hydrogen produced cheaper elsewhere. Relaxing this requirement – as applied under the REACTORS storyline – drives domestic blue hydrogen production based on natural gas with CCS (Table 3-7). In this case, domestic hydrogen production would outcompete imported hydrogen although still significant volumes of clean molecules import would be needed to meet international transport demand.

[5] In addition, hydrogen is also produced domestically as a by-product in industrial processes such as refining and chlorine production, contributing in all scenarios up to 6 TWh to the national hydrogen supply.

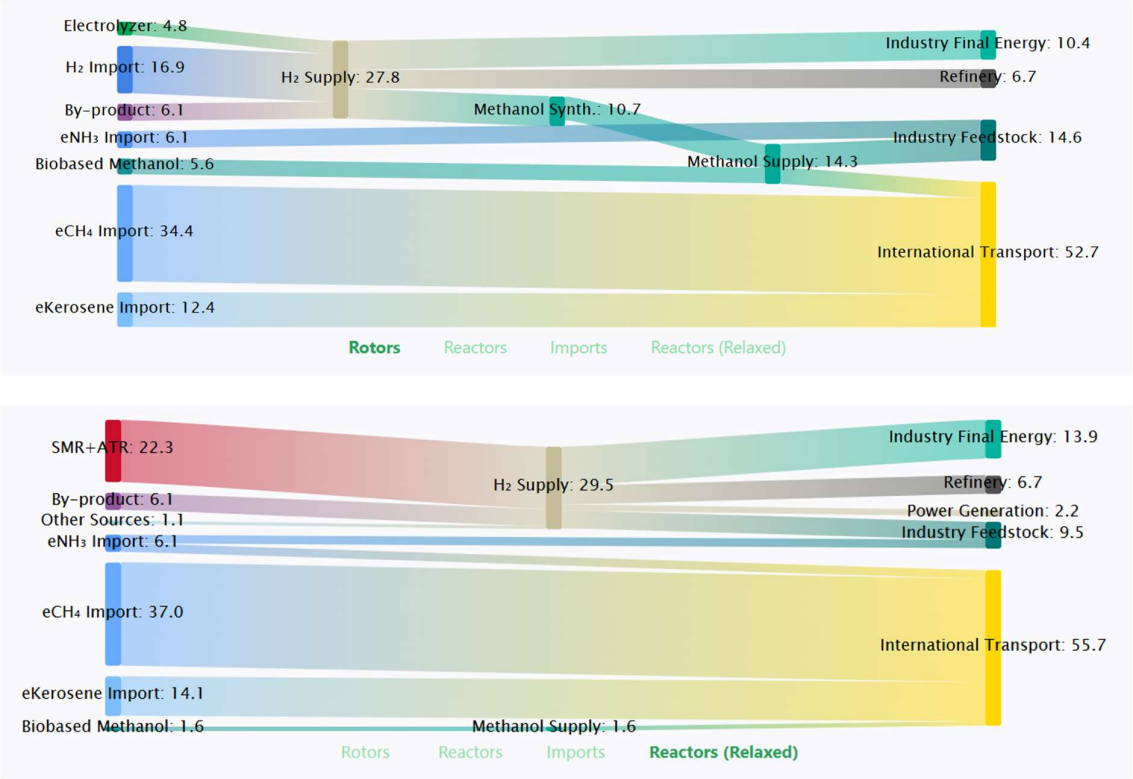


Figure 3-6: Molecules flows (TWh) from supply sources to end-use demand in 2050 for the relatively hydrogen rich scenarios ROTORS and REACTORS with relaxed hydrogen regulatory requirements

3.2.2 Representation of energy supply chains and infrastructures

Main Model: North-Sea Integration Model (NSIM)

The North Sea Integration Model (NSIM), developed by Fluxys, is a multi-energy optimization model designed to assess the role of integrated energy infrastructures in achieving a carbon-neutral energy system. The model simultaneously optimizes investments and operation across multiple energy carriers in order to supply a given demand scenario. The modelled energy carriers include electricity, methane, hydrogen, ammonia, methanol, oil derivatives and CO_2 transport networks. NSIM covers Belgium and nine neighbouring North-West European countries, allowing the representation of cross-border energy exchanges, offshore renewable resources, hydrogen production pathways, storage facilities and import routes. NSIM combines hourly operational modelling over a whole year with long-term infrastructure optimization to identify cost-efficient system configurations under climate neutrality constraints.

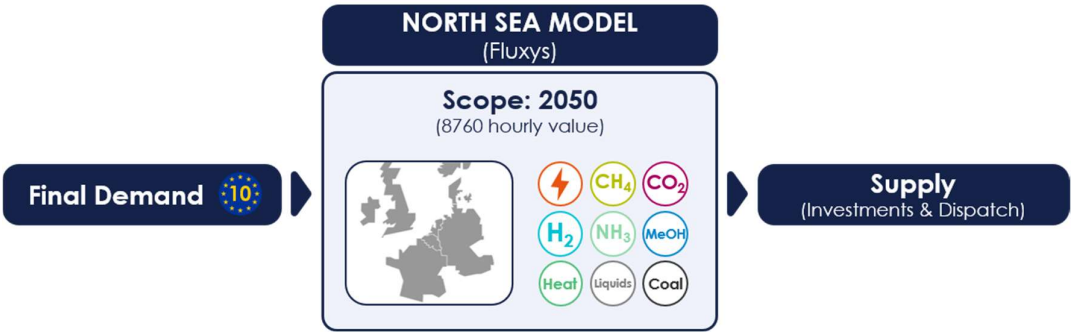


Figure 3-7: Schematic representation of the NSIM modelling framework

A key strength of NSIM is its detailed representation of energy supply chains and infrastructures. Unlike models primarily focused on energy demand and technology uptake, NSIM explicitly captures the interactions between offshore wind development, electricity networks, hydrogen production, hydrogen transport infrastructure, CO_2 transport and storage, and international energy trade. This enables a comprehensive assessment of how electricity and molecules can jointly contribute to the decarbonisation of the energy system.

The analyses performed with NSIM highlight the systemic role of Power-to-Gas as an essential enabler of deep decarbonisation. The results show that hydrogen provides flexibility between sectors by connecting renewable electricity production with industry, transport and energy imports, while also offering opportunities for large-scale and long-duration energy storage. Analyses demonstrate that integrated planning of electricity, hydrogen and CO_2 infrastructures can reduce overall system costs and facilitate the integration of large volumes of offshore renewable energy (for details see [2]).

NSIM is highly complementary to energy system planning models like TIMES-BE. While TIMES-BE provides a detailed representation of the Belgian energy demand sectors and identifies cost-optimal technology pathways for the energy transition, NSIM offers a much more detailed representation of the supply side, including international infrastructure development, cross-border energy exchanges, offshore energy hubs and hydrogen supply chains. TIMES-BE helps determine the future demand for hydrogen and renewable fuels within Belgium, whereas NSIM assesses how these energy carriers can be produced, transported, imported and integrated into the broader North-West European energy system. Together, the two models provide a comprehensive assessment of the role of Power-to-Gas by linking detailed national demand projections with infrastructure and supply-chain considerations at regional scale.

3.2.3 Impact of European hydrogen infrastructure on the Belgian energy system

Main Model: POMMES-EU

POMMES is a Python modelling framework for multi-horizon planning and operation of multi-energy systems under a cost-minimization objective. It is modular in both geographical scope and temporal granularity. On this basis, a POMMES-EU model instance was built coupling the European electricity and hydrogen system towards 2050. Results below come from a single-horizon 2050 run, with hourly operations, covering 27 countries so that cross-border electricity and hydrogen exchanges are captured. Capacity expansion is bounded for (mostly renewables, nuclear and hydrogen underground storage) by technology-specific potentials (mostly based on TYNDP2024/PEMMDB assumptions) while methane reforming, other dispatchable capacity and batteries may expand freely. Belgian demands and renewable potentials were adapted to match PATHS2050 assumptions, keeping the results comparable with the TIMES-BE and Integration analyses of this report. Full assumptions are documented in [2].

Three European infrastructure scenarios are compared. ISO has no hydrogen backbone and therefore no underground storage, no extra-European imports, and SMR+CCS limited by TYNDP2024 carbon-capture assumptions. EHB adds the hydrogen backbone and underground storage and releases the CCS cap but still excludes extra-European imports. EHB+I additionally allows extra-European imports, with volumes optimized by the model. Because Belgian hydrogen demand in 2050 is highly uncertain (32 TWh in the PATHS2050 ROTORS scenario[6] against about 96 TWh in the TYNDP2024 Distributed Energy scenario) the reference demand was scaled by two and three in each scenario. These Belgian variations barely affect European-wide results and are therefore examined at Belgian level only.

The hydrogen demand scenario used here is the PATHS Main Edition 2025 ROTORS scenario, time horizon 2050, as adopted for the combined model analysis (Section 4.2). Its 32 TWh comprises 7.3 TWh of industrial final energy, 6.7 TWh for refineries and petrochemicals (the full hydrogen requirement, not netted for by-product supply) and 3.3 TWh of ammonia for international maritime bunkers, together with 8.6 TWh of methanol and 6.1 TWh of imported ammonia reported under the TYNDP hydrogen category. TYNDP2024's Distributed Energy figure is dominated by international shipping, 45 of its 96 TWh attributed to transport. Excluding bunkering from both datasets narrows the gap from a factor of three to roughly 1.8, so the headline difference is largely an artefact of how bunkering is attributed rather than of industrial hydrogen ambition. The two sources also differ in accounting boundary: the most recent ROTORS scenario (Figure 3-6) shows a single international transport node of 52.7 TWh, met almost entirely by imported e-molecules — 34.4 TWh e-methane, 12.4 TWh e-kerosene, some 5.9 TWh methanol — of which only 3.3 TWh surfaces as Belgian hydrogen demand. TYNDP2024 instead

[6] PATHS Main Edition 2025. Following TYNDP2024 methodology, this number includes final energy and non-energy consumption of ammonia and methanol

books international shipping fuel, largely ammonia, as domestic demand, which is why 44.7 of its 96 TWh sits in that category.

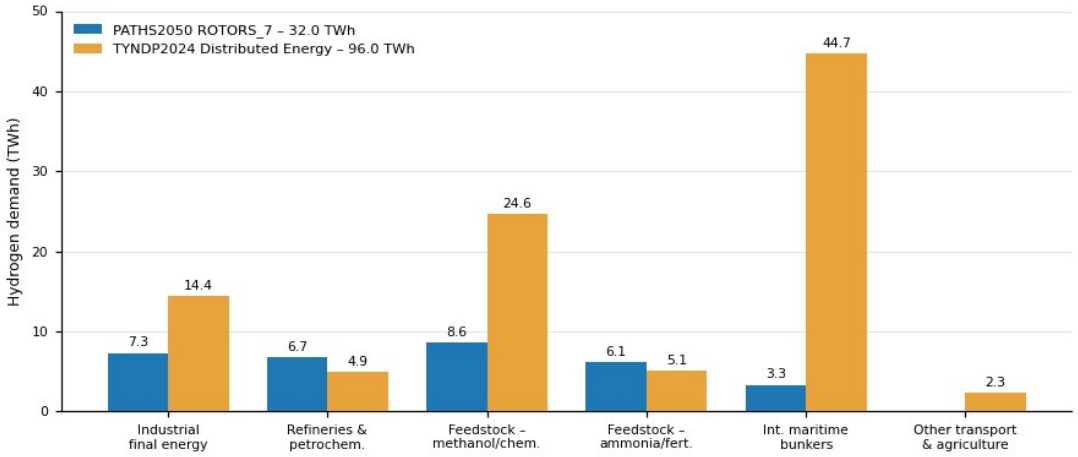


Figure 3-8: Hydrogen demand (inc. ammonia and methanol) by sector in Belgium in 2050 PATHS2050 ROTORS (32 TWh) compared with the TYNDP2024 Distributed Energy scenario (96 TWh). Excluding international maritime bunkers, the two datasets differ by a factor of about 1.8 (28.7 vs 51.3 TWh).

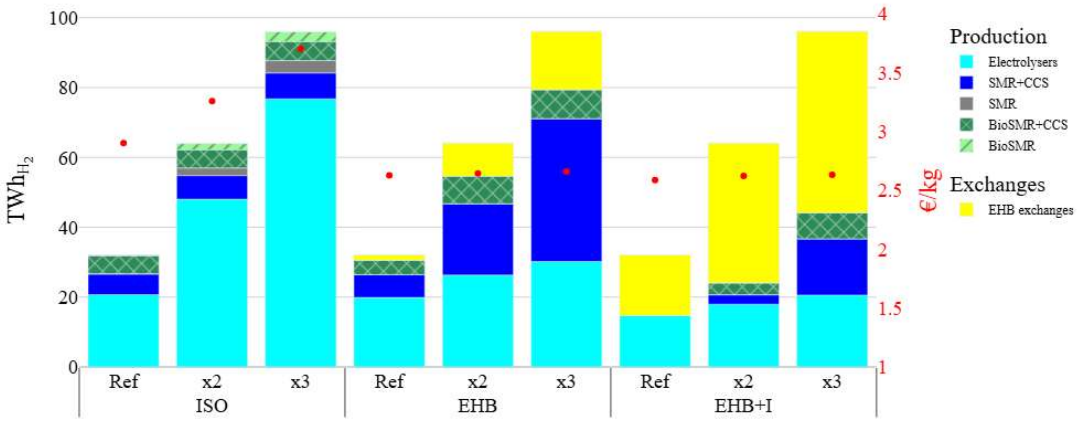


Figure 3-9: Hydrogen system yearly dispatch, hydrogen price and backbone exchanges in 2050 in Belgium for the ISO, EHB and EHB+I scenarios under reference (x1), doubled (x2) and tripled (x3) hydrogen demand

Under ISO, increments of Belgian hydrogen demand are mostly met with additional electrolysis (Figure 3-9). The incremental electricity demand is absorbed by saturating the solar PV potential and by higher electricity imports (Figure 3-10), pushing electricity prices from around 75 to nearly 95€/MWh and hydrogen prices from 2.9 to 3.7€/kg. At such levels, hydrogen-based decarbonization of Belgian industry loses competitiveness against neighbours with better access to low-cost supply, and unabated SMR progressively re-enters the mix as a cost relief valve (a detrimental outcome from an emissions standpoint).

The electricity system carries much of that strain (Figure 3-10): the additional electrolyzer load spreads into the dispatch through higher imports, saturated solar output and shifts in gas turbine utilization and biogas allocation. Eventually, the cost of an electricity centred hydrogen supply is ultimately shared with all electricity consumers.

The picture changes markedly once network infrastructure and CCS access are available. Under EHB, hydrogen prices remain close to 2.5€/kg across all demand levels, because incremental demand is largely absorbed by SMR+CCS and by backbone exchanges rather than by more electrolysis. Notably, at the reference hydrogen demand of 32 TWh, Belgium reaches over 95% domestic self-sufficiency at prices nearly as competitive as the import-heavy cases, indicating that sufficiency and cost-competitiveness are not mutually exclusive at moderate demand.

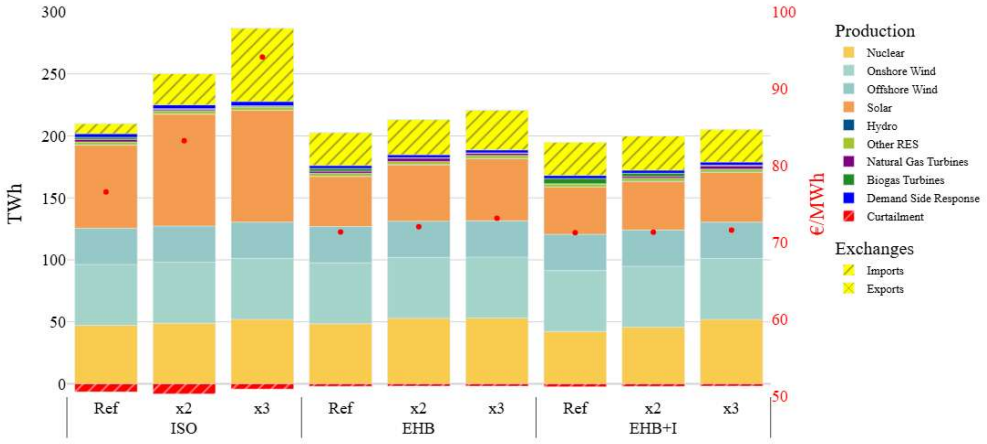


Figure 3-10: Electricity system yearly dispatch in 2050 in Belgium, for the ISO, EHB and EHB+I scenarios under reference (x1), doubled (x2) and tripled (x3) hydrogen demand

Even under EHB+I, with cheap extra-European imports landing in Spain and Italy, a non-negligible share of Belgian electrolysis and SMR+CCS remains competitive: domestic assets coexist with imports rather than being crowded out. As demand scales up, however, imports increasingly dominate the Belgian mix. This mirrors the European picture, where backbone, underground storage and expanded CCS access cut total system cost by 11% relative to ISO, while extra-European imports ultimately account for a quarter of hydrogen supply.

Two insights follow for Belgium. First, infrastructure availability rather than demand ambition is the decisive lever: the same hydrogen demand can be served near 2.5€/kg with a backbone and CCS access, or up to 3.7€/kg without them. Furthermore, that difference is passed on to industry and, through electricity prices, to other consumers. Sectoral hydrogen targets are therefore best conditioned on infrastructure milestones. Second, electricity and hydrogen cannot be planned separately, since hydrogen demand growth spreads into electricity prices and biogas allocation.

Because hydrogen demand is exogenous in POMMES-EU, the comparison with PATHS2050 can only be drawn on the supply side. In the PATHS2050 deep-dive on molecules, hydrogen demand is modelled endogenously through an integrated system optimisation co-optimized over demand- and supply-side technologies. Resulting hydrogen demand ranges from some 10.7 TWh in REACTORS to 29.5 TWh once the RFNBO requirement in industry is relaxed, so the 32 TWh reference used here sits just above the highest level PATHS2050 reaches endogenously. One finding is nonetheless consistent between the models. Where extra-European imports are allowed, they take a large share of Belgian supply: some 17 of 32 TWh under EHB+I, against 16.9 of 27.8 TWh in ROTORS. The models differ, however, in what drives domestic supply: in POMMES-EU it is infrastructure, with Belgium largely self-sufficient under ISO and EHB and losing domestic share only once extra-European imports are allowed. On the other hand, in the PATHS2050 scenarios, the low electricity prices needed for cost-competitive electrolysis-based domestic hydrogen are generally lacking. Therefore, regulation is the driver, with domestic production of blue hydrogen becoming competitive only once the RFNBO requirement in industry is relaxed.

At comparable volumes, the domestic routes thus differ: SMR/ATR with CCS supplies some 22.3 TWh in the relaxed PATHS2050 case, whereas electrolysis leads under POMMES-EU's EHB scenario at roughly 21 TWh. This reflects the relative cost of domestic hydrogen rather than the availability of infrastructure. This could be partly driven by natural gas prices assumptions - around ~25€/MWh in PATHS2050 (based on WEO 2024) against ~35€/MWh in POMMES-EU (based on WEO 2025) – although this cost difference alone is not expected to close the cost gap between blue and green hydrogen in TIMES-BE. To fully appreciate these model differences, further research is needed to analyse in detail differences in electricity prices, commodity prices, weather data and other factors affecting competitive domestic production.

3.3 Modelling Integrated Multi-Energy Market Designs

The increasing integration of electricity, gas, hydrogen and heat systems creates a growing need for coordination between energy markets. Multi-carrier technologies such as gas-fired power plants, combined heat and power plants and electrolysers operate across different energy carriers and are therefore simultaneously exposed to market structures that were largely designed independently. Differences in temporal granularity are particularly relevant: electricity markets increasingly operate with short trading intervals, whereas gas products (and potentially future hydrogen products) are structured over considerably longer delivery periods. These differences can constrain the ability of multi-carrier technologies to coordinate their positions across markets and respond efficiently to short-term market signals.

Building on the market barriers and coordination concepts identified in Chapter 2 of ReInvent Deliverable 1.2 [3] this section quantitatively assesses two specific changes aimed at improving the temporal coordination of the markets: increasing the temporal granularity of day-ahead gas and hydrogen products and changing the

starting time of the gas and hydrogen day. Their impact is assessed for three representative sector-coupling technologies: a gas-fired power plant (GFPP), a combined heat and power plant (CHP), and an electrolyzer, using VITO's market optimization and flexibility valuation model. The analysis focuses on the resulting changes in asset profitability and balancing-market participation, providing a quantitative assessment of whether greater temporal granularity and improved alignment between market timelines can facilitate the economic utilization of cross-carrier flexibility.

3.3.1 Model description

The VITO's market optimization and flexibility valuation model determines the optimal operating and market-participation strategy of an asset by maximizing its economic value across the considered energy markets while respecting its technical and operational constraints. Market participation is co-optimized, allowing the generation, consumption and available flexibility of the asset to be dynamically allocated across the different markets included in each configuration. This framework therefore captures both the direct economic value obtained in individual markets and the interactions and opportunity costs that arise when an asset participates simultaneously in multiple markets. For this analysis, the framework is applied to three technologies representing different forms of sector coupling: a GFPP, a CHP, and an electrolyzer. The GFPP links the gas and electricity systems, the CHP additionally couples electricity and gas operation with heat production, while the electrolyzer links the electricity and hydrogen systems. The technologies differ in their operational constraints and can therefore respond differently to changes in market design.

Table 3-4 Main technical characteristics of the technologies considered in the market-model simulations.

Characteristic	GFPP (CCGT)	CHP	Electrolyzer
Main energy conversion	Gas → electricity	Gas → electricity + heat	Electricity → hydrogen
Maximum electricity production/consumption	875 MW production	320 MW production	25 MW consumption
Minimum electricity production/consumption	260 MW production	0 MW production	5 MW consumption
Minimum heat output	–	50 MW	–
Maximum heat output	–	205 MW	–
Minimum hydrogen output	–	–	3.10 MW
Maximum hydrogen output	–	–	16.63 MW
Ramp-up/down limit	3,000 MW/h	100 MW/h	40 MW/h
Can shut down	Yes	Yes	No

As shown in Table 3-4, the three technologies have substantially different operational characteristics. The GFPP has a large operating range and high ramping capability, allowing electricity production to respond strongly to market conditions. The CHP is additionally constrained by its heat-production requirements, with heat output maintained between 50 and 205 MW, limiting the extent to which its operation can be driven exclusively by

electricity and gas-market signals. The electrolyzer is an electricity-consuming asset operating between 5 and 25 MW, whose electricity consumption determines hydrogen production. These differences in operational constraints and flexibility are important for interpreting the results, as they influence the extent to which each technology can exploit changes in the temporal design of the gas or hydrogen markets.

The model simultaneously optimizes the asset's operation and its positions in the markets available under the considered market configuration. These include the day-ahead (DA) electricity market, automatic Frequency Restoration Reserve (aFRR), the DA gas market, DA hydrogen market, the within-day gas market and hydrogen markets. Note that there is no DA and within-day markets for Hydrogen at the moment, but given the expected future developments, those markets are assumed to have a design similar to the markets for gas. For aFRR, both upward and downward capacity reservation and energy activation are represented. In the underlying modelling framework, balancing capacity reservation and activation are treated separately, with capacity committed over predefined reservation periods and activation represented at the operational simulation resolution. This makes it possible to assess not only the effect of market-design changes on total asset profitability, but also their impact on the amount of flexibility reserved and activated in the balancing market.

3.3.2 Simulation framework

The simulations are performed over a one-year optimization horizon, from September 2024 to September 2025, with a temporal resolution of 15 minutes. This resolution is used to represent asset operation and market interactions throughout the simulation period. The simulations use historical market data over the considered period to represent electricity and gas-market conditions. Electricity-market inputs, including DA electricity and balancing-market data, are obtained from ENTSO-E and Elia [11, 12, 13, 14], while gas-market prices are based on the EEX prices for the Belgian ZTP hub, using the European Gas Spot Index (EGSI) for the day-ahead gas market and the Within-Day Reference Price (WDRP) for the within-day gas market [15]. As liquid DA and within-day hydrogen markets do not currently exist, hypothetical hydrogen markets are represented in the model assuming a temporal market structure similar to that of the gas market. The corresponding hydrogen prices are synthetically generated based on the production costs of green and grey hydrogen, providing a representation of potential future hydrogen-market price conditions.

The market optimization is performed under perfect foresight, meaning that the market prices and other exogenous market information considered by the model are assumed to be known in advance over the relevant optimization horizon. This allows the model to determine the economically optimal operation and market-participation strategy for each technology under the considered market conditions. Consequently, the results should be interpreted as the maximum economic value that could have been captured under the model assumptions, rather than as the profitability of a bidding strategy operating under real-world forecast uncertainty. The perfect-foresight assumption is applied consistently across all scenarios and therefore provides a common basis for comparing the alternative market designs. This approach is consistent with the general

implementation of the market optimization framework, in which perfect foresight is used to estimate an upper bound on the economic value of flexibility.

The objective of the sensitivity analysis is to assess how greater temporal granularity and alternative starting times in the DA gas and hydrogen markets affect asset operation, profitability and balancing-market participation. Two dimensions of market design are varied systematically: the duration of the DA gas or hydrogen product and the starting hour of the corresponding gas or hydrogen day.

Three product durations are considered:

- 24 hours, representing the current/reference design;
- 12 hours; and
- 6 hours.

For each duration, three starting hours are evaluated:

- 06:00, representing the current/reference starting hour;
- 03:00; and
- 00:00.

The combination of these assumptions results in nine market-design variants for each market configuration. Scenarios are denoted as sXX_lYY, where sXX represents the starting hour and lYY the product duration. For example, s06_l24 corresponds to a product starting at 06:00 with a duration of 24 hours and constitutes the reference market design, while s24_l06 represents a 6-hour product starting at midnight.

The sensitivity analysis is performed for three market-participation configurations for each technology. For the GFPP and CHP, the configurations progressively introduce participation in the electricity DA market, gas DA market, aFRR, and within-day gas market, with revenues from heat bilateral contracts additionally considered for the CHP. For the electrolyzer, the configurations combine participation in the electricity and hydrogen markets with aFRR. Table 3-5 presents the market configurations considered per technology. Within each market configuration, all nine combinations of starting hour and product duration are simulated while keeping the remaining modelling assumptions unchanged. This isolates the effect of the temporal design of the gas or hydrogen market.

Table 3-5 Market configurations considered for each technology.

Technology	Market configuration	Markets considered
GFPP	da_e + da_g	DA electricity + DA gas
	da_e + afrr + da_g	DA electricity + aFRR + DA gas
	da_e + afrr + da_g + wd_g	DA electricity + aFRR + DA gas + within-day gas
CHP	da_e + da_g + heat	DA electricity + DA gas + heat
	da_e + afrr + da_g + heat	DA electricity + aFRR + DA gas + heat bil.contract
	da_e + afrr + da_g + wd_g + heat	DA electricity + aFRR + DA gas + within-day gas + heat bilateral constract
Electrolyzer	da_e + da_h2	DA electricity + DA hydrogen
	da_e + afrr + da_h2	DA electricity + aFRR + DA hydrogen
	da_e + afrr + da_h2 + wd_h2	DA electricity + aFRR + DA hydrogen + within-day hydrogen

The main reference scenario is s06_l24, corresponding to the current 06:00 starting hour and 24-hour product duration. Results are primarily evaluated relative to this reference, allowing the effect of each market-design modification to be distinguished from differences in absolute profitability between technologies and market configurations. The analysis considers both economic indicators, including annual profit and its decomposition across market components, and balancing indicators, including upward and downward aFRR activation and reserved capacity.

An important feature of the simulation framework is that the different markets retain their respective temporal structures. DA electricity trading and aFRR energy activation are represented at a 15-minute resolution, whereas aFRR capacity is reserved in fixed 4-hour blocks starting at midnight. The temporal structure of the DA gas and hydrogen markets varies according to the scenarios considered, with product durations of 24, 12 or 6 hours and starting times of 06:00, 03:00 or 00:00. Consequently, changing the start time or duration of the gas and hydrogen products also changes their temporal alignment with the electricity and balancing markets. The simulations therefore capture two related aspects of improved market coordination: increased temporal granularity, through shorter gas and hydrogen products, and cross-market temporal alignment, through alternative starting hours. This distinction is important for interpreting the results: shorter products increase the frequency at which gas or hydrogen positions can be adjusted, whereas changing the starting hour alters how these positions align with the 15-minute electricity and aFRR activation intervals and, particularly, with the fixed 4-hour aFRR capacity-reservation blocks.

Figure 3-11 summarizes the overall simulation framework and the interactions between its main components. The technology characteristics, available markets and alternative gas and hydrogen market designs constitute the main model inputs. For each combination, the optimization determines the optimal asset

operation and market decisions, from which the economic and flexibility indicators used in the subsequent analysis are derived.

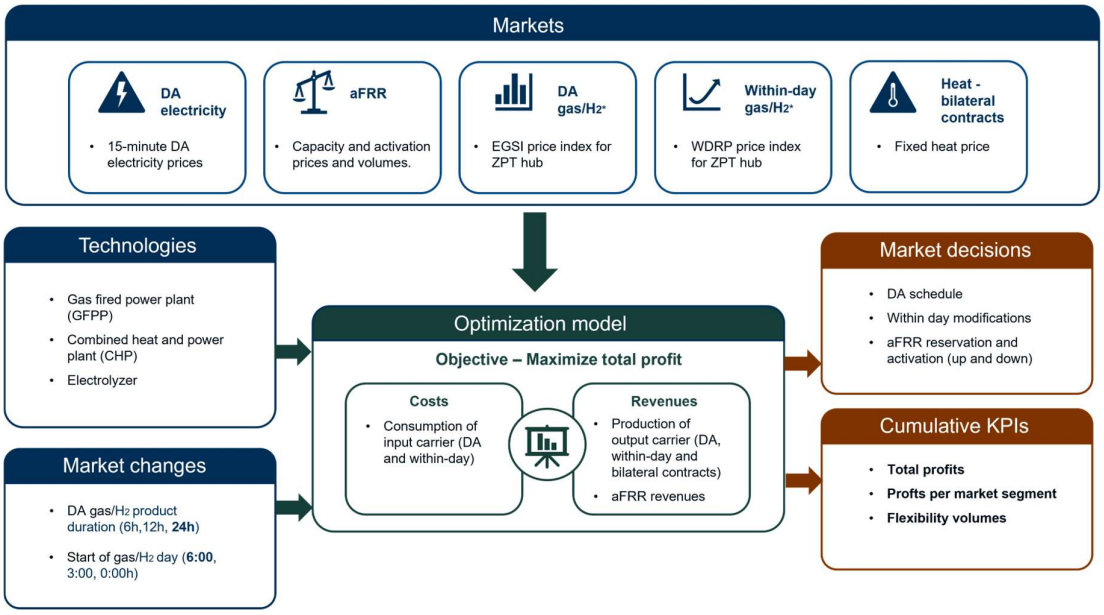


Figure 3-11 Overview of the market optimization and simulation framework.

3.3.3 Impact on profits

This section assesses how changes in the temporal design of the DA gas and hydrogen markets affect the annual profitability of the GFPP, CHP and electrolyzer. The analysis considers both the magnitude of the resulting change in total annual profit and the market components through which this change is realized, allowing the effects of product granularity and market-day alignment to be distinguished. Particular attention is also given to how access to additional markets, such as aFRR and within-day trading, influences the value that each technology can obtain from the alternative gas and hydrogen market designs.

3.3.3.1 GFPP

The impact of the modifications on GFPP profitability is summarized in Figure 3-12, which reports annual profit relative to the corresponding s06_l24 reference scenario (gas day starting at 06:00 with a 24-hour product). The results show that shortening the DA gas-product duration is the main driver of profitability improvements. For da_e+da_g, the 6-hour configurations increase profit to 117.88–120.69% of the reference, compared with 103.27–113.16% for the 12-hour configurations. The same pattern is observed with aFRR participation: 6-hour products yield 111.73–113.97% for da_e+afrr+da_g and 110.86–113.99% for da_e+afrr+da_g+wd_g, while 12-hour products provide smaller improvements of approximately 102–109%.

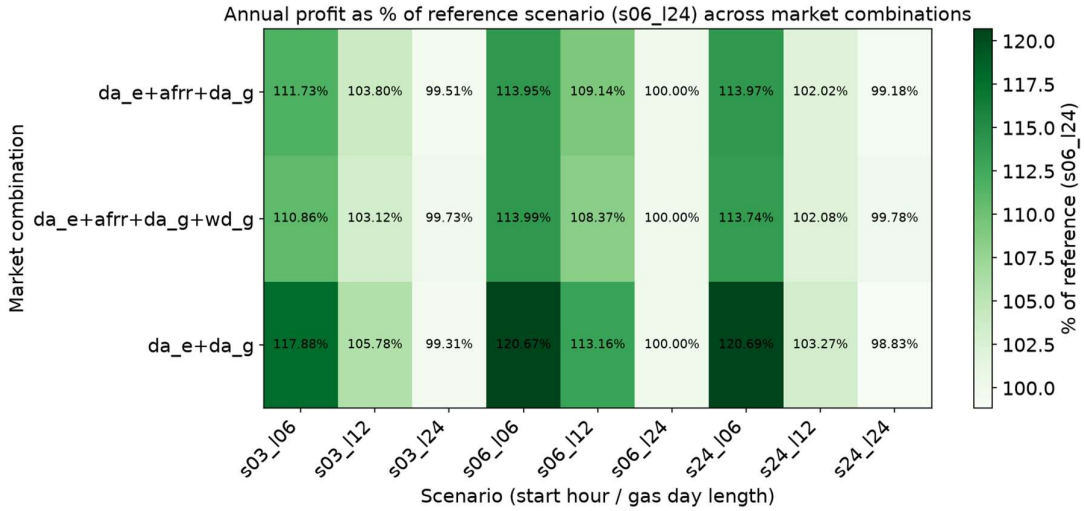


Figure 3-12 Annual GFPP profit across gas-market designs and market participation combinations. Annual profit is expressed as a percentage of the corresponding reference scenario (s06_l24: gas day starting at 06:00 with a 24-hour product).

The gas-day start time has a smaller and less systematic effect, and its impact depends on product duration. For 24-hour products, changing the start time provides no improvement, with profits remaining at 98.83–99.78% of the reference. For 12-hour products, a 06:00 start consistently performs best (108.37–113.16%), whereas for 6-hour products both 06:00 and 24:00 generally outperform 03:00, with only small differences between them. Thus, the value of changing the start time is conditional on product duration, whereas the benefit of shortening the gas product is consistent across market combinations. The relatively limited effect of shifting the gas-day start from 06:00 to 24:00 can be explained by the fact that the change primarily shifts the temporal boundaries of the gas products rather than increasing the frequency at which the GFPP can adjust its gas position. Over the full simulation horizon, the plant's underlying fuel requirement and electricity-market opportunities remain largely unchanged, and gas positions can be redistributed across consecutive gas products. Consequently, aligning the gas-day start with midnight provides only limited additional value. This is reflected in the very similar profitability of s06_l06 and s24_l06: for example, profits amount to 120.67% and 120.69%, respectively, for da_e+da_g, and 113.95% and 113.97% for da_e+afrr+da_g. In contrast, shortening the product duration from 24 h to 12 h or 6 h increases the frequency at which gas positions can be adjusted, providing substantially greater flexibility and therefore a stronger profitability effect.

Figure 3-13 provides a complementary perspective by showing the best-to-worst profitability range for each market combination. Unlike Figure 3-12, profits are expressed relative to a common da_e+da_g s06_l24 benchmark, allowing differences in overall profitability across market combinations to be observed. The da_e+da_g case shows the largest sensitivity to gas-market design, with profits ranging from 99% to 121%, a spread of approximately 22 percentage points. This decreases to 17 percentage points for da_e+afrr+da_g (111–

128%) and 16 percentage points for da_e+afrr+da_g+wd_g (113–129%). Hence, participation in additional markets is associated not only with a higher overall profit level but also with lower sensitivity of GFPP profitability to the gas-market configuration.

The extremes shown in Figure 3-13 further support the importance of product duration: all best-performing configurations use a 6-hour product, whereas all worst-performing configurations use a 24-hour product. The optimal starting hour, however, varies across market combinations, again indicating that start time is a secondary and more context-dependent design parameter.

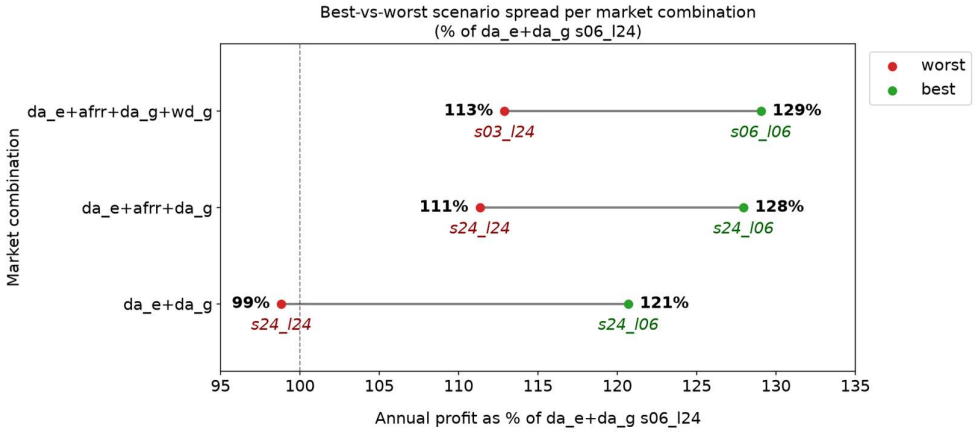


Figure 3-13 GFPP annual profit range across gas-market designs and market participation combinations The figure shows the best- and worst-performing gas-market configurations, with annual profit expressed relative to the da_e+da_g s06_l24 benchmark.

Finally, Figure 26 summarizes the maximum benefit that can be obtained from gas-market reform within each market combination. Relative to the respective s06_l24 reference, the maximum annual-profit improvement amounts to approximately +20.7% for da_e+da_g and +14.0% for both aFRR-enabled configurations. The lower incremental gain in the aFRR-enabled cases indicates that GFPP profitability becomes less dependent on gas-market design when additional market opportunities are available, although the benefit of increased gas-market granularity remains substantial.

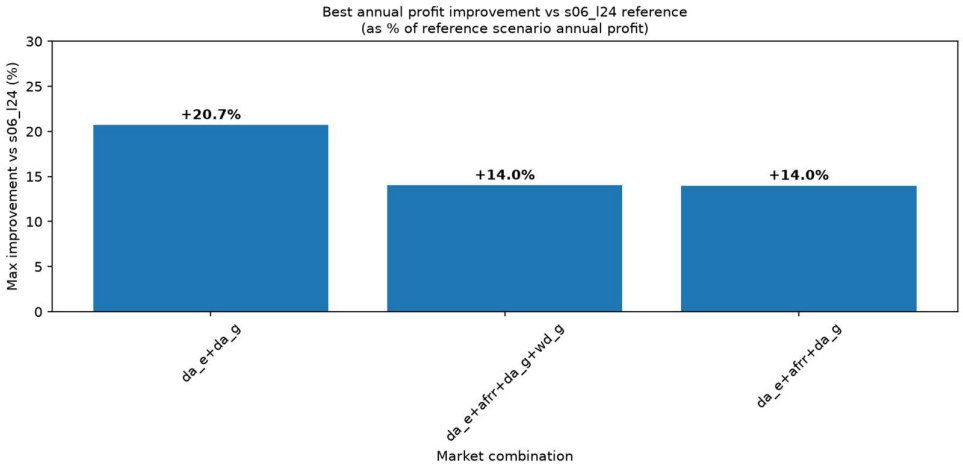


Figure 3-14 Maximum improvement in GFPP annual profit from gas-day reform by market participation combination. Values represent the percentage increase in annual profit of the best-performing gas-market configuration relative to the corresponding s06_l24

To better understand the drivers behind these profitability improvements, Table 3-6 decomposes the profit difference between the best-performing gas-market configuration and the corresponding s06_l24 reference across the different market segments. For da_e+da_g, the improvement is explained by positive contributions from both DA electricity (+9.80 percentage points) and DA gas (+10.89 pp). When aFRR participation is included, DA electricity remains the largest contributor (+9.15 pp), followed by DA gas (+4.11 pp), while the net contribution from aFRR is comparatively small. When within-day gas trading is also available, the decomposition changes substantially: the large positive contribution from DA gas (+48.24 pp) is largely offset by a negative contribution from within-day gas (−43.89 pp), resulting in a much smaller net contribution from gas trading. Overall, the decomposition indicates that the profitability gains from gas-market reform arise primarily through changes in the GFPP's electricity and gas-market positioning (i.e., in the DA markets) rather than through a substantial increase in the contribution from aFRR.

Table 3-6 Decomposition of the GFPP annual-profit improvement between the best-performing gas-market configuration and the corresponding s06_l24 reference scenario. Values represent percentage-point contributions to the change in total annual profit, normalized by the absolute total annual profit of the reference scenario.

Market combination /Market segment	aFRR down	aFRR up	DA electricity	DA gas	Within day gas
da_e+da_g [best: s24_l06]	-	-	9.80%	10.89%	-
da_e+afrr+da_g [best: s24_l06]	1.08%	-0.37%	9.15%	4.11%	-
da_e+afrr+da_g+wd_g [best: s06_l06]	0.98%	-0.32%	8.99%	48.24%	-43.89%

3.3.3.2 CHP

The CHP results confirm the main qualitative finding obtained for the GFPP: shortening the DA gas-product duration improves profitability, whereas changing the gas-day starting hour has a considerably smaller effect. However, the magnitude of the improvement is substantially lower for the CHP, indicating that the value of increased gas-market granularity depends strongly on the operational characteristics of the asset. Figure 3-15 shows annual CHP profit relative to the corresponding s06_l24 reference scenario. For da_e+da_g+heat, reducing the gas-product duration to 6 hours increases annual profit to 104.52–104.66% of the reference scenario, while 12-hour products result in a smaller increase of 101.79–102.46%. The same pattern is observed with additional market participation. With aFRR, 6-hour products yield 103.56–103.64%, compared with 101.42–101.98% for 12-hour products. When within-day gas trading is also included, the corresponding ranges are 102.81–103.50% and 101.07–101.46%, respectively.

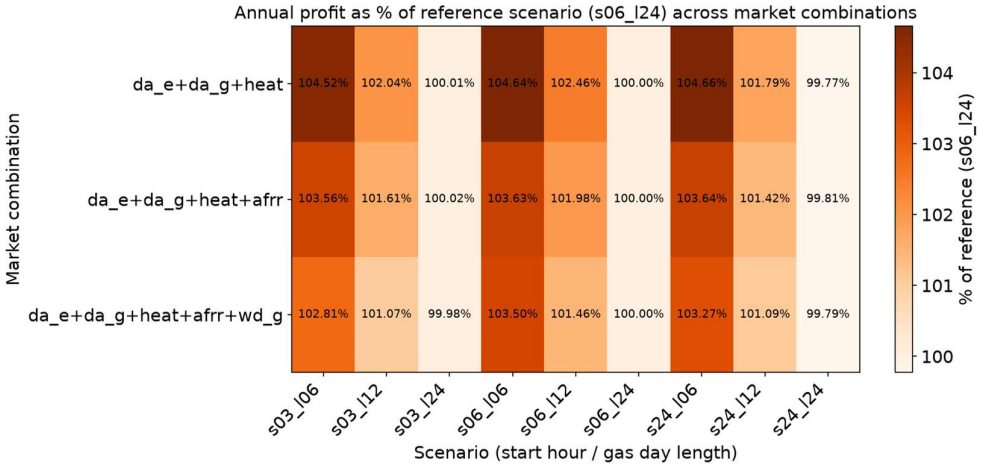


Figure 3-15 Annual CHP profit across gas-market designs and market participation combinations. Annual profit is expressed as a percentage of the corresponding reference scenario (s06_l24: gas day starting at 06:00 with a 24-hour product).

The effect of the gas-day starting hour is particularly limited for the CHP. For a 6-hour product, for example, da_e+da_g+heat profitability varies only from 104.52% at 03:00 to 104.66% at 24:00. With aFRR, the corresponding range narrows further to 103.56–103.64%. For 24-hour products, changing the starting hour also produces virtually no improvement, with results remaining around 100% of the reference. Hence, as for the GFPP, changing the starting hour mainly shifts the timing of the gas-product windows, whereas shortening the product increases the frequency at which the CHP can adjust its gas position. It is this additional temporal granularity, rather than the alignment of the gas-day boundary itself, that generates most of the economic benefit.

The magnitude of this benefit is nevertheless considerably smaller than for the GFPP. The maximum annual-profit improvement reaches approximately +4.7% for da_e+da_g+heat, decreasing to +3.6% with aFRR and

+3.5% when aFRR and within-day gas trading are both available. By comparison, the corresponding improvements for the GFPP reached approximately +20.7% without aFRR and around +14% with aFRR participation. This indicates that the GFPP is substantially more sensitive to gas-market granularity than the CHP. A likely explanation lies in the heat-production requirement of the CHP: its operation cannot respond exclusively to electricity and gas-market opportunities, which limits the extent to which additional gas-market flexibility can be exploited.

The profit decomposition in Table 3-7Table 3-7 Decomposition of the CHP annual-profit improvement

between the best-performing gas-market configuration and the corresponding s06_l24 reference scenario. Values represent percentage-point contributions to the change in total annual profit, normalized by the absolute total annual profit of the reference scenario. provides further insight into these differences. For the best da_e+da_g+heat configuration, the improvement is mainly associated with the profits from heat production (+4.3 percentage points), while changes in DA electricity (+0.1 pp) and DA gas (+0.3 pp) are small. With aFRR participation, heat production again provides the largest positive contribution (+4.7 pp), while DA electricity contributes +0.9 pp and DA gas −2.3 pp. When within-day gas trading is included, the decomposition reveals substantial redistribution between the two gas-market segments. The positive contribution from DA gas (+38.4 pp) is largely offset by the negative contribution from within-day gas (−40.3 pp). Consequently, these values should not be interpreted independently as gains or losses generated by gas-market reform; rather, they indicate that the reform substantially changes where gas transactions and their associated value are allocated, while the net effect on total CHP profitability remains modest.

Table 3-7 Decomposition of the CHP annual-profit improvement between the best-performing gas-market configuration and the corresponding s06_l24 reference scenario. Values represent percentage-point contributions to the change in total annual profit, normalized by the absolute total annual profit of the reference scenario.

Market combination /Market segment	aFRR down	aFRR up	DA electricity	DA gas	heat contract	Within day gas
da_e+da_g+heat [best: s24_l06]			0.10%	0.30%	4.26%	
da_e+da_g+heat+afrr [best: s24_l06]	0.45%	-0.13%	0.87%	-2.26%	4.71%	
da_e+da_g+heat+afrr+wd_g [best: s06_l06]	0.32%	-0.08%	0.59%	38.38%	4.54%	-40.25%

3.3.3.3 Electrolyser

The electrolyzer results reinforce the general importance of increasing market temporal granularity, but also reveal a substantially stronger interaction between hydrogen-market design and participation in other flexibility markets. Figure 3-16 shows annual electrolyzer profit relative to the corresponding s06_l24 reference scenario. As for the GFPP and CHP, shortening the product duration provides a substantially larger profitability benefit

than changing the start of the market day. However, the magnitude of this effect differs considerably depending on whether the electrolyzer participates in aFRR or not.

For the da_e+da_h2 market configuration, the impact of shortening the hydrogen DA product is particularly pronounced. Six-hour products increase annual profit to 139.86–145.33% of the reference, while 12-hour products result in 113.67–123.72%. In contrast, changing the start time while retaining a 24-hour DA product has virtually no effect, with annual profit remaining between 99.44% and 100.00% of the reference. The best-performing configuration is s24_l06, reaching 145.33%, corresponding to an improvement of approximately +45.3% relative to s06_l24. When aFRR participation is available, shorter hydrogen products remain beneficial, but their incremental value decreases substantially. For da_e+afrr+da_h2, 6-hour products result in 107.99–108.04% of the reference and 12-hour products in 103.36–103.96%. A very similar pattern is observed when within-day gas trading is also available: 6-hour products yield 107.65–107.83%, while 12-hour products yield 103.21–103.68%.

As for the other technologies, the hydrogen-day starting hour has little influence when the product duration remains at 24 hours. However, its interaction with shorter products is more visible for the electrolyzer than for the CHP. Without aFRR, for example, profitability for a 6-hour product ranges from 139.86% at 03:00 to 145.33% at 24:00, while for a 12-hour product it ranges from 113.67% at 24:00 to 123.72% at 06:00. There is therefore no single starting hour that systematically maximizes profitability across product durations. Product duration remains the dominant parameter, but the optimal starting hour depends on the product length and market participation combination. With aFRR participation, this start-time sensitivity becomes considerably smaller, with the three 6-hour configurations differing by less than half a percentage point.

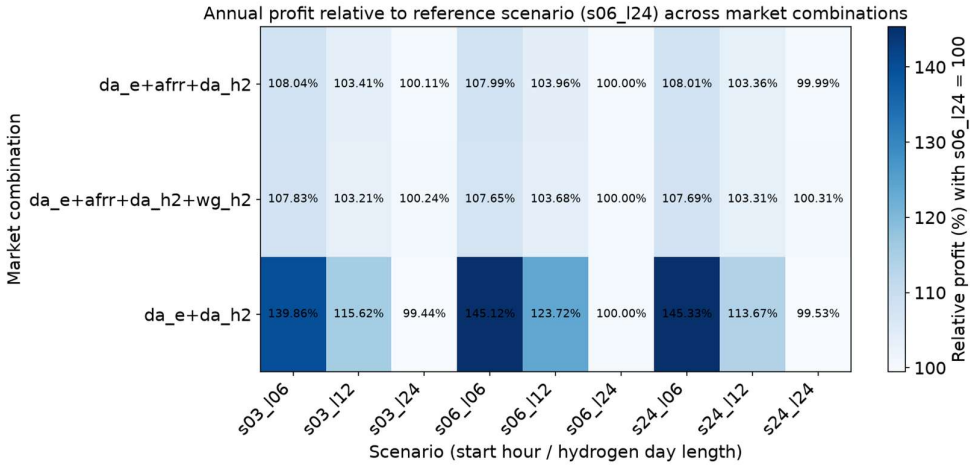


Figure 3-16 Electrolyzer profit by hydrogen-market design and market participation combination. Annual profit is expressed as a percentage of the corresponding reference scenario (s06_l24).

The contrast between market combinations is summarized in Figure 3-17. The maximum annual-profit improvement reaches +45.3% for da_e+da_h2, compared with only +8.0% for da_e+afrr+da_h2 and +7.8% when within-day gas trading is additionally available. This indicates that access to aFRR strongly reduces the sensitivity of electrolyzer profitability to hydrogen-market design. When participation of aFRR is unavailable, greater hydrogen-market granularity represents a major source of additional flexibility and value. When aFRR is available, the electrolyzer has additional opportunities to monetize its operational flexibility, and the marginal benefit associated with reforming the hydrogen-market temporal structure is considerably smaller.

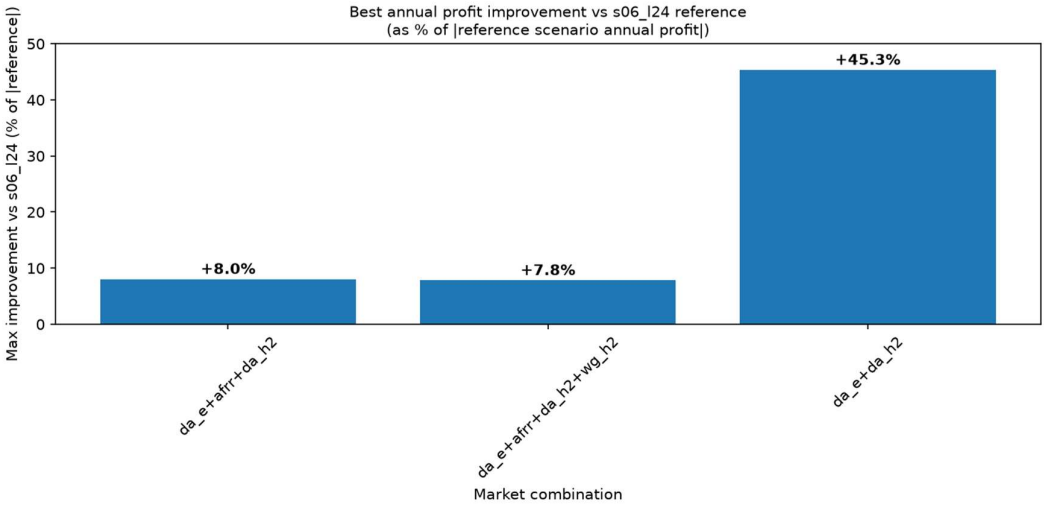


Figure 3-17 Maximum improvement in electrolyzer annual profit from hydrogen-market reform by market participation combination. Values represent the percentage increase in annual profit of the best-performing hydrogen-market configuration relative to the corresponding s06_l24 reference scenario.

The profit decomposition in Table 3-8 provides further insight into the mechanisms behind these differences. Without aFRR, the profitability improvement in the best-performing da_e+da_h2 configuration is dominated by the DA hydrogen component, which contributes +41.3 pp, supplemented by a +4.0 pp contribution from DA electricity. The large overall improvement is therefore closely associated with changes in the value captured through hydrogen production and sales under the shorter hydrogen-product configuration. The decomposition changes markedly when aFRR participation is available. For the best da_e+afrr+da_h2 configuration (s03_l06), the hydrogen component contributes only +2.3 pp, while substantial changes are observed in the aFRR-related components, including +9.6 pp for aFRR-up and −4.1 pp for aFRR-down . A similar pattern is observed when within-day gas trading is included: the DA hydrogen contribution remains relatively small (+2.6 pp), while the aFRR-related components account for larger positive and negative changes. These results indicate that, once balancing-market participation is available, changes in the optimal operation induced by hydrogen-market reform are increasingly reflected in aFRR participation rather than predominantly in the hydrogen component itself.

Table 3-8 Decomposition of the electrolyzer annual-profit improvement between the best-performing hydrogen-market configuration and the corresponding s06_l24 reference scenario. Values represent percentage-point contributions to the change in total annual profit, normalized by the absolute total annual profit of the reference scenario.

Market combination /Market segment	aFRR down	aFRR up	Day-ahead electricity	Day-ahead hydrogen	Within day hydrogen
da_e+da_h2 [best: s24_l06]			4.00%	41.30%	
da_e+afrr+da_h2 [best: s03_l06]	-4.00%	9.60%	0.10%	2.30%	
da_e+afrr+da_h2+wd_h2 [best: s03_l06]	-3.90%	8.50%	0.40%	2.60%	0.20%

3.3.4 Impact on system flexibility

The changes in gas- and hydrogen-market design also affect how the three technologies participate in the balancing market. Figure 3-18 and Figure 3-19 show aFRR activation and capacity reservation, respectively, relative to the corresponding s06_l24 reference scenario. While shorter gas and hydrogen products generally improve profitability across all three technologies, their impact on balancing-market participation differs substantially. In particular, a distinction emerges between aFRR activation, which reflects the flexibility actually activated, and capacity reservation, which reflects the flexibility committed to the balancing market.

For the GFPP, shorter gas products are associated with lower aFRR activation. With 6-hour products, aFRR-up activation falls to approximately 92–94% of the reference, compared with around 99–100% for 12-hour products and 100–102% for 24-hour products. A similar and slightly stronger pattern is observed for aFRR down, where activation falls to 90–91% for 6-hour products and 95–97% for 12-hour products, while the 24-hour configurations remain around 100–102%. Thus, although shorter gas products substantially improve GFPP profitability, this does not translate into greater activation in the balancing market. This is consistent with the profitability decomposition presented above, which showed that most of the economic gain is associated with changes in DA electricity and gas-market positioning rather than an increased contribution from aFRR.

The CHP shows considerably less sensitivity. aFRR-up activation remains between approximately 98 and 100% of the reference across all configurations, while aFRR-down activation remains around 99–101%. Changes in gas-market timing therefore have almost no effect on the amount of CHP flexibility actually activated. This limited response is consistent with the CHP profitability results, where the benefits of shorter gas products were also considerably smaller than for the GFPP. The heat-production requirement constrains the CHP's ability to reorganize its operation in response to changes in gas-market timing and therefore also limits changes in its balancing-market behaviour.

A different pattern is observed for the electrolyzer. Here, shorter hydrogen products systematically increase aFRR activation. With 6-hour products, aFRR-up activation rises to approximately 110–111% of the reference

and aFRR-down activation to around 108%. Moreover, the differences between starting hours are small for a given product duration. For example, aFRR-up activation with a 6-hour product is 111%, 110% and 111% for starts at 03:00, 06:00 and 24:00, respectively. This indicates that, for activation, hydrogen-product duration is substantially more important than the starting hour. The result also complements the profitability decomposition, which showed that once aFRR participation is available, changes induced by hydrogen-market reform are increasingly reflected in balancing-market participation.

The effect on aFRR capacity reservation is more complex and generally more sensitive to market timing, as shown in Figure 3-19. For the GFPP, particularly large variations are observed. Depending on the configuration, aFRR-up capacity ranges from 56% to 122% of the reference and aFRR-down capacity from 59% to 127%. For example, with a 6-hour gas product, upward capacity reservation increases from 56–62% with a 03:00 start to 84–91% with a 06:00 start and 84–90% with a 24:00 start. The CHP again exhibits a more moderate response: upward capacity reservation varies approximately between 83 and 101%, while downward reservation remains within roughly 95–104%. For the electrolyzer, upward capacity reservation is also sensitive to the starting hour. With a 6-hour hydrogen product, it amounts to only 90–92% with a 03:00 start, but rises to 113% with a 06:00 start and 113–115% with a 24:00 start. Changes in downward electrolyzer capacity are smaller, generally remaining between approximately 98 and 107%.

The stronger sensitivity of capacity reservation to the market-day starting hour can be explained, by the temporal alignment between the DA and within day markets and balancing markets. In the model, aFRR capacity is reserved in fixed 4-hour blocks starting at midnight, whereas the gas and hydrogen products considered here start at 00:00, 03:00 or 06:00 and have durations of 6, 12 or 24 hours. Changing the start time and product duration therefore changes how gas or hydrogen trading intervals overlap with the fixed aFRR capacity blocks. This can affect assests ability to simultaneously manage the short term-market position and commit operational flexibility to aFRR. The effect is particularly visible for the GFPP and electrolyzer, where capacity reservation can vary substantially between configurations with the same product duration but different starting hours. The results therefore suggest that cross-market temporal alignment matters more for capacity reservation than for total annual profitability or actual aFRR activation.

3.3.5 Discussion

The results across profitability and balancing-market participation reveal a consistent but technology-dependent impact from the suggested changes. Across all three technologies, shortening the DA product duration is considerably more influential than changing the starting hour of the market day. In particular, a 6-hour DA gas or hydrogen product is the preferred option across all technology and market-participation configurations, with the best-performing profitability scenario consistently relying on the shortest product duration considered. Shorter products increase the frequency at which gas or hydrogen positions can be adjusted and therefore improve the coordination between gas/hydrogen procurement or production and

electricity-market operation. By contrast, changing the starting hour mainly shifts the boundaries of otherwise unchanged market intervals, explaining its comparatively limited effect on annual profitability.

The magnitude of the economic benefit nevertheless differs substantially between technologies. The CHP is least sensitive to increased market granularity, with a maximum profitability improvement of approximately 4.7%, compared with approximately 20.7% for the GFPP and 45.3% for the electrolyzer in the configurations without aFRR. This difference reflects their operational characteristics. The CHP's heat-production requirement constrains its ability to reorganize operation in response to market conditions, whereas the GFPP can exploit shorter gas products more directly to coordinate fuel procurement with electricity generation. The electrolyzer exhibits the strongest response when operating without aFRR, indicating a particularly high value from coordinating electricity consumption and hydrogen production over shorter market intervals.

Access to additional markets also reduces the marginal value of the proposed changes. For the GFPP, the maximum profitability improvement decreases from approximately 20.7% without aFRR to around 14% with aFRR participation, while for the electrolyzer the reduction is considerably stronger, from 45.3% to approximately 8%. This suggests that gas and hydrogen-market granularity and access to balancing markets provide partly alternative mechanisms through which operational flexibility can be monetized. This finding also has implications for different types of market participants. Assets or market participants that do not have access to, or are unable to participate in, multiple short-term and balancing markets may derive particularly large benefits from greater granularity in the gas or hydrogen market itself. Conversely, participants able to optimize their positions across several markets can already monetize part of their flexibility elsewhere and therefore obtain a smaller incremental benefit from the proposed changes. Nevertheless, the positive profitability effect observed across the different market configurations indicates that shorter gas and hydrogen products remain beneficial even when additional market opportunities are available. Consequently, the design of one market cannot be considered entirely independently of the opportunities available in other markets.

Importantly, however, higher profitability from shorter products does not imply a uniform increase in balancing-market participation. The technologies respond in very different ways. For the GFPP, shorter gas products increase profitability while reducing aFRR activation; for the CHP, activation remains almost unchanged; and for the electrolyzer, shorter hydrogen products increase both upward and downward activation. This shows that greater market flexibility can either substitute for, coexist with, or facilitate balancing-market flexibility depending on the operational characteristics of the asset. The economic value of market modifications should therefore not be interpreted directly as an increase in the volume of balancing flexibility supplied to the system.

A further distinction emerges between aFRR activation and capacity reservation. Activation is primarily affected by product duration and shows relatively little sensitivity to the market-day starting hour. Capacity reservation, in contrast, can vary substantially with both start time and product duration, particularly for the

GFPP and electrolyzer. This difference can be linked to the temporal structure of the markets. Because aFRR capacity is reserved in fixed four-hour blocks starting at midnight, changing the boundaries of the gas or hydrogen products changes their alignment with these balancing-market blocks. The ability to commit capacity is therefore affected not only by the amount of operational flexibility available, but also by whether gas and hydrogen market commitments and balancing-market reservation intervals are temporally compatible. If shorter gas or hydrogen products are introduced, the interaction with the temporal granularity of balancing-capacity products should therefore also be considered. In particular, investigating shorter aFRR capacity-reservation periods (e.g., 1-hour instead of 4-hour blocks) could determine whether finer balancing products improve cross-market alignment and allow assets to make greater use of the flexibility created by shorter products.

Taken together, the results indicate that temporal granularity and temporal alignment represent two distinct dimensions of market coordination. Greater market granularity (more specifically a 6h DA product) consistently improves the ability of flexible technologies to respond to changing market conditions and is the main driver of the observed profitability gains. Temporal alignment between DA and balancing markets has a smaller effect on annual profitability but can substantially influence how flexibility is made available to the balancing market. The magnitude and direction of both effects depend strongly on the technology and on the combination of markets in which it participates. These findings therefore support a coordinated approach to market design in which gas, hydrogen, electricity and balancing-market structures and modifications are considered jointly rather than independently. In this context, further increasing the granularity of balancing-capacity products represents a relevant next step for assessing whether the benefits of shorter gas and hydrogen products can be complemented by better temporal coordination with the balancing market.

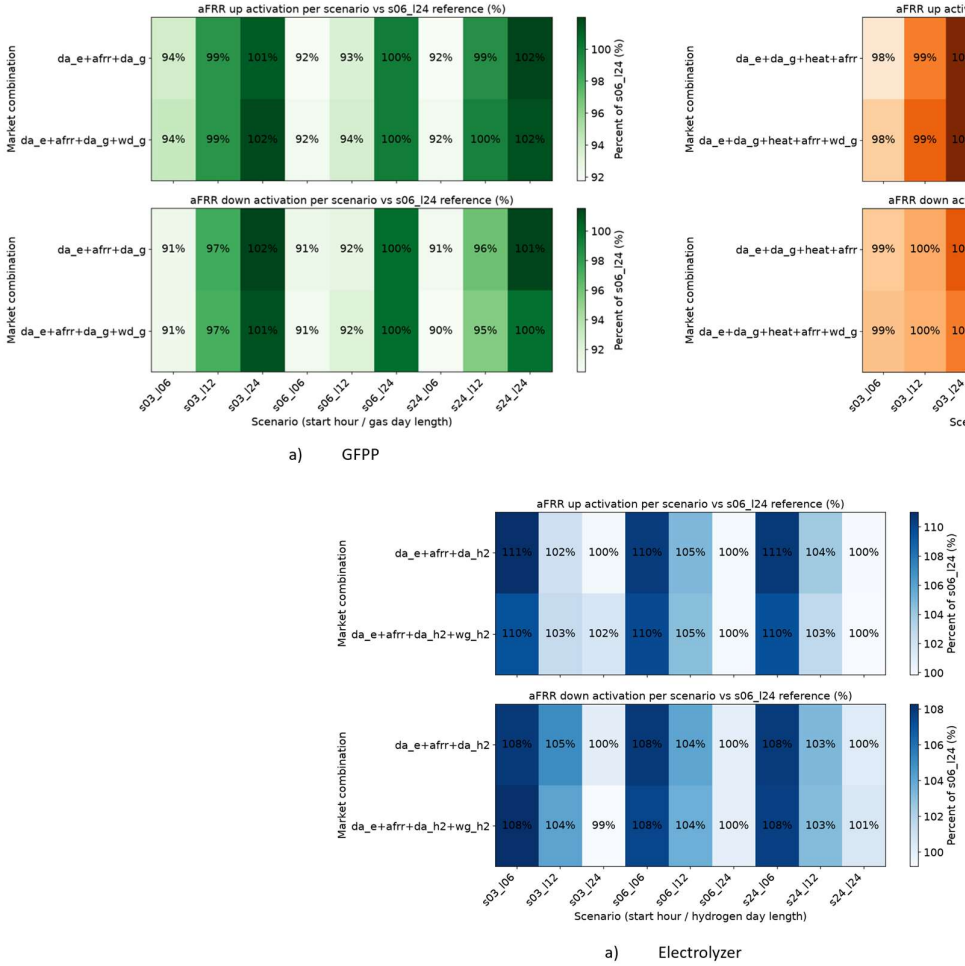


Figure 3-18: Upward and downward aFRR activation across market combinations and scenarios. Activation is expressed as a percentage of the corresponding s06_l24 reference scenario.

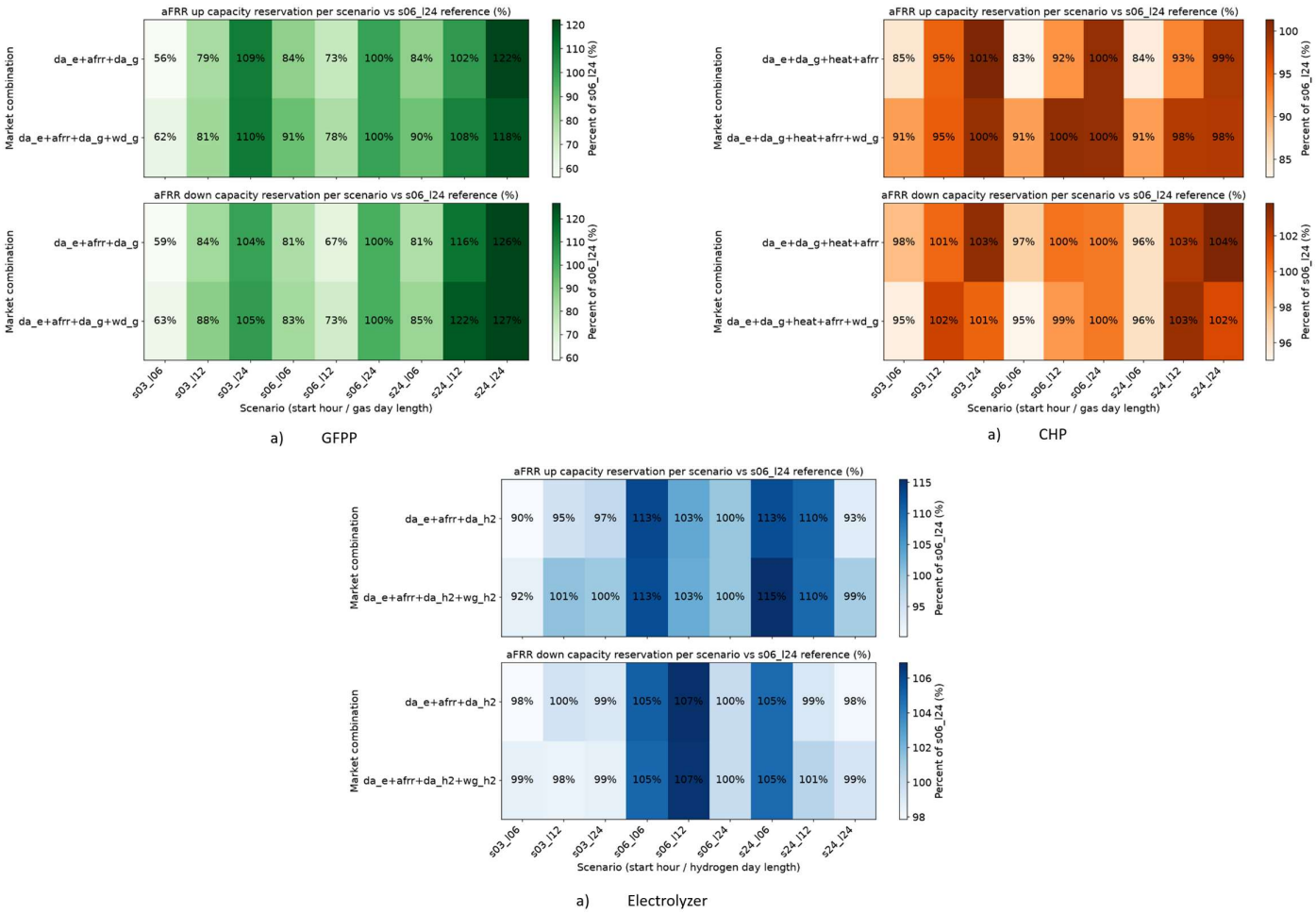


Figure 3-19: Upward and downward aFRR reservation across market combinations and scenarios. Capacity reservation is expressed as a percentage of the corresponding s06_l24 reference scenario.

4 Combined model analysis of sector-coupling

4.1 Relevance and approach

Each energy system model discussed in Chapter 3 has its specific scope, strengths and limitations. This suggests added value can be gained by exploiting synergies between different models. For example, whereas TIMES-BE offers an explicit, sector-resolved representation of final energy demand, models like NSIM and POMMES provide a considerably more detailed representation of hydrogen and synthetic molecule import routes, and associated prices. Moreover, any modelling exercise requires assumptions on uncertain parameters like energy import costs. Applying models in a combined model analysis enables critical cross-evaluations of those assumptions, possibly leading to improved and more consistent representations.

To explore the synergies of a combined model analysis, TIMES-BE and the North-Sea Integration Model have been linked in an iterative manner to assess the impact of sector-coupling. The linkage works in two directional steps. First, the sector-specific final energy demands for Belgium generated by TIMES-BE are passed to NSIM as an input, updating its demand-side assumptions. Second, the resulting run of NSIM produces refined supply routes and prices for hydrogen and other synthetic molecules, which are then fed back into TIMES-BE to update its import prices, quantities, and potentials for these commodities. This iterative exchange allows each model to retain its own area of specialization while ensuring internal consistency between demand and supply-side assumptions.

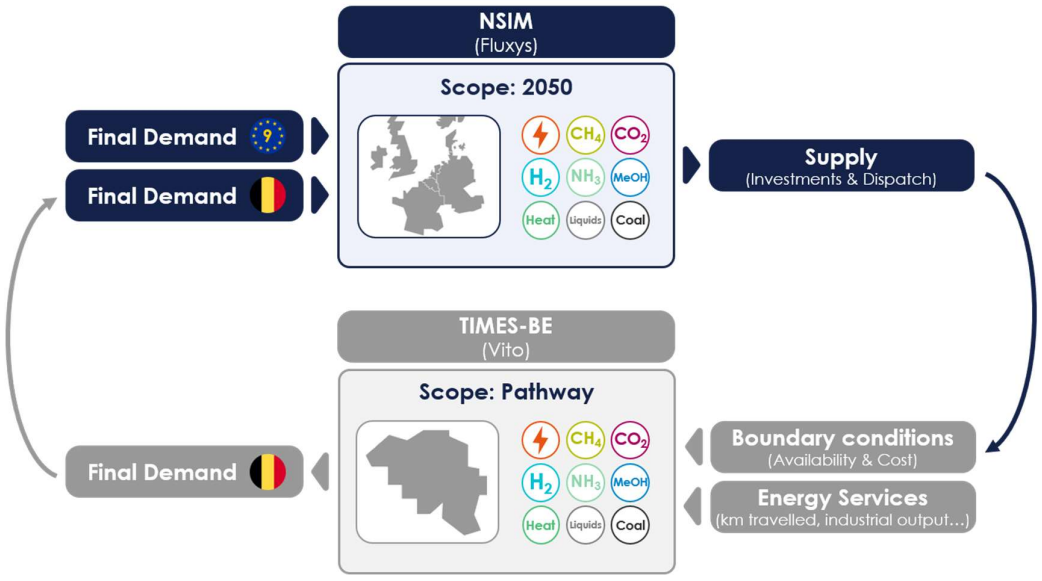


Figure 4-1: terative TIMES-BE–North Sea model linkage for sector-coupling assessment

4.2 Updated reference scenarios

The PATHS 2050 ROTORS scenario (ROTORS25) was selected as the main reference to test the iterative approach. The main criterion was that – among the different PATHS scenarios - it features the most significant role of hydrogen in Belgium, both in terms of demand and domestic production.

4.2.1 Updated results from Fluxys North Sea Integration Model (NSIM)

As a first step in the iterative approach, the Belgian demand assumptions in the North Sea Integration Model (NSIM) were updated using the sectoral energy demands obtained from the PATHS2050 ROTORS25 scenario[7] [7]. The original NSIM simulations were based on the Distributed Energy (DE2024) scenario from the ENTSOs' TYNDP 2024. Replacing the Belgian demand assumptions with ROTORS allows the assessment of a more consistent integrated scenario while maintaining the detailed representation of European energy infrastructure available in NSIM.

Figure 4-2 compares the original DE2024 demand assumptions with the updated Belgian ROTORS25 demand. The largest differences are observed for hydrogen and its derivatives (ammonia and methanol), which partly relate to a substantially lower allocation of international maritime transport demand to Belgium in ROTORS25. Whereas in ROTORS25 this (lower) demand is fulfilled mostly via imported e-methane, under the original NSIM runs this demand was fulfilled with similar shares of methane, liquids, and clean molecules. To avoid modifying the overall demand balance of the ten-country NSIM model, the reduction in Belgian international transport demand was redistributed across the nine remaining countries. Further main differences apply in industry, with mainly for steel and chemicals a significantly higher clean molecules demand in DE2024 compared to ROTORS25. All other model assumptions were kept identical to the original NSIM simulations, including renewable potentials, nuclear capacity assumptions, CCS availability[8], and the requirement for carbon neutrality at the aggregated North-West European level.

[7] Data from the Main Edition 2025
[8] A main difference in model set-up concerns CCS availability, with a CCS limit under ROTORS25, which is not adopted under NSIM.

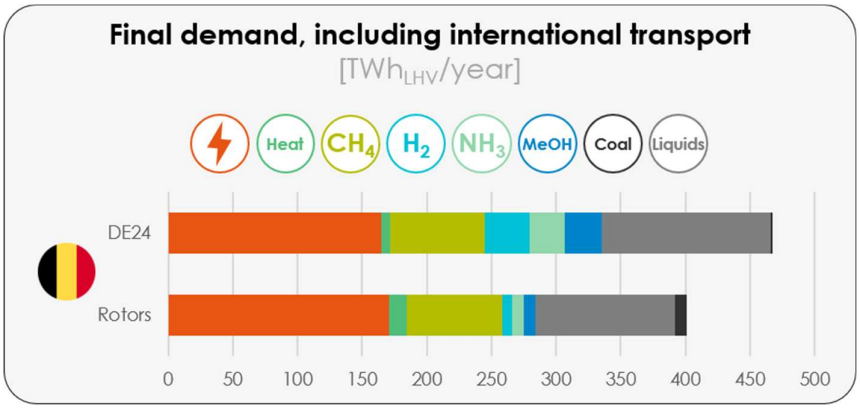


Figure 4-2: Comparison of Belgian final energy and feedstock demand assumptions used in NSIM for the Distributed Energy (DE2024) and ROTORS scenarios (excluding biofuels).

The updated demand assumptions were subsequently used to perform a new NSIM simulation. The resulting Belgian energy balances are presented in Figure 4-3 and compared with the original Distributed Energy case. As expected, the lower demand for hydrogen derivatives in ROTORS leads to lower absolute volumes of hydrogen production, ammonia imports, methanol imports and CO_2 capture activities. Nevertheless, the overall supply structure remains remarkably similar between both scenarios.

In both cases, hydrogen is produced predominantly through autothermal reforming of methane combined with carbon capture and storage (ATR-CCS), indicating that under the common cost and infrastructure assumptions of the model, this pathway remains more competitive than large-scale electrolysis in Belgium. Similarly, ammonia and methanol continue to be supplied predominantly through imports, reflecting the lower transport costs associated with liquid molecules compared to hydrogen. The main effect of the demand reduction is therefore a proportional decrease in the quantity of molecules handled by the system rather than a structural change in the optimal supply mix.

A noteworthy difference appears in the electricity sector. The NSIM-ROTORS scenario exhibits a larger contribution from gas-fired power plants compared to the original Distributed Energy scenario. Although annual generation from combined-cycle gas turbines approximately doubles, from around 5 TWh to 10 TWh, the overall contribution remains limited compared with renewable generation, nuclear production and electricity imports. This reflects a different balance between domestic electricity supply and molecule demand rather than a structural shift towards gas-based electricity generation.

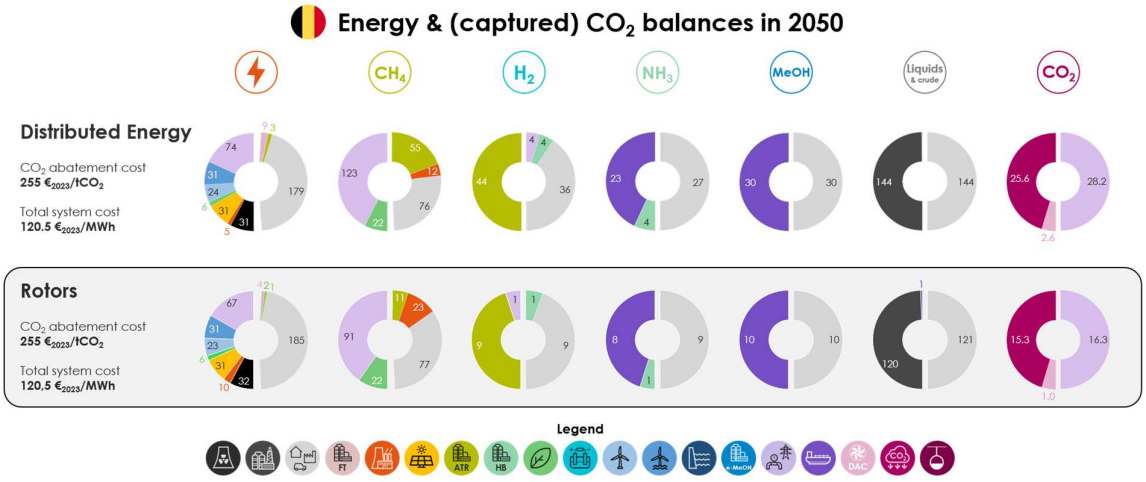


Figure 4-3: Comparison of Belgian annual energy balances obtained with NSIM for the Distributed Energy (top) and ROTORS (bottom) demand scenarios.

Beyond annual energy balances, NSIM also provides detailed hourly import and export profiles together with the associated marginal prices. Figure 4-4 illustrates a typical electricity interconnection flow. Since all countries are optimized simultaneously, cross-border exchanges emerge endogenously from the model and therefore reflect both infrastructure constraints and generation costs in neighbouring countries. The marginal value of imports can be derived directly from the shadow price of the exporting region and provides an estimate of the import cost faced by Belgium.

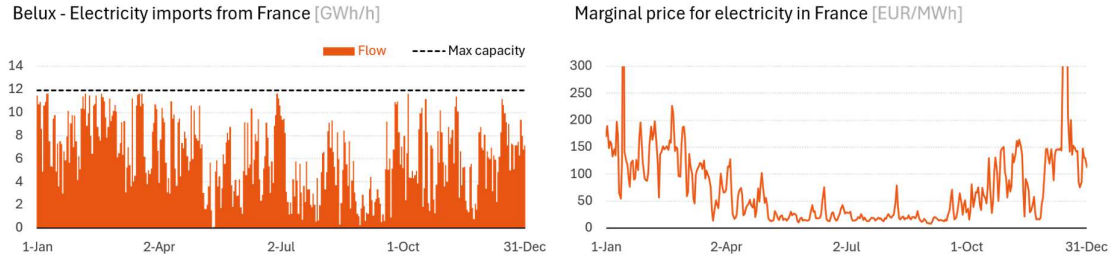


Figure 4-4: Example of hourly electricity imports and associated marginal prices derived from NSIM for a representative interconnection.

The same approach applies to hydrogen and other molecules exchanged between neighbouring countries. Figure 4-5 presents an example of hydrogen imports from the far North Sea zone. Similar hourly profiles and marginal prices are available for all modelled interconnection points and can be used to characterise both the availability and cost of imported molecules.

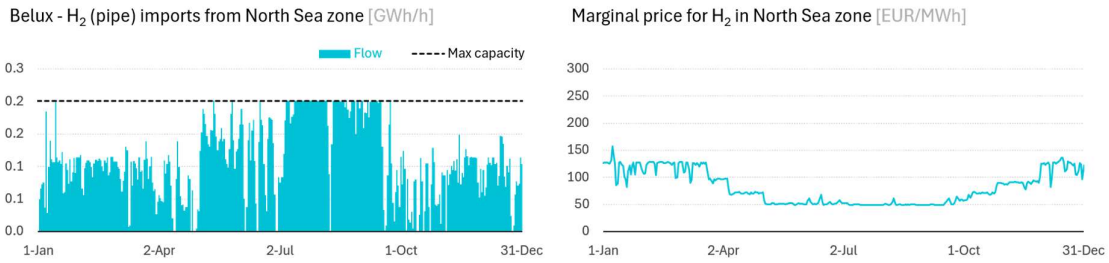


Figure 4-5: Example of hourly hydrogen imports and associated marginal prices derived from NSIM for a representative hydrogen interconnection.

In addition to exchanges within North-West Europe, NSIM explicitly represents imports from overseas production hubs. These remote hubs are co-optimized together with the European system, allowing the model to determine both optimal import volumes and corresponding production and transport costs. Such results provide additional information regarding the competitiveness of imported hydrogen, ammonia, methanol and other clean molecules under different geographical sourcing options.

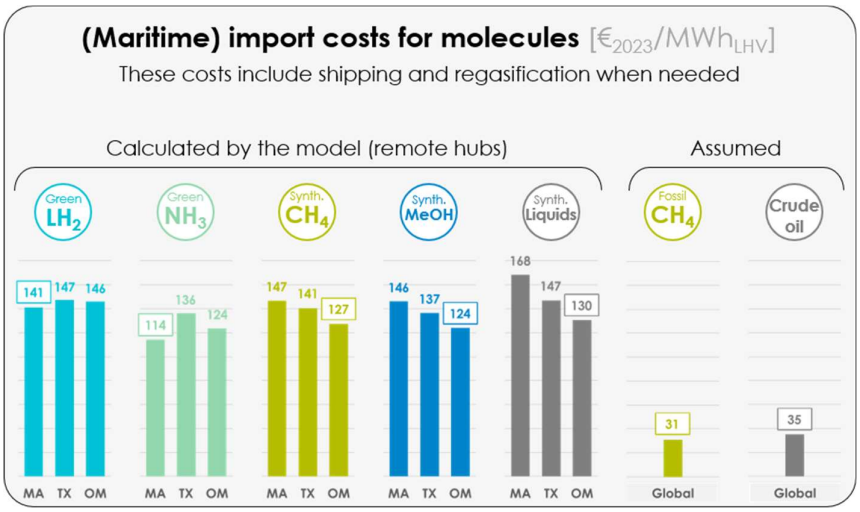


Figure 4-6: Modelled production and transport costs for molecules imported from overseas hubs in the NSIM framework.

4.2.2 Updated results TIMES-BE

The complete set of hourly import profiles, import capacities and marginal prices generated by NSIM were made available for use in the subsequent TIMES-BE analysis. This data was processed in the following way. For hydrogen import by pipeline, hourly hydrogen imports and associated marginal prices were transformed to bi-hourly price curves associated with the representative days in TIMES-BE. For other the maritime import costs, TIMES-BE annual average import price assumptions were replaced with the ones calculated with NSIM. Electricity import prices were used as a comparison. Implementing alternative electricity prices proved difficult as TIMES-BE already endogenizes electricity imported volumes and costs via temporally explicit cost curves reflecting import and export prices as a function of traded volumes.

Applying the Integration model's prices to TIMES-BE changes the cost landscape for hydrogen and synthetic molecules compared to the original TIMES-only assumptions. For most commodities, in particular hydrogen delivered by pipe, methanol, ammonia, eDiesel, eMethane, and eKerosene, the NSIM-derived prices in 2050 fall between, or below, the two original 'Default' (e.g. for ROTORS) and 'Low' (for IMPORTS) TIMES scenario assumptions (Table 3-1). In general, NSIM prices land closer to the IMPORTS price level, thus smoothing out some of the larger discrepancies previously seen between ROTORS and IMPORTS. NSIM electricity import prices, on the other hand, sit slightly above the original TIMES ROTORS assumptions.

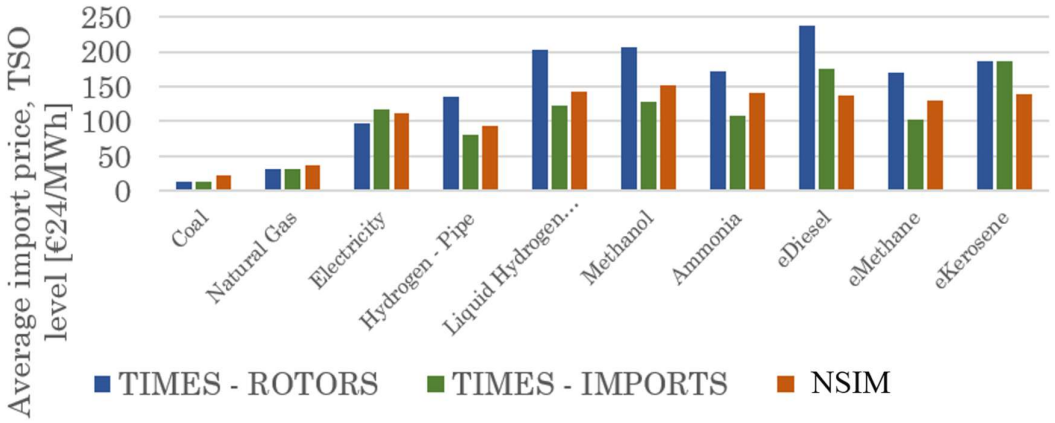
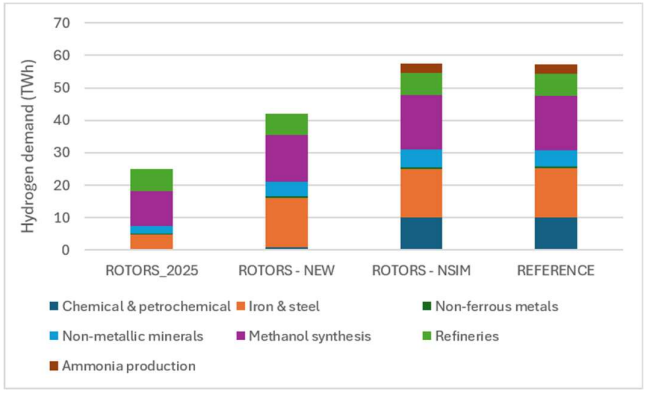


Figure 4-7: Average import fuel and electricity prices comparison across scenarios (2050)

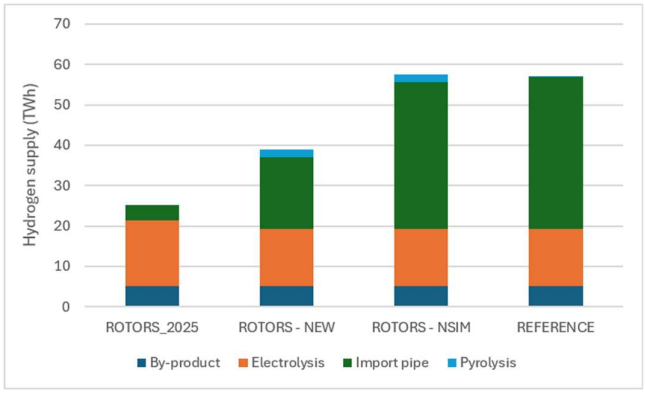
These revised price signals translate into materially different outcomes once fed back into TIMES-BE. Four scenarios are shown (Figure 4-8), including the original ROTORS25 scenario, the ROTORS – NEW scenario based on the TIMES-BE development branch used under REINVENT, the ROTORS – NSIM scenario that consequently substitutes default with NSIM molecules import process, and the REFERENCE scenario, which on top applies partial flexibility. Hydrogen demand increases (Figure 4-8a) with new demands come into the mix, including for ammonia production (substituting for ammonia import) and chemicals. In terms of hydrogen production (Figure

4-8b), ROTORS-NSIM shows a marked increase of both electrolysis-based hydrogen and pipeline imports. Concerning the imports of other synthetic molecules (Figure 4-8c): the new ROTORS run with NSIM prices shows – despite a decrease of ammonia imports - an increase in total import volumes relative to the original runs, higher contributions from e-Methane and e-kerosine , and an emerging share of methanol imports.

a)



b)



c)

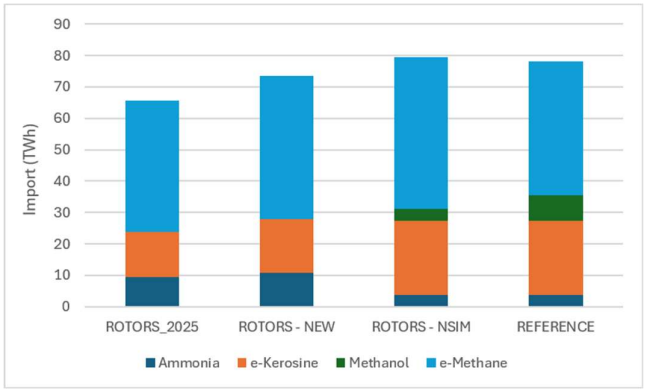


Figure 4-8: Comparison of a) hydrogen demand, b) hydrogen supply, and c) other clean molecules import under scenarios with TIMES default import prices (ROTORS_2025 & ROTORS – NEW) and import prices from NSIM (ROTORS – NSIM & REFERENCE)

4.3 Sector coupling scenario results

The final analysis of this chapter brings together the two flexibility dimensions, heating flexibility and EV charging flexibility, alongside a dedicated assumption on power-to-X (P2X) cost development, to assess how they impact the design of the energy system by 2050, with a special focus on the local production of clean molecules.

4.3.1 Scenario design

Demand-side flexibility here combines two components, EV charging flexibility and heating flexibility. The former aims at quantifying the maximum penetration of flexible EV chargers as well as vehicle-to-grid (V2G)-enabled ones. The uptake ranges from a "No Flex" case where neither smart charging nor V2G is available, through a "Reference" case with more moderate and gradually increasing shares (following the projections from the Elia Adequacy and Flexibility study 2026-2036[9], interpolated with the results of the survey by TML for 2050[10]), up to a "High Flex" case in which smart charging is already fully available from 2030 onward and vehicle-to-grid uptake follows a more optimistic scenario drafted starting from the aforementioned survey, climbing progressively from a negligible share in 2030 to around 70% by 2050 (Figure 4-9). Heating flexibility similarly ranges from “No Flex” to Reference flex where only flexibility for water heating is allowed, to High flex with full flexibility for heating technologies, allowing to range between plus 50% and minus 50% of the baseline heating demand.

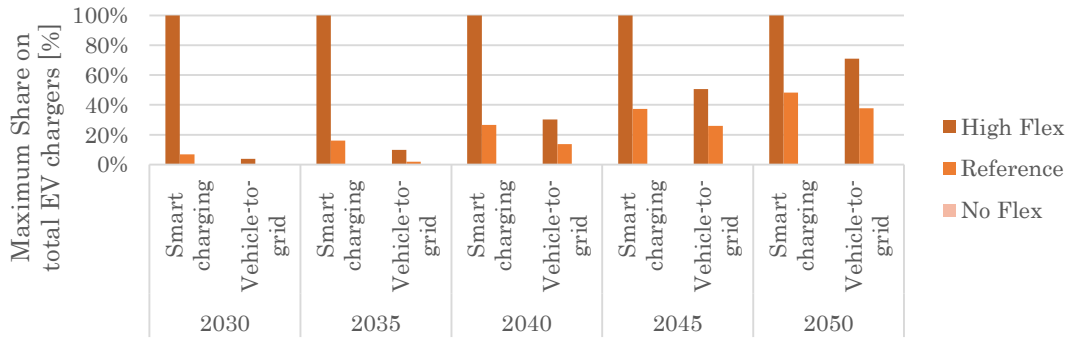


Figure 4-9: Maximum uptake of flexible EV chargers for different scenario choices

The sensitivity analysis on P2X is focused here specifically on the power-to-hydrogen step, being it the crucial step for local clean molecules generation. While for the NoP2X scenarios, the assumption is simply the one to exclude this kind of technologies, for the High P2X scenarios, electrolyzer investment costs (covering alkaline,

[9] https://www.elia.be/en/electricity-market-and-system/adequacy/adequacy-studies
[10] https://epocbelgium.be/sites/epoc/files/2.2.2.2%20Vanp%C3%A9e%20et%20al.%20V2G%20market%20potential.pdf

PEM, and SOE technologies) is assumed to halve by 2040 and 2050 relative to the Reference cost trajectory (Figure 4-10). This reflects an accelerated cost-reduction pathway for electrolyzer technologies compared to the more conservative Reference case.

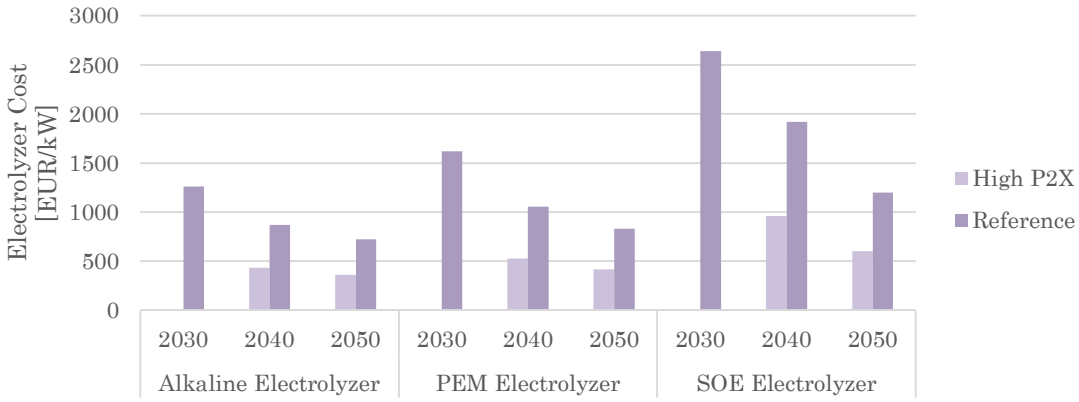


Figure 4-10: Electrolyzer cost per type and scenario choice option

Based on these assumptions, four extreme combinations were run, crossing the presence or absence of demand-side flexibility (Flex vs. NoFlex) with the presence or absence of accelerated P2X cost reduction (P2X vs. NoP2X), reflecting the full range from weak to strong sector-coupling. The REFERENCE scenario is also included as a reference point to the extreme cases, and to allow a quantification of the system cost gains and losses.

Table 4-1: Extreme scenario cases ranging from weak to strong sector-coupling

	Power-2-X potential		
Demand flexibility potential	**Demand-side Flex only** *High* demand side flex *No* power2X and H2-storage		**Strong sector-coupling** *High* demand side flex *Low-cost* power2X and H2-storage
		REFERENCE *Ref* demand side flex *Ref* power2X and H2-storage	
	Weak sector-coupling *Low* demand side flex *No* power2X and H2-storage		**P2X only** *Low* demand side flex *Low-cost* power2X and H2-storage

4.3.2 Results and discussion

The results confirm the expected direction: system costs increase in the cases without demand-side flexibility, which emerges as the dominant driver of cost savings, and further increase when P2X cost reduction is also unavailable. Comparing undiscounted annualized savings relative to the Reference scenario across the four extreme cases in 2030 and 2050 provides several useful insights.

In 2030, savings remain modest and relatively similar across the cases with equal demand-side flexibility, with a more significant difference between the scenarios with high and low demand-side flexibility. This is expected, since demand flexibility options cost reductions have had time to diverge substantially from the Reference case this early in the horizon.

By 2050, the picture changes considerably. The two flexible cases (Strong sector-coupling and Demand-side flex only) show markedly higher savings compared to the two non-flexible cases (Weak sector-coupling and P2X only), which show negative savings relative to the Reference scenario. This confirms that demand-side flexibility, rather than P2X cost assumptions, is the primary lever driving system cost reductions by mid-century.

Looking at the cost components behind these savings, the high-flexibility cases benefit substantially from lower investment needs in insulation and heating technologies, as well as meaningful savings in batteries as a source of flexibility, and dispatchable power plant capacity. This is partially counterbalanced by higher investments in EV chargers and PV capacity.

The non-flexible cases, by contrast, show negative contributions concentrated in "Other Import/Export" and dispatchable power plants, indicating that the absence of flexibility forces the system into costlier import positions (for both fossil and clean fuels) and higher reliance on dispatchable generation to cover peak demand. Interestingly, the Weak sector-coupling case in 2050 shows the largest negative swing in "Other Import/Export", reinforcing that the combined absence of both flexibility and cheap P2X technology compounds the system's reliance on costly imports rather than domestic, flexible solutions.

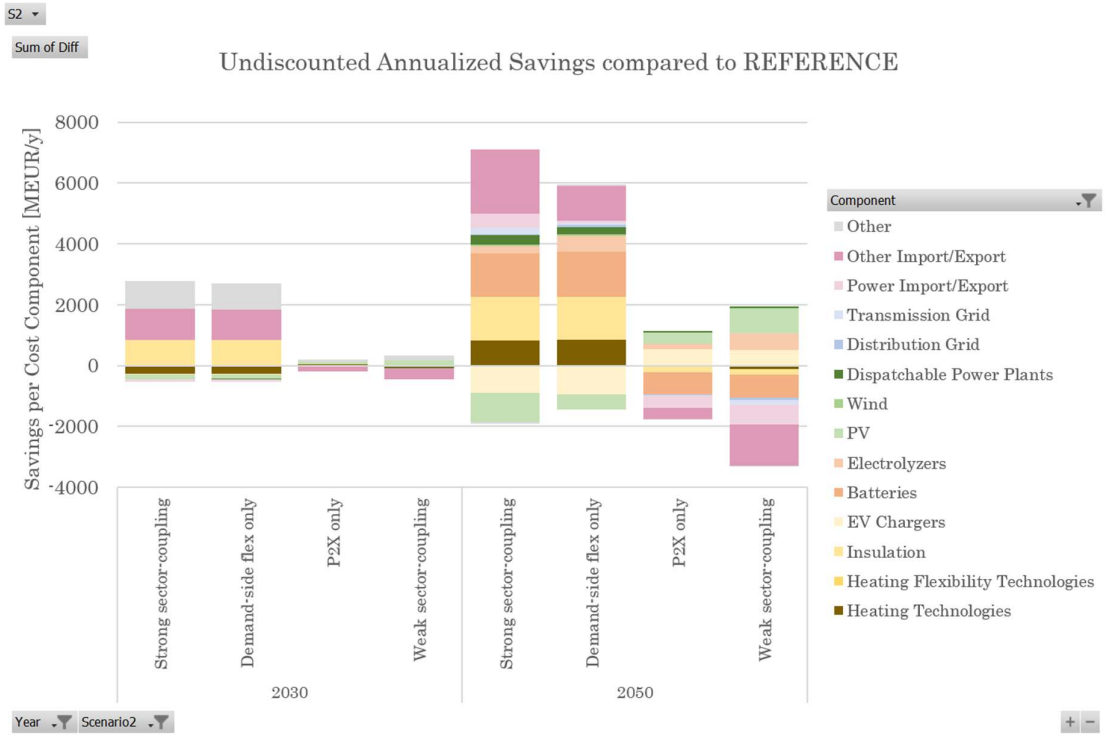


Figure 4-11: System cost savings and additional expenditure of sector-coupling scenarios compared to the REFERENCE scenario

Note that hydrogen demand under the ROTORS storyline is partly driven by the CCS limit of 10Mt per year, which in turn drives hydrogen demand for methanol synthesis. Therefore, additional scenario variants were generated by relaxing the constraint on Carbon Capture and Storage (CCS) potential in the ROTORS storyline for the scenarios that could not rely on P2X. Unlocking a higher CCS potential gives the model more room to decarbonize domestically rather than relying on imported clean molecules, which in turn may reduce the volume of clean molecule imports needed in 2050.

Looking at hydrogen production and imports by source across the extreme cases (Figure 4-12), a clear substitution pattern emerges depending on P2X availability and CCS constraints. When P2X is enabled and electrolyzers are cheap, domestic hydrogen production (via PEM and alkaline electrolysis) reaches around 7 TWh in 2040 and roughly 15 TWh/year by 2050. When P2X is disallowed, this volume is replaced by pipeline imports. The picture changes substantially, however, once CCS is unconstrained: in the No CCS Limit variants, the overall need for hydrogen production and import, as the availability of lower-cost domestic decarbonization via CCS displaces the need for clean hydrogen and clean molecules.

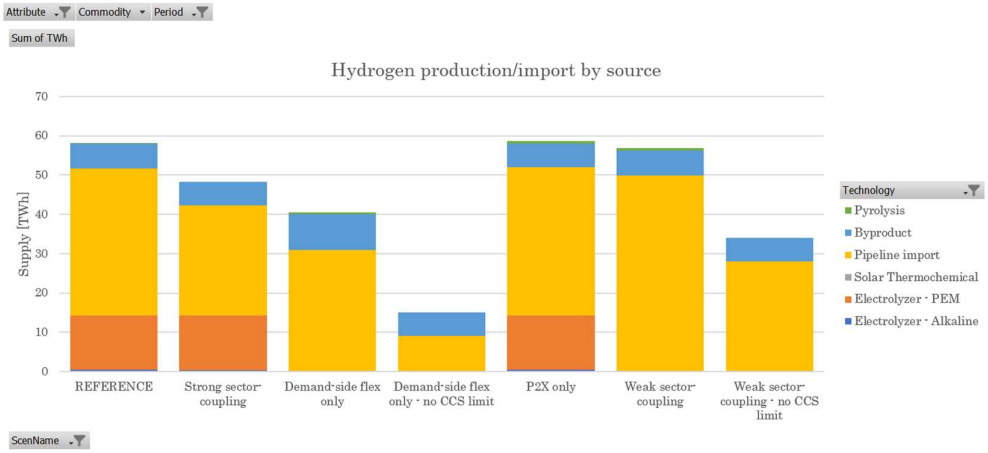


Figure 4-12: Hydrogen supply for all sector-coupling scenarios (year 2050)

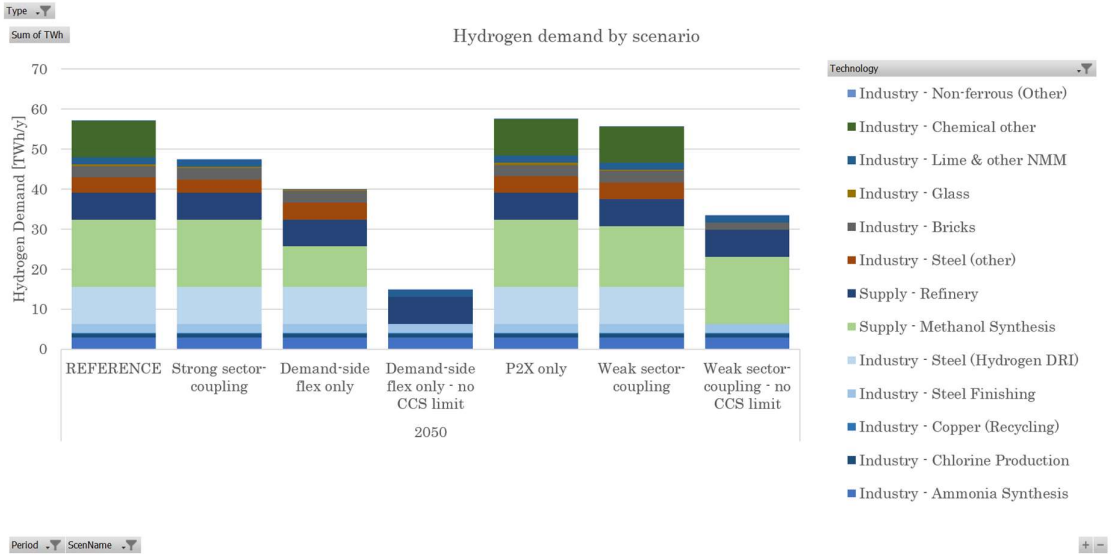


Figure 4-13: Hydrogen demand for all sector-coupling scenarios (year 2050)

Concerning centralized hydrogen storage capacity, finally, we observe that disabling P2X removes domestic electrolysis and shifts supply toward imported hydrogen instead, consequently removing the need for hydrogen storage capacity (Figure 4-14). For other scenarios, tanks storage capacities come into play, mostly so for the reference case. This suggests that the need for tank storage is correlated with both P2X, as well as the level of demand-side flexibility and the overall level of hydrogen demand. But its precise role as a flexibility provider in the energy system needs to be addressed in future research.

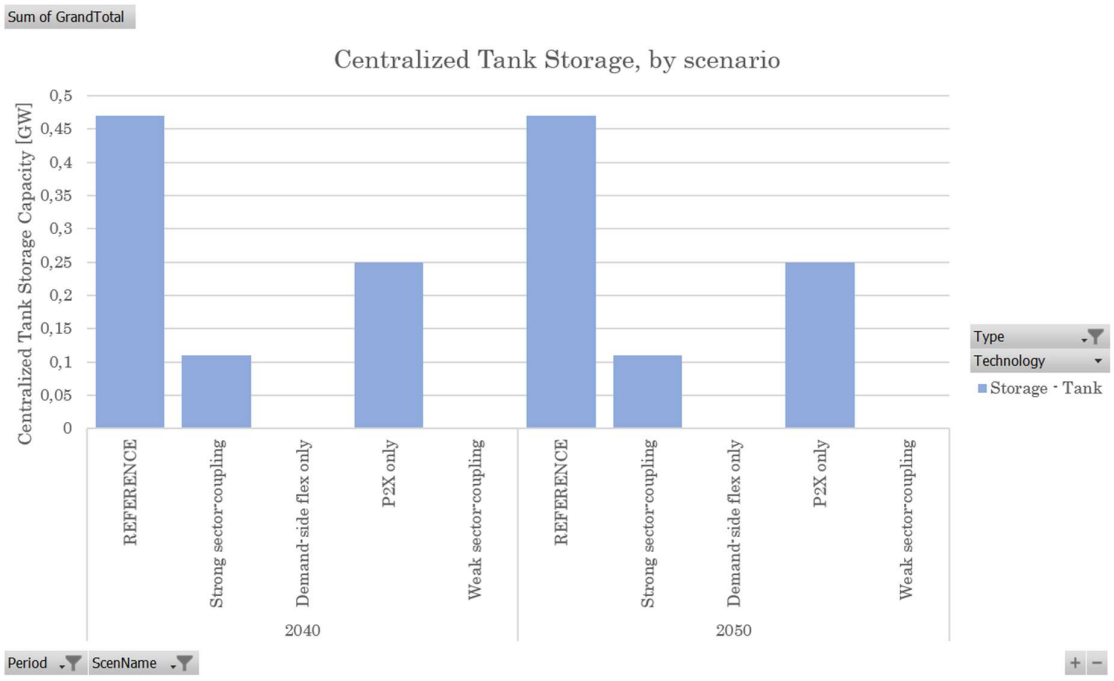


Figure 4-14: Hydrogen tank storage capacity by scenario

4.4 Benefits and challenges of a combined model analysis

We conclude this section with a methodological reflection on the main added values and challenges of combing different models in the analysis. In general, combining different types of models in a consistent analysis is important to bridge different strands of knowledge. This holds, for example, for combining energy and economy models to capture the interaction between energy system and macro-economic development [16]. Different ways of combining models can be envisaged, ranging from applying models separately, to iterative model-linking procedures, to model integration [17].

The combined analysis tested in this chapter has stayed within the realm of the energy system. It focused on bridging different types of energy system optimization models, i.e. a more integrated model (TIMES-BE) co-optimizing demand and supply, and more supply-side oriented models (NSIM, POMMES) based on exogenous demand projections, but with a broader geographical scope and higher detail for representing energy supply chains and infrastructures. The methodological approach followed the rationale of iterative soft-linking, covering one iteration of a two-way data exchange between the two models.

During this exercise, the modelling teams encountered several methodological and practical challenges. First, iterative soft-linking is a rather time-intensive process that requires significant effort for understanding the different modelling approaches, for comparing model inputs and results (with generally different sector

disaggregation), and preparing data-exchanges in the right formats. Secondly, more fundamental challenges relate to model consistency. Although the different model assumptions can be aligned to some extent, there are limits to this alignment, amongst others due to the sheer number of potentially relevant assumptions adopted over significant model development periods. A concrete consistency issues encountered in linking TIMES-BE and NSIM is the adoption of different weather years, which may significantly affect results, and is difficult and time-intensive to modify. Another consistency issue arose from differences in geographical scope. While the demand side projections offered by TIMES-BE only cover Belgium, remaining North-Sea countries followed original TYNP projections, which dampened the potential impact of demand-side changes on supply-side model results. Moreover, this may imply limited coherence of demand-side projections between Belgium and other North-Sea countries.

Yet, the modelling exercise was also valuable. In general, it forces modelling teams to critically reflect on specific modelling assumptions, when other models suggest alternative plausible assumptions. In the concrete application described above, for example, TIMES-BE offers alternative demand projections for hydrogen and its derivatives with generally lower industry demands compared to the TYNDP2024 Distributed Energy scenario. Vice-versa, substituting TIMES-BE clean molecules import price assumptions with NSIM output significantly drives up modelled hydrogen demand. The POMMES model finds relatively large shares of domestic electrolysis compared to TIMES-BE, which spurs reflection on the specific drivers behind. Yet, further research is needed to analyse those model differences in detail, whether related to electricity generation potentials and costs, energy commodity prices, weather data, model structure and scope and other factors affecting competitive domestic production. Overall, allowing experts to learn from other models and other experts contributes to an improved global knowledge in the industry.

From this perspective, further combined model analysis would be beneficial, which could also be based on stand-alone model application. Such an analysis could be structured around specific research questions, for example on the cost-optimal level of domestic green hydrogen in Belgium, or on the role of offshore electrolysis. Consequently, addressing these questions from the perspective of different models, with careful analysis of the explanatory factors of differences in model results, would lead to insights into main controversies: the critical uncertain factors underlying different viewpoints on energy system planning. This, in turn, could provide valuable insights to maintain a broad scope of plausible futures in further scenario design.

5 Conclusion: main impacts of sector-coupling

In this report, sector-coupling was analysed from a system-level, top-down perspective. The first aim of this deliverable has been to examine the scalability and replicability potential of the different business use cases deployed under ReInvent, to understand how local-level sector-coupling initiatives can generate impacts beyond the pilot and simulation phases. A second aim has been to evaluate the impact and value of sector-coupling, particularly for electrification and demand-side flexibility, for Power2X in relation to clean molecules import, and for multi-energy market design. A methodological objective, finally, was to explore how different system level models can work together in a complementary way through a combined model analysis.

Scalability and replicability potential of the business use cases

Concerning the scalability and replicability potential of the business use cases, the analysis shows that sector-coupling solutions generally have potential for wider deployment, but that scaling and replication depend on the alignment of technical, economic, regulatory and stakeholder-related boundary conditions. Scalability and replicability should therefore not be understood as straightforward expansion or duplication of successful pilots. While many of the underlying technologies and operational principles are transferable, deployment at larger scale or in new contexts typically requires adaptation to local infrastructure, market conditions, regulation and stakeholder needs.

For electrification and demand-side flexibility, the growing deployment of EVs, heat pumps, batteries and other controllable electrical assets create an expanding flexibility potential. Realising this potential at scale, however, requires effective coordination of increasingly diverse and distributed resources, and sufficient economic incentives for users to participate. Replication across regions and customer groups appears feasible because the underlying flexibility principles are broadly transferable, but implementation needs to account for differences in asset availability, interoperability, tariffs and flexibility mechanisms, regulation and user preferences.

For collective energy sharing, modularity and economies of scale can support wider deployment by spreading fixed costs across more participants and improving opportunities to match local generation and demand. At the same time, expansion can increase governance and administrative complexity and may encounter local infrastructure constraints. Replication is particularly dependent on the regulatory and market context, as well as on locally appropriate governance, contractual and benefit-sharing arrangements. The analysis therefore points to a balance between standardisation and local adaptation: common technical and organisational solutions can reduce replication efforts, but each project still needs to fit local conditions and provide a transparent and credible value proposition for participating stakeholders.

For clean molecules and Power2X, scalability and replicability are more strongly conditioned by the surrounding infrastructure and market ecosystem. Although technologies such as electrolysers are modular and

increasingly standardised, scaling requires sufficient renewable electricity and grid capacity, suitable hydrogen transport and storage infrastructure, and stable demand from industrial or mobility off-takers. Economic viability remains closely linked to high utilisation and sufficiently competitive hydrogen production, while permitting and renewable hydrogen requirements can further influence project development. Replication is therefore less a matter of reproducing a standard technical configuration than of finding locations where the necessary infrastructure, demand, regulatory conditions and stakeholder commitments can be brought together.

The impact and value of sector-coupling at system level

The system-level impact assessment on sector-coupling has analysed the value of different sector-coupling options, which generally have significant system benefits. Demand side flexibility technologies are largely 'no-regret' from a techno-economic perspective, since they provide high value to the system at low cost. Water heating buffers and flexible EV charging, for example, prove highly attractive from a system optimization perspective, reaching the full utilization of their maximum potential in every scenario where they are enabled. Other flexibility options, like thermal inertia in buildings and the uptake of two-way flexible charging (vehicle to home, building or grid) are exploited more moderately up to respectively some 20% and 35% of their maximum potential. Overall, the monetary system-level benefits from demand side flexibility are significant, and can be attributed to having more VRE integration, lesser imports of power and molecules, lesser battery investment, and more efficient heating systems.

Besides electrification, hydrogen and other clean molecules are found to have an important role in a climate-neutral Belgian energy system, although significant uncertainty applies. There is considerable uncertainty on the drivers of hydrogen demand, such as access to affordable electricity, deployment of CO_2 storage, regulatory requirements on renewable hydrogen supply. As a result, hydrogen demand scenarios for Belgium developed with TIMES-BE indicate a broad range from some 11 to 30 TWh (out which some 6 TWh being supplied as a byproduct, mainly from refineries). Furthermore, there is uncertainty on cost-optimal hydrogen supply routes, with different results among the different cases and models (TIMES-BE, NSIM, POMMES). For example, the models TIMES-BE and POMMES differ on the cost-optimal domestic supply routes, with notably higher levels of electrolysis in POMMES compared to TIMES-BE. To fully appreciate these model differences, further research is needed to further analyse differences in electricity prices, commodity prices, weather data and other factors affecting competitive domestic production. Overall, first estimates of the value of Power2X for Belgium indicate significant system-levels savings from enabling Power2X, albeit smaller to those of demand side flexibility. These savings could materialize over a long-term timeframe (2050) and are primarily attributed to enhanced PV integration, with reduced needs for imported clean molecules and power.

More coordinated energy market designs can be an important enabler for sector coupling. The Belgian electricity, gas, hydrogen and heat markets are already physically interconnected through technologies that

convert energy between carriers. However, these physical interactions are not yet fully reflected in market organisation. Differences in trading products, temporal granularity and market arrangements can limit the ability of multi-carrier technologies to respond efficiently to signals across energy markets. The results indicate that temporal granularity and temporal alignment represent two distinct dimensions of market coordination. Greater market granularity, more specifically through shorter day-ahead gas or hydrogen products, consistently improves the ability of flexible technologies to respond to changing market conditions and is the main driver of the observed profitability gains. Temporal alignment has a smaller effect on annual profitability but can substantially influence how flexibility is made available to the balancing market. The magnitude and direction of both effects depend strongly on the technology and the combination of markets in which the technology participates. These findings therefore support a coordinated approach to market design, in which changes to gas, hydrogen, electricity and balancing-market structures are considered jointly rather than independently.

We conclude with main methodological reflections on ways in which different system level models can work together in a complementary way. An iterative soft-linking procedure was tested between the more integrated energy system model TIMES-BE and the more supply-oriented model NSIM, covering one iteration of a two-way data exchange. This modelling exercise was valuable as it forces modelling teams to critically reflect on modelling assumptions that - in light of uncertainty - may be chosen differently between different models. Yet, the exercise is also challenging, first since model coupling is a time-intensive process, and second as it remains difficult to arrive at fully consistent model set-ups. Further combined model analysis, therefore, could also consider stand-alone model application structured around common research questions. Careful analysis of the explanatory factors of differences in model results would reveal critical uncertain factors underlying different viewpoints on energy system planning, as a valuable input for further scenario analysis and robust policy-making.

References

[1] ReInvent, "Deliverable 1.1 Implication and opportunities for sector coupling in Belgium," 2024. [Online]. Available: https://reinvent-project.be/en/publications. [Accessed September 2026].

[2] ReInvent, "Deliverable 3.4 Evaluation of Business Use Cases.," 2026. [Online]. Available: https://reinvent-project.be/en/publications. [Accessed October 2026].

[3] ReInvent, "Deliverable 1.2 Report on improved market design, business models and financing models for sector coupling," 2026. [Online]. Available: https://reinvent-project.be/en/publications. [Accessed October 2026].

[4] L. Sigrist, K. May, A. Morch, P. Verboven, P. Vingerhoets and L. Rouco, "On Scalability and Replicability of Smart Grid Projects—A Case Study.," 2016. [Online]. Available: https://doi.org/10.3390/en9030195.

[5] D. Makrygiorgou, N. Andriopoulos, I. Georgantas, J. Rong, I. Moraitis, E. Calatayud and M. Matoses, "Scalability and replicability analysis of smart grid projects: Insights from the H2020 CROSSBOW project," *Frontiers,* 2023.

[6] EC, "Guidelines for implementing the prescribed technology – Additional subroutines and requirements, scientific background and state of the art, scalability & replicability task force," 2023. [Online]. Available: https://data.europa.eu/doi/10.2833/48123.

[7] VITO / EnergyVille, "PATHS2050: The Power of Perspective," [Online]. Available: https://perspective2050.energyville.be/. [Accessed September 2026].

[8] ALEXANDER, "Deliverable 4.2 Energy system planning informed by consumer preference for the adoption of exible electric vehicle chargers in Belgium," 2025.

[9] ReInvent, "Deliverable 2.1 The ReInvent modelling environment," 2026. [Online]. Available: https://reinvent-project.be/en/publications. [Accessed October 2026].

[10] VITO / EnergyVille, "PATHS2050 Deepdive 2025 Scenarios: Molecules," September 2026. [Online]. Available: https://perspective2050.energyville.be/results/main-edition-2025/deepdive-2025-scenarios/molecules.

[11] Elia, "Day-ahead reference price," 2026. [Online]. [Accessed 10 July 2026].

[12] Elia, "Open data – activation prices (dataset ods166).," 2026. [Online]. [Accessed 10 July 2026].

[13] Elia, "Open data – activation volumes (dataset ods127)," 2026. [Online]. [Accessed 10 July 2026].

[14] ENTSO-E, "Transparency platform – amount and prices paid of balancing reserves under contract," 2026. [Online]. [Accessed 10 July 2026].

[15] EEX Group, "EEX Public Market Data," EEX Group Webshop, 2026. [Online]. Available: https://webshop.eex-group.com/eex-public-market-data. [Accessed 13 August 2026].

[16] P. Crespo del Granado, R. van Nieuwkoop, E. Kardakos and C. Schaffner, "Modelling the energy transition: A nexus of energy system and economic models," *Energy Strategy Reviews,* vol. 20, p. 229–235, 2018.

[17] E. Lenaerts, "Endogenizing Industrial Demand in Energy System Optimization Models. A Novel: Classification and Case Studies," in *Presented at IAEE Conference: Energy Solutions for a Sustainable and Inclusive Future*, Paris, 2025.