Aboveground seasonal energy storage: comparative analysis of hydrogen and its derivatives

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Aboveground seasonal energy storage: comparative analysis of hydrogen and its derivatives

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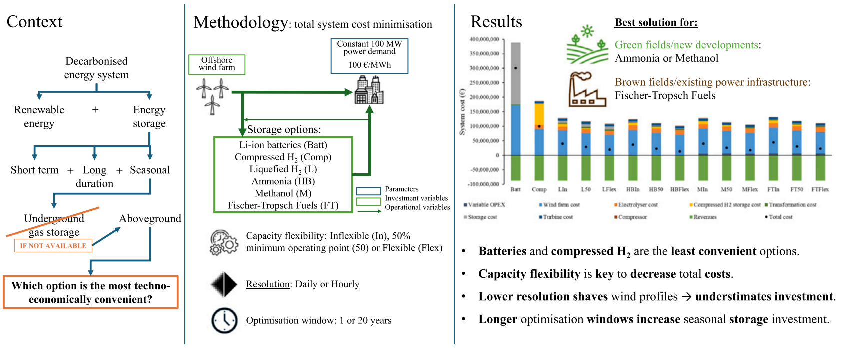
HIGHLIGHTS

- Ammonia and methanol are the most cost-effective solutions for new developments.
- Fischer-Tropsch fuels are preferred for existing power generation sites.
- Lithium-ion batteries are the worst-performing option in all scenarios.
- Capacity flexibility is key to decreasing energy storage costs.
- Low temporal resolution and short optimisation periods decrease storage investment.

GRAPHICAL ABSTRACT



- **Batteries** and **compressed H_2** are the **least convenient** options.
- **Capacity flexibility** is **key** to **decrease** total **costs**.
- **Lower resolution shaves** wind profiles → **understimates investment**.
- **Longer** optimisation **windows increase** seasonal **storage** investment.

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ABSTRACT

Seasonal energy storage is key to the future of fully decarbonised energy systems. Geological features capable of storing hydrogen at low costs are not universally available, and solutions to store renewable energy above ground will be required. In this study, an isolated energy hub investment optimisation model is developed with a constant demand centre of 100 MW, and different aboveground seasonal energy storage solutions are evaluated with different minimum load operation levels. In addition, the effects of different temporal optimisation resolutions and optimisation windows are evaluated. The results show that the current utility-scale lithium-ion battery system performs poorly in techno-economic terms at the seasonal storage level. Similarly, compressed hydrogen tanks are among the least competitive options. In contrast, ammonia and methanol are the most cost-effective solutions for new development sites reaching break-even electricity selling prices of 116€/MWh. However, for power generation sites with existing infrastructure like gas turbines, storage and pipelines, Fischer-Tropsch fuels become the most competitive option. Process capacity flexibility is also studied, and it is shown that it significantly decreases the costs. For these evaluated processes to reach commerciality, developing flexible production processes is crucial and should be prioritised. Finally, it is shown that seasonal storage investment is lower when lower temporal optimisation resolutions are used and increased when longer optimisation windows are considered.

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Nomenclature

n:	node
u:	unit
t:	time step
conn:	connection
rev:	revenues
v:	variable
p:	parameter
Pv:	total investment cost
R:	discount rate
N:	lifetime of the asset

1. Introduction

In response to concerns over climate change and energy security, energy systems are on a pathway to decarbonisation, resulting in a steep increase in renewable power generation over recent decades. The non-dispatchable nature of variable renewable energy sources such as wind and solar PV necessitates the exploration of storage solutions for periods when renewable power is not being generated. In this context, lithium-ion (Li-ion) batteries have been shown to be highly effective over short durations, providing not only power for the market, but also grid services that support the stability of the system [1,2]. Regional and international interconnection can also help mitigate the challenges of variable supply, but due to geopolitical conflicts in recent times, security of supply and energy independence have become major topics on the political agenda of several jurisdictions [3–5]. Furthermore, while interconnection can reduce the requirement for storage, it does not eliminate it, with storage featuring in the optimal decarbonisation solution even in highly interconnected systems [6–8]. Hence, in a high renewable penetration system, seasonal energy storage is expected to play a crucial role in ensuring secure supply [9,10]. Despite this, the literature is relatively sparse on comparisons of seasonal energy storage solutions, with the majority of studies considering storage solutions that are unsuited for longer time durations (*e.g.,* batteries) and/or considering the benefits of generic storage solutions without comparing and contrasting the specifics of different technology options. These observations motivate this paper.

1.1. Seasonal energy storage solutions

The importance of having long-duration energy storage (LDES) available to sustain a decarbonised electricity system is studied by Ref. [10]. The authors define one type of LDES ranging between 10 and 20 hours of storage to manage daily cycles of generation deficit, and another group with weekly or monthly capacity for seasonal generation deficit. For the purposes of this study, seasonal energy storage considers technological solutions capable of storing energy that can be turned into power for weeks or months.

Different technological solutions for energy storage are available. Some are in development, such as flow batteries, thermal storage and thermochemical storage, and some are more mature alternatives, such as pumped hydro and compressed air storage [11]. Due to the scale of seasonal storage requirements, safety concerns, and other technical limitations, most of the mentioned technologies are restricted to the *"up to 20 hours of storage"* group [9,12]. This leaves the seasonal storage group restricted to energy storage solutions of hydrogen and hydrogen derivatives, followed by compressed gas storage and pumped hydro, that could provide several days of energy storage [9,13]. Among the most common hydrogen derivatives proposed in the industry are ammonia and electrofuels (efuels), such as methanol and some synthetic hydrocarbons, such as Fischer-Tropsch (FT) fuels. Efuels are fuels produced from renewable carbon dioxide and hydrogen produced from renewable electricity that are capable of replacing traditional fuels from the petrochemical industry.

1.1.1. Hydrogen

Hydrogen (H_2) production from renewable sources and storage in underground geological facilities has been reported to be the most economical long-term way to store energy [9,14,15]. One study showed that in order to provide the United States of America (USA) with enough seasonal storage capacity for the system to run on renewable sources of electricity alone, compressed H_2 required only 6 km^3 of underground storage volume [16]. This is compared to 2300 km^3 of elevated water (1000 m), and 72 km^3 of compressed air storage. Compressed hydrogen in salt caverns is one of the best-positioned and most realistic options for long-term energy storage because it provides the scale required and enables the storage of energy for long periods [17]. This is due in part to the fact that it does not self-discharge like other types of storage technologies [18]. Another study concluded that storing large amounts of energy for a long time (>17 hours) is more cost-effective when H_2 is used as an energy storage option [19]. In the Californian power system, a study showed that replacing natural gas power stations with hydrogen gas turbines is more competitive than doing so with Li-ion batteries for seasonal energy storage applications [20].

However, in many cases, renewable resources are not located in places with geological formations suitable for H_2 storage. Without an extensive dedicated H_2 pipeline or sufficient spare power grid capacity to transport the energy to places with underground storage facilities, aboveground energy storage may be the only feasible seasonal energy storage solution available in those cases. Aboveground seasonal energy storage solutions are those that do not require specific subterranean geological features, like salt caverns or depleted gas fields, to store large amounts of energy for very long periods. As mentioned before, the technologies capable of doing this are based on the synthesis of highly energetically dense molecules like hydrogen and its derivatives. Compressed H_2, liquefied H_2 and ammonia tanks have been proposed as ways of storing energy in energy hubs [21,22] as part of countries' security of supply policies [23–25].

All these solutions present their own challenges. The liquefaction of hydrogen presents some operational challenges regarding its flexibility because it is a process that comprises several low-temperature thermal unitary operations for which a steady state operation is preferable to maximise process efficiencies [26].

1.1.2. Ammonia

With compressed H_2 tanks being expensive at scale and H_2 liquefaction being an energy-intensive process, ammonia appears as an attractive option, not only to store energy above ground without the requirements of underground geological features, but also as an alternative to transmitting energy from remote locations, such as offshore wind farms, to demand centres. A recent study has shown that ammonia is the most efficient way to transport and store energy when compared to electricity cables, compressed air and hydrogen [27]. Less definitive are the results obtained by Ref. [28], in which ammonia and hydrogen end up being compared as two options with similar round-trip efficiency results when it comes to the transport and storage of energy. Ammonia gas turbines and reciprocating engines are currently being developed by major original equipment manufacturers, and commercial power generation units are expected to become available this decade [29,30]. However, ammonia production via the Haber-Bosch (HB) process has a minimum operating point that makes it unsuitable to operate directly with highly variable input. A minimum operating point is the minimum load at which a unit or reactor can operate without hindering the production efficiency or quality [31]. To avoid that last issue, ammonia production requires H_2 storage or another type of energy storage buffer to maximise its steady-state operation.

1.1.3. Efuels

Another type of chemical energy storage is carbon-based electrofuels (efuels), like methanol or Fischer-Tropsch fuels. These carbon-based efuels present an attractive alternative for power generators because they can be stored in liquid form at ambient temperature in traditional fossil fuel tanks. In the case of Fischer-Tropsch fuels, these can be used as drop-in fuels, which implies that utilities do not have to change their existing transport, storage or power generation infrastructure to fulfil demand. Existing dual-fuel gas turbines are capable of utilising diesel as a power generation fuel, which can be replaced directly by an efuel like ediesel produced by a Fischer-Tropsch process. On the other hand, methanol presents some challenges that will require modifications to existing gas turbines [32,33].

These chemicals require carbon dioxide as a feedstock, and although renewable or biogenic carbon dioxide is not as abundant as nitrogen from the air, for ammonia production, or water for hydrogen production, direct air carbon capture technologies are developing quickly with steep cost decreases expected in the next ten years [34]. Besides, the total production costs of efuels depend heavily on the cost of renewable electricity and hydrogen, at around 62% of the total cost of production, and less on the carbon dioxide cost, at around 13% of the total production costs [35,36]. These fuels are produced in chemical processes that traditionally run in a steady-state regime [37]. However, recent advancements suggest that Fischer-Tropsch [37], reverse water gas shift reactors [38], and methanol production processes [39] will be engineered to increase their flexibility to withstand variable renewable electricity inputs.

1.2. Comparative studies

As shown in Table 1, some studies on efuel usage for seasonal storage purposes have concentrated their efforts on methanol [40–42], and dimethyl ether [40], both of which are not drop-in fuels for current power generation infrastructure. That last study concluded that for the Spanish case, methane or methanol are preferred options for low energy demands (up to 500 GWh per year), but as the demand for power increases, ammonia is adopted for larger energy demand rates (topping up to 1 TWh per year) [40]. Ammonia became the preferred option for larger energy demand rates because the model had a limit on the availability of low-cost renewable carbon dioxide required to produce methanol and methane. The authors also highlighted the low storage costs of ammonia and methanol as being one of the main drivers of their total lower costs when compared to the other options. Other research compared ammonia and methanol as energy storage solutions with a focus on comparing thermochemical (combustion) and electrochemical (fuel cell) production of electricity [41]. According to their study, the conversion of ammonia and methanol to electricity through combustion is more efficient and economically favourable than fuel cells. A study by Ref. [42] evaluated different seasonal storage options for a renewable generation site. They compared hydrogen, ammonia, methanol and methane, and concluded that hydrogen is the option with the highest load coverage, which is the capacity of the storage system to cover a given demand, and with the highest efficiencies, followed by ammonia, methanol and finally methane. In that study, they highlighted that hydrogen required around 17 times more volume than the methanol-based solution, making it a challenging case when no geological features are available on-site. Although the study considered technical details absent in other studies, it did not compare the economic performance of the options for storing energy. On the other hand, studies like [43,44], among others, studied the costs of production of efuels from renewable power but did not consider those fuels for energy storage and subsequent power generation purposes.

1.3. Optimisation conditions

The issue of process flexibility has been mentioned several times in previous sections. This is because, to optimally integrate variable renewable inputs into chemical processes certain levels of process flexibility have to be included. A study by Ref. [45] describes the four main types of chemical process flexibility: feedstock flexibility, capacity flexibility, product flexibility and operational flexibility. The flexibility that concerns the issue previously mentioned is capacity flexibility, as it ensures that product quality is not hindered by variable feed flow rates.

In addition, to represent the flexibility issues related to intermittent renewable power generation and steady-state chemical processes, optimisation models have to consider a reasonable level of time resolution to obtain meaningful results. These models have to consider sufficiently long optimisation windows to take into account the seasonal variation of power generation and/or demand. The number of historical years required to have an accurate prediction of the behaviour of a project depends *“on the characteristics of the renewable resource and the level of renewable penetration in the system”* [46]. A study by Ref. [47] showed that investment results can vary significantly when using different optimisation windows, suggesting a minimum of 20 years of input data for wind-to-hydrogen storage systems. However, considering long optimisation windows with a very high resolution is extremely computationally demanding. As shown in Table 1, studies have not explored the effect that different resolutions and optimisation time frames have on the results of seasonal energy storage solutions. This is particularly relevant for technologies that have certain levels of flexibility to respond to changes in the input of renewable power and that, at the same time, have to produce a fuel to be stored for long periods of absence of excess renewable power.

1.4. Objectives

This study aims to evaluate and compare different seasonal aboveground energy storage technologies to determine which option is most techno-economically suitable for deployment on sites that lack geological H_2 storage facilities. In this paper, we evaluate and techno-economically optimise different solutions and configurations for aboveground energy storage by considering a base case of variable power supply and constant power demand of 100 MW during a full year with hourly resolution in an isolated system.

The storage solutions studied are compressed hydrogen tanks, liquid hydrogen storage, ammonia tanks, methanol tanks, and Fischer-Tropsch fuel tanks. To analyse how those solutions compare with the current aboveground energy storage benchmark, grid-scale battery storage systems, a Li-ion battery system scenario is included. To study the effects of potential development on capacity flexibility in the economic performance of the systems, scenarios with lower minimum operating points are analysed. Minimum load flexibility is not a definitive and complete way to represent capacity flexibility. However, it allows us to study the potential improvements in the system without compromising computational capacity.

In this study, the computational compromise between resolution and optimisation window is explored to find the right balance between accuracy and practicality of seasonal energy storage modelling. A full year of optimisation at hourly and daily resolution is analysed to compare the effects of a lower resolution on the optimisation results. Finally, a twenty-year optimisation period at a daily resolution is analysed to compare the investment levels in seasonal storage when longer periods of optimisation are considered.

This study therefore, contributes to the literature in four ways. First, it adds a better understanding of how different aboveground seasonal storage solutions compare to each other in techno-economic terms. Second, it studies the influence of capacity flexibility on the economic performance of hydrogen and hydrogen derivatives production for seasonal energy storage purposes. Third, it studies the effect of lower

Table 1
Long-duration seasonal storage and hydrogen derivatives studies.

Study	Focus / Scope	Methodology	Technologies Compared	Main Findings	Limitations / Notes
[10]	Importance of LDES in decarbonised electricity systems	Review	LDES categories (10-20h vs. weekly/monthly)	Defines two LDES categories; stresses need for long-duration storage	Classification focus; no tech cost comparison
[11]	Overview of energy storage technologies	Review	Flow batteries, thermal, thermochemical, pumped-hydro, compressed gas	Mature vs. developing storage tech	No seasonal storage analysis
[12]	Tech limits of current storage	Review	Various	Most techs limited to 20h storage	Highlights need for hydrogen-based solutions
[9]	Hydrogen long-duration energy storage	Review	Hydrogen storage solutions	Hydrogen storage as the most preferable choice for large and long-term energy storage	China focused
[13]	Seasonal storage options	Report	Hydrogen, compressed gas, pumped hydro	Hydrogen and derivatives best for long durations	General global view
[14]	H_2 storage in geological formations	Techno-economic assessment	Hydrogen	Underground H_2 storage is most economical for long-term	Cost-based comparison
[15]	Levelised cost of electricity storage	Levelised cost of storage	Various	H_2 storage is the best for long duration discharse times	Cost-based comparison
[16]	USA seasonal storage volume needs	Volumes requirement comparison	H_2, hydro, compressed air, biomass	$6\,\text{km}^3$ of H_2 needed vs. $2300\,\text{km}^3$ of water	Volume comparison only
[18]	H_2 storage properties	Review & underground H_2 storage model	Hydrogen	H_2 in salt caverns does not self-discharge and H_2 storage is a complex problem to model	Tech-specific insight
[19]	Cost-effectiveness of storage	Levelised cost of storage	Various	H_2 17 hours more cost-effective than others	Economic modelling
[20]	California's seasonal storage	Levelised cost of electricity	Hydrogen, batteries	H_2 turbines Li-ion for seasonal	Regional scope
[21]	Sector coupling hydrogen investment optimisation	Least cost energy system. Hourly resolution with 30 representative weeks	Hydrogen	Importance of using an integrated energy system framework with multiple energy vectors to decrease decarbonisation costs	Policy-oriented
[22]	Comparison of four power-to-X options	Review	Compressed/ Liquefied H_2, ammonia, methanol	In the German case ammonia is the best option	Policy-oriented
[26]	Hydrogen liquefaction challenges	Report	Liquefied H_2	Best operated at steady state	Process-focused
[27]	Energy transport efficiency	Cost effectiveness comparison	Ammonia, H_2, cables	Ammonia most efficient for transport/storage for distances >140 km	Energy transport focused
[28]	Round-trip efficiency	Efficiency comparison	H_2, Ammonia	Similar efficiency between H_2 & ammonia	No economic assessment
[35]	Cost breakdown of efuels	Comparative cost analysis	Fischer-Tropsch, Methanol-to-jet	62% of cost is electricity & H_2. But also sensitive to CO_2 cost	Process economics
[36]	Cost breakdown of efuels	Techno-economic assessment	Different Fischer-Tropsch and Methanol-to-jet configurations	Electricity price and electrolyser costs as the key cost factors	Process economics
[37]	Process flexibility of fuel prod.	Review	Fischer-Tropsch	FT synthesis would benefit from including dynamic operation	Technical innovation angle
[39]	Flexible Methanol processes	Levelised cost of Methanol	Methanol	Proposed method can reduce hydrogen storage capacity by 90% and total methanol production costs by 80%	Operation innovation
[40]	Seasonal storage in Spain	System cost minimisation. Hourly resolution during a year of optimisation	Methane, methanol, DME, ammonia	Methane/methanol for low demand; ammonia for high	Cost-focused; assumes CO_2 constraints
[41]	Thermochemical vs. electrochemical storage	Process design comparison and techno-economic evaluation	Ammonia, methanol	Combustion more efficient than fuel cells	Process focus
[42]	Tech comparison at generation site	Efficiency and optimal load capacity comparison	H_2, ammonia, methanol, methane	H_2 most efficient but needs 17× more volume than methanol	Tech-focused, no cost data
[43]	Cost of efuels	Techno-economic assessment	Fischer-Tropsch	External factors have a strong impact on competitiveness of efuels	Did not assess storage or electricity regeneration
[44]	Cost of efuels	Techno-economic assessment	Fischer-Tropsch	Energy storage costs are relevant and can be removed by adding baseload power	Did not assess storage or electricity regeneration

resolutions in seasonal storage optimisation models. Fourth, it revises the influence of longer optimisation windows on the overall investment decision results and the compromise between modelling practicality and the accuracy of results produced by the changes in optimisation window and temporal resolution. In addition, the inclusion of Fischer-Tropsch liquid fuels for seasonal energy storage purposes is a novel feature not present in the energy hubs optimisation literature on seasonal energy storage. This study also discusses the economic reality of these technologies in real-life environments, acknowledging the challenges developers face in the transition towards net-zero. The mentioned objectives and novelties aim to incentivise the discussion regarding techno-economic barriers to the deployment of crucial carbon-neutral energy storage solutions to address the affordability, sustainability and resilience of the energy system.

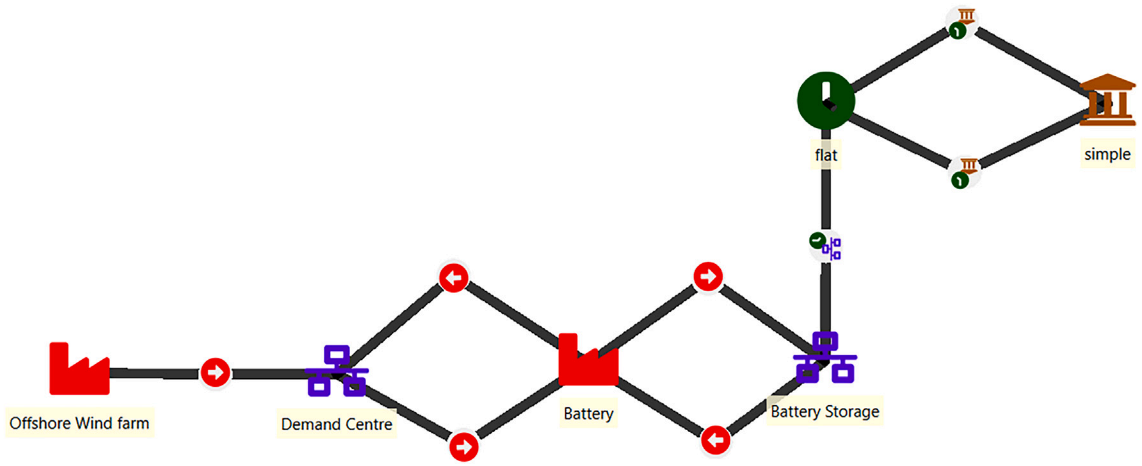

Fig. 1. Optimisation model example graphical description. Red blocks represent units, purple blocks represent nodes, the green block represents the temporal block, the brown block represents the model block. Red arrows represent energy flows and other block interactions represent relationships.

This paper's structure starts with the materials and methods description, followed by the key results and their respective discussions, finishing with the conclusions.

2. Materials and methods

2.1. Optimisation model

An optimisation model of an energy hub system was developed using SPINEOpt and SPINEToolbox version 0.6.18.dev0 running on Python 3.8.10. An energy hub system is a clustered group of energy generation and storage units serving a specific energy demand. SPINEOpt is a Julia-based energy system investment and operation optimisation platform that allows high flexibility on a temporal, spatial and technological level [48]. SPINEToolbox is used to manage the data coming in and out of the model. The models are based on fundamental blocks, also known as functional elements, and their interactions. These fundamental blocks represent generic energy system model components, with some examples being the model block, nodes, units, interconnections, and temporal blocks. The model block is where the modelling conditions are established, such as the optimisation window and the solution algorithm. The central element of the energy system models is the nodes, *i.e., "a notional point where energy flows are balanced, and which may have a state, allowing storage and/or transport dynamics to be considered."* [48]. Units allow flow conversion and have operational status variables. Similarly, connections also allow interaction between nodes by representing the physical transportation of energy flows. Temporal blocks store information about the different temporal resolutions and temporal restrictions (*e.g.,* cyclic conditions) of the different fundamental blocks.

An example of some of the fundamental blocks can be described with one of the systems which is modelled in this study shown in Fig. 1. To fulfil a constant power demand represented by a node, an offshore wind farm, represented by a unit block, can be connected to that node, providing power with a variable input determined by the user. Since not all the power can always be consumed by the demand centre, and sometimes not enough power is produced by the unit to fulfil the demand, a storage method is required. That storage method can be represented by lithium-ion batteries in the form of a unit that transforms the power connected to a node that stores the energy. To define the modelling conditions, such as the optimisation period or solving algorithm, a model block is used. A temporal block is connected to the lithium-ion battery node to force a cyclic condition, which obliges the storage node to finish the optimisation at the same level, or higher, than it started.

The objective function in SPINEOpt is the minimisation of the total cost of the system, which includes operational expenses and capital investment for the optimisation period of the technological options available in each run. In this study, each run represents a different exogenously chosen technological scenario, in which the model minimises total investment and operational costs given the technology portfolio available. The objective function is presented in Eq. (1), subject to the constraints presented in Eq. (2)–(7).

$$\min Cost = Investment + OPEX - Rev \tag{1}$$

Subject to:
Nodal balance:

$$0 = \frac{\Delta v^{node\_state}_{(n,(t-1,t))}}{\Delta t_{(t-1,t)}} - p^{demand}_{(n,t)} + \sum_{connection/unit} v^{conn/u\_flow}_{(conn/u,n,to\_node,t)} - \sum_{connection/unit} v^{conn/u\_flow}_{(conn/u,n,from\_node,t)} \qquad \forall t \tag{2}$$

Node state capacity:

$$v^{node\_state}_{(n,t)} \le p^{node\_state\_cap}_{(n)} \qquad \forall t \tag{3}$$

Cyclic condition:

$$v^{node\_state}_{(n,start)} \le v^{node\_state}_{(n,end)} \qquad \forall t \tag{4}$$

Ratios between flows (units and connections):

$$0 = v^{unit\_inflow}_{(u,t)} \cdot p^{efficiency}_{(u)} - v^{unit\_outflow}_{(u,t)} \qquad \forall t \tag{5}$$

Minimum operating point:

$$v^{unit\_flow}_{(u,t)} \ge p^{unit\_capacity}_{(u)} \cdot p^{min\_operating\_point}_{(u)} \qquad \forall t \tag{6}$$

Available investment units:

$$v^{units/storage\_invested\_available}_{(u/n,t)} < p^{candidate\_units/storage}_{(u/n)} \qquad \forall t \tag{7}$$

The decision variables (v) are the investment (*units/storage_invested_available*) in units (u) and storage capacity represented by certain nodes (n), and the units, connections (*conn*) and nodes output (*unit_flow, unit_inflow, unit_outflow*). Parameters (p) include unit efficiencies, minimum operating points, unit capacities, candidate units/storage, node state cap, and demand and power generation profiles.

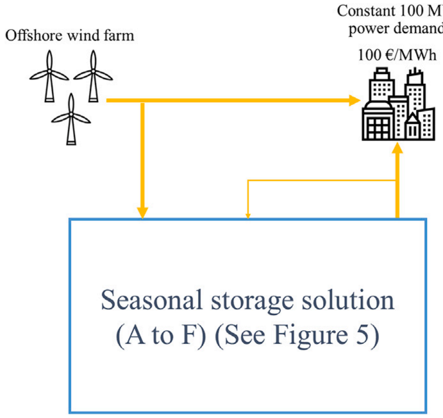

Fig. 2. General energy system study case scheme.

The total investment is broken down into unit investment costs and storage costs as follows:

$$Investment = \sum_{unit,t} v^{units\_invested}_{(u,t)} \cdot p^{units\_investment\_cost}_{(u,t)} + \sum_{node,t} v^{storages\_invested}_{(n,t)} \cdot p^{storages\_investment\_cost}_{(n,t)} \quad (8)$$

Where the variables are the storage invested and the unit invested, and the parameters are the annualised cost per unit and storage. The latter value calculation procedure is shown further down in the text. Similarly, the operational expenditure (*OPEX*) is calculated by adding the variable operational expenditure, fuel costs, taxes and electricity bought via interconnectors as shown in the following equation:

$$OPEX = \sum_{u,n,t} v^{unit\_flow}_{(u,n,t)} \cdot p^{var\_cost}_{(u,n,t)} \cdot \triangle t + \sum_{u,n,t} v^{unit\_flow}_{(u,n,t)} \cdot p^{fuel\_cost}_{(u,n,t)} \cdot \triangle t + \sum_{u,n,t} v^{unit\_flow}_{(u,n,t)} \cdot p^{carbon\_tax}_{(u,n,t)} \cdot \triangle t + \sum_{conn,t} v^{conn\_flow}_{(conn,t)} \cdot p^{conn\_flow\_cost}_{(conn,t)} \cdot \triangle t \quad (9)$$

Where the variables are the units and connection flows, and the parameters are the variable operational costs, fuel costs, carbon tax and connection flow costs. Fixed operational expenditure are included in the units and storages investment costs as is explained in the following subsections. Revenues (*Rev*) are calculated by adding the revenues from selling electricity to the demand centre as follow:

$$Rev = \sum_{u,n,t} v^{unit\_flow}_{(u,n,t)} \cdot p^{electricity\_price}_{(u,n,t)} \cdot \triangle t \quad (10)$$

Where the variables are the unit flows, and the parameter is the electricity price.

2.2. Energy hub configuration

The energy hub modelled in this study consists of an offshore wind farm that is connected to a constant power demand centre. The same wind farm is connected to a seasonal energy storage solution, which is then connected back to the demand centre as detailed in Fig. 2. The system modelled considers a hypothetical offshore wind farm off the west coast of Ireland with a certain annual wind power generation profile obtained from Renewables Ninja (www.renewables.ninja) [49,50]. The hourly capacity factor of the wind farm during the year is presented in Fig. 3, with an overall average of 61.36%. The cumulative capacity factor relative to the amount of time of the year is presented in Fig. 4. A maximum capacity of 1 GW is considered for the wind farm in the optimisation model. A constant 100-MW power demand on the electric demand node is assumed as the main constraint to be fulfilled. This assumption is made with a dual purpose. First, it could represent an industrial energy user with a steady-state operation that requires a fixed amount of power at each hour, such as a data centre or a chemical plant. Second, it allows the different energy storage solutions' flexibilities to be compared more clearly, without the noise that a variable demand or a demand response program could add to the results. The constant demand of 100 MW is selected as an indicative large-scale energy consumer that is completely isolated. This case, although it seems unlikely, could easily happen in an island nation with a thriving data centre, mining or other heavy industries sector. The size of the equipment is optimised according to the model described in Section 2.1.

Electricity flows directly to the demand node or the energy storage system. When the wind farm does not produce enough power to satisfy the demand, the energy storage releases power to the demand node. In some cases, due to the requirements of the system, the same stored

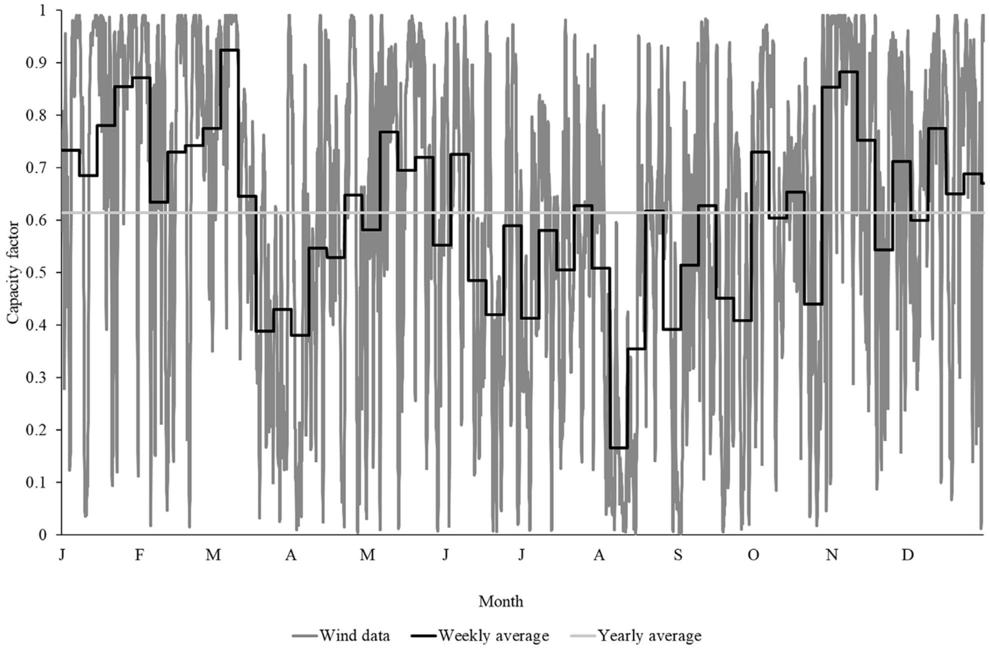

Fig. 3. A wind farm one-year hourly capacity factor.

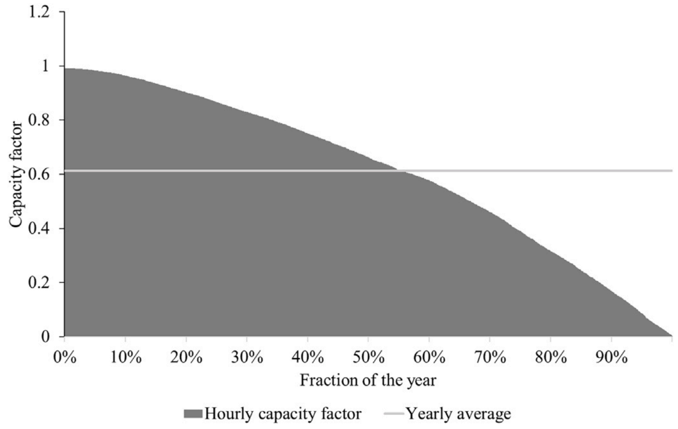

Fig. 4. A wind farm one-year capacity factor relative to the percentage of the year.

energy powers the fuel production process to fulfil the minimum operation levels of the units. In this configuration, there is no other source of power than the wind farm. The demand node pays a constant rate per MWh delivered, a value similar to the most recent awarded Irish Offshore Renewable Electricity Support Scheme auction (Tonn Nua offshore auction). A simplified version of the system is presented in Fig. 2.

2.3. Scenarios description

The energy storage solutions evaluated in this study are Li-ion battery packs, compressed hydrogen in tanks at 200 bar, liquid hydrogen stored in cryogenic tanks, liquid ammonia stored in refrigerated tanks, methanol stored in methanol tanks, and Fischer-Tropsch synthetic diesel stored in diesel tanks. All the seasonal storage solutions evaluated, except for the battery scenario, start with hydrogen production in an electrolyser. Once the hydrogen is produced, it is stored in compressed hydrogen tanks. For the liquid hydrogen scenarios, the compressed hydrogen is liquefied and stored in cryogenic tanks. In the case of the ammonia scenarios, the compressed hydrogen enters a Haber-Bosch plant, where it is converted into ammonia using nitrogen separated from air, which is later stored in refrigerated ammonia tanks. The carbon-based hydrogen derivatives are produced with compressed hydrogen and an assumed source of renewable carbon dioxide in either a methanol synthesis process or in a reverse water gas shift reactor integrated with a Fischer-Tropsch reactor (synthetic hydrocarbons plant) to produce the respective fuels, which are later stored in their respective fuel tanks. Since the cryogenic processes and the chemical reactors typically operate at a steady state, the default minimum operating point is set at 100%. However, scenarios with a 50% minimum operating point and a fully flexible production (0% minimum operating point) are evaluated to understand the effects of potential future technological improvements on the economics of the seasonal storage solutions. In each scenario, except for the batteries scenario, a gas turbine produces power from the different fuels at a fixed efficiency of 50%. This assumption is made by considering an average efficiency between conventional open-cycle gas turbines and combined-cycle gas turbines. It is expected that new fuels being burned in new turbines will reach similar efficiency values [51]. The different storage solutions are graphically described in Fig. 5 and summarized in Table 2.

2.4. Optimisation periods

Three different optimisation cases are performed for each of the different scenarios. The first optimisation window considered for this study

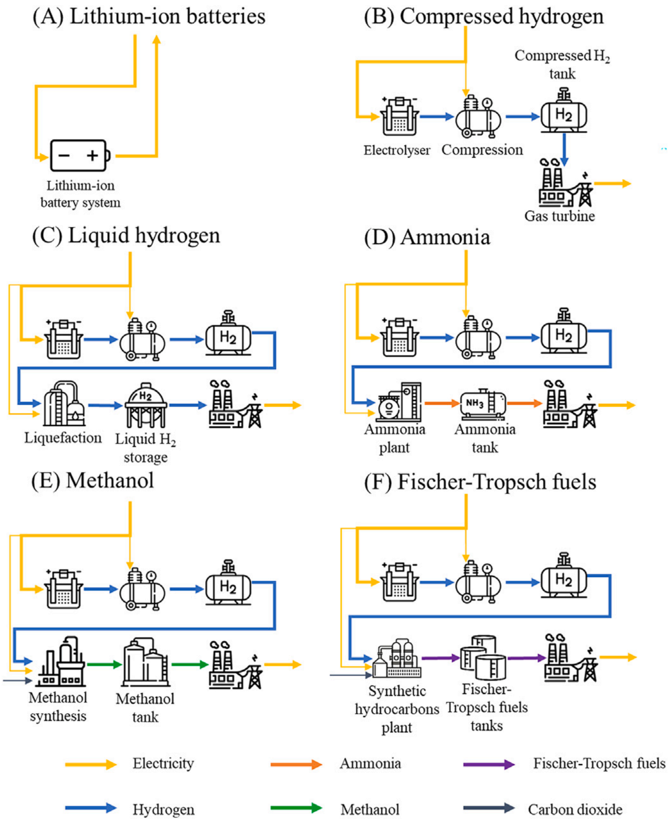

Fig. 5. Seasonal energy storage solutions proposed in this study. (A) Li-ion batteries storage (scenario Batt). (B) Compressed hydrogen storage (scenario Comp). (C) Liquid hydrogen storage (scenarios LFlex, LIn, L50). (D) Ammonia storage (scenarios HBFlex, HBIn, HB50). (E) Methanol storage (scenarios MFlex, MIn, M50). (F) Fischer-Tropsch fuels storage (scenarios FTFlex, FTIn, FT50).

Table 2
Scenarios evaluated.

Scenario name	Main transformation stage	Carbon dioxide feedstock	Minimum operating point
Batt	Li-ion batteries	No	0%
Comp	H_2 Compression	No	0%
LIn	H_2 Liquefaction	No	100%
L50	H_2 Liquefaction	No	50%
LFlex	H_2 Liquefaction	No	0%
HBIn	Haber-Bosch	No	100%
HB50	Haber-Bosch	No	50%
HBFlex	Haber-Bosch	No	0%
MIn	Methanol synthesis	Yes	100%
M50	Methanol synthesis	Yes	50%
MFLex	Methanol synthesis	Yes	0%
FTIn	Fischer-Tropsch	Yes	100%
FT50	Fischer-Tropsch	Yes	50%
FTFlex	Fischer-Tropsch	Yes	0%

is a full year of operation using hourly resolution that captures the hourly renewable power variability. A second optimisation round is performed for the same period but on a daily resolution. The wind data used in that case is the simple daily average of the hourly generation. The purpose of that optimisation round is to compare the investment results between the different resolutions, which are impacted by the smoothing of hourly peaks and troughs of production to daily averages. The final optimisation round is made by considering 20 years of wind data on a daily resolution. The wind data used is presented in Fig. 6. That last optimisation round allows the model to size energy storage considering long periods of wind data with low and high availability of wind generation.

2.5. *Techno-economic assumptions*

The parameters (p) used in this study are presented in Table 3 and include efficiencies, unit-specific investment costs, equipment lifetime and power requirements.

To calculate the total cost of the system, it is necessary to obtain the appropriate annualised cost of each unit or storage total investment cost for the optimisation period. This is done by considering the total specific CAPEX of the unit or storage (Pv), the lifetime of the assets (N) (in Table 3) and a discount rate (R) of 8%. The annualised cost of investment also includes the fixed annual OPEX of the unit or storage, as shown in Eq. (11). For the single-year optimisation rounds, the annualised cost of the investment for a single year is considered. In the case of the 20-year optimisation round, the annualised cost is multiplied by 20 to calculate the total investment cost of the system for that respective period.

$$p^{units/storage\_investment\_cost}_{(n,u)} = \frac{(Pv \cdot R)}{[1-(1+R)^{(-N)}]} + Fixed\_annual\_OPEX \quad (11)$$

The total system efficiency is calculated by dividing the total energy delivered by the system, which is represented by the total demand during the evaluated period, by the total electric energy that the system is capable of producing in that same period, which in this case is determined by the size of the wind farm.

2.6. *Model limitations*

The model developed for this study presents several limitations that are worth mentioning. First, the limitations related to the software and optimisation algorithm. SpineOpt supports linear and mixed-integer linear problem solving, which affects the representation of the specific cost curves for different storage technologies, which, for simplicity, are assumed to be constant. Second, the limitations related to the formulation of the system; it is assumed for this case study that the system is completely isolated and has a constant power demand of 100 MW. This assumption could be challenged, but it helps focus attention on the flexibility capabilities in the supply of power side, which is the main driver of the high variability in net demand in a system with high wind generation penetration. In places with high wind penetration profiles, the alignment between demand and supply is not correlated as it is in places with high building cooling demand and solar PV generation. As mentioned by Ref. [10], seasonal storage requirements arise from the variable nature of renewable power, which creates the mismatches between supply and demand. Furthermore, the model is formulated as a deterministic model, which allows the model to use a perfect forecast of the wind generation, hence allowing the model to reach the state of zero storage, something

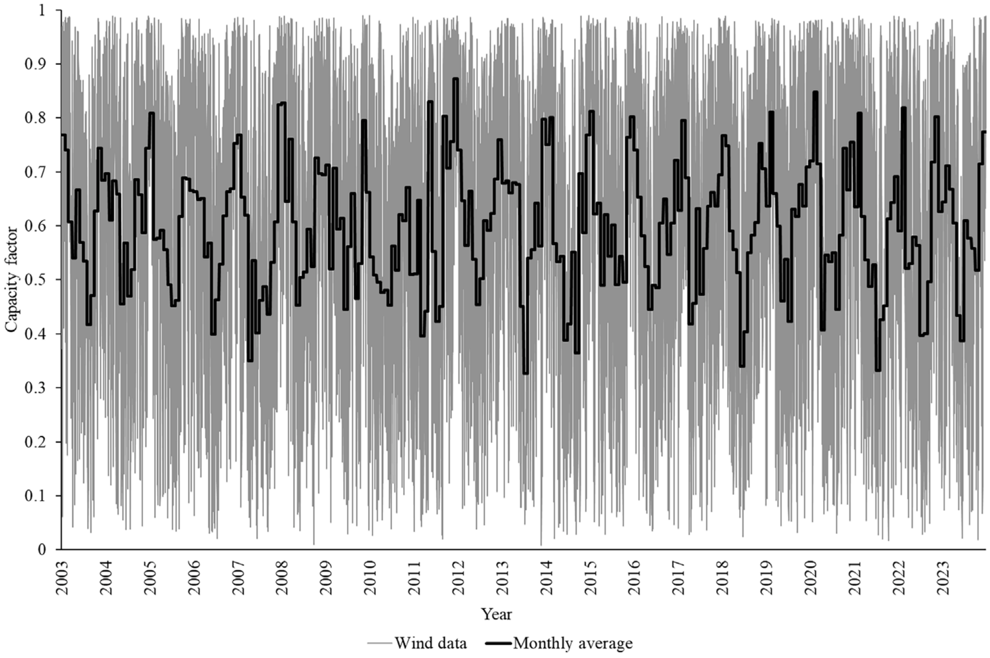

Fig. 6. A wind farm twenty-year daily capacity factor.

Table 3
Parameters used in this study.

Parameter	Value	Units	Lifetime	Source
Carbon dioxide cost	100	€/tonne		[52]
Electrolyser				
Electricity to hydrogen efficiency	69.44%			[53]
Electrolyser CAPEX	1743	€/kW	25 years	[54]
Electrolyser OPEX	2%	CAPEX/year		[55]
Ammonia plant				
Hydrogen to ammonia efficiency	5.29	$kgNH_3/kgH_2$		[56]
Ammonia plant CAPEX	4192	€/($kgNH_3$/h))	25 years	[57]
Ammonia plant OPEX	88.57	€/($kgNH_3$/h)/year		[58]
Ammonia energy content	5.21	$kWh/kgNH_3$		
HB electricity consumption	0.6	$MWh/tonneNH_3$		[59]
Ammonia storage tanks CAPEX	0.991	€/$kgNH_3$	30 years	[60]
Ammonia storage tanks OPEX	3%	CAPEX/year		[60]
Gas turbine				
Turbine efficiency	0.5	kWhelec/kWhfuel		
Turbine CAPEX	715.89	€/kW	30 years	[59]
Turbine OPEX	16,218	€/MW/year		[59]
Compression & storage				
Compressed hydrogen storage CAPEX	694.39	€/kg	20 years	[59]
Storage tanks OPEX	1%	CAPEX/year		[61]
Compression specific energy consumption	1.9	kWh/kgH_2		[62]
Compression CAPEX	146	€/kWelectrolyser	30 years	[63]
Compression OPEX	2%	CAPEX/year		[53]
Liquefaction & storage				
Liquefaction plant energy consumption	7.6	kWh/kgH_2		[64]
Liquefaction plant CAPEX	33,003	€/(kg/h)		[64]
Liquefaction plant OPEX	4%	CAPEX/year	30 years	[65]
Storage tanks CAPEX	38.51	€/kgH_2	30 years	[64]
Storage tanks OPEX	2%	CAPEX/year		[64]
Offshore wind farm				
Offshore wind farm CAPEX	2450	€/kW	27 years	[66]
Offshore wind farm OPEX	3%	CAPEX/year		[55]
FT plant				
Electricity consumption	0.258	kWh/kg		[60]
Conversion efficiency	73%	$kWfuelout/kWhH_2$		[67]
Efuelsplant specific CO_2 consumption	3.14	$kgCO_2$/kgDiesel		Stoichiometric analysis
FT plant CAPEX	700,000	€/MWoutput	25 years	[67,68]
FT plant OPEX	4%	CAPEX/year		[68]
Diesel storage tank CAPEX	25.75	€/MWh	30 years	[60]
Diesel storage tank OPEX	3%	CAPEX/year		[60]
MeOH plant				
Electricity consumption	0.216	kWh/kgMeOH		[60]
Conversion efficiency	79%			[67]
Efuels plant-specific CO_2 consumption	1.37	$kgCO_2$/kgMeOH		Stoichiometric analysis
MeOH plant CAPEX	500,000	€/MWoutput	25 years	[67,68]
MeOH plant OPEX	4%	CAPEX/year		[68]
Methanol storage tank CAPEX	0.131	€/kg	30 years	[60]
Methanol storage tank OPEX	3%	CAPEX/year		[60]
Li-ion batteries				
Charge efficiency	98%			[61]
Discharge efficiency	97%			[61]
Batteries CAPEX	500,000	€/MWh	20 years	[69]
Batteries fixed OPEX	14.01	€/MW/year	20 years	[69]
Batteries variable OPEX	1.869	€/MWh	20 years	[69]

that in real life would not be allowed. Furthermore, some operational conditions like liquid H_2 boil-off, max ramping rates and downtimes are not considered as part of the technical analysis. Similarly, capacity flexibility was simplified to the level of only being considered as a variable minimum operating point. This ignores the effects on other parameters like turndown ratios, minimum operating and downtimes, as well as changes in efficiencies. Those parameters were left aside to improve computing efficiency. Another limitation related to the capacity flexibility is related to the CAPEX assumptions. It is assumed that the specific investment costs of the units are equal for the flexible and inflexible plants. Finally, to simplify the techno-economic analysis, elements such as the physical footprint, environmental, safety and health risks are neglected; however, these are discussed qualitatively later in this manuscript.

3. Results and discussion

3.1. Current state of the technology: li-ion batteries, compressed hydrogen and low capacity flexibility

In this subsection, we analyse the results of the scenarios that consider batteries, compressed hydrogen storage, inflexible production of liquid hydrogen, ammonia, methanol, and synthetic hydrocarbons in a single year of optimisation with an hourly resolution, with the current technology readiness. This assumes the chemical transformation plants

Table 4
Current state of the technology scenarios' results in a one-year optimisation window with hourly resolution.

Scenario	Batt	Comp	LIn	HBIn	MIn	FTIn
Total cost (m€)	301.2	99.4	40.6	36.9	40.7	44.9
Total units investment cost(m€)	174.9	113.9	111.6	114.3	113.0	115.5
Total storage investment cost(m€)	213.8	73.1	16.6	10.2	10.1	11.3
Wind farm (MW)	581	302	290	293	294	300
Electrolyser (MW output)	–	76	65	80	75	77
Compressed H_2 storage (GWh)	–	31.4	4.0	3.8	4.3	4.8
Turbine (MW output)	–	100	106	103	101	101
Transformation stage (MW output)	138	53	26	26	25	23
Storage (GWh)	4.5	31.4	58.4	61.4	56.3	53.7
System efficiency	28%	53.9%	56.2%	55.5%	55.4%	54.3%

and liquid hydrogen have inflexible loads. In Table 4, the main results of those scenarios are presented.

From Table 4, it is possible to see that none of the evaluated scenarios generate a net profit or break-even. This is due to the total costs of the system being higher than the total revenues, and that difference is reflected by the "total cost" row in Table 4. The ammonia scenario presents the lowest total costs, but does not have the lowest total unit investment costs. The methanol scenario has one of the lowest unit investment costs and the lowest storage investment costs. Despite this, methanol production requires carbon dioxide, which is an extra cost input that the ammonia scenario does not present. The ammonia scenario also presents the smallest compressed hydrogen storage buffer and the largest seasonal storage capacity, which decreases overall costs due to the expensive nature of compressed hydrogen tanks and the lower costs of ammonia tanks in comparison. On the other hand, compressed hydrogen, although being a fully flexible scenario, has expensive hydrogen storage tanks, making it at least twice as costly as the other H_2-based scenarios. Li-ion batteries present the highest total costs, being more than three times the cost of compressed hydrogen storage. This is driven mostly due to the high costs of storage per MWh of Li-ion batteries when compared to the other technologies. The cost of Li-ion batteries is so high for seasonal storage that the optimisation model oversized the wind farm to its maximum capacity allowed. The model does this because it is a cheaper option than building more batteries, even if that means increasing the curtailment and decreasing the system efficiency significantly.

Another result worth inspecting is the system efficiency, which is defined as the amount of energy delivered to the demand centre divided by the electricity that the wind farm sized by the system is capable of producing during the same period. Hence, this metric is inversely proportional to the size of the wind farm. In this case, battery storage has the lowest system efficiency and the liquid hydrogen scenario presents the lowest wind farm size and the highest system efficiency, which means that the system curtails less energy than in the other scenarios. Another energy use that decreases the overall system efficiency is the power recycled to the transformation stage (*i.e.,* the stage that transforms the energy into its final storage form), which is the power that the system provides from the stored energy to keep running the transformation stage at a given output due to the flexibility restrictions. Thus, there is a direct relationship between the flexibility capability, or lack thereof, of the transformation stage, and the efficiency of the overall system. Finally, although the different scenarios present very different results, the wind farm size of all hydrogen and derivatives scenarios is between 290 MW and 302 MW, which means that for a 100 MW constant demand, a minimum of 290 MW wind farm size with a seasonal storage solution is required to fulfil the demand with the current technology. This is almost 3 times the size of the hourly demand, despite the fact that the average capacity factor of the wind farm is over 60%. In the case of battery storage, the factor goes up to 5.8 times the size of the hourly demand. A similar trend is concluded in the Californian case studied by Ref. [20]. They showed that for replacing the existing gas turbines' capacity in the system with a mixture of Li-ion batteries and hydrogen turbines, the total curtailment produced by the state of California would need to increase in 3.7 times the amount produced in 2019. This shows how much excess power is required to run, on a system level, the storage necessary to decarbonise the energy sector. Another study, shows that for the Greek island of Tilos to reach electricity self-sufficiency utilising only wind, solar PV and Li-ion batteries, an increase to 3.5 times the current renewable capacity is required to reach the most cost-effective battery size configuration [70]. The mentioned case study had an average annual demand of 0.354 MW, and a total installed renewable capacity of 0.96 MW. With the increase in capacity required to reach self-sufficiency, the total renewable capacity would become 3.36 MW, a size 9.5-fold of the average annual hourly power demand.

It is worth mentioning that the size of the wind farm in this study is the variable that contributes the most to the total cost of the system. Hence, as long as the seasonal energy storage solution does not become more expensive than the wind farm, a decrease in the size of the wind farm will decrease the total costs of the system more than any other variable.

3.2. Future developments: capacity flexibility

Due to the high penetration of variable renewable generation in the energy system, it is expected that original equipment manufacturers will start offering flexible green chemical production solutions for the next generation of ammonia plants [71], synthetic hydrocarbon plants, liquid hydrogen plants and methanol plants. This will improve the systems' performance for highly variable energy input. In this section, we analyse the effect on the techno-economic performance of the system of decreasing the minimum operating point of the liquid hydrogen, ammonia, methanol, and synthetic hydrocarbons manufacturing units.

From Table 5, Figs. 7 and 8, it is possible to see how more flexible technologies result in cheaper scenarios. This is due in large part to the decrease in investment in an oversized wind farms and reduced reliance on an expensive hydrogen buffer. As a direct consequence of the system being able to utilise available renewable generation at any given time, the transformation stage and the seasonal storage capacity increase in size in all scenarios, while decreasing the total system costs. This last

Table 5
Flexible and semi-flexible technology scenarios' results in a one-year optimisation window with hourly resolution.

Technology	L		HB		M		FT	
Scenario	50	Flex	50	Flex	50	Flex	50	Flex
Total cost (m€/year)	28.6	20.4	22.6	14.0	26.5	18.4	30.4	22.4
Total units investment cost (m€/year)	102.8	98.2	104.1	99.8	103.9	100.2	106.6	103.6
Total Storage investment cost (m€/year)	13.4	9.8	6.1	1.8	4.5	0.2	5.3	0.2
Wind farm (MW)	259	240	259	241	260	242	266	248
Electrolyser (MW output)	64	63	78	80	78	82	79	85
Compressed H_2 storage (GWh)	1.8	0	1.9	0	1.8	0	2.2	0
Turbine (MW output)	104	100	102	100	101	100	101	100
Transformation stage (MW output)	33	44	33	46	32	45	30	43
Storage (GWh)	73.5	77.9	76.4	79.3	74.5	78.5	70.5	76.0
System efficiency	63.0%	68.0%	62.8%	67.7%	62.6%	67.3%	61.2%	65.6%

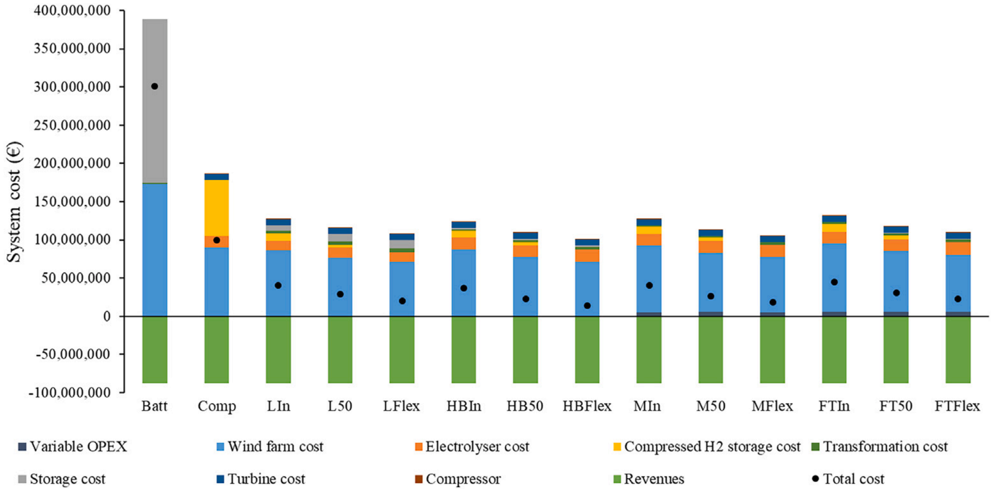

Fig. 7. Total cost breakdown of the one year optimisation with hourly resolution scenarios.

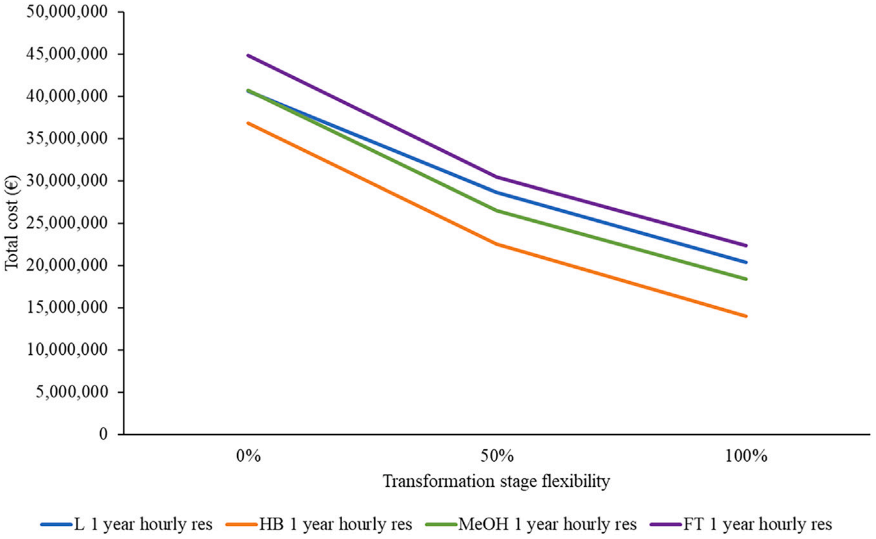

Fig. 8. Total cost of the one year optimisation with hourly resolution scenarios.

point is also reflected in the system efficiency values, which increase drastically when more operational flexibility is considered in all scenarios. This happens because of the decrease in investment in oversized wind farms, which makes the system rely more on the energy stored and hence curtails less power. The system efficiency is affected by several factors, but with more flexibility and less wind curtailment, the inefficiencies of the system can be attributed to the transformation process inefficiencies, which is one of the reasons why liquid hydrogen is more efficient than ammonia, methanol or synthetic hydrocarbons.

It is also important to mention that, although the system cost decreases significantly when compared to the non-flexible scenarios, the systems, as shown in Figs. 7 and 8, are still far from breaking even. Further, following the trend of non-flexible scenarios, the least costly scenario in a fully flexible scenario is the ammonia scenario, which, because it does not require a carbon dioxide source, presents a cheaper option than the methanol and the Fischer-Tropsch fuels route. In Fig. 8, it is also shown that the liquid hydrogen scenario is more expensive than the ammonia scenario due to the more expensive cryogenic hydrogen storage tanks, which have to keep a cryogenic liquid at a temperature much lower than the ammonia or carbon-based storage solutions.

One big improvement from the inflexible scenarios is the decrease in the size of the wind farms. To fulfil a 100-MW constant demand, an oversized offshore wind farm of 259 MW is required for a 50% minimum operating point energy storage solution, and 240 MW for a fully flexible energy storage system (see Fig. 9).

In Figs. 8 and 9, it is possible to see that the steepest change in all scenarios for total costs and investment in wind capacity happens from the inflexible scenario to the 50% flexibility scenario. This is important because it shows how early developments in the technology flexibility could decrease the total costs of the system in a more significant way than later further flexibility development if the specific CAPEX of the process remains the same. Achieving more impactful effects on the economics of the process by making the processes more flexible (up to 50%) could mean that an economically successful project could be reached earlier in the development of the aboveground seasonal energy storage industry rather than later.

Another point to note from Figs. 8 and 9 is the flatter slope of the liquid hydrogen curve. This happens due to a higher specific storage cost per MWh. As mentioned before, when the compressed hydrogen buffer and the wind farm decrease in size, the seasonal storage capacity increases. This is needed to compensate for the lack of direct wind power generation on certain occasions due to the decrease in size of the wind farm. In the liquid hydrogen case, the seasonal storage is much more expensive per MWh than the other technologies, which leads to a slower

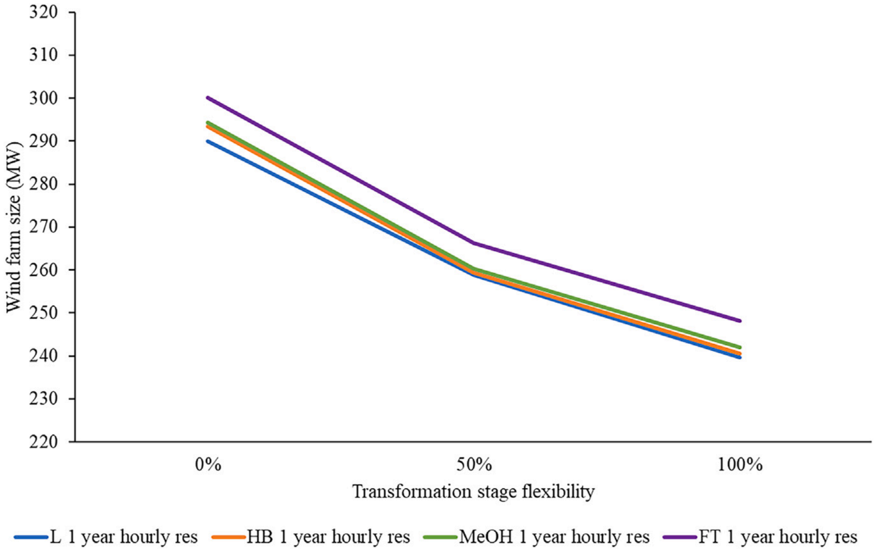

Fig. 9. Wind farm size of the one year optimisation with hourly resolution scenarios.

Table 6
The average difference across all the storage option scenarios between two one-year optimisation rounds results, the base case with an hourly resolution and another with a daily resolution.

	% Average Difference between daily and hourly resolution
Total cost without revenue (m€)	− 9.31%
Total units investment cost(m€)	− 8.55%
Total storage investment cost(m€)	− 10.59%
Wind farm (MW)	− 4.52%
Electrolyser (MW)	− 27.88%
Compressed H_2 storage (GWh)	− 22.47%
Turbine (MW output)	− 8.03%
Transformation stage (MW output)	− 27.78%
Storage (GWh)	− 8.76%
System Efficiency	+ 4.78%

decrease in the total costs of the system and a slower decrease in the size of the wind farm to compensate for the high costs of the storage.

3.3. *Effects of the model time resolution on the investment results*

One of the main challenges of renewable electricity is its intermittency, which can change power outputs in a matter of minutes. However, modelling energy systems with very high resolutions to reflect the variability of the power generation over time-scales of interest requires a large amount of computing capacity. Finding a satisfactory balance between result accuracy and manageable computational times is important for formulating energy systems optimisation models. Here, we compared the hourly resolution results with the daily resolution results for the same optimisation problem with a full year of operation and investment.

From Table 6, it is possible to observe the difference in the total costs of the systems with hourly and daily resolution models without adding the revenue produced by selling the electricity. Reaching up to 9.31% on average, this difference shows that changing the system resolution from hourly to daily in this case keeps the values at the same order of magnitude. All the daily resolution results show a lower cost than the base hourly resolution case, which is mostly due to the smoother daily wind energy profile obtained by the daily average of wind generation. This daily resolution optimisation round decreased the computational times significantly and allowed the model to obtain results that are on the same order of magnitude as the hourly resolution optimisation results. This is a natural result of adding more constraints to an optimisation problem, which in this case is multiplying a constraint 24 times. Another point to highlight is that the larger differences (more than 20%) are spotted in the elements that are more sensitive to variable energy inputs, like the electrolyser, the hydrogen storage buffer and the transformation stage. The seasonal storage, the wind farm and the turbine to produce power are less affected by the resolution of the optimisation, since those components normally deal with the seasonal storage issue, which is still represented in a daily resolution optimisation problem.

In Fig. 10, the difference between the state of the Fischer-Tropsch fuels storage in both optimisation resolution cases is shown, and it can be seen that the energy storage and release are captured very well by the daily resolution scenarios when compared to the hourly resolution case. The peaks are less pronounced, which causes the discrepancies and the final lower investment in storage at a daily resolution. It is also noticeable that the difference produced by the temporal resolution is less than the one produced by the flexibility of the processes. This is important because it highlights the relevance of developing flexible transformation processes, which affect the performance of the systems even more than temporal resolution constraints in energy system models. This is true only if the CAPEX of the flexible units remains the same as that of the conventional inflexible units.

The results obtained are comparable to those obtained by Ref. [72]. Which models the electricity systems of Kenya and Benin. When the resolution is changed from an hourly to a daily resolution, the total costs of the system varied by 14% and 7%, respectively. They concluded that temporal resolution is an important parameter to consider since it affects the overall insights of the modelling from total costs, to renewables share and grid expansion. In their case, the optimisation period is a single day, and a full country energy system is modelled, not a single energy hub as in this research. Due to the shorter optimisation periods, the effect of the operational costs is less relevant than for longer optimisation windows. In addition, compared to a green field development model, the level of investment in a grid expansion model that already has infrastructure in place is lower. Despite this, Ref. [72] points out the importance of high temporal resolutions in their model to reach more accurate results. In this study, we show that when the aim is to evaluate the effects of different operational variables, *e.g.,* capacity flexibility, on the total infrastructure investment, having a lower temporal resolution does not alter the relative difference between the different scenarios that evaluate the variable under study.

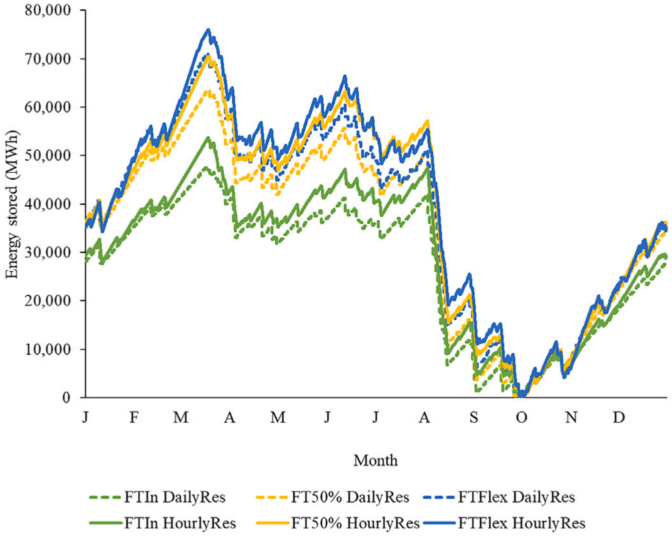

Fig. 10. Year-long Fischer-Tropsch fuels storage tank state for the different scenarios with daily and hourly resolution.

Table 7
Current state of the technology scenarios' results in a twenty-year optimisation window with daily resolution.

Scenario	Batt	Comp	LIn	HBIn	MIn	FTIn
Total cost (m€)	3804	2560	1023	760	772	844
Total units investment cost(m€)	323	3049	2307	2276	2270	2322
Total storage investment cost(m€)	5233	1264	469	237	168	182
Wind farm (MW)	1000	438	317	305	305	312
Electrolyser (MW output)	–	69	49	65	64	66
Compressed H_2 storage (GWh)	–	27	3	4	3	4
Turbine (MW output)	–	97	102	100	99	98
Transformation stage (MW output)	92	48	20	20	20	19
Storage (GWh)	5.5	27.1	131.9	158.6	175.5	169.4
System efficiency	15.9%	36.4%	50.2%	52.2%	52.2%	51.1%

Table 8
50% minimum operating point technology scenarios' results in a twenty-year optimisation window with daily resolution.

Scenario	L50	HB50	M50	FT50
Total cost (m€)	801	502	512	580
Total units investment cost(m€)	2128	2076	2056	2112
Total storage investment cost(m€)	426	179	112	117
Wind farm (MW)	286	271	267	274
Electrolyser (MW output)	49	63	65	66
Compressed H_2 storage (GWh)	2	2	2	2
Turbine (MW output)	101	100	99	99
Transformation stage (MW output)	25	28	28	26
Storage (GWh)	132.2	185.1	226.3	212.4
System efficiency	55.8%	58.9%	59.7%	58.2%

Table 9
Fully flexible technology scenarios' results in a twenty-year optimisation window with daily resolution.

Scenario	LFlex	HBFlex	MFlex	FTFlex
Total cost (m€)	599	301	320	388
Total units investment cost(m€)	1989	1967	1962	2021
Total storage investment cost(m€)	363	87	15	14
Wind farm (MW)	253	245	244	250
Electrolyser (MW output)	55	69	71	73
Compressed H_2 storage (GWh)	0	0	0	0
Turbine (MW output)	98	99	99	99
Transformation stage (MW output)	38	40	39	37
Storage (GWh)	144.2	192.3	242.2	234.9
System efficiency	62.9%	65.0%	65.2%	63.7%

3.4. *Effect of optimisation period on the investment results*

Following the fact that with a daily resolution, the models respect the trends in the investment and the seasonal storage profiles within a reasonable margin of accuracy, a 20-year optimisation window on a daily resolution is performed for all the energy storage solutions. This is done to study the effects of longer time-scales on the seasonal energy storage solutions investment.

In Tables 7–9, the main results are presented, and the first feature that is apparent is that the total cost of the system increases dramatically. Since this model considers 20 years of operation, the total costs of investment and operation are higher as well. This is due to the investment costs being an annualised cost, which increases the more years are considered in the optimisation. Similarly, the operational costs increase due to the larger periods being evaluated. Furthermore, the multiplying factor across the different scenarios is around 20 times the cost of a year of operation. This confirms that a seasonal storage system like the ones evaluated would not be economically feasible without additional support under the market assumptions made, because in this case, it is just an accumulation of deficits produced by the system each year. The 20-year optimisation round shows similar trends in terms of systems' costs, with only one noticeable difference. Maintaining the lowest total costs are the ammonia cases, followed closely by the methanol options, but the difference with the one-year optimisation round is that the liquid hydrogen scenarios are significantly more costly than the Fischer-Tropsch fuels scenarios. This is a consequence of the increase in storage investment. In one-year optimisation rounds, the more expensive liquid hydrogen storage is counterbalanced by less expensive transformation unit investment, leaving the Fischer-Tropsch fuels as a more costly option. In the twenty-year optimisation scenarios, the cost of storage increased relative to the total unit investments, making liquid hydrogen storage scenarios the least economically attractive scenario after compressed hydrogen and batteries. Larger investments in seasonal energy storage capacity occur due to multiple consecutive low wind generation periods in a row.

Another thing that arises from the results is that the only result that changes dramatically is the investment in seasonal storage. With the exclusion of the compressed hydrogen and battery scenarios, the other seasonal storage investment increased by an average of 165% when compared to the one-year hourly resolution case. This supports the findings of [47], which show that shorter optimisation periods underestimate the requirements of seasonal storage to ensure enough storage capacity through years of varying renewable energy production.

Another point worth highlighting is the system efficiency, which decreased when compared to the one-year optimisation case with hourly resolution. This, as mentioned before, depends on the size of the wind farm and in all scenarios, the model invested in a larger wind farm. The difference between scenarios is not substantial, with the exception of the compressed hydrogen scenario and battery scenarios, which see increases in wind farm sizes of 136 MW and 419 MW, respectively. With this, it can be concluded that an aboveground compressed hydrogen system cannot fulfil a constant 100 MW demand for 20 years without having a wind farm at least 4.38 times larger in capacity powering the system. An even more extreme case is the battery storage scenario, in which the model topped out the maximum candidate units available for wind farms, showing that for a 20-year optimisation round, a long-duration energy storage solution based on Li-ion batteries might require a wind farm at least 10 times the size of the constant demand expected to be fulfilled. It is important to remember that these results are based on a daily resolution optimisation round, and it is likely that under an hourly resolution regime, costs, wind farm size, electrolyser size and storage size would increase.

3.5. Energy storage solutions

After analysing the results, it is clear that ammonia storage scenarios are shown as the most economically attractive option for a new development. A cheaper and well-known transformation process with relatively inexpensive storage technology profiles, this option is the most competitive among the evaluated technologies, but without making it a profitable option under the assumptions made in this study. Ammonia also has other commercial opportunities in the commodity market, with global production reaching 150 million metric tonnes in 2023 [73]. Several elements prevent ammonia from being deployed at scale in the energy sector, one of which is safety. Ammonia is a highly toxic chemical, which, if leaked, can react with moisture in the surroundings to form a heavy ammonia-water fog that moves with the wind, representing a hazard to humans' and other species' health [74–76]. The behaviour of ammonia when leaked depends greatly on the storage and ambient conditions [75,76]. Another point against ammonia is the readiness of ammonia-to-power technology. Currently, original equipment manufacturers are developing ammonia-fired turbines and reciprocating engines [29,30], but none have reached a commercial state. Some of the technical difficulties involving ammonia burning include its low laminar flame speed, high minimum ignition energy, lower heating value, and higher autoignition temperature when compared with conventional fuels [30]. Ammonia-hydrogen blends are being investigated as a solution to the poor fuel qualities of ammonia [77,78].

The next best alternatives, according to the results from this study, are the methanol scenarios. Methanol has been discussed for years as an alternative to conventional fuels because it burns at lower temperatures and does not contain sulfur or nitrogen [79]. However, as with ammonia, it faces similar technological readiness challenges on the methanol-to-power side. Tests have been conducted on existing gas turbines that have proven to be capable of burning 100% methanol with minor modifications [32,33,79]. This could make methanol a fuel of preference due to its lower toxicity and easier implementation in existing power generation infrastructure.

As mentioned before, this study evaluated the development of a new power-generation site. Under that assumption, the Fischer-Tropsch fuels scenarios present either the third or fourth lowest cost among the evaluated options, depending on the modelling conditions. However, those fuels are the only ones evaluated that could be potentially blended with conventional fuel or used directly in existing thermal generation infrastructure. This point is important to consider for places with legacy infrastructure with a pathway towards decarbonisation. Currently, different utilities across the world are implementing hydrotreated vegetable oil (HVO) to decarbonise their existing thermal power generation infrastructure. Fischer-Tropsch fuels could play a similar role during the energy transition. Although the evidence shows that those fuels are more expensive than HVO and conventional fuels, they come with less potential environmental sustainability burden [80,81]. This is due to the lower total life-cycle emissions that efuels present when compared to fossil fuels, and the absence of potential unsustainable feedstocks like virgin palm oil in HVO production [82]. The geographical uniqueness of each site requires a dedicated analysis to evaluate the different options to decarbonise the energy sector, with consideration of existing infrastructure and natural features. For example, in this study, if the costs of a new gas turbine and new fuel storage infrastructure are assumed as sunk costs for scenarios FTFlex, FTIn, and FT50, the inflexible Fischer-Tropsch fuel (FTIn) system's total costs decrease to the point of being the most affordable option (€36.7 m) for a year of optimisation under hourly resolution. Although in a fully flexible scenario, a Fischer-Tropsch fuels system's cost (€14.1 m) is similar to the ammonia system cost, once the optimisation window increases to twenty years on a daily resolution, the total cost difference increases dramatically, with a fully flexible Fischer-Tropsch fuels system total cost of €215.2 m, 28.5% less costly than the ammonia system. Further studies could analyse whether synthetic hydrocarbon routes perform economically better than ammonia or methanol in real locations with existing gas turbines and storage tanks, since those results are based on the assumption of complete existing power generation sites requiring no modifications.

Another finding from the scenarios run in this study involves the state of storage tanks during the twenty years of optimisation. As shown in Fig. 11, throughout the 20 years of optimisation, there is at least one point in all scenarios in which the level of the storage reaches zero MWh. This is because the model optimises the size of the storage to fulfil just what is enough at the minimum possible cost. In actual operations, a contingency factor would be added to ensure enough storage for even the periods of lowest renewable power generation. With that said, it is interesting to mention that the liquid hydrogen and ammonia scenarios reached the zero point more than once during the twenty years. This could be interpreted as a sign of lower system resilience, and it is due to the higher specific storage investment costs of liquid hydrogen and ammonia relative to carbon-based fuels. This leads to lower storage capacity investments, reaching depletion quicker than the other scenarios. The model works under a "perfect forecast" approach, knowing when it is safe to run without seasonal storage due to enough future availability of wind generation. In actual operations, reaching the zero point in storage would be considered an emergency state, and to have the optimisation model continuously reach that point in the optimised scenario is undesirable. Besides, that optimisation round is performed on a daily resolution, which smoothed the generation peaks and also, as shown previously, underestimates the storage investments. This means that in a real scenario with more pronounced peaks and troughs of wind power generation, the liquid hydrogen and ammonia scenarios could provide insufficient storage to fulfil demand unless more investment in storage is made, which would increase the total costs of the system.

Operation flexibility is a key element in this study, with a clear impact on the total system cost, system efficiency and compressed hydrogen investment. Original equipment manufacturers are developing more flexible systems, but none of them have yet been commercially proven [38,83]. Operational flexibility of hydrogen and hydrogen derivative systems is a key feature for transitioning the economy away from fossil

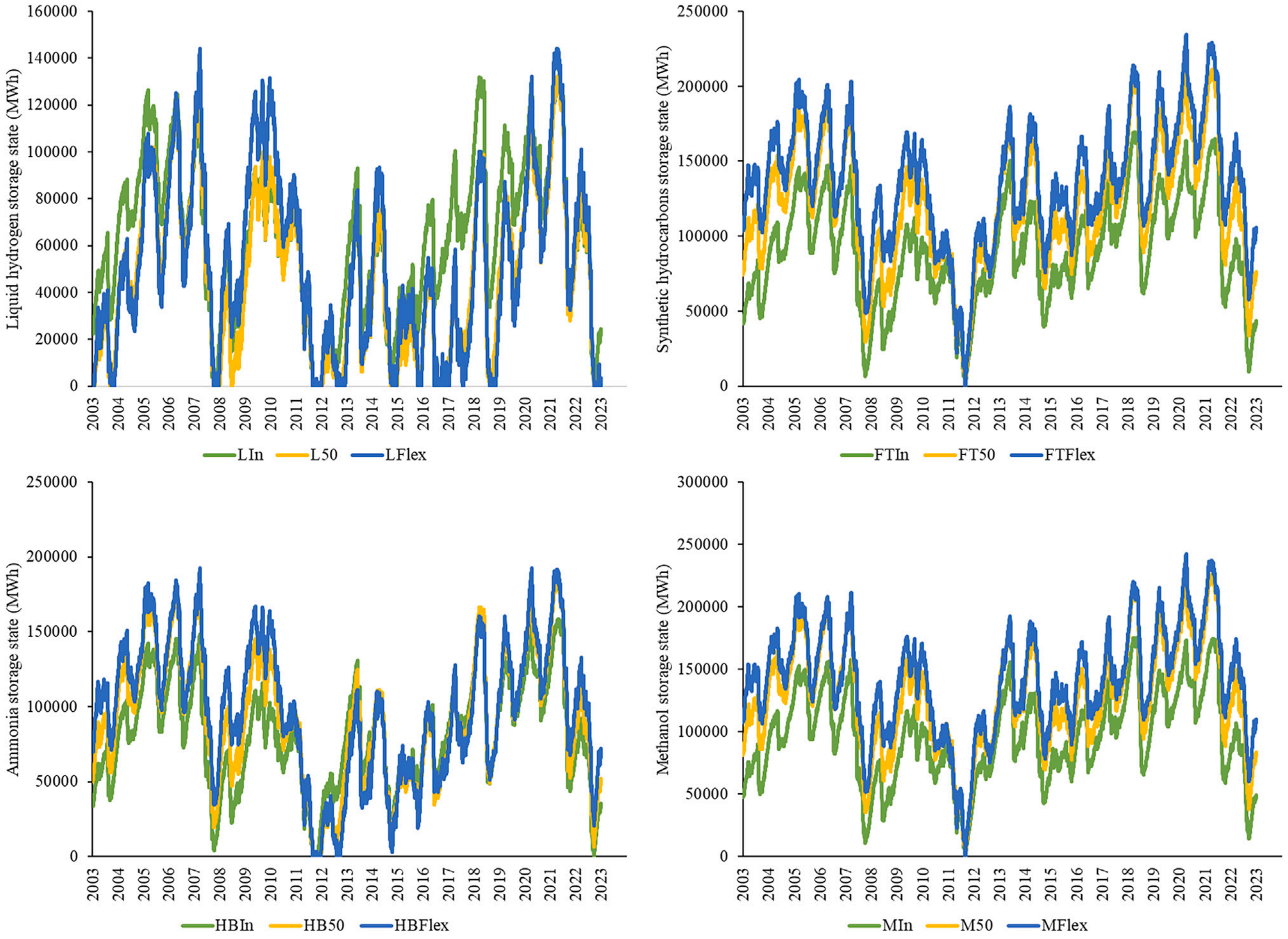

Fig. 11. Storage state of seasonal storage technologies in a twenty years optimisation round with a daily resolution.

fuels. This element should be addressed as soon as possible because it could hinder the deployment of hydrogen and hydrogen derivative production due to the evident cost increase of having an inflexible system when compared to a fully flexible production operation. Another important element to consider is the potential increase in CAPEX in flexible processes. According to [71], a more flexible plant could incur additional capital investment, diminishing the positive economic effects of capacity flexibility improvements.

The last point mentioned is especially relevant because the current alternative for seasonal energy storage is based on electrochemical technology. The results of this study show that although the costs of Li-ion battery storage systems have drastically reduced in the last decade, they are still too expensive to address the seasonal energy storage issue.

Because of those last points, it is important to highlight the non-profitable nature of the scenarios evaluated. The lack of a viable business case is one of the reasons for the lack of success of hydrogen and derivatives projects to date. The break-even electricity price is 117 €/MWh for the fully flexible ammonia scenario on a 20-year optimisation window and 116 €/MWh on an hourly resolution one-year optimisation. On the other hand, the battery storage scenario requires an electricity price of 317 €/MWh on a 20-year optimisation round and 443.7 €/MWh on the one-year optimisation round with hourly resolution to break even.

An alternative to increasing seasonal energy storage projects' economic viability is to diversify the range of products produced. For instance, ammonia is a precursor for many chemical products and fertilisers, which can have a higher selling price than the electricity being produced. Other examples are the Fischer-Tropsch products like waxes, naphtha and sustainable aviation fuels. This last one has been recently mandated by the European Union to be deployed by 2030 onwards with increasing quotas in the aviation sector starting with 1.2% of the total fuel consumption in the union and ramping up to 35% by 2050. A premium cost is expected to come with those mandates, which could help these projects become more profitable.

To recapitulate, in this study it is shown that for a greenfield seasonal energy storage development, ammonia and methanol represent the most cost-effective solutions. It is also shown that Li-ion battery costs make those projects prohibitively expensive to support a constant demand for season-long periods. Furthermore, on a site with existing generation assets, drop-in fuel production, like Fischer-Tropsch fuels, represents the best alternative to provide seasonal energy storage in economic terms. Finally, the urgency of developing flexible production processes is highlighted. Flexibility decreases the costs of the projects significantly and brings them closer to commerciality.

4. Conclusions

In a decarbonised world with high rates of variable renewable energy generation, seasonal energy storage will be crucial to deliver 24/7 renewable power. The most economical form of seasonal storage usually includes geological storage of gases like hydrogen. However, these geological features are not available in every region of the world. In this study, an investment and operational optimisation model was developed in SPINE that simulated an off-grid renewable hub with a constant electricity demand fed by a wind farm with a perfect power generation forecast and a non-geological energy, hydrogen, or hydrogen derivative storage system.

The current state of the technology does not allow large industrial thermochemical processes to react flexibly to variable renewable energy input. This research showed that, if the specific capital investment of the plant does not increase, developing flexible operating hydrogen transformation processes to easier-to-store derivatives significantly decreases the costs of the systems, and increases the total system efficiencies by decreasing the wind farm size and the total energy curtailed. It is shown that Li-ion batteries are not suitable for seasonally storing energy due to high costs. This is also the case for compressed hydrogen tanks. This research also explored the differences between different temporal resolution optimisation rounds and longer optimisation periods. Lower temporal resolutions decreased the total cost of the system by shaving the renewable generation peaks and troughs, smoothing the generation curve, hence requiring less storage investment. On the contrary, by increasing the optimisation window, the investment in storage capacity increased significantly to allow the system to resiliently go through several years of poor renewable generation.

Although ammonia and methanol are the best performing scenarios, when a brown field with existing power generation infrastructure is considered, Fischer-Tropsch fuels become the most economic alternative, which also allows the system to smoothly transition from fossil to renewable by even creating blends of conventional and synthetic fuels. None of the evaluated scenarios is economically feasible under the market assumptions made in this study; however, the least costly scenario's break-even electricity price is estimated to be between 116 and 117.2 €/MWh.

This study presented some techno-economic limitations such as operational constraints and non-linear cost curves, which are linearised due to the nature of the optimisation model. Similarly, the model considered a deterministic approach for the weather forecast and a constant demand for power. It is worth mentioning that this study concentrated purely on the power demand as a unique source of income for the system. Hydrogen and hydrogen derivative systems could benefit from a product diversification approach, in which sustainable aviation fuels, fertilisers, and other chemicals could generate additional streams of revenue to achieve a better economic performance.

Finally, the conclusions obtained in this study are valid under the assumptions made for the specific study case described earlier (constant demand, isolated system and complete reliability), and a case-by-case assessment has to be made given the infrastructure, power generation and demand profile requirements of each site.

Future work will address these issues by considering a broader systemic approach.

CRediT authorship contribution statement

F.B. Bozzolo Lueckel: Writing – review & editing, Writing – original draft, Visualization, Validation, Methodology, Investigation, Formal analysis, Data curation, Conceptualization. **M.Á. Lynch:** Writing – review & editing, Supervision, Project administration, Methodology, Formal analysis, Conceptualization. **R.F.D Monaghan:** Writing – review & editing, Supervision, Project administration, Methodology, Funding acquisition, Conceptualization.

Declaration of competing interest

The authors declare the following financial interests/personal relationships that may be considered as potential competing interests:

Fabio Battista Bozzolo Lueckel reports that financial support was provided by Science Foundation Ireland/Research Ireland. Fabio Battista Bozzolo Lueckel reports a relationship with Electricity Supply Board that includes: employment.

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Data availability

Data will be made available on request.

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