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ORIGINAL RESEARCH PAPER

Multi-sectoral flexibility measures to facilitate wind and solar power integration

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Abstract
As power systems evolve towards integrating higher shares of renewables, the demand for additional levels of flexibility is increased. Meanwhile, o-ther energy consuming sectors, such as transport and heating, could provide flexibility when they move from fossil fuels to electricity. In this paper, the impact of a range of flexibility measures is assessed for the island system of Ireland, with a high share of renewable energy, particularly wind and solar. Flexibility measures studied include hybrid heating in domestic and industrial processes, smart charging of electric vehicles, renewable hydrogen, power to ammonia, peak shaving demand response and batteries. The novelty of this paper lies in directly quantifying the interactions and dependencies between different flexibility measures, with the objective of increasing the operational flexibility of an increasingly renewable energy-dominated power system. Four different scenarios are modeled to explore this interplay between the different flexibility measures. The costs and benefits of several sector-coupling measures. The scenarios have also been compared in terms of their influence on system inertia, renewable energy curtailment and non-synchronous penetration levels. The results indicate the potential importance of electricity-based heating in the industrial sector, smart charging of electric vehicles, batteries and power-to-ammonia, as part of achieving future targets

1 | INTRODUCTION

The past decade has witnessed a dramatic rise in the share of non-conventional energy sources in the generation portfolios of several energy systems across the globe. In view of the declining costs of these technologies and the new binding targets for decarbonisation, continued growth in variable renewable energy (VRE) shares is expected in the coming decades. This has resulted in countries, such as Denmark and Portugal, sourcing over 50% of their electricity consumption from variable renewables at certain times [1]. More intriguing is the high instantaneous shares achieved in isolated power systems with limited interconnection and storage capabilities, such as the island of Ireland at 65% at the end of 2020[2].

The large-scale expansion of wind and solar power raises questions regarding how to best manage these sources, how to address energy oversupply and how to use the available resources in an efficient way. Of late, several studies have focused on the potential of exploiting synergies through coupling of various sectors, such as electricity, transport and heat, facilitating lower costs of the energy transition[3] and improving energy efficiency[4]. Sector coupling may take various forms such as directly substituting fossil fuels by electricity or production of electrofuels which can substitute fossil fuels. However, sector coupling is not panacea as some sector coupling measures may actually lead to increased emissions [5].

The latest Climate Action Plan (CAP) for Ireland states that 70% of electricity should come from VRE by 2030 [6]. The main energy sources are likely to be wind and solar power, which would result in regular periods of energy oversupply, when considering the predicted demand profile based on existing load types, as well as stability limits for the power system. Consequently, in order for the plan to be successful, there is considerable opportunity, and perhaps need, to utilise electricity in other energy consuming sectors, such as transport and heating, in a flexible manner. We use 'flexibility' as in [7]: "the ability of a power system to respond to change in demand and supply". The importance of incorporating a range of flexibility options, in order to meet Ireland's future renewable generation targets, is widely accepted in future outlooks for the sector, with ambitious plans to increase the fleet of electric vehicles (EVs) on the road over the next decade. Wide-scale installation of heat pumps are also anticipated. In addition to grid-scale batteries and demand response [8–11], hydrogen has also been identified as a potential energy carrier for future large-scale renewable integration.

Ongoing research examines the impact of many of these measures for the island of Ireland. Ekhtiari et al. [12] considered hydrogen storage potential within the Irish gas network, while Andrade-Cabrera et al. [13] explored the integration of building retrofit optimisation and power system optimisation. Calnan et al. [14] examined the impact of EVs on electricity generation costs and emissions.

1.1 | Research gaps and paper contributions

Existing studies that focus on the entire energy sector, with multiple energy carriers, were primarily performed using models without high temporal or spatial detail. With high VRE shares in the power sector, and electrification of other energy sectors, this approach presents serious deficiencies [15, 16]. This is especially true for a power system, such as the island of Ireland, which is synchronously isolated, with ambitious renewable energy targets, and subject to several operational constraints arising from the small system size and the characteristics of converter-connected VRE generation [17].

There are also efforts to model energy sector coupling, while including power system operational constraints and using higher temporal resolution. Such studies often focus on improving the modelling of a specific sector (e.g. building sector in [18]). Thus, while a range of flexibility options will be required to meet emissions targets in Ireland, in the literature, options have typically been analysed in isolation. Consequently, interactions and dependencies between options, both good and bad, have not been adequately recognised. A recent review of sector coupling literature by Ramsebner et al.[19] found no study where a model with high temporal detail was used to analyse all sector coupling technologies together, which would be required for more robust outcomes.

To this end, this paper aims to illustrate what can be achieved when analysing future energy systems using a rich combination of sector coupling measures and data, and the great importance of doing so, since the flexibility measures also compete. The sector coupling measures include: electrification of heating and transport, as well as green hydrogen and green ammonia production. The intent is to pre-screen methods – or measures – which could be important for an ambitious climate plan, such as in Ireland, when analysed within a state-of-the-art energy system model. To find most promising sector coupling technologies, the paper performs a cost-benefit analysis for a number of scenarios.

1.2 | Paper structure

This paper is an invited extension of a conference paper [20], presented at the IET RPG 2020 conference, which has been considerably expanded into a journal article. In Section 2, the model description is now more detailed, including the main equations of the model, supported by an explanation of how the different unit types have been modelled using a standardised process. Section 3 describes the range of scenarios and flexibility measures considered, including a more detailed description of the parameterisation choices and modelling assumptions. Section 4 contains the expanded results, including an assessment of costs-benefits, power system stability and renewables curtailment concerns, and Section 5 concludes.

2 | ENERGY SYSTEM MODEL

Analysis was performed using the energy systems modelling tool Backbone, which is capable of performing multi-sectoral analysis while maintaining a relatively detailed power system representation (detailed description in [21] and code available at [22]. For this study, the tool was used in a unit commitment and economic dispatch (UCED) mode using mixed integer linear optimisation, with a rolling horizon, in order to optimise generating plant operations for the Irish power system, and its interactions with other energy sectors, across a full year using time series profiles from 2016, which were extrapolated for the target year of 2030. The simulation rolls forward in 12 hour steps, with a horizon of 96 hours, which was deemed sufficient to model storage behaviour, typically used for daily arbitrage, run-of-river hydro and slow starting units. The simulation did not include forecast errors to keep the computation time manageable, which may undervalue the service provided by fast ramping capability inherent in some of the flexibility options. Different energy sectors can be modelled using the adaptable grid and node structure of Backbone. Nodes within one grid can be connected to each other using energy transfer links – in this particular model there were transfer links between Ireland, France and Great Britain. Connections between grids can be achieved using energy conversion units, which are connected to the desired nodes within each grid. For this model instance, there were many grids with only one node – representing other energy sectors. The layered structure makes it convenient to include electric vehicles, power-to-gas units, etc. within the model. Nodal balance is maintained as shown in Eqn. 1:

$$p_n^{\text{specificStorage}} \times (v_{n,t}^{\text{state}} - v_{n,t-1}^{\text{state}})$$

$$= \Delta_t \times \left(\sum_{u \in U_n} v_{n,u,t}^{\text{gen}} - p_n^{\text{selfDischargeLoss}} \times v_{n,t}^{\text{state}} \right.$$

$$+\sum_{n'\in N_n}\left(p^{\text{diffusionCoeff}}_{n',n}\times v^{\text{state}}_{n',t}-p^{\text{diffusionCoeff}}_{n,n'}\times v^{\text{state}}_{n,t}\right)$$

$$-\sum_{n'\in N_n^{\text{n-to-n}'}}\left(v^{\text{transfer}}_{n,n',t}+p^{\text{transferLoss}}_{n',n}\times v^{\text{transferLeftward}}_{n,n',t}\right)$$

$$+\sum_{n'\in N_n^{\text{n}'\text{-to-n}}}\left(v^{\text{transfer}}_{n',n,t}-p^{\text{transferLoss}}_{n',n}\times v^{\text{transferRightward}}_{n',n,t}\right)$$

$$\left.+p^{\text{influx}}_{n,t}-v^{\text{spill}}_{n,t}+v^{\text{slackUp}}_{n,t}-v^{\text{slackDown}}_{n,t}\right)$$

$$\forall n\in N, t\in T \qquad (1)$$

See explanation of symbols in Table 1. Note that the transfer can be positive (left-to-right reading of indices) or negative (right-to-left), but losses are accounted for using the transfer loss parameter applied in the appropriate direction, left or right, where values are only positive. Dummy generation (Up) or consumption (Down) slack variables ensure model feasibility and are penalised with a high cost.

The resulting balance equation for nodes is highly generic and flexible. It can be directly applied to different energy sectors, and consequently to different flexibility measures, by using appropriate input data to select which terms within the balance equation are active. For example, a hydrogen tank is a node that maintains an energy balance between incoming hydrogen from an electrolysis unit and outgoing hydrogen flows to the natural gas network and/or ammonia process (v^{transfer}). It can store hydrogen for a number of hours (using the v^{state} variable), but storage losses are ignored in this particular case ($p^{\text{selfDischargeLoss}}=0$) and there is no energy diffusion to other nodes ($p^{\text{diffusionCoeff}}=0$).

$$v^{\text{objective}}$$

$$=\sum_{t\in T}\Delta_t\times\left(\sum_{n\in N,u\in U}\left(v^{\text{gen}}_{n,u,t}\times p^{\text{variableCost}}_{n,u,t}\right)\right.$$

$$+\sum_{u\in U_{\text{online}},s\in S_{\text{startType}}}\left(v^{\text{startup}}_{u,s,t}\times p^{\text{startupCost}}_{u,s,t}\right)$$

$$+\sum_{u\in}\left(v^{\text{shutdown}}_{u,t}\times p^{\text{shutdownCost}}_{u,t}\right)$$

$$+\sum_{n\in N,u\in U}\left(v^{\text{genRamp}}_{n,u,t}\times p^{\text{rampCost}}_{n,u,t}\right)$$

$$+\sum_{n'\in N_n^{\text{n-to-n}'}}\left(v^{\text{transferLeftward}}_{n,n',t}\times p^{\text{transferCost}}_{n,n',t}\right)$$

$$\left.+\sum_{n'\in N_n^{\text{n}'\text{-to-n}}}\left(v^{\text{transferRightward}}_{n',n,t}\times p^{\text{transferCost}}_{n',n,t}\right)\right)$$

TABLE 1 List of symbols

Symbol	Explanation
Δ_t	Length of time step t (h)
d	Direction of reserve product, up or down
$n\in N$	Nodes for calculating energy balance
$N_n^{\text{n-to-n}'}$	Nodes that have a connection from node n
N_n	Nodes connected to node n
$p^{\text{diffusionCoeff}}_{n,n'}$	Coefficient of uncontrolled transfer (diffusion) from node n to n'
$p^{\text{influx}}_{n,t}$	Exogenous import (e.g. inflow and positive) or export (demand, negative) of energy (MWh/h)
$p^{\text{investCost}}_{n,n',t}$	Investment cost of connection from node n to n' (€/MW)
$p^{\text{investCost}}_{u,t}$	Investment cost of unit u (€/MW)
$p^{\text{rampCost}}_{n,u,t}$	Wear and tear cost of ramping (€/MW)
$p^{\text{resDemand}}_{r,d,n,t}$	Demand for reserve product r (direction d) in node n during t (MW)
$p^{\text{resIncrease}}_{n,u,r}$	Unit output is multiplied by this factor to get the increase in reserve demand
$p^{\text{selfDischargeLoss}}_{n}$	Self-discharge of node n per unit of state and time
$p^{\text{shutdownCost}}_{u,t}$	Cost shutting down unit u (€/shutdown)
$p^{\text{specificStorage}}_{n}$	Unit conversion process (MWh/p.u.)
$p^{\text{startupCost}}_{u,s,t}$	Cost of type s start-up of unit u (€/start-up)
$p^{\text{storageValue}}_{n}$	Average value of stored energy (€/MWh)
$p^{\text{transferCost}}_{n,n',t}$	Cost for transfer from node n to n' (€/MWh)
$p^{\text{transferLoss}}_{n,n'}$	Transfer loss (p.u.) from node n to n'
p^{unitSize}_{u}	Size of unit u (MW)
$p^{\text{variableCost}}_{n,u,t}$	Variable cost of unit u during time t (€/MWh)
$r\in R$	Reserve products: primary and tertiary operating reserves
R_r	Other reserve products that can be used instead of r
$s\in S_{\text{startType}}$	Types of startup: cold or warm
$t\in T$	Time index
T_{invest}	Time steps when investments are possible
$u\in U$	Units to represent generators, storages or loads
U_{fail}	Units that might fail
U_{online}	Units with integer online status
U_r	Units capable of providing reserve r
$v^{\text{gen}}_{n,u,t}$	Generation or consumption (MW) of unit u during time t
$v^{\text{genRamp}}_{n,u,t}$	Change in generation or consumption of unit u during step t (MW/h)
$v^{\text{investGen}}_{u,t}$	Sub-unit investments into unit u (#)
$v^{\text{investTransfer}}_{n,n',t}$	Amount invested into transfer connection from node n to n'
$v^{\text{objective}}$	Objective function value
$v^{\text{res}}_{r,d,n,u,t}$	Provision for reserve product r into direction d by unit u
$v^{\text{resMissing}}_{r,d,n,t}$	Dummy variable to decrease demand for a reserve after it has been locked (MW)

(Continues)

TABLE 1 (Continued)

Symbol	Explanation
$v^{\text{resSlack}}_{r,d,n,t}$	Dummy variable to decrease demand for a reserve before it has been locked (MW)
$v^{\text{resTransferLeftward}}_{r,d,n,n',t}$	Transfer capacity reserved from node n' to n (MW)
$v^{\text{resTransferRightward}}_{r,d,n,n',t}$	Transfer capacity reserved from node n to n' (MW)
$v^{\text{shutdown}}_{u,t}$	Sub-units (#) shut down during step t
$v^{\text{slack}}\{\text{Up/Down}\}_{n,t}$	Dummy generation (Up) and consumption (Down) variables to ensure model feasibility
$v^{\text{spill}}_{n,t}$	Spill rate from node n (MWh/h)
$v^{\text{startup}}_{u,s,t}$	Sub-units (#) brought online during step t
$v^{\text{state}}_{n,t}$	State of node n at the end of time t
$v^{\text{transfer}}_{n,n',t}$	Controlled energy transfer from node n to n' (MW)
$v^{\text{transferLeftward}}_{n,n',t}$	Transfer from node n' to node n (≥ 0)
$v^{\text{transferRightward}}_{n,n',t}$	Transfer from node n to node n' (≥ 0)
$p^{\text{infeed2Reserve}}_{u,r}$	Proportion of the generation of a tripping unit that needs to be covered by reserves from other units

$$
\begin{aligned}
&+ \sum_{u\in U, t\in T_{\text{invest}}} \left(v^{\text{investGen}}_{u,t} \times p^{\text{unitSize}}_{u} \times p^{\text{investCost}}_{u,t} \right) \\
&+ \sum_{n'\in N_n^{\text{n-to-n}'}, t\in T_{\text{invest}}} \left(v^{\text{investTransfer}}_{n,n',t} \times p^{\text{investCost}}_{n,n',t} \right) \\
&+ \left(v^{\text{state}}_{n,t_{\text{solveEnd}}} - v^{\text{state}}_{n,t_{\text{solveStart}}} \right) \times p^{\text{storageValue}}_{n}
\end{aligned} \tag{2}
$$

The objective function of the model combines variable fuel and emission costs (pre-processed into variable cost), start-up and shut-down costs, ramping costs, and transfer costs, as shown in Eqn. 2. Penalty costs are also included for violating nodal balance and (contingency) reserve requirements, but these have been left out for brevity. In the investment mode (shown in the equation, but not active in the simulations), additional terms account for the investment cost of units, and transfer connections, as well as a further penalty term for violating the capacity margin requirement (not shown).

The thermal generation fleet was represented on an individual unit basis, incorporating start-up, ramping and other constraints. The plant portfolio was based on 2030 scenarios, as outlined by the transmission system operators of Ireland and Northern Ireland, EirGrid and SONI. The medium ambition Centralised Energy [8] and Modest Progress [9] scenarios aim to meet a 70% renewable energy target for 2030. The aggregated generation capacities of the portfolio for the combined All Island system can be found in Table 2. Wind, solar and hydro power were aggregated, except for the existing pumped hydro plant. The baseline modelling approach respects the Irish operational constraints guide, including minimum generation in specific locations (to provide regional voltage support and avoid network constraints), inertia limits, and the main reserve categories [2]. Primary operating reserve (POR) and tertiary operating reserve (TOR) constraints were enforced, based on minimum requirements, in addition to an $N-1$ generation constraint based on a percentage of the largest single infeed (POR – 75% LSI, TOR – 100% LSI). POR must be delivered within 5 s and maintained until 15 s after a frequency event, while TOR, a slower reserve, must be delivered within 90 s and maintained for 5 min. The reserves and $N-1$ constraints are described in Equations 3 and 4 respectively. An operational inertia limit of 23,000 MWs was also enforced. In future, with a system non-synchronous penetration (SNSP) limit as high as 95%, the rate-of-change-of-frequency (RoCoF) limit raised to 1 Hz/s, and additional interconnections, including the new Celtic interconnector to France creating a 700 MW infeed, etc. [8, 9], these constraints are likely to evolve and one of the scenarios explores the impact of such changes, as detailed below.

$$
\begin{aligned}
&\sum_{u\in U_r} \left(v^{\text{res}}_{r,d,n,u,t} \times p^{\text{resReliability}}_{r,d,u} \right) \\
&\quad + \sum_{u\in U_r, \forall r'\in R_r} \left(p^{\text{res2res}}_{r',d,r} \times v^{\text{res}}_{r',d,n,u,t} \times p^{\text{resReliability}}_{r,d,u} \right) \\
&\quad + \sum_{n'\in N_n^{\text{n-to-n}'}} \left(p^{\text{transferLoss}}_{n',n} \times v^{\text{resTransferLeftward}}_{r,d,n,n',t} \right) \\
&\quad + \sum_{n'\in N_n^{\text{n}'\text{-to-n}}} \left(p^{\text{transferLoss}}_{n',n} \times v^{\text{resTransferRightward}}_{n',n,t} \right) \\
&\quad\quad \geq p^{\text{resDemand}}_{r,d,n,t} + \sum_{u\in U_n} \left(v^{\text{gen}}_{n,u,t} \times p^{\text{resIncrease}}_{n,u,r} \right) \\
&\quad + \sum_{n'\in N_n^{\text{n}'\text{-to-n}}} \left(p^{\text{transferLoss}}_{n',n} \times v^{\text{resTransferLeftward}}_{r,d,n,n',t} \right) \\
&\quad + \sum_{n'\in N_n^{\text{n-to-n}'}} \left(p^{\text{transferLoss}}_{n,n'} \times v^{\text{resTransferRightward}}_{n,n',t} \right) \\
&\quad - v^{\text{resSlack}}_{r,d,n,t} - v^{\text{resMissing}}_{r,d,n,t} \\
&\qquad\qquad \forall r\in R, d\in\{\text{up},\text{down}\}, n\in N, t\in T
\end{aligned} \tag{3}
$$

$$
\begin{aligned}
&\sum_{u\in U_r - U_{\text{fail}}} \left(v^{\text{res}}_{r,\text{up},n,u,t} \times p^{\text{resReliability}}_{r,d,u} \right) \\
&\quad + \sum_{n'\in N_n^{\text{n-to-n}'}} \left(p^{\text{transferLoss}}_{n',n} \times v^{\text{resTransferLeftward}}_{r,\text{up},n,n',t} \right) \\
&\quad + \sum_{n'\in N_n^{\text{n}'\text{-to-n}}} \left(p^{\text{transferLoss}}_{n',n} \times v^{\text{resTransferRightward}}_{r,\text{up},n',n,t} \right) \\
&\quad \geq \sum_{u\in U_n} \left(v^{\text{gen}}_{n,u,t} \times p^{\text{infeed2Reserve}}_{u,r} \right) \\
&\quad + \sum_{u\in U_n} \left(v^{\text{gen}}_{n,u,t} \times p^{\text{resIncrease}}_{n,u,r} \right)
\end{aligned}
$$

TABLE 2 Installed capacities

Technology	Installed capacity (MW)
Onshore wind	7,350
Offshore wind	3,500
Solar	988
Biomass*	320
Hydro	246
Wave and tidal	80
CCGT	3,790
OCGT (gas)	1,201
Distillate	200
CHP**	350
Waste**	40
DSM†	750
PHES‡	292
DC Interconnector	2,150

*Including renewable waste, biogas & landfill gas.
**Fossil fuel or non-renewable component.
†Demand side management.
‡Pumped hydro energy storage.

$$+ \sum_{n' \in N_n^{n'-\text{to}-n}} \left(p^{\text{transferLoss}}_{n',n} \times v^{\text{resTransferLeftward}}_{n,n',t} \right)$$
$$+ \sum_{n' \in N_n^{n-\text{to}-n'}} \left(p^{\text{transferLoss}}_{n,n'} \times v^{\text{resTransferRightward}}_{n,n',t} \right)$$
$$- v^{\text{resSlack}}_{r,\text{up},n,t} - v^{\text{resMissing}}_{r,\text{up},n,t}$$
$$\forall r \in R, n \in N, t \in T \quad (4)$$

It was assumed that by 2030 four DC interconnectors will connect the All Island system to Great Britain and France, with a capacity of 2,150 MW. Greenlink and Celtic interconnectors are to be built during the 2020s [8]. Simplified models of GB and France, including aggregated wind, solar, base load and gas-fired generation, informed the interconnector power flows. Thermal units had a decreasing efficiency across their operating range, which yielded an increasing marginal cost curve, approximating a marginal price curve of a real system with a large number of units. Interconnectors could also provide reserve for the All Island system, and were considered as part of the $N-1$ reserve constraints. For the scenarios presented below, the neighbouring systems depicted possible 2030 situations, but they did not change between the scenarios as the focus is on analysing the Irish targets.

Wind and solar generation capacity factors were based on weather profiles for 2016 [23]. The demand time series was based on historical load data (2016), while also accounting for new load types expected in 2030, including electric vehicles, heat pumps and data centres. The time series were scaled to match annual values for the target year 2030. The peak electricity demand was 9038 MW while the average demand was 5786 MW, which does not include the flexible sources of electricity demand, as their time of use is decided by the model. The constraints and capacities of the flexibility measures are presented in the next section. Fuel and carbon prices were based on 2030 projections [24].

Finally, the individual units, including those representing the flexibility measures to be detailed in the next section, were subject to different constraints and capabilities. As Backbone has a large number of different kinds of constraints and alternative formulations, these are not all detailed here. They are available at [21] and in full detail in the GAMS code [22]. Instead, Table 3 shows what constraints and capabilities were applied to each unit type. Backbone provides different methods to model the efficiency of the conversion process taking place in units. 'No online' means that the unit is presented by simple efficiency loss/gain without online variable. With an online variable the unit can only produce if the online variable is active, which typically induces a fuel consumption independent of unit outputs. The online variable can be either linear (0–1) or binary (0, 1). The efficiency in relation to the unit output can also be represented with a piecewise linear approximation. Finally, 'Dual pathways' means that the process includes two separate pathways to generate the desired output while 'multiple outputs' indicates that the unit can produce more than one kind of an output.

3 | SCENARIOS AND FLEXIBILITY MEASURES

In order to identify the most promising flexibility measures, four future scenarios were analysed. A Base scenario included conservative assumptions relating to power system inertia, fuel and CO_2 prices, as well as variable power generation capacity. In each subsequent scenario, one of these parameters was relaxed in order to create a range of alternative future scenarios (see Table 4). These scenarios were first simulated as such, to obtain comparison cases, and then seven flexibility measures were run against each scenario (see Table 5). Finally, a case with all measures implemented together was also run for all scenarios to form a total of 36 runs (four scenarios multiplied by nine cases), in order to quantify the relative importance of measures under varying scenario conditions. Sub-sections 3.1–3.7 introduce technological and financial data for each of the seven flexibility measures to be used by the model and by the cost/benefit comparison in the results section, and Figure 1 presents an overview of how the measures connect to the system.

The scenarios, and many of the assumptions, were selected with 2030 policy targets in mind, but these targets, and associated policy actions, are still evolving and the chosen volume of measures represent a combination of different governmental ambitions. However, changes in assumptions would not materially change the main results, depicting the benefit-cost ratio for each measure. Furthermore, the enabled measures are not necessarily of similar magnitude, which creates a further reason to focus on results on a per unit basis. Table 5 indicates the size of each measure for reference.

TABLE 3 Constraints and capabilities of unit types

	Reserve provision	Inertia provision	Startup cost	Min. output	Min. time online	Ramp limits	No online	Linear online	Binary online	Piece-wise	Dual pathways	Multiple outputs	Storage
Building heat	x						x				x		
Industrial heat	x						x				x		
Electric vehicles	x						x					*	x
Hydrogen	x						x						x
Ammonia	x				x			x			x		x
Demand response	x						x						
Batteries	x						x						x
Small thermal	x	x	*	*	*	*	*	*					
Larger thermal	x	x	*	x	x	x	*		*	*			
Hydro power	x	x			x		x						
Pumped hydro	x	x			x				x				
Wind/PV	x						x						

*Only some of the units use the constrain/capability.

TABLE 4 Scenarios to be analysed

Tag	Description
Base	Base scenario
Inertia	Inertia requirement reduced to 17,500 MWs
Fuel+	Higher fuel and CO_2 prices
VRE+	6.3% more wind and solar power generation

TABLE 5 Cases considered for each scenario, including seven separate measures to improve system operation, no measures, and all measures combined

Tag	Description	Data
None	No additional measures	-
Bld	Dual heating system in buildings	170,000 dual households
Ind	Dual heating for industrial processes	20% industrial gas demand with electrical heat source
EV	Smart charging electric vehicles	500,000 EVs
H_2	Hydrogen to gas grid	Max. 3% hydrogen infeed (using higher heating value)
P2A	Power to ammonia	Irish domestic fertiliser demand (375 kt/year)
DR	Peak shaving demand response	150 MW
Batt	Batteries	450 MW/450 MWh
All	All measures included	As above

3.1 | Building heat

The 'No Measures' case (None) included an estimate of 170,000 new heat pumps in Ireland by 2030. Since flexible (electric) heating is of interest for the 'Building heat' case (Bld), it was assumed that these heat pumps are introduced into buildings which already have gas-based heating, thus forming a 'dual' arrangement, which is potentially flexible from a power system perspective, while also reducing gas heater based emissions. It was assumed that the heat pumps are sized to cover 70% of the peak heat demand in the converted buildings, since heat pumps are typically undersized and supplemented by an electric heater in the device. In this case, the electric heater was sized to cover 35% of the peak heat load for a combined full coverage. At the same time, the natural gas heater was left in place. Consequently, the Backbone model optimised between electric and gas heating for the dual device system. Building stock with dual heating system was aggregated, with one heat pump, electric heater and gas heater serving the aggregated load, represented by a single node (see Figure 1). An additional node represented the heat demand for buildings with gas heaters only. The air-source heat pumps were assumed to have a temperature dependent efficiency (coefficient of performance, COP, of 2.5–4.5), while the electric heaters had a fixed efficiency of one. Energy balance for the heat nodes was ensured, and energy flows from the electricity and gas networks were co-optimised (see Eqn. 1). The

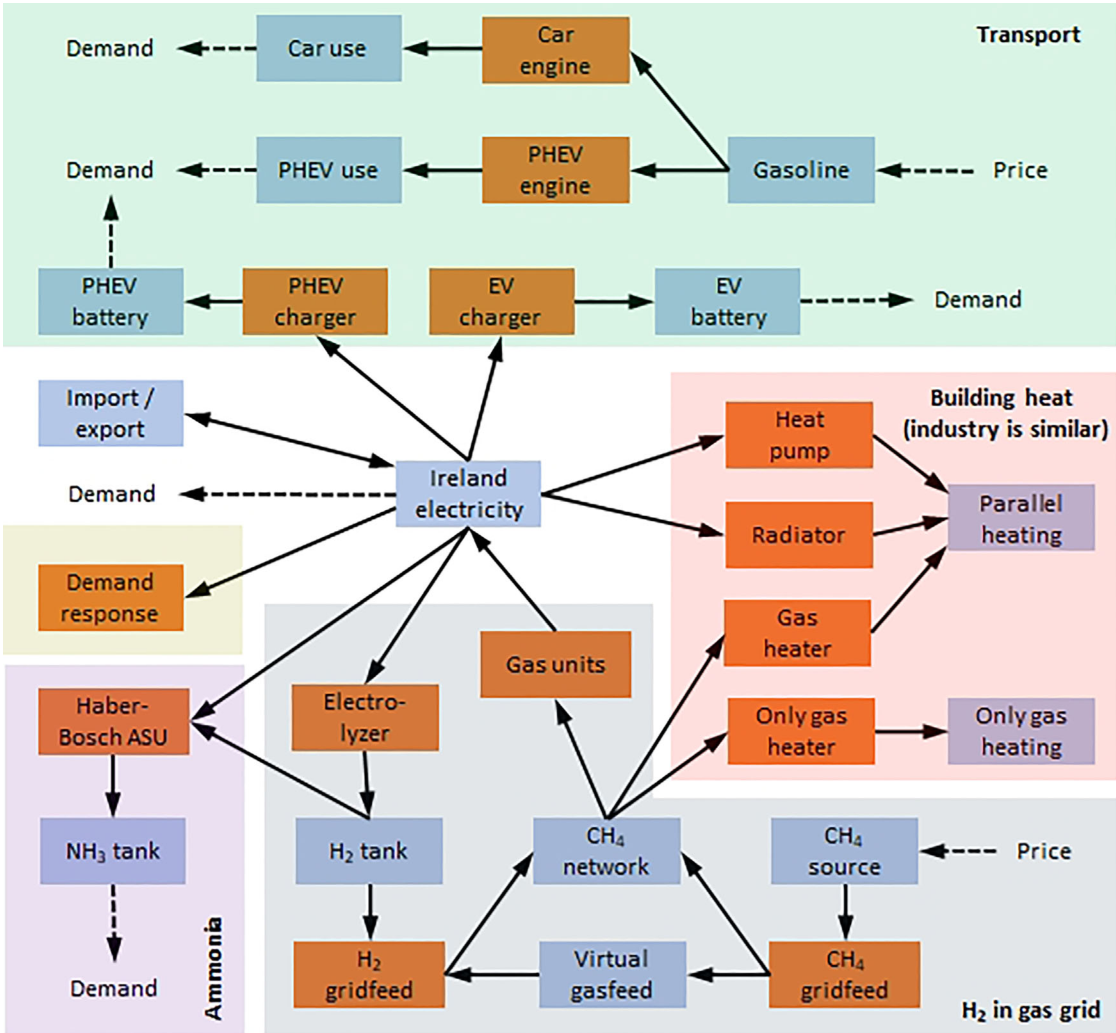

FIGURE 1 Partial presentation of cross sector energy flows in the modelled system

heat pump costs for 2030 (2,348 MW at €317/kW_{th} (thermal power)) were estimated from heating installation technology data [25], supported by approximate cost estimates for electric heaters including installation costs (1,174 MW at €200/kW_{th}).

3.2 | Industrial heat

Industrial and commercial sector natural gas use on the island of Ireland is currently 21 TWh, with a large portion associated with heating. For the 'Industrial heat' case (Ind), it was assumed that 20% of the non-residential gas demand is supplemented by an electrical energy source. From European statistics, 25% of industrial heat demand is at temperature levels below 100 °C. Ireland was assumed to be similar in this regard and hence 25% of the converted heat demand was considered to be serviceable by ground source heat pumps (COP 2.3 – some heat needs to be supplied at 100 °C, which decreases the effective COP), with the remaining 75% supplied by electric heaters (efficiency 100%). Gas heating was retained as an alternative heat source in both cases. The costs of heat pumps were estimated from [25] (117 MW large ground source heat pump at €500/kW_{th} and 352 MW electric heater at €150/kW_{th}). The low and high temperature heat demands formed separate nodes with distinct aggregated units serving the respective loads. As with the 'Building heat' case, energy balance for the heat nodes was ensured, and energy flows from the electricity and gas networks were co-optimised (see Equation 1). With no time series available, the industrial heat demand was assumed flat across the year. Furthermore, heat storage and thermal inertia were not considered.

3.3 | Electric vehicles

For the 'Electric vehicles' case (EV), electric vehicles were modelled as price sensitive charging (only) loads requiring full batteries for vehicles exiting the grid [26]. The approach applied a time series of currently plugged-in capacity. When disconnecting from the grid, each vehicle leaves with a fully charged battery and returns with a partially discharged battery.

The model decides when plugged-in vehicles recharge the energy consumed during road trips. The consumption patterns were pre-calculated, based on statistics of car travel in a Finnish data set [26] and adjusted to Irish average annual driving distances. Driving patterns in Finland and Ireland are likely to differ, since Ireland is a more densely populated country. Still, in both countries, most driving activity is for the purpose of reaching a daytime workplace and to reach other activities in the evening.

The electric vehicle fleet was divided into fully electric (75% of all EVs) with 70 kWh (average) batteries, and plug-in hybrid (25%) with 20 kWh (average) batteries, which were presented as aggregated units in the model. Both vehicle types could charge at a maximum of 6 kW based on the standard domestic 12 kVA connection in Ireland. It was assumed that vehicle owners prefer to maintain a relatively high state of charge for grid-connected vehicles: the vehicle aggregates are penalised in the model objective function when they reach a low state of charge (two levels: €4/MWh/h below 34% and an additional €20/MWh/h below 20%). Energy balance was maintained at separate nodes (see Figure 1), representing the EV batteries and the engines (where applicable), where energy conversions, storage and demand are all considered (see Equation 1).

3.4 | Hydrogen

Given the large capacity of the gas sector, immediate emission reductions could be obtained by injecting renewable hydrogen into the existing gas grid, which was considered for the 'Hydrogen' case (H_2). Due to the differing combustion characteristics, the maximum concentration of hydrogen in the gas grid was, however, limited [27]. It is assumed here that the volumetric hydrogen concentration could be increased to 10%, corresponding to 3% of the higher heating value. Most countries stipulate lower admissible concentrations. Upgrades to gas consumption and storage equipment may increase the permissible limit.

Electrolysis requires no other feedstock than water and has potential for very low emissions. Electrolysis was thus chosen as the production method to serve hydrogen infeed to the natural gas grid ('H_2'). Consequently, when hydrogen injection or power-to-ammonia measures were available, the modelled system included an electrolyser with 400 MW output capacity, in terms of higher heating value (HHV).

The drawback of electrolysis is its high capital cost and energy losses. An expert elicitation study [28] predicted an efficiency of 4.5–5.0 kWh/Nm^3 (71–79% HHV) for proton-exchange-membrane electrolysis by 2030. Here, 75% (HHV) was assumed. Capital cost predictions of €500–1500/kW$_e$ (electrical power) were also indicated for the same period, implying significant future cost uncertainty due to production scale-up and system size factors. Here, a capital cost of €700/kW$_e$ was assumed.

Depending on the operating strategy of the electrolyser, the product gas storage may be dimensioned differently [29]. In the present study, a large 2-day buffer storage (3,840 MWh) was chosen, with an assumed capital cost of €600/kg (€15/kWh HHV) [30].

3.5 | Ammonia

Annual nitrogen fertiliser consumption in Ireland is currently 375,000 tonnes (calculated as elemental nitrogen). The case where the fertiliser is indigenously produced was explored here for the 'Ammonia' case (P2A). The precursor to manufacturing nitrogen fertiliser is ammonia (NH_3). Currently, the dominant production process involves steam methane reforming (SMR) of natural gas, followed by Haber–Bosch synthesis of ammonia. The SMR process produces hydrogen and nitrogen, which are subsequently combined in the Haber–Bosch synthesis. The process uses fossil natural gas, both as fuel and feedstock, and produces significant amounts of CO_2 [31]. The power-to-ammonia (P2A) concept, which is currently in a demonstration phase, has been suggested as an alternative route. In the P2A route, the Haber–Bosch process is fed with electrolytic hydrogen together with nitrogen, which is separated from the air using an air separation unit (ASU). With renewable electricity, the process route can achieve very low CO_2 emissions. In addition, P2A represents a demand for hydrogen, thus increasing the amount of flexibility produced by electrolysis.

As shown in Figure 1, in this study, the Haber–Bosch process and ASU were treated as one combined conversion unit. The capital cost of the ammonia plant was set to €7,700/(kg/h) [32], while the electrical consumption of the ammonia plant was set to 0.7 kWh/kg.

The SMR process was available in all cases, while 'P2A' and 'All' cases were able to utilise P2A. To increase the flexibility for the power sector, the model included a 2-day ammonia storage facility and 40% oversizing of the ammonia production capacity.

3.6 | Demand response

The price and quantity for peak shaving ('price sensitive') demand response is not known for 2030, and the modelled demand response is demonstrative only: 150 MW capability (approximately 2% of peak load) was assumed here for the 'Demand response' case (DR) at an offer price of €120/MW/h, which potentially could be supplied from industrial processes, data centres, etc. Since the price is high, based on the assumption that regular interruptions are undesirable, the main contribution of this demand response is towards contingency reserve, providing 75 MW for an indefinite period. The base data set considered 750 MW of demand response, with a €500/MW/h price level, which was not permitted to provide reserve products, and was very rarely deployed by the model.

3.7 | Batteries

Battery energy storage systems (BESS) have been deployed recently in increasing numbers. The 'Batteries' case (Batt)

TABLE 6 Costs and benefits of the different measures under different scenarios

Measure	Annualised installation cost (M€)	Operational benefit (M€)				Benefit/cost ratio			
		Base	Inertia	Fuel+	VRE+	Base	Inertia	Fuel+	VRE+
Bld (Dual heating system in buildings)	74	50	60	73	72	0.67	0.81	0.99	0.97
Ind (Dual heating in industrial proc.)	8	33	30	50	44	4.13	3.75	6.25	5.50
EV (Smart charging electric vehicles)	–	697	709	937	717	–	–	–	–
H2 (Hydrogen to gas grid)	37	19	21	31	26	0.51	0.57	0.84	0.70
P2A (Power to ammonia)	67	59	55	83	77	0.88	0.82	1.24	1.15
DR (Peak shaving demand response)	–	13	7	21	19	–	–	–	–
Batt (Batteries)	15	35	45	50	31	2.33	3.00	3.33	2.07
All (All measures included)	≥200	888	880	1207	944	–	–	–	–

introduced a battery storage with 450 MWh storage capacity. The charge / discharge capability of the storage was 450 MW, in line with future scenarios[8]. The battery duration is also representative of future scenarios where batteries are exploited primarily for ancillary service provision, driven by strong market signals. A conservative round-trip efficiency of 81% was assumed [33]. The battery storage was allowed to offer 50% of its discharge capacity to the upward primary reserve market, when sufficiently charged. There is considerable uncertainty surrounding future stationary battery storage capital costs: a value of €250/kWh was assumed here. The batteries considered here were intended for power (peak shaving) purposes, but they were also used for reserves and energy arbitrage.

4 | CASE STUDY RESULTS

4.1 | Costs and benefits of different measures

The efficacy of the multi-sector energy system model was tested through various scenario model runs (see Tables 4 and 5) for the target year 2030, at a 1 hour resolution, with the operational benefits for each technology subsequently determined. The operational benefits accrue from fuel and emission cost savings, as well as from lower O&M costs. In Table 6, operational cost savings are compared against the estimated installation costs for each technology, which were annualised using a 5% interest rate and varying expected lifetimes. For the EV and demand response measures, the benefit per unit was calculated, due to the challenges of realistically estimating the installation costs..

Dual heating systems, in the building sector, generated economic benefits through replacing most of the natural gas consumption (83–86% across the cases). However, in general, the benefits did not outweigh the annualised installation costs. It is important to note that only approximate cost estimates were used for electric heaters (see Section 3.1). A further source of uncertainty follows from the need (or not) to consider network upgrade costs, arising from the proximity to capacity limits of building cabling, grid connections and distribution networks, particularly for wide-scale technology rollout.

In the industrial sector, the benefits of dual heating systems appeared to significantly outweigh the costs by a factor of 3.8 in the Inertia scenario to 6.3 in the Fuel scenario. However, cost uncertainty is considerable – especially grid connection costs for industrial sites that did not previously have high electricity consumption. Possibilities for heat storage, instead of dual systems, should also be explored in future studies.

Electric vehicles (based upon 2,250 MW of BEV charging with 26,250 MWh of battery capacity, and 750 MW of PHEV charging capacity with 2,500 MWh of battery capacity) saved €1,500/vehicle in fuel costs with a tax-free petrol price of €1.2/litre. At the same time, charging the vehicles costed (on average) €82/vehicle per year. This is not the consumer price, but rather the change in operational cost for the energy system due to aggregate EV charging, which should form the basis for societal decision-making. However, it is difficult to assess procurement cost differences between electric and petrol vehicles in 2030, but the fuel savings are considerable, and it is clear that energy system modelling should consider the possibility for a relatively rapid switch from petrol to electric vehicles at some point.

Introducing hydrogen (up to 3% of higher heating value) to the natural gas grid resulted in annualised costs that are approximately twice the benefits in the base scenario. However, the benefits improved when assuming higher fuel prices (by a factor of 0.84) and a greater VRE share (by a factor of 0.70). The greater opportunity arose from switching from fossil-based CH_4 to power-based CH_4, although the process is more costly and less efficient. Nevertheless, with continuous advancement of hydrogen production technologies, hydrogen storage represents one potential pathway for de-carbonising the final fossil fuel components from the energy system, as it can achieve large capacity and long-term storage while also alleviating VRE curtailment levels by utilising excess renewable generation to produce climate-neutral hydrogen fuel [34].

In the P2A cases (with P2A units that had 400 MW H_2 input and 35 MW electricity input for 60 tonnes of NH_3 output), annual benefits (59 M€ for the Base scenario and 55 M€ for the Inertia scenario) were of a similar magnitude to the annualised costs (67 M€), while for those cases with higher fuel prices (Fuel+) and a higher VRE share (VRE+), the societal benefits (83 M€ for Fuel and 77 M€ for VRE scenarios) were higher than the costs. It should be noted that both fossil-fuel-based SMR and power-based Haber-Bosch synthesis were assumed to be available, although the latter option was utilised much more to meet ammonia demand (88–95% of ammonia produced). Hence, in general, it is not sensible or viable to invest both in SMR and power-to-ammonia capacity. Ammonia is relatively inexpensive to store, while P2A, together with H_2 and ammonia storage, can be a flexible power system asset. The P2A case indicates that power-based ammonia production can play a vital role in future energy system modelling: a conclusion further amplified by the possibility of using ammonia for peak power generation in gas turbines or fuel cells (1,000 MW H_2 feeder in addition to H_2 equipment detailed in Section 3.4).

Demand response could be obtained from many different load categories, with the trigger price for that response depending on the underlying electricity use. Hence, it is not at all straightforward to estimate the potential cost for peak shaving demand. It can be expected that the per unit cost of demand response is lower when the demand is high, for example in industrial applications. Focusing on the benefits, the results indicate that the annual system costs were reduced by €50–140/kW, which is significant. Again, as expected, the benefits were greater when assuming higher fuel prices. However, in the model runs, demand response usage was very limited (due to the high price of €120/MWh), with benefits mainly accruing from the availability of upward reserves. The actual use of reserves was not simulated in the model.

The benefits from using batteries were more than double the annualised cost, indicating that battery storage can be used to provide valuable flexibility to the isolated Irish system with high shares of variable renewable generation. Discharging of batteries for energy arbitrage was approximately 1,700 full-load hours for scenarios without alternative flexibility measures, and approximately 1,100 h for scenarios with all other flexibility measures included. Increasing the VRE share by 6.3% also increased battery use by approximately 270 h.

4.2 | Ramps

When flexibility in the demand side is increased, it can be expected that the ramping of conventional units would be reduced. However, Figure 2 shows that most flexibility measures seem to impact the ramping of conventional units only very little (from +4% in Bld to -8% in Batt). Only the battery case and the case with all flexibility measures demonstrate a clear reduction in the average ramping. The reason is that in many cases VRE units were providing a flexibility service through curtailment and the new flexibility measures often just exploit that previously curtailed generation. Batteries, and to a lesser extent demand response, replace peak generation and hence decrease the ramping of pumped storage and high marginal cost thermal units.

4.3 | VRE curtailment

The VRE share in the 'No additional measures' case of the 'Base' scenario was already quite high, potentially generating 58% of electricity usage, if there was no curtailment. However, the relative scale of the projected VRE capacity, with respect to the size of the power system, suggests that available VRE generation may far exceed the total demand requirement at certain times, activating stability, network and other limits, and render curtailment of available VRE inevitable. Therefore, actual VRE curtailment in the base scenario was around 9%. In order to demonstrate the impact of the availability of the flexibility measures on the integration of VRE, additional cases were considered with increasing VRE shares. When additional VRE capacity was added, 37–48% of the production from the new capacity was curtailed (Figure 3, dark line). For instance, increasing the VRE share from 60% to over 75%, increased the curtailment levels from ≈10% to over 17%. However, with all flexibility measures applied, the initial curtailment was ≈3%, while 20–32% of the new generation was curtailed (Figure 3, green line). Although curtailment levels of the order of 20–32% are very high as an incremental rate, they indicate more room for (some of) the flexibility measures studied in this paper.

4.4 | System inertia and System non-synchronous penetration (SNSP)

One of the constraints which limits the instantaneous share of non-synchronous wind and solar generation is the inertial floor. While the Base scenario enforced a 23 GWs inertial floor, the Inertia scenario considered a lower floor of 17.5 GWs [8]. Figure 4 shows an annual duration curve of the system inertia for the Base and Inertia scenarios, considering the 'No additional measures' case and the 'All measures' case. For most of the operating hours, this constraint forced additional units online to provide inertia, leading to additional curtailment, and the duration curves were well matched for a given scenario. The higher inertia hours occurred when RES generation was low, and for these hours the duration curves were matched depending on the measures rather than the scenario considered. While the 'All measures' case effectively managed the variability and uncertainty of demand and supply across different timescales, through an aggregation of the different flexibility measures, in contrast, for the 'No additional measures' case, the lack of cross-sectoral flexibility means that demand during low RES hours was slightly higher, resulting in higher levels of online system inertia.

The system non-synchronous penetration (SNSP) constraint places a limit on the fraction of the demand (including exports) which can be supplied by non-synchronous sources (i.e. wind, solar and DC imports) due to power system stability concerns [35]. This constraint was not explicitly enforced in this work. However, the inertial floor prevented very high SNSP levels, with maximum values of 87% and 91% seen for the Base and Inertia scenarios, respectively, regardless of the measures

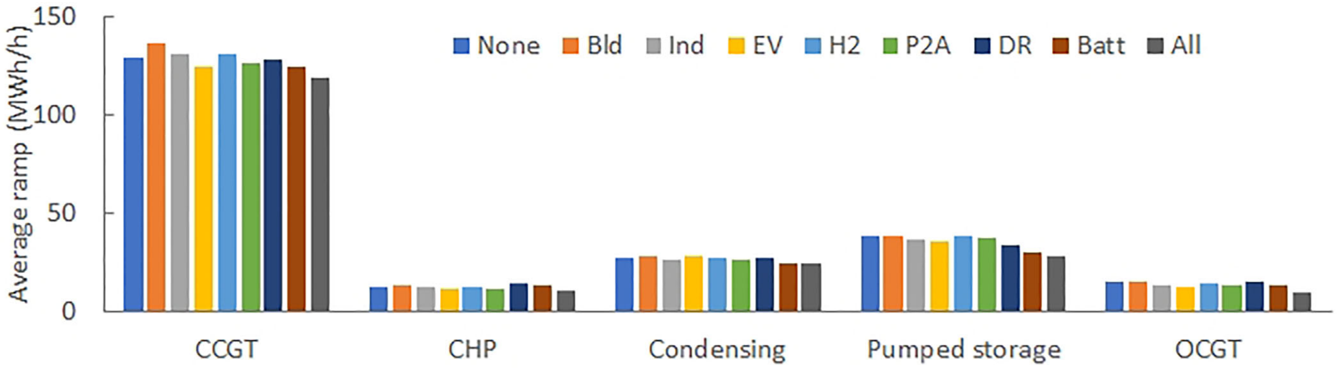

FIGURE 2 Average ramps of selected technologies across scenarios

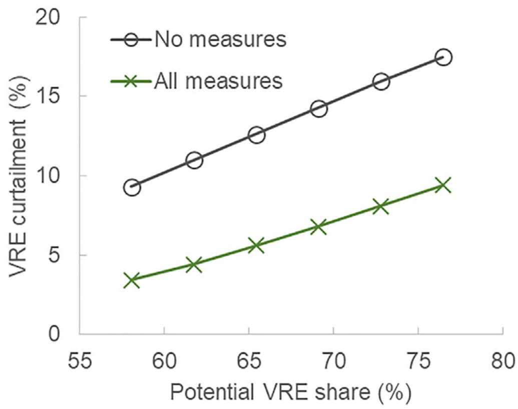

FIGURE 3 Curtailment of VRE with increasing annual share

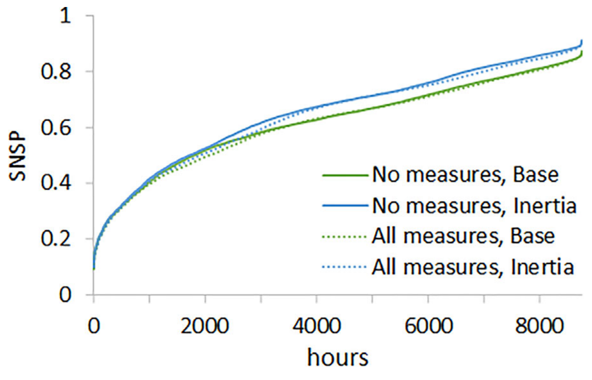

FIGURE 5 Duration curve for SNSP considering Base inertial floor (23 GWs) and reduced inertial floor (17.5 GWs) from the Inertia scenario for the No Measures and All Measures cases

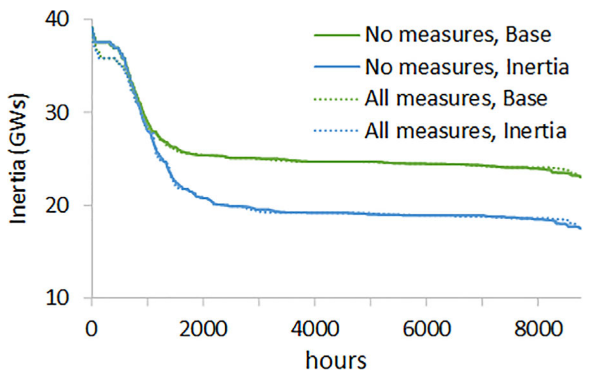

FIGURE 4 Duration curve for system inertia considering Base inertial floor (23 GWs) and reduced inertial floor (17.5 GWs) from the Inertia scenario for the None and All cases

considered. The measures are seen not to have a large impact on the shape of the SNSP duration curve (see Figure 5). While the 'All measures' case resulted in higher demands, it also facilitated higher levels of RES generation and lower levels of curtailment, as shown in Figure 3.

Noting that all the above results could have been affected by the comparatively small size (and associated operating cost) of the Irish power system in relation to the GB and French systems, which were also modelled, it could follow that that those scenarios which changed only the Irish system directly may not show meaningful results if modelling run inaccuracies were greater than the differences between scenarios. However, when running the Backbone model multiple times with the same settings, only marginal variations were observed in the results, providing clear differences between individual scenarios.

5 | CONCLUSION

Seven different measures (building heating, industrial heating, electric vehicles, hydrogen to gas grid, power to ammonia, demand response, and batteries) were analysed, with the objective of increasing the operational flexibility of an increasingly VRE-dominated power system. The results achieved indicate direction(s) for further analysis. For example, the potential to replace natural gas with renewable gas alternatives in the industrial sector, rapid adoption of electric vehicles and the potential role of batteries initially emerged above other measures. In addition, power-to-ammonia shows promise, while the techno-economic viability of hydrogen-based pathways require further study. The assumed costs of dual heating systems in buildings were higher than the modelled benefits, although at higher VRE shares they were almost equal. However, there is considerable uncertainty concerning the assumed costs. Most benefits from the flexibility measures were derived from the reduction of VRE curtailments as VRE did not need to provide as much flexibility. From the authors' previous work [36], it is clearly important to also consider the impact of any new flexibility measures on the optimal energy system portfolio. In this work, analysis was informed by evolving Irish national plans. Consequently, the generation portfolio adopted here is not considered to be optimal, and hence the presented results can be considered indicative only, i.e. they identify those technologies which have the first potential to be important for future energy systems. Further work is required to elaborate and question the assumptions made here, and to incorporate investment optimisation as part of operational analysis. Future work will also analyse the impact of changing targets for each of the measures, considering anticipated updates arising from the imminent 2021 Climate Action Plan (CAP) of Ireland.

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CONFLICT OF INTEREST

The authors have declared no conflict of interest.

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