RESTOR

Renewable Energy STORage planning model for islandic energy systems

Deliverable 3.1

Definition of use cases and business models for energy storage

Work Package 3

Funded by the CET Partnership 2023 under code CETP-2023-00031

cet Partnership

Co-funded by
the European Union

Proposal code	CETP-2023-00031
Project Acronym	RESTOR
Project Title	Renewable Energy STORage planning model for islandic energy systems
Starting date of project	15.12.2024
Project duration	36 months

Work package	WP3: Methods, requirements and concepts
Related task	T3.1: Definition of use cases and business models for energy storage
Deliverable due date	M10: 30 October 2025
Actual delivery date	30 January 2026
Dissemination level	PU – Public
Deliverable responsible	UR

Document Information

Document Version:	1.1
Revision / Status:	Ready for submission

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Document History

Revision	Content/changes	Resp. partner	Date
0.1	Initial draft and draft structure	UR	01 September 2025
0.2	First draft	UR	17 October 2025
0.3	Updated version	UR	2 December 2025
1.0	Updated version for submission	UR	23 January 2026
1.1	Updated template and disclaimer	UR	24 January 2026

Document Approval

Final approval	Name	Resp. partner	Date
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Executive Summary

This deliverable provides a comprehensive framework for defining energy-storage use cases and business models across four diverse pilot regions: the Aran Islands (Ireland), Gotland (Sweden), La Réunion (France), and Remanso (Brazil). These locations represent a wide spectrum of geographical, socio-economic, technical, and regulatory conditions, allowing RESTOR to explore solutions adaptable to different forms of islanded and weakly interconnected energy systems.

The methodology integrates multiple layers of analysis within a harmonised framework that supports cross-site comparability. It begins with a detailed characterisation of each pilot's energy infrastructure, stakeholder ecosystem, regulatory framework, and socioeconomic context. This is followed by a review of relevant storage technologies and integration potentials. Each use case is then formulated in a structured manner, defining objectives, system boundaries, actors, operational sequences, performance metrics, and enabling conditions. The methodology concludes with business-model development using a Business Model Canvas approach.

There is a diversity of challenges across sites—from grid constraints, inertia scarcity and seasonal demand fluctuations, to socio-economic vulnerabilities, regulatory uncertainty and microgrid governance issues. Yet they also reveal common opportunities: strong renewable resources, emerging flexibility markets, supportive policy frameworks, community willingness to engage, and the growing maturity of storage technologies. Use cases include peak-shaving and backup resilience in the Aran Islands, production expansion and frequency regulation in Gotland, multi-service grid support in La Réunion, and renewable-powered microgrid consolidation in Remanso.

Each use case is complemented by a preliminary business model describing pathways for value creation and revenue stacking. These models highlight the importance of combining multiple services to achieve financial viability. The analysis underscores that while commercially driven models can be viable in European island contexts, community-led and grant-supported models remain essential in regions such as Remanso.

Overall, this deliverable lays a foundation for the technical simulations and MCDA evaluations that will follow in WP3–WP5. It provides the conceptual and analytical building blocks needed to design storage configurations that are not only technically sound but socially inclusive, economically sustainable, and replicable across insular and isolated energy systems.

Contents

Abbreviations

AIT	Austrian Institute of Technology (Austria)
BESS	Battery Energy Storage System
CAPEX	Capital Expenditures
DSO	Distribution System Operator
EMS	Energy Management System
ESS	Energy Storage System
GDPR	General Data Protection Regulation
HVDC	High Voltage Direct Current
MCDA	Multi-Criteria Decision Analysis
OPEX	Operational Expenditures
RES	Renewable Energy Sources
RG	Region Gotland (Sweden)
SCADA	Supervisory Control and Data Acquisition
TRL	Technology Readiness Level
TSO	Transmission System Operator
UG	University of Galway (Ireland)
UR	Université de La Réunion (France)
UU	Uppsala University (Sweden) – Project Coordinator (RESTOR)
V2G	Vehicle to Grid
VoLL	Value of Lost Load
VPP	Virtual Power Plant

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1 Introduction

This deliverable focuses on defining use cases and business models for energy storage, serving as a cornerstone for Work Package 3 within the RESTOR project. Our main goal is to develop a thorough understanding of what each community actually needs when it comes to energy storage, along with the real-world opportunities and challenges they face.

We're working with four very different communities, each offering unique insights into island energy planning:

- **Aran Islands (Ireland)**: Home to about 850 people, these islands show us the energy realities of small, remote communities where every resident knows their neighbours and energy decisions directly impact daily life
- **Gotland (Sweden)**: With 61,000 inhabitants, this island demonstrates how medium-sized communities balance growing energy needs with sustainable development goals
- **La Réunion (France)**: This overseas territory of 900,000 people presents the complex energy puzzle of a large, diverse island population with varied economic activities
- **Remanso (Brazil)**: Though technically on the mainland, this isolated community faces the same energy challenges as any island, showing us that geography isn't just about being surrounded by water

Our work here covers four main areas. We start by getting to know each place - understanding not just their energy infrastructure, but also who makes the decisions, what regulations they navigate, and how their geography shapes their options. We then dig into what's holding back energy storage deployment and what conditions might help it succeed. From there, we develop specific use cases that actually make sense for each community's unique situation and needs. Finally, we sketch out business models that could realistically work in these contexts, considering local economic conditions and stakeholder capabilities.

2 Methodology

This section outlines the methodology adopted for this deliverable, detailing the processes and tools applied throughout its execution. It describes the approach used for data collection, analysis, and validation, as well as the technical procedures and decision-making criteria guiding this task. The objective is to provide a transparent and replicable method, ensuring the project is consistent. The following methodology has been developed in coherence with the overall WP3–WP5 workflow and is applied uniformly across the four pilot sites.

The definition of use cases and business models for the pilot sites complies with a cohesive methodological framework that integrates technical analysis, regulatory and socio-economic evaluation, and stakeholder involvement. The goal of this process is to make sure that each use case takes into account the local situation, addresses the energy problems that have been identified, and leads to a business model for deploying energy storage in systems that are isolated or only partially connected to the grid.

2.1 Characterisation of Pilot Sites

The process starts with a thorough description of the pilot sites. This includes:

- mapping the current energy infrastructure and looking at the characteristics of generation, transmission, and demand;
- looking at national and regional energy plans to find local priorities and transition goals;
- looking at regulatory and policy frameworks that set the rules for the current market, grid codes, and incentives for integrating renewable energy and storage;
- finding key stakeholders and possible obstacles.

This first step provides the basic knowledge required to develop energy storage use cases that are specific to each pilot.

2.2 Review of energy storage technologies and integration potentials

In parallel, the state-of-the-art in energy storage technologies is reviewed, including their technical characteristics, costs, and maturity levels, as well as their integration potential in island and isolated energy systems. The outcome of this step is a pre-selection of feasible technologies for each pilot site, forming the technical foundation for subsequent simulations and use case formulation.

2.3 Definition of use cases

Based on contextual and technological analyses, specific use cases are defined for each pilot. Each use case represents a targeted operational scenario in which storage provides a service or solves a system challenge. The use cases are defined through a framework that includes objectives and rationale, actors and roles, system boundaries and preconditions, operational sequence, performance indicators, and barriers and enablers.

2.4 Definition of Business Models

For the selected use cases, business models are developed to define the mechanisms through which value is created and captured. Each business model follows the Business Model Canvas structure, specifying the value proposition, customer segments and stakeholders, revenue streams, cost structure, and partnerships. This ensures that each technically feasible use case is supported by a financially sustainable model for implementation.

2.5 Link to other tasks and work packages

Following the definition of use cases, a number of simulations of potential storage configurations are conducted under realistic regional conditions (WP3). These simulations integrate parameters such as grid constraints, load forecasts, renewable generation potential, and network codes. Each configuration is tested for its ability to meet the regional energy transition goals while improving flexibility, reliability, and renewable integration.

The simulated configurations and their associated use cases are evaluated through a multi-criteria decision analysis (MCDA) approach (WP4–WP5). The evaluation criteria (technical, environmental, social, and economic) are defined through stakeholder consultation and adapted to each regional context. Each criterion is assigned a relative weighting, and the overall performance of each use case is assessed accordingly.

Finally, the defined use cases and business models are validated through stakeholder feedback, expert review, and pilot-level testing. Their replicability and scalability are analysed to identify the conditions under which similar solutions can be deployed in other islands or isolated systems.

In summary, this methodology ensures that the development of energy storage use cases and business models is grounded in technical evidence, regulatory realities, and stakeholder priorities. It provides a systematic path from contextual analysis to validated solutions, contributing to the acceleration of energy transition in island and isolated energy systems.

3 Energy storage state-of-the-art

3.1 Overview of energy storage solutions and applications in island systems

Energy storage is crucial for the transition to low-carbon energy systems in non- or weakly interconnected power networks. These systems face distinct constraints associated with isolation, a significant reliance on imported fossil fuels, and restricted grid interconnections, which limit flexibility and increase generation costs. At the same time, islands have generally significant renewable energy potential, especially wind, solar, and hydro resources, establishing optimal conditions for storage-enabled decarbonisation.

Current research and practical experience demonstrate that energy storage systems (ESS) are essential for sustaining grid stability, optimising renewable energy use, and enhancing system resilience. The primary technologies relevant to island situations can be categorised by discharge duration (Table 1).

Table 1. Energy storage technologies categorization by discharge duration

Category	Representative Technologies	Maturity Level	Primary Applications in Island Systems
Short-term (seconds–minutes)	Flywheels, Supercapacitors, Lithium-ion	Commercial	Frequency and voltage regulation, synthetic inertia, black-start capability
Medium-term (minutes–hours)	Lithium-ion, Sodium-sulfur, Redox-flow batteries	Mature / Commercial	Renewable firming, peak shaving, load shifting, system optimization
Long-term (hours–days–months)	Hydrogen, Compressed Air, Thermal Energy Storage (TES), Gravity storage (Pumped-hydro)	Emerging / Demonstration (except for Pumped-hydro)	Seasonal balancing, sector coupling, resilience, long-duration backup

Electrochemical storage, particularly lithium-ion battery systems, constitutes the predominant storage method utilised on islands, accounting for around 60% of all applications (Psarros, 2024). Global prices for systems have significantly decreased in recent years. By 2024, the average price is projected to be approximately 165 USD/kWh, reflecting a 40% decrease from the preceding year (BloombergNEF, 2024). These trends render Li-ion battery the optimal selection for small and medium-sized island grids due to its rapid response to frequency fluctuations, ability to substitute spinning reserves, and enhancement of renewable energy sources.

Pumped-hydro storage (PHS) remains the most advanced large-scale solution. It possesses a lifespan of several decades and a round-trip efficiency ranging from 70% to 85%. The hybrid wind-pumped hydro storage system at El Hierro (Canary Islands) has demonstrated renewable penetration exceeding 40% (Latorre, 2019). Marine PHS alternatives are emerging for islands lacking mountainous terrain, such as Symi and Astypalaia (Katsaprakakis, 2019). These utilise seawater as a storage medium.

Hydrogen and Power-to-Gas technologies are the most effective solutions for long-term and seasonal storage. On the islands of Orkney and Majorca within the European project BIG HIT (Orkney) and GREEN HYSLAND (Majorca), two pilot sites are set to absorb additional renewable energy, reducing CO_2 emissions, and operating for extended periods without requiring external power sources. Despite the current low round-trip efficiency of approximately 40%, the economic outlook is promising due to decreasing hydrogen production costs, projected to reach 1.0–1.5€/kg by 2050, alongside increasing regulatory assistance.

Complementary technologies such as hydro-pneumatic systems (HPES) were diligently developed. The FLASC project in Malta demonstrated that underwater compressed air energy storage achieved a thermal efficiency of over 93%, indicating its compatibility with offshore wind power (Buhagiar, 2019). Thermal energy storage (TES), power-to-heat systems, and sector integration with desalination, heating and cooling, and electric mobility enhance the significance of storage in island ecosystems.

3.2 Lessons learned from demonstration projects and literature

A large number of European and international initiatives such as TILOS (Greece), SMILE (Orkney, Samsø, Madeira), INSULAE (Menorca, Bornholm), ISLANDER (Borkum), and MAESHA (Mayotte), have generated substantial evidence on the technical, economic, regulatory, and social dimensions of storage deployment in insular and isolated systems. These findings confirm and complement the lessons highlighted in recent European demonstration projects.

From a technical standpoint, storage systems (particularly fast-response BESS) have proven essential for maintaining grid stability in low-inertia island systems. Demonstrations show that advanced energy management systems (EMS), accurate forecasting, and grid-forming inverter capabilities significantly enhance the ability of hybrid systems (RES + storage) to reach high renewable penetration levels, often above 80 %, while maintaining frequency and voltage stability (Kaldellis 2020). These results are consistent with European pilots showing that multistorage coordination (e.g., hybrid storage such as RFB + supercapacitors) improves overall performance by combining long-duration energy delivery with rapid frequency support. Moreover, several projects confirm the technical value of Virtual Power Plant (VPP) approaches for increasing system flexibility and reducing RES curtailment.

Economically, hybrid RES-plus-storage systems achieve levelised costs of electricity (LCOE) markedly below diesel-based generation typically around 0.15–0.25 USD/kWh, compared with 0.30–0.50 USD/kWh for diesel (Kaldellis, 2020). European demonstrations further show that the financial viability of BESS depends strongly on local electricity price structures and the availability of targeted incentives. Without adequate support schemes, high upfront CAPEX for batteries remains a barrier, as reported in TILOS and SMILE business-model assessments. Additionally, projects such as MERLON highlight the need to balance revenue-oriented operation (e.g., energy arbitrage or ancillary services) with maintaining sufficient State of Charge (SoC) to guarantee security of supply in islanding mode, where the avoided cost of lost load (VoLL) can be significant, reaching values around 10,000 €/MWh in some pilots of the MERLON project.

On the social and governance dimensions, community-based models remain a cornerstone for gaining and sustaining public acceptance. They are well illustrated in Samsø (Denmark) and in the COMPILE project. The document further stresses the importance of co-ownership structures, transparent tariff mechanisms, and local reinvestment schemes as long-term enablers of community support. Capacity-building is equally critical: small island experiences (e.g., Tonga or Apolima) align with European findings indicating that local technical skills, maintenance capabilities, and robust communication infrastructure (4G, secure SCADA links) are prerequisites for reliable operation and for reducing dependence on external service providers.

The regulatory environment also plays a decisive role. Constraints on maximum RES penetration, along with lengthy permitting procedures and fragmented administrative responsibilities, can slow down deployment, as observed in INSULAE and RE-EMPOWERED. Conversely, pilots implemented in fully isolated systems demonstrate that regulatory frameworks crafted for island-wide use cases can be highly replicable across other remote or non-interconnected areas.

In summary, the key enabling factors for large-scale storage deployment in insular and isolated systems are:

- Integrated hybrid systems combining renewables, storage, advanced EMS, and demand-side management;
- Coherent regulatory and market frameworks that recognise both the economic and resilience value of storage;
- Community participation, knowledge transfer, and local capacity-building to ensure durability and replicability of the solutions.

These conclusions are consistent with the broader lessons from European projects, which show that storage acts not only as an energy asset but also as a resilience mechanism capable of transforming structurally vulnerable island grids into high-renewable, stable, and economically viable systems.

3.3 Analytical framework and evaluation criteria

To ensure comparability among the project's pilot regions, a harmonised and multidimensional analytical framework has been established. This framework integrates technical, environmental, economic, social-regulatory, and ICT-related criteria and follows the structure applied in recent European initiatives and KPI catalogues for smart grids and energy-storage demonstrators. It aligns with evaluation practices used in projects such as INSULAE, ISLANDER, and GIFT, and draws on state-of-the-art indicator sets identified in the literature. The resulting framework provides the basis for use-case definition (WP3) and subsequent multi-criteria decision analysis (WP4–WP5).

3.3.1 Technical dimension

This dimension captures the operational efficiency, reliability, and grid-support performance of storage systems under island conditions.

- Frequency and voltage regulation capability; synthetic inertia provision (grid-forming behaviour)
- Renewable-curtailment reduction (%)
- Energy-autonomy and resilience indicators (e.g., storage-to-load ratio, islanding capability)
- Round-trip efficiency and conversion losses
- Battery State of Health (SoH) and expected lifetime under local cycling conditions
- Performance degradation and stress factors specific to island grids (low inertia, frequent cycling)
- Forecasting accuracy (load/RES), relevant for optimal scheduling
- Hosting-capacity improvement and peak-load reduction potential

These indicators correspond to the technical KPIs commonly applied to assess BESS, HESS, and grid-support functions in smart-grid pilots.

3.3.2 Environmental dimension

Environmental assessment follows Life-Cycle Assessment (LCA) principles, taking into account both upstream and operational impacts.

- CO_2-emission-reduction potential (tCO_2eq/year) relative to a diesel-based baseline
- Fossil-fuel substitution (m^3 or equivalent)
- Resource use and material intensity (including Bill of Materials for batteries)
- Land and water footprint
- LCA hotspots (manufacturing, use phase, end-of-life)

- Circular-economy aspects (recycling or reuse of components, especially electrolytes for flow batteries)

The LCA methodology requires a clearly defined functional unit, transparent inventory documentation, and explicit treatment of end-of-life scenarios to ensure comparability across technologies.

3.3.3 Economic dimension

Economic criteria evaluate the affordability, long-term viability, and value creation associated with each storage option.

- Levelised Cost of Storage (LCOS)
- CAPEX/OPEX structure, including replacement and maintenance (LCC perspective)
- Net Present Value (NPV), Internal Rate of Return (IRR), and Payback Period
- Local value creation and revenue-generation potential
- Employment impacts and contribution to the local economy

These indicators reflect standard economic KPIs used for smart-grid and storage-system evaluations.

3.3.4 Social and regulatory dimension

This dimension assesses user acceptance, institutional compatibility, and policy alignment.

- Stakeholder acceptance, participation, and awareness indicators
- User satisfaction and community engagement (e.g., co-ownership, participation rate)
- Compliance with grid codes, permitting procedures, and market-access rules
- Alignment with national/regional policy objectives, including renewable-energy targets
- Replicability and scalability across other island contexts
- Adequacy of the legal/regulatory framework supporting storage deployment

These indicators correspond to social KPIs and regulatory suitability assessments used in existing island demonstrators.

3.3.5 ICT-related dimension

An ICT dimension should be integrated to capture digital-infrastructure performance:

- Availability and reliability of communication networks (e.g., 4G, SCADA)
- Data quality, cybersecurity, and GDPR compliance
- EMS and forecasting tool performance

This dimension is particularly relevant for islands that rely on advanced EMS for real-time control of storage and RES integration.

3.4 Synthesis

The combined literature review and demonstration-project analysis confirm that high renewable penetration, up to and beyond 90 %, is technically feasible in island systems, though it may require RES and storage capacities 6–7 times peak demand (Psarros, 2024). Rapid technological progress and cost declines, especially in lithium-ion, hydrogen, and hybrid mechanical storage, now make such targets increasingly realistic.

However, long-term success depends on integrating regulatory innovation, flexibility-based market design, and community-driven governance with technical deployment. The analytical framework developed in this project provides a coherent foundation for cross-site evaluation, supporting harmonised use-case development and business-model design. It ensures consistency, comparability, and replicability of energy-storage solutions for diverse island and semi-isolated systems, reinforcing their role as living laboratories of the clean-energy transition.

4 Pilot Site Profile

4.1 Aran Islands (Ireland)

4.1.1 Geographic and energy context

The Aran Islands lie off Ireland’s west coast at the mouth of Galway Bay and belong to County Galway. The archipelago consists of three inhabited islands, with a total population of around 1,347 inhabitants, of which approximately 850 live on Inis Mór, according to the 2022 Census (CSO, 2022). Inis Mór, the largest island (31 km²), serves as the main population and service centre (Figure 1). The landscape is defined by karst limestone, low-lying grasslands, and exposure to Atlantic winds, which shape both settlement patterns and infrastructure.

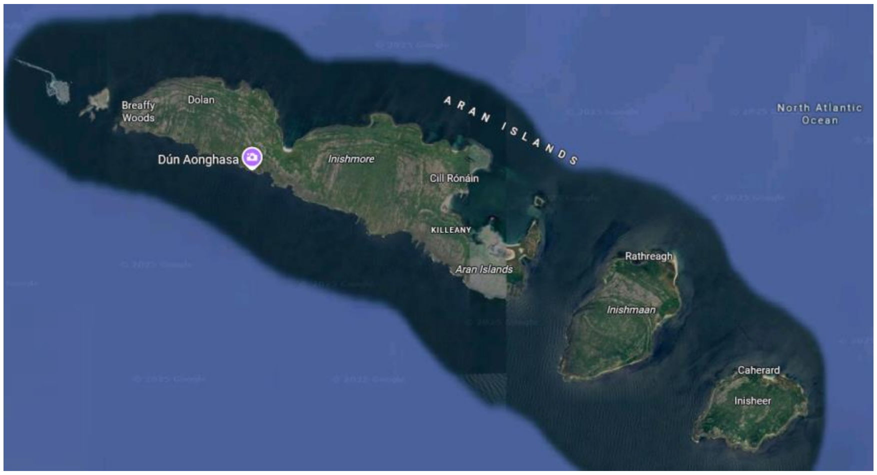

Figure 1. Map of Aran Islands

4.1.2 Existing infrastructure and energy mix

The Aran Islands are interconnected with the mainland through a 3 MW subsea cable. Hence, in a broader sense, Ireland’s national energy mix also applies to the islands, as depicted in Figure 2. Natural gas is the main contributor, accounting for around 48.8% in 2024 according to the International Energy Agency (IEA, 2024), while wind represents over 37% and solar PV around 2.3% of the total.

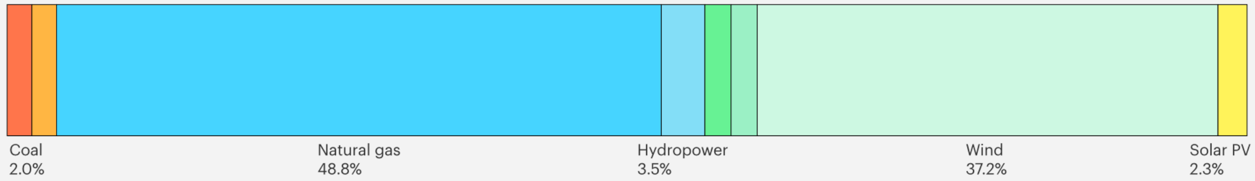

Figure 2. Electricity generation, Ireland, 2024 (Source: IEA)

As part of the RESTOR project, an existing and operational pilot on Inis Mór comprises eleven operational small-scale photovoltaic (PV) systems (3 public buildings and 8 residences) with a combined installed capacity of approximately 45 kWp. Based on an average capacity factor of 11%, representative of solar performance in Ireland (Ayompe, 2009), their estimated annual generation is about 42 MWh (Table 1). These installations contribute modestly to the island's overall electricity demand, which remains largely met through imported grid power from the mainland.

Table 2. Installed photovoltaic capacity and estimated annual electricity generation on the Inis Mór small scale pilot.

Source	Installed Capacity (MWp)	Annual Energy Generation (MWh/year)
Solar Photovoltaic (PV)	0.045	~42 (estimated)

4.1.3 Key stakeholders

The Aran Islands Pilot involves a broad range of local, regional, and national stakeholders working together to promote a sustainable energy transition and improve living conditions on Inis Mór. Collaboration between community organisations, public authorities, and academic partners is essential to support the island's transition towards renewable energy and social resilience.

- **Comharchumann Forbartha Árann (CFA):** Community cooperative on Inis Mór, CFA's aim and objective are to promote both the social and economic development for the community of the island.
- **Comharchumann Fuinneamh Oileáin Árann Teoranta (Aran Islands Energy Cooperative):** community-based organisation leading renewable energy initiatives on the islands.
- **ESB Networks:** ESB is the company responsible for building, operating, and maintaining the electricity distribution and transmission networks in the Republic of Ireland.
- **Galway County Council:** Local government authority responsible for planning, housing, and infrastructure across the islands.
- **Sustainable Energy Authority of Ireland (SEAI):** National energy agency supporting community-led energy transition and renewable projects.
- **Department of Rural and Community Development (DRCD):** National body overseeing the *Our Living Islands – National Islands Policy 2023–2033* and promoting sustainable island development.

- **Údarás na Gaeltachta:** It is the regional authority responsible for the economic, social and cultural development of the Gaeltacht (Gaelic speaking areas).

These stakeholders collectively contribute to the pilot's objectives, ensuring that the transition process reflects both community priorities and national energy goals while fostering cross-sectoral collaboration.

4.1.4 Regulatory and socio-economic context

The Aran Islands Pilot operates within Ireland's national energy and climate framework, regulated by the Commission for Regulation of Utilities (CRU) and guided by the National Energy and Climate Plan 2021–2030, which targets 80% renewable electricity by 2030.

The *Sustainable Energy Authority of Ireland (SEAI)* and the *Our Living Islands Policy 2023–2033* provide institutional support for community-led energy projects. However, specific regulations for island microgrids and energy storage systems remain underdeveloped, limiting autonomous energy operation.

The Aran Islands face several socioeconomic challenges that influence the implementation and sustainability of the energy transition.

- Community Engagement: Although the islands have a strong social fabric and community spirit, introducing new technologies such as photovoltaic systems and battery storage requires continuous engagement and capacity building to ensure public acceptance and understanding.
- Economic Dependence and Seasonality: The local economy relies heavily on tourism, leading to income fluctuations and limited investment capacity during off-season periods. This economic structure increases vulnerability to external shocks and limits funding for local infrastructure.
- Housing and Affordability: A shortage of affordable housing and high property prices hinder population retention and the attraction of skilled workers, which in turn constrains the long-term sustainability of community-led initiatives.
- Energy Vulnerability: Dependence on imported electricity and fossil fuels, combined with limited local generation and storage, results in high energy costs and reduced resilience to supply disruptions.
- Skills and Capacity Building: There is a need for local training in renewable energy system maintenance and management to reduce reliance on external contractors and to strengthen community autonomy.

4.2 Gotland (Sweden)

Gotland is the largest island in Sweden, located approximately 90 km off the country's southeastern coast in the Baltic Sea. The territory covers around 3,100 km² but remains sparsely populated, with only about 60,970 permanent residents. The regional hub and only city is Visby, a Hanseatic cultural heritage site and administrative capital (Figure 3).

Despite its small resident population, Gotland experiences a dramatic seasonal influx: around one million tourists visit the island each summer, making it one of Sweden's most popular domestic tourist destinations. This seasonal pattern strongly influences local energy demand, mobility patterns, and consumption behaviors. From an energy perspective, Gotland relies heavily on renewable electricity generation, primarily wind energy. However, its geographical isolation and dependence on mainland connections create strategic challenges for grid stability, flexibility, and self-sufficiency.

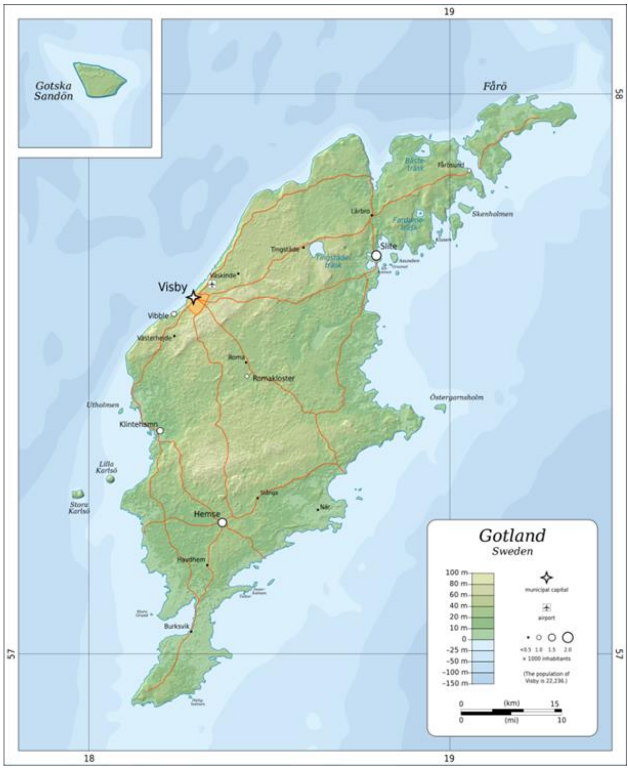

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Figure 3. Map of Gotland

4.2.1 Existing infrastructure and energy mix

Gotland's electricity production is almost entirely based on renewable energy, with more than 90% generated from wind power. Current installed capacities include:

- 178 MW of wind energy capacity
- 38 MW of solar PV capacity

Electricity exchange with mainland Sweden occurs through two HVDC submarine cables, which are essential for both importing and exporting electricity and stabilizing the local grid. Limited local storage and variability in renewable output imply that approximately 50% of electricity consumed on Gotland is imported. Energy use on Gotland amounts to between 850 - 1000

GWh/year. Where industry accounts for about 1/3, the city of Visby for 1/3, and the rest of Gotland for 1/3. Due to the cement industry's electrification, Gotland's electricity use is expected to more than double after 2030. Where industry is expected to increase its use to 1.5 TWh/year with a power requirement of approx. 200 MW. Gotland's electricity grid is already being expanded significantly to cope with this transition. The cost of the reconstruction of the grid is estimated at SEK 2 billion by 2040.

A target value for connected electricity production capacity in 2035 is estimated at 235 MW of wind power and 200 MW of solar power. When the overhead grid on Gotland is renewed, Gotlands DSO estimates that 500 MW of wind power and 500 MW of solar power will be able to be connected to the grid.

Although summer tourism significantly increases the population, electricity demand is higher in winter (Figure 4). This counterintuitive pattern is explained by:

- Widespread use of heat pumps in households
- Prolonged cold periods requiring intensive heating
- Generally lower solar irradiation in winter

In 2023, Gotland reached a peak load of 180 MW, highlighting the need for improved flexibility, storage, and grid reinforcement. The cement industry accounts for approximately 35 MW of the 180 MW.

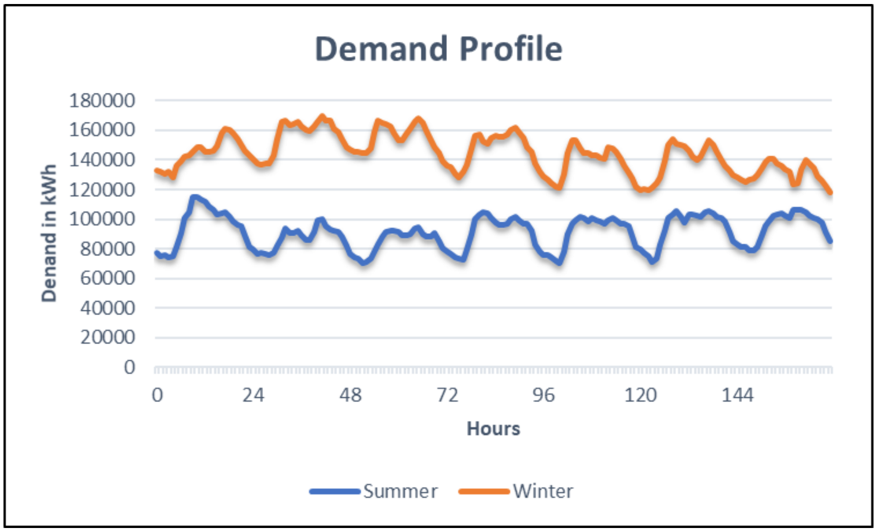

Figure 4. Demand profile of a week in Summer and Winter

Due to low electricity trading prices in relation to feed-in tariffs, wind power is being shut down more frequently. In 2024, this loss of production was estimated at around 100 GWh.

4.2.2 Key stakeholders

Gotland's energy system involves several central stakeholders:

- **Gotlands Energi AB (GEAB)**: Local grid operator
    - Ownership: Vattenfall (75%) and Region Gotland (25%)
- **Vattenfall (State-Owned)**: Owner and operator of the two HVDC cables
- **Region Gotland**: Regional government responsible for planning, climate strategies, and infrastructure
- **Tourism industry**: Hotels, services, transportation
- **Food processing industries**
- **Lime and cement industries** on the western coast, which are high energy consumers and strategic for decarbonisation

These actors are essential to shaping Gotland's pathway toward energy transition and system resilience.

4.2.3 Regulatory and Socio-Economic Context

Gotland is a central element of Sweden's national decarbonisation strategy. As an island with clearly defined boundaries and substantial renewable resources, it has been designated as a pilot region for energy transition. Gotland belongs to the electricity price zone SE3 (of SE1–SE4). Prices are uniform across the zone. The 2024 average electricity price was 35.77 €/MWh. A national scheme currently provides a 60 €/MWh tax reduction for electricity produced and sold to the grid by prosumers; however, this incentive is scheduled to end in early 2026. The variable component of the distribution network tariff is currently approximately 0.50 SEK per kWh on Gotland. Under the current regulatory framework, customers have limited incentives to provide flexibility. However, new EU-aligned regulations introducing capacity-based tariffs will take effect in 2027, followed by a new regulatory period for the revenue cap beginning in 2028, which is expected to provide stronger incentives for the use of flexible resources.

Within this framework, regulatory focus will shift away from treating CAPEX and OPEX as separate cost categories and instead assess their combined impact through a total expenditure (TOTEX) approach.

Tourism remains the primary economic engine of Gotland, driving strong seasonal patterns in employment, mobility, and energy consumption. Alongside this seasonal economy, agriculture, livestock production, and related food-processing industries provide stable year-round employment and play an important role in the island's socio-economic structure. At the same time, energy-intensive industrial activities, most notably the lime and cement sectors, represent major sources of emissions and are therefore central targets for electrification and decarbonisation within Gotland's broader transition strategy.

Gotland has pledged to achieve net-zero emissions by 2040, requiring major transformations, including:

- Decarbonising the cement and agricultural sectors
- Expanding renewable generation
- Deploying energy storage solutions to reduce mainland dependence
- Increasing local flexibility and grid resilience
- Enhancing system reliability to support growing electrification

4.3 La Reunion (France)

4.3.1 Geographic and energy context

La Réunion Island is a French overseas department in the Indian Ocean. Its coordinates are 20°18′ S, 55°31′ E. According to the National Institute for Statistics (INSEE), the population is expected to be about 896,200 people in 2025. The island's geography includes both large rural and mountainous areas and dense urban centres like Saint-Denis, Saint-André, Saint-Pierre, and Saint-Paul (F). Its growth plan focuses on sustainability and energy independence. The Programmation Pluriannuelle de l'Énergie (PPE) for La Réunion targets 100% renewable electricity production by 2028, aligning with France's broader energy transition goals.

Figure 5. Map of La Reunion

The island's economy is mainly driven by the tertiary sector, including trade, tourism, and public administration, complemented by agriculture and agri-food industries. Due to its insular character, La Réunion's energy system operates in isolation, making energy security and self-sufficiency key priorities.

4.3.2 Existing infrastructure and energy mix

As of 2024, the island's installed generation capacity totals approximately 1,035 MW, distributed unevenly across 24 substations (OER, 2025). The renewable energy share reached 92.4% of total electricity generation, indicating significant progress toward decarbonization. The generation mix in 2024 is presented in Table 3.

Table 3. La Reunion electricity generation mix in 2024 (Source: OER)

Source	Installed Capacity (MW)	Generation (GWh)	Share of total production
Hydropower	134.4	419.2	13.7 %
Photovoltaic	312.1	310.6	10.1 %
Pellets of wood	195.8	710.9	23.2 %
Biodiesel	211.0	1 162.5	37.9 %
Bagasse (sugarcane residue)	—	174.1	5.7 %
Wind	19.8	35.4	1.2 %
Biogas	6.9	18.8	0.6 %
Bioethanol	—	2.8	0.1 %

Batteries (centralized)	10.0	3.1	0.1 %
Diesel & residual fossil backup	~80	230	7.5 %

On La Réunion, electricity load curves exhibit clear seasonal differences driven primarily by climate and household energy use (Figure 6). During the austral summer, high temperatures and humidity lead to increased use of cooling and ventilation systems, producing pronounced midday and early-evening peaks, especially in densely populated coastal areas. In contrast, the austral winter brings milder temperatures and reduced reliance on cooling, resulting in lower daytime demand and a more moderate evening peak linked mainly to lighting and household activities. Despite these variations, overall consumption remains relatively steady throughout the year, but summer load curves consistently show higher peak intensities due to climate-driven cooling needs and increased economic activity. These distinct patterns underline the importance of flexible resources capable of managing strong summer peaks and maintaining system stability in an isolated grid.

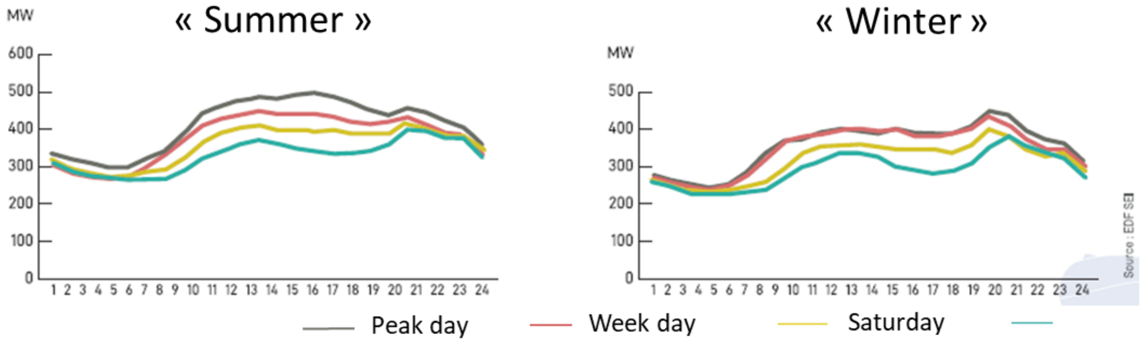

Figure 6. Demand profile of typical days in Austral summer and winter in La Reunion (source: EDF SEI)

La Réunion's power grid is isolated and experiences periodic capacity limitations due to uneven load distribution and limited flexibility. To enhance grid stability and RES integration, battery storage systems have been deployed, including:

- 5.6 MW / 2.5 MWh (EDF DSO)
- 5 MW / 9.8 MWh (Corsica Sole)

No energy imports or exports are currently feasible due to the island's geographic isolation.

4.3.3 Key stakeholders

The main actors in La Réunion's energy system include:

- **EDF SEI** (Électricité de France – Systèmes Énergétiques Insulaires): grid operator and main electricity supplier.
- **OER** (Observatoire Énergie Réunion): energy observatory managing statistics and policy monitoring.

- **Regional Council of La Réunion**: in charge of implementing the PPE and local energy planning.
- **DEAL (Direction de l'Environnement, de l'Aménagement et du Logement):** the regional government agency in La Réunion implementing public policies from France's Ministry
- **ADEME** (French Environment and Energy Management Agency): supporting renewable and efficiency projects.
- **Private developers** such as Corsica Sole and Quadran (TotalEnergies), active in PV and storage deployment.

These actors collaborate to reach the 100% RES goal through coordinated planning, funding mechanisms, and public–private partnerships.

4.3.4 Regulatory and socio-economic context

La Réunion's energy sector follows French and EU regulations, adapted to the specificities of non-interconnected zones. The PPE defines priority investment areas, grid codes, and RES integration targets. Licensing for storage and generation projects is managed by local authorities under the national energy code, while EDF SEI oversees grid connection and operational compliance.

Electricity tariffs are regulated and standardized under the national tariff system, with feed-in tariffs available for renewable producers (particularly PV and biomass). Despite higher generation costs compared to mainland France, consumers benefit from equalized tariffs supported by national solidarity mechanisms.

The main socio-economic challenges include high dependency on imports (for fuel and equipment), limited land availability, and social sensitivity to energy pricing. However, the strong institutional framework, combined with active public engagement and EU co-funded programs, provides favourable conditions for deploying innovative energy storage and renewable technologies.

4.4 Remanso (Brazil)

4.4.1 Geographic and energy context

The Xique-Xique Community is a rural site located in Remanso, Bahia, Brazil (-9.40395149, -42.05046175). It is situated in a semi-arid region characterized by high solar irradiation, with an average of 5950 Wh/m2 day, and temperatures ranging from 10.4 ºC to 41 ºC. The community is exclusively rural, serving 110 residential households along with essential services like a school, a deep artesian well, and a community center.

The local economy relies on subsistence activities, including small-scale livestock farming (goat and sheep), farming (beans and cassava), and beekeeping. Electricity consumption is low and stable, with no observed seasonal load variability due to the negligible influence of tourism. Local development is aligned with Brazil's national energy targets of achieving 80% to 85% renewable sources in the electricity generation mix by 2050 (PNE 2050).

4.4.2 Existing infrastructure and energy mix

The Xique-Xique Community operates as an isolated microgrid system, featuring a 100% renewable energy share supplied by solar PV.

Table 4. Installed photovoltaic capacity and annual electricity generation in the Xique-Xique Community.

Source	Installed Capacity	Annual Energy Generation (MWh)
Solar Photovoltaic (PV)	0.24332MWp / 0.2062MW	Expected: 141.9 Measured: 82.75

The total measured annual electricity consumption is 63.73MWh, with a low peak load of less than 20kW. To ensure stability and 48 hours of autonomy, the isolated grid incorporates a Tesla Powerpack Lithium-ion Battery Energy Storage System (BESS) with a capacity of 4x232kW. A major operational issue is that at least 80% of the solar production is curtailed due to the microgrid's low loading capacity and technical constraints, such as the low power factor (0.4 to 0.6). The system is located approximately 20km from the conventional distribution network of the DSO.

4.4.3 Key stakeholders

The primary actors involved in the Xique-Xique energy system include:

- **Neoenergia Coelba**: The local distribution system operator (DSO) and owner of the solar photovoltaic system.
- **Residential Households and Local Residents' Association**: The main energy consumers and managers of the community center, affected by the photovoltaic system performance and stability.
- **National Government Bodies** (MME, ANEEL): Responsible for defining national energy targets (PNE 2050) and regulatory frameworks (e.g., ANEEL R&D Program, Res. Number 1000/2021).
- **Funding Institutions** (BNDES, CAIXA, etc.): Provide financial mechanisms (e.g., BNDES Finem, Fundo Clima) to support the expansion and modernization of renewable energy infrastructure.

4.4.4 Regulatory and socio-economic context

The project operates under the Brazilian energy regulations, including the Luz para Todos (LPT) national program for universal access and the legal framework for distributed generation (Law N. 14.300/22). Key incentives include tax exemptions (e.g., ICMS CONFAZ Agreement 16) and the Social Renewable Energy Program (PERS).

A major regulatory gap is the lack of a specific framework for BESS deployment, which currently relies on rules for distributed generation connection (PRODIST Module 3). Furthermore, the microgrid regulation (ANEEL Res. N. 1000/2021) mandating high autonomy (36 to 48 hours) contributes to system oversizing and increased CAPEX/OPEX.

The main challenges are based on the community context:

- Community Acceptance: Lack of trust among the population in new technologies due to previous negative experiences with isolated solar systems.
- Safety: Limited user knowledge leads to inadequate electrical installations and the use of inefficient appliances, compromising system safety and performance.
- Poverty and Access: Barriers such as illiteracy, low educational levels, and logistical challenges prevent many users from fully benefiting from public policies and support programs.
- Economic Viability: The implementation of this infrastructure was made economically feasible thanks to strategic funding derived from a regulated R&D project under the ANEEL R&D Program

5 Identified barriers and opportunities

This section consolidates the primary obstacles and facilitating conditions recognised throughout the four pilot locations: the Aran Islands (Ireland), Gotland (Sweden), La Réunion (France), and Remanso (Brazil). It utilises the site characterisation and regulatory and market analysis conducted. The objective is to highlight elements that may hinder or promote the implementation of energy storage and to guide the selection and design of use cases and business models discussed in subsequent parts.

Barriers and opportunities are examined across four dimensions:

- Technical and infrastructural,
- Regulatory and institutional frameworks,
- Economic and financial,
- Societal and ecological.

5.1 Site-specific barriers

Aran Islands (Ireland)

- Technical: Limited grid capacity, the interconnection with the mainland restricts renewable expansion. Although the import capacity is 3 MW, it is estimated a 50% loss in the transmission. The export capacity is estimated at 650 kW. Absence of advanced forecasting and control tools.
- Regulatory: Energy communities and microgrids are only partially supported under current Irish regulation; lack of a dedicated framework for island operation.
- Economic: Small consumer base and limited scale reduce investment attractiveness; dependence on subsidies for storage deployment.

- Social: Local population supportive of renewables but cautious about new tariffs or ownership models.

Gotland (Sweden)

- Technical: Limited interconnection capacity to the mainland. High share of wind generation causes curtailment and frequency instability during HVDC outages; insufficient local flexibility resources. Dependent on the mainland connection for frequency regulation.
- Regulatory: Existing market rules do not fully value fast-response storage; limited incentives for ancillary services in island mode. No definitions in the legislation for energy communities.
- Economic: High capital costs for large-scale storage and uncertainty about revenue streams beyond 2030.
- Social: Acceptance is high for renewable projects, but limited awareness of storage benefits.

La Réunion (France)

- Technical: High PV penetration (≈ 30%) leads to frequent curtailment and grid congestion; land constraints for new infrastructure.
- Regulatory: Centralised grid operation under EDF SEI limits third-party participation; lengthy permitting process for generation and storage assets.
- Economic: Tariffs are regulated, limiting market-based remuneration for flexibility; dependency on national equalisation mechanisms.
- Social: Public support for renewables but growing sensitivity to land use and visual impact of industrial facilities.

Remanso (Brazil)

- Technical: Microgrid system suffers from power factor instability and under-utilised PV production; lack of smart control integration.
- Regulatory: No dedicated framework for storage operation; reliance on distributed-generation rules (PRODIST Module 3).
- Economic: Limited financing mechanisms for rural and small-scale storage; high CAPEX compared to local incomes.
- Social: Low technical literacy and limited user training reduce operational reliability and trust in the system.

5.2 Enabling conditions or local opportunities

Despite these barriers, each site also presents favourable conditions that can accelerate storage deployment and serve as enablers for the identified use cases.

Table 5. Enabling conditions for energy storage deployment in the pilot sites.

Category	Aran Islands (IE)	Gotland (SE)	La Réunion (FR)	Remanso (BR)
Technical	Ongoing smart-grid pilot projects; growing PV deployment	High RES penetration and existing HVDC links enabling hybrid operations	Mature grid management by EDF SEI; expanding battery installations	Existing Tesla BESS and strong solar resource
Regulatory / Institutional	Supportive EU framework for energy communities	National strategy for 100 % fossil-free grid by 2040	PPE 2028 targets for 100 % renewable electricity	National distributed-generation law and rural electrification programs
Economic / Financial	Access to funding and community ownership models	Public support for energy-transition pilots	Availability of feed-in tariffs and regional subsidies	National development banks (BNDES) and social energy funds
Social / Environmental	Strong local identity and cooperative culture	Public acceptance of renewable innovation	High environmental awareness and public engagement	Community cohesion and desire for energy independence

These opportunities demonstrate that each island or community possesses unique strengths that can be leveraged to overcome local barriers. In several cases, technical innovation and policy experimentation are possible under existing regional energy-transition frameworks.

5.3 Cross-site synthesis

A comparative analysis highlights several recurrent challenges across all pilots:

- Grid constraints and intermittency management remain the main technical barrier.
- Regulatory misalignment between national frameworks and island needs often delays deployment.
- Economic feasibility depends heavily on public support or mixed-revenue models.
- Limited local capacity (skills, maintenance, governance) constrains long-term sustainability.

Conversely, the following cross-cutting enablers have emerged:

- Existence of regional energy transition strategies targeting high renewable shares;
- Increasing policy attention to storage and flexibility in non-interconnected systems;
- Availability of EU and national funding instruments (CETP, FEDER, ADEME, BNDES, etc.);
- Strong community interest and social capital, offering fertile ground for participatory ownership and local acceptance.

These findings confirm that energy storage is both technically necessary and socially desirable in island systems but requires integrated regulatory and financial frameworks to become economically viable.

6 Use cases

6.1 Aran Islands (Ireland)

6.1.1 Peak demand

This use case focuses on addressing peak electricity demand on the Aran Islands through the integration of energy storage, flexible demand management, and system optimisation. As observed across Ireland, evening peaks coincide with increased use of lighting, cooking appliances, and electric heating, putting additional stress on local distribution networks. To mitigate these constraints, the use case proposes the deployment of a community-scale battery energy storage system coupled with an energy management system capable of forecasting and controlling demand peaks. The simulation scenarios will analyse the loads and decide to store excess renewable generation during low-demand periods, and discharge during peak times to flatten the load curve and reduce grid stress. In addition, demand-side management strategies, such as smart heat-pump operation, will be explored to complement the storage component.

Overall, this use case will demonstrate how energy storage and demand flexibility can effectively reduce peak electricity loads on the Aran Islands, improving grid stability and lowering operational costs. By integrating storage with smart control and dynamic tariffs, it will increase renewable utilisation and decrease reliance on fossil-fuel back-up generation. The results will serve as a replicable model for other Irish islands and rural communities seeking to enhance flexibility and resilience.

6.1.2 Backup power for critical services

This use case explores how energy-storage solutions can support the community by providing backup power for critical services during outages. The Aran Islands have recently experienced major disruptions due to severe storms, particularly in the winter months. For example, in January 2025, a storm caused a failure in a mainland substation that left island residents without electricity. In some cases, it took up to two weeks for services to be fully restored, mostly in rural and isolated areas. During the outage, the local community lacked access to essential services, communications and heating, with some residents considering diesel-generator purchases as a contingency measure. In this use case, the proposal is to establish two community hubs on Inishmore equipped with battery energy-storage systems. These hubs would enable islanders to access essential services during outages, such as access to kitchen appliances (microwave, oven, kettle, fridge, etc), electric shower, and charging station for small devices (smartphones, laptops, etc.). The two identified buildings can be seen in the figure below:

Figure 7. Onaght Co-op facility and Childcare facility locations.

The operational strategy for this use case will be designed to account for the energy demand required to provide essential services during outages. The battery energy storage system (BES) will be tested under different load configurations, including variations in the number and type of connected devices. The strategy may involve limiting peak loads or establishing a prioritisation hierarchy for essential services, thereby optimising energy use and ensuring a more cost-effective solution. A comprehensive on-site assessment will be conducted at both proposed locations to determine the most feasible operational scenario, considering the expected number of users and their energy needs. Consultations with the community manager and local stakeholders will be undertaken to ensure that the final solution aligns with community priorities and effectively addresses real-world requirements. This use case will enhance the Aran Islands' resilience to power outages by providing reliable, renewable-based backup energy scenarios for essential community services. The deployment of battery energy storage systems will reduce dependence on diesel generators, strengthen local emergency preparedness, and contribute to a more sustainable and self-sufficient island energy system.

6.1.3 Tourism season load balancing

The Aran Islands are a major Irish heritage destination that attract roughly 250,000 visitors annually. During summer, daily footfall can reach 1,000 to 3,000 people, placing intense seasonal pressure on local services. Population increases substantially: the permanent population of about 1,300 (around 850 in Inishmore) rises to a summer peak near 3,900 (approximately a 200% increase). This use case aims to assess how energy storage systems can contribute to a more balanced and resilient energy profile considering significant seasonal variations in demand. During the off-peak season, many restaurants, hotels, and shops close, and numerous houses are used only as holiday homes, leading to notably lower activity levels in winter. On the other hand, energy use during this period remains high due to increased heating requirements in occupied buildings.

The operational strategy for this use case will be designed to manage seasonal load variations, ensure resilience and optimise both energy usage and cost. The battery energy storage system will through a load profiling and scenario testing to define its operational characteristics and appropriate sizing, taking into account variations in energy demand across different times of the year. During periods of high demand, the storage system will be employed for balancing demand and supply. This strategy aligns with recent research on island energy systems, which demonstrates that such storage systems can effectively smooth demand fluctuations and support higher integration of renewable sources. Use of energy management analytics (e.g. state of charge forecasts, load forecasting) will support performance optimisation and cost-effective lifecycle management.

6.2 Gotland (Sweden)

6.2.1 Expanded Production Capacity

This use case examines how Gotland can increase its installed renewable energy capacity despite existing transmission constraints and limited local demand during periods of high production. Today, a significant share of Gotland’s wind generation operates below potential due to insufficient export capacity and a lack of storage to absorb excess output. Nearly half of the island’s electricity demand is met through imports from mainland Sweden, underscoring the need for a more balanced and autonomous system. The deployment of utility-scale and distributed storage—alongside emerging technologies such as hydrogen production and compressed-air energy storage—offers a pathway to host additional wind and solar installations without exacerbating curtailment or overloading the grid. The upcoming bidirectional 2×220 kV AC cable planned for 2030 will further enhance export capability, but storage remains essential for unlocking new hosting capacity in the interim. This use case therefore focuses on determining how much renewable capacity can be added before and after the grid upgrade, and how strategic storage placement, dynamic tariffs, and flexibility markets can enable Gotland to expand renewable production while maintaining system stability and minimising reliance on mainland imports.

6.2.2 Island Operation with Frequency Stability

This use case explores Gotland's ability to operate with greater autonomy from the mainland grid, focusing specifically on maintaining frequency stability in scenarios ranging from short-term islanding to potential long-duration or full-time independent operation. Although Gotland's grid can currently isolate itself briefly using gas turbines, the high penetration of inverter-based wind and solar generation provides limited inertia, making frequency control a central challenge. Advanced storage technologies—such as battery systems providing synthetic inertia, flywheels enabling rapid frequency response, and hydrogen electrolysers offering flexible load modulation—are therefore critical to sustaining stable operation during islanding events. This use case evaluates how each technology contributes to inertia, frequency containment, and system recovery, while also assessing the role of real-time measurement tools and predictive control. As Gotland moves toward electrifying its lime and cement industries and developing hydrogen or methanol for Baltic shipping, frequency stability becomes even more central to secure operation. By combining storage-enabled services with improved grid-forming capabilities and opportunities for frequency trading with the mainland, this use case provides a roadmap for progressively enabling secure, renewable-dominated island operation.

6.3 La Reunion (France)

This use case focuses on enhancing grid stability and accelerating the transition toward full renewable autonomy on La Réunion through the deployment of multi-service battery energy storage systems. Although the island already achieves a renewable electricity share above 90%, primarily from solar PV, hydro, and biomass, this high penetration has introduced increasing operational challenges. Rapid PV development has led to significant variability, frequent curtailment during midday hours, and greater sensitivity to frequency disturbances. In addition, the island's exposure to cyclones and the rising load associated with the electrification of transport—especially the growth in EV charging—place further stress on an isolated electricity system that lacks interconnections with mainland grids. To support the national objectives set in the PPE 2028, which targets 100% renewable electricity by 2028 and full energy autonomy by 2030, advanced storage solutions are required to provide system-level flexibility, reliability, and resilience.

To address these challenges, the use case proposes the deployment of a coordinated fleet of battery storage systems capable of delivering grid-forming and grid-support functions. These systems will operate across multiple layers of the network, ranging from large utility-scale installations at medium-voltage substations to distributed storage units co-located with industrial consumers and PV production sites. This multi-level architecture will enable dynamic frequency control, renewable energy firming, peak-load management, and backup support for critical infrastructure, thereby reducing dependence on fossil-fuel generators and improving the overall quality of supply on the island.

The proposed configuration includes a mix of lithium-ion (LFP/NMC) systems with an initial installed capacity of 10–15 MW and 20–30 MWh, controlled through EDF SEI's advanced energy-management platform. Complementary assets such as forecasting tools, SCADA upgrades, and EV-charging coordination infrastructure will further support real-time optimisation of storage dispatch. This flexible and modular approach ensures that storage resources can be adapted to the diverse geographic conditions and heterogeneous demand centres found across La Réunion.

The operational strategy for this use case is designed to maximise the contribution of storage to both system reliability and economic performance. During periods of high PV production, surplus energy will be stored and later discharged to support evening peaks or cloudy intervals, effectively reducing curtailment and increasing renewable utilisation. Storage units will provide rapid active- and reactive-power response to stabilise the 50 Hz system frequency within ±0.1 Hz and maintain appropriate voltage levels, particularly in weak grid areas. Additional services include peak-load reduction, black-start capability, and backup power for essential facilities such as hospitals and emergency operations during cyclones or network faults. Coordination with EV-charging infrastructure will also help mitigate future demand peaks arising from transport electrification. All operations will be managed centrally using predictive algorithms informed by renewable and load forecasting.

Overall, this use case will demonstrate how multi-service energy storage can reinforce La Réunion's electricity system under conditions of high renewable penetration. Expected outcomes include up to a 25% reduction in PV curtailment, improved frequency stability, and decreased unserved energy during peak events or extreme weather conditions. Environmentally, storage deployment is projected to reduce fossil-fuel backup by 10–15%, corresponding to roughly 25,000 tCO_2eq per year in avoided emissions. Economically, the solution will lower curtailment and balancing costs while delaying investments in new thermal units. Socially and strategically, it will enhance the reliability of supply for households and industries, strengthen resilience during natural disasters, and support the island's trajectory toward full energy autonomy. The approach also offers high replicability for other non-interconnected territories seeking to integrate high shares of variable renewable energy.

6.4 Remanso (Brazil)

This use case examines how a renewable-based microgrid can provide reliable and sustainable electricity to the traditional community of Xique-Xique, located in the municipality of Remanso, Brazil. The region lies within the Caatinga biome, a semi-arid ecosystem characterized by high temperatures, prolonged droughts, and fragile biodiversity. These environmental conditions, combined with the community's cultural identity as Fundo e Feixo de Pasto, a form of communal land management dedicated to small-scale family agriculture, make the area particularly sensitive to external disturbances. Many residents had limited or outdated access to electricity, with some relying on individual solar systems installed more than 15 years ago. For others, the microgrid represented their first opportunity to access modern electric power.

Although the conventional distribution grid lies fewer than 20 km from the community, extending the network was deemed socially and environmentally disruptive. Instead, the project was implemented under a national Research and Development (R&D) programme designed to promote innovative technologies for the Brazilian electricity sector. The goal was not only to supply clean and reliable energy to Xique-Xique but also to evaluate the microgrid's potential as a replicable model for other traditional communities located near protected areas or fragile ecosystems.

The system is based on solar PV generation supported by a battery energy storage system (BESS), chosen due to the region's high solar irradiation and the maturity of battery technologies. At the time of installation, Brazilian regulations required isolated systems to guarantee a minimum of 48 hours of autonomy in the event of generation loss. To meet this requirement, the BESS was designed to supply all nighttime loads and maintain grid-forming functions supported by a dedicated substation. This architecture ensures compliance with national electricity-quality standards and enables stable microgrid operation. Recent regulatory changes have since reduced the autonomy requirement to 36 hours, suggesting that future deployments could potentially benefit from lower storage costs.

The operational strategy limits each household to 80 kWh of monthly energy consumption, with a maximum instantaneous demand of 3.5 kW (220 V / 16 A), meeting sector regulations for isolated systems. During daylight hours, household loads are supplied directly by solar generation, while any surplus energy charges the battery system. Stored energy is then used during the night and contributes to maintaining the required autonomy buffer. System sizing accounted for expected battery degradation over ten years to ensure long-term performance and reliability.

Following commissioning, the microgrid underwent continuous monitoring and adjustments. Initially, overall consumption remained below the designed limit, as many socially vulnerable households had few electrical appliances. Over time, however, the introduction of new devices and evolving habits led to a gradual increase in demand, with occasional exceedances of the original thresholds. Despite these variations, the microgrid demonstrated strong performance, frequently producing surplus energy and successfully meeting the evolving needs of the community.

Beyond basic electrification, the project revealed several key opportunities for system improvement and future phases of the RESTOR initiative. The microgrid suffers from gaps in protection coordination, where a fault in a single home may shut down the entire system. Power quality issues, including a low power factor (~0.5) and episodes of solar curtailment, also signal opportunities to integrate smart-grid features, improved automation, and advanced control strategies. The region additionally presents untapped potential for complementary renewable resources, particularly biomass, which could diversify the generation mix and improve resilience. Finally, because the main distribution grid lies only 20 km away, the technical feasibility of a future hybrid connection remains an option for strategic expansion.

Overall, this use case demonstrates how a solar-plus-storage microgrid can deliver reliable electricity to isolated and environmentally sensitive communities while preserving traditional land-use practices. It also illustrates how targeted enhancements such as improved protection schemes, power-quality management, and integration of additional renewable resources could support long-term scalability, resilience, and replicability across similar regions in Brazil and beyond.

7 Business Models

This section summarises the business models associated with the RESTOR use cases, using a Business Model Canvas perspective. The focus is on how value is created, delivered and captured in each context, and on the role of revenue stacking, investment deferral and policy support in determining viability. The analysis covers the Aran Islands (Ireland), Gotland (Sweden), La Réunion (France) and Remanso (Brazil), followed by a comparative view of revenue streams, financing needs and replication potential.

7.1 Aran Islands (Ireland)

7.1.1 Peak Demand Management

In the Aran Islands peak-demand use case, the primary customer is the grid operator ESB Networks, with residential and commercial consumers and the wider island community as indirect beneficiaries. The value proposition centres on a 15–25% reduction in peak electricity demand, lower electricity bills for consumers (around €80–120k/year in community savings), improved grid stability, and reduced reliance on fossil-fuel backup. By limiting peak flows, the solution also helps protect customers from future price increases.

The business model relies on a combination of direct grid-service contracts and technology-enabled customer engagement. Services are delivered through smart meters, automated demand-response systems, community communication campaigns, and mobile applications that allow consumers to monitor their own consumption. Relationships are largely automated and data-driven, supplemented by transparent reporting of cost savings and a dedicated liaison with the grid operator.

Revenue is generated from the following sources: peak shaving/demand response payments, energy arbitrage margins, frequency regulation services, and an investment deferral value.

Key resources include a BESS, an advanced EMS with forecasting, smart metering, and SCADA systems, alongside market-pricing data. Core activities cover real-time optimisation and dispatch of storage, market participation, performance monitoring and regulatory compliance.

The cost structure is dominated by CAPEX for the battery and balance of system (around 150–235 k€ for a 150 kW system) and OPEX for maintenance, monitoring and insurance. Financial costs include interest on debt (4–7%) and equity returns (8–15%), plus administrative expenses for compliance and market participation. With an estimated payback period of 10–15 years and technology already at TRL 8–9, the model is commercially feasible but depends on revenue stacking across peak shaving, arbitrage, and frequency services to achieve an attractive return.

7.1.2 Backup Power for Critical Services

The backup-power use case targets the Community cooperative (CFA) and the energy co-op (CFO) as the main buyers, along with operators of critical infrastructure and community members who use emergency shelters during outages. The value proposition is built on guaranteed backup power for 48–72 hours, increased community resilience during storms, reduced economic losses from blackouts and protection of vulnerable populations. Reducing the use of diesel generators also brings cost and environmental benefits. A major part of the value lies in avoiding Value of Lost Load (VoLL).

Delivery channels include direct service agreements with local authorities, integration into emergency-planning frameworks, community notification systems (SMS, radio), and regular maintenance/testing protocols. Relationships are long-term and service-oriented, involving multi-year contracts, periodic emergency drills, clear activation procedures, and post-event impact reporting.

Revenues come from capacity availability payments, performance-based service fees, VoLL-related gains per avoided blackout, and possible grant or concessional financing for resilience infrastructure.

The solution relies on Li-ion LFP batteries in weatherproof containers, a diesel genset for extended events, distribution circuits, and load-shedding systems. Key activities include regular battery cycling and testing, SOC monitoring during storms, diesel maintenance, hub operations, and coordination with emergency services.

CAPEX per hub covers batteries, containers, genset, and integration. OPEX includes battery maintenance, diesel fuel and servicing, monitoring costs, and emergency-coordination labour. Additional costs arise from debt service, insurance, and permits for fuel storage, plus administrative overheads (GDPR compliance and community coordination). The estimated payback period is 15–25 years, highly sensitive to the assumed frequency and valuation of blackout events. The technology is at TRL 8 and is emerging as a standard resilience measure in storm-prone regions. The revenue model combines standing capacity payments with event-based compensation, reflecting the dual nature of the service.

7.1.2 Tourism Season Load Balancing

The tourism load-balancing use case serves ESB Networks as the primary customer, with hospitality businesses (hotels, restaurants, B&Bs), residential consumers, the tourism board and local government as important stakeholders. The value proposition is to maintain grid stability during a 200% seasonal population increase, avoid or defer €5–10 million in grid reinforcements over ten years, support tourism growth without major infrastructure expansion, and provide predictable, stable electricity for businesses. The model also enables additional renewable integration (around 12% extra RES hosting) and lower off-peak bills through dynamic tariffs.

Services are marketed and delivered through wholesale market participation (day-ahead, intraday, balancing), direct procurement by the DSO/TSO, collaboration with tourism associations, and dynamic pricing channels via mobile apps and web portals. Customer relationships rely on automated algorithmic optimisation, transparent real-time pricing, cooperative forecasting with the tourism board and long-term service agreements with grid operators.

Revenue sources include energy arbitrage, peak shaving payments, capacity market revenues, frequency regulation income, and payments for RES integration support (€20–50/MWh). Additional value may come from the tourism sector's willingness to pay for a stable supply.

The solution employs a BESS, an EMS with seasonal forecasting, smart metering, dynamic tariff infrastructure, and renewable forecasting models, alongside required licenses and connectivity.

CAPEX covers the battery, BOS, grid interconnection, and forecasting software. OPEX includes maintenance, degradation, monitoring, insurance, and market participation fees, as well as regulatory and coordination labour. With batteries at TRL 8–9 and a payback of 8–12 years, this is one of the more attractive models, provided that multi-stream revenue stacking is achieved and seasonal demand forecasting is accurate.

7.2 Gotland (Sweden)

7.2.1 Expanded Production Capacity

In Gotland's expanded-capacity use case, the primary customer is the Transmission System Operator (Svenska Kraftnät), complemented by wind and solar producers, regional industrial customers and electricity traders. The value proposition is to enable 80–100 MW of additional RES capacity without immediate grid reinforcement, defer €40–60 million in transmission upgrades until 2030, reduce solar curtailment from 15% to below 5%, and improve utilisation of the HVDC cable from 70% to 80%. The approach offers a cheaper and more flexible alternative to conventional reinforcement while increasing revenue capture for producers.

The commercial model uses wholesale markets (day-ahead, intraday, balancing), direct contracts with producers, grid-capacity auctions and regional DSO coordination. Relationships are built around long-term capacity contracts (5–10 years), automated dispatch based on grid signals, revenue-sharing agreements, transparent pricing and regulatory liaison.

Revenues include energy arbitrage, congestion-relief and peak-shaving payments, capacity market earnings, grid deferral and capacity payments, potentially complemented by RES incentive schemes.

The physical setup consists of BESS deployed at 3–5 nodes, smart metering for industrial loads, SCADA/EMS with predictive algorithms, flexibility platforms, and dynamic tariffs.

Total CAPEX for a 100 MW system is estimated at 97.5–222 M€, and OPEX at 1–3 M€/year for maintenance**,** 5–10 M€/year for degradation, plus monitoring, insurance, and market tools. Financial costs include debt service on 50–150 M€ and equity returns; administrative costs relate to compliance and fees. The resulting payback period is 15–25 years, justified by the magnitude of grid deferral. Technology readiness is TRL 8, and deployment depends critically on TSO's willingness to pay and on capturing a fair share of deferral value through contracts.

7.2.2 Island Operation with Frequency Stability

The island-operation use case has Svenska Kraftnät as the primary grid-stability customer, with industrial producers, local consumers, and European market participants as key stakeholders. The value proposition is to enable 100% renewable island operation (beyond the current 2–4 hours), maintain frequency within ±0.15 Hz (improving from ±0.5 Hz), replace mainland-provided inertia, eliminate fossil peaking units, and support industrial electrification without additional reinforcement. The model also captures trading opportunities in cross-border markets during surplus periods and delivers strategic energy security for Gotland.

Channels comprise wholesale electricity and capacity markets, contracts with TSO/DSO for grid services, power purchase agreements with industrial customers, long-term hydrogen offtake agreements, and participation in cross-border trading and European flexibility mechanisms. Relationships involve real-time automated dispatch, multiple-year contracts with industrial and hydrogen offtakers, strategic partnerships with the grid operator, and transparent communication around energy-independence milestones.

Revenue is highly diversified: frequency regulation services, energy arbitrage in wind/solar–hydrogen–power chains, capacity market earnings, peak shaving/demand response, hydrogen sales (€3–8/kg), potential thermal/waste heat use, carbon credits (20–50 €/tCO_2), and a strategic premium for critical grid services.

The asset base includes a multi-layer storage portfolio (batteries, CAES, hydrogen, V2G, pumped hydro), large electrolyser and fuel-cell capacities, grid-forming inverters, advanced EMS, monitoring infrastructure, hydrogen storage/distribution, and flexibility platforms.

CAPEX for the full system is estimated at 97–342 M€, plus OPEX dominated by renewable electricity input, maintenance, safety systems, and control. Financing is complex, relying on blended green finance (3–6% rates), equity, and long maturities. The payback period is estimated between 20 and 40 years, reflecting the strategic nature of the investment. Technology readiness is high for batteries and CAES/pumped hydro, but lower for hydrogen components (TRL 5–7). Commercial success depends on hydrogen cost reductions, industrial demand, long-term contracts and supportive regulation. Strategic value—energy security, climate leadership, industrial competitiveness—significantly exceeds straightforward financial returns.

7.3 La Réunion (France)

7.3.1 Multi-Service Battery Storage

On La Réunion, the multi-service storage use case targets EDF SEI as the main grid-services customer, with prosumers, industrial and commercial users, communities, and government agencies as additional stakeholders. The value proposition is to deliver frequency stability within ±0.1 Hz in a tropical island grid, cut solar curtailment from 18% to below 5%, manage peak loads to avoid 50–100 MW of fossil generation, provide black-start and cyclone resilience (4–8 hours of critical-load backup), enable 100% renewable electricity by 2028 and reduce dependency on imported fuels.

Services are delivered via centralised BESS at MV substations, distributed storage co-located with solar farms, behind-the-meter systems for prosumers, direct ancillary-services contracts with EDF SEI, participation in balancing markets, and emergency-management channels. Relationships centre on automated dispatch, multi-year service contracts, community communication about grid-modernisation benefits, transparent reporting on renewable integration, and coordinated emergency preparedness. Prosumers are engaged through dashboards and incentive schemes.

Revenue streams include frequency and voltage regulation services, renewable firming/curtailment avoidance, peak demand management payments, capacity availability fees, black-start services, grid investment deferral, prosumer self-consumption premiums, and distributed-storage aggregation revenues.

Key resources comprise 10–15 MW / 20–30 MWh centralised BESS**,** 3–5 MW / 6–10 MWh PV-integrated storage**,** 1–3 MW / 2–5 MWh prosumer systems, tropical-rated batteries, advanced EMS with weather forecasting, SCADA and backup diesel capacity. Activities include continuous frequency/voltage regulation, solar forecasting, peak management, cyclone preparation and recovery, degradation monitoring, market participation and community engagement.

CAPEX totals 14–46 M€ for a 14–23 MW portfolio, with OPEX driven by cooling, maintenance, degradation, monitoring, and readiness costs, plus financing and administrative overheads. With a 20–35-year payback and TRL 8–9 technology, profitability is strongly linked to service pricing, realised curtailment-avoidance value, aggregation performance, and equitable sharing of investment-deferral benefits. Policy support is strong, backed by PPE targets and potential EU green-transition financing, and the model adds a significant resilience and social equity component.

7.4 Remanso (Brazil)

7.4.1 Community Microgrid

The Remanso community microgrid use case serves households in Xique-Xique, organised under a community cooperative, and interacts with rural-development programmes, government energy-access initiatives and environmental organisations. The value proposition is centred on first-time electricity access, 24-hour reliable supply (versus 2–4 hours previously), reduced diesel reliance, protection of the Caatinga biome by avoiding grid extension, support for agriculture (e.g. water pumping), improved education (4–5 evening study hours), better health and safety and participatory energy governance.

Delivery channels are community-based: assemblies, cooperative structures, peer-to-peer training, local technician capacity building, participatory operation and regular meetings with transparent benefit sharing. Relationships are rooted in participatory governance, with voting rights, support for vulnerable households, flexible load management and conflict-resolution mechanisms.

The revenue model includes membership fees, sharing of avoided diesel costs, potential sales of excess electricity if the regional grid arrives, demand-response compensation where applicable, small revenues from community services, and carbon credit monetisation (5–15 €/tCO_2).

Resources include a PV array, battery storage, grid-forming inverter, EMS with load prioritisation, smart metering, a cooperative governance framework, and local maintenance capacity.

Activities cover daily dispatch, billing and cost-sharing, maintenance, governance meetings, training, awareness programmes, emergency procedures, carbon-credit documentation and liaison with authorities and NGOs. CAPEX for a typical 60 kWp / 200 kWh system is between 170 k€ and 406k€, with OPEX comprising maintenance, replacement reserves, software and coordination labour. Financing blends grants, concessional loans, community contributions and carbon-credit revenue. Profitability hinges on concessional finance; commercial rates would be unaffordable. Technology is at TRL 8–9, though the community-operated business model remains in pilot/demonstration phase.

Critical success factors include community willingness to govern the system, adequate local capacity, sufficient grant support, carbon-credit revenue, and sustainable cost-recovery mechanisms. Social and environmental value, such as energy access, climate mitigation, and biodiversity protection, far exceeds narrow financial returns, and replication potential is high for similar off-grid communities, provided models are adapted to local conditions.

7.5 Comparative Insights and Enabling Conditions

Across all use cases, revenue stacking emerges as a decisive factor: combining peak shaving, arbitrage, frequency services, capacity payments, curtailment avoidance, grid-deferral value, hydrogen sales, or carbon credits is necessary to shorten payback periods and justify investment. In developed markets (Aran Islands, Gotland, La Réunion), mature pricing mechanisms and supportive policy frameworks make commercial financing increasingly viable, but value capture from grid deferral and ancillary services must be explicitly encoded in contracts. In developing or off-grid contexts like Remanso, grant funding and concessional finance are essential, and business models must prioritise social and environmental objectives over pure profit.

Policy and regulation play a structural role. Nordic and European islands benefit from clear grid codes and emerging flexibility markets; tropical territories rely on strong national targets and development financing; off-grid communities require dedicated energy-access programmes and robust community governance. Technology readiness for battery storage is uniformly high, whereas multi-technology systems (hydrogen, CAES, pumped hydro) are more capital-intensive and less mature, suited primarily to long-term strategic investments such as Gotland's island-operation scenario.

Overall, the RESTOR business models illustrate that while no single template fits all contexts, well-designed combinations of storage, tailored revenue mechanisms, and supportive policy frameworks can deliver both commercially viable and socially transformative outcomes across a wide variety of island and off-grid settings.

8 Conclusion

Across the four pilot sites, storage emerges as a multi-functional asset capable of addressing a wide range of challenges: stabilising grids with high shares of inverter-based generation, reducing curtailment, providing backup power for critical services, absorbing seasonal demand variations, supporting industrial electrification, and enabling universal access to modern energy services.

Despite the diversity of contexts, several cross-cutting conclusions can be drawn. First, successful storage deployment requires a holistic understanding of local constraints and opportunities, going beyond technology selection to address governance, regulatory design, economic feasibility, and community engagement. Second, storage value is maximised when systems provide multiple services simultaneously—highlighting the central role of revenue stacking and flexibility markets in financial sustainability. Third, social acceptance and capacity building are decisive factors for long-term success, especially in community-operated systems or regions with limited technical training.

The use cases and business models developed here establish a foundation for the next phases of RESTOR, where detailed simulations and multi-criteria evaluations will quantify technical performance, environmental impacts, and economic viability. They also provide actionable insights for policymakers, system operators, and communities seeking to accelerate the energy transition in insular and remote areas. Beyond the pilot regions, the lessons learned have wider relevance for any energy system transitioning toward high shares of variable renewables and confronting the need for flexibility and resilience.

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