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Impacts of tidal stream power on energy system security: An Isle of Wight case study

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ABSTRACT

The new Energy System Model for Remote Communities (*EnerSyM-RC*) is implemented to quantify impacts from adopting tidal stream power alongside solar PV, offshore wind and energy storage in the Isle of Wight energy system. Based on scenarios with gross renewable energy generation matched to projected annual demand (equivalent to 136 MW mean power), installing 150 MW of solar PV, 150 MW of offshore wind, and 120 MW of tidal stream capacity enhances supply–demand balancing whilst also reducing the magnitude of maximum power surplus, both by 25% relative to the best performing solar+wind system. Tidal stream adoption also reduces total land/sea space by 33%. The economic viability of tidal stream capacity adoption is heavily dependent on the price of reserve energy; when the reserve energy price exceeds the average 2022 forward delivery contracts price (250 £/MWh), adopting tidal stream capacity reduces the levelised cost of whole-system energy relative to solar+wind systems. This tipping point, at which the whole-system levelised cost of energy is 92 £/MWh, occurs when the premium on tidal stream energy is outweighed by savings on reserve energy. In general these system benefits arising from tidal stream adoption are consistent over a range of different demand profiles, and in cases where gross annual renewable supply is oversized relative to demand.

1. Introduction

Energy security has been identified as a key challenge in the power sector's transition to net-zero carbon emissions, as energy production shifts from relying heavily on dispatchable, fossil fuel technologies to variable renewables [1,2]. Energy security is defined as 'the uninterrupted process of securing the amount of energy that is needed to sustain people's lives and daily activities while ensuring its affordability' [3]. Research to date shows that diversifying the renewable power generation mix, through the adoption of new, alternative power generation technologies such as tidal stream and wave power, alongside solar PV and wind, has the potential to enhance supply–demand balancing and limit/prevent grid upgrade requirements [4–16]. Supply–demand balancing enhancement improves energy security by limiting reliance on uncertain and often economically volatile reserve energy supply [17]. National scale energy system modelling, implemented using the Energy System Modelling Environment (ESME) [18] and the Integrated Whole Energy System (IWES) model [19] demonstrate that the adoption of tidal stream energy can provide economic benefits when installed at gigawatt scale, but only if its levelised cost of energy (LCoE) can fall to around 50 £/MWh in the future.

The research presented in this paper builds on the aforementioned progress to date by delivering novel research in two areas. The first is the development and adoption of a new open-source energy system model that implements multi-objective, brute force optimisation of the renewable supply capacity mix. The model (Energy System Model for Remote Communities - *EnerSyM-RC*) is openly available (https://github.com/danielcoles/EnerSyM-RC), and builds on previous studies that adopt intuitive/arbitrary approaches to assigning the installed capacities of future renewable power capacities [17,20], which as shown here, can lead to sub-optimal energy system design. A range of energy system performance indicators are considered. These include supply–demand balancing (for both instantaneous power and net annual energy), whole-system cost of energy, and spatial coverage of the renewable energy projects. This multi-objective approach helps reduce bias that can arise when seeking a single optimal system design based on only one objective functional (e.g. whole-system cost of energy) [21]. Instead, by also considering near-optimal designs for any

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give objective functional, it becomes possible to establish the most suitable energy system that fulfils multiple objectives. *EnerSyM-RC* is open source to enable independent review and validation, which is necessary to improve confidence in model results [22].

The second area of novelty is the study's focus on the Isle of Wight energy system. This addresses a gap in knowledge highlighted in Osman et al. [23]; that there is a need to move away from hypothetical system modelling to more realistic systems to enable real-world implementation. The results presented here are being used by the Isle of Wight Council and Scottish & Southern Electricity Networks to establish a scope of work for grid upgrades on the island. The results are also being used by Scotia Gas Networks (SGN) in a new whole-system study that builds on the research presented here that focuses on the islands electricity system.

2. Isle of Wight energy system

In 2017, the Isle of Wight's total annual electricity consumption was 541 GWh. This is equivalent to an average power demand of 62 MW. Demand was split evenly between domestic and non-domestic consumption [20]. The minimum and maximum power demand over the year was approximately 30 MW and 110 MW respectively. The island's domestic electricity consumption fell 9% between 2010 and 2017, in line with the UK as a whole. This decline is expected to reverse, given the forecasted growth in electrification of heat and transport in the coming decades [24]. Assuming the island continues to follow UK forecasts, its total electricity consumption will reach approximately 1.1 TWh/year by 2050.

Currently the island's primary source of power is a 140 MW gas fired power station, which is also used for supply–demand balancing and frequency response services to the mainland UK, via three sub-sea electric cables. The island's primary source of renewable power is solar photovoltaic (PV), with a total installed capacity of around 80 MW. This comprises of 70 MW of ground mounted and 10 MW of rooftop installations. The island also has an anaerobic digestion plant and landfill gas plant, with installed capacities of 1.3 MW and 1.2 MW respectively [20].

The Isle of Wight has set out a net-zero delivery plan, with an ambition to achieve net-zero carbon emissions by 2040. The plan allows 15% of energy generation from carbon emitting technologies, as long as the emitted carbon is offset. The island aims to secure energy autonomy by generating as much energy as it consumes over an annual cycle [25].

Expansion of the island's renewable energy capacity is constrained by the available space. This is largely because of consenting barriers, with large regions of the island designated as areas of outstanding natural beauty, and thus protected. Planning permission for the near-by Navitus Bay 970 MW offshore wind farm was refused in 2015 as a result of the visual impact the development would have on both the island and the Jurrasic Coast, which is a world heritage site. The island has a tidal stream energy resource located around its southern most tip; St Catherine's Point. Preliminary technical studies suggest that the site has potential for 250 MW [26], but limited consideration has been made for environmental impacts such as changes to stratification and mixing [27], seabed scour [28–30], and interaction with marine mammals [31–33]. The economic viability of such large arrays also requires further consideration, since the added drag introduced by the turbines is likely to cause significant local wakes and array scale blockage that reduces the available energy to the turbines, lowering their energy yield and revenue potential [12,34,35]. The site has 30 MW of consented tidal stream capacity that is currently eligible to bid for subsidy support under the UK government's contracts for difference scheme.

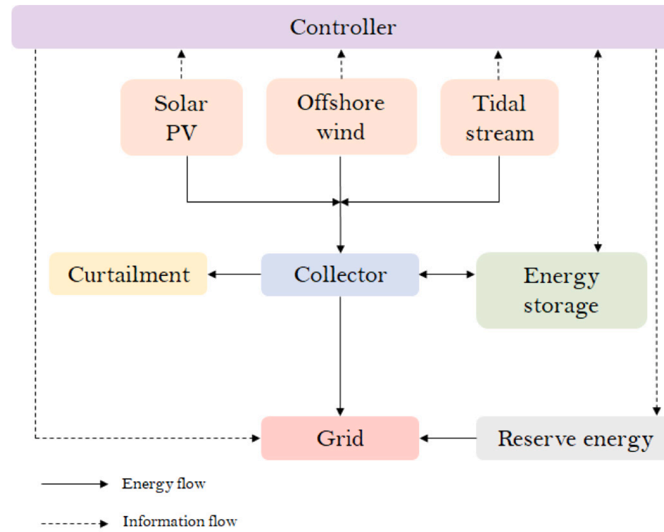

Fig. 1. Schematic of the solar PV, tidal stream, offshore wind hybrid system considered in the net-zero scenarios.

3. Energy system modelling

3.1. Energy System Model for Remote Communities (*EnerSyM-RC*)

This research has developed and implemented the new Energy System Model for Remote Communities (*EnerSyM-RC*). The open-source model has been developed to rapidly optimise the installed capacity of solar PV, offshore wind and tidal stream, with two primary objectives; (i) to maximise supply–demand balancing to reduce dependency on reserve supply, and (ii) to minimise whole-system cost of energy. This is achieved through a simple brute-force optimisation approach, where a wide range of solar PV, offshore wind and tidal stream installed capacity mixes are simulated over a 1 year period to assess the influence of their combined temporal variability and installed capacities on energy system performance. In all capacity cases, the combined gross annual renewable energy production from solar PV, offshore wind and tidal stream equals the gross annual demand, of 1.1.TWh. The brute-force approach to optimising the renewable capacity mix was adopted to overcome the challenge of designing systems for multiple, often conflicting objectives. For example, the renewable capacity mix that minimises the whole-system cost of energy may not also maximise supply–demand balancing. Simulating a wide range of renewable capacity cases makes it possible to identify optimal and near-optimal solutions across a range of objective functionals. *EnerSyM-RC* also quantifies other system performance metrics such as the plan area needed to install the renewable power and energy storage technologies, and the amount of inter-seasonal energy storage needed for the system to absorb all surplus renewable power. These performance metrics are described further in Section 3.3.

Fig. 1 provides a schematic of the *EnerSyM-RC* architecture used for the Isle of Wight case study. Solar PV, offshore wind and tidal stream capacity are the primary sources of power supply. The modelling neglects onshore wind because of uncertainty regarding the viability of development, given the island specific constraints regarding visual impact. Other less variable renewable power technologies, such as energy from waste and anaerobic digestion, are also neglected in this early stage research, under the assumption that these technologies will not contribute significantly to future supply, which may change in the future.

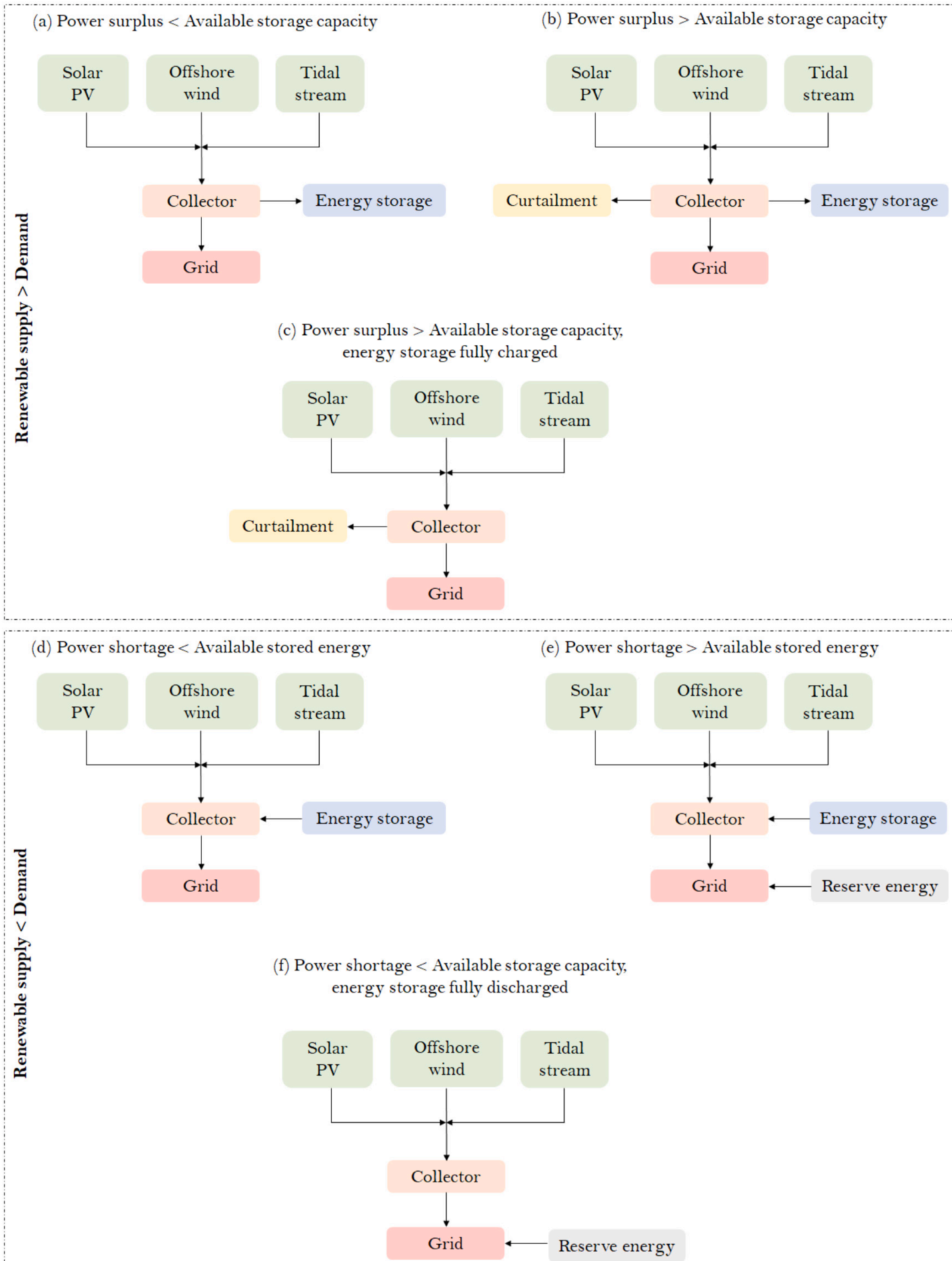

Fig. 2. Summary of the energy system operating modes.

The model simulates the power flows between components at 1 h temporal resolution. Short duration energy storage helps absorb excess renewable power at times of surplus renewable supply. Any surplus renewable power is curtailed. Dispatchable reserve supply is used to balance supply with demand during periods when demand cannot be met by renewable supply directly and/or from the energy storage. Whilst the technology used to provide reserve supply is not defined explicitly, the reliance on reserve supply is discussed in Section 4.3 to consider the cost contribution it makes to the whole-system. The grid refers to the local grid on the Isle of Wight, which is the source of electricity demand. The connection between the Isle of Wight and mainland UK is neglected to focus on the island's strategy of achieving energy autonomy in the future.

Fig. 2 shows the different operating states of the energy system. When renewable supply exceeds demand, and the available energy storage capacity is sufficient, surplus power is used to charge the energy storage system (Fig. 2a). At times when the energy storage system can only be used to store a proportion of the surplus power, the rest is curtailed (Fig. 2b). When the energy storage system is fully charged, all surplus renewable power is curtailed (Fig. 2c). When demand exceeds renewable power, the energy storage system is used to balance the remaining demand, when the availability of the energy storage system is high enough (i.e. when the power shortage is equal to or lower then the nominal power of the energy storage system, and there is enough stored energy - Fig. 2d). When the availability of the energy storage system is not high enough to balance all of the power shortage, reserve supply is also used (Fig. 2e). Finally, when the energy storage system is fully discharged, reserve supply is used as the sole source of power supply to balance demand with supply (Fig. 2f).

The model was run with and without energy storage. In cases without energy storage, when renewable power supply exceeds demand, all excess renewable energy is curtailed. At times when electrical demand cannot be met by renewable supply, reserve supply is used.

For cases with energy storage, the sizing of the energy storage system was assessed by quantifying the effect of incrementally increasing the number of energy storage units on supply–demand balancing. Each energy storage unit has a power rating of 1.5 MW and an energy storage capacity of 6 MWh (i.e. 4 h duration). This specification is loosely based on lithium-ion and vanadium redox flow battery storage, which have been integrated with renewable power projects [36,37]. The energy storage capacity adopted here is higher than current designs to reflect expected future technology developments. The energy storage units have a round trip efficiency of 85%, a 100% depth of discharge, and do not degrade over time.

3.2. Model inputs

Solar PV and offshore wind power data were obtained directly from the *Renewables.ninja* tool [38,39] at hourly resolution over the whole of 2019. The tool derives solar PV and wind power from resource data made available by the Modern-Era Retrospective analysis for Research and Applications (MERRA-2) project. The year 2019 was chosen because it is representative of an average solar and wind resource year; based on estimates of annual solar PV and wind turbine capacity factors, the mean annual solar and wind resource over 2019 falls within 3% of the average between 2010–2020.

The solar PV power data was derived based on an azimuth of 180°, 35° panel tilt and no tracking, at 50.5922° latitude, −1.3646° longitude. The general equation for solar PV power is

$$P_s = G A_s \eta \tag{1}$$

where P_s is solar PV power, G is solar irradiation, A_s is the total area of the panels and η is the conversion efficiency of the solar PV panels.

Offshore wind power data were derived based on the power curve of a Vestas V164 9500, 9.5 MW device with a rotor diameter of 164 m, at 50.4022° latitude, −1.3646° longitude. The equation for deriving wind power is

$$P_w = \frac{1}{2}\rho_w u_w^3 c_{p,w} A_w \tag{2}$$

where P_w is wind turbine power, ρ_w is the density of air, u_w is the hub height flow speed, $c_{p,w}$ is the power coefficient and A_w is the swept area of the rotor.

Eq. (2) was also used to derive tidal stream power based on parameters specific to tidal stream turbines, i.e the density of seawater (ρ_t), the hub height current speed (u_t), the tidal stream turbine power coefficient ($c_{p,t}$) and the swept area of the tidal stream turbine (A_t). Tidal stream flow speed data were obtained from an Acoustic Doppler Current Profiler (ADCP) data set collected at St Catherine's point on the south of the island, over a period of one month. The data was harmonically extrapolated over 2019 at hourly resolution. The rotor diameter (24 m) and rated power (1.3 MW) of the tidal stream turbines were selected to achieve an average annual capacity factor of 0.4, which is synonymous with the performance of operational turbines at sites such as MeyGen [40].

System losses of 10% were applied to the solar PV, offshore wind and tidal stream power timeseries data to account for electrical losses between the location of power generation and demand. It was assumed that the renewable supply operates with 100% availability throughout the year (i.e. no downtime for maintenance). Without system losses, the capacity factors of the solar PV, offshore wind and tidal stream technologies are 0.17, 0.52 and 0.40 respectively.

Fig. 3 shows the temporal variability in solar PV, offshore wind and tidal stream power, over (a–d) the whole of 2019, (e–h) a winter spring-neap period, and (i–l) a summer spring-neap period. Power data is normalised by the installed capacity of each technology. The temporal variability in solar PV, offshore wind and tidal stream power generation are significantly different from one another, which is expected given the nature of their energy sources. During the winter spring-neap period, the capacity factor of solar PV, offshore wind and tidal stream are 0.04, 0.58 and 0.34 respectively. These change to 0.23, 0.33 and 0.35 during the summer spring neap period (i.e. a 500% increase in solar PV capacity factor, and a 45% reduction in offshore wind capacity factor, whilst tidal stream capacity factor stays approximately the same throughout the year).

The level of balancing between supply and demand depends on the proportion of solar PV, offshore wind and tidal stream capacity that is installed in each capacity case. To investigate this, the energy system model was run with a wide range of solar PV, offshore wind and tidal stream capacities. In each capacity case, the gross annual renewable energy production was kept equal to gross annual demand. This aligns with the islands aim to generate as much energy as the island consumes over a year. The limits on solar PV, offshore wind and tidal stream capacity were set to 300 MW, 250 MW and 380 MW respectively. These limits are informed by the literature [26], and our own energy system modelling assessment that established the practical power capacity ranges that may be achievable in the long-term. The combinations of installed capacities are shown in Fig. 4 by the black markers. Both solar PV and offshore wind installed capacity are varied at 50 MW intervals. For each capacity case, the installed capacity of tidal stream is derived based on the capacity needed for gross annual renewable supply to equal gross annual demand, resulting in thirty seven capacity cases. Any cases where gross annual renewable energy production from solar PV and wind exceeds gross annual demand (e.g. when the installed capacity of solar PV and offshore wind are 300 MW and 250 MW respectively) were discarded. The level of supply–demand balancing then relies on the timing of renewable supply and demand, and the ability of the energy storage system to store surplus renewable energy for use at times when demand exceeds renewable supply.

Subsequent to this, additional capacity cases were simulated to quantify the impact of oversizing renewable supply on energy system performance. In these cases the gross annual renewable supply was increased up to 1.5 TWh/year, which is equivalent to 140% of gross annual electricity demand.

Electricity demand data was obtained from Scottish and Southern Electricity Networks (SSEN), the network operator for the island. The data was scaled to account for the projected increase in future electricity demand, from its current level of 0.55 TWh/year, to 1.1 TWh/year. This is based on 2050 electricity demand projections for the UK, when net-zero emissions are targeted [24]. A range of different electricity demand profiles were considered, by scaling the current demand data up to the projected 1.1 TWh/year level in different ways. In the first (demand case A; 'scaled' demand, Fig. 5a), current demand is multiplied by 2 to increase annual demand to 1.1 TWh/year. In demand case B ('elevated' demand, Fig. 5b), the current demand profile is

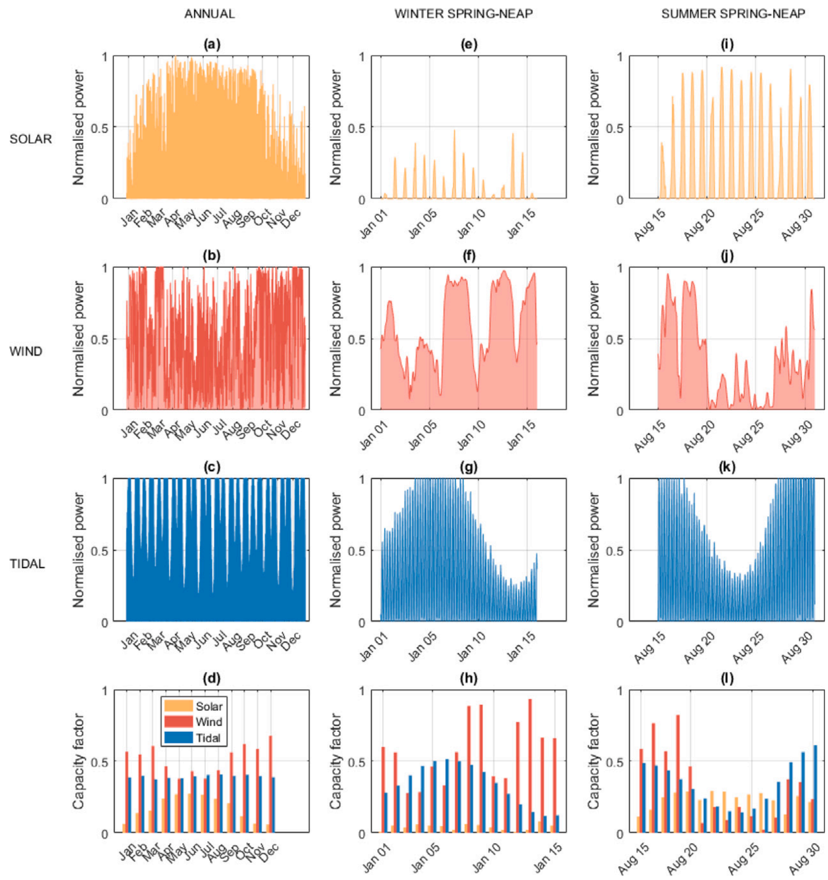

Fig. 3. Input solar PV, offshore wind and tidal stream power data used for energy system modelling; Annual variability in (a) solar PV, (b) offshore wind, and (c) tidal stream power, with (d) monthly capacity factors, as well as daily variability in (e) solar PV, (f) offshore wind, and (g) tidal stream power, over a winter spring-neap period, with (h) daily capacity factors, and daily variability in (i) solar PV, (j) offshore wind, and (k) tidal stream power, over a summer spring-neap period, with (l) daily capacity factors. Power is normalised by the installed capacity of each technology.

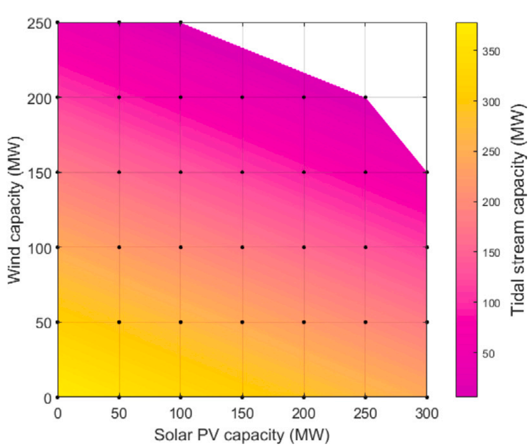

Fig. 4. Relationship between solar PV, tidal stream and wind capacity. Data points show the combinations used in the energy system modelling.

increased by a constant across each time step over the year. This results in less temporal variability in demand relative to demand case A. In demand case C, ('constant' demand, Fig. 5c), demand remains level throughout the year. Finally, in demand case D ('supply following', Figs. 5d–f), additional demand is added to the current demand at times when there is renewable power generation, to mimic high adoption of demand response technologies. In demand case D the annual demand profile is different for each of the thirty seven capacity cases, since the power supply profile is different in each capacity case. Three demand timeseries examples are provided in Fig. 5d–f, that demonstrate high temporal variability relative to demand cases A–C.

3.3. Energy system performance

In each of the thirty seven capacity cases, a range of energy system performance indicators are quantified. These are described in Table 1. Supply–demand balancing is calculated by quantifying the net annual energy shortage and energy surplus of each capacity case. Net values take account for the timing of supply and demand, so that if renewable supply cannot be used to balance demand directly, or charge the energy storage system, it must be curtailed. Net annual energy shortage quantifies the additional reserve supply that is needed to fully balance supply and demand. This is an important consideration as the source of reserve supply may be expensive, unreliable and/or carbon emitting.

Power surplus is the difference between net renewable power supply and power demand. It quantifies the power rating of any additional energy storage system(s) that would be needed to fully prevent curtailment by absorbing all surplus energy. In this research the 95th percentile (P95) of power surplus is considered. This is the magnitude of power surplus at which only 5% of the power surplus data from

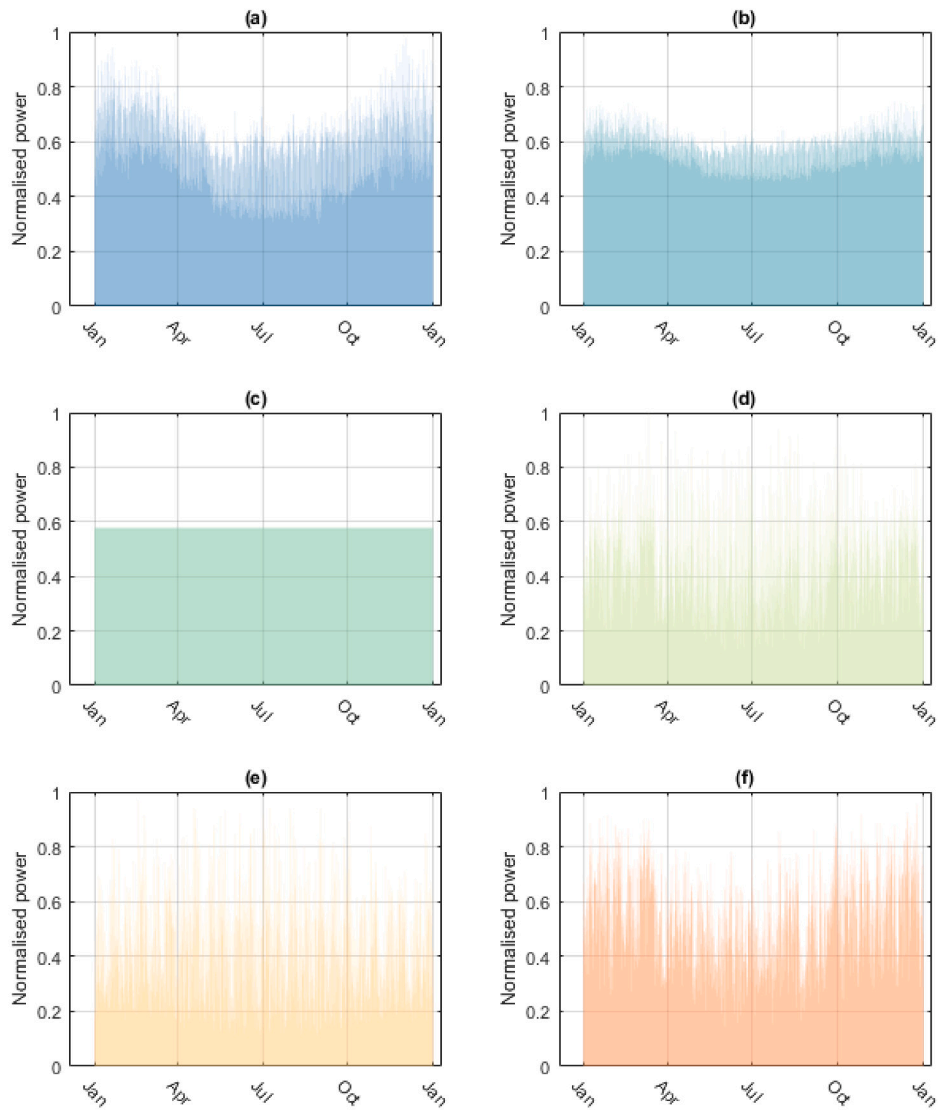

Fig. 5. Power demand profiles; (a) scaled - A, (b) elevated - B and (c) constant - C and (d–f) supply following. The demand D examples use solar PV, wind and tidal stream capacities of (d) P_s = 250 MW, P_t = 270 MW, (e) P_s = 250 MW, P_w = 200 MW, and (f) P_w = 200 MW, P_t = 115 MW. Power is normalised by the maximum power demand over the year.

the annual timeseries exceeds. The quantification of P95 power surplus removes extreme values that are unlikely to drive the design specification of infrastructure such as energy storage systems. I.e. it is unlikely that the power rating of additional energy storage systems will be sized to absorb all surplus power from the system, because to do so would reduce its load factor significantly, below the level needed for it to be economically viable. In this context the load factor is defined as the ratio of the average annual energy discharged by the energy storage system, and the maximum theoretical annual energy input of the energy storage system. The magnitude of power shortages quantify the power rating of reserve supply needed to match supply with demand.

The system LCoE in 2040 is estimated to help establish the economic viability of adopting tidal stream. LCoE is a measure of a systems net present cost of electricity. It is the ratio of total costs to the energy produced over the project lifetime, as described in Eq. (3),

$$LCoE = \sum_{t=1}^{n} \frac{\frac{C_t+O_t+F_t}{(1+r)^t}}{\frac{E_t}{(1+r)^t}} \tag{3}$$

where t is the year, n is the lifetime of the energy source in years, C_t, O_t and F_t are the capital, operations and maintenance and fuel costs respectively in year t, r is the discount rate (i.e. the rate of return used to discount future cash flows back to their present value), and E_t is the energy produced in year t. The sources of energy supply, from which costs arise, are solar PV, offshore wind and tidal stream energy production, short duration energy storage, and reserve supply.

Table 1
Description of parameters used to describe the design/performance of the energy systems.

Parameter	Description
Energy system design	
P_s	Installed solar PV capacity.
P_w	Installed offshore wind capacity.
P_t	Installed tidal stream capacity.
Performance metrics	
Capacity factor	Ratio of energy delivered to grid, to the maximum energy delivered to grid with continuous rated power operation.
Load factor	Ratio of the energy discharged from the energy storage system, to the maximum energy discharged with continuous rated discharge operation.
Net annual energy shortage	The shortfall in renewable energy supply over the year due to instances when supply is lower than demand and there is insufficient stored energy. Net annual energy shortage quantifies the amount of reserve supply needed to fully balance demand with supply.
Net annual energy surplus	The excess renewable supply during periods when demand exceeds renewable energy supply, and excess renewable supply cannot be stored by short-duration energy storage.
P95 power shortage	The 95th percentile magnitude of renewable power shortage that cannot be absorbed by the demand or short duration energy storage. This provides an indication of the power rating of additional infrastructure (either additional supply or storage) needed to deliver power during periods of high demand relative to supply.
P95 power surplus	The 95th percentile magnitude of renewable power surplus that cannot be absorbed by the demand or short duration energy storage. This provides an estimate of the power rating of additional energy storage required to absorb surplus power.
Accumulated energy surplus	The amount of surplus energy, that in the absence of adequate energy storage and/or grid infrastructure to export surplus power, must be curtailed. This provides an indication of the additional energy storage capacity needed to absorb all surplus energy.
LCoE	The ratio of discounted DevEx, CapEx, OpEx, to the discounted energy yield. The LCoE of all renewable and reserve supply is combined to provide an overall system LCoE.
Power density	The ratio of installed capacity to plan area.
Energy density	The ratio of annual energy yield to plan area.

Projected levelised costs for each energy source are obtained from the literature [41–44]. The solar PV, offshore wind and tidal stream LCoE projections are corrected to account for the level of curtailment in each of the thirty seven capacity cases. Similarly, the energy storage projections are corrected to account for load factor. Typically the LCoE of Vanadium flow batteries are based on a load factor of 0.06. The LCoE of bi-directional hydrogen storage, which provides inter-seasonal storage, are typically based on a load factor of 0.32 [45]. Whole-system LCoE is derived by combining the individual LCoE sources using a weighted average that accounts for the proportion of total supply provided by each source.

Finally, the spatial efficiency of the energy sources in each of the thirty seven capacity cases is quantified, using power and energy density. This is a particularly important consideration for regions such as the Isle of Wight, where energy development is spatially constrained.

4. Results

4.1. Supply–demand balancing

4.1.1. Net annual energy balancing

Figs. 6a–d show the relationship between solar PV, offshore wind and tidal stream installed capacity, and net annual energy shortage, for each of the four demand scenarios (A–D), respectively. Energy shortage data are normalised by the annual energy demand, of 1.1 TWh. Results obtained from energy system modelling without energy storage are also plotted in grey to compare against annual energy shortage and surplus when short-duration energy storage is adopted. The short duration energy storage system has a power rating of 225 MW and an energy storage capacity of 900 MWh (i.e. 4 h duration). This energy storage specification was chosen to enable capacity cases 1–4 to reduce annual energy shortage considerably (by at least 30%). Results and discussion from an analysis conducted to assess the suitable energy storage specification are provided in Appendix A.

Figs. 6e–h show the relationship between solar PV, offshore wind and tidal stream installed capacity, and net annual energy surplus, with comparisons against the performance of the energy system performance without energy storage.

In all demand cases annual energy shortage is minimised using approximately 150 MW of solar PV, 150 MW of offshore wind, and 120 MW of tidal stream capacity. The energy systems without energy storage minimise annual energy shortage with 50 MW less solar PV capacity, 50 MW more offshore wind capacity, and 45 MW less tidal stream capacity.

As expected, in all demand cases the adoption of short-duration energy storage reduces net annual energy shortage/surplus. This is especially true in capacity cases that adopt high tidal stream capacity. The semi-diurnal cycling of the tidal stream resource helps enhance the utilisation of the energy storage system through multi-hour charging/discharging cycles to augment supply–demand balancing. The high-frequency charging/discharging enhances the energy storage load factor, as shown in Fig. 7, which provides the relationship between solar PV, offshore wind and tidal stream capacity, and the load factor of the energy storage system. Load factor of 0.06 is the typical level expected of short duration energy storage, and is typically used to estimate levelised cost of short duration energy storage [45]. Adopting low levels of tidal stream capacity (<100 MW) results in energy storage load factors that fall below 0.06.

Figs. 3 and 7 show that the wind resource exhibits far higher power persistence (i.e. longer duration periods of power generation and no power generation) than solar PV and tidal stream [11,15], which limits the frequency of battery charging and discharging [12], and energy storage load factor. Once tidal stream capacity exceeds 100 MW, every 100 MW increase in tidal stream capacity increases the energy storage load factor by 0.04 (or between 30%–100%). Opportunities for the energy storage system to earn revenue in the wholesale market become more limited as energy storage load factor reduces [46]. The cost

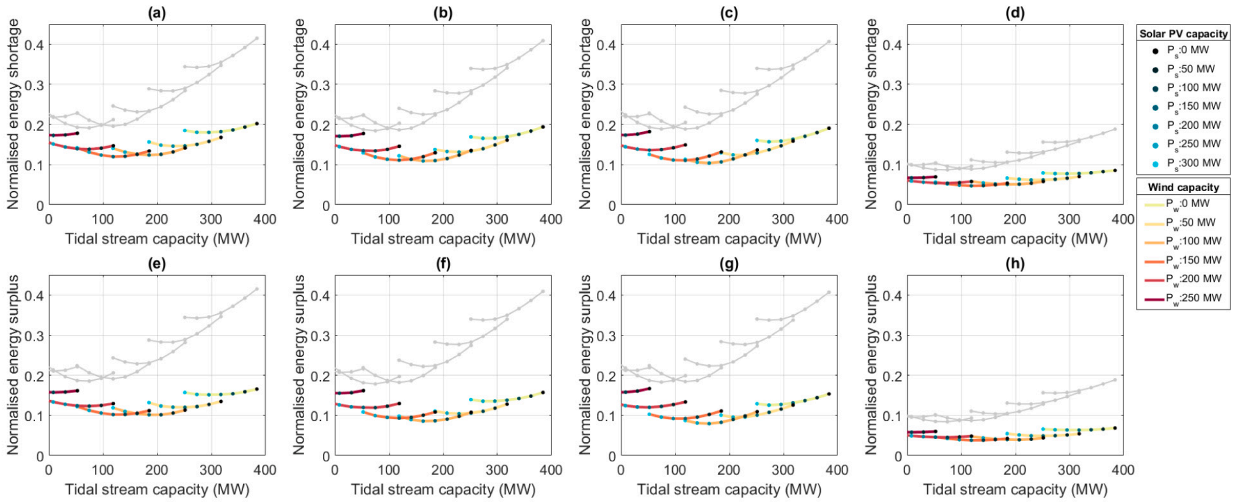

Fig. 6. Relationship between tidal stream, offshore wind and solar PV power capacity and net annual (a–d) energy shortage, and (e–h) energy surplus, based on demand cases A (a,d), B (b,f), C (c,g) and D (d,h). Results obtained from energy system modelling without energy storage are plotted in grey. Results are normalised by the annual energy demand.

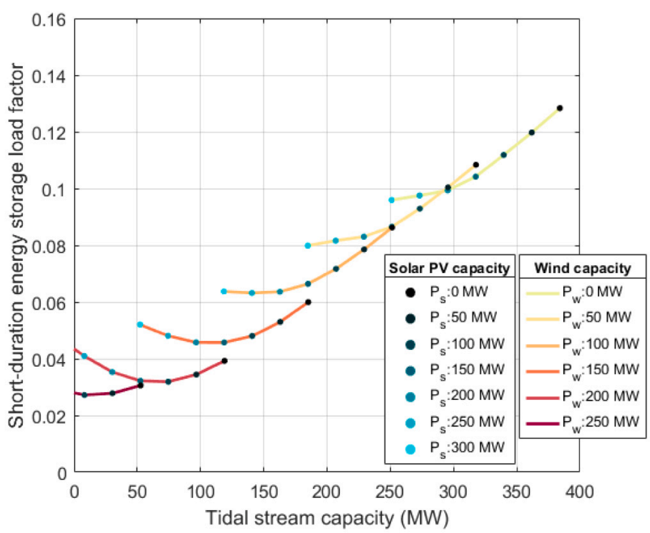

Fig. 7. Relationship between solar PV, offshore wind and tidal stream capacity, and energy storage load factor. Results presented based on an energy storage system with 225 MW power capacity, 900 MWh energy storage (4 h duration) and 85% round-trip efficiency.

implications of increasing the short duration energy storage load factor are explored further in Section 5.2.

In demand case C, the annual energy shortage is minimised using 200 MW of solar PV, 100 MW of offshore wind, and 160 MW of tidal stream. A factor contributing to the reduction in offshore wind capacity in this case relative to the other demand cases is the flat annual demand profile, which removes the seasonal correlation between offshore wind power generation and demand that exists in demand cases A, B and D. The increases in solar PV and tidal stream capacity minimises annual energy shortage by 10% relative to the case with 150 MW of solar PV, 150 MW of offshore wind, and 120 MW of tidal stream capacity.

Table 2 summarises the annual energy shortage and surplus for the best performing capacity cases, based on each combination of technology adoption. Results are based on demand case A only. The percentage differences between capacity case 1, and 2, 3 and 4 are also provided. The P95 power shortage/surplus results are also provided, for discussion in Section 4.1.3. The maximum accumulated energy surplus figures are discussed in Section 4.2. The system performance comparison of capacity cases 1 and 2 highlights that through the adoption of tidal stream alongside solar PV, offshore wind and short-duration energy storage, net annual energy shortage is reduced by 26%, 50% and 11% relative to capacity cases 2, 3 and 4 respectively. This demonstrates that by adopting tidal stream alongside solar PV and offshore wind, reliance on reserve supply is significantly reduced. If reserve supply is sourced from fossil fuel technology, the same percentage drops in carbon emissions or carbon capture/offsetting requirement would also be realised by adopting tidal stream. Net annual energy surplus is also reduced by adopting tidal stream, relative to capacity cases 2, 3 and 4, by 31%, 49% and 10% respectively. The cost implications of these impacts are explored in Section 4.3.

4.1.2. Monthly energy balancing

Fig. 8 shows the distribution of monthly energy (a) shortage, and (b) surplus, based on capacity cases 1–4 and demand case A. Data plotted in grey provides the monthly energy shortage and surplus achieved without energy storage. The data reflects the capacity cases that minimise annual energy shortage, as shown in Table 2, noting that the capacities of solar PV, offshore wind and tidal stream that minimise annual energy shortage change with the addition of energy storage.

Capacity case 4 exhibits the lowest winter month energy shortage, and the lowest summer month energy surplus, when offshore wind capacity is high and solar PV is absent. Summer energy shortage is minimised using capacity cases 1 and 3, when solar PV capacity is high. Fig. 8b shows that during winter months, energy surplus is minimised using capacity case 3, when offshore wind is absent. In Section 4.2, these results are discussed in the context of the inter-seasonal energy storage system required to shift surplus energy to periods with a net energy shortage.

Table 2
Energy system performance based on demand case A, and the capacity cases that minimise annual energy shortage.

Capacity case	Installed capacities			Annual energy shortage	Annual energy surplus	P95 power shortage	P95 power surplus	Max. accumulated energy surplus
	Solar	Wind	Tidal					
No energy storage								
1:Solar+wind+tidal	100 MW	200 MW	75 MW	228 GWh	220 GWh	105 MW	100 MW	–
2:Solar+wind	100 MW	250 MW	–	259 GWh (+14%)	250 GWh (+14%)	115 MW (+10%)	107 MW (+7%)	–
3:Solar+tidal	250 MW	–	275 MW	407 GWh (+79%)	407 GWh (+85%)	150 MW (+43%)	191 MW (+91%)	–
4:Wind+tidal	–	200 MW	120 MW	252 GWh (+11%)	245 GWh (+11%)	117 MW (+11%)	115 MW (+15%)	–
With energy storage								
1:Solar+wind+tidal	150 MW	150 MW	120 MW	143 GWh	121 GWh	100 MW	101 MW	60 GWh
2:Solar+wind	100 MW	250 MW	–	180 GWh (+26%)	158 GWh (+31%)	110 MW (+10%)	125 MW (+24%)	76 GWh (+27%)
3:Solar+tidal	250 MW	–	275 MW	215 GWh (+50%)	180 GWh (+49%)	134 MW (+34%)	170 MW (+68%)	131 GWh (+118%)
4:Wind+tidal	–	200 MW	120 MW	159 GWh (+11%)	133 GWh (+10%)	112 MW (+12%)	124 MW (+23%)	27 GWh (-55%)

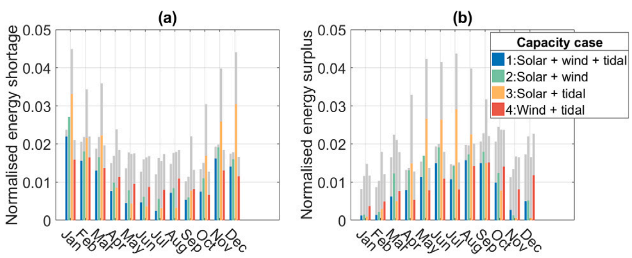

Fig. 8. Monthly net energy (a) shortage, and (b) surplus. Results obtained from energy system modelling without energy storage are plotted in grey.

4.1.3. Instantaneous power balancing

Fig. 9 provides the P95 power shortage and surplus magnitudes of the energy systems. Results are normalised by the maximum power demand over the year. As with the presentation of annual energy shortage/surplus, results are compared to those obtained from the equivalent energy systems without short-duration energy storage, shown in grey. Results obtained with and without energy storage show very similar power shortage/surplus trends, where in general, P95 power shortage/surplus is minimised using the same installed capacities that minimised annual energy shortage; 150 MW of solar PV, 150 MW of offshore wind, and 120 MW of tidal stream capacity. Small changes in these capacities result in minimal change to the P95 power shortage/surplus as the gradient is relatively flat around the global minimum of P95 power shortage and surplus.

Increasing tidal stream capacity above 150 MW leads to a significant increase in P95 power surplus. A contributing factor to this is the high occurrence of surplus tidal power generated during the night when demand is low. A significant increase in P95 power surplus also occurs when solar PV capacity exceeds 200 MW, especially without short-duration energy storage. This is the result of high surplus power during summer months when demand is generally low (with the exception being demand case C). In general the adoption of offshore wind helps to reduce the magnitude of power shortages/surpluses, as long as solar PV capacity is limited to below 200 MW and tidal stream capacity is greater than 120 MW.

Table 2 compares the P95 power shortage and surplus of capacity cases 1–4, using demand case A. The magnitude of power shortage has relevance to the power capacity rating requirement of reserve supply. The magnitude of power surplus has relevance to the power capacity rating of additional energy storage systems required to store surplus energy. When short-duration energy storage is adopted, P95 power shortage and surplus are minimised using capacity case 1, to 105 MW and 100 MW respectively. The adoption of solar PV and offshore wind only (i.e. capacity case 2) limits supply–demand balancing, resulting in a 10% increase in P95 power shortage and a 7% increase in P95 power surplus, relative to capacity case 1. Capacity case 3, which adopts solar PV and tidal stream only, results in a 43% increase in P95 power shortage relative to capacity case 1. This is driven predominantly by the absence of wind power capacity, which is well correlated with demand, with both being greatest during winter months when the solar PV contribution is low. The P95 power surplus of capacity case 3 is 91% higher than that of capacity case 1. This significant increase is the result of high tidal power generation during spring tides that coincide with high solar PV generation during bright summer days. Capacity case 4, which adopts offshore wind and tidal stream only, results in an 11% increase in P95 power shortage, and a 15% increase in P95 power surplus, relative to capacity case 1.

In general, the adoption of short-duration energy storage leads to relatively small reductions in the magnitude of P95 power shortage/surplus, of around 10%. This is explained by the limited energy storage capacity of the system. Power shortage often occurs when the energy storage system is fully discharged. Similarly, periods with power surplus often occur when the energy storage system is fully charged, preventing the system from absorbing further surplus energy. The exception to this is capacity cases that adopt high levels of solar PV and tidal stream capacity, which reduce the magnitude of P95 power surpluses by up to 25% when short-duration energy storage is adopted. As discussed in Section 4.1.1, this is made possible by the high frequency cycling of solar PV and tidal stream power generation, which is better suited to integration with short-duration energy storage than the more persistent wind resource. This may be a mute point however, because even with short-duration energy storage, adopting more than 150 MW of tidal stream still results in relatively high P95 power surplus. The role of longer duration energy storage to reduce the magnitude of power shortages/surpluses is discussed further in Section 4.2.

4.2. Inter-seasonal energy storage

Fig. 6 shows that short-duration energy storage reduces the net annual energy shortage of the energy systems to within 10%–20% of annual demand in demand cases A–C. Any further increase in short-duration energy storage capacity cannot make significant further improvements to supply–demand balancing due to its storage duration limitation, as demonstrated in Appendix A. Additional energy storage must be able to store higher levels of energy relative to the power capacity of the energy storage system, i.e. it requires longer duration, inter-seasonal storage. There are a wide range of long duration energy storage technologies under development, all at different technology readiness levels. These include chemical technologies such as the production, storage and oxidation or combustion of electrolytic

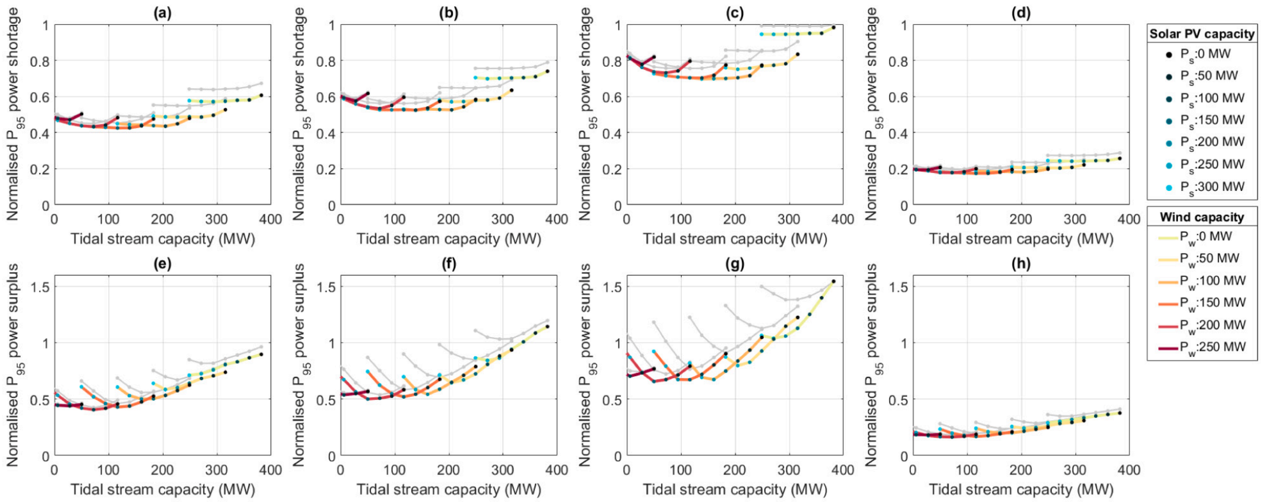

Fig. 9. Relationship between tidal stream, offshore wind and solar PV power capacity and (a–d) P95 power shortage, and (e–h) P95 power surplus, based on demand cases A (a,d), B (b,f), C (c,g) and D (d,h). Results obtained from energy system modelling without energy storage are plotted in grey. Results are normalised by the maximum power of the demand.

hydrogen [47,48], thermal technologies such as sensible or latent heat storage [49,50], and mechanical technologies such as compressed air and pumped hydroelectric [51]. A drawback of long duration energy storage is that the round trip efficiency, which is a primary driver of cost, is far lower than that of short-duration energy storage (30%–60% depending on long-duration technology vs. 85% of short duration technologies) [52,53]. Here we assess the specification of inter-seasonal duration energy storage needed to complement the short-duration energy storage already considered, to further enhance supply–demand balancing.

Fig. 10 shows the annual power shortage/surplus timeseries of the four capacity cases that minimise annual energy shortage. Results are normalised by the maximum power demand over the year. In capacity case 3, high power surplus during summer months must be shifted to winter periods, when power shortages are most prevalent. This highlights the need for inter-seasonal storage, that retains energy over long periods with minimal standing losses. The magnitude of power shortage/surplus is lower in capacity cases 1, 2 and 4 than in capacity case 3, because power shortage and surplus periods are more evenly distributed across the year.

Based on the results presented in Table 2, it can be concluded that when short-duration energy storage is adopted, net annual energy surplus is around 15% lower than net annual energy shortage in capacity cases 1–4. Inter-seasonal energy storage would allow the remaining energy surplus to be absorbed by the system, but its relatively low round trip efficiency means that only 30%–60% of the energy surplus would feed back to provide supply, depending on the storage technology used [52,53]. This would still leave a net annual energy shortage equivalent to over 10% of annual demand in each capacity case. For the Isle of Wight this may be acceptable given that the island currently plans to accept up to 15% of energy supply to be delivered by fossil fuels if the carbon emissions are offset.

P95 power shortages and surpluses presented in Table 2 indicate the specification of the additional, longer duration energy storage system(s) that would be needed in order to shift the remaining surplus power to periods with power shortage. For example, in the case of green hydrogen production, the P95 power surplus provides an indication of the electrolyser power capacity requirement. Minimising the power capacity requirement of this additional infrastructure is achieved in capacity case 1. Comparison of capacity cases 1 and 2 shows that

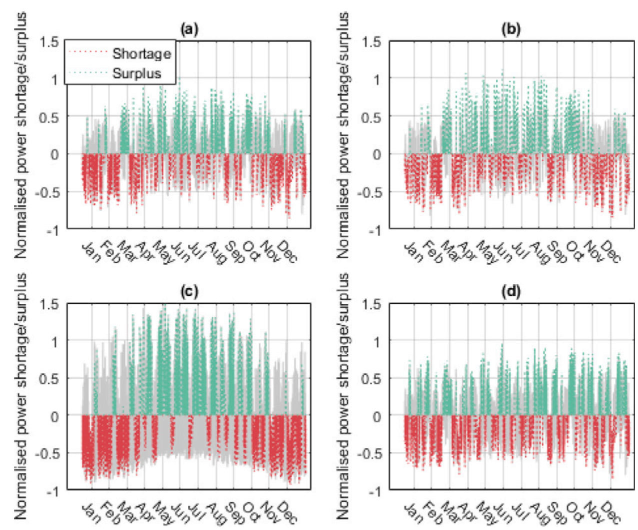

Fig. 10. Time series of power shortage/surplus based on (a) capacity case 1, (b) Capacity case 2, (c) Capacity case 3, and (d) Capacity case 4. The power shortage/surplus of the energy systems without energy storage are plotted in grey. Results are normalised by the maximum power demand over the year.

adopting tidal stream results in a 24% reduction in P95 power surplus. Capacity case 3 is the worst performing of the four; the magnitude of P95 power surplus is 68% higher than capacity case 1. Relative to capacity case 1, capacity case 4 demonstrates a 23% increase in P95 power surplus magnitude.

Table 2 also provides the maximum accumulated energy surplus of each capacity case. Energy surplus accumulates during periods with high occurrence of power surplus, resulting in a build up of surplus energy, that in the absence of adequate energy storage and/or grid infrastructure to export surplus power, must be curtailed. The accumulation of energy shortage/surplus is illustrated in Fig. 11 for capacity cases 1–4. Between January and April there is a build up of energy

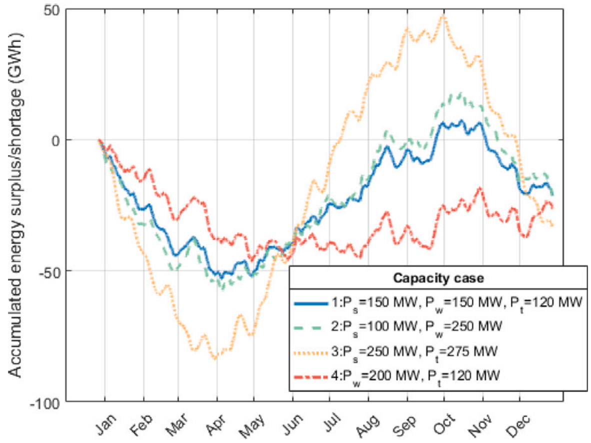

Fig. 11. Time series of energy shortage/surplus accumulated through the year in capacity cases 1–4.

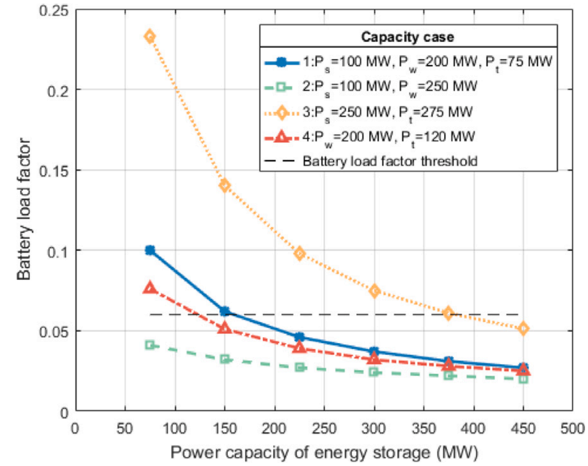

Fig. 12. Relationship between the power capacity of short duration energy storage, and the battery load factor of capacity cases A, B, C and D. The black dashed line indicates the load factor at which the LCoE from short duration energy storage achieves its mid-range level of 200 £/MWh.

shortage in all four capacity cases, as a result of high winter/early spring demand. In capacity cases 1–3 accumulated energy shortage starts to decrease after April, as demand reduces and the solar resource increases. This results in a build up of energy surplus. This trend then reverses again around October, when demand starts to increase and the solar resource reduces. In capacity case 4, the system remains in a state of net accumulated energy shortage throughout the whole year. One reason for this is that without solar PV capacity, the energy shortage accumulated between January and April is unable to recover during the summer months. The build up of surplus energy between April and October amounts to 60 GWh, 76 GWh, 131 GWh and 27 GWh in capacity cases 1–4 respectively. These figures provide an indication of the inter-seasonal energy storage capacity that is required to absorb all remaining energy surplus, which is another driver of energy system cost [52,53]. In the case of hydrogen, cryogenic or compressed air energy storage, maximum accumulated energy surplus provides an indication of the volume of the storage tanks required to store surplus energy. Results presented here demonstrate that the adoption of tidal stream capacity can reduce the energy storage requirement of inter-seasonal storage significantly; capacity case 1 achieves a 21% reduction relative to capacity case 2, a 53% reduction relative to capacity case 3, and a 122% increase relative to capacity case 4.

By the end of the year all four capacity cases have a net accumulated energy shortage of around 20 GWh. This highlights the importance of multi-year energy system modelling, as this energy deficit will impact the energy system performance of the following year.

4.3. Whole-system cost of energy

The system performance comparison of capacity cases 1 and 2 provided in Table 2 demonstrates that by adopting tidal stream capacity alongside solar PV, offshore wind and short-duration energy storage, the following system benefits arise:

- Net annual energy shortage is reduced by 26%.
- The magnitude of P95 power surplus is reduced by 24%.
- The maximum accumulated energy surplus is reduced by 21%.

The economic viability of tidal stream adoption within hybrid systems depends on the value of system benefits such as these, relative to the additional cost of tidal stream energy technology. Projected 2040 levelised cost of energy (LCoE) estimates for solar PV, offshore wind and tidal stream are presented in Table 3. Baseline solar PV and offshore wind estimates are based on figures provided by UK Government Department for Business, Energy and Industrial Strategy (BEIS) [41]. The 2040 baseline LCoE of tidal stream is estimated to be 90 £/MWh, based on a cumulative installed capacity of 1 GW [42]. The LCoE of reserve supply is based on the average forward delivery contract electricity price during 2022 [43], of 250 £/MWh. Forward delivery contract electricity price has been highly volatile during 2022, ranging between 150 £/MWh in February and 511 £/MWh in August. The impact of this reserve energy price range on system LCoE is considered in due course. LCoE projections for short-duration and inter-seasonal energy storage are also provided. The LCoE of short duration storage is based on vanadium flow batteries and the LCoE of inter-seasonal storage is based on bi-directional hydrogen energy storage and delivery [44].

The baseline LCoE projections are corrected to account for curtailment in the case of renewable energy supply, and load factor in the case of energy storage. Correcting the LCoE of energy supply for curtailment results in increases in the LCoE of solar PV, offshore wind and tidal stream of up to 27%, 25% and 20% respectively. The LCoE of short duration energy storage reduces in cases where load factor exceeds 0.06, from its baseline estimate of 200 £/MWh, to as low as 80 £/MWh. This occurs in cases with high tidal stream adoption which augments the energy storage load factor significantly (see Fig. 7). Conversely, in cases where load factor falls below 0.06, the LCoE of short duration energy storage reaches levels up to 375 £/MWh. The LCoE of inter-seasonal energy storage, once corrected for load factor, exceeds its baseline estimate of 1500 £/MWh significantly in all capacity cases. This is a common finding where curtailed renewables is the only source of power to the electrolyser and fuel cell in bi-directional hydrogen energy storage and delivery [54].

As demonstrated in Table 3, the LCoE of both short duration and inter-seasonal storage changes significantly depending on their load factor. Results presented in Section 4.1 (Fig. 7) and Appendix A show that the adoption of tidal stream capacity significantly enhances the load factor of short duration energy storage. This is also demonstrated in Fig. 12, which shows how the load factor of short duration energy storage is affected by the amount of storage deployed in capacity cases 1–4. In all cases, as battery capacity increases, load factor reduces. Capacity cases 1 and 2 demonstrate the highest load factors across the battery capacity range, due to the adoption of tidal stream capacity. It is estimated that for the storage to deliver a mid-range LCoE

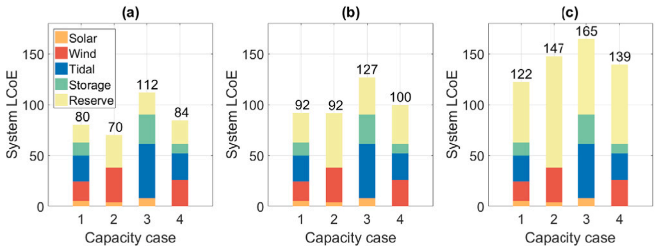

Fig. 13. Whole-system LCoE of capacity cases 1–4, with the price of reserve energy ranging between the lowest and highest levels seen during 2022; (a) 150 £/MWh, (b) 250 £/MWh, and (c) 511 £/MWh, The contributions of solar, wind, tidal, short duration energy storage and reserve energy to the whole-system LCoE are indicated by the stacked bars.

Table 3
Projected LCoE of solar PV, offshore wind and tidal stream. Baseline LCoE has been corrected to account for curtailment of renewable energy, and the load factor of short duration and inter-seasonal energy storage.

Technology	Baseline LCoE	Corrected LCoE
Energy supply		
Solar PV	33 £/MWh [41]	36–42 £/MWh
Offshore wind	40 £/MWh [41]	43–50 £/MWh
Tidal stream	90 £/MWh [42]	96–108 £/MWh
Reserve supply	250 £/MWh [43]	N/A
Energy storage		
Short duration energy storage	200 £/MWh [44]	80–375 £/MWh
Inter-seasonal energy storage	1500 £/MWh [44]	3095–8855 £/MWh

(i.e. 200 £/MWh), load factor must be equal to 0.06 [45]. This is achieved in capacity cases 1, 3 and 4 using an energy storage power capacity of 155 MW, 390 MW and 115 MW respectively. In capacity case 2 the battery cannot reach a load factor of 0.06 because wind capacity, with high resource persistence, is too dominant.

The ability of tidal stream capacity to enhance energy storage load factor is an important consideration in energy system design and system LCoE; whilst tidal stream energy has a higher LCoE than wind and solar based on the power supply technologies in isolation, if tidal stream can facilitate higher adoption of short-duration energy storage so that the system relies less on expensive reserve energy, it may provide economic benefit to the system as a whole. Fig. 13 illustrates this point, by providing the estimated whole-system LCoE of capacity cases 1–4, when in each case the amount of energy storage capacity adopted is based on that needed to achieve a load factor of 0.06. Fig. 13a provides the system LCoE of capacity cases 1–4 when the cost of reserve power is at its lowest level seen in 2022 to date (150 £/MWh). In this case capacity case 2 achieves the lowest system LCoE, because the cost of reserve energy is less than that of tidal energy and stored energy. In Fig. 13b the reserve energy cost is equal to the average over 2022 to date (250 £/MWh). In this case the system cost of capacity cases 1 and 2 both equal to 92 £/MWh, whilst capacity cases 3 and 4 provide more expensive solutions. This represents the tipping point at which any further increase in the price of reserve supply results in the whole-system cost of capacity case 2 exceeding that of capacity case 1. It is interesting to note that on islands, reserve energy is often supplied by oil/diesel generators, with cost that far exceed 250 £/MWh [12]. In Fig. 13c the cost of reserve energy has been increased to the highest level seen during 2022 to date (511 £/MWh), resulting in the system LCoE of capacity case 2 (147 £/MWh) exceeding that of capacity case 1 (122 £/MWh) by 20%. This result highlights the importance of considering the contribution of all component parts when estimating whole-system cost of energy to establish the most economically viable mix of renewable power technologies.

Table 4
Power and energy densities of solar PV, tidal stream and offshore wind projects, and the plan area required to build out capacity case 1.

Technology	Power density	Energy density	Area
Solar PV	50 W/m^2	74 kWh/m^2	3 km^2
Offshore wind	7 W/m^2 [55]	32 kWh/m^2	21 km^2
Tidal stream	92 W/m^2	315 kWh/m^2	1.3 km^2

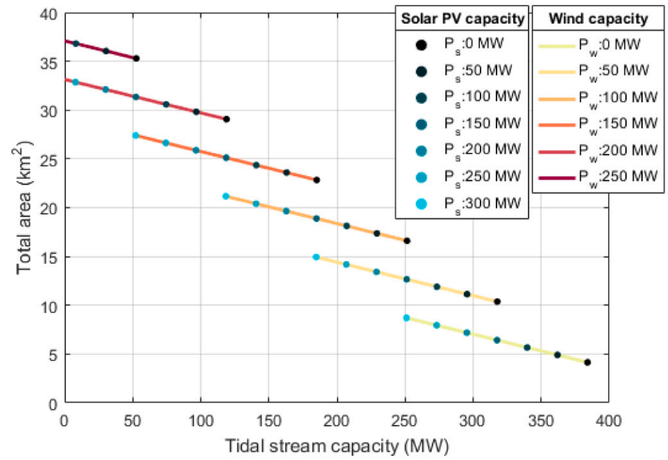

Fig. 14. Relationship between the installed capacity of solar PV, tidal stream and offshore wind, and their total plan area.

4.4. Spatial requirements

Future energy system design must consider the spatial coverage requirement of projects. The power and energy densities of solar PV, offshore wind and tidal stream projects located in/around the Isle of Wight are displayed in Table 4, alongside the area required to install capacity case 1, with 150 MW of solar PV and offshore wind, and 120 MW of tidal stream capacity. Power density quantifies the spatial efficiency of power generation schemes; it is the ratio between the installed capacity of the project and its plan area. Similarly, energy density is the ratio of annual energy yield to plan area.

Fig. 14 shows the relationship between solar PV, offshore wind and tidal stream capacity, and the total land/sea space requirement. Total area is highly dependent on the amount of offshore wind capacity installed, as it is the least spatially efficient technology of the three, with power and energy density of 7 W/m^2 and 32 kWh/m^2 respectively. Tidal stream is the most spatially efficient technology, with a power and energy density of 92 W/m^2 and 315 kWh/m^2 respectively. This assumes that array scale blockage is minimal by implementing tidal stream turbine micro-sited with lateral spacing of five rotor diameters, and longitudinal spacing of ten rotor diameters.

Fig. 15 illustrates the plan area needed to build out capacity case 1, with energy storage. 150 MW of ground-mounted solar PV requires a total area of approximately 3 km^2. This is equivalent to less than 1% of the islands total land area. Rooftop solar PV has a higher power density, so this is seen as a conservative estimate given that of the 80 MW of solar PV already installed on the island, approximately 10 MW is rooftop mounted, with further rooftop installations likely in the future. The 150 MW offshore wind farm requires a sea area of 21 km^2 (equivalent to 5.5% of the Isle of Wight land area). As discussed in Section 2, it is currently unclear if the visual impact of offshore wind turbines will be accepted locally in the future to enable development. The 120 MW of tidal stream requires an area of 1.3 km^2, equivalent

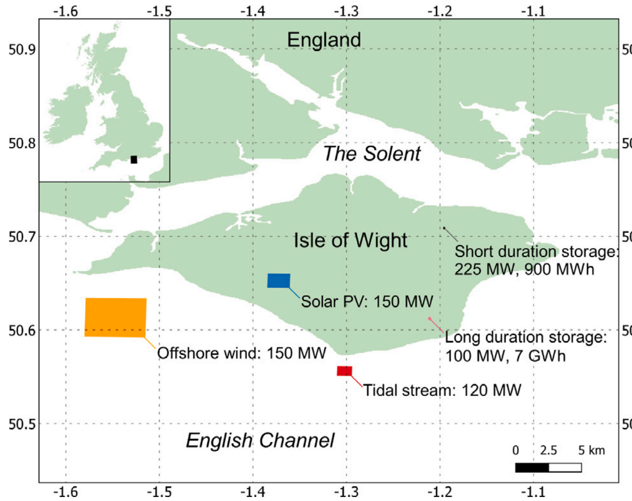

Fig. 15. Map of the Isle of Wight, illustrating the plan area needed to install 150 MW of solar PV (blue polygon), 150 MW of offshore wind (orange polygon), and 120 MW of tidal stream (red polygon) capacity, as well as 225/900 MWh (short-duration) energy storage, and 100 MW/7 GWh (inter-seasonal) energy storage. CHECK.

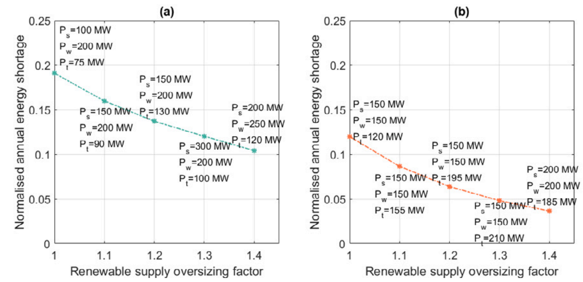

Fig. 16. Relationship between the level of oversizing of renewable supply, and the annual energy shortage, based on energy systems (a) without energy storage, and (b) with energy storage. The power capacities of solar PV (P_s), offshore wind (P_w) and tidal stream (P_t) that achieve the lowest annual energy shortage in each case are annotated. Results are normalised by the annual energy demand.

to 0.35% of the Isle of Wight land area. Visual impact will also be a consideration for tidal stream energy development, especially if floating devices are proposed. The total land/sea space of capacity case 1 is 25.3 km^2. Capacity case 2, which adopts solar PV and offshore wind only, requires a total land/sea area of 28 km^2.

Fig. 15 also provides an illustration of the land areas required for the short and long duration energy storage systems discussed in Section 4.2. The spatial requirement of short-duration storage is based on the 300 MW grid scale lithium-ion battery storage project that is operational in Geelong, Australia [56], with an estimated density of 13 kW/m^2. As shown, the land requirement of the energy storage systems is very low, so they are not expected to be prohibitive.

5. Additional considerations and further work

5.1. Oversizing renewable supply

Results presented in Section 4.1.1 report the annual energy shortage of the energy systems that generate a gross annual renewable supply that is equal to annual demand. It has been shown that introducing energy storage helps to reduce annual energy shortage, by shifting energy surplus to periods with energy shortage. Another approach that can reduce annual energy shortage is to oversize the renewable supply, so that gross annual renewable supply exceeds annual demand. Site specific studies indicate that when optimally designed, oversizing can result in production costs that are below current generation [57]. Here we briefly investigate the impact of oversizing renewable capacity on the Isle of Wight's energy system performance.

Fig. 16 shows the relationship between the level of oversizing of renewable supply, and the normalised annual energy shortage, based on energy systems (a) without short-duration energy storage, and (b) with short-duration energy storage. The full results are included in Appendix B. As expected, results show that as renewable supply is increased to exceed annual demand, energy shortage reduces. In general, the installed capacities of solar PV, offshore wind and tidal stream that minimise annual energy shortage all increase as renewable supply increases. It is also noticeable that in cases with short duration energy storage, as the level of oversizing increases, the proportion of tidal stream capacity that enhances supply–demand balancing also increases. This is because of the compatibility of tidal stream with short duration energy storage, as described previously. Results in Fig. 16 provide consistency with the previous findings; that supply–demand balancing is enhanced by diversifying the renewable supply technology mix.

The ability to oversize renewable capacity will depend on the practical constraints that limit the capacity build out of renewable projects. Given the scale of the suggested developments, it is important to acknowledge that estimates of wind and tidal stream power generation used in this study do not account for the impacts of array blockage, which can reduce the available resource significantly by redirecting the wind and tidal flows around the turbines as a result of the added drag the turbines introduce [58]. To address this, regional scale models that introduce the added turbine drag and its effects on energy yield are necessary. The practical viability of these scales of development will also depend on wide ranging considerations such as environmental impacts, grid reinforcement requirements, and visual impact [59].

5.2. Whole-system cost of energy

Section 4.3 presented initial insights into the whole-system cost of the Isle of Wight energy systems considered in this research. A key challenge that has prevented further detailed study in this area is uncertainty in future cost projections, either through estimates derived from bottom up engineering, or technology learning rates. Technology learning rate describes the percentage reduction in costs with every doubling of cumulative installed capacity [60]. The levelised cost of solar, wind and tidal energy is intrinsically linked to the cumulative capacity that is built out in the future, which facilitates learning that drives down the cost of future projects [61]. Less developed technologies such as tidal stream energy are currently on steep cost reduction pathways relative to more established technologies such as solar PV and offshore wind. This means that for the Isle of Wight, the economic viability of technologies such as tidal stream are highly sensitive to the level of their adoption elsewhere, which remains uncertain.

Importantly, methods for quantifying whole-system costs are now being widely adopted, especially in the context of installing high penetrations of solar and wind capacity in energy systems [5,62–64]. Metrics such as 'enhanced' levelised cost of energy acknowledge the fact that variable renewable power generation technologies are responsible for knock-on cost impacts to the system as a whole [65]. A challenge for energy system modelling is to quantify whole-system costs whilst accounting for the high uncertainty in technology costs as time progresses.

5.3. Socioeconomic impacts of extreme weather

The results reported here are based on wind data from 2019, which is representative of an average wind year. Extreme weather will effect the performance of energy systems significantly [66]. This was demonstrated in the UK during August and September 2021, when a sustained period with low wind resource coincided with low nuclear power availability and increasing imported wholesale natural gas prices that were driven by high global demand. These simultaneous events contributed to a *ca.* 75% increase in wholesale electricity prices in the UK over a 1 month period [43], and consequently, an increase in consumer energy bills and fuel poverty. These costs must be assessed on a system specific basis. Whilst this is out of the scope of this paper with respect to the Isle of Wight energy system, it is clear that resilient energy system design that considers extreme weather events is crucial to protect against any potential detrimental socioeconomic impacts.

6. Conclusions

Results presented in this paper highlight the importance of holistic energy system design optimisation, which is necessary in order to consider the wide range of often conflicting objective functionals that must be traded-off against each other to derive a practical energy system design.

For the Isle of Wight, with a future gross annual demand of 1.1 TWh (equivalent to a mean power demand of 136 MW), an approximately balanced portfolio of solar PV (150 MW), offshore wind (150 MW) and tidal stream (120 MW) capacity results in several energy system performance benefits. These include a minimisation of net annual/monthly energy shortage and surplus, which reduces reliance on additional reserve energy supply by 26% relative to the best performing solar PV+offshore wind system.

Tidal stream adoption also minimises the magnitude of maximum power shortages and surpluses across the year, by 11% and 24% respectively. Minimising power shortages reduces the power rating requirement of additional reserve supply. Reducing the magnitude of power shortage/surplus also helps to minimise the required power rating of additional energy storage systems, which is a driver of energy storage cost [53]. From a qualitative perspective, these findings are consistent over a wide range of future demand profiles, and in cases where gross annual renewable supply equals and exceeds annual demand.

When the reserve energy price is 250 £/MWh (i.e. equivalent to the average forward delivery contracts during 2022 to date), adopting 120 MW of tidal stream capacity results in a whole-system cost of energy of 92 £/MWh. This is equal to the whole-system LCoE of the best performing system that adopts solar PV and offshore wind only. This is possible because the high levelised cost of tidal stream is balanced by the systems reduced reliance on relatively expensive reserve energy. The adoption of tidal stream capacity enhances the load factor of short duration energy storage because of its semi-diurnal power cycling, which enables the storage system to frequently charge and discharge. This increases the amount of short duration energy storage that can be adopted. It is critical that future energy system modelling optimises tidal stream capacity and energy storage capacity together for this reason. When the cost of reserve power exceeds 250 £/MWh, the whole-system cost is minimised by adopting tidal stream capacity.

The adoption of tidal stream capacity also reduces the energy storage capacity and charge/discharge capacity requirement of an additional, inter-seasonal energy storage system needed to absorb curtailed energy, by 21%, relative to the best performing system using solar PV and offshore wind only.

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CRediT authorship contribution statement

Daniel Coles: Designed the study, Drafted and edited the manuscript, Generated the figures and carried out the cost of energy analysis. **Bevan Wray:** Supported in the evolution of the energy system modelling, Drafting and editing of the manuscript. **Rob Stevens:** Supported in the evolution of the energy system modelling, Drafting and editing of the manuscript. **Scott Crawford:** Supported in the evolution of the energy system modelling, Drafting and editing of the manuscript. **Shona Pennock:** Supported in the evolution of the energy system modelling, Drafting and editing of the manuscript. **Jon Miles:** Supported in the evolution of the energy system modelling, Drafting and editing of the manuscript.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

Data availability

Data will be made available on request.

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Appendix A. Short-duration storage sizing

Here we investigate the impact of adopting short-duration energy storage in the thirty seven energy systems capacity cases on energy system performance. Fig. 17 shows the relationship between the power capacity of the energy storage that has been introduced to the systems, and the annual energy (a) shortage, and (b) surplus, from capacity cases 1–4 presented in Table 2. Results are based on demand case A. In all cases the energy storage duration is kept equal to 4 h, so that the energy storage capacity increases with the power capacity of the energy storage system, up to 1.8 GWh when the power capacity of the storage system reaches 450 MW. As the power capacity of the energy storage system increases, the amount of surplus power absorbed by the system also increases. In capacity cases 3 and 4, there is a relatively steep reduction in annual energy shortage and surplus

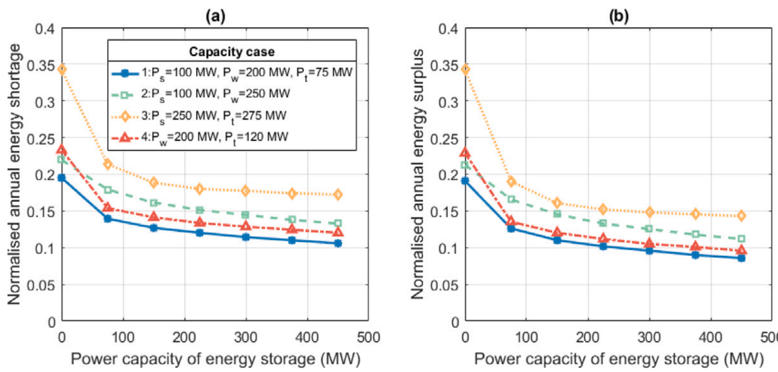

Fig. 17. Relationship between total battery capacity and (a) annual energy shortage, and (b) annual energy surplus.

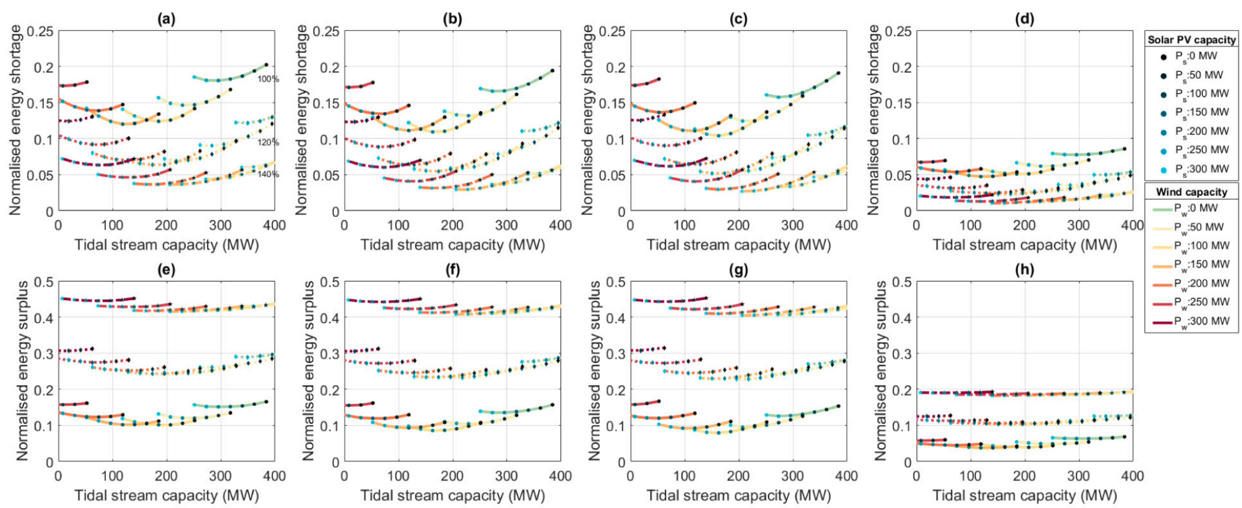

Fig. 18. Relationship between tidal stream, offshore wind and solar PV power capacity and net annual (a–d) energy shortage, and (e–h) energy surplus, based on demand cases A (a,d), B (b,f), C (c,g) and D (d,h). Results are obtained from energy system modelling without energy storage. Data is plotted for cases where total annual renewable supply is (i) equal to annual demand (solid lines with circle markers), (ii) 120% of annual demand (double-dashed lines with diamond markers), and (iii) 140% of annual demand (dashed lines with star markers).

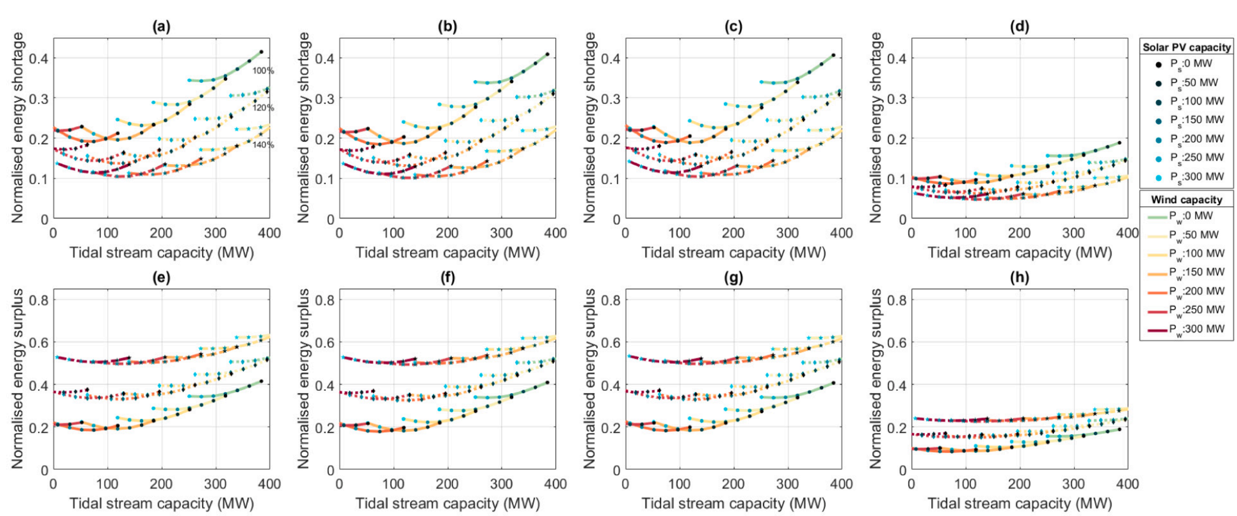

Fig. 19. Relationship between tidal stream, offshore wind and solar PV power capacity and net annual (a–d) energy shortage, and (e–h) energy surplus, based on demand cases A (a,e), B (b,f), C (c,g) and D (d,h). Results are obtained from energy system modelling with short-duration energy storage. Data is plotted for cases where total annual renewable supply is (i) equal to annual demand (solid lines with circle markers), (ii) 120% of annual demand (double-dashed lines with diamond markers), and (iii) 140% of annual demand (dashed lines with star markers).

initially as the power capacity of the energy storage is increased from 0–75 MW, of around 40%.

Further reductions in annual energy shortage and surplus start to plateau as the power capacity of the energy storage system approaches and exceeds 150 MW. This is partly because it is rare for surplus power to exceed 150 MW, as demonstrated in Fig. 9. The second reason is that significantly more than 1.8 GWh of energy storage capacity is needed to shift the majority of the energy contained within remaining periods with continuous power surplus, to periods with power shortage, as is explored in Section 4.2.

Based on the results presented here, short-duration storage with a power capacity of 225 MW, and an energy storage capacity of 900 MWh is adopted within the energy system modelling in order to reduce the annual energy shortage by at least 30% in capacity cases 1–4.

Appendix B. Oversizing renewable supply

Figs. 18a–d show the relationship between solar PV, offshore wind and tidal stream installed capacity, and net annual energy shortage, for each of the four net-zero demand scenarios (A–D), respectively. Results are normalised by the annual energy demand, of 1.1 TWh. Results are based on the energy system performance without energy storage. Results are presented for cases where total annual renewable supply is equal to annual demand (100%), 120% of annual demand, and 140% of annual demand. Similarly, Figs. 18e–h show the relationship between solar PV, offshore wind and tidal stream installed capacity, and net annual energy surplus, with comparisons against the performance of the energy system performance without short-duration energy storage.

Figs. 19a–h show the same set of results, but this time obtained with the short-duration energy storage installed. Oversizing renewable energy production reduces the net annual energy shortage, and increases net annual surplus. In all cases the net annual energy shortage is minimised by adopting similar solar PV, offshore wind and tidal stream capacities. When short-duration storage is included, the minimum annual shortage occurs when the proportion of the tidal component is increased from 120 MW (18(a) to 180 MW (19(a).

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