



Final Report

Impacts and challenges of high shares of solar PV generation

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Date: 24/04/2025



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Contents

1	Introduction	1
2	Literature review	2
2.1	Background information	2
2.2	Solar variability due to cloud cover	5
2.3	Minimum operational demand	6
2.4	Ramping	8
2.5	Conclusion of literature review	9
3	Project aims	10
4	Methodology	11
4.1	2030 solar generation	11
4.1.1	Large scale solar	12
4.1.2	Small Scale Solar	12
4.1.3	2030 All Island solar PV generation	13
4.2	2030 All Island demand	13
4.2.1	Irish demand	13
4.2.2	Northern Irish demand	15
4.3	2030 AIPS portfolio	16
4.3.1	Solar PV generation	16
4.3.2	Wind generation	17
4.3.3	Hydropower generation	18
4.3.4	Gas generation	18
4.3.5	Pumped hydro storage	19
4.3.6	Battery storage	19
4.3.7	Synchronous condensers	20
4.3.8	Demand side units	21
4.3.9	Flexible EV demand	21
4.3.10	V2G EV charging	22

4.3.11	Flexible heat pump demand	23
4.3.12	Interconnection	23
4.3.13	Operational constraints	25
4.3.14	General assumptions made	26
4.4	2030 unit commitment programme	27
4.4.1	Demand	27
4.4.2	Solar PV generation	28
4.4.3	Wind generation	29
4.4.4	Hydropower generation	29
4.4.5	Gas generation	30
4.4.6	Pumped hydro storage	31
4.4.7	Battery storage	31
4.4.8	Synchronous condensers	32
4.4.9	Demand side units (DSU)	33
4.4.10	Flexible EV demand	33
4.4.11	V2G EV charging	34
4.4.12	Flexible heat pump demand	35
4.4.13	Interconnection	35
4.4.14	Global Constraints	36
5	Results and discussion	38
5.1	Geographical spread	38
5.2	Demand	38
5.2.1	Potential solutions	39
5.3	Duck curve	39
5.3.1	Potential solutions	40
5.4	Full solar penetration	40
5.4.1	Potential solutions	41
5.5	Solar variability	41
5.5.1	Potential solutions	42

5.6	Unit commitment results	42
5.6.1	Base scenario	43
5.6.2	Flexible demand sensitivity	45
5.6.3	Storage sensitivity	45
5.6.4	Interconnector export sensitivity	49
5.6.5	MUON sensitivity	49
5.7	Final discussion	51
6	Ethics and Sustainability	54
6.1	Sustainable Development Goals	54
6.2	Future Reliability of Solar PV	55
7	Conclusion	56
8	Proposed future work	57
9	References	58
A	Unit commitment Python PyPSA code for the base scenario	68

1 Introduction

The urgent need to decarbonise global energy systems has positioned renewable electricity generation at the forefront of climate action. Solar photovoltaic (PV) energy, alongside wind, is central to this transition due to its scalability, declining cost, and emissions-free generation. As electricity grids shift away from fossil fuels, the increasing penetration of solar PV brings a unique set of operational challenges that must be addressed to ensure system reliability and stability.

The All-Island Power System (AIPS), which includes the electricity networks of both Ireland (IE) and Northern Ireland (NI), offers a compelling case study for examining these challenges. Both IE and NI have committed to ambitious 2030 targets: 80% of electricity from renewable sources, including significant contributions from solar PV. In IE, the solar capacity target is 8 GW, with 2.5 GW expected from rooftop installations. NI aims for 600 MW, including 200 MW of rooftop solar (EirGrid and SONI, 2023*d*). These targets mark a substantial increase from current capacity levels.

The characteristics of solar PV generation present several operational challenges for the AIPS, particularly under the projected 2030 scenario of high renewable penetration. Limited system flexibility, including inflexible demand and uncontrollable rooftop solar, combined with storage and export constraints, can lead to curtailment of solar power. This is exacerbated by the misalignment between peak solar output and low midday demand, and by steep evening ramps that must be met by conventional generation. Additional constraints, such as minimum unit output levels and transmission bottlenecks, further restrict the effective use of available solar energy. Addressing these issues is critical to meeting solar integration targets while maintaining system security.

This report investigates the technical and operational impacts of high solar PV penetration on the AIPS, with a focus on the projected 2030 power system. It evaluates the scale of potential integration challenges, including solar variability, minimum operational demand constraints, and ramping requirements, and explores a range of mitigation measures informed by existing research and international case studies. In doing so, it aims to assess the viability of achieving solar integration targets without compromising system security and with minimum solar power wastage.

2 Literature review

2.1 Background information

As of 2024, the Irish electricity network, operated by EirGrid (the national transmission system operator), has a total installed solar PV capacity of 1,185 MW, according to the 2024 Scale of Solar report by the Irish Solar Energy Association (ISEA) (2024). This capacity includes both large-scale and small-scale systems. Large-scale solar refers to installations above 1 MW, contributing 643 MW, typically from utility-scale farms exporting directly to the grid. The remaining 542 MW comes from small-scale systems such as residential rooftops and commercial units near the point of consumption. Solar installations are connected through either the transmission or distribution network.

The transmission network operates at 400 kV, 220 kV, and 110 kV and connects large generators to substations. The distribution network, which delivers electricity to homes and businesses, operates at 38 kV, medium voltage (10 to 20 kV), low voltage, and a regional 110 kV system specific to Dublin (Sustainable Energy Authority of Ireland (SEAI), 2021). As of 2024, IE has 18 large-scale solar farms: 7 connected to transmission and 11 to distribution. All are controllable by EirGrid, which can adjust their output in real time. In contrast, small-scale systems are not controllable or visible to EirGrid. Around 100,000 homes have rooftop PV (ESB Networks, 2024). These systems are ‘behind-the-meter’, primarily serving on-site demand, and are unobservable to the TSO. Another 170 MW comes from uncontrollable commercial and auto-producing systems, adding complexity to grid planning and forecasting.

The NI network, operated by the System Operator for NI (SONI), has a total solar capacity of 300 MW as of 2024 according to the 2024 generation capacity statement (GCS) by EirGrid and SONI (2024a). Approximately 100 MW comes from rooftop solar installations and 200 MW from 11 large-scale sites, 9 of which are controllable by SONI. Additionally, there is 32 MW of uncontrollable small scale commercial installations as stated in the EirGrid (2025c) system renewable data reports. All solar installations in NI are connected via the distribution network which operates using 33 kV, 11 kV, 6.6 kV and low voltage lines (Northern Ireland Electricity (NIE), 2015). Approximately 30,000 homes are fitted with rooftop solar as of 2024 according the the Microgeneration Certification

Scheme (MCS Certified, 2025).

The distribution of solar PV installations across IE and NI in 2024 is heavily concentrated along the east coast. This regional clustering is primarily due to higher solar irradiance and lower average cloud cover in eastern areas (Met Éireann, 2025*b*), which improves the energy yield of solar panels. Additionally, the east of the island includes major urban centres such as Dublin and Belfast, where population density is highest, resulting in a greater number of rooftop solar installations. As a result, the spatial distribution of solar generation across the island is relatively narrow. This increases the susceptibility of the solar PV generation profile to variation due to small pockets of cloud cover, making solar generation more variable and less predictable on short time scales.

The IE and NI networks are currently connected via a 275 kV interconnector, with a 400 kV North-South interconnector under construction to improve security of supply. The AIPS is also connected to Scotland via the Moyle interconnector from NI, and to Wales via the East West Interconnector from IE. The Celtic Interconnector will link IE and France, while the Greenlink HVDC interconnector between IE and Wales has been operational as of early 2025 (EirGrid, 2025*a*).

Both IE and NI have set targets of 80% renewable electricity generation by 2030. Although as of 2024 wind energy is the main contributor to the percentage of renewable electricity within the AIPS, the capacity for solar PV electricity generation is rapidly increasing. By 2030 IE aims to have 8 GW of solar capacity, with 2.5 GW of this attributed to rooftop solar. NI has a 2030 target of 600 MW of solar capacity with roughly 200 MW from rooftop solar (EirGrid and SONI, 2023*e*). The ambitious 2030 solar integration targets set by IE and NI face several challenges. The primary limitations to solar PV integration stem from factors such as solar variability and steep ramping requirements, midday overgeneration, limited storage and export capacity, and insufficient system flexibility. These challenges restrict how much solar PV can be accommodated on the grid, meaning actual solar penetration may remain modest despite high installed capacity.

To maintain grid stability amid these challenges, the AIPS is subject to four key operational limits: system non-synchronous penetration (SNSP), the minimum number of conventional units online (MUON), the maximum rate of change of frequency (RoCoF), and the minimum inertia floor. When these thresholds are reached, the TSO instructs controllable solar sites to reduce

output, while uncontrollable sources, such as rooftop PV, continue to inject power into the grid. The current values of these constraints and their projected changes by 2030 are shown in Table 1. Among them, SNSP, MUON, and RoCoF are most directly associated with solar curtailment. In addition to operational constraints that lead to solar curtailment, network constraints, such as limited transmission capacity for new solar sites and local voltage fluctuations caused by high concentrations of PV, also restrict the extent to which solar PV can be integrated into the grid.

Table 1: Operational constraints for the AIPS in 2023 and 2030.

Year	SNSP	MUON	Inertia floor	RoCoF
2023	75%	7 units	23 GVAs	1 Hz/s
2030	95%	3 units	20 GVAs	1 Hz/s

Dispatch down occurs as a result of either transmission constraints or curtailment due to the operational constraints. Transmission constraints are limits in the form of physical grid constraints such as maintenance and local carrying capacity, whereas a curtailment refers to one of the four aforementioned operational constraints. In 2024, 7.4% of All Island solar generation was dispatch down, with 4.1% due to curtailment compared to 2.1% in 2023 (EirGrid and SONI, 2024*b*). As solar capacity grows so does the percentage of solar generation that will be curtailed; although the evolution of operational constraints by 2030 as seen in Table 1 will allow provide a looser binding on solar penetration. It is important to note that solar PV generation is treated in the same way as wind generation in the AIPS. As a result, dispatch down levels for solar can be relatively high even though installed solar capacity remains modest, since the same curtailment mechanisms and prioritization rules apply to both solar and wind generation. This is reflected in 2024 curtailment figures, where wind power, despite having more than three times the installed capacity of solar PV and a higher capacity factor, experienced only 4.7% curtailment. This highlights the unique challenges associated with integrating solar PV into the grid.

The objective of this literature review is to examine existing research on the impacts of high shares of solar PV generation on power systems, with a focus on the AIPS. The review is structured into three sections: solar variability, minimum operational demand and ramping. In each section, the relevance of the challenge within the AIPS currently and in 2030 will be discussed. Additionally, case studies of other power systems which have encountered and overcome such challenges and their

solutions will be presented. Lastly, the applicability of these potential solutions will be determined for the AIPS.

2.2 Solar variability due to cloud cover

Solar PV exhibits yearly, daily, and short term variation in its power output. This variation is caused by the diurnal cycle of the Sun, and changes in sun irradiance due to variations in cloud cover.

A study conducted in Malaysia found power output reductions of up to 63% due to rapid changes in cloud coverage. These fluctuations occurred over short timescales, typically within seconds to minutes, and were highly localised, caused by frequent passing clouds in the region’s humid tropical climate. The study monitored a 7.2 kW grid-connected PV system and highlighted the challenges such variability poses for voltage stability and grid integration (Lim and Tang, 2014). Malaysia has a slightly higher cloud occurrence than IE (University of Washington Atmospheric Sciences, 2025), with the annual frequency of occurrence of a clear sky in Malaysia at zero and in IE between one and two days. These short term variations in power output affect generator dispatch, system balance and voltage and frequency control.

It has been shown that the variation in power output of a solar PV system decreases with increased geographical spread (Aldeman et al., 2023). This is because sites in a solar PV system with a wider geographical distribution have a lower correlation in power output i.e. the solar generation profiles do not experience the same short term variations. Consequently, the total solar output becomes more predictable. As mentioned previously, the current All Island geographical solar distribution is largely focused along the east coast of the island. Therefore, the expected solar capacity increase by 2030 should be implemented with a wider spread to mitigate against short term variations in power output and reduce forecast errors. As the number of utility-scale solar installations increases across IE and NI to meet the 2030 targets, a broader geographical spread may naturally emerge due to land availability constraints.

A study analysing the impact of high shares of wind and solar generation within the Swedish power system found that, while solar generation exhibits higher sub-hourly variation than wind, a system with both wind and solar penetration actually reduces the total variation across the two sources

(Widen, 2011). The negative correlation between wind and solar power output across both monthly and daily time scales produces a smoothing effect across the total generation profile. A similar case study of the Italian power system corroborates these findings (Monforti et al., 2014). There is 5.5 GW of installed wind capacity combined in IE and NI. By 2030 there is a target of 5.5 GW of offshore and 11.45 GW of onshore wind capacity across the island. Therefore, within the AIPS the projected combination of wind and solar penetration in 2030 may alleviate some of the inherent variations present in wind and solar PV generation.

2.3 Minimum operational demand

The diurnal cycle of the sun means that the daily peak in solar PV generation occurs at midday. However, as of 2024, demand in the AIPS is typically at one of its lowest points around midday. This is also likely to be the case in 2030, depending on how energy consumption habits evolve. This combination of high solar penetration and a droop in demand leads to a phenomenon called the ‘duck curve’. As a result, on a sunny day, demand at midday can potentially fall below the minimum operational demand limit. At this point, the number of conventional generators required by the MUON operational constraint cannot reduce their output any further, making it impossible to match the low remaining demand without curtailing the controllable share solar generation. A report published on solar curtailment in the Californian power system outlines the negatives of high percentages of solar PV curtailment, which include a reduction in revenue of the curtailed solar plant and subsequent difficulty in financing future installations due to lack of investor confidence (Golden and Paulos, 2015). Similarly, IRENA highlights that persistently high levels of curtailment can undermine the economic viability of solar PV, diminish investor support, and threaten the long-term scalability of renewable energy deployment (International Renewable Energy Agency (IRENA), 2020).

An alternative solution to solar curtailment during overgeneration is demand side management, as outlined in a report by Sambasivam and Xu (2023), which studied the reduction of solar curtailment in Karnataka, India. In an attempt to balance midday demand with solar PV generation, the state of Karnataka moved the irrigation electricity load from night time to day time. Furthermore, the state introduced an economic dispatch policy which gave priority to cheaply generated solar power.

The subsequent reduction of curtailment of solar PV resulted in an increase of the solar capacity factor from 12.7% in 2017 to 22% in 2019. Additionally, energy storage systems provide another solution to the loss of solar generation due to curtailment. A study conducted using solar data from California found that storing excess solar energy using battery energy storage systems (BESS) resulted in a 30% increase in total PV penetration, as the energy is dispatched at a time when solar generation is low (Shams et al., 2021). According to a study on the impacts of electric vehicles in conjunction with renewable energy integration, countries with large numbers of electric vehicles may benefit from vehicle to grid storage (Bogdanov and Breyer, 2024). The study found that implementing vehicle to grid energy storage could reduce the required system storage capacity by 25%.

While large scale controllable solar can be curtailed, uncontrollable small scale sources such as rooftop solar, cannot. These installations are behind the meter and unobservable from the point of view of the TSO. As the All Island rooftop solar capacity is set to increase considerably by 2030, the consequences of this must be considered. A conference paper by Moshari et al. (2024) on the expected solar integration challenges within the AIPS outlines a scenario in 2030 in which embedded rooftop solar PV is generating at maximum power on a summer’s day. This would result in a system demand profile with a severe midday dip. In such a situation, if the North-South interconnector were to trip while there is full electricity import via the current and planned interconnectors, there would be an imbalance between supply and demand, as indicated in Fig. 1.

Demand-side solutions such as that implemented in Karnataka, in India (Sambasivam and Xu, 2023), could also be implemented to combat the effects of uncontrollable distributed solar PV generation. Other potential solutions include energy storage systems, which can shift excess midday solar generation to later in the day, and interconnector export, which offers another pathway to absorb surplus solar during periods of overproduction. Studies of integrated European systems highlight the role of electricity export via interconnectors in smoothing renewable variability and reducing curtailment (ENTSO-E, 2021). Within the AIPS, enhanced interconnector capacity to Great Britain (GB) and France—via Moyle, EWIC, Greenlink, and the planned Celtic Interconnector—can allow surplus solar energy to be exported during periods of low domestic demand. However, the extent of this benefit depends on factors such as market conditions, system needs in

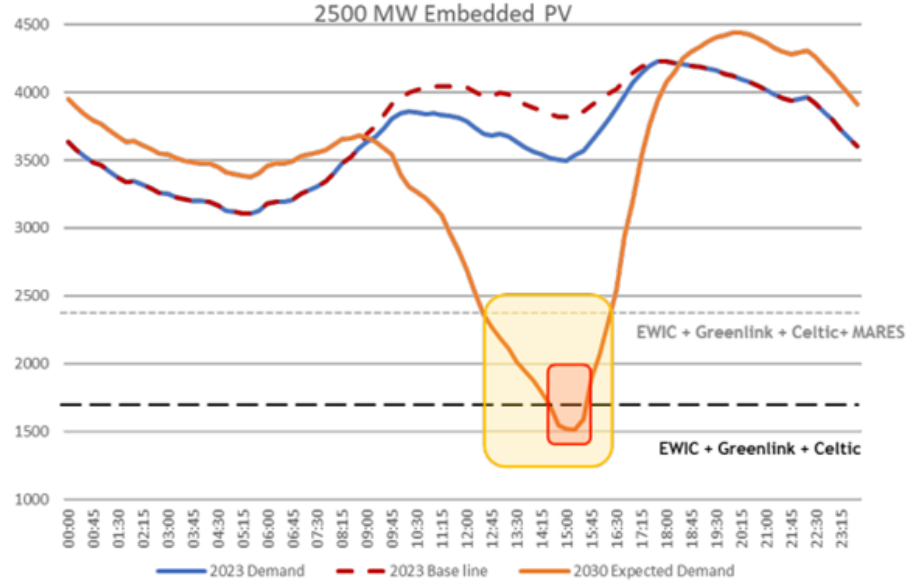


Figure 1: Potential mismatch between supply and demand in the AIPS on a sunny day in 2030 (Moshari et al., 2024).

neighbouring countries, and interconnector availability.

2.4 Ramping

Another consequence of both the duck curve and short term variations in solar PV power output is high ramp rates. This is the rate at which alternative generation must ramp up or down to compensate for a decrease or increase in solar generation coupled with an increase in system demand. Conventional generators as well as interconnectors and grids have ramp rate limits. A study conducted on the AIPS on behalf of EirGrid predicts potential 2030 evening solar PV ramp rates of up to 20 MW/min (Moshari et al., 2024). The current maximum All Island HVDC interconnector ramp rate is 10 MW/min (EirGrid and SONI, 2023c). Methods of reducing solar PV ramp rates to an acceptable level include BESS, quickly dispatchable conventional generation, curtailment, and flexible demand (Iwabuchi et al., 2025).

As mentioned previously, flexible demand can mitigate the effects of both the midday demand drop and high ramp rates. Flexible demand can include smart electric vehicle (EV) charging, smart meters, and flexible industrial demand. A study by the national energy system operator for the UK (National Electricity System Operator (NESO), 2023) found that domestic demand flexibility

could reduce peak demand by up to 10% in 2030. The largest decrease in peak household demand was seen for EV owners. In 2030, EirGrid and SONI (2023e) expect 20% flexible demand in both IE and NI. This is a combination of price-responsive EV charging and demand side units (DSU), such as industrial loads and data centres. The 2023 Climate Action Plan also recognises the importance of demand flexibility and highlights the role of smart technologies, time-of-use tariffs, and consumer engagement in enabling more responsive electricity consumption, particularly through electrified transport and heating (Government of Ireland, 2023).

A study on ramp rate control in relation to solar PV generation proposed an integrated ESS based on fluctuations in solar PV output (Alam et al., 2014). The advantages of a shared ESS are outlined in a study based on distributed PV in Australia. The study concluded that an ESS with shared ownership between consumers and the distribution system officer (DSO) can reap benefits both financially and for the successful integration of distributed solar PV systems (Keck and Lenzen, 2021).

2.5 Conclusion of literature review

As solar capacity within the AIPS increases by 2030, so will the severity of the challenges encountered. Variability and unpredictability of solar PV power output will affect generator dispatch, security of supply, and voltage and frequency stability. However, increasing the geographical footprint of solar installations alongside growing wind penetration can help mitigate this variation. Curtailment, and the subsequent storage or export of solar energy, will be necessary when minimum operational demand is exceeded. While curtailment can act as a short-term operational tool, it is generally undesirable as it reduces the effective contribution of renewable energy, leads to financial losses for solar producers, and undermines investor confidence. High ramp rates can be mitigated by battery storage and dispatch. The impact of midday peaks in solar generation and uncontrollable sources like rooftop PV can be addressed through demand-side solutions such as flexible demand and evolving energy habits. Lastly, variability in solar PV will require fast dispatch of alternative generation and an accurate unit commitment (UC) model.

3 Project aims

The aims of this project are threefold, each contributing to a comprehensive evaluation of solar PV integration within the AIPS in 2030.

The first aim is to identify and characterise the key operational and planning challenges associated with increased shares of solar PV generation. These include, but are not limited to, solar variability, steep evening ramping requirements, and minimum system demand thresholds, which can lead to curtailment. These factors may affect the ability of the AIPS to operate securely and reliably, and reduce the proportion of available solar energy that can be utilised.

The second aim is to explore and propose mitigation strategies informed by existing literature, case studies, and international best practices. These strategies target the identified challenges and may include measures such as increasing system flexibility, implementing demand-side interventions, deploying energy storage, and reducing curtailment.

The third aim is to model and simulate the 2030 AIPS to assess system behaviour under high solar PV penetration. Solar generation is represented alongside other key system inputs—such as wind generation, system demand, and thermal generation—to ensure realistic and representative results. Within this framework, selected solution strategies are implemented and evaluated based on their feasibility, effectiveness, and contribution to overall system sustainability and the increased integration of solar PV. The analysis also considers ethical aspects, including fairness, environmental impact, and potential implications for consumer costs.

Together, these aims support a deeper understanding of how solar PV can be integrated into the AIPS in a technically robust and socially responsible way, in line with IE’s and NI’s 2030 renewable energy targets.

4 Methodology

4.1 2030 solar generation

To identify the potential challenges that the AIPS will face in 2030, it is necessary to model a projection of All-Island solar PV power output. The 2030 solar capacity targets are 8,000 MW in IE and 600 MW in NI, to be achieved through a mix of small-scale systems, such as rooftop installations, and large-scale solar farms. The actual power output from each installation will depend on both the installed capacity and its geographic location. While IE has a clearly defined solar target, NI aligns with the broader 80% renewable electricity goal. Capacity projections for 2030 in NI vary, but this report adopts the 600 MW figure cited by EirGrid and SONI (2023*e*).

‘Renewables Ninja’ (Pfenninger and Staffell, 2016) is an online resource, which was used to model the yearly solar PV output of a solar installation given its location, capacity, tilt, system losses, and azimuth angle. The azimuth angle refers to the compass direction the solar PV panels face, measured in degrees from true north. Throughout the simulations described in this report, the solar panel tilt used is 35° . This is roughly the angle of a pitched roof and also the optimum tilt in IE to maximise solar generation. All installations are assumed to be south facing, with an azimuth angle of 180° (Jerez et al., 2015*a*). The system loss fraction refers to the percentage of solar energy that is lost between the PV panels and the final usable electricity output. The loss fraction used for the simulations is 0.1 as this reflects the average (Kennedy, 2023). Renewables Ninja generates the solar output using weather data from a specified year. The year used in this study was 2019. Weather years during the Covid-19 pandemic were avoided due to the unusual electricity demand patterns during this time. It should be noted that the temporal resolution of Renewables Ninja is hourly, meaning solar generation acquired did not include sub-hourly data. Renewables Ninja uses MERRA-2 climate data to produce its output, and the locational accuracy of the application depends on this dataset. MERRA-2 has a spatial resolution of approximately 0.5° latitude by 0.625° longitude, which corresponds to grid cells roughly 50 to 60 km across (Gelaro et al., 2017).

4.1.1 Large scale solar

The All Island large scale solar generation in 2030 was modelled in this report as an amalgamation of the current solar output as of November 2024, and generation attributed to the additional solar installations required to fulfil the 2030 solar capacity targets in IE and NI, which are 5500 MW and 400 MW respectively.

The capacity and location of the current large scale solar in IE and NI was acquired from the System and Renewables Data Reports available on the SONI and EirGrid websites (EirGrid, 2025*c*). The additional installations required in 2030 are assumed to be the solar farms currently under construction or in planning in IE and NI. It is acknowledged that these ‘planned’ installations may not all in reality be connected to the grid in 2030, and the final capacities may differ from those planned. As a result of these assumptions and the locational resolution of Renewables Ninja, the projected solar output used in this analysis may differ from what will be technically achievable in 2030. The names and expected capacities of solar farms yet to be connected to the grid in IE are listed in the Enduring Connection Policy (ECP) 2.3 reports provided by EirGrid and SONI (2023*b*). The 2022 Energy Constraint and Curtailment Report contains the planned controlled solar generation locations and capacities for NI (EirGrid and SONI, 2023*a*). The exact location of each installation was found with the help of the SEAI (2024) solar atlas and Google Maps. This location was translated to latitude and longitude. The capacities and location of the planned solar farms across IE and NI were input into Renewables Ninja. A data set containing the hourly solar power output was downloaded for each installation.

4.1.2 Small Scale Solar

A model for the current and future rooftop solar output in IE was independently developed using the information provided by the SEAI (2025) regarding their solar installation grants. While there are approximately 100,000 rooftop solar installations in IE currently, the SEAI have provided 62,000 solar grants. Some households and businesses do not qualify for the grant, but an assumption was made that the houses that do not qualify are evenly distributed across IE. The percentage of total rooftop solar installations per county was calculated, with the assumption that on average the installations are the same size. To model the current capacity for rooftop solar in each county this

percentage was multiplied by the current total capacity of 343 MW, and scaled to the predicted 2.5 GW. The yearly output was modelled in Renewables Ninja using one location in each county with the highest population density. For NI, a similar approach was taken. The Microgeneration Certification Scheme (MCS) provides data on the amount of rooftop solar installed per region (MCS Certified, 2025). This was converted to a percentage of the 32,000 rooftop solar installations and scaled to meet SONI’s 2030 capacity projection of 200 MW (EirGrid and SONI, 2023*e*). It was assumed that rooftop solar capacity will increase uniformly across all locations in IE and NI.

The All Island system demand provided by EirGrid for 2019 includes the effect of the uncontrollable solar rooftop supply. Therefore, when the 2030 rooftop solar supply is deducted from the demand, this deduction must exclude the rooftop solar supply of 2019. In 2019, IE had an estimated rooftop solar capacity of approximately 12 MW (Sustainable Energy Authority of Ireland (SEAI), 2019), while NI had around 100 MW (EirGrid and SONI, 2019). This 2019 generation was used to estimate and subtract hourly rooftop solar output from the total projected 2030 rooftop supply.

4.1.3 2030 All Island solar PV generation

The large and small scale hourly solar output data sets for IE and NI were concatenated and processed using Python to form the total 2030 All Island solar PV generation projection.

4.2 2030 All Island demand

To further assess the impact of solar generation on the All Island grid in 2030, the system demand model is required. As 2019 was the weather year used to simulate the 2030 solar generation, the 2019 All Island system demand WAS used as a base to model the projected 2030 demand profile. The 2019 actual All Island system demand was acquired from EirGrid (2025*b*). The scale of increase of the demand between 2019 and 2030 is based on several factors, which differ between IE and NI.

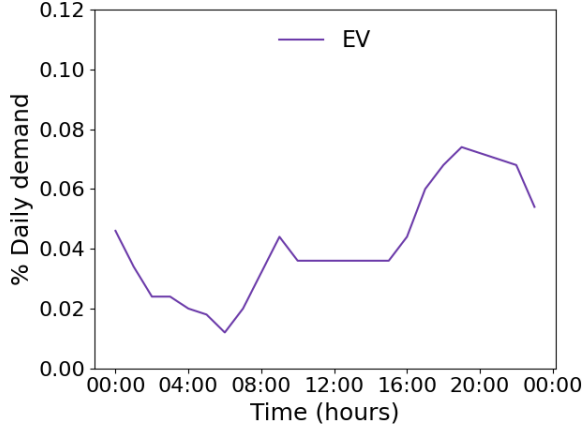
4.2.1 Irish demand

The combined residential, industrial, and commercial electrical demand increase in IE between 2019 and 2030 was modelled as a flat increase as these loads do not exhibit significant variation over time. According to the EirGrid and SONI (2024*a*) 2023 Generation capacity statement (GCS), residential

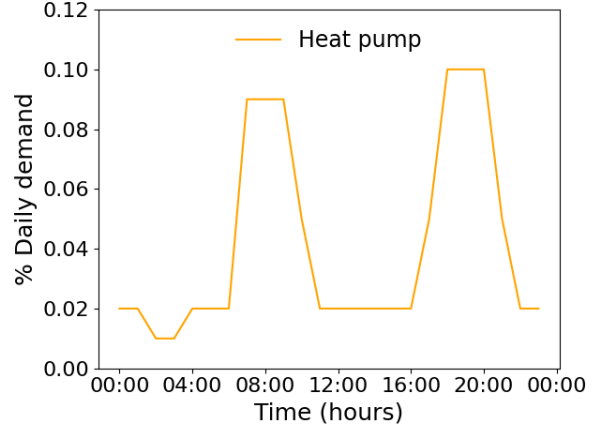
demand is set to increase by 0.39 TWh between 2019 and 2030 while industrial and commercial demand decrease by 0.36 TWh and 0.47 TWh respectively. These changes can be attributed to population growth, and an increase in the efficiency of appliances and industrial processes. Data centre and large tech demand is expected to increase by 8.97 TWh. The combined flat demand increase between 2019 and 2030 due to these four sectors is 9.41 TWh. Given that demand is assumed to be evenly distributed across all hours of the day, this results in an hourly increase of 1074.2 MW.

EV usage and subsequently EV charging demand in IE is set to greatly increase by 2030. This includes commercial vehicles such as buses as well as privately owned cars and vans. According to GCS 23 data (EirGrid and SONI, 2024a), the annual demand due to EV charging in IE is projected to increase by 2.18 TWh between 2030 and 2019 which is equivalent to 5972.6 MWh per day. The EV charging demand profile exhibits much variation and cannot be modelled as a flat demand. In Tomorrows Energy Scenarios NI 2020, SONI (2020) includes a daily EV charging distribution for the different types of EV. The daily EV demand model used in this report is based on the ‘simple’ weekday charging profiles which assume no smart charging, as well as another study on EV charging patterns based in Denmark (Ziras et al., 2024). The approximated daily distribution can be seen in Fig. 2a, with a considerable evening peak. This distribution was multiplied by the daily EV demand increase to achieve the hourly increase. It was assumed that the monthly demand profile is constant (Fig. 2c), although in reality there may be some variation due to seasonal travel patterns and temperature-related battery efficiency.

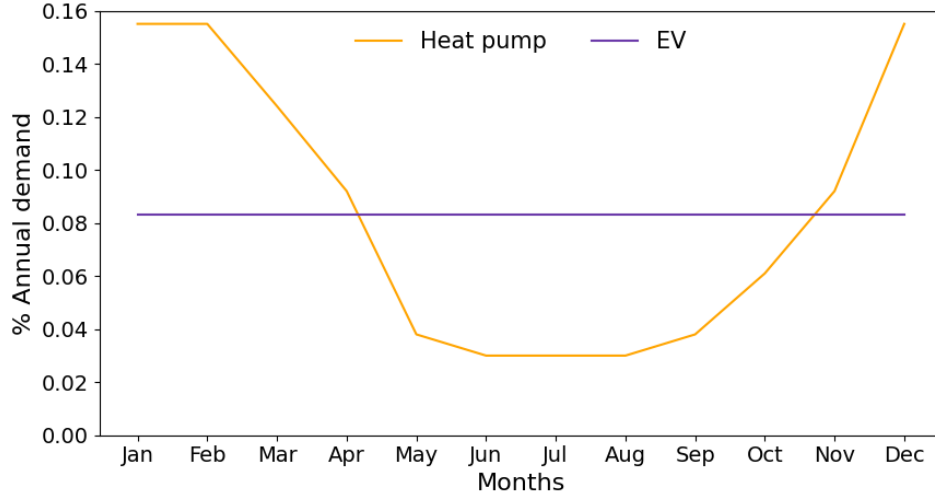
The electrification of heating in the form of heat pumps will contribute significantly to the increase of electrical demand in IE by 2030. According to the GCS 2023, the increase in demand between 2019 and 2030 which can be attributed to heat pumps is 2.63 TWh (EirGrid and SONI, 2024a). The distribution of heat pump demand varies both annually and over a 24 hour period. As before, only weekday profiles are being considered. During colder winter months the demand for heating increases. In creating the monthly distribution of heat pump usage, the Met Éireann (2025a) monthly average temperatures as well as a study on the daily trends in household heating (Wang and Mancarella, 2016) and example models in the Sustainable Energy Authority of Ireland (SEAI) (2025) guide to heat pump implementation. Additionally, it is estimated in the UK that



(a) Daily EV charging demand profile



(b) Daily heat pump demand profile



(c) Annual heat pump and EV demand profile

Figure 2: Heat pump and EV daily and annual demand variation.

approximately 60% of annual heat pump demand occurs in the months of December, January, and February (Grant UK, 2022). The final monthly and daily heat pump demand profiles can be seen in Fig. 2b and 2c, with the daily demand exhibiting significant evening and morning peaks. These distributions were used to find the variable hourly increase in demand between 2019 and 2030.

4.2.2 Northern Irish demand

According to Tomorrow's Energy Scenarios (TES) NI 20 (SONI, 2020), residential demand is projected to increase by 0.3 TWh between 2019 and 2030. This is assumed to be due primarily to heat pumps. In this analysis, the entire increase in residential demand is attributed to the increased

use of heat pumps. While factors such as improved energy efficiency and population growth also contribute to overall demand trends, these were not considered in the modelling of the demand profile. The heat pump demand profile determined in Fig. 2 was also used for NI. Tertiary demand in NI is projected by TES NI 20 to decrease by 0.3 TWh between 2019 and 2030, due to an expected increase in efficiency of appliances. Industrial demand, which includes large tech and data centres, is set to increase by 1.5 TWh. Combined, this represents a uniform increase in demand of 1.2 TWh across the year, or 137 MW per hour. SONI predicts an increase of 1 TWh of demand due to transport. In this model this report assumes that this is due to EV charging demand. The daily EV demand profile in Fig. 2a is used. The annual demand increase of 1 TWh is translated to 2740 MWh per day. This is multiplied by the demand profile to achieve the hourly demand addition between 2019 and 2030.

The All Island demand for 2030 using the 2019 weather year as a base is achieved by adding the hourly demand increases for IE and NI determined above. EirGrid estimates that there is an 8% loss as the power passes through the transmission system (EirGrid and SONI, 2024a). This is considered when calculating the final All Island demand.

4.3 2030 AIPS portfolio

To date, the impact of solar PV in the AIPS for 2030 has been examined using forecasted demand and availability data. However, a full assessment requires consideration of generation dispatch, grid flexibility, and interconnection. To achieve this, a UC (UC) programme is to be constructed to simulate system operation under these expanded conditions. As a first step, the complete power system portfolio must be defined to serve as the foundation for the UC programme. To account for modelling assumptions and the inherent uncertainty in long-term forecasts, a range of scenarios is evaluated for generation, system flexibility, and interconnection in the 2030 AIPS context.

4.3.1 Solar PV generation

Solar PV generation in the AIPS in 2030 is constrained by the solar availability profile established in Section 4.1. At any given time, solar output cannot fall below the rooftop solar availability, as this component is non-dispatchable and cannot be curtailed by the TSO. The marginal price

assigned to solar generation is €0 to prioritise dispatch of renewables within the system.

Table 2: Solar PV capacity in the AIPS in 2030.

	Solar solar PV capacity (MW)
IE	8000
NI	600

4.3.2 Wind generation

Wind generation in IE in 2030 will have a capacity of 14 GW. This consists of 5 GW of offshore and 9 GW of onshore capacity. In NI, a wind capacity of 2958 MW is predicted, 500 MW of which is offshore and 2498 MW of which is onshore wind generation according to EirGrid and SONI (2023*d*). The hourly wind power availability in 2030 is achieved by scaling the 2019 actual All Island wind power availability by the expected increase in capacity between 2019 and 2030. 2019 wind availability data is used as a base to ensure weather consistency as this was the weather year used for the 2030 demand and solar PV availability projection. The hourly 2019 wind availability in NI and IE was acquired from the EirGrid system quarter-hourly data for 2018-19 (EirGrid and SONI, 2019). While wind generation capacity in 2019 was predominantly onshore - totalling 4,113 MW in IE and 1,276 MW in NI, with just 25 MW of offshore wind in IE (EirGrid and SONI, 2020) - the 2030 AIPS anticipates a significant contribution from offshore wind. Offshore wind generation has a higher capacity factor than onshore wind, which must be taken into account when scaling to create the 2030 wind power availability. For the purpose of this study it was assumed that onshore wind has a capacity factor of 30% and offshore wind has a capacity factor of 50% (MaREI, 2023). The additional 5000 MW of capacity in IE and 500 in NI between 2019 and 2030 that is attributed to offshore wind was scaled by a factor of $\frac{5}{3}$ to account for this difference in capacity factor. The 2019 wind power availability in IE and NI was then scaled by the onshore wind capacity increase plus the adjusted offshore wind capacity increase. A distinction was not made between controllable and uncontrollable wind generation, the total 2030 capacity in NI and IE is assumed to be controllable by the TSO. The marginal price assigned to wind generation is €0 to prioritise dispatch of renewable energy.

Table 3: Onshore and offshore wind capacity in IE and NI in the AIPS in 2030.

	Median wind capacity	
	Onshore (MW)	Offshore (MW)
IE	9000	5000
NI	2498	500

4.3.3 Hydropower generation

According to EirGrid and SONI (2024a), hydropower generation in IE in 2030 will have a capacity of 242 MW comprised of 14 large hydropower units providing 216 MW of capacity and 26 MW of small scale hydro generation. The predicted capacity in NI is 6 MW of small scale hydropower. The maximum and minimum ramping limits and maximum capacity of each hydropower station in 2030 were acquired using data provided by the Single Electricity Market (SEM) PLEXOS Model Validation (SEM Committee, 2021). The minimum power output is assumed to be 0 MW. The inertia provided by each of the large hydropower units is calculated by multiplying the MVA rating and inertia constant of each unit. The MVA ratings of the hydro power plants were calculated using the maximum capacities assuming a power factor of 0.95 according to the (EirGrid, 2015). The inertia constant of the hydropower units is assumed to be 3 seconds (Muftić Dedović et al., 2024). The marginal cost of hydropower generation is acquired from SmartPower (Smart Power, 2025) who provide current marginal prices for every generating unit in the AIPS. This report assumes that any increase in marginal price in hydropower generation between 2025 and 2030 does not significantly impact the outcome of the UC programme in relation to the impact of solar PV generation.

4.3.4 Gas generation

In 2030, gas generation capacity is projected at 5,905 MW for IE and 2,151 MW for NI (EirGrid and SONI, 2024a), provided by combined cycle gas turbines (CCGT) and open cycle gas turbines (OCGT). The expected generating units were sourced from SEM Committee (2021), though these did not fully match the capacities projected by EirGrid and SONI. To align with the GCS forecasts, three additional CCGT units were added for IE and one OCGT for NI. The technical parameters of these units, including capacity, ramp rates, and minimum up/down times, were based on Tynagh Power Station’s CCGT and Kilroot’s OCGT, reflecting the most advanced technologies in the AIPS. This results in 13 CCGT and 10 OCGT units in IE, and 6 CCGT and 10 OCGT units in NI for

2030. Start-up and marginal costs were derived from SmartPower data (Smart Power, 2025), using ‘warm’ start-up costs and averaged electricity prices as marginal costs. Inertia for each unit was calculated from MVA ratings (based on a power factor of 0.85 (Electricity Supply Board (ESB), 2023)) and inertia constants of 8 seconds for CCGTs and 4 seconds for OCGTs (Meegahapola, 2014). It was assumed that cost increases between 2025 and 2030 would not significantly affect UC dispatch. Shut-down and no-load costs were excluded, as their impact on dispatch and overall system costs was considered minimal.

4.3.5 Pumped hydro storage

Energy storage in 2030 is provided by pumped hydro and battery storage systems in NI and IE. EirGrid and SONI (2024a) predicts a 292 MW pumped hydro capacity in IE in with a maximum storage duration of 5.45 hours. The efficiency of hydro storage was assumed to be 75% for both pumping and generation (National Renewable Energy Laboratory, 2022). NI is not expected to have any pumped hydro storage capacity in 2030. When generating, pumped hydro storage is a synchronous generation source providing the grid with inertia. The inertia constant and power factor of pumped hydro storage was assumed to be the same as the figures used for hydropower generation. No ramping limits were enforced on generation. The marginal price of the pumped storage was obtained from Smart Power (2025), assuming that any increase in cost between 2025 and 2030 will not significantly impact the dispatch of generation within the UC programme.

4.3.6 Battery storage

Battery storage will account for the majority of energy storage capacity in 2030 in the AIPS. A combination of short, medium and long duration storage will be available. In the SEOF report by EirGrid and SONI (2023e), the predicted battery storage capacity in IE and NI is 3225 MW and 625 MW respectively. This is contradicted by the GCS report, in which EirGrid and SONI (2023e) predict a battery storage capacity of 1010 MW in IE and 200 MW in NI. To account for this significant inconsistency, a median and a lower scenario were created. The distribution of capacity across different storage durations is provided in the SEOF report but not the GCS report. Scaling the SEOF distribution by a ratio of 1010:3225 for IE and 200:625 for NI achieved the capacities and corresponding storage durations seen in Fig. 4 in the lower scenario. The capacities outlined

by SOEF and corresponding storage durations form the median scenario.

The round trip battery efficiency was assumed to be 90% which is the average of the efficiency of batteries currently in the AIPS according to SEM Committee (2021). Ramping limits are not considered as the UC programme has an hourly time step and any ramping limitations for battery storage do not exceed one hour. The marginal price assigned to all battery storage was €0.

Table 4: The 2030 IE and NI battery storage capacities and average storage durations under median and low scenario predictions for 2030.

	Duration avg. (hours)	Median scenario (MW)	Low scenario (MW)
IE	2	800	251
IE	4	375	117
IE	6	1350	423
IE	8	700	219
NI	2	250	80
NI	4	125	40
NI	8	250	80

4.3.7 Synchronous condensers

In 2030 synchronous condensers will be used within the AIPS to produce inertia and compensate for the decrease in synchronous gas and hydro generation in favour of wind and solar power. The Moneypoint (Ulibarri, 2022) and Shannon Bridge (Siemens Energy, 2023) synchronous condensers in IE, the latter of which is set to be connected in 2027, will supply 4000 MWs of inertia each to the AIPS in 2030. Additionally in IE, in 2024 four low carbon contracts have been awarded by EirGrid (2024) for synchronous condensers which will supply a combined inertia of 6963 MWs. This combined capacity was modelled as one single condenser due to lack of information regarding individual sites. In NI two synchronous condensers have been contracted in Coolkeeragh and Coleraine according to Renewables Grid Liaison Group (2024). Information on the amount of inertia these condensers will supply is not available as of 2025. This report assumed that they will supply 4000 MWs each in line with the synchronous condensers in IE. Table 5 lists the synchronous condensers and corresponding inertia capacities assumed to be connected in 2030 and included in the UC programme. The marginal cost assigned to the synchronous condensers was 10€/MWh. This value was chosen to be cheaper than gas generation and hydropower to prioritise synchronous condensers to fulfil inertia requirements over gas generation to minimise carbon emissions without

Table 5: Synchronous condensers in operation in the AIPS in 2030 and their corresponding inertia capabilities.

	Synchronous condenser	Inertia (MWs)
IE	Moneypoint	4000
IE	Shannon Bridge	4000
IE	low carbon contracts	6963
NI	Coolkeeragh	4000
NI	Coleraine	4000

reducing potential solar and wind generation.

4.3.8 Demand side units

Demand side units are loads that can decrease and increase their demand according to the needs of the grid. In 2030 according to EirGrid and SONI (2024a), IE will have 745 MW and NI will have 237 MW of DSU capacity. 80% of this capacity in both IE and NI will have an average run time limitation of 2 hours. The remaining 20% was assumed to have no run time limitations. The marginal cost of these units were set to 70 €/MWh. This value was chosen to be higher than hydropower, wind, and solar generation, but lower than gas generation to prioritise renewable dispatch and minimise carbon emissions.

4.3.9 Flexible EV demand

Flexible demand in the AIPS in 2030 is demand which can change its distribution throughout the day in order to reduce peaks in All Island demand and ease stress on the grid. In 2030, EirGrid and SONI (2023e) predicts 400 MW and 120 MW of flexible EV demand in IE and NI respectively. This is EV demand that participates in price responsive charging. A capacity of 520 MW of EV demand at peak charging times corresponds to approximately 50% of EV demand in the AIPS in 2030. Flexible EV demand is restricted by the availability of EV charging, i.e. when EVs are plugged in. The EV daily demand distribution in Fig. 2a was modified to represent EV charging availability. This report assumed that once plugged in during the demand spike at approximately 6 pm, that the EVs remain plugged in until approximately 6 am when the drop in demand can be seen. The morning peak was not extended as this is last minute morning charging involving a plug out not long after plug in. The charging availability profile in Fig. 3a was created based on these

assumptions.

The EV demand availability distribution in Fig. 3a does not allow for flexibility of charging at midday. During the summer months, with increased solar PV generation, the penetration of renewable energy at midday will be high. As of 2025, electricity prices in the AIPS are lowest during the night (Electric Ireland, 2025). However, in 2030, high shares of renewable energy at midday could mean that electricity prices will be lower, providing an incentive for EV owners to charge at midday (ZareAfifi et al., 2025). EV owners who work from home or have workplace EV charging facilities could participate in daytime charging. Having taken this into consideration, a 2030 EV demand availability distribution with higher EV plug in around midday was formed (Fig. 3b). A study by for Transport (2022) found that 30% of EV owners can charge their EV at a workplace. Accounting for EV owners that work from home, and an increase in work places with EV chargers by 2030, this report assumed that 50% of EV owners will have access to a charger during daytime hours. The distribution in Fig. 3b was applied to the months May, June, July, and August which exhibit the highest solar PV availability hourly averages.

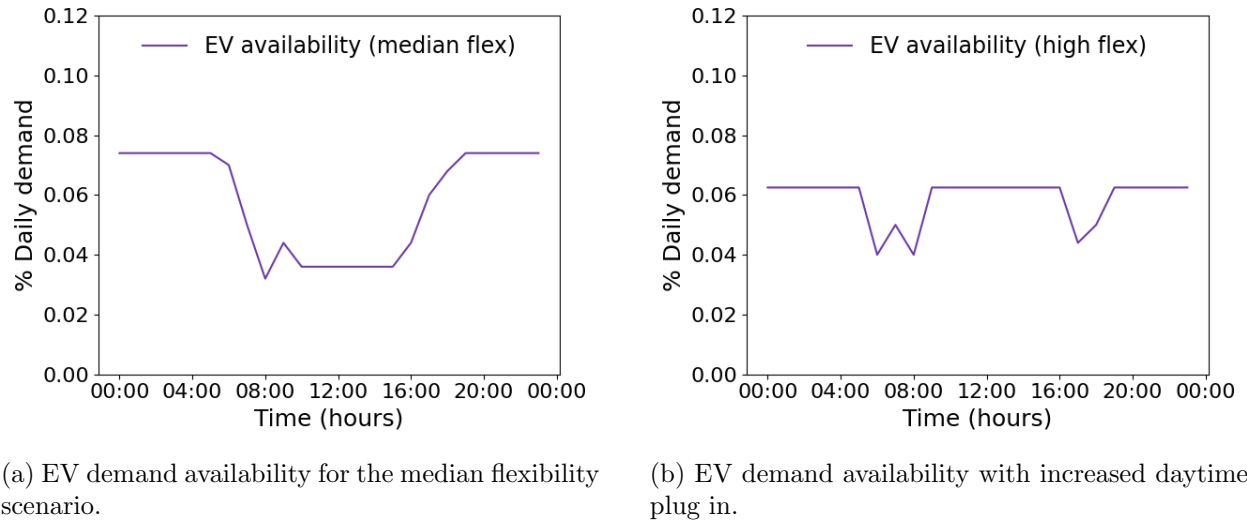


Figure 3: Daily EV demand availability distributions for two flexibility scenarios in 2030 in the AIPS.

4.3.10 V2G EV charging

Vehicle to grid (V2G) charging is an emerging trend that will be seen more commonly in 2030. V2G charging is bidirectional charging which allows EVs to not only draw power from the grid

but also to discharge stored energy back to the grid. EVs participating in V2G charging act as storage units, providing additional flexibility to the grid. There are no concrete predictions on the percentage of EVs that will be participating in V2G in 2030 in IE and NI, however an estimation can be made. A case study conducted by Siemens (2023) in Munich estimates an average of 20% of EVs with V2G charging capabilities by 2030. Due to the limited 2030 V2G predictions available the figure of 20% participation was used. The V2G EV charging was constrained by the EV plug in availability in Fig. 3a, as EVs can only participate in bidirectional charging when they are plugged in.

4.3.11 Flexible heat pump demand

EirGrid and SONI do not provide forecasts for heat pump flexibility in 2030. However, studies from Austria and the Netherlands estimate that 23–30% of heat pumps could offer grid flexibility by 2030 (Suna et al., 2022; Flexible Energy, 2019). Based on this, a conservative 20% flexibility assumption was applied to heat pump demand within the AIPS. Domestic heat storage typically lasts 12–24 hours (European Association for Storage of Energy, 2016), but assuming limited adoption, an average 6-hour storage duration was used. Accordingly, 20% of heat pump demand was redistributed, extending up to six hours prior to heat requirements. This results in the heat pump availability profile shown in Fig. 4, where the total daily demand remains unchanged, but flexible demand is shifted based on grid needs. The monthly demand distribution in Fig. 2c remains valid.

4.3.12 Interconnection

In 2030 there will be 4 HVDC interconnectors providing a connection between the AIPS and GB and France. These interconnectors and their rated capacities are shown in Table 6. A ramping limit of 10 MW/min was imposed for all interconnectors (EirGrid and SONI, 2024a). An optimistic assumption is that maximum interconnector export capacity is available at all times. However, in reality this is not the case as market factors, maintenance down time and the availability of renewable generation in France and GB must be considered.

Interconnector import data for 2024 from Elexon (n.d.) shows that the Moyle and EWIC links between GB and the AIPS experience higher electricity imports into GB during winter months. A

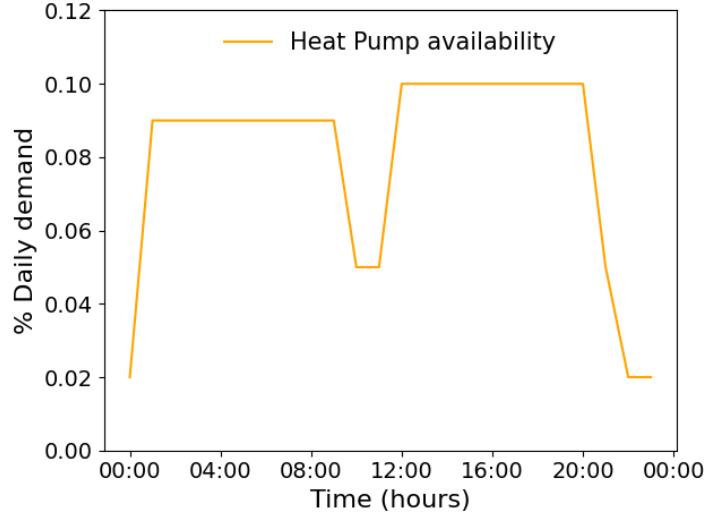


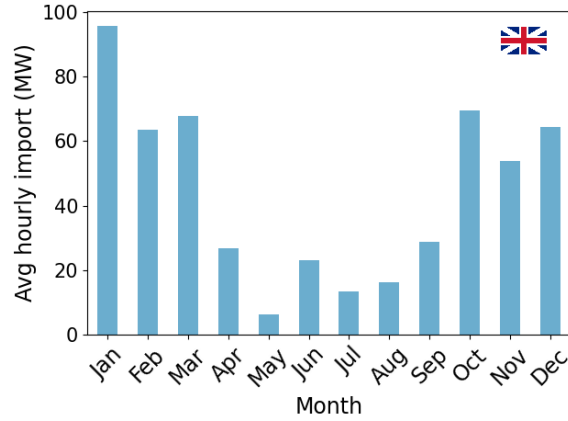
Figure 4: The heat pump flexible demand availability distribution for 50% of heat pumps in the AIPS in 2030.

Table 6: Interconnectors connecting the AIPS to GB and France in 2030.

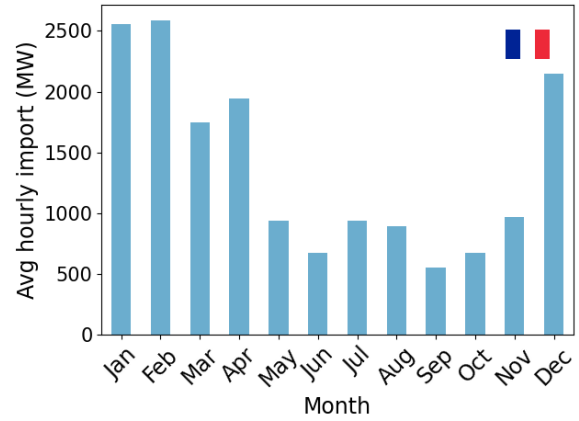
Interconnector	Connection	Capacity (MW)
Moyle	NI-Scotland	500
EWIC	IE-Wales	500
Greenlink	IE-Wales	500
Celtic	IE-France	700

similar seasonal pattern is observed for France, where total monthly interconnector imports also peak in winter and decline in summer (RTE France, 2025). Derating factors give an indication of how reliable interconnector power transfer is and what percentage of the rated capacity is reliable for import. While interconnector capacities are modelled based on rated values, derated capacities were applied to reflect historical performance and operational limitations. This approach aligns with observed trends where actual transfer capabilities can be constrained by system conditions. According to Department for Energy Security and Net Zero (2024), imports to GB from IE via interconnectors have a derating factor of 54% in the T4 auction for 2028/29. This means that just 54% of the 1500 MW interconnector export capacity to GB is deemed reliable by GB for import. Applying the monthly average import levels from Fig. 5 for the respective interconnectors to GB and France and a total annual derating factor of 54% for all interconnectors, including the Celtic interconnector, an approximate distribution for interconnector export availability for the AIPS in 2030 was formed. This monthly distribution represents the low export scenario, while the high

export scenario assumes maximum export capacity availability at all times.



(a) Electricity import in GB via the Moyle and EWIC interconnectors.



(b) Electricity import in France via all interconnectors.

Figure 5: The average hourly electricity import in GB and France via interconnectors for each month in 2024.

4.3.13 Operational constraints

In the AIPS in 2030, operational constraints will be in place to maintain stability within the grid. The operational constraint targets for 2030 according to EirGrid and SONI (2023c) are shown in Table 1. The SNSP constraint limits the amount of non-synchronous generation that can penetrate the grid at each time step. Non-synchronous generation includes wind generation, solar PV generation and battery storage discharge. The MUON constraint is the minimum number of large gas generators that can be online at any time step. In this report large gas generators include all CCGT units. The RoCoF constraint is assumed to be the change in frequency that would occur with the loss of the largest infeed at each time step. The RoCoF depends on both the size of this infeed and the level of inertia in the system.

In this report, only primary operating reserve was considered. There must be enough reserves available to cover 75% of the loss of the largest single infeed according to EirGrid and SONI (2023c). Additionally, in 2030 in IE there must be 150 MW of reserves available at each time step and in NI there must be 75 MW. Gas generators and battery storage systems provide reserve within this UC programme. The gas generators were assumed to follow a flat back reserve profile with a maximum of 15% of the generator capacity and a slope of 0.9. The maximum potential reserve

Table 7: Three possible MUON constraint scenarios in the AIPS in 2030.

	Low MUON	Median MUON	High MUON
IE	1	2	3
NI	1	1	2

supplied by battery storage systems at each time point was limited to 30% of their state of charge.

The 2030 operational constraints listed in Table 1 are targets subject to incremental trial runs between 2025 and 2030. Depending on system strength and trial outcomes, these targets may not be achieved. The SNSP limit of 95% is unlikely to be active in 2030 due to the MUON constraint of three units since the MUON ensures synchronous generation is online. Given the large synchronous condenser capacity assumed, neither the inertia floor nor the RoCoF constraint is expected to significantly limit non-synchronous generation. The MUON constraint remains the most binding for renewable integration. To assess its impact, multiple sensitivities were developed around the median MUON projection, with upper and lower scenarios shown in Table 7. A MUON of zero was excluded, as synchronous generation is still required for grid forming, which the AIPS is not expected to fully emulate by 2030.

4.3.14 General assumptions made

The 2030 AIPS portfolio was developed under several simplifying assumptions to ensure computational feasibility. Each day was modelled as a weekday, excluding weekend demand variations, and the model operated on an hourly resolution, omitting sub-hourly fluctuations. The system was treated as a single bus, with no transmission constraints or power flow across the North-South Tie-line, which likely underestimates local congestion and regional curtailment. Maintenance downtime for generators and grid assets was not considered, nor were smaller generation sources such as CHP, biomass, oil, and diesel. Electricity imports were excluded, focusing solely on internal balancing, though this likely overestimates curtailment and surplus renewable energy. Perfect forecasting for wind and solar availability was assumed to isolate the effects of system constraints and flexibility measures; however, in practice, forecast errors can significantly increase operational challenges. Collectively, these assumptions simplify the model but may lead to more optimistic results than would be observed in a real-world system.

4.4 2030 unit commitment programme

With the AIPS 2030 portfolio defined, a UC programme was implemented using the Python-based PyPSA library (Brown et al., 2018) to assess the impact of high solar PV shares. The model’s objective function aimed to optimise dispatch by minimising total operational costs in the AIPS. These included fuel, start-up, and flexibility costs from demand-side units and synchronous condensers, as outlined in Eq.1.

Each day was optimised over a 36-hour window, with only the first 24 hours retained. This overlap prevents unrealistic end-of-day behaviour, such as full storage discharge, and allows flexible EV charging to be optimised across nighttime hours. The final dispatch state of each day was carried into the next to maintain continuity.

Wind and solar were assigned zero marginal cost, while other cost parameters were defined in this section. Without locational constraints, dispatch decisions during oversupply were based solely on availability and solver behaviour.

$$C_t = \sum_{i=1}^{N_{\text{hyd-gen}}} C_{\text{hyd-gen},i} + \sum_{i=1}^{N_{\text{gas}}} C_{\text{gas},i,t} + \sum_{i=1}^{N_{\text{hyd-sto}}} C_{\text{hyd-sto},i,t} + \sum_{i=1}^{N_{\text{batt}}} C_{\text{batt},i,t} + \sum_{i=1}^{N_{\text{sync}}} C_{\text{sync},i,t} + \sum_{i=1}^{N_{\text{DSU}}} C_{\text{DSU},i,t} \quad (1)$$

Variables are determined during the optimisation process and represent the decision values calculated by the model. The variables used in the UC programme, along with their corresponding notation, are presented in Table 8.

Parameters refer to fixed input values that remain constant throughout the optimisation, such as generator capacities or efficiency ratings. Constraints define the physical, technical, and operational limitations applied to the variables, ensuring the model produces feasible and realistic outcomes. The constraints implemented in the UC programme are outlined in Eq. 2-36.

4.4.1 Demand

The hourly demand used in the UC programme is a fixed parameter, based on the 2030 projections in Section 4.2. Demand remains constant at each time step during optimisation, requiring generation

Table 8: Variables used in the UC programme as well as their corresponding notation.

Variables	Symbol
Solar PV generation	$P_{\text{solar},t}$
Wind generation	$P_{\text{wind},t}$
Gas generation	$P_{\text{gas},i,t}$
Gas unit binary status	$u_{\text{gas},i,t}$
Hydro generation	$P_{\text{hyd-gen},i,t}$
Hydro unit binary status	$u_{\text{hyd-gen},i,t}$
Synchronous condenser negligible generation	$P_{\text{sync},i,t}$
Synchronous condenser binary status	$u_{\text{sync},i,t}$
Battery storage charging	$P_{\text{bat},i,t}^{\text{ch}}$
Battery storage discharging	$P_{\text{bat},i,t}^{\text{dis}}$
Hydro storage pumping	$P_{\text{hyd-sto},i,t}^{\text{ch}}$
Hydro storage generation	$P_{\text{hyd-sto},i,t}^{\text{dis}}$
Interconnector power transfer	$P_{\text{int},i,t}$
Flexible heat pump demand	$D_{\text{HP},t}$
EV charging	$D_{\text{EV},t}^{\text{ch}}$
EV V2G discharging	$D_{\text{EV},t}^{\text{dis}}$
DSU binary commitment	$u_{\text{DSU},i,t}$
DSU demand reduction	$P_{\text{DSU},i,t}$

to match it exactly.

$$\begin{aligned}
\text{Demand}_t = & P_{\text{solar},t} + P_{\text{wind},t} + \sum_{i=1}^{N_{\text{gen}}} P_{\text{gen},i,t} + \sum_{i=1}^{N_{\text{hyd-gen}}} P_{\text{hyd-gen},i,t} + \sum_{i=1}^{N_{\text{bat}}} P_{\text{bat},i,t}^{\text{dis}} - \sum_{i=1}^{N_{\text{bat}}} P_{\text{bat},i,t}^{\text{ch}} \\
& + \sum_{i=1}^{N_{\text{hyd-sto}}} P_{\text{hyd-sto},i,t}^{\text{dis}} - \sum_{i=1}^{N_{\text{hyd-sto}}} P_{\text{hyd-sto},i,t}^{\text{ch}} - D_{\text{HP},t} - D_{\text{EV},t}^{\text{ch}} + D_{\text{EV},t}^{\text{dis}} - D_{\text{EV},t} + \sum_{i=1}^{N_{\text{DSU}}} P_{\text{DSU},i,t}
\end{aligned} \tag{2}$$

4.4.2 Solar PV generation

The parameters for solar PV generation were the rooftop solar availability and large-scale solar availability for each time step. As rooftop solar cannot be controlled by the TSO in IE or NI and therefore cannot be curtailed, the minimum solar output in the UC programme was set to rooftop solar generation:

$$P_{\text{solar,min,t}} \leq P_{\text{solar,t}} \leq P_{\text{solar,max,t}} \quad (3)$$

Table 9: Parameters in the UC programme relating to solar PV generation.

Parameter	symbol
Max solar PV generation (MW)	$P_{\text{solar,max,t}}$
Min solar PV generation (MW)	$P_{\text{solar,min,t}}$

4.4.3 Wind generation

The parameter applicable to wind generation was the hourly wind availability data set, providing a maximum wind generation for each time step. The only constraint assigned to wind power generation was maximum and minimum generation for each hour. Minimum generation was set to 0 MW as all wind is assumed controllable:

$$0 \leq P_{\text{wind}} \leq P_{\text{wind,max,t}} \quad (4)$$

Table 10: Parameters in the UC programme relating to wind generation.

Parameter	symbol
Max wind generation (MW)	$P_{\text{wind,max,t}}$

4.4.4 Hydropower generation

Hydropower units were modelled as committable generators using a binary variable indicating online (1) or offline (0) status. Key parameters included maximum and minimum power outputs, ramping limits, and inertia (Table 11). Constraints applied to hydropower generation were ramping limits (Eq. 5) and maximum power output (Eq. 6). The operational cost at each time step was calculated as the marginal cost multiplied by power output (Eq. 7).

$$-RD_{\text{hyd-gen},i} \leq P_{\text{hyd-gen},i,t} - P_{\text{hyd-gen},i,t-1} \leq RU_{\text{hyd-gen},i} \quad (5)$$

$$0 \leq P_{\text{hyd-gen},i,t} \leq u_{\text{hyd-gen},i,t} \cdot P_{\text{hyd-gen,max},i} \quad (6)$$

$$C_{\text{hyd-gen},i} = c_{\text{hyd-gen},i,t} \cdot P_{\text{hyd-gen},i,t} \quad (7)$$

Table 11: Parameters in the UC programme relating to hydropower generation.

Parameter	symbol
Max hydropower generation (MW)	$P_{\text{hyd-gen,max},i}$
Ramp up limit (MW/hr)	$RD_{\text{hyd-gen},i}$
Ramp down limit (MW/hr)	$RU_{\text{hyd-gen},i}$
Inertia (MWs)	$E_{\text{hyd-gen},i}$
Marginal cost (€/MWh)	$c_{\text{hyd-gen},i}$

4.4.5 Gas generation

Gas generation parameters are listed in Table 12. Gas units were modelled as committable generators using a binary variable indicating online (1) or offline (0) status. Constraints included maximum and minimum power output (Eq. 8), minimum up time (Eq. 10), minimum down time (Eq. 11), and ramping limits (Eq. 9).

$$u_{\text{gas},i,t} \cdot P_{\text{gas,max},i} \leq P_{\text{gas},i,t} \leq u_{\text{gas},i,t} \cdot P_{\text{gas,max},i} \quad (8)$$

$$-RD_{\text{gas},i} \leq P_{\text{gas},i,t} - P_{\text{gas},i,t-1} \leq RU_{\text{gas},i} \quad (9)$$

$T_{\text{on, gas}}$ = time step when unit was last turned on

$T_{\text{off, gas}}$ = time step when unit was last turned off

$$\sum_{t=T_{\text{on, gas}}}^{t+k} u_{\text{gas},i,t} \geq UT_{\text{gas},i} \quad \text{where} \quad k \geq UT_{\text{gas},i} \quad (10)$$

$$\sum_{t=T_{\text{off, gas}}}^{t+k} (1 - u_{\text{gas},i,t}) \geq DT_{\text{gas},i} \quad \text{where} \quad k \geq DT_{\text{gas},i} \quad (11)$$

$$C_{\text{gas},i,t} = c_{\text{gas},i} \cdot P_{\text{gas},i,t} + s_{\text{gas}} \cdot SU_{\text{gas},i,t} \quad (12)$$

$SU_{\text{gas},i,t}$ = Binary start up indicator

Table 12: Parameters in the UC programme relating to gas generation.

Parameter	symbol
Max gas unit generation (MW)	$P_{\text{gas,max},i}$
Ramp up limit (MW/hr)	$RD_{\text{gas},i}$
Min up time (hrs)	$UT_{\text{gas},i}$
Min down time (hrs)	$DT_{\text{gas},i}$
Ramp down limit (MW/hr)	$RU_{\text{gas},i}$
Inertia (MWs)	$E_{\text{gas},i}$
Marginal cost (€/MWh)	$c_{\text{gas},i}$
Start up cost (€)	$s_{\text{gas},i}$

Table 13: UC parameters relating to pumped hydro storage.

Parameter	Symbol
Maximum storage capacity (MW)	$P_{\text{hyd-sto, max, i}}$
Maximum duration (hrs)	$T_{\text{hyd-sto, i}}$
Marginal cost (€/MW)	$c_{\text{hyd-sto},i}$
Efficiency	$\mu_{\text{hyd-sto, i}}$

4.4.6 Pumped hydro storage

Pumped hydro storage was modelled as a PyPSA storage unit with parameters including marginal cost, storage duration, and capacity. Constraints included maximum charging and discharging rates (Eq. 13) and the energy balance (Eq. 14). Operational costs were applied during pumping (Eq. 15).

$$E_{\text{max,hyd-sto},i} = P_{\text{hyd-sto, max, i}} \cdot T_{\text{hyd-sto},i}$$

$$0 \leq E_{\text{hyd-sto},i,t} \leq E_{\text{max,hyd-sto},i} \quad (13)$$

$$E_{\text{hyd-sto},i,t} = E_{\text{hyd-sto},i,t-1} + \eta \cdot P_{\text{hyd-sto, i},t}^{\text{ch}} \cdot \Delta t - \frac{1}{\eta} \cdot P_{\text{hyd-sto, i},t}^{\text{dis}} \cdot \Delta t \quad (14)$$

$$C_{\text{hyd-sto},i,t} = c_{\text{hyd-sto},i} \cdot P_{\text{hyd-sto},i,t}^{\text{ch}} \quad (15)$$

4.4.7 Battery storage

Battery storage, like pumped hydro, was modelled as a PyPSA storage unit. Variables include charging and discharging power at each time step, with parameters such as marginal cost, storage duration, capacity, and efficiency. Constraints applied were the maximum energy limit (Eq. 17)

Table 14: UC parameters relating to battery storage.

Parameter	Symbol
Maximum storage capacity (MW)	$P_{\max, \text{ batt, i}}$
Maximum duratio (hrs)n	$T_{\text{batt,i}}$
Marginal cost (€/MWh)	$c_{\text{batt,i}}$
Efficiency	$\eta_{\text{batt,i}}$

and energy balance (Eq. 18). The marginal cost was applied during discharging (Eq. 19).

$$E_{\max, \text{ batt, i}} = P_{\max, \text{ batt, i}} \cdot T_{\text{batt, i}} \quad (16)$$

$$0 \leq E_{\text{batt, i, t}} \leq E_{\max, \text{ batt, i}} \quad (17)$$

$$E_{\text{batt, i, t}} = E_{\text{batt, i, t-1}} + \eta \cdot P_{\text{batt, i, t}}^{\text{ch}} \cdot \Delta t - \frac{1}{\eta} \cdot P_{\text{batt, i, t}}^{\text{dis}} \cdot \Delta t \quad (18)$$

$$C_{\text{batt, i, t}} = c_{\text{batt, i, t}} \cdot P_{\text{batt, i, t}}^{\text{dis}} \quad (19)$$

4.4.8 Synchronous condensers

Synchronous condensers were modelled as committable generators with negligible power output limits of 0.001 MW and an inertia parameter. Their operation was represented by a binary variable indicating online or offline status. When online, they provided inertia at their specified MWs value. A marginal cost of 10,000 €/MW was assigned, resulting in a total cost of 10 €when online, as defined in the AIPS portfolio (Eq. 21).

$$u_{\text{sync, i, t}} \cdot P_{\text{sync, neg, i, t}} \leq P_{\text{sync, i, t}} \leq u_{\text{sync, i, t}} \cdot P_{\text{sync, neg, i}} \quad (20)$$

$$C_{\text{sync, i, t}} = c_{\text{sync, i}} \cdot P_{\text{sync, neg, i, t}} \quad (21)$$

Table 15: UC parameters relating to synchronous condenser operation.

Parameter	Symbol
Negligible power output (MW)	$P_{\text{sync, neg, i, t}}$
Inertia (MWs)	$E_{\text{sync, i, t}}$
Marginal cost (€/MWh)	$c_{\text{sync, i}}$

4.4.9 Demand side units (DSU)

Within the UC programme, DSUs were modelled as two generators: one representing 80% of units with a run-time restriction and the other representing the remaining 20% without restrictions. Although DSUs reduce demand, they were represented as generators with positive power output equivalent to the demand reduction (Eq. 22) and were committable via a binary variable. Parameters included maximum and minimum power output, along with a maximum run time for 80% of capacity (Table 16). Operational costs were calculated as the marginal cost multiplied by the DSU power output (Eq. 24). Constraints included a minimum up time, applicable only to the 80% of units with restricted operation (Eq. 23).

$$0 \leq P_{\text{DSU},i,t} \leq P_{\text{DSU},\text{max},i,t} \cdot u_{\text{DSU},i,t} \quad (22)$$

$T_{\text{on}, \text{DSU}}$ = time step when DSU was last reducing demand

$$\sum_{t=T_{\text{on}, \text{DSU}}}^{t+k} u_{\text{DSU},i,t} \leq UT_{\text{DSU},i} \quad \text{where} \quad k \geq UT_{\text{DSU},i} \quad (23)$$

$$C_{\text{DSU},i,t} = -c_{\text{DSU},i} \cdot P_{\text{DSU},i,t} \quad (24)$$

Table 16: Parameters in the UC programme relating to DSU operation.

Parameter	symbol
Max demand decrease (MW)	$P_{\text{DSU},\text{max},i}$
Max up time (hrs)	$UT_{\text{DSU},i}$
Marginal cost (€/MWh)	$c_{\text{DSU},i}$

4.4.10 Flexible EV demand

In this UC programme, flexible EV demand was modelled to support least-cost optimisation, equivalent to price-responsive charging. Flexible charging was represented as a link to an external bus with a maximum power transfer capacity defined by the charging availability profile (Eq. 25). EVs were modelled as a single battery at this external bus. Constraints ensured that total daily charging matched the fixed daily EV demand for 50% of vehicles (Eq. 28). Additionally, the state of charge at the end of each nighttime and daytime charging period was constrained to match the

level without flexibility, ensuring a full charge (Eq. 26, Eq. 27).

$$0 \leq D_{EV,t}^{\text{ch}} \leq D_{EV,\text{max},t} \quad (25)$$

$$\sum_{t=t1}^{t2} D_{EV,t}^{\text{ch}} = SOC_{EV, \text{night}} \quad (26)$$

$$\sum_{t=t3}^{t4} D_{EV,t}^{\text{ch}} = D_{EV, \text{day}} \quad (27)$$

$$\sum_{t=1}^{24} D_{EV,t}^{\text{ch}} = D_{EV, \text{total}} \quad (28)$$

t1 = start of nighttime charging period

t2 = end of nighttime charging period

t3 = start of daytime charging period

t4 = end of daytime charging period

Table 17: Parameters in the UC programme relating to flexible EV demand.

Parameter	symbol
Maximum EV demand (MW)	$D_{EV, \text{max},t}$
EV morning state of charge (MW)	$D_{EV, \text{day}}$
EV evening state of charge (MW)	$D_{EV, \text{night}}$
EV daily demand (MW)	$D_{EV, \text{total}}$

4.4.11 V2G EV charging

V2G charging was modelled as an additional link enabling power transfer from the EV battery (representing flexible demand) back to the grid. The link's maximum capacity was set by the flexible EV demand distribution for the proportion of EVs participating in V2G. Total daily EV demand remained unchanged (Eq. 32), ensuring that any power discharged to the grid was recharged to the EVs. This constraint was also applied to the nighttime and daytime charging periods (Eq. 30, Eq. 31).

$$0 \leq D_{EV,t}^{\text{dis}} \leq D_{EV,\text{max},t}^{\text{dis}} \quad (29)$$

$$\sum_{t=t1}^{t2} D_{EV,t}^{ch} - D_{EV,t}^{dis} = SOC_{EV, \text{ night}} \quad (30)$$

$$\sum_{t=t3}^{t4} D_{EV,t}^{ch} - D_{EV,t}^{dis} = D_{EV, \text{ day}} \quad (31)$$

$$\sum_{t=1}^{24} D_{EV,t}^{ch} - D_{EV,t}^{dis} = D_{EV, \text{ total}} \quad (32)$$

Table 18: Parameters in the UC programme relating to flexible V2G EV charging.

Parameter	symbol
Maximum EV discharge (MW)	$D_{EV, \text{ max}, t}^{dis}$

4.4.12 Flexible heat pump demand

Similar to flexible EV demand, flexible heat pump demand was modelled as a link to an external bus with an associated battery. The link's maximum transfer capacity was constrained by the heat pump availability distribution for the proportion of demand participating in flexibility (Eq.34). Total daily heat pump demand remained fixed (Eq.33).

$$\sum_{t=1}^{24} D_{HP,t} = D_{HP, \text{ total}} \quad (33)$$

$$0 \leq D_{HP,t} \leq D_{HP, \text{ max}, t} \quad (34)$$

Table 19: Parameters in the UC programme relating to flexible heat pump demand.

Parameter	symbol
Maximum heat pump demand (MW)	$D_{HP, \text{ max}, t}$
Total daily demand (MW)	$D_{HP, \text{ total}}$

4.4.13 Interconnection

Interconnection in the 2030 UC programme was optimised separately from the main AIPS model. Surplus renewable generation from the AIPS was input to a dedicated interconnector programme, where surplus dispatch was optimised across the four interconnectors. Exported power included only wind and solar surplus, excluding any discharge from battery storage. Interconnectors were

modelled as links, constrained by maximum and minimum capacity (Eq. 35) and ramping limits (Eq. 36), with a minimum transfer capacity of 0 MW, as only power export was considered.

$$0 < P_{\text{inter},i,t} < P_{\text{inter,max},i} \quad (35)$$

$$-R_{\text{inter},i} \leq P_{\text{inter},t} - P_{\text{inter},t-1} \leq R_{\text{inter},i} \quad (36)$$

Table 20: Parameters in the UC programme relating to interconnector flow.

Parameter	symbol
Maximum interconnector flow (MW)	$P_{\text{inter, max},i}$
Ramping limit (MW/hr)	$R_{\text{inter},i}$

4.4.14 Global Constraints

A global constraint in the UC programme refers to a system-wide condition rather than one applied to individual units. This includes operational constraints required to maintain grid stability. Inertia is supplied by synchronous condensers and synchronous generators, including hydropower and gas units. The total system inertia provided by these units is:

$$E_{\text{total},t} = \sum_{i=1}^{N_{\text{gas}}} E_{\text{gas},i} \cdot u_{\text{gas},i,t} + \sum_{i=1}^{N_{\text{hyd-gen}}} E_{\text{hyd-gen},i} \cdot u_{\text{hyd-gen},i,t} + \sum_{i=1}^{N_{\text{hyd-sto}}} E_{\text{hyd-sto},i} \cdot u_{\text{hyd-sto},i,t} + \sum_{i=1}^{N_{\text{sync}}} E_{\text{sync},i} \cdot u_{\text{sync},i,t}$$

The total system inertia at each time step must be greater than the inertia floor limit:

$$E_{\text{total},t} > \text{Inertia floor} \quad (37)$$

The RoCoF limit constraint was implemented as follows, where the loss of the largest infeed is (ΔP) and f_o is the grid frequency of 50Hz.

$$-\text{RoCoF} < \frac{\Delta P}{2E_{\text{total},t}}(f_o) < \text{RoCoF} \quad (38)$$

The MUON constraint was separately enforced for IE and NI CCGT units:

$$\sum_{i=1}^{N_{\text{Lgas-IE}}} u_{\text{Lgas-IE},i,t} \geq \text{MUON IE} \quad (39)$$

$$\sum_{i=1}^{N_{\text{Lgas-NI}}} u_{\text{Lgas-NI},i,t} \geq \text{MUON NI} \quad (40)$$

The constraint enforcing the SNSP limit within the programme is defined as:

$$P_{\text{non-sync},t} = P_{\text{wind},t} + P_{\text{solar},t} + \sum_{i=0}^{N_{\text{bat}}} P_{\text{bat},i,t}^{\text{dis}} \quad (41)$$

$$\frac{P_{\text{non-sync},t}}{\text{Demand}_t} < \text{SNSP}$$

It was assumed that primary operating reserve in the AIPS is supplied by gas generators, battery storage, and pumped hydro units. Reserve requirements were subject to the maximum contributions of each technology type, as specified in the AIPS generation portfolio.

$$R_{\text{total},t} = \sum_{i=1}^{N_{\text{gas}}} \min(0.15(P_{\text{gas,max},i}), 0.9(P_{\text{gas,max},i} - P_{\text{gas},i,t})) + \sum_{i=1}^{N_{\text{bat}}} 0.3P_{\text{bat},i,t}^{\text{soc}} + \sum_{i=1}^{N_{\text{hyd-sto}}} 0.3P_{\text{hyd-sto},i,t}^{\text{soc}} \quad (42)$$

$$R_{\text{total, NI},t} \geq 75MW \quad (43)$$

$$R_{\text{total, IE},t} \geq 150MW \quad (44)$$

5 Results and discussion

5.1 Geographical spread

The projected 2030 geographical spread of large scale solar in IE represents a significant increase in comparison to 2024 (Fig. 6), however, in NI very little change is observed. Overall however, this is a positive trend as IE will make a significantly higher contribution to All Island solar capacity in 2030. As outlined in the literature review, a wider spread of solar installations decreases the short term variability of the power output. In terms of rooftop solar, this study assumed consistent growth across all regions so the distribution shows no change with installations concentrated in cities and large towns. This study found that there are an additional 92 large scale solar installations required in IE and 12 in NI to meet 2030 targets.

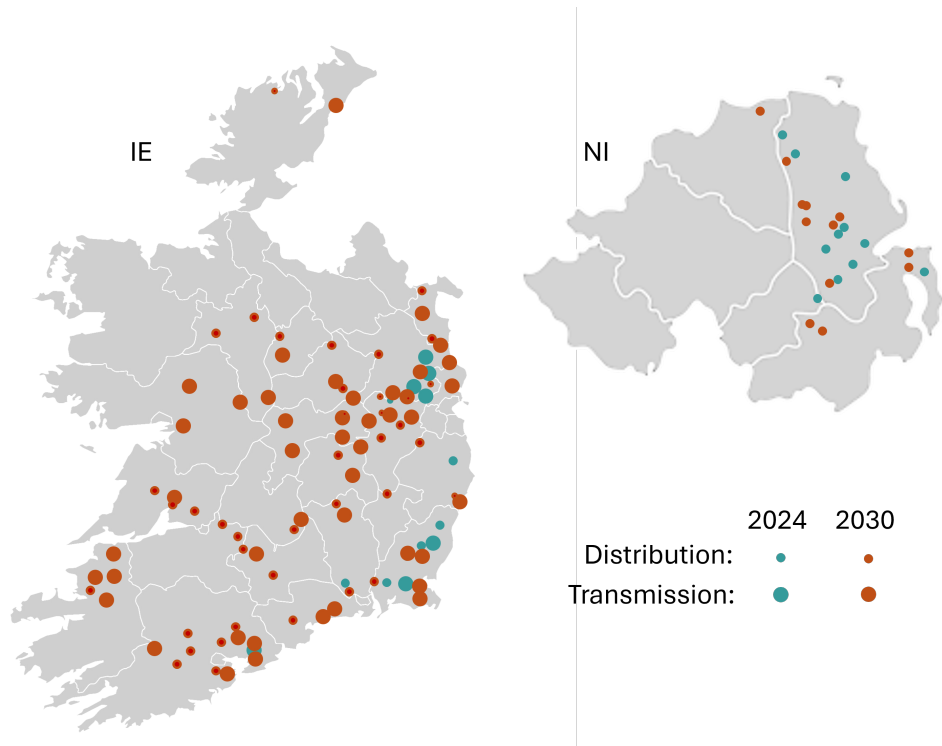


Figure 6: Distribution of large scale solar PV installations in NI and IE in 2024 and additional installations required by 2030.

5.2 Demand

All Island Demand for a summer's day (excluding rooftop solar generation) as shown in Fig. 7 is projected to increase considerably by 2030, with morning and evening peaks reaching almost

6.5 and 7.5 GW respectively. The uniform increase in demand, including midday levels, results from growth in data centre and industrial demand, while the additional peaks in demand can be attributed to increased usage of EVs and heat pumps. summer's day is used to illustrate the evolution in All Island demand as this is when solar PV generation is most impactful on the AIPS. As this is a summer's day these peaks can be largely attributed to EV charging rather than heat pump usage.

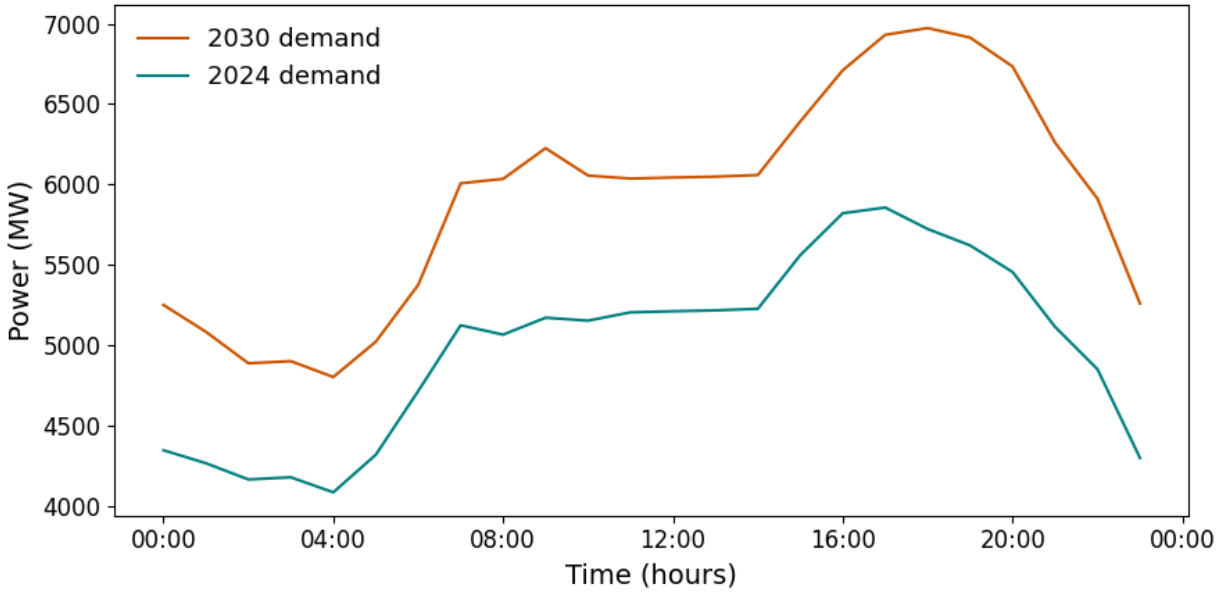


Figure 7: All Island demand (excl. rooftop solar) for a summer day in 2024 and 2030.

5.2.1 Potential solutions

Shifting the demand profile toward a flatter shape can be facilitated through the implementation of flexible demand, EV smart charging, and changes in consumer electricity usage.

5.3 Duck curve

The actual All Island demand profile as seen by the TSO is the system demand minus rooftop solar generation. Fig. 8 shows the expected impact of rooftop solar generation on All Island demand in 2030. The duck curve is clearly visible, with midday demand dropping to approximately 4000 MW. This is primarily a seasonal issue, most evident during sunny summer days, when solar output is highest and overall demand is relatively low.

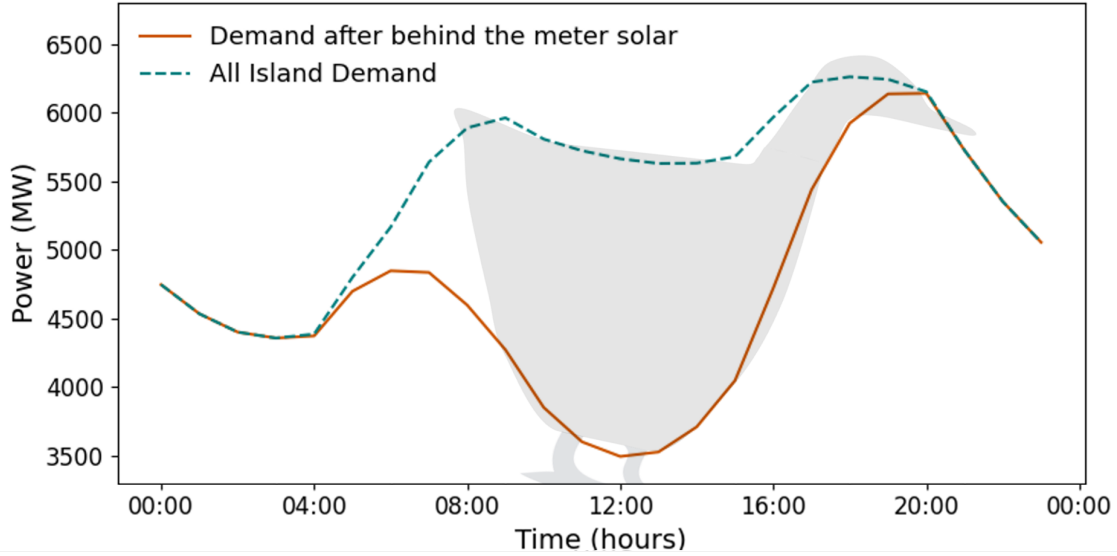


Figure 8: All Island demand on a summer day in 2030 with and without the effects of rooftop solar which creates the duck curve effect.

5.3.1 Potential solutions

As rooftop solar generation is uncontrollable, demand side solutions such as those discussed in section 5.2 can be implemented. Accurate scheduling of alternative generation through UC and economic dispatch will be necessary to ensure a balance between supply and demand as there is significant variation in demand seen throughout a day.

5.4 Full solar penetration

The effects of the duck curve are more evident with full solar penetration on a summer's day, as seen in Fig. 9. In this instance, midday demand has dropped to approximately 250 MW. Due to the 2030 All Island MUON constraint of three units this midday dip could breach the minimum operational demand, depending on the minimum power output of the conventional generators online. Additionally, the sharp evening decrease in solar generation in the evening coupled with the 2030 evening demand peak results in a steep ramp rate of 23 MW/min. As mentioned in the literature review, the maximum interconnector ramping is 10 MW/min. The ramp rate of alternative generation depends on the conventional generators online in 2030.

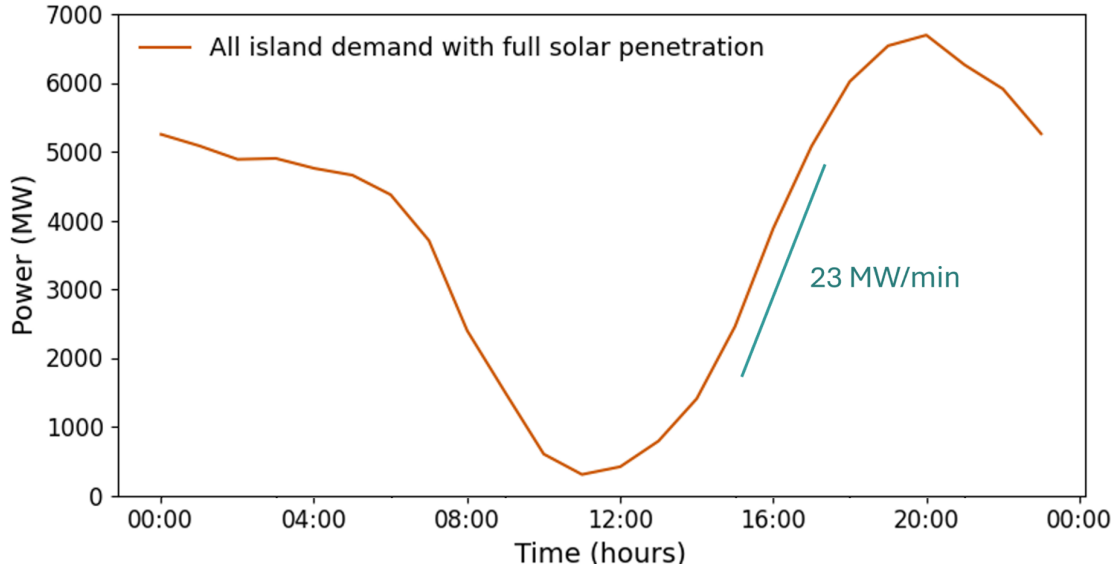


Figure 9: All Island demand in 2030 after full solar penetration on a summer's day with a ramp rate of 23 MW/min.

5.4.1 Potential solutions

Once again, demand side solutions will help to flatten the 2030 demand profile. These measures would both increase midday demand and decrease the ramp rates. Excess solar generation during midday can be stored and later dispatched in the evening, when solar output drops sharply, through the use of ESSs. To avoid wastage of midday solar energy it can also be exported via interconnectors providing ramp rates have been minimised.

5.5 Solar variability

This study does not include sub-hourly variation in demand, which can negatively affect voltage and frequency stability within the system. However, significant hourly variation in All Island solar generation in 2030 has been seen, producing high ramp rates and threatening the MUON operational constraint. Furthermore, day to day variation in solar output in 2030 will be considerable. Fig. 10 illustrates a potential difference of nearly 5000 MW in peak solar generation between two consecutive days in September 2030, driven by varying cloud cover conditions. This level of day-to-day variation presents operational challenges for forecasting, scheduling generation, and ensuring system flexibility.

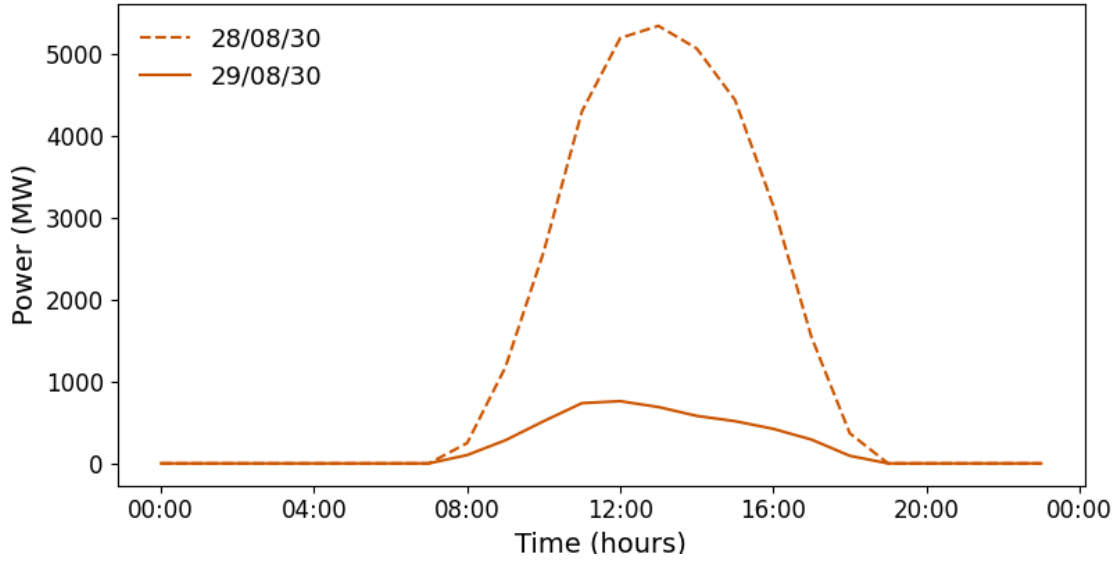


Figure 10: All Island solar generation in 2030 for two consecutive days, 28/08 and 29/08.

5.5.1 Potential solutions

Significant day-to-day variation in solar PV generation, as seen in Fig. 10, may or may not be predictable depending on the accuracy of weather forecasts. In some cases, forecasts may be partially accurate, allowing for limited adjustments rather than full scheduling certainty. When variation is predictable, the scheduling of conventional generation, wind generation, and energy storage systems such as battery storage and pumped hydro can be planned in the day ahead market. When it is not, measures such as solar curtailment, storage activation, or export through interconnectors may be required. These fluctuations highlight the importance of accurate UC scheduling within the AIPS, along with the availability of quickly dispatchable electricity sources.

5.6 Unit commitment results

The challenges and potential solutions associated with high shares of solar PV in the AIPS in 2030, as outlined in Sections 5.2 to 5.5, are evaluated through the implementation of a UC programme. A base scenario serves as the foundation for a series of sensitivity analyses, each designed to assess the impact of specific mitigation measures and account for the various potential outcomes in 2030.

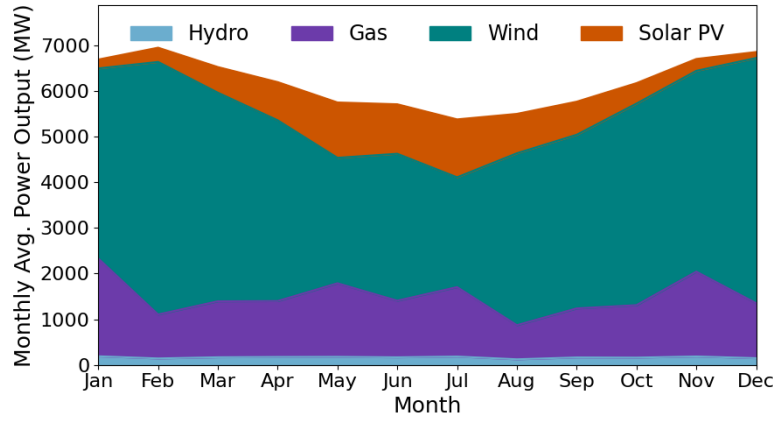
5.6.1 Base scenario

The base scenario is defined by the following parameters as detailed in Section 4.3:

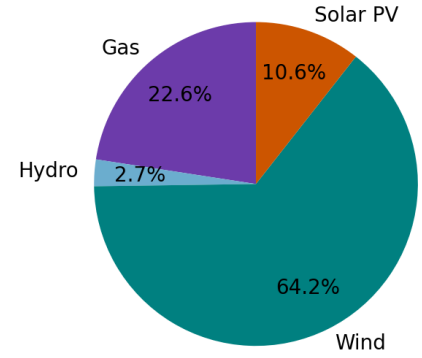
- Median demand flexibility
- High export capacity
- High storage capacity
- Median MUON constraint

Based on the selected parameters, the base scenario reflects an optimistic outlook for the AIPS in 2030. Table 21 presents the wind and solar PV metrics from the UC optimisation. As both are assigned equal dispatch priority, their curtailment, surplus, and export values are combined. The renewable electricity share (RES-E) refers to the percentage of demand met by wind, solar PV, and hydropower. Unused wind and solar power is the portion of available renewable energy not used for generation or export. Surplus represents the share of wind and solar that exceeds demand and interconnector capacity in a given hour, excluding what is used for charging storage. Curtailment is the share that cannot enter the grid due to UC constraints. Combined, surplus and curtailment equal total unused power. Both IE and NI aim for 80% RES-E by 2030, but this scenario achieves 77.43%, falling slightly short. Fig. 11 illustrates the average hourly generation mix across each month of the year (Fig. 11a) and the total percentage of electricity demand met by each generation source in 2030 (Fig. 11b). The monthly average generation mix shows that wind power dominates the system throughout the year, maintaining consistently high output. Solar PV contributes more noticeably during summer months.

Figure 12 shows available and generated wind and solar power alongside demand on the 2030 day with both the highest RES penetration and the highest unused RES. The high level of unused renewable energy is primarily due to surplus, though curtailment also contributes, which is evident from the gap between wind generation and demand in the morning and evening. At midday, uncontrollable rooftop solar forces a reduction in wind output to maintain system balance. The example of this day highlights the potential for wind and solar to meet nearly all AIPS demand, constrained only by system operational constraints.



(a) The average hourly generation mix for each month.



(b) The percentage demand covered by each generation source.

Figure 11: The generation mix in the AIPS in 2030 for the base scenario.

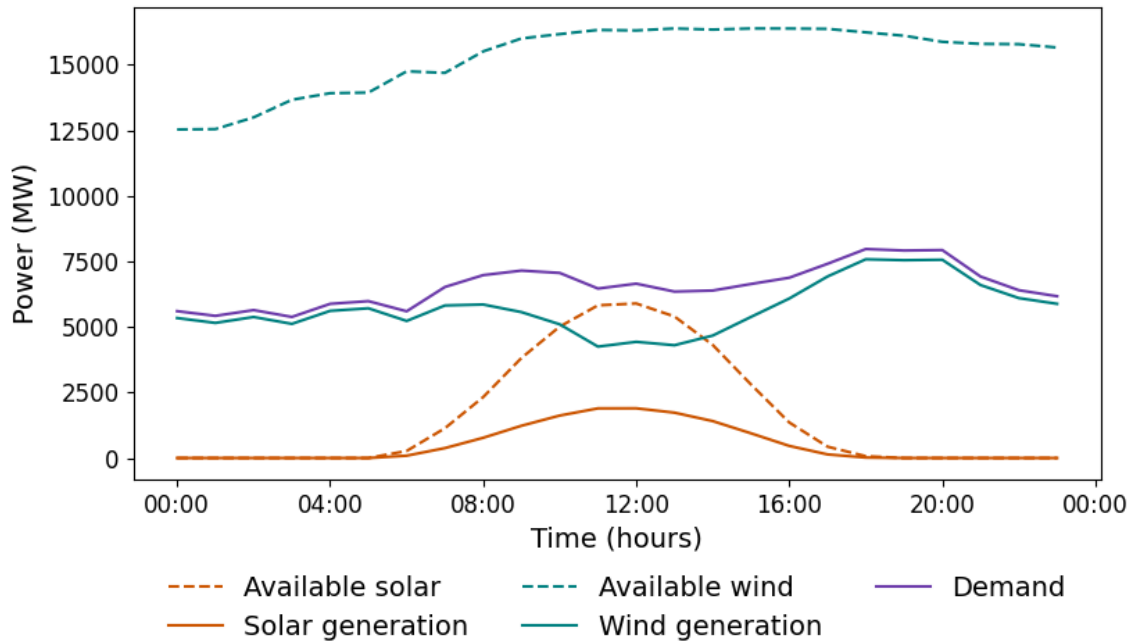


Figure 12: Wind and solar generation and availability and demand in the AIPS on the day with the highest RES penetration in 2030 (13/04/30) under the base scenario.

Table 21: Wind and solar power generation metrics for the base scenario in the AIPS in 2030.

	Base scenario
Curtailed	5.356%
Surplus	12.431%
Unused	17.787%
Export	13.470%
RES-E demand share	74.775%

5.6.2 Flexible demand sensitivity

The flexible demand scenarios are as follows:

- Low flexibility - No EV charging or heat pump demand flexibility
- Median flexibility - EV charging and heat pump demand flexibility implemented
- High flexibility - Daytime EV charging availability increased

The percentage of unused wind and solar power decreases as flexibility increases as can be seen in Table 22. As a result, the RES-E percentage also increases. In Fig. 13a and 13b EV charging on a summers day against CO₂ intensity is plotted for the median and high flexibility scenarios respectively. CO₂ intensity is the CO₂ emissions produced by the AIPS per MWh of electricity demand. In the median flexibility scenario, EV demand does not align with times of low carbon intensity. However, in the high flexibility scenario when daytime charging is incentivised, EV charging aligns with the midday solar PV spike, during which the carbon intensity is much lower. Subsequently, the morning and evening CO₂ intensity reduces. Fig. 14 plots All Island demand demand for a summers day for the three flexibility scenarios. The high flexibility scenario results in a significantly flattened demand profile with a reduced evening peak. The median scenario exhibits some reduction in peak demand but not as effectively as is seen with increased daytime charging. Demand flexibility is successful in reducing unused wind and solar PV power. By shifting demand to times of day when wind and solar power are more available and by reducing the steep evening demand peaks curtailment and surplus wind and solar power are reduced.

5.6.3 Storage sensitivity

Increased storage capacity decreases the share of unused wind and solar power as outlined in Table 23. Both surplus and curtailment are reduced as the energy storage systems store wind and solar

Table 22: Wind and solar power generation metrics for three different levels of demand flexibility in the AIPS in 2030.

	Low flexibility	Median flexibility	High flexibility
Curtailed	5.446%	5.356%	5.245%
Surplus	12.511%	12.431%	12.375%
Unused	17.957%	17.787%	17.619%
Export	13.645%	13.470%	13.382%
RES-E share	77.042%	77.433%	77.598%

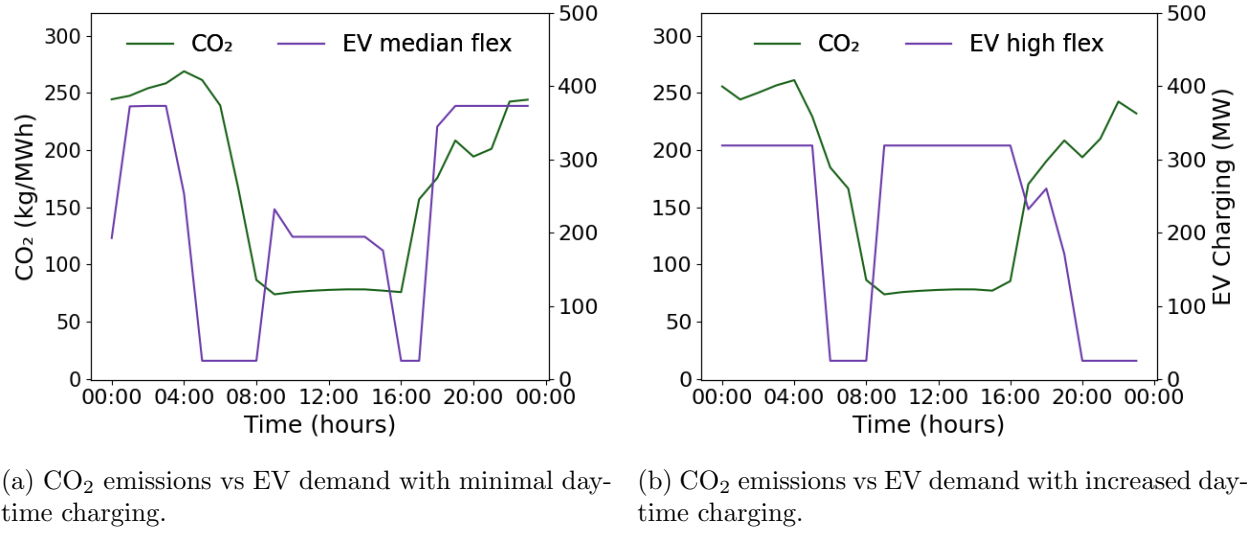


Figure 13: CO₂ intensity in the AIPS for a summers day in 2030 (04/07/30) vs EV charging demand for two demand scenarios.

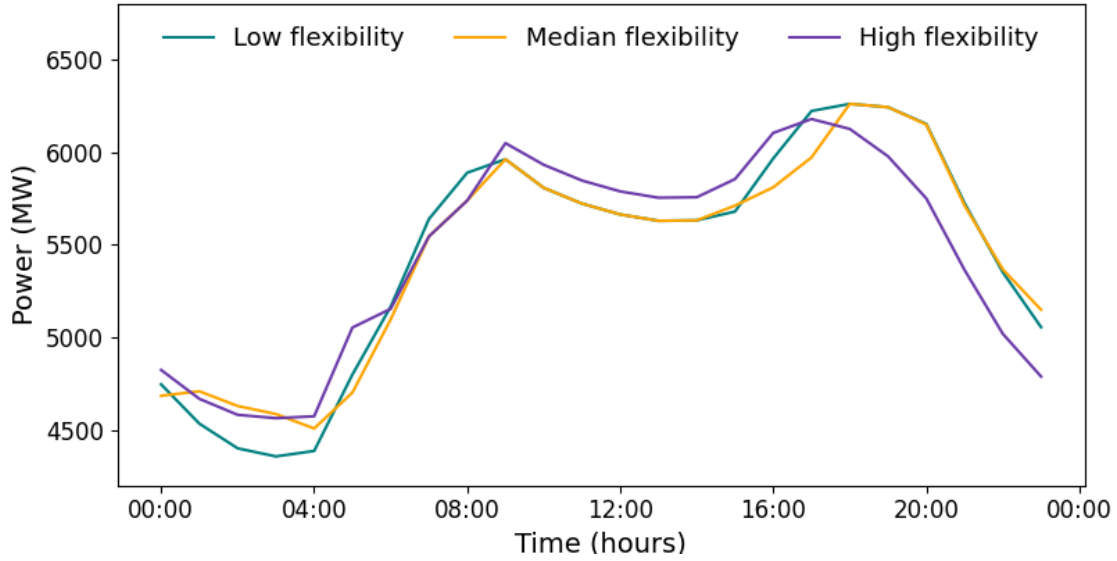


Figure 14: All Island demand on a summers day in 2030 (03/07/30) with no heat pump or EV demand flexibility, some EV and heat pump flexibility, and increased EV daytime charging flexibility.

power that would otherwise be curtailed or a surplus. Fig. 16 illustrates this for a summers day with high solar availability. At midday when the available solar power exceeds demand, the excess power is used to charge the energy storage systems. This power then is discharged in the evening when solar power is no longer available, providing quickly dispatchable power to compensate for the steep ramp down of solar. On this particular day, wind availability is low, increasing the necessity of storage systems to increase RES penetration outside daylight hours. Fig. 15 shows the average hourly charging power of storage units in the AIPS in 2030 under the high and median storage capacity scenarios. In the high storage case, average charging peaks during the winter months, aligning with high wind availability. However, notable charging activity also occurs during the summer, despite lower overall renewable availability. This reflects the need for storage to manage the variability of solar generation. In contrast, the median storage scenario shows peak charging during the summer months, highlighting that lower storage capacity is less effective at absorbing high wind output and is more influenced by solar-driven variability.

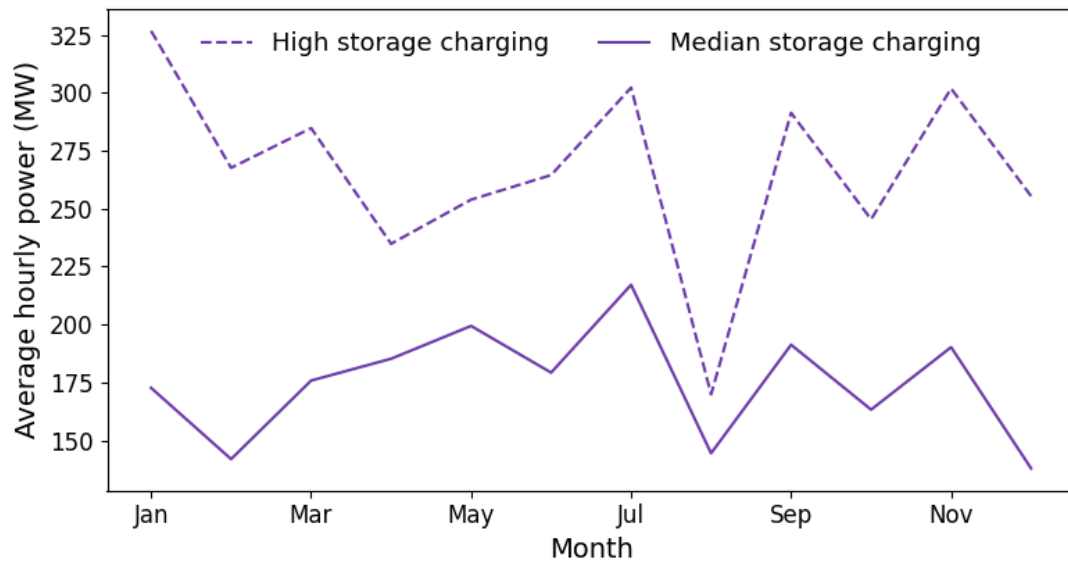


Figure 15: The average hourly charging of energy storage units for each month in the AIPS in 2030 under the median and high storage scenarios.

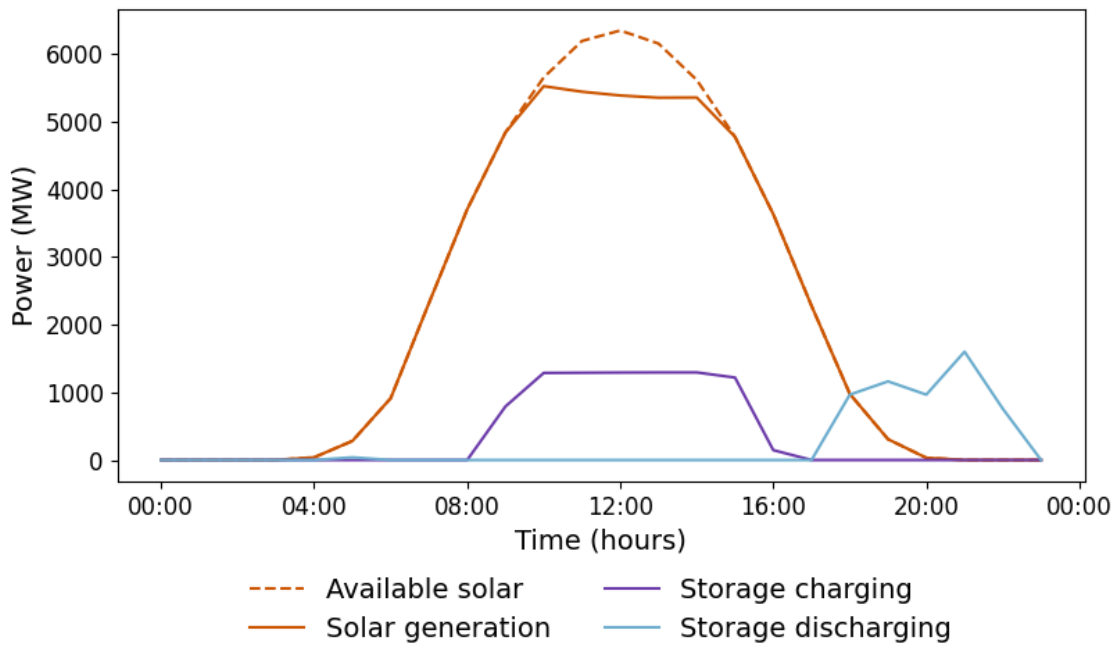


Figure 16: Solar PV generation and availability and storage charging and discharging in the high storage scenario for a summers day (03/07/30) in the AIPS in 2030.

Table 23: Wind and solar generation metrics under two storage scenarios.

	Median storage capacity	High storage capacity
Curtailed	5.501%	5.356%
Surplus	12.445%	12.431%
Unused	17.946%	17.787%
Export	13.618%	13.470%
RES-E share	77.112%	77.433%

5.6.4 Interconnector export sensitivity

Electricity export via interconnectors is an effective means of reducing surplus wind and solar power. As shown in Table 24, the scenario with lower derated interconnector capacity results in a reduced share of exported renewable energy and a corresponding increase in surplus power. Fig. 17 presents the average hourly available wind and solar generation alongside interconnector exports for both high and low export capacity scenarios. Notably, the distribution of average export power throughout the year in the low export scenario closely mirrors that of the high export scenario. This suggests that electricity import and export trends with France and GB align well with periods of excess renewable energy in the AIPS. While the export profile does not align with peak solar PV output in the summer months, this is of limited consequence given that the vast majority of surplus energy originates from wind generation. Overall, the AIPS would benefit significantly from increased interconnector capacity, as even in the high export scenario, the monthly average surplus from wind and solar exceeds the average exported power in every month.

Table 24: Wind and solar PV power export and waste power in the AIPS in 2030 for full export capacity and a derated export capacity.

	Low interconnector export	High interconnector export
Curtailed	5.2446%	5.2446%
Surplus	16.213%	12.431%
Unused	21.458%	17.757%
Export	9.800%	13.470%

5.6.5 MUON sensitivity

The MUON constraint ensures grid stability by requiring a minimum number of synchronous generators to provide inertia and frequency control. This limits the reduction of fossil-based generation, especially during periods of high solar output and low demand. While reducing the MUON con-

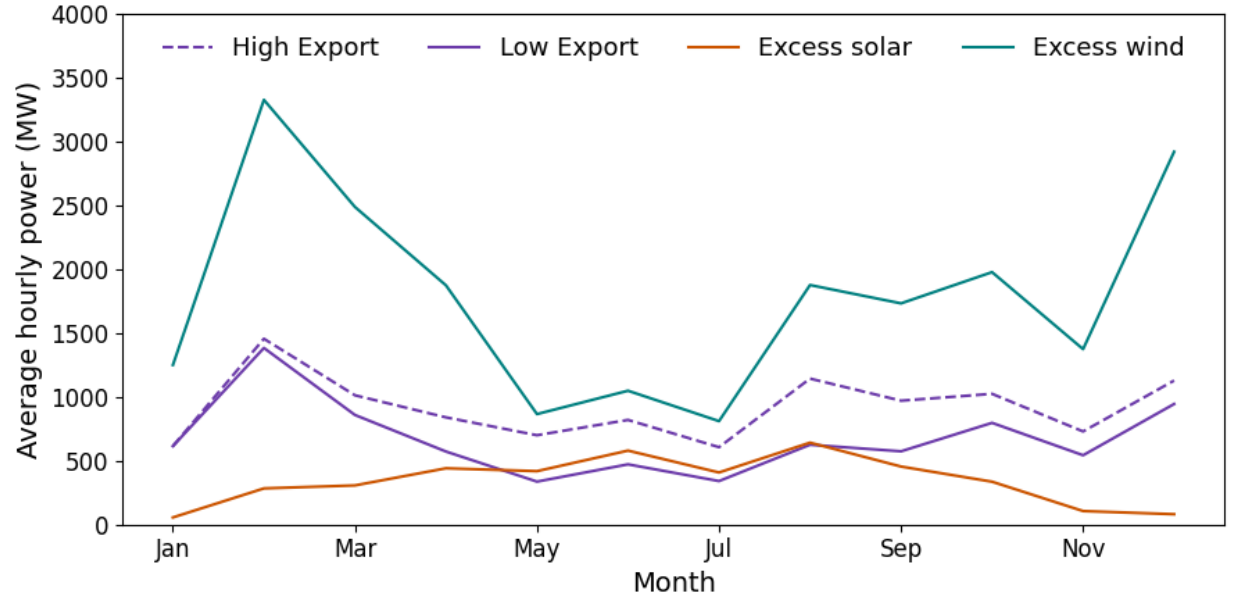


Figure 17: Average monthly interconnector export, and excess wind and solar power available for export in 2030 in the AIPS for the derated interconnector capacity scenario.

Table 25: Wind and solar generation metrics under two MUON constraint scenarios.

	Low MUON	Median MUON	High MUON
Curtailed	5.341%	5.356%	6.615%
Surplus	12.428%	12.431%	11.767%
Unused	17.769%	17.787%	18.382%
Export	13.468%	13.470%	13.596%
RES-E share	77.904%	77.433%	76.299%

straint had a small effect on the total unused wind and solar power, it did increase the RES-E share noticeably. This is because the share of hydro power generation has increased from 2.66% to 3.11%, meaning there is still a need for synchronous generation. Because one less large gas unit is required, hydropower can fulfil the inertia and RoCoF constraint instead of the additional CCGT unit, increasing the overall share of hydropower generation. If the MUON constraint were potentially reduced to zero in a scenario past 2030, hydropower generation within the AIPS could be used to provide grid forming services. While the total percentage unused wind and solar power increases under the high MUON scenario, the surplus power does the opposite. This is because a larger portion of unused renewable energy is classified as curtailment, due to stricter operational constraints that prevent generation.

5.7 Final discussion

This study examined the challenges associated with integrating high levels of solar PV into the AIPS by 2030, focusing on operational limitations such as variability, steep ramping, and midday overgeneration, which conflict with system constraints and result in unused renewable generation. Using a UC model, the analysis quantified both curtailment, defined as the portion of renewable generation that could otherwise have penetrated the grid but is not used due to operational constraints, and surplus generation, defined as the portion of available renewable generation that is not dispatched to the grid or exported.

Across all modelled scenarios, combined wind and solar curtailment ranged from 5.25% to 6.62%, with the highest curtailment occurring under the high MUON scenario. This confirms that the minimum number of conventional units online remains a binding constraint for renewable integration within the AIPS. The lowest level of curtailment was observed under the high demand flexibility scenario. Furthermore, the reduction in curtailment between the median and high storage cases suggests that further increases in storage capacity could continue to lower curtailment. Interestingly, the low MUON scenario did not yield the lowest level of curtailment, as other constraints, such as inertia floor and RoCoF, became binding when synchronous generation was reduced. Curtailment represents both an operational inefficiency and an economic cost, as €0 marginal cost renewable electricity is left unused despite reliance on more expensive gas powered backup generation. In

addition to implementing further flexibility and storage solutions within the AIPS, the most effective method of reducing curtailment is the relaxation of operational constraints such as MUON. However, this cannot be successfully achieved without the deployment of grid-forming technologies and enhanced frequency control capabilities, which would otherwise be provided by conventional synchronous generation.

The share of total unused wind and solar generation, including both curtailment and surplus, ranged from 18.38% to 21.43% across all scenarios. The base case scenario, which resulted in 17.619% unused energy, represents an optimistic outcome based on favourable assumptions such as high storage and export capacities as well as median flexible demand. The share of surplus wind and solar generation alone varied between 12.38% and 16.21%, with the higher value corresponding to the most realistic scenario in which derated interconnector capacities were applied. This surplus arises when available renewable generation exceeds both demand and the system's capacity to export. While increased storage capacity and flexible demand contributed to a modest reduction in surplus power, the most effective strategy for managing surplus identified in this study was interconnector export. This highlights the potential for the AIPS to act as a major exporter of renewable electricity in 2030 and beyond, provided that sufficient interconnection capacity is in place. However, current and planned interconnector capacity may not be adequate to absorb excess renewable energy during peak generation periods, leaving significant quantities of wind and solar power unutilised.

The 2024 Climate Action Plan in IE set a 2030 dispatch down target of 7% (Sustainable Energy Authority of Ireland, 2025). Dispatch down includes the reduction in wind and solar power due to curtailment, surplus and physical transmission and maintenance constraints. There is no information available regarding dispatch down targets in NI. In this study, the lowest level of unused renewable energy observed was 17.62%, more than double the IE target. It is important to note that this value reflects idealised assumptions, including unconstrained transmission, which likely underestimate real-world levels of dispatch down. In reality, physical transmission constraints, maintenance outages, and the slow pace of network upgrades would further limit renewable utilisation within the AIPS. These findings suggest that without significant improvements in both grid infrastructure and operational practices, current policy targets may be unachievable.

Reducing curtailment and surplus renewable generation is essential for increasing the effective penetration of solar PV and maximising the return on infrastructure investments. Persistent high levels of unused wind and solar power not only reflect technical inefficiencies but also pose economic and strategic risks. If renewable energy continues to go unused despite high installed capacities, investor confidence in both solar PV and wind power may weaken. This could reduce revenue expectations for developers, hinder investment viability, and ultimately slow the pace of deployment. Without adequate investor support, IE and NI may struggle to meet their 2030 renewable electricity targets of 80%. Furthermore, underutilisation of renewable capacity places additional pressure on other generation sources, often resulting in higher system costs and increased emissions.

The results of the implemented UC programme demonstrate that, with adequate system flexibility, both curtailment and surplus generation can be reduced. Enhanced grid flexibility, achieved through demand-side response, energy storage systems, and interconnector exports, is key to increasing renewable utilisation. Shifting demand through smart charging and flexible loads can help align system demand with peak solar output. Storage systems can capture excess generation and release it during evening ramps or low-generation periods, and interconnection with neighbouring systems provides an additional layer of flexibility. All of this shows that there is a potential to reduce the share of unused wind and solar power further than the values achieved in this study.

Although none of the scenarios assessed in this report achieved the 80% RES-E target in isolation, the target may be attainable through the inclusion of electricity imports, which were not considered in this study. It should also be noted that the assumption of perfect forecasting for wind and solar generation, and the exclusion of transmission constraints, likely results in an optimistic view relative to real-world conditions.

This project demonstrates that integrating high levels of solar PV within the AIPS is technically feasible but requires addressing several interconnected operational and planning constraints. The modelling results provide a clearer understanding of how solar generation interacts with system limitations and grid flexibility infrastructure. They also highlight key areas where future improvements, such as enhanced flexible demand deployment, storage optimisation and increased interconnector capacity, can strengthen system performance and sustainability.

6 Ethics and Sustainability

6.1 Sustainable Development Goals

Solar PV plays a central role in achieving several UN Sustainable Development Goals (SDGs) (United Nations, 2025), particularly SDG 13: Climate Action. As outlined throughout this report, solar PV supports the shift away from fossil fuels by enabling low-carbon electricity generation. In regions where electricity is primarily fossil-based, such as in the study by Tawalbeh et al. (2021), each kilowatt-hour of solar PV generation can reduce CO₂ emissions by up to 0.53 kg. However, the carbon footprint associated with the manufacture, installation, and end-of-life disposal of PV panels is not negligible. According to Mehedi et al. (2022), life-cycle emissions range between 20 and 60 gCO₂-eq per kWh, depending on panel technology and system conditions. Material extraction also contributes substantially to these emissions. With an operational lifespan of 20 to 30 years, the global increase in solar PV integration is projected to result in 9 million metric tonnes of PV waste by 2050 (Vellini et al., 2017). This raises important concerns regarding SDG 12: Responsible Consumption and Production. Nonetheless, advances in end-of-life recycling processes have demonstrated potential to significantly reduce the overall environmental impact (Vellini et al., 2017).

Solar PV is now among the most cost-effective energy sources (International Energy Agency (IEA), 2025), aligning strongly with SDG 7: Affordable and Clean Energy. While its production carries environmental costs, its operation yields clean electricity with no direct emissions. Solar PV also supports SDG 3: Good Health and Well-Being and SDG 11: Sustainable Cities and Communities by reducing air pollution and facilitating cleaner urban energy systems. Furthermore, it contributes to SDG 8: Decent Work and Economic Growth, with 4.9 million jobs globally in 2023, making it the fastest-growing sector in the renewable energy industry (International Renewable Energy Agency (IRENA), 2023).

SDG 15, focused on life on land and biodiversity, is also relevant to solar PV deployment. Among all generation technologies, solar PV has one of the highest land-use footprints (Tawalbeh et al., 2021). In IE and NI, this creates tension between the expansion of renewable energy and agricultural land use. While solar installations on farmland can provide greater economic returns (The Agriculture

and Food Development Authority (Teagasc), 2025), they may negatively impact local ecosystems during construction (Pimentel da Silva and Branco, 2018). Agrivoltaics, the dual use of land for both agriculture and solar generation, offers a promising compromise, supporting food security while improving farm income (Joint Research Centre (JRC), 2023).

6.2 Future Reliability of Solar PV

As a variable, weather-dependent resource, solar PV presents inherent challenges to system reliability. Ensuring a stable and secure electricity supply is an ethical responsibility for system operators. This project evaluates the integration of high levels of solar PV into the AIPS and finds that, with appropriate grid flexibility and sufficient wind generation, solar PV can contribute a substantial share to the overall generation mix and support decarbonisation targets. However, the analysis does not consider forecast uncertainty or rare but impactful weather events such as prolonged anti-cyclones, which are high pressure systems that can lead to prolonged periods of low wind, or solar eclipses, which may introduce operational difficulties and reduce the predictability of solar output.

Climate change could further influence the long-term reliability of solar PV by altering patterns of solar irradiance and cloud cover. Rising sea levels may also reduce the amount of land available for ground-mounted PV installations. Additionally, increasing weather volatility will intensify temporal variability and forecasting uncertainty in solar generation. On a global scale, irradiance variability is expected to increase, with generation potential rising in parts of the southern hemisphere while declining in regions of the northern hemisphere. In IE and NI specifically, annual solar output may decrease by 5 to 10% compared with 2015 levels (Jiang et al., 2023; Jerez et al., 2015b).

These ethical and sustainability considerations underline the importance of designing solar integration strategies that not only meet technical requirements but also align with broader environmental and societal goals. Addressing these issues is essential to delivering a secure, low-carbon energy future for the AIPS.

7 Conclusion

This study investigated the operational challenges and system impacts of integrating high levels of solar PV generation into the AIPS by 2030. Using a UC model alongside projections of the future system, the analysis identified key barriers to maximising solar PV utilisation, including the inherent variability of solar output, midday overgeneration, and operational constraints such as MUON.

The results highlight that while solar PV capacity expansion is vital to meeting IE's and NI's renewable electricity targets, it is not sufficient on its own. Without complementary investments in demand-side flexibility, energy storage, and interconnector capacity, significant portions of wind and solar generation risk going unused. These inefficiencies not only delay progress toward renewable targets but also undermine the economic value of renewable infrastructure, potentially affecting investment confidence. Furthermore, the gap between modelled renewable utilisation and policy goals, such as the Climate Action Plan's 7% dispatch down target, underscores the scale of infrastructure improvement required within the AIPS.

To enable higher solar PV integration, coordinated action is needed across system design, operational practices and policy. This includes relaxing operational constraints through advanced grid technologies, enhancing frequency control, and introducing incentives that reward grid flexibility. While this study provides framework for understanding these dynamics, future research incorporating transmission constraints, forecast uncertainty, and alternative weather scenarios will be essential for refining system assessments. Ultimately, the successful integration of solar PV into the AIPS hinges not only on capacity growth but also on aligning infrastructure, technology, and policy to deliver a resilient and sustainable energy system.

8 Proposed future work

Due to time limitations, this study relied on a number of simplifying assumptions to prioritise the development and execution of a working UC model. As a result, several potentially valuable paths of analysis were not explored. Future work could involve incorporating transmission constraints, which would allow for a more realistic representation of congestion and regional bottlenecks within the AIPS. Additionally, including electricity imports from interconnected systems could provide a more accurate assessment of the system's ability to reach the 80% RES-E target, particularly during periods of low renewable availability. Incorporating 2030 demand and wind and solar availability based on different base weather years could also provide insight into how varying weather conditions affect system performance and reliability.

Further analysis could also account for the forecastability of wind and solar power, enabling a more realistic assessment of reserve requirements and operational flexibility needs. Another area of interest would be to differentiate between storage systems based on duration, to evaluate the relative benefits of short-term vs. long-duration storage in reducing curtailment and managing variability. Finally, an investigation into the optimal mix of wind and solar capacity that minimises curtailment while maximising renewable generation could provide valuable insight for planning future RES deployment.

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A Unit commitment Python PyPSA code for the base scenario

```
# Importing the necessary libraries

import pypsa
import pandas as pd
import numpy as np


# Uploading all of the relevant data sets
# Reading in the demand data frame (which excludes flex EV and HP demand)
# as well as full demand
demand_df = pd.read_csv("smart_AI_demand_2030_19.csv",
on_bad_lines='skip')
no_flex_demand_df = pd.read_csv("AI_demand_2030_19.csv",
on_bad_lines='skip')
demand_df.columns = ["time_date", "demand"]
demand = demand_df["demand"].tolist()


no_flex_demand_df.columns = ["time_date", "demand"]
no_flex_demand = no_flex_demand_df["demand"].tolist()
time_date = demand_df["time_date"].tolist()


# Reading in the heat pump monthly distribution
HP_m = open("HP_profile.csv", 'r', encoding="utf-8-sig")
lines = HP_m.readlines()
HP_monthly = [float(line.replace('\uff', ' ').strip()) for line in lines]
HP_m.close()


# Gas generator parameters
# IE CCGT
L_IE_gas_df = pd.read_csv("L_IE_gas.csv", header=0, on_bad_lines='skip')
L_IE_gas_df.columns = ["Loc", "name", "type", "fuel", "min_cap",
"max_cap", "ramp_up", "ramp_down", "min_up", "min_down",
"MVA", "H", 'fuel_cost', 'start_cost']
```

```

# IE OCGT
S_IE_gas_df = pd.read_csv("S_IE_gas.csv", header=0, on_bad_lines='skip')
S_IE_gas_df.columns = ["Loc", "name", "type", "fuel", "min_cap",
                        "max_cap", "ramp_up", "ramp_down", "min_up", "min_down",
                        "MVA", "H", 'fuel_cost', 'start_cost']

# NI CCGT
L_NI_gas_df = pd.read_csv("L_NI_gas.csv", header=0, on_bad_lines='skip')
L_NI_gas_df.columns = ["Loc", "name", "type", "fuel", "min_cap",
                        "max_cap", "ramp_up", "ramp_down", "min_up", "min_down",
                        "MVA", "H", 'fuel_cost', 'start_cost']

# NI OCGT
S_NI_gas_df = pd.read_csv("S_NI_gas.csv", header=0, on_bad_lines='skip')
S_NI_gas_df.columns = ["Loc", "name", "type", "fuel", "min_cap",
                        "max_cap", "ramp_up", "ramp_down", "min_up", "min_down",
                        "MVA", "H", 'fuel_cost', 'start_cost']

# Hydropower parameters
hydro_pumped_df = pd.read_csv("2030_hydro.csv", header=0,
on_bad_lines='skip')
hydro_pumped_df.columns = ["Loc", "name", "type", "fuel", "min_cap",
                            "max_cap", "ramp_up", "ramp_down", "min_up", "min_down",
                            "MVA", "H", 'cost']

# Pumped hydro parameters
hydro_df = pd.read_csv("2030_hydro_pumped.csv", header=0,
on_bad_lines='skip')
hydro_df.columns = ["Loc", "name", "capacity", "MVA", "H", "cost"]

nominal = 20000 # Nominal power for solar and wind

# Wind availability

```

```

wind_df = pd.read_csv("AI_2030_available_wind.csv", on_bad_lines='skip')
wind_df.columns = ["time_date", "power"]
wind = wind_df["power"].tolist()

# Solar availability
solar_df = pd.read_csv("Total_all_island_solar.csv", header=0,
on_bad_lines='skip')
solar_df.columns = ["time_date", "power"]
solar = solar_df["power"].tolist()

# Day 0 is optimised outside the loop as the initial hour paramters must
# be added manually
day_num = 0
for day in range(364):
    # updating indexes for new day
    day_num += 1
    # The optimisation starts at the start of each day
    index_start = day_num*24
    index_end = index_start + 24
    # Optimising over 36 hours (12 hour overlap)
    n = pypsa.Network(snapshots=time_date[0:36])

    # ----- BUS, DEMAND, CARRIERS -----

    # One bus represents the entire AIPS
    n.add("Bus", "bus", overwrite=True)

    n.add("Load", "load", bus="bus", p_set=demand[index_start:index_end],
    overwrite=True) # All Island demand

    n.add( # Adding the different types of generation
        "Carrier",
        ["large IE gas", "small IE gas", "large NI gas", "small NI gas",

```

```

"solar", "hydro", "wind", "DSU_long",
"DSU_short", "hydro_storage", "battery_storage", "sync"],
overwrite=True)

# ----- Synchronous Condensers -----

n.add(
    "Generator",
    "Money point",
    bus="bus",
    p_nom=0.01,
    p_max_pu=1,
    p_min_pu=1, # The output does not go above or below 0.001 MW,
    ensuring marginal price of \eur 10
    carrier='sync',
    committable=True, # Binary variable
    inertia=4000, # Inertia provided when on (MWs)
    overwrite=True,
    marginal_cost=1000
)

n.add(
    "Generator",
    "Shannonbridge",
    bus="bus",
    p_nom=0.01,
    p_max_pu=1,
    p_min_pu=1,
    carrier='sync',
    committable=True,
    inertia=4000,
    overwrite=True,
    marginal_cost=1000
)

```

```

)

n.add(
    "Generator",
    "Coolkeeragh",
    bus="bus",
    p_nom=0.01,
    p_max_pu=1,
    p_min_pu=1,
    carrier='sync',
    committable=True,
    inertia=4000,
    overwrite=True,
    marginal_cost=1000
)

```

```

n.add(
    "Generator",
    "Coleraine",
    bus="bus",
    p_nom=0.01,
    p_max_pu=1,
    p_min_pu=1,
    carrier='sync',
    committable=True,
    inertia=4000,
    overwrite=True,
    marginal_cost=1000
)

```

```

n.add(
    "Generator",
    "Low carbon",

```



```

        bus="bus",
        p_nom=0.01,
        p_max_pu=1,
        p_min_pu=1,
        carrier='sync',
        committable=True,
        inertia=6963,
        overwrite=True,
        marginal_cost=1000
    )

# ----- DSU -----

# 20% OF DSU have no up time limitations
n.add(
    "Generator",
    "DSU_long",
    committable=True,
    bus="bus",
    carrier='DSU_long',
    marginal_cost=70,
    p_max_pu=1,
    p_min_pu=0,
    p_nom=196.4, # Capacity of demand reduction of DSU
    overwrite=True
)

# 80% OF DSU have up time limitations
n.add(
    "Generator",
    "DSU_short",
    bus="bus",
    carrier='DSU_short',

```

```

        committable=True,
        marginal_cost=70,
        p_max_pu=1,
        p_min_pu=0,
        p_nom=785.6, # Capacity of demand reduction of DSU
        overwrite=True
    )

# ----- GAS GENERATION -----

# Looping through all of the CCGT units in IE
# parameters retrieved from the uploaded data frame
for index, row in L_IE_gas_df.iterrows():
    n.add(
        "Generator",
        row['name'],
        bus="bus",
        carrier='large IE gas',
        committable=True,
        marginal_cost=int(row['fuel_cost']),
        start_up_cost=int(row['start_cost']),
        p_min_pu=row['min_cap'] / row['max_cap'],
        p_nom=row['max_cap'],
        # Defined at the end of the previous day
        up_time_before=ontime[row['name']],
        down_time_before=offtime[row['name']],
        min_up_time=int(row['min_up']),
        min_down_time=int(row['min_down']),
        ramp_limit_up=row['ramp_up']*60/row['max_cap'],
        ramp_limit_down=row['ramp_down']*60/row['max_cap'],
        overwrite=True,
        # inertia calculated using H and MVA rating
        inertia=2 * row['MVA'] * row['H']
    )

```

```

    )

# Looping through all of the OCGT units in IE
for index, row in S_IE_gas_df.iterrows():
    n.add(
        "Generator",
        row['name'],
        bus="bus",
        carrier='small IE gas',
        committable=True,
        marginal_cost=int(row['fuel_cost']),
        start_up_cost=int(row['start_cost']),
        p_min_pu=row['min_cap'] / row['max_cap'],
        p_nom=row['max_cap'],
        up_time_before=ontime[row['name']],
        down_time_before=offtime[row['name']],
        min_up_time=int(row['min_up']),
        min_down_time=int(row['min_down']),
        ramp_limit_up=row['ramp_up']*60/row['max_cap'],
        ramp_limit_down=row['ramp_down']*60/row['max_cap'],
        overwrite=True,
        inertia=2 * row['MVA'] * row['H']
    )

# Looping through all of the CCGT units in NI
for index, row in L_NI_gas_df.iterrows():
    n.add(
        "Generator",
        row['name'],
        bus="bus",
        carrier='large NI gas',
        committable=True,
        marginal_cost=int(row['fuel_cost']),

```

```

        start_up_cost=int(row['start_cost']),
        p_min_pu=row['min_cap'] / row['max_cap'],
        p_nom=row['max_cap'],
        up_time_before=ontime[row['name']],
        down_time_before=offtime[row['name']],
        min_up_time=int(row['min_up']),
        min_down_time=int(row['min_down']),
        ramp_limit_up=row['ramp_up']*60/row['max_cap'],
        ramp_limit_down=row['ramp_down']*60/row['max_cap'],
        overwrite=True,
        inertia=2 * row['MVA'] * row['H']
    )

# Looping through all of the OCGT units in IE
for index, row in S_NI_gas_df.iterrows():
    n.add(
        "Generator",
        row['name'],
        bus="bus",
        carrier='small NI gas',
        committable=True,
        marginal_cost=int(row['fuel_cost']),
        start_up_cost=int(row['start_cost']),
        p_min_pu=row['min_cap'] / row['max_cap'],
        p_nom=row['max_cap'],
        up_time_before=ontime[row['name']],
        down_time_before=offtime[row['name']],
        min_up_time=int(row['min_up']),
        min_down_time=int(row['min_down']),
        ramp_limit_up=row['ramp_up']*60/row['max_cap'],
        ramp_limit_down=row['ramp_down']*60/row['max_cap'],
        overwrite=True,
        inertia=2 * row['MVA'] * row['H']
    )

```

```

    )

# ----- WIND GENERATION -----
# Adding wind power as a non-committable generator
n.add(
    "Generator",
    "wind",
    bus="bus",
    carrier='wind',
    marginal_cost=0,
    start_up_cost=0,
    p_min_pu=0,
    # Fixed capacity of 20000 - larger than any availability
    p_nom=nominal,
    # Scaling factor (0 <= p_max_pu <= 1)
    p_max_pu=[w / nominal for w in wind[index_start:index_end]],
    overwrite=True
)

# ----- SOLAR GENERATION -----
# Adding solar power as a non-committable generator
n.add(
    "Generator",
    "solar",
    bus="bus",
    carrier='solar',
    marginal_cost=0,
    start_up_cost=0,
    p_min_pu=0,
    # Fixed capacity of 20000 for scaling purposes
    p_nom=nominal,
    # Scaling factor (0 <= p_max_pu <= 1)
    p_max_pu=[s / nominal for s in solar[index_start:index_end]],

```

```

        overwrite=True
    )

# ----- HYDRO GENERATION -----

# Looping though all of the hydropower units
for index, row in hydro_df.iterrows():
    n.add(
        "Generator",
        row['name'],
        bus="bus",
        carrier='hydro',
        committable=True,
        marginal_cost=row['cost'],
        start_up_cost=0,
        p_min_pu=0, # No minimum power output
        p_nom=row['max_cap'],
        up_time_before=ontime[row['name']], # Defined at the end of
        the previous day
        down_time_before=offtime[row['name']],
        min_up_time=0, # No minimum up or down times
        min_down_time=0,
        # Ramping limits converted to MW/hr in pu
        ramp_limit_up=row['ramp_up']*60/row['max_cap'],
        ramp_limit_down=row['ramp_down']*60/row['max_cap'],
        overwrite=True,
        # Inertia calculated using H and MVA rating
        inertia=2 * row['MVA'] * row['H']
    )

# ----- STORAGE -----

# Looping through the four pumped hydro storage in IE

```

```

for index, row in hydro_pumped_df.iterrows():
    n.add(
        "StorageUnit",
        row['name'],
        bus="bus",
        carrier="hydro_storage",
        p_nom=row['capacity'], # Max capacity
        max_hours=row['duration'], # Storage duration
        efficiency_store=0.75, # Charging efficiency
        efficiency_dispatch=1, # Round trip efficiency = 75%
        marginal_cost=row['cost'],
        # Defined at the end of the last day
        state_of_charge_initial=laststored["hydro_storage"],
        overwrite=True
    )

# Adding the battery storage units of varying durations and capacities
n.add(
    "StorageUnit",
    "battery_long",
    bus="bus",
    carrier="battery_storage",
    p_nom=500, # capacity
    max_hours=4, # Storage duration
    efficiency_store=0.9, # Charging efficiency
    efficiency_dispatch=1, # Round trip efficiency = 90%
    marginal_cost=0,
    # Defined at the end of the previous day
    state_of_charge_initial=laststored["battery_long"],
    overwrite=True
)

n.add(

```

```

    "StorageUnit",
    "battery_longer",
    bus="bus",
    carrier="battery_storage",
    p_nom=1350, # capacity
    # Storage duration (MWh capacity = p_nom * max_hours)
    max_hours=6,
    efficiency_store=0.9, # Charging efficiency
    efficiency_dispatch=1, # Round trip efficiency = 90%
    marginal_cost=0,
    # Defined at the end of the previous day
    state_of_charge_initial=laststored["battery_longer"],
    overwrite=True
)

n.add(
    "StorageUnit",
    "battery_longest",
    bus="bus",
    carrier="battery_storage",
    p_nom=950, # capacity
    # Storage duration (MWh capacity = p_nom * max_hours)
    max_hours=8,
    efficiency_store=0.9, # Charging efficiency
    efficiency_dispatch=1, # Round trip efficiency = 90%
    marginal_cost=0,
    # Defined at the end of the previous day
    state_of_charge_initial=laststored["battery_longest"],
    overwrite=True
)

n.add(
    "StorageUnit",

```



```

    "battery_short",
    bus="bus",
    carrier="battery_storage",
    p_nom=1050, # Capacity
    # Storage duration (MWh capacity = p_nom * max_hours)
    max_hours=2,
    efficiency_store=0.9, # Charging efficiency
    efficiency_dispatch=1, # Round trip efficiency = 90%
    marginal_cost=0,
    # Defined at the end of the previous day
    state_of_charge_initial=laststored["battery_short"],
    overwrite=True
)

# ----- FLEXIBLE DEMAND -----
\%age_flex_hp = 0.2 # 20% heat pumps flexible
\%age_flex_ev = 0.5 # 50% EVs flexible

# The flexible EV demand availability distribution:
charging_availability = pd.Series(
    [0.074, 0.074, 0.074, 0.074, 0.074, 0.074, 0.07, 0.05, 0.032,
    0.044, 0.036, 0.036, 0.036,
    0.036, 0.036, 0.036, 0.044, 0.06, 0.068, 0.074, 0.074, 0.074,
    0.074, 0.074, 0.074, 0.074,
    0.074, 0.074, 0.074, 0.074, 0.07, 0.05, 0.032, 0.044, 0.036,
    0.036], index=time_date[0:36])

# The flexible HP demand availability distribution:
HP_availability = pd.Series(
    [0.02, 0.02, 0.01, 0.05, 0.09, 0.09, 0.09, 0.09, 0.09, 0.09,
    0.05, 0.02, 0.02, 0.02, 0.02,
    0.10, 0.10, 0.10, 0.10, 0.10, 0.10, 0.05, 0.02, 0.02, 0.02,
    0.01, 0.05, 0.09, 0.09, 0.09,
    0.09, 0.09, 0.09, 0.05, 0.02, 0.02], index=time_date[0:36])

```

```

# The total HP and EV demand for the flexible shre for each day
p_nom = (2180000 + 1000000) * 0.5 * 1.08 / 365
p_nom_HP = (350000 + 2630000) * 0.5 * float(HP_monthly[day_num]) /
30.4

# Adding seperate buses to model flexible HP AND ev DEMAND
n.add("Bus", "EV_Bus")
n.add("Bus", "HP_Bus")

# Storage unit modelling EV flexible demand
n.add(
    "StorageUnit",
    name="EV_Battery",
    bus="EV_Bus",
    p_nom=1000000) # Arbitrary capacity

# EV Charging Link (follows availability profile) linking EV bus to
# the rest of the grid
n.add(
    "Link",
    name="link_EV",
    bus0="bus",
    bus1="EV_Bus",
    p_nom=p_nom, # Maximum charging power in MW
    efficiency=1,
    p_max_pu=charging_availability) # Charging availability

# V2G charging
n.add(
    "Link",
    name="EV_discharging",
    bus0="EV_Bus", # Power comes from the EV battery

```

```

        bus1="bus", # Power goes to the grid
        p_nom=p_nom * (2 / 5), # Maximum discharging power (MW) only
        20\% of EVs participating
        efficiency=1, # Discharging efficiency
        p_max_pu=charging_availability # Only allow discharging during
        plug in
    )

# Storage unit modelling heat pump flexible demand
n.add(
    "StorageUnit",
    name="HP_Battery",
    bus="HP_Bus",
    p_nom=1000000) # Arbitrary nominal capacity

# Link to control the flow of electricity from the grid to the
# flexible EV load
n.add(
    "Link",
    name="link_HP",
    bus0="bus",
    bus1="HP_Bus",
    p_nom=p_nom_HP,
    efficiency=1,
    p_max_pu=HP_availability) # Follows the HP demand availability
    profile

# ----- MODELLING CONSTRAINTS -----

m = n.optimize.create_model() # Creating the model

# ----- Flex EV AND HP constraint -----

```

```

link_p = m.variables["Link-p"] # link power flow variable

# The total EV demand for the day must remain the same
# (> to account for recharge after v2g discharge)
m.add_constraints(link_p.sel(Link="link_EV").isel(snapshot=slice(0,
24)).sum(dim='snapshot') > p_nom,
                  name='GlobalConstraint-EV')

# The total EV demand for the 12 hour overlap must be reasonable
m.add_constraints(link_p.sel(Link="link_EV").isel(snapshot=slice(24,
36)).sum(dim='snapshot') > (12 / 24) * p_nom,
                  name='GlobalConstraint-EV2')

# The total EV nighttime demand must remain the same
m.add_constraints(link_p.sel(Link="link_EV").isel(snapshot=slice(18,
30)).sum(dim='snapshot') > 0.744 * p_nom,
                  name='GlobalConstraint-EV1')

# making sure the vehicles are still charged despite V2G
m.add_constraints(link_p.sel(Link="link_EV").isel(snapshot=slice(0,
24)).sum(dim='snapshot') -
                  link_p.sel(Link="EV_discharging").isel(snapshot=slice(0,
24)).sum(dim='snapshot') == p_nom,
                  name='GlobalConstraint-v2g')

soc_ = m.variables["StorageUnit-state_of_charge"] # state of charge
variable

# making sure the vehicles are still charged despite V2G in the
# 12 hour overlap
m.add_constraints(link_p.sel(Link="link_EV").isel(snapshot=slice(24,
36)).sum(dim='snapshot') -
                  link_p.sel(Link="EV_discharging").isel(snapshot=slice(24,

```

```

36)).sum(dim='snapshot') == ( 12 / 24) * p_nom,
name='GlobalConstraint-v2g2')

# ensuring the cars are still fully charged by morning time
m.add_constraints(link_p.sel(Link="link_EV").isel(snapshot=slice(0,
7)).sum(dim='snapshot')
-link_p.sel(Link="EV_discharging").isel(snapshot=slice(0,
7)).sum(dim='snapshot') == 0.514 * p_nom,
name='GlobalConstraint-v2g3')

# The total daily heat pump demand must remain the same
m.add_constraints(link_p.sel(Link="link_HP").isel(snapshot=slice(0,
24)).sum(dim='snapshot') == p_nom_HP, name='GlobalConstraint-HP')

# The total EV demand for the 12 hour overlap must be reasonable
m.add_constraints( link_p.sel(Link="link_HP").isel(snapshot=slice(24,
36)).sum(dim='snapshot') == (12 / 24) * p_nom_HP,
name='GlobalConstraint-HP2')

# ----- SNSP Constraint -----

# Non synchronous sources - wind, solar, battery
nonsync_generators =
n.generators.loc[n.generators.carrier.isin(["wind", "solar"])].index
nonsync_storage =
n.storage_units.loc[n.storage_units.carrier.isin(["battery_storage"])].index

# Synchronous storage is pumped hydro
sync_storage =
n.storage_units.loc[n.storage_units.carrier.isin(["hydro_storage"])].index

# Extracting power output variables
gen_p = m.variables["Generator-p"]

```

```

storage_p_discharge = m.variables["StorageUnit-p_dispatch"]

# Computing total wind + solar + battery generation at each snapshot
nonsync_generation
=(gen_p.sel(Generator=nonsync_generators).sum(dim="Generator") +
storage_p_discharge.sel(StorageUnit=nonsync_storage).sum(dim="StorageUnit"))

# Getting total system demand per snapshot (excl. flex demand)
total_demand = n.loads_t.p_set.sum(axis=1)

# Ensuring demand has the correct dimensions
total_demand = total_demand.reindex(n.snapshots) # Align index with
snapshots

# SNSP constraint total SNSP < 95\%, total demand includes HP and EV
# flex demand minus V2G charging
m.add_constraints(nonsync_generation - link_p.sel(Link="link_EV") -
link_p.sel(Link="link_HP")
+ link_p.sel(Link="EV_discharging") <= 0.95 *
total_demand,
name="SNSP")

# ----- MUON Constraint -----

# Minimum number of large gas units online
L_gas = n.generators.loc[n.generators.carrier.isin(["large IE gas",
"large NI gas"])]].index
IE_L = n.generators.loc[n.generators.carrier.isin(["large IE
gas"])]].index
NI_L = n.generators.loc[n.generators.carrier.isin(["large NI
gas"])]].index

# Seperate constraints enforced for IE and NI

```

```

global_muon_ie =
m.add_constraints(m.variables["Generator-status"].sel({"Generator-com":
IE_L}).sum("Generator-com") >= 2, name="GlobalConstraint-muon_ie")

global_muon_ni =
m.add_constraints(m.variables["Generator-status"].sel({"Generator-com":
NI_L}).sum("Generator-com") >= 1, name="GlobalConstraint-muon_ni")

# ----- DSU Up-time constraint -----
# 80% of DSU have up time limitation

gen_status = m.variables["Generator-status"]
max_time = 2 # for 80% of dsu 2.3 hrs is the average maximum up time
per day, rounding down to 2 hours here

# Looping over each time step to enforce the constraint
DSU_short_index = n.generators.query("carrier == 'DSU_short']").index

daily_up = gen_status.sel({"Generator-com":
DSU_short_index}).sum(dim="snapshot")

n.model.add_constraints(daily_up <= max_time, name=f"max_time_DSU")
# can't exceed max up time for the day

#----- INERTIA FLOOR and RoCoF CONSTRAINT -----

# Extract power output and generator status variables
gen_p = m.variables["Generator-p"]
gen_status = m.variables["Generator-status"]

# all sources of inertia
sync_generators_cond = n.generators.loc[n.generators.carrier.isin([
    "large NI gas", "small NI gas", "large IE gas", "small IE gas",

```

```

    "hydro", "sync"])).index

# Calculating total inertia for each time step by creating an inertia
variable
inertia = m.add_variables( lower=0, coords=[n.snapshots,
n.generators.carrier.isin(["large NI gas", "small NI gas", "large IE
gas", "small IE gas", "hydro", "sync"]).index],
name="Generator-p_inertia")

# Defining the parameters of the inertia variable i.e. the max
inertia_up_lim1 = m.add_constraints(inertia <=
(n.generators.loc[sync_generators_cond, "inertia"]),
name="Generator-inertia_upper_limit")
# Ensuring the inertia variable is dependent on the binary commitment
variables of the generators
# (with arbitrary constraint)
inertia_up_lim2 = m.add_constraints( inertia <= 10000 *
m.variables["Generator-p"], name="Generator-inertia_upper_limit2")

# Inertia floor constraint - total inertia greater than or equal to
# 20000 MWs
inertia_floor = 20000
m.add_constraints(inertia.sum("Generator") >= inertia_floor,
name="GlobalConstraint-inertia")

# RoCoF constraint - less than or equal to 1Hz for the loss of any
# single infeed
for gen in sync_generators_cond:
    m.add_constraints(
        (m.variables["Generator-p"].sel({"Generator": gen}) * 50) -
        inertia.sum("Generator") <= 0,
        name=f"GlobalConstraint-RoCoF_{gen}")
    )

```



```

#----- FIRST HOUR RAMPING CONSTRAINT -----

# The ramping between the last hour of the last optimisation and the
first hour of the current one must also adhere
# to the ramping limit

# Synchronous generation excl. sync condensers
sync_generators = n.generators.loc[n.generators.carrier.isin([
    "large NI gas", "small NI gas", "large IE gas", "small IE gas",
    "hydro"])]
sync_dispatch =
m.variables["Generator-p"].sel(Generator=sync_generators) # power
output variables

for gen in sync_generators:
    first_hour = n.snapshots[0]
    first_dispatch = sync_dispatch.sel(snapshot=first_hour,
    Generator=gen) # dispatch of first hour
    last_gen_power = lastpower[gen] # dispatch of last hour of
    previous day

    # Ramp-up/down constraint
    m.add_constraints(
        - n.generators.loc[gen, "ramp_limit_down"]*n.generators.loc[gen,
        "p_nom"] <= first_dispatch - last_gen_power <=
        n.generators.loc[gen, "ramp_limit_up"]*n.generators.loc[gen,
        "p_nom"], name=f"first_ramp_up_{gen}"
    )

# ----- Primary operating reserve -----

# Retrieving the required parameters - power output of units

```

```

# supplying reserve
IE_sync = n.generators.loc[n.generators.carrier.isin(["large IE
gas", "small IE gas", "hydro"])].index
NI_sync = n.generators.loc[n.generators.carrier.isin(["large NI
gas", "small NI gas"])].index
storage =
n.storage_units.loc[n.storage_units.carrier.isin(["battery_storage",
"hydro_storage"])].index
storage_soc = m.variables["StorageUnit-state_of_charge"]

# reserve variable for synchrononous generators
reserve = m.add_variables(
    lower=0,
    coords=[n.snapshots, n.generators.carrier.isin(
        ["large NI gas", "small NI gas", "large IE gas", "small
        IE gas", "hydro"]).index],
    name="Generator-p_reserve",
)

# reserve variable for storage units
reserve_store = m.add_variables(
    lower=0,
    coords=[n.snapshots,
n.storage_units.carrier.isin(["battery_storage",
"hydro_storage"]).index],
    name="StorageUnit-p_reserve",
)

# setting the generator reserve limits according to the flat back
reserve characteristic
reserve_up_lim1 = m.add_constraints(
    reserve <=
    0.9 * (-m.variables["Generatorp"].sel({"Generator":

```

```

sync_generators})) + n.generators.loc[sync_generators,
    "p_nom"]], name="Generator-reserve_upper_limit1")

reserve_up_lim2 = m.add_constraints(
    reserve <= 0.15 * n.generators.loc[sync_generators, "p_nom"],
    name="Generator-reserve_upper_limit2")

# Ensuring the reserve variable is dependednt on the power output
of the generators
reserve_up_lim3 = m.add_constraints(
    reserve <= 10 * m.variables["Generator-p"],
    name="Generator-reserve_upper_limit3")

# setting the battery storage reserve limitation
reserve_up_lim4 = m.add_constraints(
    reserve_store <= 0.3 * storage_soc.sel({"StorageUnit":
    storage})), name="StorageUnit-reserve_upper_limit3")

# Seperate total reserve requirements for IE and NI
reserve_req_ie = 150
reserve_req_ni = 75

# The IE and NI reserve constraints
res_ie = m.add_constraints(
    reserve.sel({"Generator": IE_sync}).sum("Generator") +
    reserve_store.sel({"StorageUnit":
    storage}).sum("StorageUnit") >= reserve_req_ie,
    name="GlobalConstraint-reserves_ie")

res_ni = m.add_constraints(
    reserve.sel({"Generator": NI_sync}).sum("Generator") +
    reserve_store.sel({"StorageUnit":
    storage}).sum("StorageUnit") >= reserve_req_ni,

```

```

        name="GlobalConstraint-reserves_ni")

# POR must be at least 75% of largest infeed
# Total reserve is calculated and each infeed is looped through
# to ensure there is a sufficient amount
for gen in sync_generators:
    m.add_constraints(
        0.75 * (gen_p.sel({"Generator": gen})) -
        reserve.sel({"Generator":
            sync_generators}).sum("Generator")
        - reserve_store.sel({"StorageUnit":
            storage}).sum("StorageUnit")
        <= 0, name=f"GlobalConstraint-reserves_{gen}")

#----- SOLVING -----

# optimising based on minimal cost
n.optimize.solve_model(assign_all_duals=True)

# ----- Data processing -----

# Converting the storage and gen dispatch arrays to data frames for
# ease of processing
dispatch_df = n.generators_t.p.copy()
storage_df_soc = n.storage_units_t.state_of_charge.copy()
storage_df_char = n.storage_units_t.p_store.copy()
storage_df = n.storage_units_t.p_dispatch.copy()
# combining all of the data frames
total_dispatch_df = pd.concat([dispatch_df, storage_df], axis=1)
# Getting the surplus of wind and solar for each hour
total_dispatch_df['wind surplus (pre export)'] =
wind[index_start:index_end] - dispatch_df['wind']
total_dispatch_df['solar surplus (pre export)'] =

```

```

solar[index_start:index_end] - dispatch_df['solar']
# Adding demand column to the dispatch data frame
total_dispatch_df['Demand'] =
(np.array(demand[index_start:index_end]) +
np.array(n.links_t.p0['link_EV']) + np.array(n.links_t.p0['link_HP']))
# adding the time and date labels for the rows
total_dispatch_df.index = time_date[index_start:index_end] # correct
index names

# Getting the last hour parameters for the next day optimisation

ontime = {}
offtime = {}
lastpower = {}
laststored = {}
secondlastpower = {}
# Getting the dispatch for the last hour of the day
for gen in dispatch_df.columns:
    # Extracts power output at index 23
    lastpower[gen] = dispatch_df.iloc[23][gen]
    # Extracts power output at index 22
    secondlastpower[gen] = dispatch_df.iloc[22][gen]

# Getting the hours on/off prior to the start of the next day
for gen in dispatch_df.columns:
    i = 0
    j = 0
    while dispatch_df.iloc[23-i][gen] != 0 and i <= 23:
        i += 1
    while dispatch_df.iloc[23-j][gen] == 0 and j <= 23:
        j += 1
    ontime[gen] = i
    offtime[gen] = j

```

```

for unit in storage_df.columns:
    laststored[unit] = storage_df.iloc[23][unit] # Extracts power
    output at index 23

# -----
# ----- SEPERATE OPTIMISATION FOR EXPORT -----
# -----

# The unused available wind and solar power for each hour is input
# into a seperate optimisation programme to be distributed for export
nominal = 50000
res_surplus = total_dispatch_df['wind surplus (pre export)'] +
total_dispatch_df['solar surplus (pre export)']
res_surplus = res_surplus.tolist()
wind_surplus = total_dispatch_df['wind surplus (pre export)']
wind_surplus = [0 if w < 1e-8 else w for w in wind_surplus]
solar_surplus = total_dispatch_df['solar surplus (pre export)']
solar_surplus = [0 if s < 1e-8 else s for s in solar_surplus]
res_surplus = [0 if r < 1e-8 else r for r in res_surplus]
time = time_date[0:24] # No overlap of optimisation required

# defining a new network with no optimisation overlap required
network = pypsa.Network(snapshots=time_date[0:24])
network.add( # Adding the different types of generation
    "Carrier",
    ["DC", "virtual", "RES"], overwrite=True)
# Adding buses
# represents AIPS
network.add("Bus", "Generation_Bus", overwrite=True)
# represents export destintations i.e. GB and France
network.add("Bus", "Demand_Bus", overwrite=True)

```

```

# ----- INTERCONNECTOR EXPORT -----

# The interconnectors are modelled as links to the demand bus
network.add(
    "Link",
    name="Moyle",
    bus0="Generation_Bus", # from internal bus
    bus1="Demand_Bus", # to external market bus
    p_nom=500,
    efficiency=1,
    marginal_cost=0,
    ramp_limit_up=10 * 60 / 500, #10MW/min ramping limit
    ramp_limit_down=10 * 60 / 500,
    carrier='DC',
    overwrite=True
)

network.add(
    "Link",
    name="EWIC",
    bus0="Generation_Bus", # from internal bus
    bus1="Demand_Bus", # to external market bus
    p_nom=500,
    efficiency=1,
    marginal_cost=0,
    ramp_limit_up=10 * 60 / 500,
    ramp_limit_down=10 * 60 / 500,
    carrier='DC',
    overwrite=True
)

network.add(

```

```

    "Link",
    name="Greenlink",
    bus0="Generation_Bus", # from internal bus
    bus1="Demand_Bus", # to external market bus
    p_nom=500,
    efficiency=1,
    marginal_cost=0,
    ramp_limit_up=10 * 60 / 500,
    ramp_limit_down=10 * 60 / 500,
    carrier='DC',
    overwrite=True
)

network.add(
    "Link",
    name="Celtic",
    bus0="Generation_Bus", # from internal bus
    bus1="Demand_Bus", # to external market bus
    p_nom=700,
    efficiency=1,
    marginal_cost=0,
    ramp_limit_up=10 * 60 / 700,
    ramp_limit_down=10 * 60 / 700,
    carrier='DC',
    overwrite=True
)

# Adding solar and wind to be exported as generators
network.add(
    "Generator", "wind Export", bus="Generation_Bus", p_nom=50000,
    marginal_cost=0, p_max_pu=[w / 50000 for w in wind_surplus],
    carrier="RES", overwrite=True)

```



```

network.add(
    "Generator", "solar Export", bus="Generation_Bus", p_nom=50000,
    marginal_cost=0, p_max_pu=[s / 50000 for s in solar_surplus],
    carrier="RES", overwrite=True)

# Adding a virtual Gas Generator (higher marginal cost) to cover any
# of the 'demand' that the RES can't cover to ensure
# demand=genconstraints are met
network.add(
    "Generator", "Curtailed and surplus Res", bus="Demand_Bus",
    p_nom=50000, marginal_cost=50, p_max_pu=1, carrier="virtual",
    overwrite=True)

# Adding Demand as the amount of RES available for export
network.add("Load", "Demand", bus="Demand_Bus", p_set=res_surplus,
    overwrite=True)

# ----- FIRST/LAST DAY RAMPING CONSTRAINT -----
model = network.optimize.create_model()

# Retrieving link power flow variables
interconnectors =
network.links.loc[network.links.carrier.isin(["DC"])].index
link_p = model.variables["Link-p"]
link_dispatch = link_p.sel({"Link": interconnectors})

# The ramping constraint must transfer across the first and last
# hours of separate optimisations
for l in interconnectors:
    first_hour = network.snapshots[0]
    first_dispatch = link_dispatch.sel(snapshot=first_hour, Link=l)
    # dispatch of first hour
    last_link_export = lastexport.get(l, 0) # Defaults to 0 if key

```

```

not found

# Ramp-up/down constraint
m.add_constraints(- network.links.loc[l, "ramp_limit_down"] *
network.links.loc[l, "p_nom"] <= first_dispatch
                  - last_link_export <=
network.links.loc[l, "ramp_limit_up"] *
network.links.loc[l, "p_nom"],
name=f"first_ramp_up_{l}")

# Solving the network (least-cost optimization)
network.optimize()

# ----- Data processing -----

# Exporting the data
interconnector_df = network.links_t.p0.copy()
interconnector_df2 = network.generators_t.p.copy()
dispatch2_df = network.generators_t.p.copy()

dispatch2_df.index = time_date[index_start:index_end] # correct
index names
total_dispatch_df = pd.concat([total_dispatch_df, dispatch2_df],
axis=1)
total_dispatch_df.index = time_date[index_start:index_end] # correct
index names

# getting the last export of the previous day
interconnector_df = n.generators_t["p_reserve"].copy()
lastexport = {}
for link in interconnector_df.columns:
    lastexport[link] = interconnector_df.iloc[23][link] # Extracts
power output at index 23

```