POLICY OPTIONS TO SUPPORT THE UPTAKE OF SMALL-SCALE RENEWABLE ELECTRICITY GENERATION IN IRELAND

Report for: Sustainable Energy Authority of Ireland (SEAI)

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EXECUTIVE SUMMARY

This study aims to explore policy options for potential supports to incentivise the uptake of small-scale renewable electricity generation in Ireland. In line with plans announced in the Ireland Climate Action Plan 2021[1] and the October 2020 Programme for Government[2], the scheme aims to be technology agnostic and to provide support to small-scale renewables between 50kW and 1000kW, thereby complementing the existing Micro-generation Support Scheme (MSS)[3] and the Renewable Electricity Support Scheme (RESS)[4].

In this study, we have firstly identified a set of important lessons learned from international experience to consider when designing policy options in Ireland. In particular, case studies from policies implemented in the Netherlands, France and Germany show that:

- A feed-in-premium policy based on the prevailing market price and a cap to the overall subsidy can be effective in reducing the free-rider effect and over-subsidising.
- All three case studies seem to suggest that auction schemes for solar PV <500 kW can form a significant barrier for market entry and therefore other policy support should be made available. This is also true for community energy projects <1000kW.
- Moreover, the case studies show that adding requirements for mandatory feasibility studies and stricter permit requirements can reduce non-realisation rates for applications in auction schemes. However, grid capacity is already limited and can possibly increase the non-realisation rate of projects further. In the Netherlands, grid operators are adding additional reserve capacity to address the issue. In France, the focus is more on connections, with current plans to fast-track grid connections for small-scale projects receiving subsidies.
- All case studies also indicate it is important to consider storage in the policy design to avoid unintended outcomes of the policy on demand side management. For example, the French government has announced that self-consumption projects are exempt from a tax for non-residential electricity users[5], which is perceived as a way to further incentivise self-consumption and uptake of the Feed-in-Tariff (FIT) scheme.
- In the German scheme only 50% of electricity generated is compensated, which could be seen as incentivising self-consumption (or rather discouraging feeding into the grid). However, the prospect of these less attractive feed-in premiums (effectively 50% of those received by installations < 300 kW) could drive installers into the alternative tendering schemes, for example the tender for rooftop PV projects ranging in size from 300 kW to 750 kW[6], under which installations cannot self-consume.

Subsequently, this study has analysed the customer segments that could deploy small-scale renewables in Ireland and the capacity that they could install. Both the likelihood of deployment and the installable capacity, as well as the barriers that must be overcome in order to incentivise buildout, will vary by end-use sector, location and installed capacity band range. Therefore, a set of eight archetypes have been characterised to understand where most of the potential for PV deployment (within the capacity range concerning this study) lies. The eight archetypes that were selected and their main barriers are presented in the table below.

Table 1 Selection of ten archetypes and their main barriers characterized by severity of their impact on the possibility of deployment, i.e. high, medium, low

#	Archetype	Sector	Size (kW)	Main barriers
1	Commercial site – rooftop-mounted PV	Commercial	60	- **Grid connection:** Integration with internal low voltage and metering - **Viability gap:** premises & infrastructure ownership - **Other:** shading from nearby buildings

[1] https://www.gov.ie/en/publication/6223e-climate-action-plan-2021/
[2] https://www.gov.ie/en/publication/7e05d-programme-for-government-our-shared-future
[3] https://www.gov.ie/en/publication/b1fbe-micro-generation/
[4] https://www.gov.ie/en/publication/36d8d2-renewable-electricity-support-scheme/
[5] https://www.cru.ie/wp-content/uploads/2020/12/CRU20113-Pass-Through-Costs-for-Business-Electricity-Customers-202020212.pdf
[6] https://www.bundesnetzagentur.de/SharedDocs/Pressemitteilungen/EN/2022/20220512_Ausschreibungen.html?nn=404530

#	Archetype	Sector	Size (kW)	Main barriers
2	Agricultural site – rooftop-mounted PV	Agriculture	100	- **Grid connection:** Low associated grid capacity - **Power market rules & regulation:** Limited export - **Viability gap:** existing subsidies may reduce incentive to deploy RES - **Other:** investments prioritised towards core activities and low self-consumption
3	Public building – rooftop-mounted PV	Public	100	- **Planning and regulatory:** required processes and approvals - **Grid connection:** school year downtimes cause high exports - **Other:** public spending prioritised for other needs
4	Industrial site – rooftop-mounted PV	Industry	250	- **Grid connection:** potential disruptions due to voltage swings - **Viability gap:** easier and less risky alternatives (PPA) - **Others:** investments prioritised towards core activities
5	Predominantly export site rooftop-mounted PV	Commercial	250	- **Grid connection:** low grid capacity in rural communities and agricultural areas - **Power market rules & regulation::** limited routes to market - **Viability gap:** high competition in auctions and PPA market, along with associated risks and procedures - **Other:** Stakeholder management and engagement
6	Public building – rooftop-mounted PV	Public	325	- **Planning and regulatory:** required processes and approvals - **Grid connection:** school year downtimes cause high exports - **Other:** public spending prioritised for other needs
7	Industrial site – rooftop-mounted PV	Industry	625	- **Planning and regulatory:** planning permission currently needed - **Grid connection:** potential disruptions due to voltage swings - **Viability gap:** easier and less risky alternatives (PPA) - **Other:** Investment capacity prioritised for core activities
8	Predominantly export site – ground-mounted PV	Agriculture, Community Energy	999	- **Planning and regulatory:** planning permission - **Grid connection:** low grid capacity in rural communities and agricultural areas - **Power market rules & regulation:** limited routes to market - **Viability gap:** high competition in main route to market (which could involve RESS auctions) and PPA market, along with associated risks and procedures - **Other:** stakeholder management and engagement
9	Export-only site – ground-mounted PV	Private or Community Energy	4,000	- **Planning and regulatory:** planning permission - **Grid connection:** low grid capacity in rural areas, distance to grid, cost of bringing cables/lines back to the network - **Power market rules & regulation:** limited routes to market - **Viability gap:** high competition in main route to market (which could involve RESS auctions) and PPA market, along with associated risks and procedures - **Other:** land costs, local authority rates, stakeholder management and engagement
10	Export-only site – onshore wind	Private or Community Energy	4,000	- **Planning and regulatory:** planning permission - **Grid connection:** low grid capacity in rural areas, distance to grid, cost of bringing cables/lines back to the network - **Power market rules & regulation:** limited routes to market - **Viability gap:** high competition in main route to market (which could involve RESS auctions) and PPA market, along with associated risks and procedures - **Other:** stakeholder management and engagement

Based on the lessons learned from international experience and facilitating the addressing of barriers identified for the key archetypes for small-scale renewables in Ireland, a set of policy options have been proposed. A financial model was developed that is fit for purpose for appraising these policy options to support small-scale renewable electricity generation in Ireland. The model forecasts cash flows, such as the estimated revenue stream, capital expenses (CAPEX) and operating and maintenance (O&M) costs and calculates the levelized parameters of the viability gap applying the Discounted Cash Flow (DCF) method to inform the level of support to be provided by the policy options.

The renewable installation size range of focus for the policy support scheme falls under the eligibility of the newly introduced Clean Export Guarantee, which obligates electricity suppliers to provide micro-generators with a tariff, for any electricity they export.[7] It is therefore assumed that in all considered policy options, all archetypes that self-consume will receive this CEG at market rate (wholesale electricity price), which effectively means only the Export_Ground-mounted_999 kW archetype will be excluded from receiving this payment. The three selected policy options are outlined in the table below:

Table 2 Proposed design of three candidate support schemes

	Policy option 1 – *Basic Feed-in-Premium*	Policy option 2 – *Varied Feed-in-Premium*	Policy option 3 – *Feed-in-Premium with Community Energy support*
Type	CEG for renewable self-consumers + one rate Feed-in-Premium (FiP) for all archetypes. The level of FIP is based on the most prevalent renewable self-consumer archetype that still has a viability gap according to our analysis[8].	CEG for renewable self-consumers + three different FIP for archetypes to match viability gap as closely as possible.	Similar to support provided under policy option 1 + aid for studies and consultancy services for community energy projects
Policy lifetime	8 years	8 years	8 years
Support lifetime	15 years	15 years	15 years
Scope (installation capacity limits)	50 – 6000 kW	50 – 6000 kW	50 – 6000 kW
Level of support / tariffs	Closing viability gap, reduction over time to 2030	Closing viability gap, reduction over time to 2030	Closing viability gap, reduction over time to 2030
Grid connection / capacity provisions	Costs for connection with project developer. Enduring Connection Policy (ECP), which facilitates the deployment of new generation capacity in the RoI, to be simplified. The lower application deposit for community projects ranging from 500 kW-1MW (of EUR2k rather than EUR9k) remains in place.	Costs for connection with project developer. ECP simplified. The lower application deposit for community projects ranging from 500 kW-1MW (of EUR2k rather than EUR9k) remains in place.	Costs for connection with project developer. ECP simplified. The lower application deposit for community projects ranging from 500 kW-1MW (of EUR2k rather than EUR9k) remains in place. Processing cap for community energy projects by ESBN to be increased.
Community energy provisions	N/A	N/A	Only eligible for aid for studies and consultancy services if registered as 'Sustainable Energy Community' under the SEAI community framework
Self-consumption provisions	Exported volumes of electricity eligible for the FIP will be capped at 80% (in line with the cap in the Clean Export Premium in the MSS) with exception of	Exported volumes of electricity eligible for the FIP will be capped at 80% (in line with Clean Export Premium in MSS) with exception of the community	Exported volumes of electricity eligible for the FIP will be capped at 80% (in line with Clean Export Premium in MSS) with exception of the community

[7] https://www.gov.ie/en/press-release/bfe21-homes-farms-businesses-and-communities-to-benefit-as-minister-ryan-announces-the-micro-generation-support-scheme/

[8] In case the viability gap is zero during the policy lifetime, a hybrid approach whereby the level of support required by the next most prevalent archetype may be selected instead. This method is used to ensure support to small-scale installation over the full policy lifetime.

	Policy option 1 – *Basic Feed-in-Premium*	Policy option 2 – *Varied Feed-in-Premium*	Policy option 3 – *Feed-in-Premium with Community Energy support*
	the community energy and export-only archetypes	energy and export-only archetypes	energy and export-only archetypes
Cost recovery mechanism	Recover costs through PSO levy or equivalent	Recover costs through PSO levy or equivalent	Recover costs through PSO levy or equivalent

These options have been appraised using a multi-criteria assessment framework focused on their effectiveness and costs, ease of implementation and coherence in line with the objectives set for this policy option in the Ireland Climate Action Plan 2021[9] and the October 2020 Programme for Government[10]. The analysis presented in this report point to the following set of policy recommendations to support small-scale renewables in Ireland:

- **A sliding feed-in-premium policy is the preferred policy type**, as it offers a low risk of over-incentivising due to its flexibility and alignment with the Clean Export Premium provided in the MSS. A FIP also complements the RESS scheme in cases where community energy projects greater than 500 kW look for a simpler support scheme to apply to compared to the auctioning scheme.
- **Setting a cap** on the FIP so that applicants only receive the premium for their export up to a cap of 80% of total potential generation can **incentivise self-consumption** and also aligns well with the same cap applied in the MSS.
- To increase the chance of high uptake of small-scale renewables in response to the policy scheme, it is important to ensure that the viability gap of the **export-focused** small-scale renewables (ground-mounted solar / onshore wind 4 MW archetypes) is closed. If this is not the case, then it will prove difficult to reach scale in the coming years.
- **Further support to community renewable energy projects** as implemented in the RESS scheme can increase the effectiveness of the policy scheme. In the RESS scheme projects registered as 'Sustainable Energy Community' projects between 500 kW and 1MW have preferential access to a separate category under the Enduring Connection Policy and do not have to accept grid connection offers for two years, thereby avoiding high upfront fees. No data is available yet on how the simplified scheme for community energy projects have helped these projects thus far as it is a relatively new policy[11], however, it is recommended that this support scheme is extended to community energy projects participating under the small-scale renewable policy scheme. As the scheme already exists, it is expected that it is relatively easy to implement or expand, although capacity and budgets to deal with high numbers of community energy project applications and grid connection applications both at SEAI and ESB Networks will need to be increased. If this results in an increase in the processing cap for community energy projects for grid connection applications, then this could potentially also boost the effectiveness of the RESS where this cap has been a barrier in the past.
- The policy assessment seems to suggest there is a **slight preference for providing a blanket FIP rate** with additional support for community energy projects. This would enable the majority of viability gaps to be closed while offering reasonable cost-effectiveness and administrative simplicity, while aligning well with the European objective of supporting community energy projects, outlined in RED II.
- However, policy option 2, in which multiple FIP tariffs are offered for different archetypes, is considered **only slightly less favourable**. Establishing and updating a maximum of three different FIP rates may require higher administration costs and capacity, but it could be more effective in closing viability gaps and avoiding over-incentivising of self-consumption-focused archetypes in later years. This option could also be considered with additional support for community energy projects, as in policy option 3.

For the implementation of the preferred policy option, the following steps are recommended to be undertaken in the coming year with the objective of the support scheme being made available in the coming years:

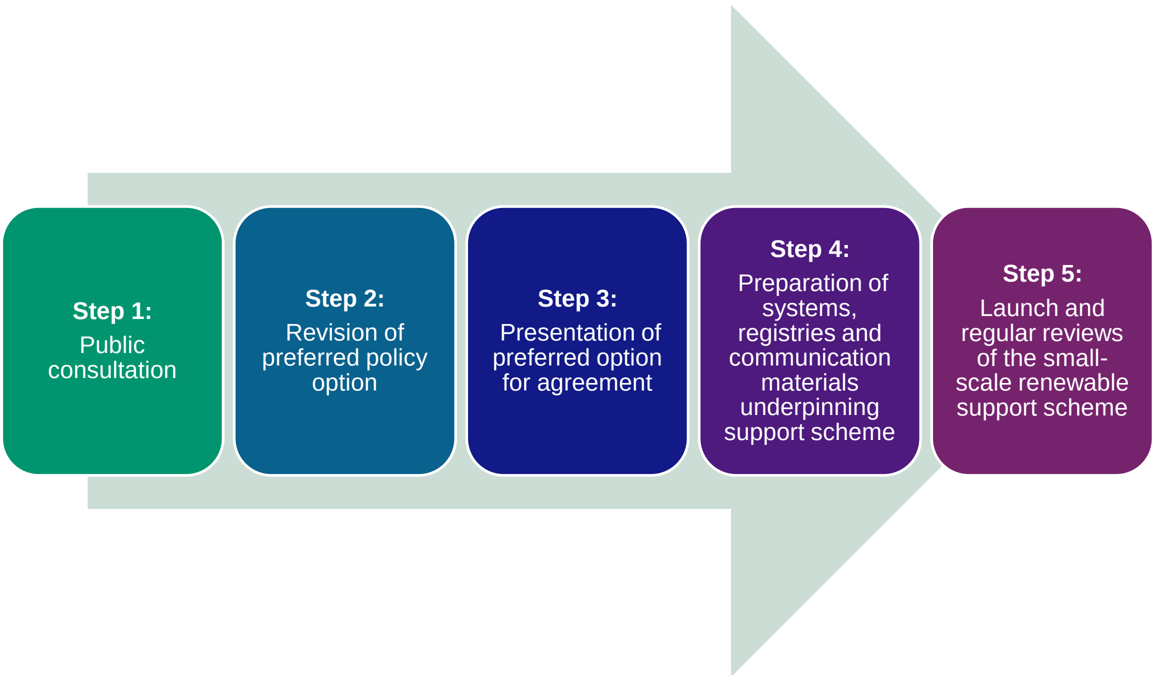
- **Step 1 : Hosting of a public consultation** on the findings of this study and the proposed policy options.

[9] https://www.gov.ie/en/publication/6223e-climate-action-plan-2021/
[10] https://www.gov.ie/en/publication/7e05d-programme-for-government-our-shared-future
[11] https://www.seai.ie/community-energy/ress/enabling-framework/

- **Step 2 : Revision of preferred policy option** based on feedback from public consultation and more detailed data in terms of updated wholesale electricity price, changing inflation levels and expected uptake.
- **Step 3 : Presentation of the revised policy option to DECC and decision-makers for agreement.** This will cover the type of support provided, eligibility requirements, timeline and length of support, additional support that may be provided and agreement with SEAI and ESB Networks on these additional measures.
- **Step 4 : Preparation of systems, registries and communication materials for the launch of the scheme.** This will include communication materials on the launch and mechanism of the scheme, the timeline, how participants can apply and their eligibility. Application forms and registries for applicants will also need to be developed as well as the planning of official reviews of the FIP rate(s) and overall performance of the scheme.
- **Step 5: Launch of the scheme with regular reviews on its performance.** The scheme is planned to be launched in 2023. The support levels for the policy options proposed in this report will need to be (re-)adjusted before introducing then when there is better visibility on the inflation figures. Moreover, it is recommended that at least every two years the scheme's performance is reviewed to update FIP rates if necessary and/or adjust complementary measures.

A schematic overview of this implementation roadmap is provided in the figure below.

Figure 1: Schematic overview of implementation roadmap for the small-scale renewable policy scheme



GLOSSARY

Acronym / Terminology	Description
ACA	Accelerated Capital Allowances
CAPEX	Capital Expenditure
CCS	Carbon Capture and Storage
CEG	Clean Export Guarantee
CEP	Clean Export Premium
DECC	Department of the Environment, Climate and Communications, Ireland
DSO	Distribution System Operator
ECP	Enduring Connection Policy
EEG	Renewable Energies Act (Germany)
ELS	Export Limiting Scheme
ETS	Emission Trading Scheme
EU	European Union
EUR	Euro
FIP	Feed-in-Premium
FIT	Feed-in-Tariff
GW	Giga Watt
HV	High Voltage
IEA	International Energy Agency
LCOE	Levelized Cost of Electricity
MEC	Maximum Export Capacity
MIC	Maximum Import Capacity
MS	Member State
MSS	Micro-generation Support Scheme
MV	Medium Voltage
MW	Mega Watt
NVD	Neutral Voltage Displacement
ODE	Sustainable Energy Surcharge (Netherlands)
OPEX	Operational Expenditure
PPA	Power Purchase Agreement
PSO	Public Service Obligation
PV	PhotoVoltaics
REC	Renewable Energy Community
RED II	Renewable Energy Directive (recast to 2030)
RES	Renewable Energy Systems

Acronym / Terminology	Description
RESS	Renewable Electricity Support Scheme
SDE	Stimulering Duurzame Energie / Stimulating Renewable Energy Policy (Netherlands)
SEAI	Sustainable Energy Authority Ireland
SEG	Smart Export Guarantee
SEM	Single Electricity Market
SER	Renewable Energy Association (SER)
SME	Small- and Medium-sized Enterprises
TAMS	Targeted Agriculture Modernisation Schemes
TSO	Transmission System Operator
UK	United Kingdom
VAT	Value Added Tax

1. INTRODUCTION

The aim of this study is to explore policy options for potential supports to incentivise the uptake of small-scale renewable electricity generation in Ireland. As outlined in the Ireland Climate Action Plan 2021[12], Ireland has committed to developing and delivering a 'Small-scale Generation Scheme' to provide support on renewable energy projects over 50 kW. This scheme aims to be technology agnostic supporting small-scale renewables whereby the existing Micro-generation Support Scheme (MSS)[13] and the Renewable Electricity Support Scheme (RESS)[14] are not able to sufficiently support due to the targeted project energy capacity. This scheme aligns with a similar commitment from the October 2020 Programme for Government[15], to 'develop a Solar Energy Strategy for rooftop and ground-based photovoltaics to ensure that a greater share of our electricity needs is met through solar power'.

In this study, we have considered the existing and planned policies in Ireland and propose policy options that can overcome barriers for small-scale renewable electricity generation for the range of 50 kW to 1000 kW, which was later expanded to include installations up to 5MW. Section 2 of this report focuses on a review of international experience as well as existing policies in Ireland that can identify lessons learned to consider for the policy options for Ireland. Next, Section 3 focuses on assessing a set of characteristics such as end-use sector, end-use load type and capacity banding range to characterise a set of archetypes and its main barriers to understand how a policy scheme could best incentivise uptake for these subsets. Subsequently, we have developed a model that can assess the viability gaps of each of these archetypes when technology costs are inputted. Lastly, this report outlines an assessment of a set of proposed policy options in Ireland to identify the most suitable option as well as a roadmap for implementation to incentivise renewable electricity generation for the range of 50 kW to 1000 kW (and 1 – 5 MW).

2. INTERNATIONAL REVIEW

There are several jurisdictions across Europe that have implemented small-scale renewable support schemes. As these schemes have been implemented a few years ago and have had varying levels of success and updates in the meantime, there are numerous lessons that can be learnt from these other jurisdictions for policy development in Ireland. In particular, there are many examples of improvements that can be made to the design of policies to ensure that they are efficient and to prevent market distortions. If designed poorly, policies can either be ineffective or result in overcompensation of the market, resulting in the inefficient deployment of technologies and impacting the policy cost.

This section outlines the main policy design considerations relevant for small-scale renewables in Ireland and then outlines the international context and a set of case studies to identify important lessons learned from international experience to consider when designing policy options for Ireland.

2.1 POLICY DESIGN CONSIDERATIONS

2.1.1 Policy Requirements

Microgeneration and community-based projects play a key role in enabling a further reach for deployment of renewable energy projects throughout the economy, whilst in turn offering financial return, security and ownership over energy supply for residences, communities, small businesses and farming. However, there currently exists a policy gap for energy projects between 50 kW and 500 kW, whereby smaller or larger installations are covered already by the MSS and RESS schemes respectively.

[12] https://www.gov.ie/en/publication/6223e-climate-action-plan-2021/
[13] https://www.gov.ie/en/publication/b1fbe-micro-generation/
[14] https://www.gov.ie/en/publication/36d8d2-renewable-electricity-support-scheme/
[15] https://www.gov.ie/en/publication/7e05d-programme-for-government-our-shared-future

There is a proposed new limit for Balance Responsibility in the I-SEM for generator units above 200 kW due to come into force in 2026 under Regulation (EU) 2019/943[16] on the internal market for electricity.

Additionally a recent communication on C(2021) 9817[17] with Guidelines on State aid for climate, environmental protection and energy has provided possibility of exemptions from competitive bidding for small electricity generation projects up to 1MW, and further exemptions to as high as 6MW for projects owned by Renewable Energy Communities[18] or SMEs.

The Small-scale Generation Scheme for installations over 50 kW explicitly states that it is targeted to develop support for 'cohorts that are not as suited to other support measures, such as the MSS and the RESS'.[19] These support mechanisms have been designed specifically for their capacity ranges. The MSS is especially useful for residential projects, small public buildings and small agricultural, commercial and community projects. The RESS has been designed for larger-scale projects. Due to their larger size, the projects put forward for auction benefit from better economies of scale and thus require different amounts of subsidy per MW to smaller projects. In addition, auction schemes tend to have high transaction costs, independent of project size, making it more costly for smaller projects[20].

The capacity range between 50-6,000kW, targeted within the Small-scale Generation Scheme, can play an important role in increasing deployment of renewables, including community energy. The government can ensure the policy overcomes the identified viability gap for Renewable Energy Community solar PV schemes and can address community energy barriers by for example including tariff guarantees/pre-registering for support since community projects take time or means to involve aggregators or agents since community stakeholders are not necessarily industry experts.

In addition, the Small-scale Generation Scheme in Ireland will need to align with existing and planned policies to ensure it can meet national targets and achieve complementary policy objectives. Therefore, taking the above purpose of the policy and policy objectives into account, the following requirements will need to be addressed in the design of the policy:

- Grid connection policy will need to be changed, extended or created to address the increasing numbers of small-scale generators being connected to the grid. Changes in the Enduring Connection Policy 2 aim to both remove the administrative pressure and improve the process for connecting projects to the grid. Currently, there is a singular application window per year each September which contains at least three annual batches of connection offers, except for 'non-batch' categories, which include projects with a Maximum Export Capacity (MEC) between 6 kW and 500 kW, DS3 systems up to 500 kW and auto producers.[21,22] These non-batch categories are limited to 15 connections per batch period with another 15 connections reserved for community projects, between 500 kW and 5000 kW. Further, ESB Networks (ESBN) recently stated in their Non-Firm Access Guide that 30% of HV and MV transformer capacity will be reserved for microgeneration up to 11 kW only.[23] Following a consultation in December 2020, ESB Networks stated that they will retain this 30% provision going forward, although they will continue to monitor developments and review the position in early 2023[24]. ESB Networks also recently ran, on a pilot basis, a new simplified connection process for projects

[16] https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX%3A32019R0943

[17] https://eur-lex.europa.eu/legal-content/EN/ALL/?uri=PI_COM:C(2021)9817

[18] RED II defines a 'Renewable Energy Community' as a legal entity: (a) which, in accordance with the applicable national law, is based on open and voluntary participation, is autonomous, and is effectively controlled by shareholders or members that are located in the proximity of the renewable energy projects that are owned and developed by that legal entity; (b) the shareholders or members of which are natural persons, SMEs or local authorities, including municipalities; (c) the primary purpose of which is to provide environmental, economic or social community benefits for its shareholders or members or for the local areas where it operates, rather than financial profits;

[19] https://www.gov.ie/en/publication/6223e-climate-action-plan-2021/

[20] https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2015/Jun/IRENA_Renewable_Energy_Auctions_A_Guide_to_Design_2015.pdf

[21] https://www.cru.ie/wp-content/uploads/2020/06/CRU20060-ECP-2-Decision.pdf

[22] An autoproducer is a person entered into a connection agreement with the TSO or DSO and generates and consumes electricity in a single premise, or on whose behalf another person generates electricity in the single premises, essentially for the first person's own consumption in that single premises. Once an exporting autoproducer's MEC reaches or exceeds twice the MIC, then the exporting autoproducer is deemed to be a generator.

[23] https://www.esbnetworks.ie/docs/default-source/publications/non-firm-access-for-distribution-connected-distributed-generators-guide.pdf?sfvrsn=290ab2c0_15

[24] https://www.esbnetworks.ie/docs/default-source/publications/esb-networks-response-paper-on-public-consultation-on-capacity-provision-for-growth-in-microgeneration-connections.pdf?sfvrsn=2364dcf9_6

between 11 and 50 kW, referred to as Mini-generation (Conditions Governing the Connection and Operation of Mini-Generation 2021), and also developed procedures for an Export Limiting Scheme (ELS) targeted also at mini-generation. An important limitation is that mini-generation sites will have a capped MEC, which is not to exceed the Maximum Import Capacity (MIC). This is a barrier to address should policy wish to encourage export-led generation opportunities at demand sites.

Although some categories of the Enduring Connection Policy (ECP) allow connections for installations from 50 kW up to 1MW, the facilitation of hybrid connections and policy development for multiple generators and/or storage units at a single site remains a work in progress. Work streams are ongoing under the FlexTech initiative to consider the complexities of hybrid connections. Under the ESBN Local Connections Programme, flexible market mechanisms are being piloted for distributed generators, including innovative pricing models that could reward small generators for relieving network constraints and delivering power and system services where they are needed in the network.

- The Department of Housing, Local Government and Heritage published proposed revisions to the existing planning exemptions for the installation of solar panels on the roofs of houses and certain non-domestic buildings on 15th June 2022.[25] A public consultation as part of the Strategic Environmental Assessment process closed on 13th July. The proposed changes are aimed at increasing Ireland's generation of solar energy and national action on climate change. The draft regulations propose the removal of the rooftop square metre based limits which currently apply in the Principal Regulations, to allow more extensive coverage, subject to certain conditions as well as restrictions in certain areas.
- 43 solar safeguarding zones have been identified within which a rooftop square metre will continue to apply to all classes of development other than houses. Solar installations covering the entire roof of houses in all parts of the country, including those within solar safeguarding zones, are proposed to be exempted under these draft regulations subject to conditions requiring the installation to be a minimum distance from the edge of the roof. Notwithstanding the introduction of solar safeguarding zones for all classes of development other than houses, the rooftop square metre limit within these areas has been increased to 60sqm. It is open to anyone seeking to avail of larger rooftop solar installations within solar safeguarding zones to apply for planning permission. Also included in the proposed expansion of the Regulations is the addition of two new classes of development relating to apartments and educational/community/religious buildings.
- Incentivisation that provides the appropriate total cost of support per kW of supplied energy for the scale and application of roof-top and ground-mounted solar PV in the targeted capacity range. Over-incentivisation can quickly overburden the allocated budget entailing in future revision or early closure.
- Ensuring the policy is aligned with the wider Irish and EU policy objectives around environment, e.g., by requesting strategic environmental assessments to be carried out, and to promote self-consumption and community energy. Moreover, compliance with State Aid rules will need to be guaranteed as well.
  - In particular, community participation must be facilitated so non-expert groups are supported in the planning, installation and maintenance of their projects. Support must also align with the defined Renewable Energy Community (REC) commitments under RED II.[26]
  - There has been a significant shift in Irish policy to achieve the up to 80% renewable electricity target in the Climate Action Plan and so harmonisation with existing and planned policies is crucial and ensuring the new scheme meets the policy principles outlined in the Climate Action Plan.
- Financial mechanisms must also protect all actors along the supply chain and ensure they are benefiting from the growth in deployment.
- This support must include all national and EU compliance measures within the process for successful applicants.
- The scheme must not overshadow current market incentives already supplied by commercial actors in the economy.
- The application process must factor in the potential number of applications to reduce transaction costs and administrative burden for the scheme and the applying parties.

[25] gov.ie - Public Consultation on the Draft Planning and Development Act 2000 (Exempted Development) (No. 3) Regulations 2022 and the Draft Planning and Development (Solar Safeguarding Zone) Regulations 2022- Solar Exemptions (www.gov.ie)
[26] https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=uriserv:OJ.L_.2018.328.01.0082.01.ENG&toc=OJ:L:2018:328:TOC

- There is the risk of providing economic incentive whilst not having appropriate or sufficient grid connection policy.

There are some tax incentives available for commercial actors installing solar. Limited companies and sole traders can avail of accelerated capital allowances (ACA), which typically allows 8 years of capital allowances to be used in the year of purchase of a qualifying system, assuming that there is an equivalent tax liability in the year of purchase. Farmers who are not VAT registered are also entitled to claim a flat-rate VAT rebate on solar installations. This is currently 5.5% of the purchase price. Larger farms with higher energy consumption are more likely to be VAT registered and claim VAT on purchases as a normal business input. The TAMS (Targeted Agricultural Modernisation Scheme) provides direct grant support of up to 40% of capital costs to qualifying systems on farms. However, this policy support is limited to systems of up to 11kW only and so not relevant for the size range of this study.

In addition, for the newly introduced Clean Export Guarantee (CEG) scheme for renewable self-consumers (see more information in section below), a tax disregard of 200 EUR for household income from exported renewable electricity was included in Budget 2021. This means that domestic users do not need to pay tax on the first 200 EUR they earn for the renewable electricity they export to the grid via the CEG scheme[27][28].

2.1.2 Types of Policy and Suitability for Installation Size Range

The main types of policies that have been used internationally to incentivise renewable electricity generation are outlined below, including assessments of their suitability for small-scale renewables (50 – 1000 kW) and the requirements outlined above:

- **Tariff-based instruments** e.g., Feed in Tariffs (FIT) and minimum export price guarantees. These types of policies incentivise investment in renewable energy technologies by offering long-term contracts to renewable producers, providing price certainty and long-term guarantees, and thereby lowering the risk for investors. These policies are therefore an attractive option for technologies that lack maturity. However, a downside of these options is that they carry a high risk of increase in support costs. Therefore, cost and volume control mechanisms are important to maintain the required cost-effectiveness of FITs and in addition give investors more certainty[29].
    - Feed-in-Premiums (FIPs) work in a similar way as FITs, but instead of a standard guaranteed payment, generators receive a premium on top of the market price of their electricity production. These premiums can either be fixed (at a constant level independent of market prices) or sliding (with levels varying in line with wholesale electricity prices). Fixed FIP schemes are simpler in design but there is a risk of overcompensation in the case of high market prices or under-compensation when market prices are low. In the case of sliding FIP schemes, the regulator faces some risk in case electricity prices decrease, as support levels fluctuate with changes in electricity market prices. On the other hand, the regulator does not risk having to pay for overcompensation, as is the case under a fixed FIP scheme. The sliding FIP scheme does however make the scheme more complex, thereby adding additional administration costs. Cost predictability can be increased by introducing a cap of maximum support on floating premiums[30].
    - A **Smart Export Guarantee (SEG)**, which is an obligation on licensed electricity suppliers of a specific size to offer an export tariff to renewable generators with eligible installations. The suppliers can decide the level of the export tariff as well as its type and length. This could mean there could be a variety of different SEG tariffs available and generators may consider switching to suppliers with the most favourable SEG.

The figures below explain the mechanisms of FiT, FiP and SEG in the context of different electricity price scenarios.

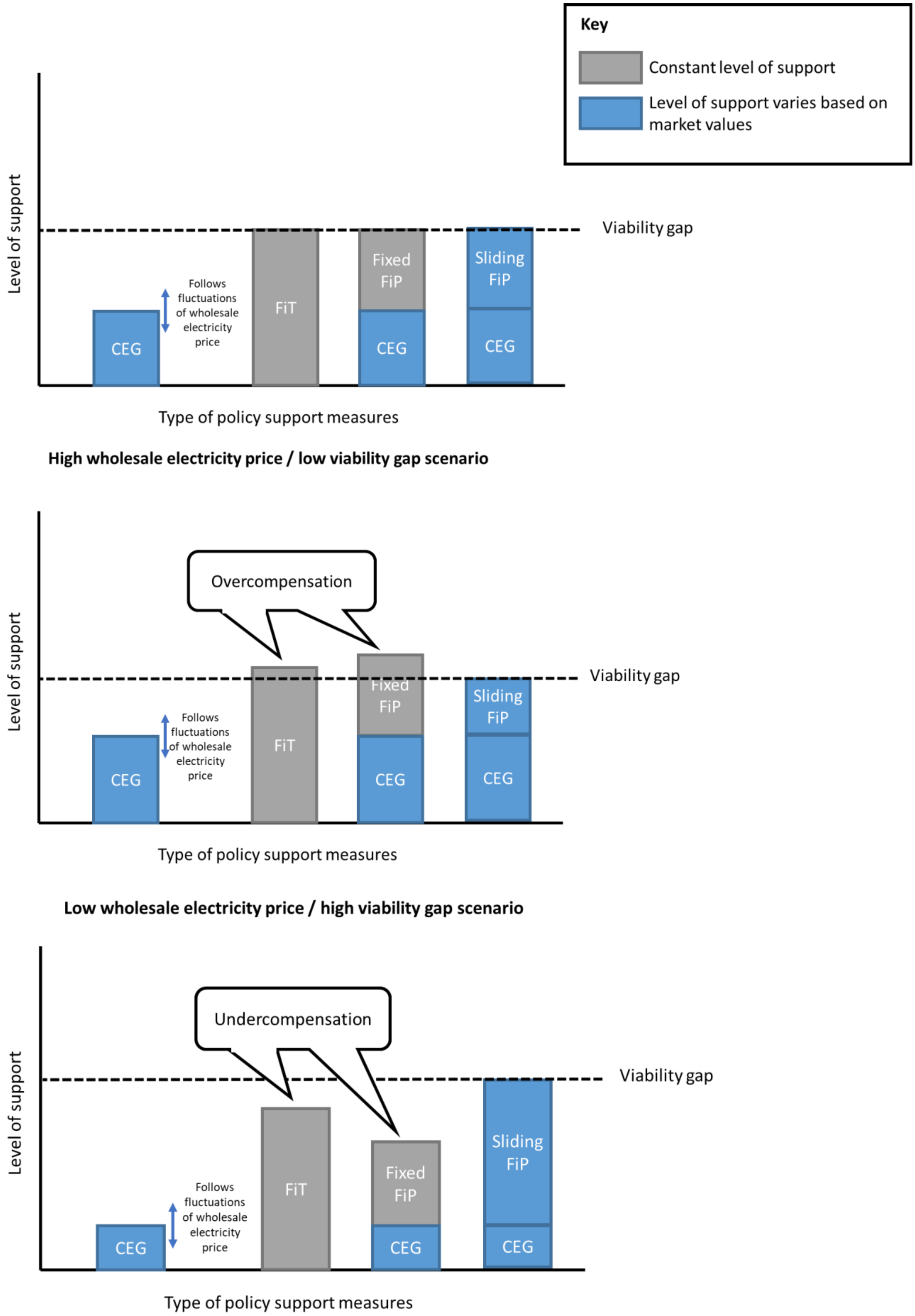
[27] https://www.gov.ie/en/press-release/bfe21-homes-farms-businesses-and-communities-to-benefit-as-minister-ryan-announces-the-micro-generation-support-scheme/

[28] Please note that the tax payments have not been modelled as part of the assessment of the policy options presented later in this report.

[29] https://ec.europa.eu/energy/sites/ener/files/documents/2014_design_features_of_support_schemes.pdf

[30] https://climatepolicyinfohub.eu/cost-effectiveness-eu-renewable-energy-support-systems.html#footnote4_cg3qnmp

Figure 2: Schematic overview of FiT, FiP and CEG policies



- **Investment subsidies or grants** can be provided for costs associated with the purchase and installation of small-scale renewable equipment. For example, enabling grants are offered for grid-scale projects under the RESS.[31] However, it should be noted that investment subsidies may not be suitable for all types of small-scale renewables, for example community energy projects, due to the Guidelines on State aid for climate, environmental protection and energy (CEEAG) which preclude costs such as grid stage payments.[32]
- **Quantity-based instruments,** e.g., purchase obligations and renewable energy certificates. These instruments provide direct control over the amount of renewable capacity installed or energy produced and thereby offer guarantees that the target will be met, unlike the measures listed above. However, these quantity-based instruments provide less guarantees to project developers with respect to future cash flows. Therefore, in practice, the risk of over/underbuilding is transferred from government to developers[33]
- **Auctions** combine features of tariff- and quantity-based instruments. They offer flexibility and "price discovery", so that the real price of the product being auctioned is brought out by means of a structured, transparent and most importantly, competitive process. This policy type thereby addresses the potential problem of information asymmetry between the regulator (or any other entity responsible for determining purchase prices and support levels) and renewable project developers[33] and it also provides greater certainty for the installed capacity to be realised. However, auctions typically work better for larger size ranges. Auction schemes tend to have high transaction costs, independent of project size, making it more costly for smaller projects especially when taking into account the risk of underbidding and delays.[33]

  It should be noted that the above measures can also be combined into hybrid approaches for example by providing a grant for equipment purchase as well as a tariff-based measure or allocating a FIP using a tendering mechanism as applied in the Netherlands.

The newly announced Micro-generation Support Scheme (MSS) in Ireland will include a mix of the policy types listed above[34]:

- A **SEG** in the form of a Clean Export Guarantee (CEG) for any exported electricity at a competitive market rate paid by the electricity suppliers.
- Domestic users can apply for a **grant** for installing renewable equipment up to a maximum of 2400 EUR (continuation of existing scheme).
- Businesses, farms, and community buildings up to 5.9 kW can apply for a **grant** similar to the scheme for domestic users from later in 2022 onwards.
- Non-domestic users of projects between 6 kW and 50 kW will receive a **Feed-in-Premium** (called Clean Export Premium) in addition to the CEG for electricity exported from Q3 in 2022 onwards, with the premium fixed by year. This is planned to be paid for a period of 15 years and will be provided by electricity suppliers, initially at a rate of 0.135 EUR / kWh in 2022 and supported by the Public Service Obligation (PSO) levy. However, exported electricity eligible for this premium will be capped at 80% of estimated total electricity generation in order to incentivise self-consumption.

2.2 INTERNATIONAL CONTEXT

Deployment of renewables continues to grow around the world, with additions of renewable power capacity setting another annual record in 2021.[35] However, according to the IEA the pace is insufficient to meet their Net Zero Emissions by 2050 Scenario, with "more efforts needed" in the deployment of solar PV for example.[36] The required increase in annual solar PV deployment until 2030 necessitates much greater policy ambition

[31] https://www.seai.ie/community-energy/ress/
[32] https://ec.europa.eu/commission/presscorner/detail/en/qanda_22_566
[33] https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2015/Jun/IRENA_Renewable_Energy_Auctions_A_Guide_to_Design_2015.pdf
[34] https://www.gov.ie/en/press-release/bfe21-homes-farms-businesses-and-communities-to-benefit-as-minister-ryan-announces-the-micro-generation-support-scheme/
[35] https://iea.blob.core.windows.net/assets/5ae32253-7409-4f9a-a91d-1493ffb9777a/Renewables2021-Analysisandforecastto2026.pdf
[36] https://www.iea.org/reports/solar-pv

and more efforts from both public and private stakeholders, with particular attention paid to the areas of grid integration and the mitigation of policy, regulatory and financial challenges.

The acceleration of renewables deployment is also seen as a crucial means to achieving Europe's climate goals. Under the 'Fit for 55' package of legislations, the recast Renewable Energy Directive (RED II) will be revised to set an increased target for 40% of final energy consumption to come from renewable sources by 2030[37]. Incentivising schemes are still necessary to drive uptake of small-scale renewables, particularly given recent elevated commodity and freight prices bringing to an end a decade of declining costs.[38] This has been evidenced by the Deemed Energy Quantity (DEQ) GWh-weighted average Strike Price of successful offers increasing from 74.08 €/MWh in RESS 1[39] to 97.87 €/MWh in the RESS 2 auctions.[40]

The variation in characteristics of installations across this capacity range (50-1000 kW), outlined in Section 2.1, means a variety of schemes have been introduced across Europe to incentivise their uptake. This includes FITs, FIPs, auction-based schemes and hybrid systems combining aspects of these approaches.

Some limitations have been imposed by the EU State Aid Guidelines, which stipulated that tendering be required for larger installations for reasons of competitiveness. The EU Guidelines on State Aid for Environmental Protection and Energy for 2014-2020[41] stipulated that small installations below 3MW for wind or 500 kW for other sources should be allowed to benefit from any form of aid, including feed-in tariffs. However, the guidelines were recently changed to allow more flexibility for Member States in the design of their aid mechanisms for small-scale installations. Under the new state aid rules[42] renewable electricity projects up to 1 MW, as well as 100% renewable energy community or SME-owned projects up to 6MW, for solar and 18MW for wind, do not require competitive bidding processes. The new guidelines also allow government and national authorities to hold tenders for specific technology applications, such as floating solar and agri-voltaics.[43]

Some of the current and historic legislation incentivising small-scale renewables in EU Member States is detailed below:

- The **Netherlands** has the highest solar power capacity per capita in Europe, with commercial rooftop market the main driver for solar.[44] In 2020, commercial rooftop installations (10-250 kW) accounted for over 40% (approx. 1.2 GW) of the total market, slightly more than the residential market (< 10 kW), which had a share of almost 40% (approx. 1 GW). Meanwhile the market for ground-mounted and floating solar PV (> 1 MW) installations accounted for more than 20% (approx. 0.6 GW).

  Commercial, industrial, and utility-scale markets rely on the SDE++ (and previous SDE+) schemes in which, using a tender mechanism, the government allocates a fixed subsidy budget towards applicants based on the lowest subsidy requirement per tonne of CO_2 reduction. Priority is given to the applications with a lower cost price, so project developers are provided with an incentive to realize their projects at the lowest costs possible. For solar PV installations < 1 MWp, the system must be completed within 2 years[45] (previously 18 months in the 2020 tender[46]).

  In the October 2020 tender, a total of 3.6 GW of solar projects were granted subsidy, about half of which was ground-mounted, with the other half large rooftop solar. Although the SDE++ was recently opened to Carbon Capture and Storage (CCS) and energy saving projects, solar still won the major share in the first round of the revised scheme in 2021. While it is too soon to tell for the SDE++ scheme,

[37] https://ec.europa.eu/commission/presscorner/detail/en/IP_21_3541

[38] https://www.iea.org/news/renewable-power-is-set-to-break-another-global-record-in-2022-despite-headwinds-from-higher-costs-and-supply-chain-bottlenecks

[39] https://www.eirgridgroup.com/site-files/library/EirGrid/RESS-1-Final-Auction-Results-(R1FAR).pdf

[40] https://www.eirgridgroup.com/site-files/library/EirGrid/RESS-2-Final-Auction-Results-(R2FAR).pdf

[41] https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX%3A52014XC0628%2801%29

[42] https://ec.europa.eu/competition-policy/system/files/2021-12/CEEAG_Guidelines_with_annexes_I_and_II_0.pdf

[43] Agri-voltaics is the simultaneous use of areas of land for both solar photovoltaic power generation and agriculture.

[44] https://www.solarpowereurope.org/wp-content/uploads/2021/12/EU-Market-Outlook-for-Solar-Power-2021-2025_SolarPower-Europe.pdf?cf_id=48112

[45] https://english.rvo.nl/sites/default/files/2021/10/SDEplusplus_oktober_2021_ENG.pdf

[46] https://english.rvo.nl/sites/default/files/2020/11/Brochure%20SDE%20plus%20plus%202020.pdf

historically the SDE+ scheme has achieved high realisation rates. In November 2019, only around 10% of project capacity from 2015 tenders had not been realised.[47]

- Solar PV in **France** is primarily driven by an extensive tendering scheme for ground-mount and rooftop systems. Projects between 100 kW and 250 kW faced a simpler process, with more complicated auctions for those above 250 kW. In 2021, the threshold for rooftop tenders has been increased from 100 to 500 kW, making more systems eligible for feed in tariffs.[48]

  Raising the FIT threshold is expected to incentivise this market segment, where projects were previously limited by tendering procedures. The French minister of the ecological transition, Barbara Pompili, confirmed this intention, stating "*Our goal is to make the implementation of projects as easy and quick as possible. I know that many projects are ready. With these new measures, they will be able to materialize quickly."*[49]

  Additional relevant measures were also announced by the Ministry of Ecological Transition in November 2021, including the launch of an audit of different categories of project promoters (local authorities, individuals, farmers, SMEs and electricians) to identify new simplification measures.[50] Furthermore, a decree will soon be published to implement the measure of the climate and resilience law, which offsets grid fee costs for small projects below 500 kW.[51]

- In **Germany**, the onsite consumption of small-scale solar PV electricity has been supported since 2009.
  To begin with, electricity producers received a fixed FIT for feeding-in electricity into the grid, whilst electricity for own use could be deducted and was incentivised at the same time. This regulation was first modified in 2010, when a "split tariff" was offered for building-integrated PV power plants smaller than 500 kW. Besides the FIT paid for the electricity fed into the grid, the onsite consumption received an additional incentive. However, the additional incentive was abolished in January 2012 in order to reflect the changing economics of solar PV with FITs for PV being lower than retail prices.[52]

  The German solar sector has been experiencing a second boost as of 2018 due to a combination of attractive feed-in premiums for medium- to large-scale commercial systems, auctions for systems up to 10 MW, a well-developed regulatory scheme and the steadily improving cost competitiveness of solar. January 2021 saw revision of the Renewable Energies Act (EEG), which has made investments in residential and small commercial systems more attractive after a self-consumption levy was eliminated. However, the changes put a financial burden on larger rooftop self-consumption systems to drive this segment into a tender scheme which meant the German market, that had grown by around 1 GW per year between 2017-2020, is estimated to have grown by less than 0.5 GW in 2021.[44]

- Expected growth in solar deployment in **Poland** will be primarily driven by national tenders. Auctions, in which projects below 1 MW and above 1 MW are placed in different baskets, are carried out at least once a year. The auctions for systems below 1 MW are being dominated by solar. As a result of the last of these auctions, which also took place in June 2021, almost 1 GW of new capacity will be installed.[44]

- **Greece** more than tripled annual PV deployment to 1.6 GW in 2021[44], driven mostly by small ground-mounted PV projects up to 500 kW, for which the government recently extended the feed-in premium until the end of 2022.

  The bottleneck for fast PV deployment in Greece is now the availability of grid capacity.[53] Self-consumption is now beginning to emerge, mainly in the commercial sector. Energy communities are also becoming popular around the country.

[47] http://aures2project.eu/wp-content/uploads/2019/12/AURES_II_case_study_Netherlands.pdf
[48] https://www.legifrance.gouv.fr/jorf/id/JORFTEXT000044173060
[49] https://www.pv-magazine.com/2021/10/06/french-government-confirms-fit-of-e0-098-kwh-for-pv-systems-up-to-500-kw/
[50] https://www.pv-magazine.fr/2021/11/03/barbara-pompili-annonce-dix-mesures-phares-pour-accelerer-le-solaire-en-france/
[51] https://www.pv-magazine.com/2021/11/04/france-announces-10-measures-to-support-pv-deployment/
[52] https://ec.europa.eu/energy/sites/ener/files/documents/2014_design_features_of_support_schemes.pdf

- The self-consumption rooftop market in **Spain** is similarly undeveloped, as the country's former 'sun tax' has made investments in that segment unattractive. However, the Spanish Recovery Plan[54] considers PV rooftops a key measure for the energy transition, and in June 2021, the government released EUR 450 million in grants for investments in self-consumption systems to be distributed by its regions. The initial EUR 450 million package can be expanded up to EUR 900 million, with EUR 400 million for the residential sector, EUR 300 million for industry and agriculture and EUR 200 million for services.[55]

From this brief overview of small-scale renewable support schemes in Europe, the need for a targeted scheme to incentivise small-scale renewables is apparent. Feed-in-tariffs appear to be effective tools for encouraging uptake (e.g., France, Greece), but the cost-effectiveness of this approach must be ensured through correction factors and regular reviews. Tender schemes have also proven effective (e.g., Netherlands, Poland) but can be off-putting due to the additional administrative burden (e.g., recently reported in Germany).

The legislative framework surrounding the issue of self-consumption also appears to be an important factor to consider, due to the large number of commercial and industrial installations in this capacity range. More countries seem to be developing specific legislation aimed at incentivising self-consumption (e.g., Germany, Spain, France). This issue is important in the context of current high electricity prices in the European Union. The sharp spike in gas and electricity prices underlines the need to improve demand management at both the individual and societal levels.

[54] https://www.lamoncloa.gob.es/presidente/actividades/Paginas/2020/espana-puede.aspx
[55] https://ratedpower.com/blog/spanish-government-solar/

2.3 INTERNATIONAL CASE STUDIES

To further inform policy options for Ireland, a set of international case studies has been selected using the criteria as outlined in the box below.

Box 1 Case study selection criteria

- **Year of implementation**, with more recent studies being prioritised, and for EU case studies those that have been aligned with the revised Renewable Energy Directive (2018/2001/EU).
- **Alignment with Irish policy principles** such as the Programme for Government and the Climate Action Plan
- Targeting of **mainly solar and renewable technologies between 50 kW – 1 MW**
- **Data availability**, including information on costs and cost control mechanisms.

A total of seven possible case studies were considered, as outlined in Table 3 and based on the selection criteria from Box 1, the Netherlands, France and Germany were taken forward for more in-depth analysis. All three of these case studies provided sufficient data availability, comparable principles in terms of alignment with Irish policy principles and solar resources, and a high data availability.

Table 3 - Long-list of case studies and their scoring against selection criteria (R/A/G)

	Netherlands	France	Germany	Denmark	Poland	Greece	Spain
Year of implementation	2011, updated 2020	2015, revised 2021	2009, revised 2021	Revised 2020	Revised in 2021	Revised 2021 up to 2022	New in 2021
Alignment with Irish policy principles and solar resources	Comparable principles	Comparable principles	Comparable principles	Comparable principles	Less comparable	Less comparable	Less comparable
Targeting of mainly solar between 50 kW – 1MW	Supports solar 15kW-1MW (also >1 MW with different premiums/ requirements)	100 - 500 kW (previously 250 kW)	Up to 10MW	Tender scheme for up to 1MW	Up to 1MW	Up to 500 kW	Also residential sector (<10 kW)
Data availability	High	High	Medium	Low (because uptake low)	Medium	Low	Low

The findings from the three case studies are summarised in Table 4.

Table 4. Case study information

	Case Study 1: Netherlands	Case Study 2: France	Case Study 3: Germany
Description	Tendering scheme for premium paid on top of market price, for systems between 15 kW–1 MW	FIT up to 500 kW, FIP allocated by tendering scheme for systems > 500 kW	Renewable Energies Act (Erneuerbare Energien Gesetz – EEG) now offers choice of auction scheme or FIT for systems between 300–750 kW
Years of implementation	SDE+: 2011-2020 SDE++: 2020-Present	FIT: 2011-2021 (< 100 kWp) FIT: 2021-Present (< 500 kWp)	EEG: 2000-Present (amended in 2004, 2009, 2012 and 2014[56], 2017[57] and 2021[58])
Administrator	Netherlands Enterprise Agency (Rijksdienst voor Ondernemend Nederland, RvO)	EDF (local distribution companies are no longer part of the mechanism)[59]	Federal Network Agency (Bundesnetzagentur, BNetzA)
Background	Whereas, the Dutch residential solar market is driven by a net-metering scheme, the commercial and utility-scale operators can participate in the SDE++ (formerly SDE+) tendering scheme. The SDE+ was one of the first large technology neutral support schemes in Europe, which allowed for large fluctuation in the type of capacity contracted, as well as the auctioning of budget instead of capacity. The progression from SDE+ to SDE++ in 2020 saw the scheme develop from a renewables support scheme to a wider CO_2 emission reduction support scheme.	Solar PV in France is primarily driven by a FIT for microgeneration and an extensive tendering scheme for ground-mount and rooftop systems. In 2021, the threshold for rooftop tenders increased from 100 to 500 kW, making more systems eligible for feed in tariffs.[60] A technology-neutral tender scheme for self-consumption from renewable energy projects ranging in size from 100 kW to 500 kW also entered into force in 2018.	The German solar sector has been experiencing a second boost as of 2018, in part due to attractive feed-in premiums for medium- to large-scale commercial systems. However, 2021 saw revision of the Feed-in Law (EEG), which has put a financial burden on larger rooftop systems to drive this segment into a tender scheme.
Scope (including installation capacity limits)	For solar PV (varying levels of subsidy): • ≥ 15 kWp and < 1 MWp (buildings; ground-mounted or floating on water) • ≥ 1 MWp (buildings; ground-mounted; ground, solar tracking; floating on water, solar tracking). Also biomass, geothermal, hydro, solar thermal,	Solar support scheme for large-scale PV installations on buildings. • Feed-in tariff (for installations 100 - 500 kW) • Feed-in premium (for installations 500 kW - 8 MW) over 20 years	The owners of PV installations ranging in size from 300 kW to 750 kW are now given two options: • Receive renumeration through a tendering procedure , but without being allowed self-consumption, or • Receive a FIT for 50% of the electricity generated. For the remaining 50%, the only options are to feed

56 https://www.futurepolicy.org/climate-stability/renewable-energies/the-german-feed-in-tariff/
57 https://www.bmwi.de/Redaktion/EN/Downloads/renewable-energy-sources-act-2017.pdf%3F__blob%3DpublicationFile%26v%3D3
58 https://www.gesetze-im-internet.de/eeg_2014/index.html#BJNR106610014BJNE015101128
59 https://cms.law/en/int/expert-guides/cms-expert-guide-to-renewable-energy/france
60 https://www.legifrance.gouv.fr/jorf/id/JORFTEXT000044173060

	Case Study 1: Netherlands	Case Study 2: France	Case Study 3: Germany
	onshore wind energy, CCS and energy saving projects	Solar support scheme for large-scale ground-mounted PV installations. • Feed-in premium over 20 years	this portion into the grid without subsidies or to consume it on site.
Investment grant	No	No	No
Tariffs/ premiums	Participants are paid a premium on top of market price which depends on the annual electricity market price development and is adjusted by a correction value accordingly. For PV ≥ 15 kWp and < 1 MWp in Phase 1: • Building-mounted: 7.03 ct/kWh • Ground-mounted/floating: 6.6 ct/kWh	Tariff has been set at 9.8 ct/kWh A bonus for landscape integration (in order to promote the use of solar tiles) is also in effect.	A maximum bid price of 5.9 ct/kWh was set for 2021. In contrast, tenders for roof-mounted plants will be held between 2021 and 2028 with a total tender volume of 2.9 GW and a maximum bid of 9 ct/kWh in 2021.[61]
Requirements, including grid connection costs	Peak output of ≥ 15 kWp Connection to the grid with a total maximum transmission value of more than 3*80 A (a large-scale energy connection). Feasibility study (less work required for < 1 MWp installations) The costs for the connection between the installation and the closest grid connection point are borne by the project developer, with costs for grid enforcements borne by the DSO/TSO. Costs for land lease, permitting, etc. are all paid by the project developer.[62]	Volume-capped periodic competitive tenders for systems from 100 kW to 30 MW are segmented according to size and application (building applications, ground based etc.). For those PV installations 100 kWp in size and above, only modules with a carbon footprint below 550 kg CO_2eq./kWp[63] will benefit from a purchase contract.[64] Producers pay only for the cost of equipment needed to make the physical connection to the grid. Costs of grid reinforcements are borne by the DSO.[65]	In a bid to reduce the imbalance in generating capacity tilted towards the north of the country, the new EEG introduces a “quota for the south” (15% between 2021-2023 and 20% as of 2024) to incentivise wind expansion in southern Germany. A similar quota also applies to tenders for biomass installations (50%).[66] Producers pay only for the cost of equipment needed to make the physical connection to the grid. Costs of grid reinforcements are borne by the DSO. [67]
Effectiveness	Trinomics, who assessed the methodological principles and coherence of the SDE++, emphasised that the choice to stimulate new greenhouse gas-reducing technologies in addition	A lack of land eligibility, grid access and lack of administrative resources, regulatory barriers and	Under the new EEG, more PV systems have to commit to feeding all of their electricity into the network to participate in the tender scheme. A medium-sized company wanting to implement a

[61] https://www.dgrv.de/news/eeg-novelle-2021-2/
[62] http://aures2project.eu/wp-content/uploads/2019/12/AURES_II_case_study_Netherlands.pdf
[63] The simplified carbon assessment of the photovoltaic power plant is based solely on the simplified carbon assessment of the photovoltaic laminate (frameless photovoltaic module). Greenhouse gas emissions related to other plant components and from other stages of the module's life cycle (transport to the commissioning and operating site, installation, use, end of life) are not considered.
[64] https://www.legifrance.gouv.fr/jorf/id/JORFTEXT000044173060
[65] https://cdn.eurelectric.org/media/3440/charges-for-producers-connected-to-distribution-systems-lr-2018-2322-0001-01-e-h-1B7D0BD3.pdf
[66] https://www.cleanenergywire.org/factsheets/whats-new-germanys-renewable-energy-act-2021
[67] https://cdn.eurelectric.org/media/3440/charges-for-producers-connected-to-distribution-systems-lr-2018-2322-0001-01-e-h-1B7D0BD3.pdf

	Case Study 1: Netherlands	Case Study 2: France	Case Study 3: Germany
	to producing renewable energy creates more relevant variables, assumptions and predictions than under the SDE+.[68] The effectiveness of SDE++ is therefore dependent on predictions about emission factors in 2030 and long-term electricity and gas prices. This increases the chance that the estimate of the subsidy requirement per ton of CO_2 avoided will differ from practice.[69] Nevertheless, the commercial rooftop market remains the main driver of the Dutch solar market.[44] Backed by its large rooftop market and solar's success in the regular technology neutral auctions, the Netherlands is expected to add about 17 GW of new solar installations in the next four years.[44] In total, up to January 1st 2018 the SDE+ (before becoming SDE++) realised approximately 3,185 MW of new installed electricity capacity[70]. In the same year it was also reported that the realisation rate of projects under SDE+ had been generally low. However, a study from the Dutch Ministry of Economic Affairs in 2016 reported that most projects under the scheme would not have been realised without funding from the SDE+[71].	stop-go support policies have hindered deployment of renewables in France.[72] However, raising the FIT capacity threshold is expected to make things easier for this market segment, where projects were previously limited by tendering procedures. Solar Power Europe say there is "no doubt that this change will generate renewed impetus to develop rooftop installation projects".[44] Annual solar installations more than doubled in 2021, indicating that the market is improving as a result of the modified legislative framework. A recent forecast predicts that France will connect 15.1 GW solar to the grid up to 2025.[44]	climate strategy with its own PV power would be unable to use any of its on-site power for its manufacturing processes and, on top of that, the company would have to take time out from its core business to participate in the bidding process. The motivation for this is likely to be very low, which is why bidding processes are expected to be undersubscribed.[73] The new law appears to have already hindered PV deployment. Many systems between 300-750 kW were installed in March 2021 as the transition period in the EEG expired in April. In the following months, a decrease in projects above the 300 kW threshold was observed, confirming the negative impact of the new law on the segment. The total German solar deployment (around 1 GW per year between 2017-2020) is estimated to have grown by less than 0.5 GW in 2021. However, Germany is still expected to install 47.7 GW by 2025.[44]

[68] http://trinomics.eu/wp-content/uploads/2020/02/Review-SDE-Methodiek.pdf
[69] https://www.dentons.com/en/insights/alerts/2020/april/16/ams-dutch-subsidies-for-renewable-energy-the-end-of-the-sde-scheme
[70]:https://www.rvo.nl/sites/default/files/2018/02/Gerealiseerd%20v ermogen%20SDE%20januari%202018.pdf
[71] Blom, M., Schep, E., Vergeer, R., Wielders, L. (2016). Rev iew of the Dutch SDE plus Renewable Energy Scheme. CE Delf t and SEO Economisch Onderzoek. Delft, the Netherlands.
[72] https://iea.blob.core.windows.net/assets/7b3b4b9d-6db3-4dcf-a0a5-a9993d7dd1d6/France2021.pdf
[73] https://www.eon.com/en/about-us/politics/eeg-2021.html

	Case Study 1: Netherlands	Case Study 2: France	Case Study 3: Germany
Efficiency / cost elements	The SDE++ is designed so that the cost effectiveness of achieving emissions reductions is the most important criterium in the selection of the projects. The technologies that are able to prevent the most CO_2 emissions at the lowest price will receive the subsidy. Because this means that much more projects are eligible and will therefore apply, it will probably be more difficult to obtain a subsidy for existing technologies such as solar PV. The expectation is that solar energy projects can be developed, without any incentives, based on PPA contracts by 2025 at the latest. RES support (all capacities) per unit of gross electricity produced in 2018: EUR 9.37/MWh.[74] In particular, the rates used for compensation of generators were broadly in line with market values, thereby minimising the number of free riders in the system to about 5-15%, which is considered low compared to other EU policies. It was also reported in the official review commissioned by the Ministry of Economic Affairs that the administrative costs of the scheme were seen as reasonable in comparison to subsidy provided[75].	Since January 2016, renewables support has fallen under the general state budget, through a dedicated purpose fund – the financing of which is decided each year by the Parliament through a Finance Law (currently, internal taxes on fossil fuels). Tariffs will be renegotiated every quarter according to the capacities installed. In 2020, the French National Assembly approved an amendment to the draft Finance Law, which seeks to implement a "targeted retroactive revision" of the feed-in tariff paid to certain photovoltaic electricity producers under contracts signed between 2006 and 2010. RES support (all capacities) per unit of gross electricity produced in 2018: EUR 7.58 /MWh.[74]	For the first time, the EEG also provides for annual monitoring, which can be used to make adjustments if necessary.[76] Germany's renewable energy levy, the surcharge in consumers' electricity bills that goes to support renewables, was 6.5 ct/kWh in 2021, reduced from EUR 6.756 in 2020. Transmission grid companies have said the cap on the surcharge would require 10.8 billion euros of federal support payments.[77] The government also decided that the fee would fall further to 6.0 ct in 2022 to relieve customers from cost burdens. The 2021 updates are seemingly aimed at making renewable uptake more market-driven by encouraging the participation of small-scale solar in tenders. By 2027, the government wants to propose how, and by when, renewables funding via the EEG could be stopped entirely.[78] RES support (all capacities) per unit of gross electricity produced in 2018: EUR 36.84 /MWh.[74] The high level of support is likely due to high payment guarantees offered during the early renewable 'boom' years.
Self-consumption	A distinction is made between 'grid supply' and 'non-grid supply' (own use). Different base energy prices and corrective amounts apply to each type of supply.	Before 2016, there was no specific framework for self-consumption in France. Self-consumption was possible in the RES support schemes but only the surplus fed into the grid was remunerated. A dedicated framework[79] has now been put in place. Since 2016, tenders for self-consumption	The self-consumption levy was eliminated for PV systems with a capacity below 300 kW in the new EEG law in January 2021. For installations between 300–750 kW, the updated FIT can be seen as incentivising self-consumption by only offering subsidies for 50% of electricity generated, although this is not a strong incentive as

[74] https://www.ceer.eu/documents/104400/-/-/ffe624d4-8fbb-ff3b-7b4b-1f637f42070a

[75] Blom, M., Schep, E., Vergeer, R., Wielders, L. (2016). Rev iew of the Dutch SDE plus Renewable Energy Scheme. CE Delf t and SEO Economisch Onderzoek. Delf t, the Netherlands.

[76] https://www.iea.org/policies/12392-germanys-renewables-energy-act

[77] https://www.iea.org/policies/12392-germanys-renewables-energy-act

[78] https://www.cleanenergywire.org/factsheets/whats-new-germanys-renewable-energy-act-2021

[79] https://energie-fr-de.eu/fr/manifestations/lecteur/conference-sur-lautoconsommation-photovoltaique-cadres-reglementaires-et-modeles-daffaires-785.html?file=files/ofaenr/02-conferences/2018/180515_conference_pv_autoconsommation/Presentations/02_Louise_Oriol_MTES_OFATE_DFBEW.pdf

	Case Study 1: Netherlands	Case Study 2: France	Case Study 3: Germany
	For self-consumption energy tax, the sustainable energy surcharge (ODE) and transmission costs do not apply.	projects have been organized which offer premiums for self-consumption which were lowered if self-consumption rates fall below 50%.	demonstrated by the market response. Alternatively, operators of this system range can participate in tenders if they do not wish to self-consume.
Storage & temporal issues	The storage sector in the Netherlands has only recently started to develop, and storage is currently not regulated under Dutch legislation. For producers of wind and/or solar with a large-scale grid connection that are eligible for receiving SDE++ subsidy, storing electricity is currently also not beneficial as no SDE++ subsidy is granted for electricity first stored and subsequently delivered to the grid. In addition, a double energy tax may be levied in the case of storage – both for the storage and the subsequent consumption of energy.[80]	Analysts suggest the self-consumption framework should encourage energy storage[81] and there is evidence it is having some effect. While in 2017 the share of French PV installers including battery storage solutions in their portfolio was 32%, by 2020 72% of surveyed installers were offering storage systems to their customers with a further 19% planning to include storage solutions by the end of 2021.[82] The revised FIT also facilitates the possibility of launching calls for tenders for large-scale storage and hydrogen projects in metropolitan France.	The EEG 2021 is forcing new renewable installations to react more flexibly to avoid excess production when electricity demand is low and power input from solar PV and wind is high. They will not receive their feed-in remuneration when the spot market price is negative for four consecutive hours, revised from six hours previously. The government reasons that plant operators will have to "find their own ways of hedging against negative price phases, for example by entering into cooperation agreements with storage operators, by using new plant technology that enables more continuous electricity production or by entering into hedging transactions on the futures market".[83]
Barriers encountered/ overcome	Rates of non-realization of projects were high until 2014, when this was addressed through mandatory feasibility studies and stricter permit requirements. Price fluctuations for solar PV strike prices between the years 2012 – 2015 were reduced through not publishing information about the remaining budget between phases and thus reducing strategic behaviour. The maximum SDE++ contribution decreases every year, so with increasing module prices and increasing logistic costs there is a chance that, for the 2022 round, this decreasing subsidy level will need to be mitigated.	Raising the capacity threshold for FIT eligibility to 500 kW appears to have overcome the barrier to market for small-sized installations. Historically low electricity prices, high taxes and network tariffs, and a regulation with heavy administrative processes are considered to act as a barrier for collective self-consumption projects.[85] Recently, the government clarified that self-consumption projects are exempt from the electricity tax, which is seen as a welcome development. The IEA suggests that France could consider fast-tracking grid connections for	The auction scheme for systems between 300–750 kW was introduced in March 2021. The appetite for mid-sized rooftop systems, which have been a major contributor to solar deployment in Germany in recent years, is already decreasing due to the added financial burden on larger rooftop systems intended to drive this segment into a tender scheme.[87] However, the new government's coalition agreement has committed to reviewing this issue.

[80] https://cms.law/en/int/expert-guides/cms-expert-guide-to-renewable-energy/netherlands
[81] https://www.greentechmedia.com/articles/read/french-law-to-spark-nascent-home-storage-market
[82] https://www.pveurope.eu/solar-storage/battery-storage-france-pv-installers-build-upon-energy-storage
[83] https://www.cleanenergywire.org/factsheets/whats-new-germanys-renewable-energy-act-2021
[85] https://www.diva-portal.org/smash/get/diva2:1423696/FULLTEXT01.pdf
[87] https://www.eon.com/en/about-us/politics/eeg-2021.html

	Case Study 1: Netherlands	Case Study 2: France	Case Study 3: Germany
	In coming years, the sector is expected to face serious delays and possibly project non-realisation caused by a lack of grid capacity on the higher and middle voltage levels. Additional reserve capacity will be put into use by the grid operators in 2022.[84]	small solar PV projects, as Portugal did in April 2020.[86]	

[84] https://www.solarpowereurope.org/wp-content/uploads/2021/12/EU-Market-Outlook-for-Solar-Power-2021-2025_SolarPower-Europe.pdf?cf_id=48112
[86] https://iea.blob.core.windows.net/assets/7b3b4b9d-6db3-4dcf-a0a5-a9993d7dd1d6/France2021.pdf

2.4 LESSONS LEARNED FROM INTERNATIONAL REVIEW

The case studies described above identify a set of lessons learned that can inform effective policymaking for the Irish situation. The lessons learned distilled from the Dutch, French and German case studies are:

- A feed-in-premium as used in the original SDE+ policy in the Netherlands based on the prevailing market price and a cap to the overall subsidy was effective in reducing the free rider effect and over-subsidising, while administrative costs were still low as the mechanism was the same for all technologies and size ranges. In addition, minimising administrative costs for applicants was also key to avoid barriers for applicants when launching the scheme, even though this led to high non-realisation rates early on in the scheme.
- All schemes studied either link the level of support to the potential for reducing emissions or plan on reducing the level of support over time with a full phase-out of subsidies at least before 2030. The link with carbon emissions seems to be more effective for small-scale solar PV when applied as an eligibility criterion for receiving a certain subsidy level (e.g., France) rather than a selection criterion compared to other technologies or sizes (e.g., Netherlands) where emission reduction potentials vary significantly.
- Adding requirements for mandatory feasibility studies and stricter permit requirements can reduce non-realisation rates in tender schemes. However, grid capacity is already constrained and can progressively increase the non-realisation rate of projects. In the Netherlands, grid operators are adding additional reserve capacity to address the issue. In France, the focus is more on connections, with current plans to fast-track grid connections for small-scale projects receiving subsidies.
- In each of the three case studies, costs for grid reinforcements are borne by the DSO. It is therefore important to clearly define the distinction between the minimum equipment required for the grid connection, as opposed to those grid reinforcements required to host these additional connections.
- Not including consideration of storage in the policy design can unintendedly disincentivise storage. For example, in the Dutch system storing energy may mean a double energy tax is levied. With the current high electricity prices in the EU, it becomes important to be aware of possible unintended outcomes of the policy on demand side management. Instead, the French government has announced that self-consumption projects are exempt from electricity tax, which is perceived as a way to further incentivise self-consumption and uptake of the FIT scheme.
- The French system shows that providing premium payments for self-consumption can increase storage technology uptake, although effects have been limited so far mainly due to low electricity prices and heavy administrative processes (compared to applications for just solar PV without storage).
- Germany’s recent changes to the EEG appear to have made installations in the 300-750 kW capacity range less attractive, particularly for self-consumers. The fact that only 50% of electricity generated is compensated could be seen as incentivising self-consumption (or rather discouraging feeding into the grid). However, the prospect of these less attractive feed-in premiums (effectively 50% of those received by installations < 300 kW) could drive installers into the alternative tendering schemes, under which installations cannot self-consume.
- For tendering schemes, reducing the amount of information published between phases can reduce strategic behaviour. In addition, the case studies seem to suggest that tendering schemes for solar PV <500 kW can form a significant barrier for market entry.

3. ARCHETYPE CHARACTERISATION

In order to understand how to best enable and incentivise the deployment of distributed renewable energy installations, it is paramount to first understand the customer segments that could deploy them and the capacity that they could install. Both the likelihood of deployment and the installable capacity, as well as the barriers that require removing in order to incentivise buildout, will vary by end-use sector, location and installed capacity band range.

As part of this project, we have therefore carried out an archetype characterisation exercise to understand where most of the potential for PV deployment (within the capacity range concerning this study) lies. Given the importance of the assumptions taken and the baseline information used for this analysis, we describe in this section not only the results but also the methodology used for the exercise.

The list below describes, from a high-level perspective, the steps taken to determine the archetypes and assess their potential in the Irish context. The sub-sections in this chapter will describe these steps in more detail:

1. **Capacity band ranges** were established by assessing the barriers applicable to deploying renewable energy projects (mainly focused on PV), based on the different barriers that apply for projects above certain capacities.
2. **Statistical information from** the National Heat Study[88], which characterises Irish energy consumers by end-use sector, type of installation and energy consumption, was then taken as one of the main inputs for the analysis.
    a. Based on assumptions (such as load profile by load type and connection capacity), the Maximum Export Capacity (MEC) for each of the energy consumer types in the study was estimated. This yielded the **theoretical maximum deployable potential** for each type.
    b. This approach differs considerably from that of previous similar studies, since potential is assessed by the maximum deployable installed capacity (subject to the capacity of the network), rather than capped by the self-consumption of the energy produced by the system.
3. This theoretical maximum deployable potential for each type was then classified within the capacity band ranges established in step 1, in order to understand **which capacity sizes are most likely to be deployed by each customer end-use type**. This would serve as a crucial input to understand which archetypes should be prioritised for further modelling and analysing.
4. Based on these results, **8 archetypes have been selected**. A detailed financial model of these projects will then be developed in further sections to understand the gaps and barriers that they face and that could be keeping their deployable potential from materialising.

3.1 CAPACITY BANDING

A qualitative analysis was undertaken to determine the barriers that apply to distributed renewable installations (mainly solar PV) depending on their installed capacity. At this stage, only the capacity of the installation was considered since other considerations such as end-use type would be incorporated later in the analysis.

Below, we detail the barriers identified for renewable energy projects, depending on project size (installed capacity). Different barriers, however, might have a much higher or lower impact on the feasibility of the project. Not all barriers will limit the possibility of deploying projects in the same way. Barriers that enact strong entry barriers (e.g., having to participate in limited capacity tenders), or have strong cost implications (e.g., having to install a substation) can have much more impact than others such as administrative processes or metering requirements. Therefore, barriers have been further classified as **green** / **amber** / **red**, depending on the severity of their impact on the possibility of deployment.

A summary table of the barriers is presented at the end of this sub-section. In summary, projects will be classified within the following capacity bands and only three-phase (3Ø) systems will be considered:

[88] https://www.seai.ie/data-and-insights/national-heat-study/heating-and-cooling-in-ir/

1. 50 kW – 100 kW
2. 100 kW – 200 kW
3. 200 kW – 500 kW
4. 500 kW – 1,000 kW

3.1.1 Single-phase systems

A significant barrier exists for single-phase systems above 50 kW, as the current these systems would handle would exceed the capacity of the connection and/or transformers to which single-phase dwellings are connected. Single-phase connections and their associated transformers serve relatively small loads and are not sized for significant demand and, therefore, having a system at or above 50 kW in such connections would require an upgrading of the connection and an increase in its Maximum Export Capacity.

ESB Networks highlights that *"Exporting of up to 50 kWp in rural areas will require a three-phase transformer and associated [medium voltage] MV line and a study to determine associated works/ costs, as well as assessment of any other network implications from interaction with existing generation"*[89]. Systems above this size are therefore not considered technically acceptable to ESB Networks. These systems are, hence, excluded from the study and all analysed systems are therefore considered to be three-phase systems.

3.1.2 Lower capacity limit: 50 kW

50 kW has been selected as the lower limit for the capacity of interest for this particular study considering that systems of smaller capacity are already covered withing existing support schemes (i.e., the Micro-generation Support Scheme (MSS)").

- **A financial barrier** applies to this capacity limit since installations above 50 kW do not have access to similar support to aid their development.

3.1.3 Capacity limit I – 100 kW

A capacity band limit at 100 kW has been proposed since, above this capacity, it is expected that a medium voltage connection would be required.

- This capacity limit poses a **technical barrier** as a medium voltage connection would require more complexity and technical expertise.

3.1.4 Capacity limit II – 200 kW

A further capacity band limit was proposed at the 200 kW level due to various barriers identified for projects above this size:

- **Balance responsibility in the I-SEM:** The enactment of responsibility for this element is considered uncertain and its impact can be considered low, if it is considered that generators are made balance responsible through their trading company or PPA provider. It is therefore expected that this item would not constitute an important barrier for deployment of projects above this size.
  - This consideration forms a **technical** and **financial** barrier as the balancing responsibility could add complexity to the management of the system and its electricity production especially when assets are expected to increase or decrease generation.
- **Additional electric protection infrastructure:** For projects below the 200 kW mark, no Directional Overcurrent protection is needed (if the project is connected at low voltage) and, if at medium-voltage level, no Neutral Voltage Displacement (NVD) protection is needed. However, once this size has been reached, this equipment becomes necessary[90]. This is expected to be a low-impact barrier.
  - The additional infrastructure forms a **financial barrier** as the requirement would involve additional costs to the system.

[89] Assessment Of The Scope For Higher Penetrations Of Distributed Generation On The Low Voltage Distribution Network, ESB Networks, July 2020. https://www.esbnetworks.ie/docs/default-source/publications/assessment-of-the-scope-for-higher-penetrations-of-distributed-generation-on-the-low-volage-distribution-network.pdf?sfvrsn=d2d501f0_0

[90] Conditions Governing Connection to the Distribution System at Medium Voltage, ESB Networks. https://www.esbnetworks.ie/docs/default-source/publications/conditions-governing-connection-to-the-distribution-system.pdf

- **Requirement for a full-spec medium voltage substation:** Above this threshold, a medium voltage substation becomes a requirement for connection. ESB Networks states: *""Large LV or smaller MV loads, typically over 200kVA, involving a substation can take 6 to 9 months from application to connection"*[91].
  - This poses a **technical barrier** to implementation due to the increased complexity of the project.
  - **Administrative barriers** also apply due to the likely need to secure planning permission in order to build the required substation, and the increased complexity of the connection process.
  - **A financial barrier** also applies, since both the substation and the planning and connection applications and processes create additional cost implications when compared to lower-scale projects.

3.1.5 Capacity limit III – 500 kW

The 500 kW capacity band limit is proposed since multiple important barriers currently apply to projects above this size:

- **Gated annual grid applications:** This constitutes an important **market barrier**, since current ESBN procedures require all export applicants above 500 kW to participate in gated annual grid application windows under the Enduring Connection Policy (ECP). This constitutes an important barrier for projects since it adds considerable uncertainty to the feasibility of projects, may pose important technical barriers in certain zones and for certain projects, and could have important risks and upfront costs associated with the application.
  - There are also **financial implications** for this since application fees increase considerably once projects go beyond the 500 kW mark. Current application fees, at the time of writing this report[92], are at EUR 1,591 for projects below 500 kW yet increase to EUR 9,037 once that capacity is exceeded.
- **Grid upgrades:** Above this capacity, it is unlikely that connections would be possible without important upgrades to the existing grid.
  - This would not only pose a **technical barrier** due to complexity, but also a **financial barrier** due to the associated costs of having to upgrade the connection and, in all likelihood, the existing transformer. ESB Networks states that *"LV connections in the range 500 kVA - 1000 kVA are possible but due to charges for MV/LV transformer capacity (as well as MV & 38 kV capacity charges) they are more costly"*[93]
- **RESS Scheme application:** Projects above this capacity can access the market through corporate PPAs (CPPAs), selling their electricity directly to suppliers, and participating in the RESS auctions. Out of the options, RESS auctions are probably the most financially feasible route to incentivise and help develop projects of this size.[94] This adds important risk, complexity, uncertainty and cost to projects and therefore constitutes an important barrier.
  - The route to market for projects above this size adds a **financial barrier** as there is large risk, complexity and uncertainty around their development and financial viability.
  - Additionally, it could form an **administrative barrier** as participating in RESS auctions could entail applications and long processes whilst CPPAs could require contracts between the offtaker and supplier.
- **Environmental impact studies:** Environmental impact increases with scale and planning exemptions are less likely to apply. The Department of Housing, Local Government and Heritage, in the context of the Climate Action Plan and in consultation with the Department of Environment, Climate and Communications, has undertaken a review of the solar panel planning exemptions set out in the Regulations, with a particular focus on facilitating increased self-generation of electricity. This review is now complete. Substantial changes to the current planning exemption thresholds for solar panels

[91] https://www.esbnetworks.ie/new-connections/multiunit-development/substation-minipillar-construction
[92] 22 February 2022
[93] ESB Networks DAC Statement of Charges - Table 2.4
[94] Renewable Electricity Support Scheme I - Terms and Conditions

are proposed which would remove the rooftop square metre based limits which currently apply in the Principal Regulations, and allow more extensive coverage, subject to certain conditions as well as restrictions in certain areas. The process for finalising these regulations is expected to be completed in the coming months.While there would be no prescriptive m^2 threshold for rooftop system size in most areas in this proposed legislation, it is prudent for larger installations to undertake detailed screening in relation for example to noise impact, glint and glare, habitats or other local site sensitivities.[95]

  - Environmental impact studies could constitute both a **financial** and **administrative barrier** as conducting the studies would not only add to the costs of the project but would also take time, feeding into the administration and planning of the project.

3.1.6 Capacity limit IV – 1,000 kW and up to 6,000 kW

While projects above this capacity can be considered beyond the scope of small-scale renewables, they might be developed by communities and other groups, and may represent an important part of the future renewable energy developments in Ireland in the near future. It is, therefore, important to note the additional barriers apply to projects above this level of installed capacity:

- **RTU requirement:** beyond this limit, a Remote Terminal Unit (RTU) is required, so that the network operator can have both visibility and control – including the ability to curtail – the generator. While curtailment can have a relatively low impact on most projects below 1 MW capacity, it can potentially have a high impact on projects above this threshold depending on the voltage of the connection and the area in which it is connected. Furthermore, this requirement adds cost due to the equipment and required communications and certification requirements.[96]
- **State aid guidance:** State aid guidance allows for exemptions to competitive bidding requirements for installations in all sectors up to 1MW and, for SMEs and Renewable Energy Communities, up to 6MW. Renewable energy communities and small and micro enterprises may also develop wind projects up to 18 MW without competitive bidding.

[95] Planning and development act 2001 as amended; Draft legislation Bill 88 of 2021 Planning And Development (Solar Panels For Public Buildings, Schools, Homes And Other Premises) (Amendment) Bill 2021

[96] Distribution Code - Version 7, ESB Networks

Table 5 - Summary of barriers applicable to renewable projects after certain installed capacity.

Limit (kVA)	Type of barrier	Effect (R/A/G)	Rationale	Sources
50 (3Ø)	Administrative		Lower band of capacity range that is the focus of the study. See above	Assessment of potential implications for the distribution network of defined higher penetrations of distributed generators, ESB Networks
100 (3Ø)	Technical		MV demand connections are considered necessary above this capacity	
	Market		Overwhelming majority of the stock is below this threshold for demand-led sites	
200 (3Ø)	Administrative		Proposed new limit for Balance Responsibility in the I-SEM. Would have a financial impact on projects and pose additional administrative hurdles and risks	[Information Paper on Balance Responsibility in the SEM, SEM Committee]
	Technical		Below this capacity, “at Low Voltage, Directional Overcurrent protection shall not be required.", Medium Voltage NVD protection not needed either	[Conditions Governing Connection to the Distribution System at Medium Voltage, ESB Networks]
	Technical		ESBN Grid code requires a full-spec MV substation above this threshold. "Large LV or smaller MV loads, typically over 200 kVA, involving a substation can take 6 to 9 months from application to connection"	[Substation Construction, ESB Networks]
	Financial			
	Administrative		A ground mount substation will most likely require planning permission	[Guide to the Process for Connection of Demand Customers to the Distribution System]
	Financial			
500 (3Ø)	Market		Current ESBN procedures require all export applicants above 500 kW to participate in gated annual grid application windows under the Enduring Connection Policy (ECP).	[Ruleset for Enduring Connection Policy Stage 2 (ECP-2), ESB Networks, EIRGRID]
	Financial		Applicable application fees: *1,591 EUR application fee for up to 500 kW *9,037 EUR for >500 kW	
	Technical			

Limit (kVA)	Type of barrier	Effect (R/A/G)	Rationale	Sources
	Financial		"LV connections in the range 500 kVA - 1000 kVA are possible but due to charges for MV/LV transformer capacity (as well as MV & 38 kV capacity charges) they are more costly" Ground-mounted projects are also faced with significant land-related expenses and local authority fees.	ESB Networks DAC Statement of Charges - Table 2.4
	Administrative		Above 500kW, available routes to market include Corporate PPAs, directly selling electricity to suppliers, and the most financially attractive option, participating in Renewable Electricity Support Scheme (RESS) auctions,	Renewable Electricity Support Scheme terms and conditions
	Administrative		Environmental impact increases with scale and planning exemptions are less likely to apply; The Department of Housing, Local Government and Heritage, in the context of the Climate Action Plan and in consultation with the Department of Environment, Climate and Communications, has undertaken a review of the solar panel planning exemptions set out in the Regulations, with a particular focus on facilitating increased self-generation of electricity. This review is now complete. Substantial changes to the current planning exemption thresholds for solar panels are proposed. The process for finalising these regulations is expected to be completed in the coming months. While there would be no prescriptive m^2 threshold for rooftop system size in most areas in this proposed legislation, it is prudent for larger installations to undertake detailed screening in relation for example to noise impact, glint and glare, habitats or other local site sensitivities.	Solar Energy Guidelines – Tuesday, 22 Mar 2022 – Parliamentary Questions (33rd Dáil) – Houses of the Oireachtas Planning and development act 2001 as amended; Draft legislation Bill 88 of 2021 PLANNING AND DEVELOPMENT (SOLAR PANELS FOR PUBLIC BUILDINGS, SCHOOLS, HOMES AND OTHER PREMISES) (AMENDMENT) BILL 2021
	Technical		At and beyond this capacity, an RTU should be installed, and the network operator should be able to curtail the generator.	Distribution Code - Version 7, ESB Networks
1,000 – 6,000 (3Ø)	Administrative		State aid guidance allows for exemptions to market-based tariffs for all categories of applicants, up to 1MW, and SMEs & RECs up to 6MW. Renewable energy communities and small and micro enterprises may also develop wind projects up to 18 MW without competitive bidding.	Guidelines on State aid for climate, environmental protection and energy 2022

3.2 DEMAND SECTOR ANALYSIS

To understand how each capacity band and sector would align with the electricity user base of the country, a demand sector analysis was developed. For this analysis, archetype data was taken from the National Heat Study[97] and used to estimate the potential sizes of solar PV that different customers would be able to deploy. The data provided, specifically, contained a list of different installation types that can be found across Ireland (industry sector, commercial activity, etc.) and, for each, it detailed[98]:

- Yearly electricity usage
- Stock: Number of dwellings or premises in Ireland that correspond to that installation type
- Average available floor area

The yearly energy demand per installation type was used as an initial input and, applying normalised demand profiles based on the customer type, the maximum demand of each type of installation was estimated. This maximum demand was calculated in order to estimate the MIC associated with each installation type, which was then used as a proxy for estimating the associated MECs, based on the assumption that the MEC is equal to the MIC.

While the maximum capacity of PV (or other renewables) that can be installed could be limited by multiple other factors beyond the MEC, the MEC is assumed to be the main driver for maximum installable capacity and was therefore used to determine the maximum capacity that could be installed. However, an additional constraint was considered during the analysis: the average available rooftop area. This was done as the available rooftop area could determine the maximum capacity of PV that can be installed. For this study, the ground space constraint was not considered due to data limitations.

To consider this parameter, the average floor area, assumed to be equivalent to the rooftop area, per installation type was used to estimate the capacity of PV that could be installed on a given location, using a $6.25m^2/kW_p$ metric and a factor of 80% to assume the rooftop area that could actually be usable. In cases where the maximum installable capacity as calculated through this metric was greater than the MEC calculated for such installation, the area-derived capacity was considered as the maximum installable capacity.

The results of this analysis were further processed to classify installations within five major sector categories:

1. Commercial
2. Agricultural
3. Industrial
4. Public buildings (such as schools, hospitals and offices)
5. Residential

The final result of this analysis was, hence, an estimation of maximum installable PV capacity per sector and per capacity band. While theoretical, this result serves as an indication on where most of the deployable PV potential lies, and therefore serves as guidance for the selection of archetypes to model and analyse further, in order to assess their gaps and barriers, as well as opportunities to incentivise and enable deployment.

A summary of the results of this analysis is shown in the heat map tables below (Table 5 and Table 6). Colour gradients have been applied in order to highlight the categories with the highest number of possible installations and/or maximum installable PV capacity in green, and those with the least number of possible installations and/or least installable PV capacity in red. It is worth noting that the potential capacity has been estimated by considering the network connection capacity (MIC), rather than self-consumption of the installation.

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[97] Heating and Cooling in Ireland Today, SEAI, https://www.seai.ie/data-and-insights/national-heat-study/heating-and-cooling-in-ir/

[98] Heating and Cooling in Ireland Today Supporting Data, SEAI, https://www.seai.ie/publications/Heating-and-Cooling-in-Ireland-Today-Supporting-Data-.xlsx

Table 6 - Potential deployable PV capacity per band and sector

	Aggregated capacity per band (kW)			
	50-100	100-200	200-500	500-1000
Commercial	112,823	-	-	-
Agriculture	-	-	-	-
Industry	16,178	224,787	-	98,740
Public	28,662	666,591	257,902	262,081

Table 7 - Potential number of PV installations per band and sector

	Number of installations per band			
	50-100	100-200	200-500	500-1000
Commercial	1,966	-	-	-
Agriculture	-	-	-	-
Industry	251	2,097	-	179
Public	447	5,741	730	363

It is worth highlighting, however, that this classification does not imply that categories with lower estimated PV potential should not be considered or analysed, but rather that the aggregated capacity in those categories is likely to be lower and that the barriers they face are mostly related to a likely low level of MIC (i.e., network constraints) and/or low availability of rooftop area.

The analysis employs the archetyping methodology developed during the National Heat Study. As with any archetyping process, the population is represented by a smaller dataset that aims to still retain the key characteristics of the entire population. However, this can lead to simplifications or the loss of variation outside of the archetypes selected. For example, in Table 5 – Table 6, there is no overlap between the agricultural sector demands and the small-scale capacity bands. However, certain agriculture sites across the country will likely have an MIC relevant to small-scale electricity generation, and as a result a certain amount of agriculture demand sites are modelled and considered feasible for installing to small-scale electricity generation on-site.

3.3 ROOFTOP AND GROUND-MOUNTED SOLAR SYSTEMS

For this analysis, both rooftop and ground-mounted solar PV systems were considered. While both systems rely on the same power generation technology and are largely similar, their costs and performance vary, and it is therefore important to differentiate them.

This section, therefore, focuses on the qualitative differences between rooftop and ground-mounted PV systems and how they affect their modelling parameters. Costs and other quantitative parameters will be discussed and further developed in Section 5.

It is worth nothing that, while calculating the maximum installable PV capacity for each of the potential archetypes, as mentioned in Section 3.2, the average available rooftop area was considered as a limitation for non-industrial categories. This limitation, however, would not apply in the case of ground-mounted systems. The effect of this parameter, therefore, was applied at later stages of the analysis, after the main archetypes selected for further modelling were selected, at which stage both cost and yield parameters become relevant.

3.3.1 Ground-mounted systems

Ground mounted systems utilise metal framings driven into the ground or pole mounts to hold solar panels at a (most commonly) fixed angle towards the sun. These systems can pose significant advantages:

- **Tilt and orientation optimisation:** Ground-mounted systems can be tilted and oriented in ways that maximise the system's yearly energy output (considering the sun's trajectory).

- **Tracking:** Ground-mounted systems also allow the possibility to install tracking systems which further optimise the system's energy yield. It is worth noting, however, that tracking systems are commonly installed in larger, utility-scale projects and are, therefore, not considered within the scope of this study.

These systems, however, also have relative disadvantages, including:

- **Use of land:** While rooftop-mounted systems enjoy the advantage of utilising free space (i.e., no additional space is required for the sole purpose of installing solar PV), ground-mounted systems do have this requirement, which can translate into both:
  - **Additional cost:** Due to the buying or renting of additional land or space.
  - **Additional environmental impact:** Due to the use-of-land-change and increased requirement for mounting structures. In some cases, projects may require partial deforestation or destruction of existing vegetation in the areas where they are deployed.
  - **Opportunity cost:** As land that could be used for other commercial purposes is now used for PV generation. This impact can be especially important in agricultural areas, where land could have been used for cattle grazing and/or for agricultural purposes. Using the land for solar PV generation instead of farming could lead to a reduction in payments received by the farm as it would minimise the agricultural output and potential. However, there could be some benefits in agri-voltaics, where the installations would be installed and operated in a way that could allow dual use of the land, in terms of solar generation and agriculture. As an example, the solar PV installations could help shade crops and help the soil retain moisture and improve growth, which could create benefits and increase income.
- **Increased surface footprint:** While tilting and aligning the solar panels to optimise the system's energy yield poses a significant advantage, it also results in larger spacing of the panels in order to avoid some panel(s) shading others.
  - Ground-mounted systems require 16 – 20 m^2/kWp of solar PV installed, while rooftop-mounted systems require ~ 6.25 m^2/kWp.
- **Increased infrastructure needs and cost:** Ground-mounted systems require additional elements, both due to the nature of the structure and anchorages that need to be installed, and due to the increased surface footprint that systems required.

3.3.2 Rooftop-mounted systems

Rooftop-mounted systems, when installed in existing premises, rely significantly on the existing infrastructure, which offers considerable advantages over ground-mounted systems:

- **Capital costs:** Due to the use of existing infrastructure and the smaller space footprint these systems have compared to ground-mounted ones, capital costs tend to be lower (although the need for roof renovation or reinforcement may cause the opposite to be true).
- **Racking and installation:** Although dependent on the type of roof, these systems often require significantly less racking and mounting infrastructure than ground-mounted systems, also reducing installation costs.
- **Permissions:** Since installing solar PV on a rooftop does not change the activity taking place on a premise and no additional land is required, permission processes for rooftop installations tend to be simple and often streamlined. Safety, reflections and other considerations must still be considered, however.

At the same time, however, these systems also may pose significant barriers and limitations:

- **Space constraints:** As highlighted in Section 3.2, the available rooftop area can become the main limitation for the installable PV capacity on a premise.
- **Panel orientation:** Since mounting systems and panels are installed on existing rooftops, this can result in the need to install panels at an angle that deviates from the optimal orientation that would result in the highest yearly energy yield.
- **Structural reinforcing:** Solar panels, along with their rooftop mounting systems and wiring, exert on average a total of 10-20 kg/m^2 of weight on the roof and its structures. Additional forces and torque can also come into play because of the wind and the need for maintenance. While this does not commonly pose a challenge, in some cases it may cause the PV system to exceed the load-bearing

capacity of the roof, triggering the need to reinforce the bearing structures. Regulations and safety factors also commonly apply. This can significantly increase the cost of a PV system and creates a significant additional barrier due to the disruption that the required works could cause.

- **Shading:** The need to install systems on existing infrastructure could also significantly limit the ability to avoid shading from nearby objects or structures, adjacent buildings, or trees. While additional analysis on an ad-hoc basis can be taken in order to determine whether a PV system is more profitable even if some of the panels are subject to shading (compared to not installing panels in those areas at all), it is most commonly not advisable to install solar panels in areas that are subject to shading.

3.3.3 Suitability of different systems for the demand sectors considered

Considering the feasibility and costs of these systems, as well as their relative advantages, it is expected that each sector considered in this study would, in general, lean considerably towards deploying a specific type of system. While this could vary on an ad-hoc basis, an analysis is presented below (Table 7 – Suitability of system types for specific sectors) summarising the type of system that each sector would be expected to deploy.

Table 8 - Suitability of system types for specific sectors

	Likely type of installation	Drivers / Reasoning
Commercial	Rooftop-mounted	• Low project scale • Lower capital cost • Driven by available rooftop space • Permissions
Agricultural	Rooftop-mounted	• Low project scale • Lower capital cost • Available rooftop space • Opportunity cost associated to land use
Community Energy Projects	Ground-mounted	• Large project scale • Land availability
Public buildings	Rooftop-mounted	• Low project scale • Rooftop space availability • Lower capital cost • Permissions
Industry	Rooftop-mounted	• Rooftop space availability • Permissions

3.4 SELECTION OF FINAL ARCHETYPES

For this study, eight (8) archetypes were selected for further modelling and assessing, in order to understand the gaps and barriers that they face and propose measures to incentivise and enable the deployment of solar PV of those respective archetypes. This would then maximise the deployment of renewables resulting from any adopted policy measures. For this selection, the following criteria were considered:

3.4.1 Selection criteria

- **Deployable solar PV potential:** based on the results summarised in Table 5, a consideration was taken depending on how much potential solar PV capacity could be enabled within each archetype, as this has implications on the potential impact of proposed measures.
- **Number of potential installations:** the number of potential installations that could be enabled within each archetype (as results shown in Table 6 summarise), was also considered when selecting which archetypes to focus on.
- **Perceived interest for the sector to deploy solar PV:** The potential interest that different sectors are expected to have towards adopting solar PV was also considered for the selection. For example:

while industrial sites may see great benefit from installing on-site renewables as it reduces one of the main sources of cost, agricultural sites may prioritise their investments towards their core economic activity. These aspects were therefore qualitatively considered in the archetype selection

- **Representation of potential project sizes:** While barriers for different project sizes will vary depending on the sector, and as most sectors seemed to indicate more potential for smaller-sized projects, an additional consideration was taken in order for different ranges of potential project sizes to be selected within the final archetype sample. This would also help gather insights on the impact of economies of scale and other effects on the deployment of solar PV.
- **Likely type of system to be deployed:** For each archetype, the likely type of system was also considered, so that the archetype could be modelled with the appropriate costs and operational parameters in further stages of the project. This was added as a characteristic of each archetype, although additional consideration was taken so that all types of projects (both ground and rooftop-mounted) are represented within the sample selection.
- **Inclusion of non-demand led sites:** While power demand is assumed to be the main driver when assessing the potential for deploying solar PV on a site (due to the likely robustness of the grid connection associated with higher demand), it is also important to consider that sites could deploy solar PV for purely exporting purposes. Non-demand led sites (i.e., sites with low power demand and that likely face network constraints) were therefore also considered in the final selection.

3.4.2 Selection of 8 archetypes for modelling

Based on the criteria listed above and SEAI's and DECC's internal consideration, the archetypes selected for further modelling were selected and are summarised in Table 9.

The capacity bands are as follows:

1. 50 kW – 100 kW
2. 100 kW – 200 kW
3. 200 kW – 500 kW
4. 500 kW – 1,000 kW
5. 1,000 kW – 6,000 kW

Table 9 - Final archetype selection and characteristics

#	Archetype	Sector	Size (kW)	Capacity band	Example Building type(s)-Size(s)	Annual demand (MWh)	Highest hourly demand (kW)
1	Commercial site – rooftop-mounted PV	Commercial	60	1	Hotel-Large, Retail-Large	231	54.6
2	Agricultural site – rooftop-mounted PV	Agriculture	105	2	N/A	342	100
3	Public building – rooftop-mounted PV	Public	100	2	Education-Large, Office-Large	192	66.7
4	Industrial site – rooftop-mounted PV	Industry	250	3	Chemicals Non-ETS, Food and Drink ETS	1,042	246.1
5	Predominantly export site rooftop-mounted PV	Commercial	250	3	Warehouse	33	7.8
6	Public building – rooftop-mounted PV	Public	325	3	Healthcare-Large, Office-Large	680	160.6
7	Industrial site – rooftop-mounted PV	Industry	625	4	Food and Drink, Chemicals	2,607	615.8

8	Predominantly export site –ground-mounted PV	Agriculture, Community Energy	999	4	N/A	N/A – Predominantly Export	N/A – Predominantly Export
9	Export-only site – ground-mounted PV	Private or Community Energy	4000	5	N/A	N/A – Export-only site	N/A – Export-only site
10	Export-only site – onshore wind	Private or Community Energy	4000	5	N/A	N/A – Export-only site	N/A – Export-only site

3.5 BARRIER ASSESSMENT BY ARCHETYPE

Whilst these archetypes have been strategically selected considering the criteria noted in Section 3.4.1, and barriers have been identified according to the size of the installation, there are still barriers for deployment that apply to each activity area that must be considered and addressed. The following section aims to build on the previously noted drawbacks to provide a brief, high level view of specific archetype barriers to inform potential actions that could be taken and the recommendations in Section 2.4.

Rooftop-mounted systems in commercial sites (60 kW)

The first archetype considered is a commercial installation with a 60 kW rooftop-mounted PV system. Commercial installations have a significant advantage as their load profile is, in general, very correlated with the solar generation profile. This maximises the possibility for self-consumption while avoiding (and/or alleviating) grid issues such as congestion. However, multiple barriers exist that can hinder its deployment – some of them are inherent and difficult to tackle from a policy perspective:

1. **Shading / reflection:** The nature of commercial sites and their often urban locations may lead to possible barriers to the proposed PV installations within this sector: shading and light reflection. With the potential for shading from other buildings and structures increasing in urban settings, the area of space that is suitable and cost effective may decrease, reducing the viability of projects. Furthermore, even for installations that do take possible shading into account, it is difficult to account for future developments that may cast shade over existing PV cells further down the line, again bringing the long-term viability of projects into question. Similar considerations must be taken due to the light reflection that the systems may cast on surrounding buildings. It should be noted that in the Netherlands shading and reflection does not seem to have been a barrier for a successful commercial rooftop market. While more research is needed for why this was the case, the evaluation commissioned by the government in 2016 speculates this may have been due to the fact that the SDE+ regulation for solar PV was mostly adopted by warehouses and distribution centres with flat rooftops and lower building heights[99].
2. **Premise and infrastructure ownership:** In most settings, commercial activity is carried out in leased premises and electricity is passed through to the leaseholders. This can be a barrier to the deployment of renewable capacity, since it can be complicated to implement schemes in which the benefits of the installation go to the investor. Infrastructure owners may also be reluctant to invest in installations given the uncertainty of occupancy.
3. **Internal works required:** The internal works required to incorporate solar PV may result disruptive or complicated, depending on the existing metering arrangements and low voltage networks of the premise.

Rooftop-mounted systems in agricultural sites (100 kW)

Agricultural sites have an advantage given that they often have significant rooftop space that is unshaded and that is very unlikely to become shaded in the future. However, significant barriers apply:

1. **Low local demand:** Often, agricultural sites present a significantly low level of power demand, as farming and processing facilities are often separated. This reduces the amount of renewable power that can be consumed by the site (self-consumption), which – depending on scheme design – would hinder the business case for their deployment.
2. **Limited network capacity:** Given the low level of demand, networks that serve agricultural loads are often of limited capacity. The installed capacity of local renewables would therefore likely need to be capped to avoid issues with the network or the need to undertake significant network upgrades.
3. **Investment prioritisation:** While agricultural sites have a relatively good capacity to access financing and/or invest, they often prioritise their resources towards their core activities.
4. **Lesser incentive:** Furthermore, the agriculture sector in Ireland benefits from significant energy subsidies. Some forms of assistance that have been available to farmers include the Green, Low-Carbon, Agri-Environment Scheme (GLAS)[100], the Basic Payment Scheme which provides support

[99] https://ce.nl/wp-content/uploads/2021/03/CE_Delft_7i97_Evaluatie_regeling_SDE_DEF.pdf
[100] GOV IE, Get a payment to protect the environment on your farm (GLAS), https://www.gov.ie/en/service/9133a5-green-low-carbon-agri-environment-scheme-glas/?referrer=http://www.agriculture.gov.ie/farmerschemespayments/glas/

based on the number of hectares used for farming[101], the Greening Payment which is a fixed percentage of the Basic Payment Scheme payment[102], and the Young Farmers Scheme which also provides support based on the number of eligible hectares[103]. There is the possibility that these subsidies may be cut, or reduced, if agricultural land is repurposed to house renewable systems, or that the incentive (or need) to deploy them is not as strong as in other sectors.

Rooftop mounted systems in public buildings (100 kW)

Public buildings often have considerable energy demand and, as a result, are often associated with robust network connections. This would paint an optimistic view for deploying renewables locally. However, there are multiple drawbacks that limit the potential for deployment:

1. **Opportunity cost of public spending:** A potential barrier associated with PVs located on public buildings is the fact that they are also publicly funded. As is the case with any public spending, the opportunity cost of this is likely to come under scrutiny and receive opposition from individuals and groups that believe taxpayers money should be spent differently.
2. **Downtimes:** While most public buildings (e.g., hospitals and offices) are expected to have a relatively stable level of demand throughout the year, the term times observed in the educational system may also pose a barrier to some projects and installations within this sector. As schools typically enjoy a break in teaching from June – August, they are likely to require much less energy during this period. This coincides with the time when PV systems produce the most energy. Considering the capacity of the installation and the energy usage of the school, when paired with rising energy costs, this may lead to a reduction in the cost effectiveness of PV applications within schools and other educational public buildings, disincentivising their installation.
3. **Processes:** Public buildings are often subject to stronger processes for expenditure approval compared to other types of buildings, due to controls and the increased need for traceability. This barrier may delay deployment of local renewables.

Rooftop-mounted systems in industrial sites (250 kW, 625 kW)

Industrial sites are often regarded as a sector with high potential for small-scale renewables due to both the large capacity that they could deploy, and their capacity for investment relatively swiftly. Furthermore, industries can find significant benefit in securing and stabilising the cost of energy, which comprises a significant proportion of their operational expenses. Some of the barriers that nonetheless apply to them include:

1. **Investment prioritisation:** While industries often have a better capacity to invest and access financing, they often prioritise their resources towards their core activities.
2. **Operational disruptions:** The installation of renewable energy in industrial sites can result in temporary disruptions due to the work involved or disruption to sensitive equipment due to voltage fluctuations caused by swings in renewable energy output. This can act as a deterrent for the deployment of renewable energy on their sites.
3. **Alternative ways to acquire renewable power:** Industrial sites are energy intensive, and on many occasions, locally deployed renewables do not fulfil their energy requirement. Industries therefore often seek to secure PPAs with larger renewable plants. This removes many of the incentives to deploy renewables locally (such as high energy costs and the need or will to decarbonise their operations) and circumvents some of its disadvantages (such as operational disruptions and the need for upfront investments).
4. **Planning permissions:** Systems above 50 square metres currently require planning permissions which add cost, time and risk to the deployment of local renewables, therefore acting as a barrier. For rooftop-mounted systems, this is expected to apply for projects above ~310 kW_{DC}.

Export sites (250 kW, 999 kW, 4000 kW)

Four of the archetypes included in the study do not consider the association of the system with a local demand. Some of the main barriers to these systems include:

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[101] Basic Payment Scheme, GOV IE, https://www.gov.ie/en/service/f16b22-basic-payment-scheme/

[102] Greening Payment, GOV IE, https://www.gov.ie/en/service/be0e94-greening-payment/

[103] Young Farmers Scheme, GOV IE, https://www.gov.ie/en/service/6e97d8-young-farmers-scheme/

1. **Public opposition, or nimbyism, to infrastructure:** People's willingness to accept infrastructure near their homes tends to be low, which may also be the cause of another barrier for deployment[104]. Examples of this may include locals opposing developments for aesthetic or economic reasons (as it might hinder tourism in surrounding areas), as well as groups arguing against possible impacts on the local environment and wildlife.
2. **Stakeholder alignment:** Many of these projects are often taken forward by communities. While this model has seen multiple successes – evidenced by the oversubscription of the community category in the RESS-1 auction – it can be difficult to scale and can face important delays and risks. Community actors must come together and remain organised for these projects to succeed. On many occasions, communities also face difficulties accessing financing and often lack the capacities needed to develop and manage these projects or the associated external service and equipment providers.
3. **Market entry:** These systems are almost exclusively only able to find a route to market through RESS auctions or PPAs. For projects below 1 MW, the cost, risk and processes associated with securing these contracts can be costly and complicated to achieve, acting as a significant deterrent to deployment.
4. **Low grid capacity:** Grid capacity tends to be considerably limited in rural communities who are likely to have the ability and land needed to deploy these projects. Costs to increase capacity can be large acting as a significant deterrent to deployment.
5. **Potential long distances to connect to existing grid:** Along with low grid capacity, the grid in rural and generally agricultural areas tend to not be widespreadily distributed. This may cause purely-export projects to be faced with considerable costs associated with installing a long electric connection in order to reach the existing grid.
6. **Planning permissions:** **Rooftop and ground-mounted** systems at this scale currently require planning permissions which add cost, time and risk to the deployment of local renewables, therefore acting as a barrier.
7. **Land and local authority rates:** Ground-mounted systems may be faced with significant land expenses and local authority rates that significantly impact project finances and, therefore, present an important barrier for feasibility.
8. **State aid guidance:** State aid guidance allows for exemptions to competitive bidding requirements for installations in all sectors up to 1MW and, for SMEs and Renewable Energy Communities, up to 6MW. Renewable energy communities and small and micro enterprises may also develop wind projects up to 18 MW without competitive bidding.

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[104] Renewable electricity generation and transmission network developments in light of public opposition: Insights from Ireland, https://www.esri.ie/system/files/publications/WP653_0.pdf

Table 10 - Summary of barriers and classification by type and impact (R/A/G)

#	Archetype	Building types-Size(s)	Barriers				
			Planning & regulatory	Grid connection	Market rule	Viability gap	Other
1	Commercial site – rooftop-mounted PV - 60 kW	Hotel-Large, Retail-Large		Integration with internal low volage and metering		Premises & infrastructure ownership	Shading from nearby buildings
2	Agricultural site – rooftop-mounted PV - 100 kW	Agricultural warehouse (no demand assumed)		Low associated grid capacity	Limited export	Existing subsidies may reduce incentive to deploy RES	Investments prioritised towards core activities Low self-consumption
3	Public building – rooftop-mounted PV - 100 kW	Education-Large, Office-Large	Required processes and approvals	School year downtimes cause high exports			Public spending prioritised for other needs
4	Industrial site – rooftop-mounted PV - 250 kW	Chemicals Non-ETS, Food and Drink ETS		Potential disruptions due to voltage swings		Easier and less risky alternatives (PPA)	Investments prioritised towards core activities
5	Predominantly export site rooftop-mounted PV - 250 kW	Warehouse		Low grid capacity in rural communities and agricultural areas	Limited routes to market	High competition in auctions and PPA market, along with associated risks.	Stakeholder management and engagement
6	Public building – rooftop-mounted PV - 325 kW	Healthcare-Large, Office-Large	Required processes and approvals	School year downtimes cause high exports			Public spending prioritised for other needs
7	Industrial site – rooftop-mounted PV - 625 kW	Food and Drink, Chemicals	Planning permission currently needed	Potential disruptions due to voltage swings		Easier and less risky alternatives (PPA)	Investments prioritised towards core activities
8	Predominantly export site – ground-mounted PV - 999 kW	N/A	Planning permissions	Low grid capacity in rural communities and agricultural areas. Potential long distances to	Limited routes to market	High competition in auctions and PPA market, along with associated risks.	Stakeholder management and engagement

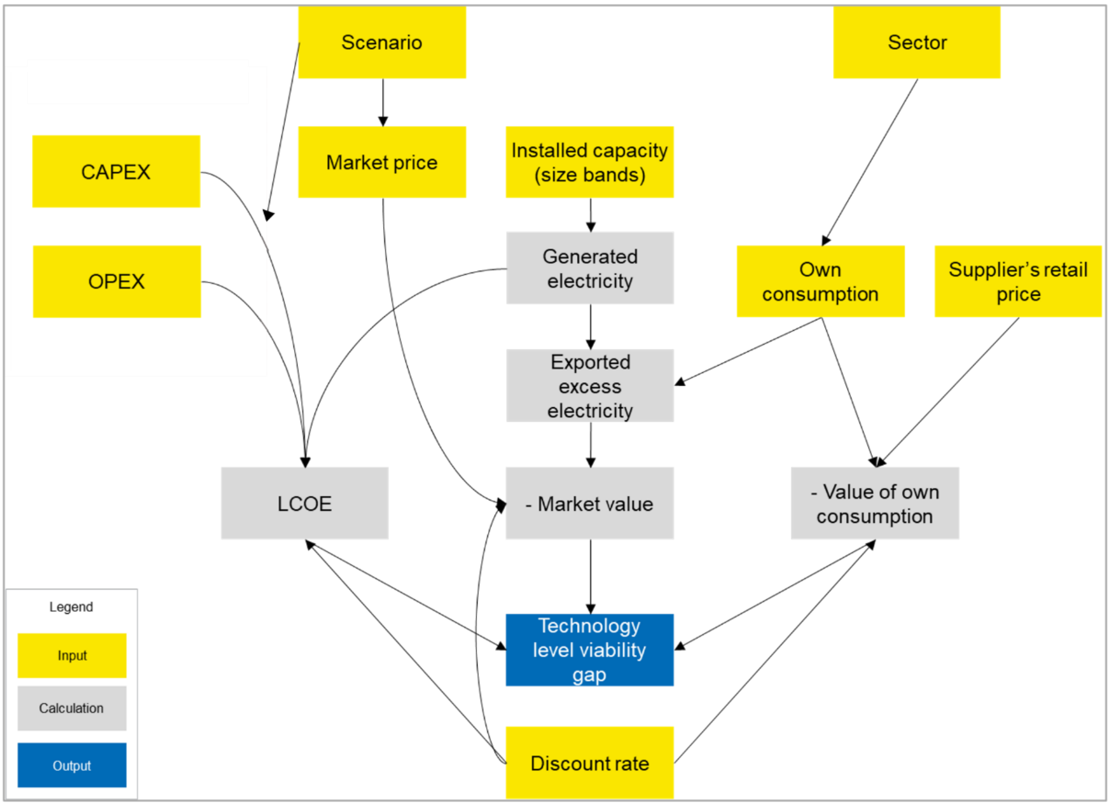
				connect to existing grid.		Land and local authority rates.	
9	Export-only site – ground-mounted PV- 4000 kW	N/A	Planning permissions	Low grid capacity in rural communities and agricultural areas, distance to grid, cost of bringing cables/lines back to the network. Potential long distances to connect to existing grid.	Limited routes to market	High competition in auctions and PPA market, along with associated risks. Land and local authority rates.	Land costs, local authority rates, stakeholder management and engagement
10	Export-only site – onshore wind - 4000 kW	N/A	Planning permissions	Low grid capacity in rural communities and agricultural areas, distance to grid, cost of bringing cables/lines back to the network Potential long distances to connect to existing grid.	Limited routes to market	High competition in auctions and PPA market, along with associated risks. Land and local authority rates.	Stakeholder management and engagement

4. MODEL DEVELOPMENT

A financial model was developed that is fit for purpose for appraising policy options to support small-scale renewable electricity generation in Ireland (50 kW to 6,000 kW).

The model forecasts cash flows, such as the estimated revenue stream, capital expenses (CAPEX) and operating and maintenance (O&M) costs and calculates the levelized parameters of the viability gap applying the Discounted Cash Flow (DCF) method. The model has been built according to our principles of best practice and calculations are kept as simple and structured as possible to ensure transparency and ease of use. The structure of the model is presented in Figure 3.

Figure 3: Schematic overview of financial model

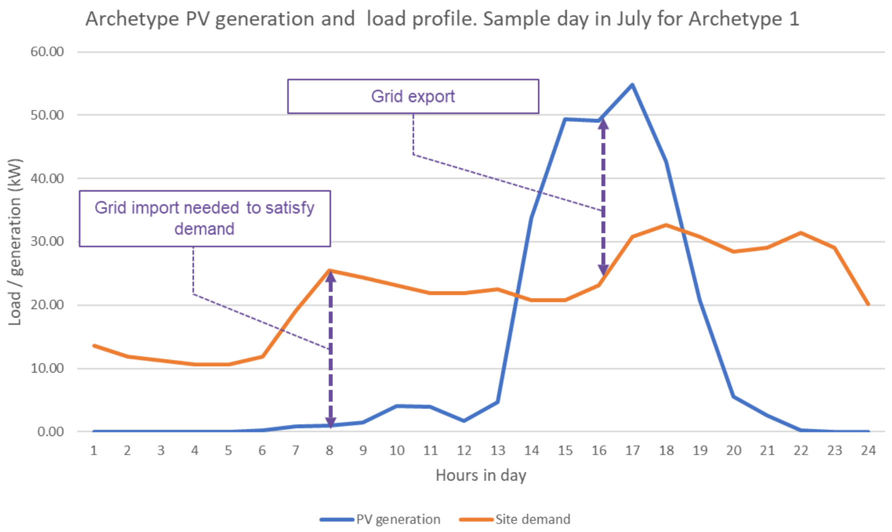


Initial technical inputs

As an input for analysis, the model used estimations of the self-consumption that was expected to happen for each of the archetypes. To derive these parameters, a demand (load) profile was assigned to each of the archetypes, based on the type of building. In the case of predominantly-export sites (archetypes number 5, 8, 9 and 10), no or in case of archetype 5 limited power demand was assumed. The hourly demand was then overlapped with the generation of the PV system, which was based on the solar generation profile of Ireland gathered from PV Sol, the capacity factor of the installation (determined by whether the installation was rooftop or ground-mounted), and the size of the system. An illustration of this overlap is shown in Figure 4. The capacity factor of rooftop solar and ground-mounted solar installations was assumed at 9.7% and 11%, respectively, assuming the installations are fixed and mono-facial. The data points were gathered using a combination of data from the Global Solar Atlas, UK datasets, and EirGrid publications, which provided average capacity factors in Ireland

[105,106,107,108]. However, for the larger export site of 4 MW MEC, the 11% capacity factor was reduced to 9.9% due to reduced output at that size due to curtailment and constraints. The curtailment and constraint impacts were assumed to be 10% combined, reducing the capacity factor by 10% (leading to 9.9% capacity factor).

Figure 4: Example of demand and PV generation overlap analysis for a sample day in July for Archetype 1 (Commercial site - rooftop-mounted PV - 60 kW) without storage



Additional considerations were taken for storage, to assess the impact of pairing electricity storage to PV systems. The addition of storage can help maximise the volume of self-consumption achieved by the installation and/or maximise the allowable capacity of the system without exceeding the MEC.

However, sizing the storage system requires an optimisation exercise and a detailed analysis of both the generation and the demand curve for the specific site, which is out of scope of the current study. A simplified and general assumption was therefore used: storage systems would be sized to be able to store one hour of maximum generation of a system 1.2 times smaller than the PV system of the archetype. For example: a 60 kW PV system would be assigned a 50 kWh battery storage.

This proportion of storage size to installed capacity was selected as it results in sensible self-consumption ratios (<90%) for the archetypes with the highest correlation between their load profile and PV generation (once storage is added). Larger battery sizes would have resulted in storage being under-utilised for a significant proportion of the time for these archetypes (e.g., during winter when daily exports are very limited or non-existent), which would unfairly hinder their business case.

[105] Global Solar Atlas, https://globalsolaratlas.info/map

[106] UK Quarterly and Annual Load Factors, GOV UK, https://www.gov.uk/government/publications/quarterly-and-annual-load-factors

[107] Enduring Connection Policy 2.1 Constraints Report for Area C Solar and Wind, EirGrid, December 2021, https://www.eirgridgroup.com/site-files/library/EirGrid/ECP-2-1-Solar-and-Wind-Constraints-Report-Area-C-v1.0.pdf

[108] Electricity Generation Costs 2020, BEIS, August 2020, Electricity Generation Costs 2020 (publishing.service.gov.uk)

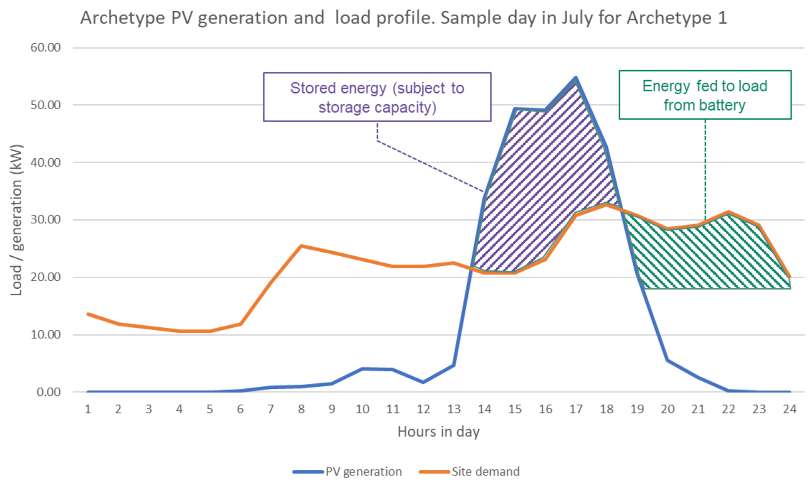


Figure 5: Example of demand and PV generation overlap analysis for a sample day in July for Archetype 1 (Commercial site - rooftop-mounted PV - 60 kW) with storage

Exports were assumed to be utilised daily to fill the capacity of the battery and are assumed to be later fed to the load during periods when demand exceeds PV generation (therefore minimising imports from the grid and maximising self-consumption). An illustration of this approach is shown in Figure 5. Additional considerations were taken to increase the accuracy of the exercise, including a 15% round-trip efficiency for the battery, and a maximum battery discharge depth of 80%.

This analysis allowed for the amount of energy imported from (or exported to) the grid and consumed on-site to be quantified for each hour in the year for cases with and without storage.

For the onshore wind archetype, the main technical input was the capacity factor. The capacity factor for the 4 MW onshore wind site was assumed at 35%. However, the 35% does not consider any reductions in dispatch due to constraints and curtailment, which would need to be considered due to the size of the asset studied. Therefore, it was assumed that curtailment and constraints would lead to a 15% reduction in output/dispatch, reducing the capacity factor by 15% of its original value. This meant that the assumed capacity factor for the 4MW onshore wind site, including constraint and curtailment considerations, was assumed at 29.75%.

5. TECHNOLOGY COST AND REMUNERATION ANALYSIS

5.1 TECHNOLOGY COST ASSESSMENT FOR 50KW – 1MW

The section below outlines the costs and assumptions used to determine the solar technology costs across the capacity bands, between 50 kW-1MW, forecasted to 2030. The costs determined for the study include the capital costs (CAPEX), variable operation and maintenance costs (variable OPEX), and the fixed operation and maintenance costs (fixed OPEX). The variable OPEX varies depending on the power output of the generator and is usually stated in EUR/kWh, while the fixed OPEX remains constant regardless of the electricity production and is given in EUR/kW.

The market has observed solar capital costs of around EUR1,036/kW in Germany, for installations between 10-100 kW[109]. Global capital costs also demonstrated to be in a range between EUR500/kW-EUR2,000/kW with a midpoint of EUR719/kW in 2020[110]. However, since 2020, there has been a spike in capital costs due to a combination of the COVID-19 pandemic and material shortages creating a

[109] https://www.ise.fraunhofer.de/content/dam/ise/de/documents/publications/studies/Photovoltaics-Report.pdf

[110] Photovoltaics Report (fraunhofer.de)

shock in material prices[111]. The IEA estimates that prices in 2022 are between 15-25% higher than they were in 2020[112], erasing years of cost reductions previously seen in the market. These percentages could continue increasing across the year due to additional challenges faced by the war in Ukraine and the continuation of material shortages paired with high demand. However, there is large uncertainty around how the market will continue to perform.

To derive the solar cost figures for the year 2022 in this study, we have assumed the solar costs to be 15% higher than they were in 2020 to reflect the IEA's insights discussed above[113]. The 15% increase excludes the additional increase from inflation. Our 2020 cost assumptions are based on datapoints provided by SEAI in combination to researched data sources and previous studies conducted by Ricardo. Due to uncertainty over market conditions, we have kept the costing value from 2022 flat, in real terms, for another year, until 2023. This reflects potential increasing costs in the market counteracted by some slight increases in efficiency gains, leaving most of the cost differentials up to inflation. However, the evolution of the cost trajectory will depend on the market conditions and if the supply chain issues are resolved. There is a risk that the costs could continue on the upward trajectory that they have been on since 2020 if the market conditions remain or get worse. Therefore, it will be vital to conduct regular tariff reviews to ensure that the tariffs in the policy are still fit for purpose and reflect the costs seen in the market.

From 2024 onwards, we applied the percent year-on-year learning curve derived from the IEA's projections of the evolution of technology costs in a business as usual scenario[114]. The learning rate applied was the average of the IEA's percent year-on-year change for the solar curve from 2022-2026, equivalent to -6.03%[115]. The learning curve applied reflects the idea that capital costs and operational and maintenance costs are expected to decrease across the forecast horizon as technology advancements are anticipated to put downward pressure on costs in the medium to long term. These advancements include module efficiency gains and material improvements, which can then decrease the number of panels required for the same amount of output and therefore can reduce capital costs and operational costs from the perspective of lower installations. Even though we have assumed a 6% year-on-year decrease in costs from 2024, the projection will highly depend on the current market conditions, how they evolve, and if the current spike and supply chain issues can be resolved to flip the cost trend back to how it was previously.

In addition to the solar costs, we assumed grid connection costs for the 999kW export site. The grid connection costs assume that the project uses 500m of underground cables, and include costs for substation, preliminaries and site mobilisation, and non-contestable costs. We assume that the site does not need a Remote Terminal Unit due to size, and therefore, that is not factored into the costing. The assumptions lead to connection costs of EUR (2023) 1,772.99/kW of MEC. The per kW costs show the benefit of scaling up the project size, which could lead to lower costs per unit of kW. The connection costs could be lowered as well by exploring overhead lines, instead of underground cables, reducing the cabling costs by almost 4-fold. However, the public does not tend to favour this option due to visual impacts and there are additional hurdles associated with overhead lines, including the need for consent, that make them less common.

The table below presents the capital costs for each of the solar PV archetypes selected, including grid connection costs. The costs are presented per kW of MEC, and the larger archetype of 999kW assumes a DC/AC ratio of 1.5. Therefore, the 999kW archetype would be equivalent to a site with 999kW of MEC and 1.5MW of solar PV (DC).

[111] What is the impact of increasing commodity and energy prices on solar PV, wind and biofuels? – Analysis - IEA
[112] IEA, Renewable Energy Market Update, 2022-2023, Renewable Energy Market Update 2022 (windows.net)
[113] IEA, Renewable Energy Market Update, 2022-2023, Renewable Energy Market Update 2022 (windows.net)
[114] What is the impact of increasing commodity and energy prices on solar PV, wind and biofuels? – Analysis - IEA
[115] What is the impact of increasing commodity and energy prices on solar PV, wind and biofuels? – Analysis - IEA

Table 11. Solar capital costs for the archetype selection in EUR(2023)/kW of MEC

Archetype	2022	2023	2024	2025	2026	2027	2028	2029	2030
Rooftop_Commercial_60 kW	1,607	1,607	1,511	1,419	1,334	1,253	1,178	1,107	1,040
Rooftop_Agriculture_100 kW	1,483	1,483	1,394	1,310	1,231	1,157	1,087	1,022	960
Rooftop_Public_100 kW	1,483	1,483	1,394	1,310	1,231	1,157	1,087	1,022	960
Rooftop_Industry_250 kW	1,209	1,209	1,136	1,068	1,003	943	886	833	782
Rooftop_Commercial _250 kW	1,209	1,209	1,136	1,068	1,003	943	886	833	782
Rooftop_Public_325 kW	1,209	1,209	1,136	1,068	1,003	943	886	833	782
Rooftop_Industry_625 kW	1,209	1,209	1,136	1,068	1,003	943	886	833	782
Ground-Mounted_Community Energy/Agriculture-Export_999 kW	3,339	3,339	3,246	3,157	3,074	2,997	2,923	2,855	2,790

Studies show that fixed operation and maintenance costs tend to be between EUR8-10/kW for smaller rooftop sites and increase with ground-mounted installations[116,117]. To estimate the fixed operation and maintenance costs for the architypes selected, we have used relative factors that derive a relationship between OPEX and CAPEX based off several sources. Research shows that the OPEX costs can range between 1-2.5% of the capital costs[118,119].

To estimate the fixed costs for the rooftop mounted sites, we assumed that the OPEX would be 1% of the capital costs, shown in Table 11. While for ground-mounted, the OPEX would be 2% of the capital costs excluding grid connection costs. These different percentages reflect the additional expenses for ground-mounted assets in the annual costs from payments such as land lease rates and land authority rates. The assumed land lease and land authority rates for the archetypes were assumed to be EUR5/kW and EUR6/kW respectively. These figures are representative and are meant to represent an average as they vary largely by the specific location of the asset. Even though we did not assume any additional rates for the rooftop archetypes, there could be additional lease rates associated with rooftop technologies that could increase costs.

Table 12 presents the fixed operation and maintenance costs for each of the solar PV archetypes selected including the land lease and land authority rates for the ground-mounted sites.

Table 12. Solar fixed operation and maintenance costs for the archetype selection in EUR(2023)/kW of MEC including the land lease and land authority rates

Archetype	2022	2023	2024	2025	2026	2027	2028	2029	2030
Rooftop_Commercial_60 kW	16	16	15	14	13	13	12	11	10
Rooftop_Agriculture_100 kW	15	15	14	13	12	12	11	10	10
Rooftop_Public_100 kW	15	15	14	13	12	12	11	10	10
Rooftop_Industry_250 kW	12	12	11	11	10	9	9	8	8

116 https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/456187/DECC_Small-Scale_Generation_Costs_Update_FINAL.PDF

117 https://www.gov.uk/government/publications/beis-electricity-generation-costs-2020

118 A European Assessment of Solar Energy Cost: Key factors and Optimal Technology, MDPI, 2021

119 Sustainable Energy Handbook, Simplified Financial Models Module 6.1, February 2016

Archetype	2022	2023	2024	2025	2026	2027	2028	2029	2030
Rooftop_Commercial _250 kW	12	12	11	11	10	9	9	8	8
Rooftop_Public_325 kW	12	12	11	11	10	9	9	8	8
Rooftop_Industry_625 kW	12	12	11	11	10	9	9	8	8
Ground-Mounted_Community Energy/Agriculture-Export_999 kW	31	31	29	27	26	24	23	21	20

According to sources, including the NREL, solar PV variable OPEX is minimal and close to zero especially due to a lack of physically moving parts in the generation process. Therefore, we assumed that the variable OPEX for the solar PV archetypes to be EUR0/kWh. However, we did assume some variable costs arising from balancing responsibility. The charges were assumed at EUR5/MWh and were only considered for installations above 400 kW from 2022-2025 and only for installations above 200 kW from 2026 onwards, due to future regulations shifting the balancing responsibility to assets larger than 200 kW from 2026 (down from 400kW) as stated in the archetype characterisation section of this report.

Co-location of solar and battery were also considered in the study. To do so, we assessed battery costs and added them to the solar costs, by considering the proportion of battery size to the solar site size, to derive the co-located capital costs.

The cost trends were derived in a similar manner than the solar costs. This consisted of increasing the 2020 battery costs by 15% to calculate the costs in 2022 as battery costs have also seen a sharp increase from the current material shortages. The assumption is that battery costs are increasing at a similar rate than solar PV. Similar to the solar PV cost trend, we assume the battery costs to flatten and stay flat until 2023 and then begin to decrease again from 2024 onwards. The year-on-year decrease used for battery costs was derived from the NREL costing baseline, by averaging the annual decrease from 2022-2030, leading to a percent change of -4.3%[120].

The capital cost assumptions for the co-located solar and battery installations are shown below, assuming the use of 1 hour duration battery storage.

[120] 2022 Annual Technology Baseline, National Renewable Energy Laboratory

Table 13. Co-located solar and battery capital costs for the archetype selection in EUR(2023)/kW of MEC

Archetype	2022	2023	2024	2025	2026	2027	2028	2029	2030
Rooftop_Commercial_60 kW	2,098	2,098	1,980	1,869	1,764	1,665	1,572	1,484	1,401
Rooftop_Agriculture_100 kW	1,659	1,659	1,562	1,470	1,385	1,304	1,228	1,156	1,089
Rooftop_Public_100 kW	1,974	1,974	1,864	1,760	1,661	1,569	1,481	1,399	1,321
Rooftop_Industry_250 kW	1,700	1,700	1,606	1,517	1,434	1,355	1,280	1,210	1,143
Rooftop_Commercial _250 kW	1,700	1,700	1,606	1,517	1,434	1,355	1,280	1,210	1,143
Rooftop_Public_325 kW	1,700	1,700	1,606	1,517	1,434	1,355	1,280	1,210	1,143
Rooftop_Industry_625 kW	1,700	1,700	1,606	1,517	1,434	1,355	1,280	1,210	1,143
Ground-Mounted_Community Energy/Agriculture-Export_999 kW	3,830	3,830	3,715	3,607	3,505	3,408	3,317	3,232	3,151

Similar to the solar PV costs, the fixed operation and maintenance costs for the batteries were considered to be related to the capital costs. The fixed OPEX was assumed to be 2.5% of the capital costs of the batteries[121]. These costs were derived for the battery assets alone and then added to the solar PV capital costs, considering the proportions of battery size and the solar site, to calculate the total fixed OPEX of the co-located asset. The table below depicts the calculated fixed OPEX for the co-located archetypes including land lease and land authority rates for the ground-mounted site.

Table 14. Co-located solar and battery fixed operation and maintenance costs for the archetype selection in EUR(2023)/kW of MEC including the land lease and land authority rates

Archetype	2022	2023	2024	2025	2026	2027	2028	2029	2030
Rooftop_Commercial_60 kW	28	28	27	25	24	23	22	20	19
Rooftop_Agriculture_100 kW	19	19	18	17	16	15	14	14	13
Rooftop_Public_100 kW	27	27	26	24	23	22	21	20	19
Rooftop_Industry_250 kW	24	24	23	22	21	20	19	18	17
Rooftop_Commercial _250 kW	24	24	23	22	21	20	19	18	17
Rooftop_Public_325 kW	24	24	23	22	21	20	19	18	17
Rooftop_Industry_625 kW	24	24	23	22	21	20	19	18	17
Ground-Mounted_Community Energy/Agriculture-Export_999 kW	43	43	41	39	37	35	33	31	29

[121] Cole, W., Frazier, A.W., NREL, Cost Projections for Utility-Scale Battery Storage: 2020 Update

5.2 TECHNOLOGY COST ASSESSMENT FOR 1 MW – 6MW

Two additional archetypes were considered above 1MW consisting of a solar and onshore wind site. This included a solar site with an MEC of 4MW and an onshore wind rated at 4MW. The costs of the two archetypes were derived using a similar methodology than that used for the 50kW-1MW archetypes.

5.2.1 Solar PV

Again, due to current market conditions, the solar capital cost trend was derived by applying an uplift of 15% to the 2020 costs to derive the costing value for 2022. This 2020 benchmark value was collected from previous analysis conducted by Ricardo. Similar to the lower banded archetypes, the 2022 cost was kept flat, in real terms, until 2023. Thereafter, the current market constraints are assumed to settle, and the costs are assumed to begin decreasing again by applying the average -6.03% year-on-year learning rate, derived from the IEA, as also applied to the lower banded solar archetypes described in the previous section[122]. It is important to consider the high uncertainty surrounding the current market and the possible fluctuations that it will cause in the future trajectory of costs. Therefore, it will be vital to perform regular reviews to ensure that the policy rates reflect the movement in costs.

In addition to the solar costs, we also added assumed grid connection costs for the site. The grid connection costs assume that the project uses 2km of underground cables, and include costs for substation, preliminaries and site mobilisation, and non-contestable costs. We also assume that the site needs a Remote Terminal Unit as it is above 1MW, and therefore, the costs reflect the additional expense. The assumptions lead to assumed connection costs of EUR (2023) 693.55/kW for 4MW of MEC, showing the large decrease in per kW costs, relative to the 999kW site. This shows the benefits from increasing the site's capacity and the applications of economies of scale.

The table below presents the capital costs for the solar PV archetype in the 1-6MW banding range, including grid connection costs. The costs are presented per kW of MEC, assuming a DC/AC ratio of 1.5.

Table 15. Solar capital costs for the archetype selection in EUR(2023)/kW of MEC

Archetype	2022	2023	2024	2025	2026	2027	2028	2029	2030
Ground-mounted_Export_4MW	1,777	1,777	1,712	1,651	1,593	1,539	1,489	1,441	1,396

The operation and maintenance cost assumptions were similar to those described in the previous section. The same land lease, land authority, and balancing responsibility costs were assumed to apply to the 4MW solar archetype as previously discussed. The results of those costs are shown below, including land lease and land authority rates.

Table 16. Solar fixed operation and maintenance costs in EUR(2023)/kW of MEC including the land lease and land authority rates

Archetype	2022	2023	2024	2025	2026	2027	2028	2029	2030
Ground-mounted_Export_4MW	22	22	20	19	18	17	16	15	14

5.2.2 Onshore wind

The capital costs for the onshore wind archetype were also derived in a similar manner as the previous solar PV archetypes. Capital costs for a 4MW onshore wind site, in 2020, were collected by using previous studies and analysis conducted by Ricardo. This 2020 value was then increased by 15% to

[122] What is the impact of increasing commodity and energy prices on solar PV, wind and biofuels? – Analysis - IEA

derive the costs in 2022. This reflects the insight stated by IEA which reports that costs in 2022 have increased by 15-25%, relative to 2020[123].

Similar to solar PV, the 2022 cost was kept flat until 2023. Thereafter, the market is assumed to resettle, and the capital costs of onshore wind are assumed to decrease again. The annual reduction applied from 2024 was assumed at -0.91%, which was calculated as the average year-on-year percent change, in onshore wind costs, forecasted by the IEA from 2022-2026 in a business as usual scenario[124]. Similar to solar PV, the actual evolution of the costs will highly depend on how the market develops and if the supply chain constraints are able to settle, therefore, it will be important to remain cautious of the current environment and conduct regular reviews to inspect the development in the space.

In addition to the capital costs, we have included grid connection costs for the onshore wind site. The grid connection costs assume that the project uses 6km of underground cables, and include costs for substation, preliminaries and site mobilisation, non-contestable, and Remote Terminal Unit costs. The assumptions lead to connection costs of EUR (2023) 1,120.35/kW.

The capital costs, including grid connection costs, for the 4MW onshore wind site are shown below.

Table 17. Onshore wind capital costs, including grid connection costs, in EUR(2023)/kW

Archetype	2022	2023	2024	2025	2026	2027	2028	2029	2030
Onshore wind_Export_4MW	3,176	3,176	3,157	3,139	3,120	3,102	3,084	3,066	3,049

Similar to the solar PV archetypes, the fixed operation costs of the onshore wind asset were assumed to be proportional or related to the capital costs. The fixed operation and maintenance costs for the onshore wind were assumed to be a set percentage of the onshore wind costs, without connection costs. The percentage was assumed to be 3.5%, which was derived from the forecasted technology costs released and published by NREL[125]. The relationship was derived by comparing the fixed OPEX and capital costs of onshore wind projects in the data published by NREL. The same land lease, land authority, and balancing responsibility costs that were applied to the solar archetypes were also assumed to apply to the 4MW onshore wind site. The results of those costs are shown below, including land lease and land authority rates.

Table 18. Onshore wind fixed operation and maintenance costs in EUR(2023)/kW including the land lease and land authority rates

Archetype	2022	2023	2024	2025	2026	2027	2028	2029	2030
Onshore wind_Export_4MW	72	72	71	70	70	69	69	68	67

5.3 VIABILITY GAP ASSESSMENT BY ARCHETYPE

Small-scale renewable energy generation support levels should be set at a level to incentivise the uptake of these technologies where there are gaps in the market (i.e., the revenue or benefits received from operating the technology do not compensate for the cost of that technology). A balance must be reached between providing a sufficient incentive to cover the difference that exists between the cost of installing a particular technology and the savings that result from self-consumption and potentially the revenues received from exporting the excess electricity to the grid. This difference is defined as the viability gap.

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[123] IEA, Renewable Energy Market Update, 2022-2023, [Renewable Energy Market Update 2022 (windows.net)]

[124] [What is the impact of increasing commodity and energy prices on solar PV, wind and biofuels? – Analysis - IEA]

[125] 2022 Annual Technology Baseline, National Renewable Energy Laboratory

In this analysis, viability gaps are calculated in 2023 EUR/kWh terms for each year between 2023 and 2030, for all archetypes (i.e., the combinations of the technologies, storage options and sectors). The detailed description of the methodology and the assumptions used for the modelling are summarised in Appendix A1.

The viability gap assessment informs the policy design exercise in defining the eligibility criteria, as in principle, only generations with positive viability gap should be subsidised. The assessment also provides information on the indicative level of required support.

5.3.1 Inputs and assumptions

The viability gap can be defined as the difference between the levelized cost of electricity for an archetype and the value of self-consumption over the lifetime of the archetype and the value of revenues received for the exported electricity over the eligibility period. The model uses technical and performance data, the technology and storage capital expenditure (CAPEX) and operating cost (OPEX) inputs from the capacity banding and cost assessment exercises to calculate the total generation, onsite consumption, exported electricity and lifetime costs of each archetype. The self-consumption is valued as the avoided purchase of electricity, for which retail electricity prices are used. The price trajectories used were recently updated and provided by SEAI.

The opportunity cost of investing in a comparable investment is captured in the discount rates. Although in reality discount rates of investors vary on a project-by-project basis, as they reflect the hurdle rate for any investment, to set a level playing field, SEAI agreed that the same discount rate for all archetypes is used. Based on the research and optimisation process which was carried out during the analysis, SEAI selected a real 6% discount rate used in the Base case.

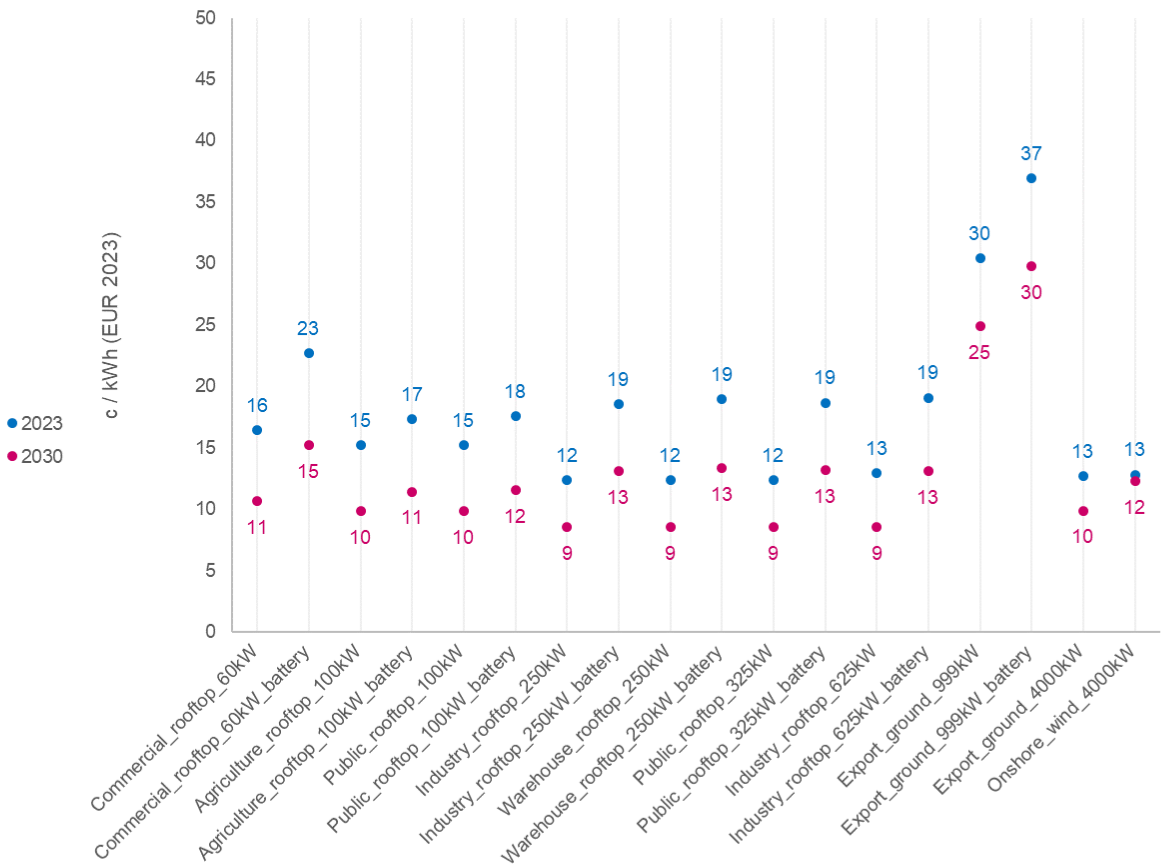
5.3.2 Results

The main results of the model are calculated using a cash flow analysis for the useful lifetime of the technologies for each archetype. With the inputs described in the previous section, the levelized cost of electricity (LCOE) per archetype is calculated first. This is then used to determine the levelized viability gaps per archetype. These are calculated for the Base case scenario. The main outputs of the model are set out below.

5.3.2.1 LCOE

The LCOE can be interpreted as the relative cost-effectiveness of the archetypes, as it is expressed per unit of electricity generated. We present the results for two years, the first and the last year of the policy implementation period (2023 and 2030) in Figure 6.

Figure 6: Base case LCOE per archetype in 2023 and 2030



The LCOE figures suggest that the archetype alternatives with storage are a less cost-efficient means of generating electricity on a small scale compared to their equivalents without a battery storage system under the assumed set of generalised battery assumptions. In 2023, the archetypes with rooftop solar in the 250-500 kW range are the most cost-efficient closely followed by the 625kW industry and the two large 4,000kW export archetypes. The 999kW rooftop solar export archetype is the least cost-efficient due to its high connection costs relative to the size. It can also be observed that LCOE figures for all archetypes decline over the period of 2023 and 2030 as CAPEX are projected to decrease by about 28% and OPEX by about 38% on average during this time (see section 5.1 and 5.2 for details).

5.3.2.2 Viability gap

The viability gap is defined as the difference between lifetime costs and lifetime electricity savings from self-consumption. In other words, it is the additional revenue that generators need to earn to cover their costs. The lifetime costs, the volume and value of the self-consumption, the additional potential revenue (i.e., the clean export guarantee - CEG), and the discount rates are the main drivers of the viability gaps over the lifetime of the archetypes.

Consequently, the variables that need to be considered when modelling the viability gap include:

a) whether an incentive is paid on electricity generated or electricity exported

b) whether CEG is paid on the exported electricity

c) the life of the technology

d) the life of the incentive scheme

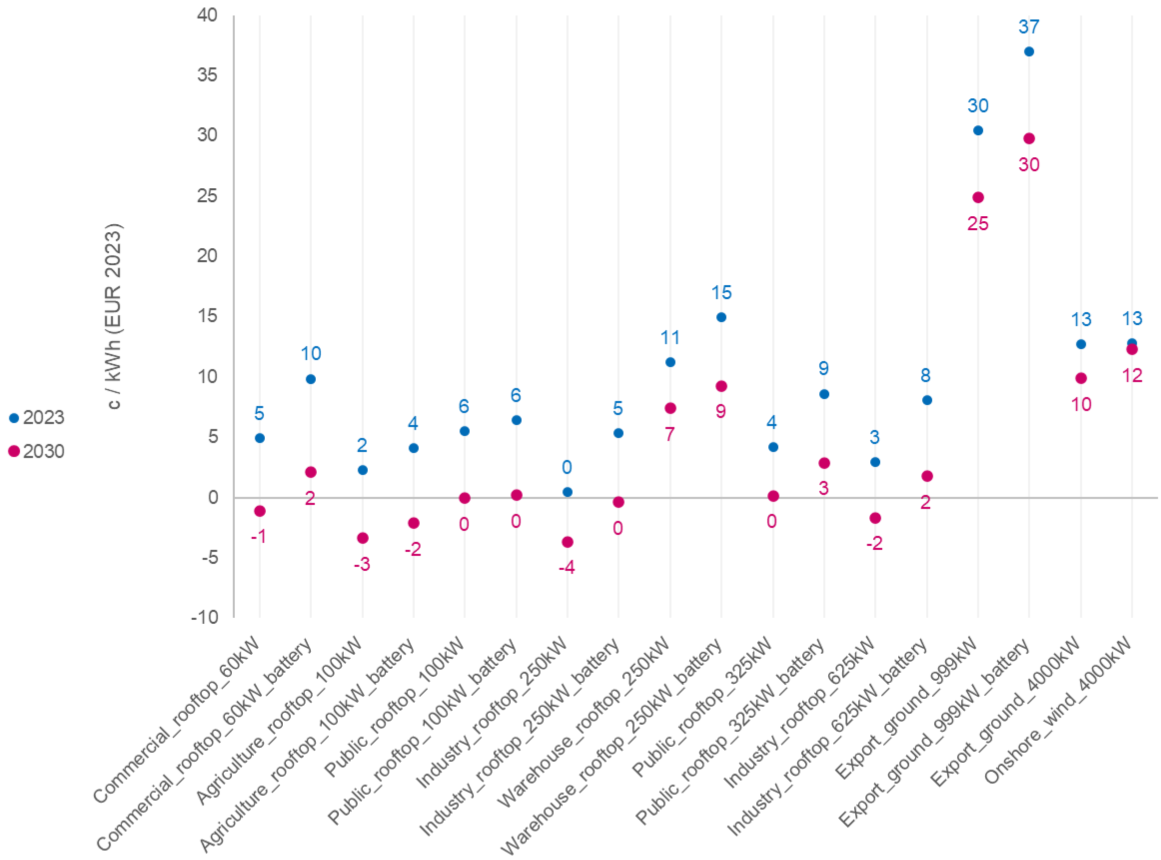
The viability gap scenarios that are modelled below are:

1) incentive is paid on electricity generated over the life of the technology before and after CEG payments, as presented in Figure 7 and Figure 8. SEAI suggested that installations above 1,000 kW will not be eligible for this payment.
2) incentive is paid on the electricity generated, over the life of the incentive scheme before and after CEG payments, as presented in Figure 9 and Figure 10.
3) incentive is paid on electricity exported over the life of the incentive scheme before and after CEG payments, as presented in Figure 11 and Figure 12.

To test the robustness of the results and to show the impact of the changes given the fact that most of the assumptions inherently have a certain degree of uncertainty, a number of additional sensitivity tests have been performed focusing on the LCOE for comparability and on the viability gap over electricity exported over the life of the incentive scheme after CEG payments, which is in particular important from the policy designing perspective. The following sensitivity testing has been run (see A1.4 for the detailed results per archetype and per installation year):

- +10% cost: to match upper end of IEA's estimate on cost increase from 2020[126] (note the base case applied the lower end of the range of 15%-25% as it is explained in section 5.1);
- -15% cost: to present results without the IEA's estimated cost increase of 15%-25%
- High electricity price: to show the uncertainty around the outlook on the future electricity prices; and
- 7% discount rate: to demonstrate the impact of the required returns on the LCOE and viability gap results.

Figure 7: Base case viability gap over lifetime generation per archetype in 2023 and 2030



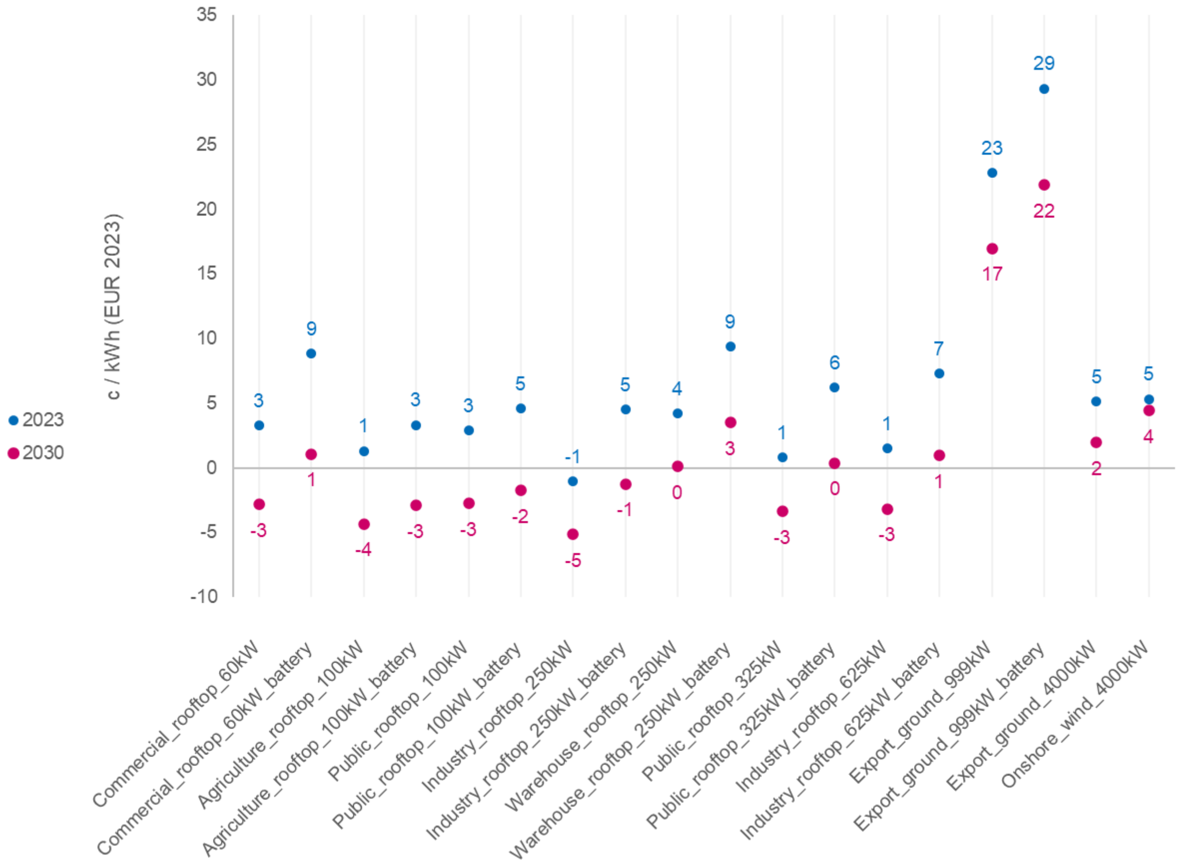
[126] IEA, Renewable Energy Market Update, 2022-2023, Renewable Energy Market Update 2022 (windows.net)

The results of the levelized viability gap over the lifetime of the technology show that the archetype options that include storage are less financially viable than their archetype counterparts without storage, under the assumed set of generalised battery assumptions. Only the 250kW industrial rooftop archetype (without storage) is financially viable (i.e., they have a viability gap of zero or less) in 2023.

By 2030 six out of ten no storage archetypes become financially viable without considering CEG payments. This is mainly driven by self-consumption as the archetypes with higher self-consumption tend to be more financially viable. The sites with low levels of self-consumption (i.e., the export sites and the warehouse site) have significant viability gaps ranging from 13-30 c/kWh without storage in 2023.

The no storage archetype with the highest viability gap both in 2023 and 2030 is the 999kW ground mount export site. It is largely attributed to its high LCOE driven by the significant connection cost per kW.

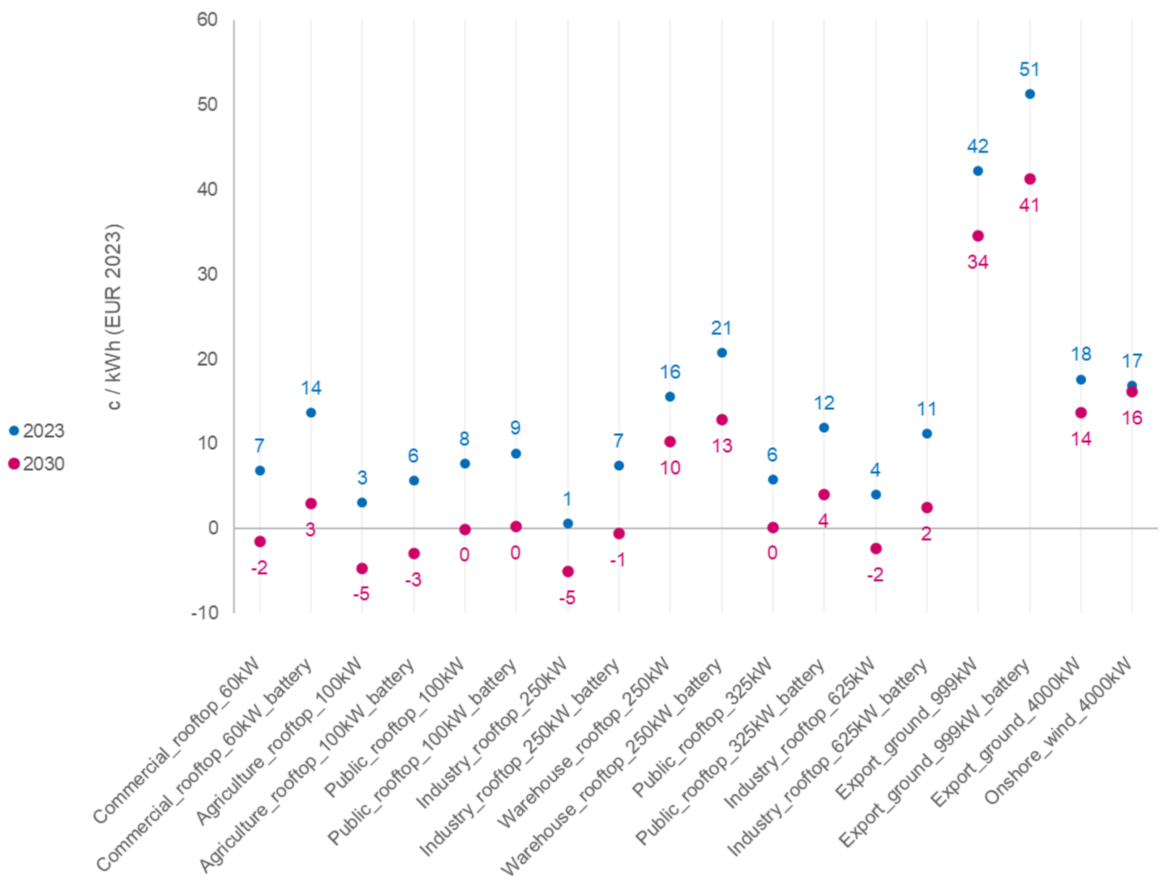
Figure 8: Base case viability gap after CEG over lifetime generation per archetype in 2023 and 2030



Viability gaps for the export archetype significantly improve when considering the viability gap over lifetime generated after CEG payments due to the wholesale price (used as a proxy for CEG) spike experienced in 2023 and 2024. Nevertheless, the largest viability gaps are still with the 999kW ground mount export site archetypes due to the high per unit connection cost values as explained in the LCOE section.

The levelized viability gap can be considered as a proxy for the required subsidy level. One option for a small-scale renewable electricity support scheme option is to pay an incentive on electricity generated. The subsidy life has a significant impact on the levelized viability gap figures as the total lifetime viability gap needs to be recovered over a shorter period and thus over a smaller electricity generation or exported electricity volume. The assumed 15-year subsidy life here aligns with the current RES scheme subsidy duration. This is shown in Figure 9 and Figure 10.

Figure 9: Base case viability gap over generated electricity during 15-year (equal to the assumed subsidy life) per archetype in 2023 and 2030



The figure above suggests that none of the archetypes is financially viable in 2023 and the 250kW industrial rooftop archetype has the lowest viability gap with 0.59 c/kWh. In 2030, the warehouse and export sites are the only archetypes among the ones with no battery option that do not break even. This is because the self-consumption levels are very low for the warehouse archetype which is below 10% (it is between 56% and 88% for the other archetypes) and by definition zero for the export archetypes. None of the with storage archetypes are financially viable in 2023, but by 2030 the agriculture, the 100kW public rooftop and the 250kW industry rooftop archetypes with storage also become economic.

Figure 10: Base case viability gap after CEG over generated electricity during 15-year (equal to the assumed subsidy life) per archetype in 2023 and 2030

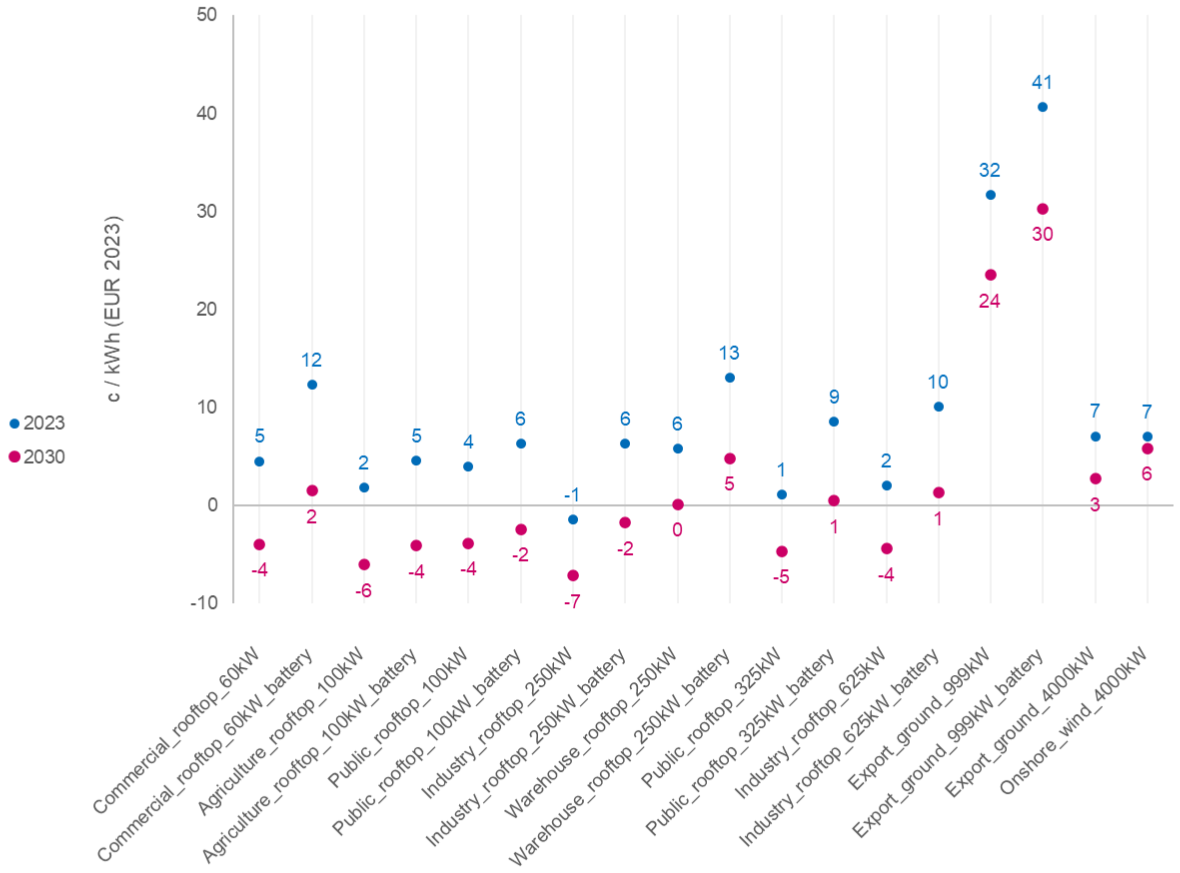
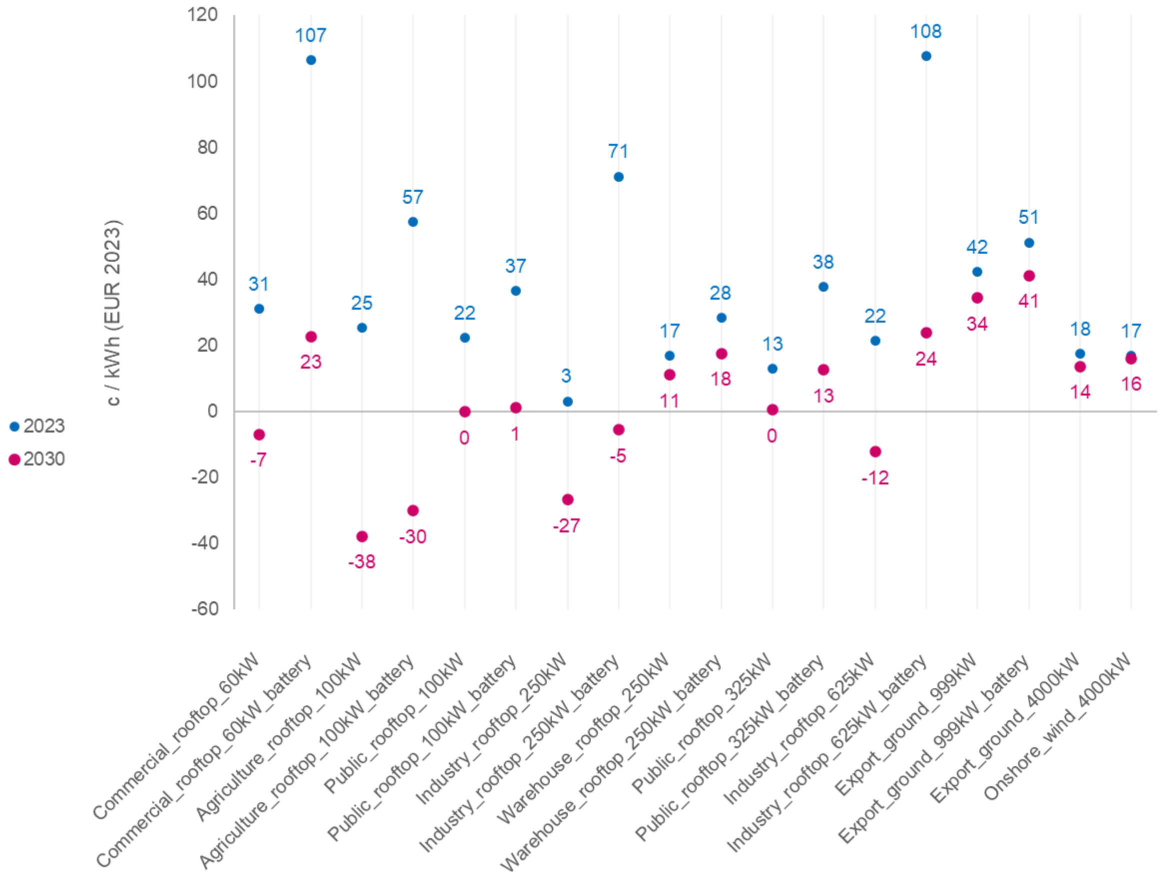


Figure 10 above shows the viability gap after CEG over-generated electricity during the subsidy life. Compared to Figure 9, adding CEG payments to the financial analysis shows that the 250kW industrial archetype breaks even and becomes financially viable in 2023.

The analyses above which explore the viability gaps over generation suggest that the archetypes with small or zero self-consumption are more sensitive to adding CEG to their revenue streams and to change the time horizon of the viability gap calculations. Overall, they show a net increase in the viability gap after these two changes. The archetypes with high self-consumption levels show a significantly lower level of volatility in their viability gaps when examining the impact of the same changes.

Another option for a small-scale renewable electricity support scheme option is to pay an incentive on electricity exported. Therefore, it is important to explore the viability gap levels also over the exported electricity. This is shown in Figure 11 (without CEG) and Figure 12 (with CEG).

Figure 11: Base case viability gap over exported electricity during 15-year (equal to the assumed subsidy life) per archetype in 2023 and 2030



The viability gap over the electricity export provides a proxy to determine the support level which would be required for a certain archetype to cover its lifetime viability gap over the subsidy life if the scheme would be designed to be paid on exported electricity.

As the self-consumption and therefore the exported electricity levels vary significantly among the archetypes, the levelized viability gap figures fluctuate significantly, when they are expressed over the exported electricity in comparison to over generated electricity.

As above, the archetypes including storage are less financially profitable than their pure solar PV equivalents. However, one can see that the viability gaps for the storage archetypes close significantly between 2023 and 2030, or even break even, in the case of several archetypes, indicating their potential value in the future. Although installing storage increases the costs of the installation, it is partially offset by the increase in the self-consumption levels by 3-22%, and in the case of warehouse sites by 253%.

None of the archetypes break even with storage in 2023 and the agriculture archetype is the first one which becomes viable in 2028. By 2030, the with storage option of the 250kW industry rooftop archetypes also becomes financially viable while the other archetypes with storage options remain financially non-viable throughout the entire outlook.

Figure 12: Base case viability gap after CEG over exported electricity during 15-year (equal to the assumed subsidy life) per archetype in 2023 and 2030

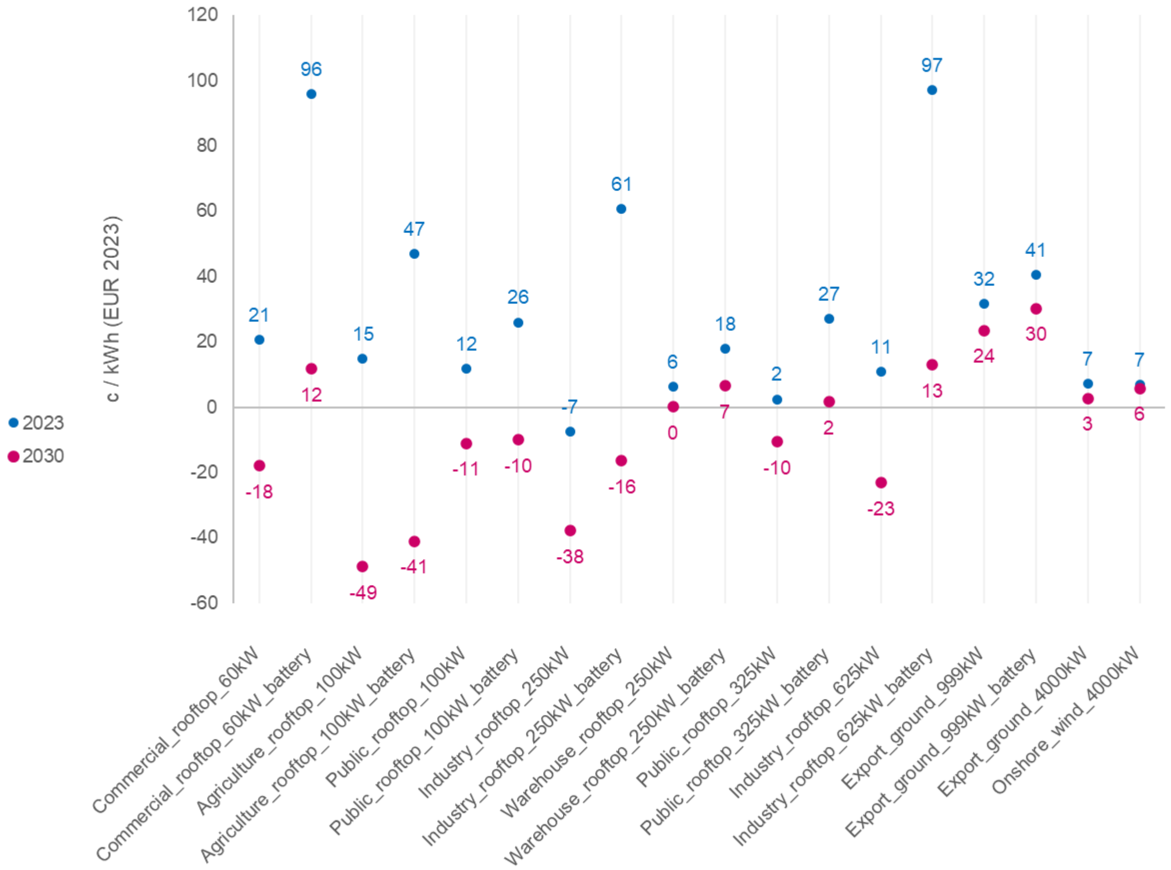


Figure 12 provides the same viability gaps over exported electricity over the subsidy life as shown in Figure 11 but includes CEG payments. Including CEG benefits, improves the viability gaps but the 250kW industrial archetype remains the only archetype which is financially viable in 2023. However, by 2030 majority of the archetypes with no storage options become financially viable and three even with their storage option: agriculture 100kW rooftop, 100kW public rooftop and the 250kW industrial archetypes.

Offsetting the retail price paid for electricity consumption is the key driver for promoting self-consumption. The assumed consumption profiles are relatively high across the considered archetypes (except for the export sites and the warehouse). In addition, as outlined in chapter 2 there is an underlining policy goal to promote self-consumption in line with the MSS. Taking these two factors into account, it is recommended that the small-scale RE policy scheme considered in this study explores the option of providing a payment based on export from a site. This is further considered in section 6.

Another important consideration for the policy design is that the closing of the viability gap is optimised by encouraging higher self-consumption. Higher self-consumption is more likely if the subsidies, which are based on exported electricity, are set lower than the retail tariffs. This consideration is also further explored in Section 6.

It should also be noted that, while a potential technical solution to increase self-consumption is the installation of storage systems, based on the viability gap assessment in this section, installations with storage options in most cases appear to have significantly higher viability gap figures than their counterparts without storage. They therefore may not provide financially viable solutions to be considered in the support scheme. The reason for this is that self-consumption creates savings for the installation by minimising the amount of generated PV energy that is exported to the grid and, therefore, is not remunerated to the owner of the installation. However, installing storage introduces additional costs for the system and, furthermore, creates losses due to the round-trip efficiency of the battery energy storage system. Results show that, while self-consumption increases by 3-22% when adding storage to the modelled archetypes (253% in the case of the warehouse archetype, although this is due to the very low associated demand on-site), the cost increasing effect has a greater impact than the increased value of self-consumption. This results, then, in larger viability gaps for archetypes that include storage.

6. POLICY DESIGN & ANALYSIS

This section identifies a set of three candidate support schemes for incentivising the uptake of small-scale generation. Firstly, we identify a set of guiding principles outlining the objectives of the desired policy support scheme. In Section 6.2, we then select and construct a set of policy options based on a broad screening, taking into account research carried out and the guiding principles. In Section 6.3 we estimate the uptake of each of the policy options so that the costs for each one can be assessed. In section 6.4 we subsequently describe the level of support provided under each policy option. Lastly, in Section 6.5 a multi-attribute decision-making framework is presented that is used to carry out a rigorous analysis to understand how each of the shortlisted policy options compares against the criteria (Section 6.6) in order to outline a preferred approach for Ireland (Section 7).

6.1 GUIDING PRINCIPLES FOR POLICY DESIGN

The following set of guiding principles for policy design to support small-scale renewables in Ireland have been identified:

- **Effectiveness and costs:** A policy's effectiveness is based on its scope, simplicity, accessibility and stability in terms of confidence it provides for investors. Design features from similar schemes from international experience that proved to be most effective as assessed in Section 2 in terms of driving uptake will be included. In addition, policy options will also be designed so that they can address the main barriers for the different archetypes as outlined in Section 3.
    - **Overcoming viability gaps in a cost-effective way:** Assurance that the policy option has the ability to overcome the viability gap of all major archetypes identified in Section 3. This may require combining design elements where appropriate, e.g., an export guarantee can be combined with an investment grant if viability gaps are high, while ensuring there is limited over-subsidizing.
    - **Flexibility:** Ensure that the level of support is dependent on ability to pay with preferential support. This implies higher flexibility in the design of the policy option and can also avoid over-incentivisation. This should also consider whether certain type of projects will need additional support with set-up costs, e.g., community energy projects, while maintaining the technology neutral nature of the policy scheme.
    - **Promoting Community Energy:** Ensure the policy can address community energy barriers by for example including tariff guarantees/pre-registering for support since community projects take time, means to involve aggregators or agents since community stakeholders are not necessarily industry experts. This could consist of streamlining the process, for example the potential to include a light-touch feasibility studies taking into account factors such as grid connection costs for larger community projects, to ensure they are viable. By addressing community energy barriers, the policy can also increase public acceptance.
- **Ease of implementation:** Avoidance of over-complicated schemes to keep administrative costs low and barrier for applications low.
- **Coherence:** This principle will consider whether the core financial incentive provided by a policy option (e.g. in the form of a grant, feed-in-tariff or feed-in-premium) needs to be augmented by enabling support, such as advice services, or creating streamlined administrative procedures etc. It also relates to the technology neutral objective of the policy options, which has an inherent risk of over subsidization, which could cause potential tension with objectives around cost-effectiveness or cost minimisation.
    - In addition, coherence also refers to **alignment of scheme with existing schemes** including the MSS, as the CEG will apply to this technology range as well and ESB Networks and others are updating IT systems in line with the MSS specifications.[127]

[127] https://www.cru.ie/wp-content/uploads/2021/10/CRU21117-CRU-Consultation-Paper-on-Interim-Clean-Export-Guarantee_.pdf

  - **Alignment with network infrastructure** is necessary to minimise network costs, and could be achieved through a high-level screening by ESB Networks early in the process, including a rough cost estimate to feed into feasibility studies.
  - **Renewable self-consumption:** Consider policy types that promote use of energy when generated for certain archetypes. For example, by defining generation thresholds for support that allow larger installations in settings where there is sufficient on-site demand or where battery technologies could apply.

6.2 THREE CANDIDATE SUPPORT SCHEMES

The renewable installation size range of focus for the policy support scheme falls under the eligibility of the newly introduced **Clean Export Guarantee**. It is therefore assumed that in all considered policy options, all archetypes that self-consume will receive this CEG at market rate (wholesale electricity price), which effectively means only the Export_Ground-mounted_999 kW archetype will be excluded from receiving this payment.

The principles outlined above, subsequently feed into the proposed policy choices as follows:

- **A Feed-in-Premium is the preferred option for providing support to small-scale renewables.** International experience highlights the **effectiveness** and **cost-effectiveness** of a FIP in comparison to a feed-in-tariff, due to a FIP's flexible nature. Moreover, a FIP policy, fixed by year and in addition to the CEG, also **aligns** well with the existing MSS where the same policy type is being introduced for smaller installations.
- **Different options for varying the level of support by archetype will be considered.** Ensuring **viability gaps are overcome** while the policy stays **cost-effective** and **equitable** may require varying the level of support based on the archetype. A downside of multiple support levels is a higher level of **difficulty of implementation** and higher administrative costs.
- **The policy options proposed in this study will consider inclusion of a distinct supportive process for community projects, in line with existing structures.** International experience shows that adding requirements for mandatory feasibility studies and stricter permit requirements can reduce non-realisation rates. The principle for **promoting community energy** also highlights the importance of streamlining processes and supporting project developers to take grid connection costs into account in feasibility studies to ensure the project can be viable. This is a barrier that has been encountered by community energy projects in the RESS scheme, which has prompted the implementation of a scheme whereby projects registered as 'Renewable Energy Community' projects between 500 kW and 5 MW have preferential access to a separate category (Category C) under the Enduring Connection Policy and do not have to accept grid connection offers for two years, thereby avoiding high upfront fees. Maintaining the requirements for feasibility studies and permit requirements however can increase the **effectiveness** of the policy by avoiding a low non-realization rate. No data is available yet on how the simplified scheme for community energy projects have helped these projects thus far as it is a relatively new policy[128].
  - **Policy options will be considered whereby community energy projects over 500 kW can receive additional upfront support similar as received under the RESS.** Some of the identified barriers, especially those for **community energy** projects, can be overcome by providing a process for pre-registering for support to unlock grant support for upfront costs, including agents that can support with feasibility studies and arrangement for sharing of energy. For this purpose, SEAI has a 'Community Enabling Framework' in place which supports community-owned RESS projects, including the ability for a community to register as a 'Sustainable Energy Community' and commence a journey with support and advice from SEAI, including mentoring, upfront fiscal support, toolkits, etc.
  - **The possibility for increasing the cap for processing additional grid connection offers will be considered for policy options specifically tailored to supporting community energy projects alongside more transparent information provision by ESB Networks.** An additional barrier to the realisation of all projects, including community energy projects, may relate to the capacity of ESB Networks to process additional grid connection offers to smaller projects. Currently there is a combined cap

[128] https://www.seai.ie/community-energy/ress/enabling-framework/

of 30 projects per year across the B (sub 500 kW, auto-producers and DS3) and C (community-owned 500kW-5MW) category projects in grid connection policy.

- **Policy options will be considered whereby exported volumes of electricity eligible for receiving subsidy support in the form of a Feed-in-Premium will be capped at 80% of electricity generated, in line with the Clean Export Premium in the MSS.** International experience demonstrated that not including consideration of **storage** in the policy design can unintendedly disincentivise storage. In addition, the French system showed that providing premium payments for **self-consumption** over 50% could increase storage technology uptake. However, there will be an exception to the 80% cap for community energy projects and larger export-only archetypes. Additional considerations may be pondered for public buildings with considerable downtimes (such as schools), so that energy exported by these systems is remunerated in a similar way to community projects. This would allow for such buildings to install solar PV without their downtimes significantly limiting their financial feasibility due to high seasonal exports. However, in the policy options outlined in this study the exception to the cap is only applied to community energy projects.

The three selected policy options are outlined in the table below:

Table 19 Proposed design of three candidate support schemes

	Policy option 1 – *Basic Feed-in-Premium*	**Policy option 2 – *Varied Feed-in-Premium***	**Policy option 3 – *Feed-in-Premium with Community Energy support***
Type	CEG for renewable self-consumers + one rate Feed-in-Premium (FiP) for all archetypes. The level of FIP is based on the most prevalent renewable self-consumer archetype that still has a viability gap according to our analysis[129].	CEG for renewable self-consumers + three different FIP for archetypes to match viability gap as closely as possible.	Similar to support provided under policy option 1 + aid for studies and consultancy services for community energy projects
Policy lifetime	8 years	8 years	8 years
Support lifetime	15 years	15 years	15 years
Scope (installation capacity limits)	50 – 6000 kW	50 – 6000 kW	50 – 6000 kW
Level of support / tariffs	Closing viability gap, reduction over time to 2030	Closing viability gap, reduction over time to 2030	Closing viability gap, reduction over time to 2030
Grid connection / capacity provisions	Costs for connection with project developer. Enduring Connection Policy (ECP), which facilitates the deployment of new generation capacity in the RoI, to be simplified.	Costs for connection with project developer. ECP simplified. The lower application deposit for community projects ranging from 500 kW-1MW (of	Costs for connection with project developer. ECP simplified. The lower application deposit for community projects ranging from 500 kW-1MW (of

[129] In case the viability gap is zero during the policy lifetime, a hybrid approach whereby the level of support required by the next most prevalent archetype may be selected instead. This method is used to ensure support to small-scale installation over the full policy lifetime.

	Policy option 1 – *Basic Feed-in-Premium*	Policy option 2 – *Varied Feed-in-Premium*	Policy option 3 – *Feed-in-Premium with Community Energy support*
	The lower application deposit for community projects ranging from 500 kW-1MW (of EUR2k rather than EUR9k) remains in place.	EUR2k rather than EUR9k) remains in place.	EUR2k rather than EUR9k) remains in place. Processing cap for community energy projects by ESBN to be increased.
Community energy provisions	N/A	N/A	Only eligible for aid for studies and consultancy services if registered as 'Sustainable Energy Community' under the SEAI community framework
Self-consumption provisions	Exported volumes of electricity eligible for the FIP will be capped at 80% (in line with the cap in the Clean Export Premium in the MSS) with exception of the community energy and export-only archetypes	Exported volumes of electricity eligible for the FIP will be capped at 80% (in line with Clean Export Premium in MSS) with exception of the community energy and export-only archetypes	Exported volumes of electricity eligible for the FIP will be capped at 80% (in line with Clean Export Premium in MSS) with exception of the community energy and export-only archetypes
Cost recovery mechanism	Recover costs through PSO levy or equivalent	Recover costs through PSO levy or equivalent	Recover costs through PSO levy or equivalent

6.3 SCALING POLICY UPTAKE

To analyse potential outcomes from the policy options, two scenarios of uptake rates of the proposed policy options have been considered: high and low. The scenarios explored the capacity deployment, by archetype, from 2023-2030, assuming the policy option gets implemented in 2023.

Due to the roll-out of three-phase smart meters beginning next year, 2023, and taking approximately two years to complete, in the process of creating the uptake scenarios, it has been assumed that there would be an interim measure in place to estimate and quantify export payments. This assumption means that the smart meter installation process and any delays that could occur from it, would not be a barrier in the uptake and deployment of the small generators in the early years of the scheme.

6.3.1 High Uptake Scenario

To create the high uptake scenario, we have collected and utilised FIT solar deployment levels from the UK for installations between 50 kW-5MW[130]. The dataset contains deployment levels, by size, for every month since the opening of the FIT scheme, April 2010. Therefore, to estimate the total capacity that could be deployed in the first year of the policy's implementation, the second value was taken from the UK data, representing the capacity between 50 kW-5MW that was deployed at the end of 2011. The value from 2011 was taken, instead of 2010, since the deployment levels of the UK FIT in 2010 were extremely low and the scheme started a quarter of the year in. This capacity value was converted into a per capita value and scaled down to an appropriate value for Ireland. The calculation also took into consideration that the High scenario was to assume 500MW of community energy projects by 2030, to align with Ireland's Climate Action Plan 2021 target, and therefore the total deployment by 2030 had to be greater than 500MW[131]. Once the first value was derived, the rest of the forecast, beyond 2023, was calculated based on the percent year-on-year change experienced by the FIT deployment for the same capacity range (50 kW-5MW), rounded to the nearest installation. This led to a total deployment level of 800MW of small generators by 2030.

[130] UK Gov, https://www.gov.uk/government/statistics/solar-photovoltaics-deployment
[131] Climate Action Plan, Gov.ie, https://www.gov.ie/en/publication/6223e-climate-action-plan-2021/

Afterwards, it was necessary to calculate how much of the capacity was deployed by each archetype. To do so, we first assumed that the combination of the export/community energy archetypes would deploy 500MW, by 2030, to align with Ireland's Climate Action Plan 2021 target[132]. This meant that the 999kW solar, 4MW solar, and 4MW onshore wind archetypes would have a combined capacity of 500MW by 2030. We then divided the number of installations equally amongst the three archetypes that would lead to the desired capacity (500MW in 2030). Therefore, the three archetypes delivered the same number of installations across the years but with varying capacity levels.

The remaining 300MW, out of the total 800MW in 2030, would be deployed through the rest of the archetypes. The curve to reach the 500MW and 300MW from 2023 to 2030 was derived using the same year-on-year percent change that was used to calculate the total 800MW, using the UK FIT data trend for the uptake of sites 50 kW-5MW, rounded to the nearest installation. Then, to find the proportion of the capacity that was coming from the remaining archetypes, not including the three large export sites (999kW solar, 4MW solar, 4MW onshore wind), the potential capacity was calculated and used for each archetype based off the stock data taken from the National Heat Study.

The methodology and calculations led to results displayed in Figure 13 - Figure 14 and Table 20 - Table 22.

Figure 13. Capacity installed by archetype in high scenario

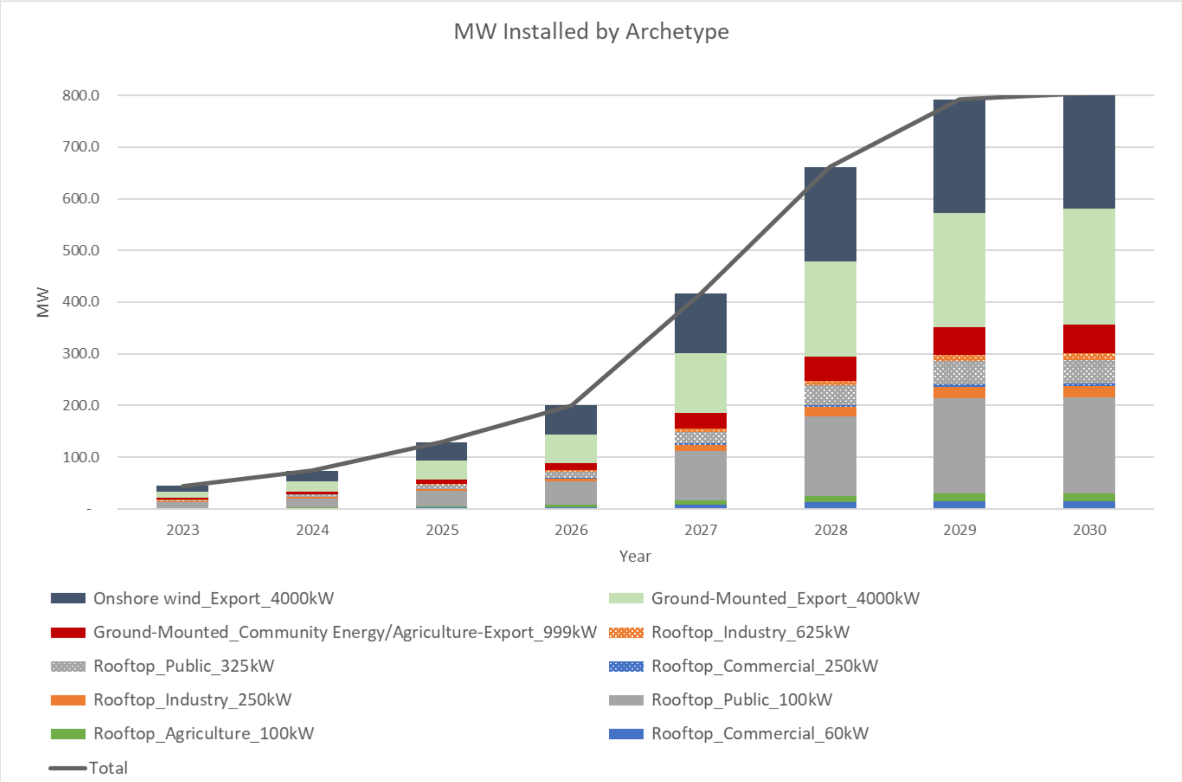


Table 20. Capacity installed by archetype, in MW, in high scenario

Archetype	2023	2024	2025	2026	2027	2028	2029	2030
Solar_Rooftop_Commercial_60 kW	0.8	1.4	2.3	3.6	7.6	12.1	14.6	14.7

[132] Climate Action Plan, Gov.ie, https://www.gov.ie/en/publication/6223e-climate-action-plan-2021/

Archetype	2023	2024	2025	2026	2027	2028	2029	2030
Solar_Rooftop_Agriculture_100 kW	0.9	1.5	2.5	3.9	8.1	13.0	15.6	15.7
Solar_Rooftop_Public_100 kW	11.0	17.5	29.5	45.7	96.0	153.2	183.9	185.3
Solar_Rooftop_Industry_250 kW	1.3	2.0	3.5	5.5	11.5	18.5	22.0	22.3
Solar_Rooftop_Commercial _250 kW	0.3	0.5	0.8	1.3	2.8	4.5	5.3	5.3
Solar_Rooftop_Public_325 kW	2.6	4.2	7.2	11.1	23.4	37.4	44.5	45.2
Solar_Rooftop_Industry_625 kW	0.6	1.3	1.9	3.1	6.3	9.4	11.3	11.9
Solar_Ground-Mounted_Community Energy/Agriculture-Export_999 kW	3.0	5.0	9.0	14.0	29.0	46.0	54.9	55.9
Solar_Export_ground_4000kW	12.0	20.0	36.0	56.0	116.0	184.0	220.0	224.0
Onshore_wind_4000kW	12.0	20.0	36.0	56.0	116.0	184.0	220.0	224.0
Total	**44.5**	**73.4**	**128.6**	**200.1**	**416.6**	**662.0**	**792.1**	**804.2**

Table 21. Year-on-year percent change in capacity deployment for high scenario

2023	2024	2025	2026	2027	2028	2029	2030
-	65.0%	75.3%	55.6%	108.2%	58.9%	19.6%	1.5%

Figure 14. Number of installations by archetype in high scenario

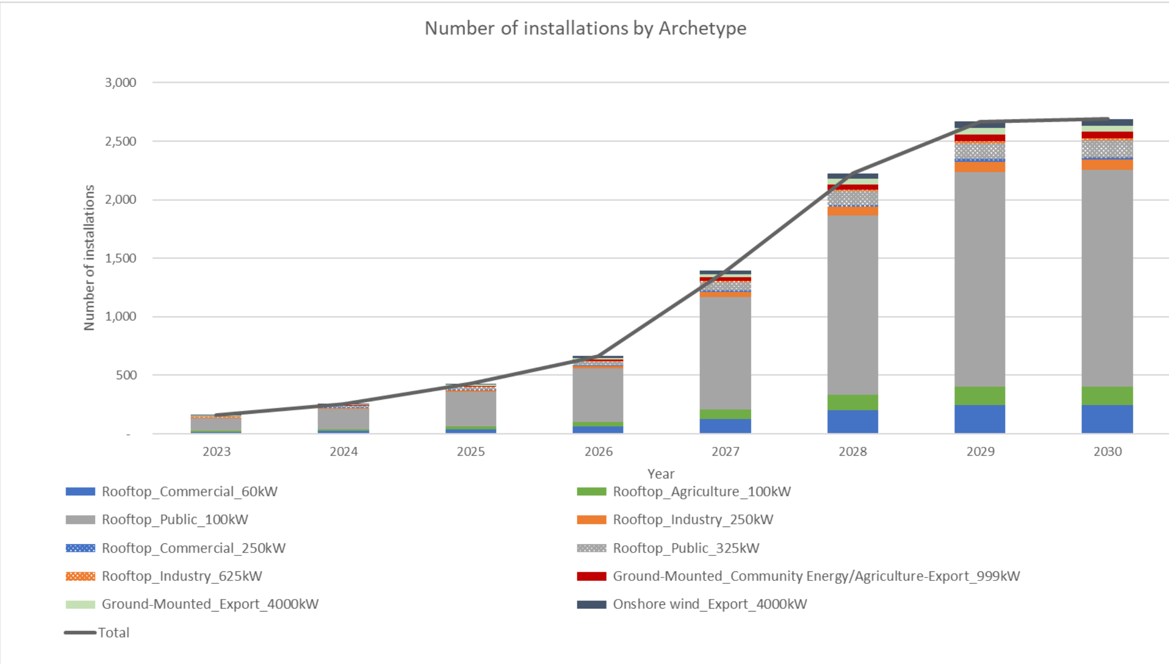


Table 22. Number of installations by archetype in high scenario

Archetype	2023	2024	2025	2026	2027	2028	2029	2030
Solar_Rooftop_Commercial_60 kW	14	23	39	60	127	202	243	245
Solar_Rooftop_Agriculture_100 kW	9	15	25	39	81	130	156	157
Solar_Rooftop_Public_100 kW	110	175	295	457	960	1,532	1,839	1,853
Solar_Rooftop_Industry_250 kW	5	8	14	22	46	74	88	89
Solar_Rooftop_Commercial_250 kW	1	2	3	5	11	18	21	21
Solar_Rooftop_Public_325 kW	8	13	22	34	72	115	137	139
Solar_Rooftop_Industry_625 kW	1	2	3	5	10	15	18	19
Solar_Ground-Mounted_Community Energy/Agriculture-Export_999 kW	3	5	9	14	29	46	55	56
Solar_Export_ground_4000kW	3	5	9	14	29	46	55	56
Onshore_wind_4000kW	3	5	9	14	29	46	55	56
Total	**157**	**253**	**428**	**664**	**1,394**	**2,224**	**2,667**	**2,691**

The high scenario deployment is dominated by the two export 4MW export sites (solar and onshore wind) in terms of capacity, each reaching 224MW by 2030, each equivalent to 28% of the total small generator capacity brought online by the policy. The rooftop, public, 100kW archetype is close behind, deploying a total of 185.3MW by 2030, or 23% of the installed capacity. When looking at the number of installations, the two 4MW eport sites, that hold the majority of the deployed capacity, only deploy 56 units each, equivalent to only 2% of the installations deployed and therefore, in terms of number of installations, the archetype is not the most prevalent.

When looking at the number of sites installed by 2030, the public, rooftop archetype rated at 100 kW deploys the majority of sites, reaching 1,853 sites by 2030 and representing the majority share, equivalent to 69% of total installations. Since the archetype is of smaller capacity than the community energy/export projects, then it reaches a smaller level of capacity deployment. Even though the capacity value is smaller than the community energy capacity, the number of sites installed reflects the large potential in Ireland in the public sector, as explored in the demand sector analysis section of this study.

6.3.2 Low Uptake Scenario

This study also created and considered a scenario with lower levels of uptake from the policy option. This scenario was created by assuming lower capacity deployment, relative to the high scenario, reaching 253.5MW by 2030. This capacity level is close to 70% lower than that of the high scenario.

Out of the 253.5MW of the capacity deployed by 2030, ~20% is assumed to be the larger export sites (999kW solar, 4MW solar, 4MW onshore wind). In this scenario, community energy projects/export sites are of much lower proportion, in terms of capacity, than in the high scenario, where the two 4MW archtypes were the dominating ones. The lower deployment from community energy projects in this scenario represents the lack of certainty and high costs around grid connections, which could limit the number of installations that are predominantly export sites.

The remaining ~80% of the capacity, or 200MW, installed by 2030 is deployed by the rest of the archetypes. The annual capacity that is installed through the scheme, from 2023-2030, can then be calculated by taking the end targets (2030 values) for the large export sites (999kW solar, 4MW solar, 4MW onshore wind-~50MW) and the remaining archetypes (200MW) and applying a year-on-year percent change based on the UK FIT uptake, similar to the methodology that was followed in the high scenario.

The annual capacity from 2023 to 2030 could then be used in combination with the proportions per archetype, in order to allocate the capacity accordingly. The proportions and methodology to get the capacity for each archetype were the same as those used in the high scenario. For the three large export sites (999kW solar, 4MW solar, 4MW onshore wind), the methodology consisted of an equal division of installations amongst the three archetypes to reach the annual values derived. For the remaining archetypes, the proportions used were derived by calculating the capacity potential of each archetype using the heat study data provided by SEAI. These potential capacity values were then translated into percent values, which were used as the proportions to allocate the capacity across the archetypes.

The methodology and assumptions resulted in the figures and values for the low uptake scenario presented below. The year-on-year percent change presented varies from the high scenario's percent change due to the rounding applied to both scenarios in terms of the number of installations to get whole numbers.

Figure 15. Capacity installed by archetype in low scenario

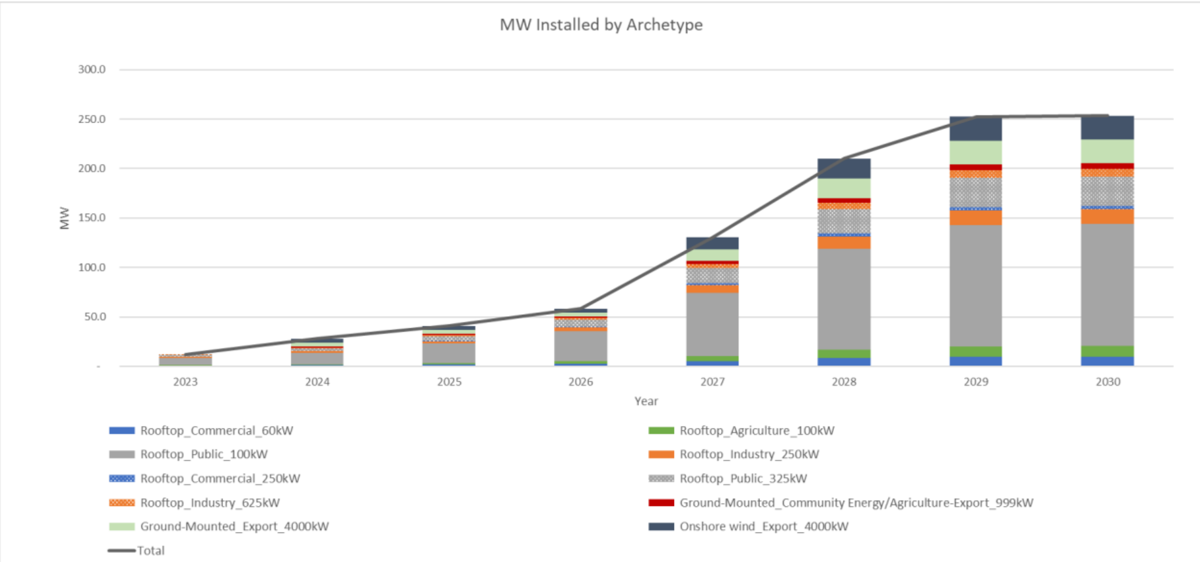


Table 23. Capacity installed by archetype, in MW, in low scenario

Archetype	2023	2024	2025	2026	2027	2028	2029	2030
Solar_Rooftop_Commercial_60 kW	0.6	0.9	1.6	2.4	5.1	8.1	9.7	9.8
Solar_Rooftop_Agriculture_100 kW	0.6	1.0	1.7	2.6	5.4	8.7	10.4	10.5
Solar_Rooftop_Public_100 kW	7.3	11.7	19.6	30.4	64.0	102.2	122.6	123.6
Solar_Rooftop_Industry_250 kW	1.0	1.5	2.3	3.8	7.8	12.3	14.8	14.8

Archetype	2023	2024	2025	2026	2027	2028	2029	2030
Solar_Rooftop_Commercial_250 kW	0.3	0.3	0.5	0.8	1.8	3.0	3.5	3.5
Solar_Rooftop_Public_325 kW	1.6	2.9	4.9	7.5	15.6	24.7	29.9	29.9
Solar_Rooftop_Industry_625 kW	0.6	0.6	1.3	1.9	3.8	6.3	7.5	7.5
Solar_Ground-Mounted_Community Energy/Agriculture-Export_999 kW	-	1.0	1.0	1.0	3.0	5.0	6.0	6.0
Solar_Export_ground_4000kW	-	4.0	4.0	4.0	12.0	20.0	24.0	24.0
Onshore_wind_4000kW	-	4.0	4.0	4.0	12.0	20.0	24.0	24.0
Total	**12.0**	**27.9**	**40.7**	**58.2**	**130.3**	**210.2**	**252.4**	**253.5**

Table 24. Year-on-year percent change in capacity deployment for low scenario

2023	2024	2025	2026	2027	2028	2029	2030
-	132.5%	46.0%	43.0%	123.8%	61.3%	20.1%	0.5%

Figure 16. Number of installations by archetype in low scenario

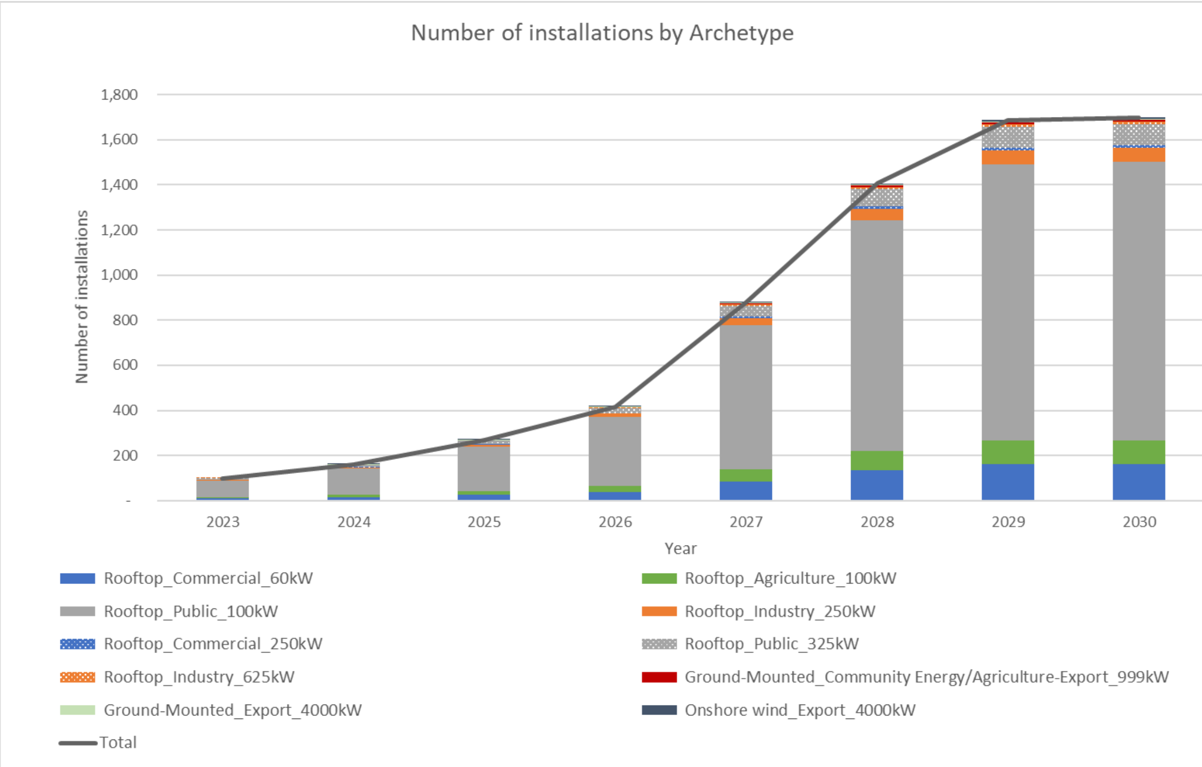


Table 25. Number of installations by archetype in low scenario

Archetype	2023	2024	2025	2026	2027	2028	2029	2030
Solar_Rooftop_Commercial_60 kW	10	15	26	40	85	135	162	163
Solar_Rooftop_Agriculture_100 kW	6	10	17	26	54	87	104	105
Solar_Rooftop_Public_100 kW	73	117	196	304	640	1,022	1,226	1,236
Solar_Rooftop_Industry_250 kW	4	6	9	15	31	49	59	59
Solar_Rooftop_Commercial_250 kW	1	1	2	3	7	12	14	14
Solar_Rooftop_Public_325 kW	5	9	15	23	48	76	92	92
Solar_Rooftop_Industry_625 kW	1	1	2	3	6	10	12	12
Solar_Ground-Mounted_Community Energy/Agriculture-Export_999 kW	-	1	1	1	3	5	6	6
Solar_Export_ground_4000kW	-	1	1	1	3	5	6	6
Onshore_wind_4000kW	-	1	1	1	3	5	6	6
Total	**100**	**162**	**270**	**417**	**880**	**1,406**	**1,687**	**1,699**

In this scenario, the public, rooftop archetype rated at 100 kW dominates, reaching 123.6MW, which is almost 50% of the installed capacity by 2030. When comparing the number of installations, this translates to over 70% of the sites. This represents the large capacity potential in the public sector in Ireland that was explored in the demand sector analysis conducted using the National Heat Study dataset.

The relative deployment levels of the 4MW export archetypes are much lower than those in the high scenario. The capacity deployment in 2030 reaches 24MW for each of the two archetypes, equivalent to only 9% of the capacity. While the number of installations reaches 6 in 2030, only 0.4% of the total number of installations in 2030. This low proportion reflects the great uncertainty and high costs around grid connections and the impact that would have on larger export sites.

6.4 LEVEL OF SUPPORT

6.4.1 Clean Export Guarantee

The level of support provided by each policy option is dependent on the type of policy mechanism and each policy's parameters that are applied. In the case of the Clean Export Guarantee, the level of support will be set by the market and the rate offered may vary by supplier. The estimates for the level of CEG provided will be based on the example of the Smart Export Guarantee in the UK. In the UK, suppliers are obligated under rules set by the regulator Ofgem[133], to ensure that "*the remuneration offered for electricity fed into the grid reflects the market value of that electricity and* [takes] *into account its long-term value to the grid, the environment and society*", in line with the requirements set under the recast Renewable Energy Directive in the EU[134]. The rate offered will depend on the costs and thus the portfolio of generators that each supplier has and the priority placed on profitability and obtaining market share. For the economic cost modelling exercise, it has been assumed that the CEG rate that is offered

[133] Ofgem. 2019. SEG: Guidance for Generators. Available from: https://www.ofgem.gov.uk/system/files/docs/2020/02/seg_generator_guidance_-_final_for_publication.pdf

[134] DIRECTIVE (EU) 2018/2001 OF THE EUROPEAN PARLIAMENT AND OF THE COUNCIL of 11 December 2018 on the promotion of the use of energy from renewable sources (recast). Article 21(2)d.

by suppliers will be equivalent to the expected wholesale electricity price, as forecasting any other level has too many associated uncertainties. In practice this assumption may represent a lower bound estimate and real prices may turn out to be higher. In this case the returns on exported generation will be greater and the viability gaps after the CEG may therefore be lower than those presented later in this chapter.

Table 26 provides an overview of the level of the Clean Export Guarantee assumed in this study. As indicated above, the level of the CEG has been assumed to be equal to the projected wholesale electricity price and this has been modelled as the low-price forecast scenario (this projection was used as base case as part of Ireland's Final National Energy and Climate Plan). The CEG levels of the low scenario come close to current values of the CEG offered by suppliers in the UK and these have been used in the assessment of total policy costs as presented in section 6.6. In the UK the values vary from 0.5 pkWh to 5.6 p/kWh[135] (compared to the modelled values of 4.24 EURc/kWh – 5.69 EURc/kWh) with an average closest to 4.2 p/kWh (4.96 EURc/kWh)[136]. When the policy was first introduced, Shell had initially set a rate of 0.001 p/kWh, but was quickly challenged by different environmental NGOs after which it raised its rate to 3.5 p/kWh to reflect a 'fair market value'.

As outlined previously, the CEG will only be provided to renewable self-consumers which means that all archetypes will be eligible to receive the CEG.

Table 26 Level of wholesale electricity price per year in the high and low scenario in EURc/kWh*

Scenario	Unit	2023	2024	2025	2026	2027	2028	2029	2030
Wholesale electricity price – High scenario	Real price EUR 2022 in EUR c/kWh	18.83	13.33	12.22	11.67	11.13	10.59	10.04	9.50
Wholesale electricity price – Low scenario		18.23	12.51	6.83	6.65	6.47	6.29	6.11	5.92

*Please note that the low scenario figures for the CEG have been used in the assessment of the policy options

6.4.2 Level of Feed-in-Premium for policy option 1 and 3

The main tariff for policy options 1 & 3 is a combination of the rates for public rooftop and export-focused ground-mounted archetypes. The public rooftop (100 kW) archetype is the basis for the premium tariff for the first two years (2023 and 2024) before the tariff then follows the ground-mounted (4,000 kW) tariff up to 2030. This represents a compromise in terms of initially closing the viability gap of the most prevalent archetype (public rooftop), while also ensuring that more archetypes are covered for a longer period of time (as the public rooftop archetype viability gap is closed by 2025). Furthermore, this method also ensures a continuous downward trajectory throughout the policy period.

The Feed-in-Premium for policy option 1 and 3 will be determined by the difference between the viability gap of the chosen archetypes in the selected years and the CEG. The results of this calculation are presented in the table below. It should be noted that these are only estimates based on projected wholesale electricity prices, while in reality the FIP levels will fluctuate to ensure each technology will

[135] SolarGuide. 2020. Compare Smart Export Guarantee Tariffs. Available from: https://www.solarguide.co.uk/smart-export-guarantee-comparison#/

[136] This compares to a wholesale electricity price of 3.51 p/kWh in January 2020 (Ofgem statistics) when suppliers with more than 150,000 domestic customers were required to launch an export tariff by

be guaranteed a level of income that will meet its viability gap. It is this guaranteed level of income that provides a level of certainty to those investing in small-scale renewables.

Table 27 Level of FIP provided in policy option 1 and 3 based on the viability gap minus the CEG , based on the Public_rooftop_100kW (2023-2024) and Export_ground_4000kW (2025-2030) archetypes in EURc/kWh

Archetypes	2023	2024	2025	2026	2027	2028	2029	2030
Public_rooftop_100kW (2023-2024) and Export_ground_4000kW	11.68	9.50	6.19	5.49	4.80	4.11	3.43	2.75

It should be noted that the initial level of the FIP is lower than the 13.5 EURc/kWh clean export premium (CEP) currently offered under the MSS.[137] This could lead to developers installing 'derated' turbines – turbines which are 'capped' so that they generate less energy to qualify for the higher premium — as has been used to exploit the multiple bands of the UK's Feed-in Tariff.[138] This loophole could be closed by placing a cap on the size of the rotor for any wind turbine looking to qualify for the MSS CEP or by capping the amount of subsidy any turbine can receive each year and so remove the financial incentive to derate large turbines. However, as the difference in the level of support between the MSS and the small-scale renewables scheme is fairly small, the risk of 'derated' turbines being installed may be insignificant.

It should also be noted that for all three policy options exported volumes of electricity eligible for the FIP will be capped at 80% of total estimated electricity generation (in line with Clean Export Premium in MSS). This is based on assumed values for installed capacity and capacity factor, it is not metered. In other words, applicants would receive the premium for all of their export, up to a cap of 80% of total potential generation with the exception of the ground-mounted community energy / agriculture expert 999 kW archetype and the two 4MW export-oriented archetypes.

6.4.3 Level of FIP for policy option 2

In policy option 2, three different levels of FIP are proposed to more closely match the viability gaps of different archetypes. The first FIP rate is a combination of the public rooftop (100kW) and warehouse rooftop (250kW) archetypes. This tariff reflects the decrement of the viability gaps of the most prevalent self—consumption-focused archetypes, while again ensuring support is offered up to 2030.

The remaining two tariffs match the solar and wind export-focused 4000 kW archetypes as these each contribute 28% of overall capacity in the high uptake scenario (or 24% in the low uptake scenario). While the levels of their viability gaps are fairly similar, the policy option could distinguish in this way and make sure these options are covered for the duration of the lifetime.

The table below provides a summary of the three proposed rates.

Table 28 Levels of FIP provided in policy option 2 based on the viability gap minus the CEG in EURc/kWh

	Associated archetype	2023	2024	2025	2026	2027	2028	2029	2030
FIP rate 1	Public_rooftop_100kW (2023-2024) and Warehouse_rooftop_250kW (2025-2030)	11.68	9.50	5.80	4.31	3.24	2.19	1.17	0.16

[137] https://www.seai.ie/news-and-media/micro-generation-support/
[138] https://www.ippr.org/files/publications/pdf/feed-in-frenzy_Feb2015.pdf

	Associated archetype	2023	2024	2025	2026	2027	2028	2029	2030
FIP rate 2	Export_ground_4000kW	7.09	6.91	6.19	5.49	4.80	4.11	3.43	2.75
FIP rate 3	Onshore_wind_4000kW	7.02	7.38	7.19	6.98	6.74	6.47	6.18	5.86

As outlined above, the FIP will be capped at 80% (in line with Clean Export Premium in MSS) with the exception of the ground-mounted community energy / agriculture expert 999 kW archetype and the two 4MW export-oriented archetypes.

6.5 MULTI-ATTRIBUTE DECISION-MAKING FRAMEWORK

The three selected candidate support schemes for incentivising the uptake of small-scale generation are assessed using a multi-attribute decision making framework. The framework is outlined below and has been created by listing a set of criteria and their weighting in line with the guiding principles for selecting the proposed policy options. The list of assessment indicators has been based on findings from Section 2 of important factors in international experience, alignment with Ireland policy objectives, and ability of policies to overcome the main barriers that have been identified in Section 3 (barrier by archetype) and Section 5 (e.g., viability gap). The basis for scoring is outlined for three categories in the table below. A more granular score between 1-10 will be assigned based on quantifiable metrics (e.g. costs can be scored based on their position in the ranges indicated) where possible as well as on expert judgement.

It should be noted that some of the assessment indicators work against each other. Most notably, policy options with a high coverage for addressing viability gaps will score well under the first element of effectiveness, but may also be more costly in absolute terms as scored in the second effectiveness element. The higher weighting for the coverage elements highlights the importance of the policy option to be able to address the main barriers in relation to its costs.

Table 29 Multi-attribute decision-making framework to appraise proposed policy options (R/A/G)

Assessment indicator	Description for assessment	Low scoring value (e.g. 1-3)	Medium scoring value (e.g. 4-6)	High scoring value (e.g. 7-10)	Weighting
Effectiveness and costs					
Covering viability gap and addressing barriers	Ability of policy to overcome identified viability gap for all relevant archetypes and address main relevant barriers	Viability gap is not closed for majority of archetypes or major barriers identified are not addressed	Viability gap is closed for major archetypes, but not for all, minor barriers are not addressed	Viability gap is closed for all archetypes and all identified barriers are addressed	30%
Total policy costs and way in which it is recovered	The total cost of the policy over its lifetime for low, medium and high uptake scenarios	>60 million EUR per year for low scenario or >300 million EUR per year for high scenario OR costs mostly recovered through consumer bills	20-60 million EUR per year for low scenario or 100-300 million EUR per year for the high scenario with combination of recovery through consumer bills and other support, e.g., export guarantee	<20 million EUR per year for low scenario or <100 per year million EUR for the high scenario OR minimal impact on consumer bills or taxpayer, e.g., provision through suppliers	20%

Assessment indicator	Description for assessment	Low scoring value (e.g. 1-3)	Medium scoring value (e.g. 4-6)	High scoring value (e.g. 7-10)	Weighting
Flexibility	Ability of policy to avoid over-incentivisation	Policy is inflexible and same rate will be applied independent of technological or economic developments and archetype (e.g., static FIT)	Policy is somewhat flexible dependent on technological or economic developments and archetype (e.g., FIT with phase out pathway)	Flexible policy where only remaining viability gap is provided if necessary, e.g., feed-in-premium etc. and this is varied by archetype	20%
Ease of implementation					
Administrative costs and complexity of implementation	Complexity of implementation of policy and associated costs and institutional capacity needed	High complexity expected to implement policy either because new institutional capacity is required, high administrative costs or frequent updates and/or high data demands .	Medium complexity expected to implement policy and medium administrative costs due to documentation/data required, changes in policy and no significant new institutional capacity required.	Low administrative costs expected with little, or no changes required in policy over lifetime and low institutional capacity, data requirements and administrative costs.	10%
Coherence					
Alignment with Irish /EU policy objectives and EU State Aid guidelines	The ability of the policy to meet all policy objectives including promoting self-consumption, community energy, energy efficiency etc. and align with State Aid Guidelines	Most Ireland policy objectives are not met, and policy is not compliant with RED II / State Aid Guidelines	Policy meets some of the Ireland policy objectives and is compliant with RED II and State Aid Guidelines	Policy meets all Ireland and EU policy objectives and is fully compliant with RED II and State Aid Guidelines	10%
Alignment with existing schemes	Ability of policy to complement existing schemes and not counteract/overlap	Policy counteracts existing schemes or overlaps so that double subsidies are provided	Policy overlaps somewhat existing schemes so that adjustments are needed	Policy complements existing scheme so that both schemes have the potential of being more effective than on their own	10%

6.6 APPRAISAL OF POLICY OPTIONS

The three policy options have intrinsic differences, primarily the ability to differentiate support for different archetypes (policy option 2) or offer greater support for community schemes (polic option 3) which will impact how well they function in a number of different regards. The distinct characteristics of each policy option may have benefits in some ways but drawbacks in others. For instance, an option with more technology differentiation may be beneficial to help avoid the risk of over-incentivisation, but may be more complex to implement. It is important, therefore, to assess these expected impacts systematically across a range of criteria, considering nuances such as the outcomes under different uptake scenarios.

The policy options will be appraised in the following areas:

- **Effectieness and costs**:
    - Percentages of viability gap covered and barriers addressed
    - Total policy costs and way in which it is recovered

    - Flexibility
- **Ease of implementation**
- **Coherence**
    - Alignment with Irish/EU policy objectives and existing schemes

Each of the policy options' scores will then be given a weighting to reflect the relative importance resulting in an overall score for each policy option (section 7).

6.6.1 Effectiveness and costs

6.6.1.1 Percentages of viability gap covered and barriers addressed

The analysis carried out as outlined in Section 6.4 shows that policy option 2 has the potential to be the most effective in terms of meeting the highest percentage of viability gaps—all except the 999 kW community export archetype—and thereby addressing the key barrier for these technologies to be installed. These results are presented in the table below.

Policy options 1 and 3 on the other hand would also not provide sufficient support to cover the viability gap of the onshore wind 4 MW archetype, in addition to the 999 kW community export archetype. As a consequence, the effectiveness of these policy options, especially in the high uptake scenario where larger capacity projects represent a larger percentage of installed capacity, is low.

Policy option 3 is considered to be more effective than option 1 as it also suggests increasing the cap for the number of connection applications that can be processed, thereby addressing upfront barriers faced by community energy projects and potentially increasing the effectiveness of the policy option.

Table 30 Percentage of viability gaps met in terms of installed capacity for each policy option

Policy option	% of viability gaps met in terms of MW in high scenario	% of viability gaps met in terms of # of installations in high scenario	% of viability gaps met in terms of MW in low scenario	% of viability gaps met in terms of # of installations in low scenario	Other barriers addressed	Effectiveness score
Policy option 1	65%	96%	88%	99%	N/A	7
Policy option 2	93%	98%	98%	100%	N/A	9
Policy option 3	65%	96%	88%	99%	Increase of processing cap helps overcome upfront barriers for community energy projects	8

*Score is based on lowest coverage figure

6.6.1.2 Total policy costs and way in which it is recovered

For the low uptake scenario the policy costs are marginally higher for policy options 1 and 3 compared to policy option 2 but, in the high uptake scenario, policy option 2 is more expensive because this assumes that a greater number of export-focused projects will require support.

Both policy options 1 and 3 would overcompensate the self-consumption-focused, lower capacitty archetypes towards the end of the period up to 2030, in order to compensate the viability gap of the more prevalent ground-mounted export archetype. This may explain why the policy costs for these options are marginally higher than costs for policy option 2 for the low uptake scenario in which these lower capacitty archetypes represent a higher percentage of installations. However, the difference is only marginal compared to the more significant cost of policy option 2 in the high uptake scenario. The cost-effectiveness score of this option is therefore adjusted downwards.

It should be noted that in FIP schemes premiums are generally adjusted annually[139] and that policy costs will likely be notably higher if the annual decrement is not followed.

Table 31 Total policy costs for low and high uptake scenario for policy options 1-3

Policy	Costs in million EUR for low uptake scenario for period 2023-2030	Costs in million EUR for high uptake scenario for period 2023-2030	Cost-effectiveness score	Rationale for scoring (related to recovery of costs)
CEG	**335.38** (41.92 on average per year)	**2,127.22** (265.90 on average per year)	N/A	Costs are covered by suppliers
Policy option 1 – FIP costs	**116.97** (14.62 on average per year)	**754.63** (94.33 on average per year)	7	Lower costs in high uptake scenario, slight risk of over-incentivising in low uptake scenario
Policy option 2 – FIP costs	**115.59** (14.45 on average per year)	**850.48** (106.31 on average per year)	6	Lower risk of over-incentivising in low uptake scenario but higher cost for high uptake scenario
Policy option 3 – FIP costs	**116.97** (14.62 on average per year)	**754.63** (94.33 on average per year)	7	Lower costs in high uptake scenario, slight risk of over-incentivising in low uptake scenario

6.6.1.3 Flexibility

All three candidate schemes offer good flexibility, as they all offer FIP tariffs fixed by year in line with the existing MSS, which only provide the remaining viability gap after the CEG is applied. Policy options 1 and 3 offer comparable flexibility in that they offer a single FIP tariff for all archetypes. However, in these policy options the FIP is set at a level so that export archetypes (Export_ground_4000kW and Onshore_wind_4000kW) may be under-incentivised. Policy option 2 affords the greatest flexibility, with three different FIPs for archetypes to match the viability gap as closely as possible while avoiding under- or over-incentivisation.

[139] https://ec.europa.eu/energy/sites/ener/files/documents/2014_design_features_of_support_schemes.pdf

Table 32 Assessment of flexibility for each policy option

Policy option	Assessment of flexibility	Score
Policy option 1 – ***Basic Feed-in-Premium***	Flexible CEG+FIP policy where only remaining viability gap is provided if necessary	9
Policy option 2 – ***Varied Feed-in-Premium***	Flexible CEG+FIP policy where only remaining viability gap is provided if necessary, additional flexibility from multiple FIP tariffs	10
Policy option 3 – ***Feed-in-Premium with Community Energy support***	Flexible CEG+FIP policy where only remaining viability gap is provided if necessary	9

6.6.2 Ease of implementation

All three policy options consist of a CEG with additional FIP. The market-based approach of a CEG system is eminently feasible and should not result in a significant administrative burden, with decisions related to the setting of tariffs passed onto energy suppliers. However, the combination of a CEG with a FIP provides additional complexity, especially if the premium requires regular recalculation. FIP schemes also come with additional costs for example, associated with the procurement of balancing services.

However, institutional capacity for implementing a FIP should already exist in Ireland by the time the small-scale support scheme is implemented. Under the MSS, the Clean Export Premium (CEP) tariff for non-domestic projects between 6 kW and 50 kW is expected to commence in Q3 of 2022.[140] Furthermore, applications for this CEP will be managed by energy suppliers. Therefore, administrative processes associated with implementing a FIP should already be in place and none of the three candidate small-scale support schemes should present a significant additional burden.

Of the three candidate small-scale support schemes, policy option 1 would be the simplest of the three options to implement due to the same FIP being applied for all archetypes. The three different FIPs in policy option 2 introduce additional complexity and, as a result, administrative costs, although the fundamental administrative processes that will need to be undertaken will be similar.

Although similar to policy option 1, some additional administrative complexity arises in policy option 3 as a result of the additional support being provided to community projects. This is not expected to be significant as additional upfront support is already offered to community projects under the RESS. However, the need to improve the capacity of ESB Networks to process additional grid connection offers to smaller projects may present additional administrative costs.

Table 33 Assessment of ease of implementation of the three policy options

Policy option	Assessment of ease of implementation	Score
Policy option 1 – ***Basic Feed-in-Premium***	Simplest of the three options to implement due to the same FIP being applied for all archetypes and absence of investment subsidies. Administrative processes should be similar to existing CEP offered under the MSS. However, introduction of a FIP still requires additional administrative effort and costs.	6

[140] Department of the Environment, Climate and Communications, 2021, Homes, farms, businesses and communities to benefit as Minister Ryan announces the Micro-generation Support Scheme https://www.gov.ie/en/press-release/bfe21-homes-farms-businesses-and-communities-to-benefit-as-minister-ryan-announces-the-micro-generation-support-scheme/

Policy option	Assessment of ease of implementation	Score
Policy option 2 – ***Varied Feed-in-Premium***	Similar to policy option 1, with additional complexity and costs arising from thee different FIPs for different archetypes	4
Policy option 3 – ***Feed-in-Premium with Community Energy support***	Similar to policy option 1. Providing subsidies in addition to FIP and CEG is likely to add some additional complexity, although this is not expected to be significant. However, the need to improve the capacity of ESB Networks to process additional grid connection offers may present additional administrative costs.	5

6.6.3 Coherence

6.6.3.1 Alignment with Irish /EU policy objectives and EU State Aid guidelines

In terms of capacity ranges, all three candidate FIP schemes comply with EU State Aid Guidelines, as a result of the recent changes to allow more flexibility for Member States.[141] The new guidelines stipulate competitive bidding processes are not required for rooftop PV projects up to 1 MW, as well as 100% renewable energy community or SME-owned projects up to 6 MW for solar and 18MW for wind. As such, the three candidate schemes fully comply.

EU State Aid Guidelines also state that *"Member States must demonstrate that reasonable measures will be taken to ensure that projects granted aid will actually be developed…for example by checking project feasibility."* All three candidate schemes require a feasibility study and therefore may be considered in line with EU State Aid Guidelines in this regard.

Policy options 1 and 3 abide by the key European principle of technology neutrality by offering the same FIP level for all technology archetypes. In policy option 2, three different levels of FIP are proposed to more closely match the viability gaps of different archetypes, thereby exhibiting less technology neutrality.

As part of the RED II transposition, a framework for the promotion of self-consumption and energy communities must be in place in EU Member States. In particular, community participation must be facilitated so non-expert groups are supported in the planning, installation and maintenance of their projects. Policy option 3 aligns most closely with this principle for promoting community energy by providing additional support for community energy projects(>500 kW).

6.6.3.2 Alignment with existing schemes

In terms of alignment with existing schemes in Ireland, all three candidate small-scale support schemes fill the policy gap that existed for energy projects not covered by the MSS and RESS schemes. The three candidate schemes align well with the MSS, in the sense that the MSS includes a Clean Export Premium (CEP) tariff for non-domestic projects between 6 kW and 50 kW.[142] Furthermore, all policy options specify that exported volumes of electricity eligible for receiving subsidy support in the form of a FIP will be capped at 80% in line with the Clean Export Premium in the MSS.

SEAI has a 'Community Enabling Framework' in place which supports community-owned RESS projects, including the ability for a community to register as a 'Sustainable Energy Community' and commence a journey with support and advice from SEAI, including mentoring, upfront fiscal support and toolkits. Policy option 3, which enables community energy projects over 500 kW to receive additional upfront support similar as received under the RESS, aligns well with this existing scheme,

As outlined in Section 6.2, we propose that grid connection policy should be changed to make it easier for energy communities to be connected to the grid. In particular, it is proposed that the processing cap

[141] https://ec.europa.eu/competition-policy/system/files/2021-12/CEEAG_Guidelines_with_annexes_I_and_II_0.pdf

[142] Department of the Environment, Climate and Communications, 2021, Homes, farms, businesses and communities to benefit as Minister Ryan announces the Micro-generation Support Scheme https://www.gov.ie/en/press-release/bfe21-homes-farms-businesses-and-communities-to-benefit-as-minister-ryan-announces-the-micro-generation-support-scheme/

for community energy projects by ESBN should be increased. This would also benefit energy communities looking to connect to the grid under the RESS scheme, so both schemes have the potential of being more effective than on their own.

Policy option 3 is therefore considered more aligned with existing schemes than policy options 1 and 2, because this option combines elements from MSS with RESS, and could increase the effectiveness of RESS as well by increasing the cap for energy community grid connections.

Table 34 Assessment of alignment of policy options with policy objectives and existing schemes

Policy option	Assessment of alignment with Irish /EU policy objectives and EU State Aid guidelines	Score	Assessment of alignment with existing schemes	Score
Policy option 1 – ***Basic Feed-in-Premium***	Policy meets all Ireland and EU policy objectives and is fully compliant with RED II and State Aid Guidelines	8	Policy complements existing MSS	8
Policy option 2 – ***Varied Feed-in-Premium***	Policy aligns with Ireland and EU policy objectives, besides technology neutrality, and is fully compliant with RED II and State Aid Guidelines	7	Policy complements existing MSS	8
Policy option 3 – ***Feed-in-Premium with Community Energy support***	Policy meets all Ireland and EU policy objectives, particularly encouragement of energy communities, and is fully compliant with RED II and State Aid Guidelines	9	Policy complements existing MSS and 'Community Enabling Framework', and could even increase the effectiveness of RESS as well by increasing the cap for grid connections.	9

7. CONCLUSION: POLICY RECOMMENDATIONS AND IMPLEMENTATION ROADMAP

The table below summarises the assessment of the three policy options outlined in Section 6. Each assessment indicator is given a weighting to reflect its significance.

Policy options 3 and 2 come out with the highest overall scores, while policy option 1 scores slightly lower mainly because of its lower effectiveness (in comparison to policy option 2) and lack of support for community energy projects (in comparison to policy option 3). These two factors appear to largely balance out in policy options 2 and 3. Both options would appear to represent effective policy choices, or elements of the two options could be combined. For instance, additional support for communities could also be provided in policy option 2 to enhance alignment with EU policy objectives. The importance of providing additional support to community energy projects is highlighted by the lower score of policy option 1 in comparison to the otherwise identical option 3.

Table 35 Summary of policy option assessment

Assessment indicator	Score			Weighting
	Policy option 1 – *Basic Feed-in-Premium*	Policy option 2 – *Varied Feed-in-Premium*	Policy option 3 – *Feed-in-Premium with Community Energy support*	
Effectiveness and costs				
Effectiveness	7	9	8	30%
Cost-effectiveness – Total policy costs and way in which it is recovered	7	6	7	20%
Cost-effectiveness - Flexibility	9	10	9	20%
Ease of implementation				
Administrative costs and complexity of implementation	6	4	5	10%
Coherence				
Alignment with Irish /EU policy objectives and EU State Aid guidelines	8	7	9	10%
Alignment with existing schemes	8	8	9	10%
Total weighted score	**7.5**	**7.8**	**7.9**	**100%**

7.1 POLICY RECOMMENDATIONS

The analysis presented in this report point to a set of policy recommendations to support small-scale renewables in Ireland:

- **A sliding feed-in-premium policy is the preferred policy type**, as it offers a low risk of over-incentivising due to its flexibility and alignment with the Clean Export Premium provided in the MSS. A FIP also complements the RESS scheme in cases where community energy projects greater than 500 kW look for a simpler support scheme to apply to compared to the auctioning scheme.
- **Setting a cap** on the FIP so that applicants only receive the premium for their export up to a cap of 80% of total potential generation can **incentivise self-consumption** and also aligns well with the same cap applied in the MSS.
- To increase the chance of high uptake of small-scale renewables in response to the policy scheme, it is important to ensure that the viability gap of the **export-focused** small-scale renewables (ground-mounted solar / onshore wind 4 MW archetypes) is closed. If this is not the case, then it will prove difficult to reach scale in the coming years.

- **Further support to community renewable energy projects** as implemented in the RESS scheme can increase the effectiveness of the policy scheme. In the RESS scheme projects registered as 'Sustainable Energy Community' projects between 500 kW and 1MW have preferential access to a separate category under the Enduring Connection Policy and do not have to accept grid connection offers for two years, thereby avoiding high upfront fees. No data is available yet on how the simplified scheme for community energy projects have helped these projects thus far as it is a relatively new policy[143], however it is recommended that this support scheme is extended to community energy projects participating under the small-scale renewable policy scheme. As the scheme already exists, it is expected that it is relatively easy to implement or expand, although capacity and budgets to deal with high numbers of community energy project applications and grid connection applications both at SEAI and ESB Networks will need to be increased. If this results in an increase in the processing cap for community energy projects for grid connection applications, then this could potentially also boost the effectiveness of the RESS where this cap has been a barrier in the past.
- The policy assessment seems to suggest there is a **slight preference for providing a blanket FIP rate** with additional support for community energy projects. This would enable the majority of viability gaps to be closed while offering reasonable cost-effectiveness and administrative simplicity, while aligning well with the European objective of supporting community energy projects, outlined in RED II.
- However, policy option 2, in which multiple FIP tariffs are offered for different archetypes, is considered **only slightly less favourable**. Establishing and updating a maximum of three different FIP rates may require higher administration costs and capacity, but it could be more effective in closing viability gaps and avoiding over-incentivising of self-consumption-focused archetypes in later years. This option could also be considered with additional support for community energy projects, as in policy option 3.

7.2 IMPLEMENTATION ROADMAP

For the implementation of the preferred policy option, the following steps are recommended to be undertaken in the coming year with the objective of the support scheme being made available in the coming years:

- **Step 1: Hosting of a public consultation** on the findings of this study and the proposed policy options. Questions may include:
    - Do you agree with the approach to introduce a Feed-in-Premium as a support scheme for small-scale renewables? If not, what alternative model would you propose and why?
    - Do you prefer a Feed-in-Premium with three different levels of support or would you prefer a blanket rate with potential for supplementing this with other support? Please elaborate your preference and detail on potential supplementary measures.
    - Do you agree with a policy lifetime of 8 years and a subsidy support lifetime of 15 years?
    - Do you agree with the export cap of 80%? If not, please elaborate why not or which other level this would need to be set at.
    - What other mechanisms for supporting community energy projects should be considered?
- **Step 2: Revision of preferred policy option** based on feedback from public consultation and more detailed data in terms of updated wholesale electricity price, changing inflation levels and expected uptake. Additional sensitivity analyses using the model developed by Ricardo may also be carried out to test alternative options suggested in the public consultation. The output of this step will be a revised preferred policy option to propose to DECC.
- **Step 3: Presentation of the revised policy option to DECC and decision-makers for agreement.** This will cover the type of support provided, eligibility requirements, timeline and length of support, additional support that may be provided and agreement with SEAI and ESB Networks on these additional measures.

[143] https://www.seai.ie/community-energy/ress/enabling-framework/

- **Step 4: Preparation of systems, registries and communication materials for the launch of the scheme.** After a final decision has been made by DECC on the implementation of a preferred policy option for support to small-scale renewables, specific systems can be developed for the implementation of the scheme. This will include communication materials on the launch and mechanism of the scheme, the timeline, how participants can apply and their eligibility. Application forms and registries for applicants will also need to be developed as well as the planning of official reviews of the FIP rate(s) and overall performance of the scheme.
- **Step 5: Launch of the scheme with regular reviews on its performance.** The scheme is planned to be launched in 2023. The support levels for the policy options proposed in this report will need to be (re-)adjusted before introducing then when there is better visibility on the inflation figures. Moreover, it is recommended that at least every two years the scheme's performance is reviewed to update FIP rates if necessary and/or adjust complementary measures.
-

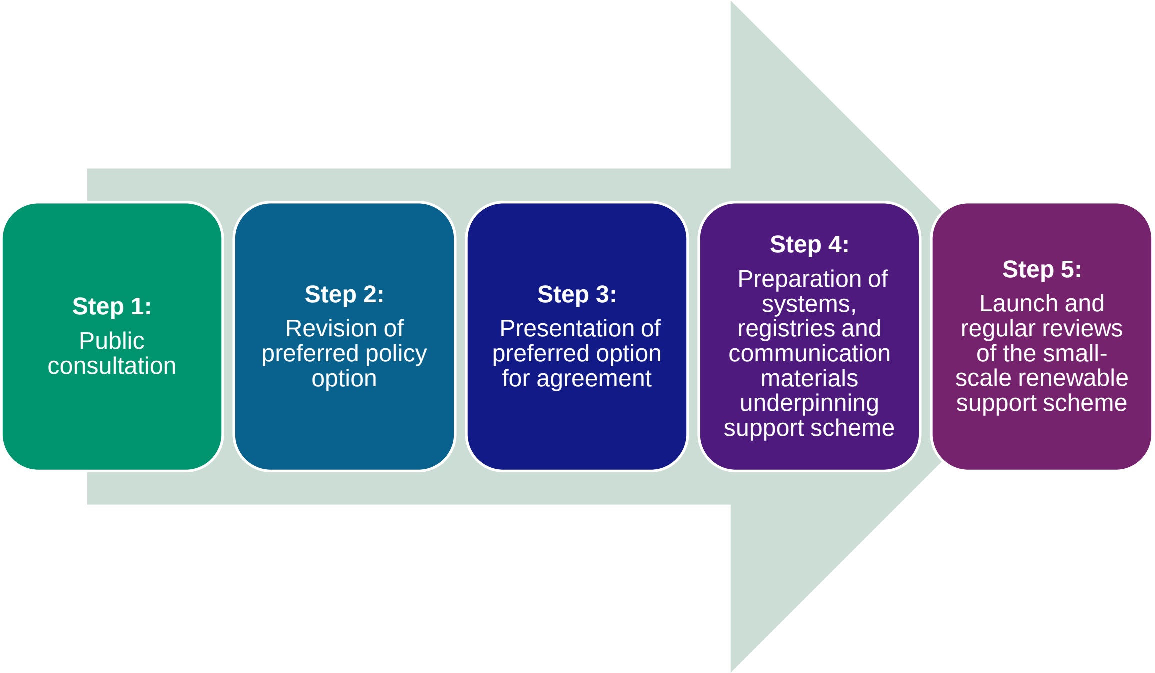


Figure 17 Roadmap for implementation of the small-scale renewable support scheme

Appendices

A1 Viability gap assessment and cost of policy options

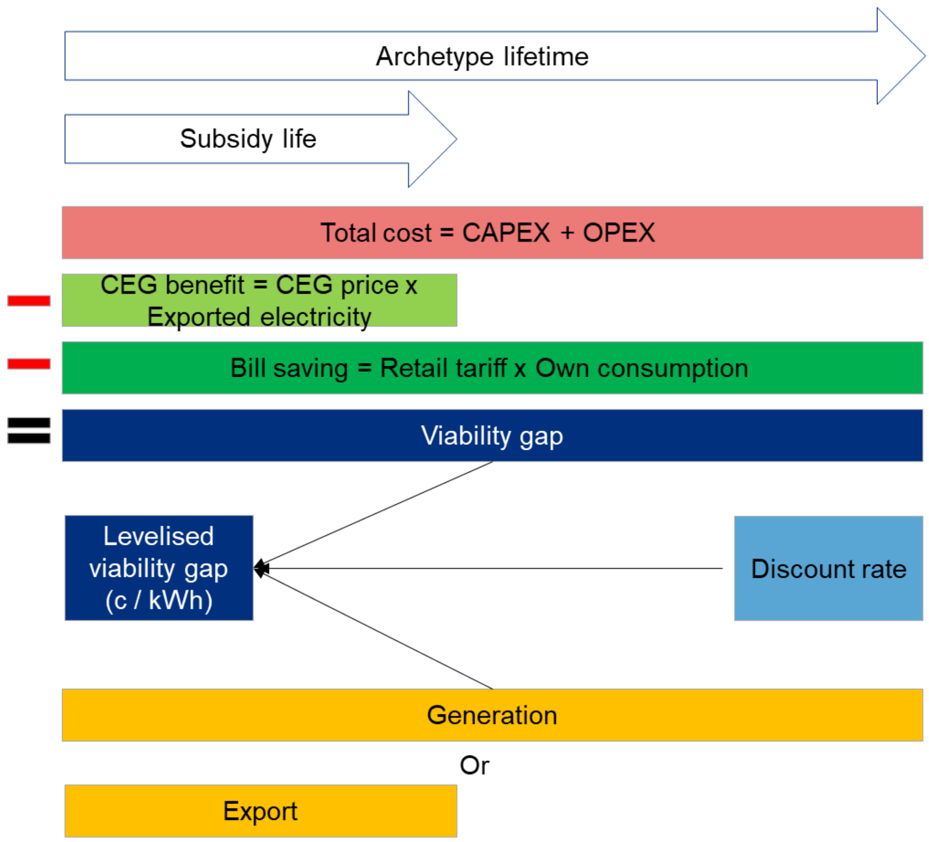
A1.1 Methodology

To estimate the viability gap of the archetypes and cost of the policy options under consideration a flexible MS-Excel based financial model has been developed (described in section 4).

As a first step, the main assumptions have been set and the outputs have been modelled for the 'Base case' scenario. The analytical framework in this assessment consisted of two core components: the total costs over the lifetime and the value of benefits, the clean export guarantee (CEG) and the value of the self-consumption (i.e., the savings to the prosumer from not having to buy the electricity from a supplier).

The annual viability gaps and generation/exported electricity of the archetype were discounted to present value at each year of the analysis (2023-2030) assuming the given year as the installation date for the technology. It was assumed that all installations in a particular year started to generate from the next year. The unit viability gap (i.e., 2023 EURc/kWh) was calculated as a ratio of total discounted viability gap and the total discounted generation or exported electricity. The framework is shown on the following chart.

Figure 18: Analytical framework for the assessment of viability gaps



To calculate the self-consumption savings on purchased electricity, the retail price trajectories were provided by SEAI. The retail price curve uses the average tariffs exclusive of the non-volume-related fixed tariff elements (i.e., standing charge and PSO portion) to account for the fact that the customer is saving against electricity purchased.

The opportunity cost of investing in a comparable investment is captured in the discount rates. Although discount rates are subjective and vary on a project-by-project bases, as they reflect the hurdle rate for any investment, to set a level playing field, SEAI agreed that the same discount rate for all archetype is used. Based on the research and optimisation process which was carried out during the analysis. SEAI selected that a real 6% discount rate is used in the Base case. The 6% discount rate was derived by rounding down the average of the estimates for wind and solar as presented in the table below.

Table 36: Components of the discount rate (WACC) estimates

Component	Technology	
	Wind	Solar PV
Risk free rate (nominal)	1.90%	1.90%
Ireland risk premium	0.50%	0.50%
Corporate default spread (BBB rating)	1.59%	1.59%
Sub-investment grade spread	1.45%	1.45%
Debt issuance costs	0.20%	0.20%
Nominal pre-tax cost of debt	**5.64%**	**5.64%**
Risk free rate (nominal)	1.90%	1.90%
Ireland risk premium	0.50%	0.50%
Equity risk premium	5.00%	5.00%
Asset beta	0.620	0.590
Levered beta	2.489	2.655
Gearing (debt ratio)	77.50%	80.00%
D/E	344%	400%
Tax rate	12.50%	12.50%
Nominal pre-tax cost of equity	**17.81%**	**18.86%**
Real pre-tax cost of equity	*15.50%*	*16.53%*
Nominal pre-tax WACC	**8.38%**	**8.28%**
Inflation	2.00%	2.00%
Real pre-tax WACC	**6.25%**	**6.16%**

A1.2 Assumptions

During the preparation of the model, a number of assumptions have been made for the viability gap assessment and for the policy cost estimates. Some of them are related to the timeline:

Table 37: Timeline assumptions

Section	Timeline
Model start date	1 January 2023
Policy scheme (8 years)	1 January 2023 – 31 December 2030
Forecast period (to match the maximum archetype lifetime)	1 January 2031 – 31 December 2060 (30 years)

Other main assumptions are set out in the following table. The detailed cost and performance data were taken from section 5.1.

Table 38: Main assumptions

Description	Assumption	Source	Further details
Discount rate – real	6%	SEAI	Used to calculate the viability gaps for all archetypes
Inflation - 2022	6.7%	ESRI	https://www.esri.ie/publications/quarterly-economic-commentary-spring-2022?adlt=strict
Risk free rate (nominal)	1.9%	ECB	https://www.ecb.europa.eu/pub/projections/html/ecb.projections202206_eurosystemstaff~2299e41f1e.en.html
Ireland risk premium	0.5%	ECB[144] (accessed on 6 Jul 2022)	Average difference over the last five years between Irish and German 10-year government bond yields
Corporate default spread (BBB rating)	1.59%	Damodaran[145] (accessed on 6 Jul 2022)	Average spread of BBB rating corporate bonds over risk-free rates
Sub-investment grade spread	1.45%	Communication from the Commission on the revision of the method for setting the reference and discount rates[146]	To model the theoretical loan margin of a project company (loan margin difference between rating B and BBB)
Debt issuance costs	0.2%	CEPA, 2017[147]	*Economic Analysis to Underpin a New Renewable Electricity Support Scheme in Ireland, CEPA* (CEPA RESS Analysis), page 102
Equity risk premium	5%	Dimson, Marsh and Staunton	Average of the historical values of UK TMR real[148] and the Development markets TMR real[149] in nominal terms (4.49% and 5.51% respectively applying 2% long-term inflation)
Tax rate	12.5%	PwC[150]	
Long-term inflation	2%	World Economic Outlook database: April 2022	Long-term inflation beyond 2024

144 https://sdw.ecb.europa.eu/browseTable.do?org.apache.struts.taglib.html.TOKEN=8f6c8ba2d65e32b5c2e1b058d9d3e09e&node=SEARCHRESULTS&org.apache.struts.taglib.html.TOKEN=0013a5c56da1591e3d6e80d4e9475a8f&org.apache.struts.taglib.html.TOKEN=312ad3f3b4dc246b458ef75658c4eea9&org.apache.struts.taglib.html.TOKEN=444ada916dba058e7c7c372cd2c9641f&type=series&type=series&type=series&type=series&start=05-07-2017&end=05-07-2022&submitOptions.x=0&submitOptions.y=0&trans=N&q=IRS.M.BE.L.L40.CI.0000.EUR.N.Z+IRS.M.DE.L.L40.CI.0000.EUR.N.Z+IRS.M.IE.L.L40.CI.0000.EUR.N.Z+IRS.M.GR.L.L40.CI.0000.EUR.N.Z+IRS.M.ES.L.L40.CI.0000.EUR.N.Z+IRS.M.FR.L.L40.CI&type=series

145 https://pages.stern.nyu.edu/~adamodar/New_Home_Page/datafile/ratings.htm

146 European Commission. 2008. Communication from the Commission on the revision of the method for setting the reference and discount rates (2008/C 14/02). Available from: https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:52008XC0119(01)&from=GA

147 https://www.dccae.gov.ie/en-ie/energy/consultations/Documents/28/consultations/Economic%20Analysis%20to%20underpin%20the%20new%20RESS%20in%20Ireland.pdf

148 Dimson, E., Marsh, P. and Staunton, M. (2022), 'Credit Suisse Global Investment Returns Yearbook 2022,' February 2022, p37

149 Dimson, E., Marsh, P. and Staunton, M. (2021), 'Credit Suisse Global Investment Returns Yearbook 2021,' March 2021, p58

150 https://taxsummaries.pwc.com/ireland/corporate/taxes-on-corporate-income

Description	Assumption	Source	Further details
Retail electricity prices – business (ex VAT) bands IA-ID	See separate trajectory	SEAI	As last data provided for 2050, this data was used for the remaining years of the projection. Prices were adjusted to EUR2023 price levels
Wholesale electricity prices	See separate trajectory	SEAI	As last data provided for 2050, this data was used for the remaining years of the projection. Prices were adjusted to EUR2023 price levels

Figure 19: Electricity retail price scenarios - Low

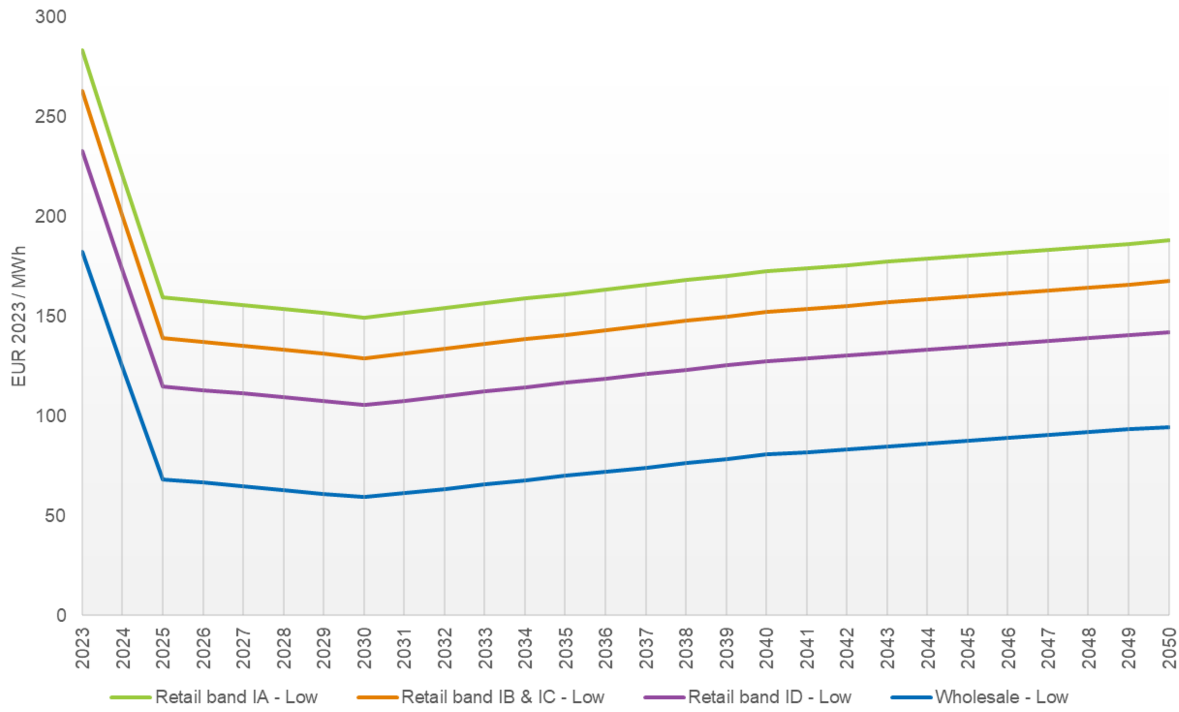
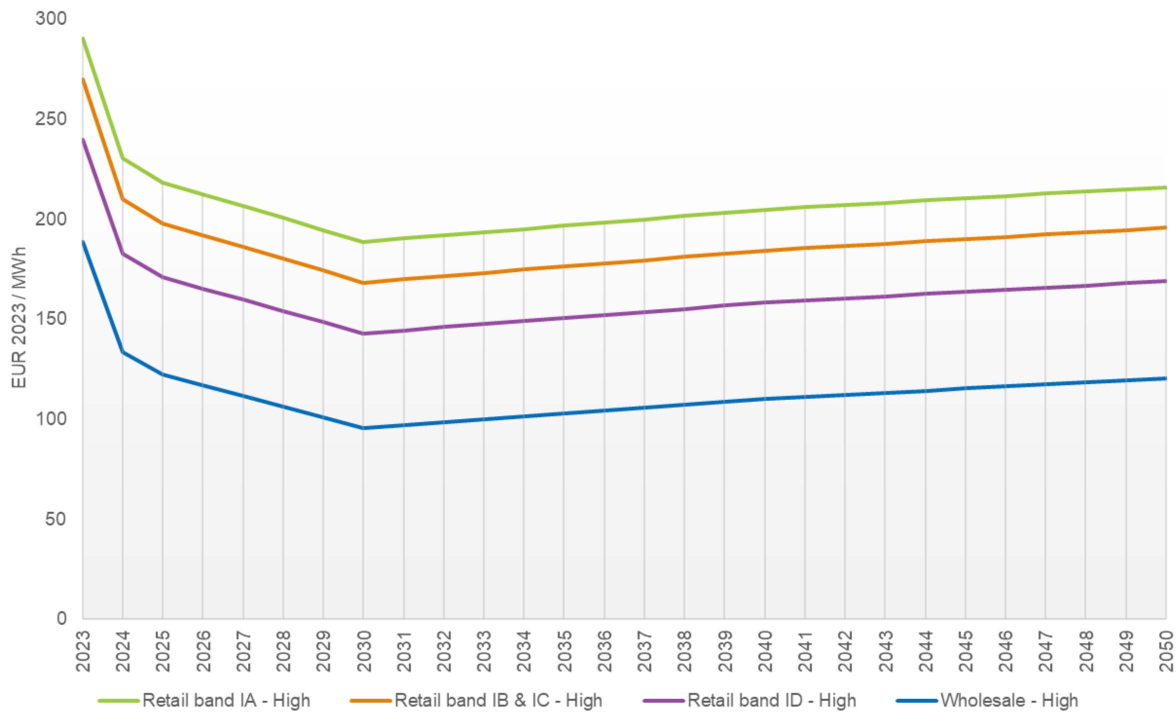


Figure 20: Electricity retail price scenarios - High



A1.3 Detailed results

Table 39: Base case levelized cost of electricity

Archetype technology	Unit	2023	2024	2025	2026	2027	2028	2029	2030
Commercial_rooftop_60kW	c/kWh	16.45	15.46	14.53	13.65	12.83	12.06	11.33	10.65
Commercial_rooftop_60kW_battery	c/kWh	22.71	21.44	20.25	19.12	18.06	17.06	16.11	15.22
Agriculture_rooftop_100kW	c/kWh	15.18	14.27	13.41	12.60	11.84	11.13	10.46	9.83
Agriculture_rooftop_100kW_battery	c/kWh	17.37	16.36	15.41	14.51	13.67	12.88	12.13	11.43
Public_rooftop_100kW	c/kWh	15.18	14.27	13.41	12.60	11.84	11.13	10.46	9.83
Public_rooftop_100kW_battery	c/kWh	17.58	16.56	15.59	14.69	13.83	13.03	12.28	11.56
Industry_rooftop_250kW	c/kWh	12.38	11.63	10.93	10.80	10.18	9.60	9.06	8.54
Industry_rooftop_250kW_battery	c/kWh	18.55	17.54	16.58	16.21	15.36	14.55	13.79	13.07
Warehouse_rooftop_250kW	c/kWh	12.38	11.63	10.93	10.80	10.18	9.60	9.06	8.54
Warehouse_rooftop_250kW_battery	c/kWh	18.93	17.90	16.92	16.53	15.66	14.83	14.06	13.32
Public_rooftop_325kW	c/kWh	12.38	11.63	10.93	10.80	10.18	9.60	9.06	8.54
Public_rooftop_325kW_battery	c/kWh	18.68	17.66	16.70	16.32	15.46	14.65	13.88	13.16
Industry_rooftop_625kW	c/kWh	12.91	12.16	11.46	10.80	10.18	9.60	9.06	8.54
Industry_rooftop_625kW_battery	c/kWh	19.09	18.07	17.11	16.21	15.36	14.55	13.79	13.07
Export_ground_999kW	c/kWh	30.43	29.48	28.59	27.75	26.96	26.22	25.52	24.87
Export_ground_999kW_battery	c/kWh	36.95	35.73	34.58	33.50	32.48	31.51	30.61	29.75
Export_ground_4000kW	c/kWh	12.72	12.23	11.78	11.35	10.94	10.56	10.20	9.87
Onshore_wind_4000kW	c/kWh	12.82	12.74	12.66	12.58	12.50	12.42	12.34	12.27

Table 40: Base case viability gaps over generation over lifetime

Archetype technology	Unit	2023	2024	2025	2026	2027	2028	2029	2030
Commercial_rooftop_60kW	c/kWh	4.95	4.26	3.28	2.34	1.43	0.56	(0.28)	(1.10)
Commercial_rooftop_60kW_battery	c/kWh	9.86	8.93	7.68	6.48	5.33	4.22	3.15	2.11
Agriculture_rooftop_100kW	c/kWh	2.26	1.69	0.77	(0.11)	(0.96)	(1.78)	(2.58)	(3.36)
Agriculture_rooftop_100kW_battery	c/kWh	4.08	3.42	2.41	1.44	0.51	(0.40)	(1.28)	(2.14)
Public_rooftop_100kW	c/kWh	5.53	4.86	3.96	3.10	2.27	1.48	0.71	(0.03)
Public_rooftop_100kW_battery	c/kWh	6.43	5.70	4.69	3.72	2.79	1.90	1.03	0.19
Industry_rooftop_250kW	c/kWh	0.43	(0.01)	(0.76)	(0.95)	(1.65)	(2.33)	(3.00)	(3.65)
Industry_rooftop_250kW_battery	c/kWh	5.35	4.68	3.66	3.22	2.27	1.36	0.46	(0.41)
Warehouse_rooftop_250kW	c/kWh	11.25	10.53	9.82	9.69	9.06	8.47	7.91	7.39
Warehouse_rooftop_250kW_battery	c/kWh	14.94	14.01	13.02	12.60	11.71	10.85	10.03	9.25
Public_rooftop_325kW	c/kWh	4.15	3.62	2.88	2.71	2.04	1.39	0.76	0.15
Public_rooftop_325kW_battery	c/kWh	8.61	7.85	6.84	6.41	5.48	4.58	3.72	2.87
Industry_rooftop_625kW	c/kWh	2.94	2.49	1.74	1.02	0.32	(0.36)	(1.02)	(1.67)
Industry_rooftop_625kW_battery	c/kWh	8.07	7.38	6.37	5.39	4.45	3.54	2.65	1.79
Export_ground_999kW	c/kWh	30.43	29.48	28.59	27.75	26.96	26.22	25.52	24.87
Export_ground_999kW_battery	c/kWh	36.95	35.73	34.58	33.50	32.48	31.51	30.61	29.75
Export_ground_4000kW	c/kWh	12.72	12.23	11.78	11.35	10.94	10.56	10.20	9.87
Onshore_wind_4000kW	c/kWh	12.82	12.74	12.66	12.58	12.50	12.42	12.34	12.27

Table 41: Base case viability gaps after CEG over generation over lifetime

Archetype technology	Unit	2023	2024	2025	2026	2027	2028	2029	2030
Commercial_rooftop_60kW	c/kWh	3.28	2.66	1.67	0.71	(0.21)	(1.10)	(1.98)	(2.83)
Commercial_rooftop_60kW_battery	c/kWh	8.88	8.00	6.74	5.54	4.37	3.25	2.16	1.09
Agriculture_rooftop_100kW	c/kWh	1.32	0.79	(0.13)	(1.02)	(1.88)	(2.72)	(3.54)	(4.34)
Agriculture_rooftop_100kW_battery	c/kWh	3.33	2.70	1.69	0.71	(0.23)	(1.15)	(2.04)	(2.91)
Public_rooftop_100kW	c/kWh	2.90	2.36	1.44	0.55	(0.31)	(1.14)	(1.95)	(2.75)
Public_rooftop_100kW_battery	c/kWh	4.58	3.93	2.91	1.92	0.97	0.05	(0.86)	(1.74)
Industry_rooftop_250kW	c/kWh	(1.01)	(1.38)	(2.14)	(2.35)	(3.07)	(3.77)	(4.47)	(5.15)
Industry_rooftop_250kW_battery	c/kWh	4.55	3.92	2.90	2.45	1.50	0.57	(0.34)	(1.23)
Warehouse_rooftop_250kW	c/kWh	4.22	3.83	3.07	2.87	2.16	1.46	0.78	0.10
Warehouse_rooftop_250kW_battery	c/kWh	9.39	8.72	7.68	7.22	6.25	5.31	4.39	3.50
Public_rooftop_325kW	c/kWh	0.79	0.41	(0.35)	(0.55)	(1.27)	(1.97)	(2.66)	(3.34)
Public_rooftop_325kW_battery	c/kWh	6.20	5.55	4.53	4.07	3.11	2.18	1.27	0.38
Industry_rooftop_625kW	c/kWh	1.50	1.12	0.36	(0.38)	(1.10)	(1.80)	(2.48)	(3.16)
Industry_rooftop_625kW_battery	c/kWh	7.27	6.63	5.61	4.63	3.68	2.75	1.85	0.97
Export_ground_999kW	c/kWh	22.82	22.23	21.28	20.36	19.48	18.62	17.79	16.98
Export_ground_999kW_battery	c/kWh	29.34	28.48	27.27	26.11	25.00	23.92	22.87	21.86
Export_ground_4000kW	c/kWh	5.11	4.98	4.47	3.96	3.46	2.97	2.47	1.98
Onshore_wind_4000kW	c/kWh	5.33	5.61	5.46	5.30	5.12	4.92	4.70	4.45

Table 42: Base case viability gaps over generation over 15-year subsidy life

Archetype technology	Unit	2023	2024	2025	2026	2027	2028	2029	2030
Commercial_rooftop_60kW	c/kWh	6.86	5.90	4.54	3.24	1.99	0.78	(0.39)	(1.52)
Commercial_rooftop_60kW_battery	c/kWh	13.67	12.38	10.65	8.99	7.40	5.86	4.37	2.92
Agriculture_rooftop_100kW	c/kWh	3.14	2.34	1.07	(0.15)	(1.33)	(2.47)	(3.58)	(4.66)
Agriculture_rooftop_100kW_battery	c/kWh	5.66	4.74	3.34	2.00	0.70	(0.55)	(1.77)	(2.96)
Public_rooftop_100kW	c/kWh	7.67	6.75	5.50	4.30	3.15	2.05	0.99	(0.05)
Public_rooftop_100kW_battery	c/kWh	8.92	7.91	6.51	5.17	3.88	2.63	1.43	0.26
Industry_rooftop_250kW	c/kWh	0.59	(0.01)	(1.05)	(1.32)	(2.29)	(3.24)	(4.16)	(5.07)
Industry_rooftop_250kW_battery	c/kWh	7.42	6.49	5.08	4.47	3.15	1.88	0.64	(0.57)
Warehouse_rooftop_250kW	c/kWh	15.60	14.60	13.62	13.44	12.57	11.75	10.98	10.25
Warehouse_rooftop_250kW_battery	c/kWh	20.72	19.43	18.05	17.48	16.24	15.05	13.91	12.83
Public_rooftop_325kW	c/kWh	5.76	5.02	4.00	3.76	2.83	1.92	1.05	0.20
Public_rooftop_325kW_battery	c/kWh	11.94	10.89	9.49	8.89	7.60	6.36	5.15	3.99
Industry_rooftop_625kW	c/kWh	4.07	3.45	2.41	1.41	0.44	(0.50)	(1.41)	(2.31)
Industry_rooftop_625kW_battery	c/kWh	11.19	10.24	8.83	7.48	6.18	4.91	3.68	2.48
Export_ground_999kW	c/kWh	42.20	40.89	39.65	38.49	37.39	36.37	35.40	34.50
Export_ground_999kW_battery	c/kWh	51.25	49.56	47.96	46.46	45.05	43.71	42.45	41.26
Export_ground_4000kW	c/kWh	17.64	16.97	16.33	15.74	15.18	14.65	14.15	13.69
Onshore_wind_4000kW	c/kWh	16.87	16.77	16.66	16.56	16.45	16.35	16.25	16.15

Table 43: Base case viability gaps after CEG over generation over 15-year subsidy life

Archetype technology	Unit	2023	2024	2025	2026	2027	2028	2029	2030
Commercial_rooftop_60kW	c/kWh	4.55	3.70	2.32	0.99	(0.29)	(1.53)	(2.74)	(3.92)
Commercial_rooftop_60kW_battery	c/kWh	12.32	11.09	9.35	7.68	6.07	4.51	2.99	1.52
Agriculture_rooftop_100kW	c/kWh	1.84	1.10	(0.18)	(1.42)	(2.61)	(3.77)	(4.90)	(6.02)
Agriculture_rooftop_100kW_battery	c/kWh	4.62	3.75	2.34	0.99	(0.32)	(1.59)	(2.83)	(4.04)
Public_rooftop_100kW	c/kWh	4.03	3.28	2.00	0.77	(0.42)	(1.58)	(2.71)	(3.82)
Public_rooftop_100kW_battery	c/kWh	6.35	5.46	4.04	2.67	1.35	0.06	(1.19)	(2.41)
Industry_rooftop_250kW	c/kWh	(1.41)	(1.91)	(2.97)	(3.26)	(4.26)	(5.23)	(6.19)	(7.14)
Industry_rooftop_250kW_battery	c/kWh	6.32	5.44	4.03	3.40	2.07	0.78	(0.47)	(1.71)
Warehouse_rooftop_250kW	c/kWh	5.85	5.32	4.26	3.98	2.99	2.03	1.08	0.14
Warehouse_rooftop_250kW_battery	c/kWh	13.03	12.09	10.66	10.01	8.67	7.36	6.09	4.85
Public_rooftop_325kW	c/kWh	1.09	0.57	(0.48)	(0.76)	(1.76)	(2.73)	(3.69)	(4.63)
Public_rooftop_325kW_battery	c/kWh	8.60	7.70	6.28	5.65	4.32	3.02	1.76	0.52
Industry_rooftop_625kW	c/kWh	2.08	1.55	0.49	(0.53)	(1.52)	(2.49)	(3.44)	(4.38)
Industry_rooftop_625kW_battery	c/kWh	10.09	9.19	7.78	6.42	5.10	3.82	2.57	1.34
Export_ground_999kW	c/kWh	31.65	30.83	29.51	28.24	27.02	25.83	24.68	23.55
Export_ground_999kW_battery	c/kWh	40.69	39.50	37.82	36.22	34.67	33.18	31.73	30.32
Export_ground_4000kW	c/kWh	7.09	6.91	6.19	5.49	4.80	4.11	3.43	2.75
Onshore_wind_4000kW	c/kWh	7.02	7.38	7.19	6.98	6.74	6.47	6.18	5.86

Table 44: Base case viability gaps over exports over 15-year subsidy life

Archetype technology	Unit	2023	2024	2025	2026	2027	2028	2029	2030
Commercial_rooftop_60kW	c/kWh	31.27	26.90	20.70	14.76	9.06	3.55	(1.77)	(6.94)
Commercial_rooftop_60kW_battery	c/kWh	106.56	96.52	83.03	70.10	57.65	45.65	34.04	22.78
Agriculture_rooftop_100kW	c/kWh	25.43	18.95	8.67	(1.22)	(10.76)	(20.00)	(28.99)	(37.77)
Agriculture_rooftop_100kW_battery	c/kWh	57.41	48.09	33.92	20.29	7.13	(5.60)	(17.98)	(30.06)
Public_rooftop_100kW	c/kWh	22.23	19.57	15.94	12.47	9.15	5.95	2.86	(0.13)
Public_rooftop_100kW_battery	c/kWh	36.58	32.43	26.69	21.18	15.89	10.79	5.86	1.07
Industry_rooftop_250kW	c/kWh	3.13	(0.04)	(5.55)	(6.96)	(12.10)	(17.10)	(21.98)	(26.77)
Industry_rooftop_250kW_battery	c/kWh	71.23	62.33	48.82	42.90	30.30	18.07	6.16	(5.48)
Warehouse_rooftop_250kW	c/kWh	16.89	15.82	14.76	14.56	13.62	12.73	11.89	11.10
Warehouse_rooftop_250kW_battery	c/kWh	28.41	26.64	24.75	23.97	22.26	20.63	19.08	17.59
Public_rooftop_325kW	c/kWh	13.03	11.36	9.05	8.51	6.39	4.35	2.38	0.46
Public_rooftop_325kW_battery	c/kWh	37.70	34.38	29.97	28.08	24.00	20.08	16.27	12.59
Industry_rooftop_625kW	c/kWh	21.54	18.25	12.76	7.46	2.34	(2.63)	(7.48)	(12.23)
Industry_rooftop_625kW_battery	c/kWh	107.69	98.55	85.04	72.04	59.47	47.28	35.43	23.86
Export_ground_999kW	c/kWh	42.20	40.89	39.65	38.49	37.39	36.37	35.40	34.50
Export_ground_999kW_battery	c/kWh	51.25	49.56	47.96	46.46	45.05	43.71	42.45	41.26
Export_ground_4000kW	c/kWh	17.64	16.97	16.33	15.74	15.18	14.65	14.15	13.69
Onshore_wind_4000kW	c/kWh	16.87	16.77	16.66	16.56	16.45	16.35	16.25	16.15

Table 45: Base case viability gaps after CEG over exports over 15-year subsidy life

Archetype technology	Unit	2023	2024	2025	2026	2027	2028	2029	2030
Commercial_rooftop_60kW	c/kWh	20.71	16.84	10.56	4.52	(1.32)	(6.98)	(12.49)	(17.88)
Commercial_rooftop_60kW_battery	c/kWh	96.00	86.46	72.89	59.85	47.28	35.12	23.32	11.84
Agriculture_rooftop_100kW	c/kWh	14.87	8.88	(1.47)	(11.46)	(21.13)	(30.53)	(39.71)	(48.71)
Agriculture_rooftop_100kW_battery	c/kWh	46.85	38.03	23.78	10.04	(3.24)	(16.14)	(28.70)	(41.00)
Public_rooftop_100kW	c/kWh	11.68	9.50	5.80	2.23	(1.23)	(4.59)	(7.86)	(11.07)
Public_rooftop_100kW_battery	c/kWh	26.03	22.37	16.54	10.94	5.52	0.26	(4.86)	(9.87)
Industry_rooftop_250kW	c/kWh	(7.43)	(10.11)	(15.69)	(17.20)	(22.47)	(27.63)	(32.70)	(37.71)
Industry_rooftop_250kW_battery	c/kWh	60.68	52.27	38.68	32.66	19.92	7.54	(4.56)	(16.42)
Warehouse_rooftop_250kW	c/kWh	6.34	5.76	4.62	4.31	3.24	2.19	1.17	0.16
Warehouse_rooftop_250kW_battery	c/kWh	17.86	16.58	14.61	13.73	11.89	10.10	8.36	6.65
Public_rooftop_325kW	c/kWh	2.47	1.30	(1.09)	(1.73)	(3.98)	(6.19)	(8.35)	(10.48)
Public_rooftop_325kW_battery	c/kWh	27.15	24.32	19.83	17.83	13.63	9.54	5.55	1.64
Industry_rooftop_625kW	c/kWh	10.99	8.19	2.62	(2.78)	(8.04)	(13.17)	(18.20)	(23.17)
Industry_rooftop_625kW_battery	c/kWh	97.14	88.49	74.90	61.79	49.09	36.75	24.71	12.92
Export_ground_999kW	c/kWh	31.65	30.83	29.51	28.24	27.02	25.83	24.68	23.55
Export_ground_999kW_battery	c/kWh	40.69	39.50	37.82	36.22	34.67	33.18	31.73	30.32
Export_ground_4000kW	c/kWh	7.09	6.91	6.19	5.49	4.80	4.11	3.43	2.75
Onshore_wind_4000kW	c/kWh	7.02	7.38	7.19	6.98	6.74	6.47	6.18	5.86

A1.4 Sensitivity analysis

A1.4.1 Cost increase of +10%

Table 46: Costs +10% levelized cost of electricity

Archetype technology	Unit	2023	2024	2025	2026	2027	2028	2029	2030
Commercial_rooftop_60kW	c/kWh	17.88	17.88	16.81	15.79	14.84	13.95	13.11	12.31
Commercial_rooftop_60kW_battery	c/kWh	24.68	24.68	23.31	22.01	20.79	19.63	18.54	17.52
Agriculture_rooftop_100kW	c/kWh	16.50	16.50	15.51	14.57	13.70	12.87	12.09	11.37
Agriculture_rooftop_100kW_battery	c/kWh	18.88	18.88	17.78	16.75	15.77	14.86	14.00	13.18
Public_rooftop_100kW	c/kWh	16.50	16.50	15.51	14.57	13.70	12.87	12.09	11.37
Public_rooftop_100kW_battery	c/kWh	19.11	19.11	18.00	16.95	15.96	15.04	14.17	13.34
Industry_rooftop_250kW	c/kWh	13.45	13.45	12.64	12.41	11.70	11.02	10.39	9.80
Industry_rooftop_250kW_battery	c/kWh	20.17	20.17	19.06	18.56	17.57	16.65	15.77	14.94
Warehouse_rooftop_250kW	c/kWh	13.45	13.45	12.64	12.41	11.70	11.02	10.39	9.80
Warehouse_rooftop_250kW_battery	c/kWh	20.58	20.58	19.45	18.92	17.92	16.97	16.08	15.23
Public_rooftop_325kW	c/kWh	13.45	13.45	12.64	12.41	11.70	11.02	10.39	9.80
Public_rooftop_325kW_battery	c/kWh	20.31	20.31	19.20	18.68	17.69	16.76	15.87	15.04
Industry_rooftop_625kW	c/kWh	13.99	13.99	13.17	12.41	11.70	11.02	10.39	9.80
Industry_rooftop_625kW_battery	c/kWh	20.70	20.70	19.60	18.56	17.57	16.64	15.77	14.94
Export_ground_999kW	c/kWh	31.80	31.80	30.77	29.80	28.88	28.03	27.22	26.47
Export_ground_999kW_battery	c/kWh	38.84	38.84	37.51	36.27	35.09	33.98	32.93	31.94
Export_ground_4000kW	c/kWh	13.42	13.42	12.89	12.40	11.93	11.49	11.08	10.69
Onshore_wind_4000kW	c/kWh	13.59	13.59	13.51	13.42	13.33	13.25	13.16	13.08

Table 47: Costs +10% viability gaps after CEG over exports over 15-year subsidy life

Archetype technology	Unit	2023	2024	2025	2026	2027	2028	2029	2030
Commercial_rooftop_60kW	c/kWh	29.76	32.15	24.95	18.04	11.39	4.96	(1.27)	(7.34)
Commercial_rooftop_60kW_battery	c/kWh	117.35	121.48	105.95	91.05	76.73	62.93	49.58	36.63
Agriculture_rooftop_100kW	c/kWh	29.70	34.00	22.12	10.71	(0.30)	(10.95)	(21.31)	(31.42)
Agriculture_rooftop_100kW_battery	c/kWh	68.10	73.49	57.16	41.48	26.36	11.74	(2.45)	(16.27)
Public_rooftop_100kW	c/kWh	16.99	18.50	14.25	10.17	6.23	2.43	(1.27)	(4.88)
Public_rooftop_100kW_battery	c/kWh	34.72	36.87	30.20	23.80	17.63	11.66	5.88	0.24
Industry_rooftop_250kW	c/kWh	0.46	3.24	(3.15)	(5.42)	(11.40)	(17.23)	(22.92)	(28.52)
Industry_rooftop_250kW_battery	c/kWh	82.18	87.28	71.76	63.91	49.46	35.45	21.83	8.52
Warehouse_rooftop_250kW	c/kWh	7.96	8.49	7.19	6.73	5.51	4.33	3.17	2.04
Warehouse_rooftop_250kW_battery	c/kWh	20.99	21.68	19.43	18.28	16.19	14.16	12.20	10.28
Public_rooftop_325kW	c/kWh	5.85	7.02	4.28	3.32	0.76	(1.73)	(4.16)	(6.55)
Public_rooftop_325kW_battery	c/kWh	34.26	35.91	30.78	28.18	23.41	18.78	14.29	9.90
Industry_rooftop_625kW	c/kWh	18.88	21.56	15.18	9.02	3.05	(2.75)	(8.41)	(13.97)
Industry_rooftop_625kW_battery	c/kWh	118.68	123.57	108.06	93.12	78.69	64.72	51.15	37.91
Export_ground_999kW	c/kWh	33.55	34.04	32.53	31.08	29.69	28.34	27.04	25.77
Export_ground_999kW_battery	c/kWh	43.32	43.81	41.89	40.06	38.29	36.60	34.96	33.37
Export_ground_4000kW	c/kWh	8.07	8.56	7.74	6.95	6.17	5.40	4.64	3.88
Onshore_wind_4000kW	c/kWh	8.04	8.51	8.31	8.08	7.83	7.56	7.26	6.92

A1.4.2 Cost decrease of -15%

Table 48: Costs -15% levelized cost of electricity

Archetype technology	Unit	2023	2024	2025	2026	2027	2028	2029	2030
Commercial_rooftop_60kW	c/kWh	13.99	13.14	12.35	11.61	10.91	10.25	9.63	9.05
Commercial_rooftop_60kW_battery	c/kWh	19.30	18.22	17.21	16.25	15.35	14.50	13.70	12.94
Agriculture_rooftop_100kW	c/kWh	12.91	12.13	11.40	10.71	10.06	9.46	8.89	8.35
Agriculture_rooftop_100kW_battery	c/kWh	14.76	13.90	13.10	12.34	11.62	10.94	10.31	9.71
Public_rooftop_100kW	c/kWh	12.91	12.13	11.40	10.71	10.06	9.46	8.89	8.35
Public_rooftop_100kW_battery	c/kWh	14.94	14.07	13.25	12.48	11.76	11.08	10.43	9.83
Industry_rooftop_250kW	c/kWh	10.52	9.89	9.29	9.26	8.74	8.24	7.78	7.34
Industry_rooftop_250kW_battery	c/kWh	15.77	14.91	14.09	13.86	13.13	12.45	11.80	11.19
Warehouse_rooftop_250kW	c/kWh	10.52	9.89	9.29	9.26	8.74	8.24	7.78	7.34
Warehouse_rooftop_250kW_battery	c/kWh	16.09	15.21	14.38	14.13	13.39	12.69	12.03	11.41
Public_rooftop_325kW	c/kWh	10.52	9.89	9.29	9.26	8.74	8.24	7.78	7.34
Public_rooftop_325kW_battery	c/kWh	15.88	15.01	14.19	13.95	13.22	12.53	11.88	11.26
Industry_rooftop_625kW	c/kWh	11.05	10.42	9.82	9.26	8.74	8.24	7.78	7.34
Industry_rooftop_625kW_battery	c/kWh	16.30	15.44	14.63	13.86	13.13	12.45	11.80	11.19
Export_ground_999kW	c/kWh	26.14	25.33	24.57	23.86	23.19	22.56	21.97	21.41
Export_ground_999kW_battery	c/kWh	31.68	30.65	29.67	28.75	27.88	27.07	26.29	25.57
Export_ground_4000kW	c/kWh	11.04	10.62	10.23	9.87	9.52	9.20	8.90	8.61
Onshore_wind_4000kW	c/kWh	11.04	10.98	10.91	10.84	10.77	10.71	10.64	10.57

Table 49: Costs -15% viability gaps viability gaps after CEG over exports over 15-year subsidy life

Archetype technology	Unit	2023	2024	2025	2026	2027	2028	2029	2030
Commercial_rooftop_60kW	c/kWh	5.12	2.19	(3.21)	(8.42)	(13.48)	(18.41)	(23.23)	(27.97)
Commercial_rooftop_60kW_battery	c/kWh	59.18	51.69	40.06	28.84	17.99	7.45	(2.81)	(12.85)
Agriculture_rooftop_100kW	c/kWh	(10.71)	(15.15)	(24.06)	(32.69)	(41.08)	(49.28)	(57.33)	(65.26)
Agriculture_rooftop_100kW_battery	c/kWh	10.20	3.51	(8.73)	(20.58)	(32.09)	(43.31)	(54.30)	(65.11)
Public_rooftop_100kW	c/kWh	2.51	0.89	(2.29)	(5.38)	(8.37)	(11.30)	(14.17)	(17.00)
Public_rooftop_100kW_battery	c/kWh	11.04	8.25	3.24	(1.59)	(6.28)	(10.86)	(15.34)	(19.74)
Industry_rooftop_250kW	c/kWh	(21.02)	(22.88)	(27.70)	(28.48)	(33.07)	(37.59)	(42.06)	(46.51)
Industry_rooftop_250kW_battery	c/kWh	23.60	17.21	5.54	1.33	(9.70)	(20.47)	(31.05)	(41.47)
Warehouse_rooftop_250kW	c/kWh	3.55	3.14	2.15	2.00	1.07	0.15	(0.75)	(1.65)
Warehouse_rooftop_250kW_battery	c/kWh	12.46	11.48	9.79	9.16	7.57	6.02	4.50	3.00
Public_rooftop_325kW	c/kWh	(3.35)	(4.17)	(6.23)	(6.56)	(8.53)	(10.45)	(12.36)	(14.25)
Public_rooftop_325kW_battery	c/kWh	14.88	12.72	8.86	7.46	3.82	0.27	(3.22)	(6.65)
Industry_rooftop_625kW	c/kWh	(2.63)	(4.60)	(9.41)	(14.08)	(18.65)	(23.15)	(27.58)	(31.98)
Industry_rooftop_625kW_battery	c/kWh	59.98	53.36	41.70	30.39	19.40	8.67	(1.84)	(12.19)
Export_ground_999kW	c/kWh	25.70	25.07	23.94	22.85	21.79	20.76	19.75	18.76
Export_ground_999kW_battery	c/kWh	33.39	32.45	31.02	29.64	28.30	27.01	25.75	24.52
Export_ground_4000kW	c/kWh	4.75	4.67	4.05	3.44	2.83	2.23	1.62	1.00
Onshore_wind_4000kW	c/kWh	4.68	5.06	4.89	4.69	4.46	4.21	3.94	3.63

A1.4.3 High electricity price

Table 50: High electricity price levelized cost of electricity

Archetype technology	Unit	2023	2024	2025	2026	2027	2028	2029	2030
Commercial_rooftop_60kW	c/kWh	16.45	15.46	14.53	13.65	12.83	12.06	11.33	10.65
Commercial_rooftop_60kW_battery	c/kWh	22.71	21.44	20.25	19.12	18.06	17.06	16.11	15.22
Agriculture_rooftop_100kW	c/kWh	15.18	14.27	13.41	12.60	11.84	11.13	10.46	9.83
Agriculture_rooftop_100kW_battery	c/kWh	17.37	16.36	15.41	14.51	13.67	12.88	12.13	11.43
Public_rooftop_100kW	c/kWh	15.18	14.27	13.41	12.60	11.84	11.13	10.46	9.83
Public_rooftop_100kW_battery	c/kWh	17.58	16.56	15.59	14.69	13.83	13.03	12.28	11.56
Industry_rooftop_250kW	c/kWh	12.38	11.63	10.93	10.80	10.18	9.60	9.06	8.54
Industry_rooftop_250kW_battery	c/kWh	18.55	17.54	16.58	16.21	15.36	14.55	13.79	13.07
Warehouse_rooftop_250kW	c/kWh	12.38	11.63	10.93	10.80	10.18	9.60	9.06	8.54
Warehouse_rooftop_250kW_battery	c/kWh	18.93	17.90	16.92	16.53	15.66	14.83	14.06	13.32
Public_rooftop_325kW	c/kWh	12.38	11.63	10.93	10.80	10.18	9.60	9.06	8.54
Public_rooftop_325kW_battery	c/kWh	18.68	17.66	16.70	16.32	15.46	14.65	13.88	13.16
Industry_rooftop_625kW	c/kWh	12.91	12.16	11.46	10.80	10.18	9.60	9.06	8.54
Industry_rooftop_625kW_battery	c/kWh	19.09	18.07	17.11	16.21	15.36	14.55	13.79	13.07
Export_ground_999kW	c/kWh	30.43	29.48	28.59	27.75	26.96	26.22	25.52	24.87
Export_ground_999kW_battery	c/kWh	36.95	35.73	34.58	33.50	32.48	31.51	30.61	29.75
Export_ground_4000kW	c/kWh	12.72	12.23	11.78	11.35	10.94	10.56	10.20	9.87
Onshore_wind_4000kW	c/kWh	12.82	12.74	12.66	12.58	12.50	12.42	12.34	12.27

Table 51: High electricity price viability gaps after CEG over exports over 15-year subsidy life

Archetype technology	Unit	2023	2024	2025	2026	2027	2028	2029	2030
Commercial_rooftop_60kW	c/kWh	(2.27)	(7.42)	(12.69)	(17.85)	(22.93)	(27.97)	(33.01)	(38.09)
Commercial_rooftop_60kW_battery	c/kWh	56.39	44.65	32.81	21.30	10.03	(1.06)	(12.05)	(22.99)
Agriculture_rooftop_100kW	c/kWh	(26.30)	(34.57)	(43.12)	(51.53)	(59.84)	(68.14)	(76.47)	(84.90)
Agriculture_rooftop_100kW_battery	c/kWh	(4.82)	(16.51)	(28.50)	(40.24)	(51.82)	(63.33)	(74.83)	(86.42)
Public_rooftop_100kW	c/kWh	(2.80)	(5.78)	(8.85)	(11.87)	(14.85)	(17.81)	(20.79)	(23.80)
Public_rooftop_100kW_battery	c/kWh	5.39	0.58	(4.34)	(9.15)	(13.89)	(18.60)	(23.29)	(28.02)
Industry_rooftop_250kW	c/kWh	(34.13)	(38.29)	(42.70)	(43.19)	(47.58)	(52.02)	(56.54)	(61.18)
Industry_rooftop_250kW_battery	c/kWh	11.77	0.64	(10.81)	(14.95)	(26.07)	(37.14)	(48.23)	(59.42)
Warehouse_rooftop_250kW	c/kWh	1.19	0.32	(0.59)	(0.70)	(1.60)	(2.51)	(3.43)	(4.37)
Warehouse_rooftop_250kW_battery	c/kWh	11.23	9.59	7.91	7.27	5.65	4.04	2.44	0.82
Public_rooftop_325kW	c/kWh	(8.73)	(10.53)	(12.43)	(12.63)	(14.52)	(16.42)	(18.35)	(20.33)
Public_rooftop_325kW_battery	c/kWh	11.34	7.64	3.84	2.45	(1.23)	(4.89)	(8.56)	(12.25)
Industry_rooftop_625kW	c/kWh	(14.72)	(18.94)	(23.39)	(27.80)	(32.21)	(36.65)	(41.16)	(45.77)
Industry_rooftop_625kW_battery	c/kWh	50.19	38.94	27.41	16.11	4.95	(6.13)	(17.21)	(28.35)
Export_ground_999kW	c/kWh	26.93	25.84	24.73	23.64	22.58	21.52	20.46	19.40
Export_ground_999kW_battery	c/kWh	35.97	34.51	33.04	31.62	30.23	28.86	27.51	26.17
Export_ground_4000kW	c/kWh	2.37	1.92	1.41	0.89	0.36	(0.20)	(0.79)	(1.41)
Onshore_wind_4000kW	c/kWh	2.48	2.59	2.60	2.57	2.48	2.34	2.15	1.89

A1.4.4 Discount rate of 7%

Table 52: Discount rate of 7% levelized cost of electricity

Archetype technology	Unit	2023	2024	2025	2026	2027	2028	2029	2030
Commercial_rooftop_60kW	c/kWh	17.98	16.90	15.88	14.92	14.02	13.18	12.38	11.63
Commercial_rooftop_60kW_battery	c/kWh	24.72	23.35	22.05	20.82	19.66	18.57	17.54	16.57
Agriculture_rooftop_100kW	c/kWh	16.59	15.59	14.65	13.77	12.94	12.16	11.43	10.74
Agriculture_rooftop_100kW_battery	c/kWh	18.95	17.85	16.81	15.83	14.91	14.05	13.23	12.46
Public_rooftop_100kW	c/kWh	16.59	15.59	14.65	13.77	12.94	12.16	11.43	10.74
Public_rooftop_100kW_battery	c/kWh	19.18	18.06	17.01	16.02	15.09	14.22	13.39	12.61
Industry_rooftop_250kW	c/kWh	13.53	12.71	11.94	11.76	11.08	10.44	9.85	9.29
Industry_rooftop_250kW_battery	c/kWh	20.19	19.08	18.04	17.59	16.66	15.78	14.95	14.17
Warehouse_rooftop_250kW	c/kWh	13.53	12.71	11.94	11.76	11.08	10.44	9.85	9.29
Warehouse_rooftop_250kW_battery	c/kWh	20.60	19.47	18.41	17.93	16.99	16.09	15.24	14.44
Public_rooftop_325kW	c/kWh	13.53	12.71	11.94	11.76	11.08	10.44	9.85	9.29
Public_rooftop_325kW_battery	c/kWh	20.33	19.21	18.16	17.71	16.77	15.88	15.05	14.26
Industry_rooftop_625kW	c/kWh	14.06	13.24	12.48	11.76	11.08	10.44	9.85	9.29
Industry_rooftop_625kW_battery	c/kWh	20.72	19.62	18.57	17.59	16.66	15.78	14.95	14.17
Export_ground_999kW	c/kWh	33.23	32.20	31.23	30.33	29.47	28.67	27.92	27.21
Export_ground_999kW_battery	c/kWh	40.27	38.95	37.71	36.54	35.44	34.39	33.41	32.49
Export_ground_4000kW	c/kWh	13.82	13.30	12.80	12.33	11.90	11.49	11.10	10.74
Onshore_wind_4000kW	c/kWh	13.74	13.66	13.57	13.49	13.40	13.32	13.24	13.15

Table 53: Discount rate of 7% viability gaps after CEG over exports over 15-year subsidy life

Archetype technology	Unit	2023	2024	2025	2026	2027	2028	2029	2030
Commercial_rooftop_60kW	c/kWh	29.43	25.44	18.90	12.62	6.54	0.66	(5.07)	(10.68)
Commercial_rooftop_60kW_battery	c/kWh	113.82	103.96	89.84	76.28	63.21	50.57	38.30	26.35
Agriculture_rooftop_100kW	c/kWh	29.90	23.74	12.97	2.59	(7.46)	(17.22)	(26.76)	(36.12)
Agriculture_rooftop_100kW_battery	c/kWh	66.96	57.87	43.06	28.79	14.99	1.59	(11.47)	(24.26)
Public_rooftop_100kW	c/kWh	16.82	14.59	10.73	7.02	3.43	(0.06)	(3.46)	(6.80)
Public_rooftop_100kW_battery	c/kWh	34.00	30.23	24.17	18.34	12.71	7.25	1.92	(3.29)
Industry_rooftop_250kW	c/kWh	1.16	(1.57)	(7.36)	(9.21)	(14.67)	(20.02)	(25.28)	(30.47)
Industry_rooftop_250kW_battery	c/kWh	79.81	71.17	57.07	50.30	37.10	24.26	11.71	(0.60)
Warehouse_rooftop_250kW	c/kWh	7.81	7.21	6.03	5.66	4.55	3.46	2.39	1.34
Warehouse_rooftop_250kW_battery	c/kWh	20.31	19.00	16.95	15.96	14.05	12.19	10.38	8.61
Public_rooftop_325kW	c/kWh	5.94	4.75	2.27	1.48	(0.85)	(3.14)	(5.38)	(7.60)
Public_rooftop_325kW_battery	c/kWh	33.22	30.32	25.66	23.41	19.05	14.81	10.67	6.61
Industry_rooftop_625kW	c/kWh	18.90	16.05	10.27	4.67	(0.78)	(6.10)	(11.32)	(16.48)
Industry_rooftop_625kW_battery	c/kWh	114.96	106.06	91.97	78.36	65.19	52.38	39.89	27.64
Export_ground_999kW	c/kWh	34.27	33.43	32.07	30.76	29.50	28.28	27.09	25.92
Export_ground_999kW_battery	c/kWh	43.68	42.46	40.73	39.07	37.47	35.93	34.43	32.97
Export_ground_4000kW	c/kWh	8.34	8.17	7.44	6.72	6.02	5.32	4.61	3.91
Onshore_wind_4000kW	c/kWh	8.02	8.42	8.24	8.03	7.80	7.53	7.24	6.92

A1.5 Working examples of the main performance of customers with internal rate of return (IRR) and payback

Table 54: Policy option 1 & 3 - 2023

Archetype technology	Export level	System cost - 2023 installation	Lifetime operating cost - 2023 installation	Total lifetime subsidy	ViaGap after CEG - 2023 installation	FiP level	1st year export - 2023 installation	1st year subsidy - 2023 installation	1st yr bill saving	IRR	Payback (incl. subsidy)
	%	€	€	€	c/kWh	c/kWh	kWh	€	€		yr
Commercial_rooftop_60kW	21.95%	96,445	28,934	18,927	20.71	11.68	11,190	1,307	7,986	5.00%	15.84
Commercial_rooftop_60kW_battery	12.83%	125,895	51,021	10,909	96.00	11.68	6,449	753	8,794	1.60%	24.75
Agriculture_rooftop_100kW	12.35%	155,719	46,716	18,633	14.87	11.68	11,016	1,286	15,689	5.79%	15.01
Agriculture_rooftop_100kW_battery	9.86%	174,104	60,505	14,820	46.85	11.68	8,762	1,023	16,073	4.33%	17.67
Public_rooftop_100kW	34.48%	148,346	44,504	49,561	11.68	11.68	29,300	3,421	11,172	6.00%	13.98
Public_rooftop_100kW_battery	24.39%	165,861	57,640	34,509	26.03	11.68	20,401	2,382	12,690	4.28%	17.15
Industry_rooftop_250kW	18.94%	302,275	90,683	68,059	(7.43)	11.68	40,235	4,698	34,555	8.28%	11.82
Industry_rooftop_250kW_battery	10.41%	424,980	182,711	36,922	60.68	11.68	21,828	2,549	37,695	3.58%	19.29
Warehouse_rooftop_250kW	92.33%	302,275	90,683	331,765	6.34	11.68	196,135	22,902	3,270	9.72%	9.55
Warehouse_rooftop_250kW_battery	72.93%	424,980	182,711	253,515	17.86	11.68	149,875	17,500	11,161	3.54%	15.84
Public_rooftop_325kW	44.21%	392,958	117,887	206,503	2.47	11.68	122,082	14,255	30,920	8.73%	10.93
Public_rooftop_325kW_battery	31.67%	552,474	237,525	145,004	27.15	11.68	85,724	10,010	37,121	3.57%	18.44
Industry_rooftop_625kW	18.91%	755,688	305,821	169,888	10.99	11.68	100,435	11,728	74,825	6.09%	14.34
Industry_rooftop_625kW_battery	10.39%	1,062,451	534,865	92,105	97.14	11.68	54,451	6,358	81,617	1.55%	25.01
Export_ground_999kW	100.00%	3,336,017	1,076,382	1,628,312	31.65	11.68	962,636	112,404	-	-1.83%	n/a
Export_ground_999kW_battery	100.00%	3,826,346	1,439,074	1,570,911	40.69	11.68	928,702	108,442	-	-4.58%	n/a
Export_ground_4000kW	100.00%	7,107,593	3,363,105	8,801,685	7.09	11.68	5,203,440	607,591	-	9.74%	9.41
Onshore_wind_4000kW	100.00%	12,702,967	8,566,598	18,258,410	7.02	11.68	10,424,400	1,217,227	-	10.64%	8.85

Table 55: Policy option 1 & 3 - 2030

Archetype technology	Export level	System cost - 2030 installation	Lifetime operating cost - 2030 installation	Total lifetime subsidy	ViaGap after CEG - 2030 installation	FiP level	1st year export - 2030 installation	1st year subsidy - 2030 installation	1st yr bill saving	IRR	Payback (incl. subsidy)
	%	€	€	€	c/kWh	c/kWh	kWh	€	€		yr
Commercial_rooftop_60kW	21.95%	62,408	18,722	4,450	(17.88)	2.75	11,190	307	5,230	9.00%	11.43
Commercial_rooftop_60kW_battery	12.83%	84,061	34,962	2,565	11.84	2.75	6,449	177	5,759	5.39%	15.81
Agriculture_rooftop_100kW	12.35%	100,763	30,229	4,381	(48.71)	2.75	11,016	302	10,274	10.43%	10.30
Agriculture_rooftop_100kW_battery	9.86%	114,281	40,367	3,484	(41.00)	2.75	8,762	241	10,526	8.72%	11.74
Public_rooftop_100kW	34.48%	95,992	28,798	11,652	(11.07)	2.75	29,300	804	7,316	9.41%	11.03
Public_rooftop_100kW_battery	24.39%	108,870	38,456	8,113	(9.87)	2.75	20,401	560	8,310	7.96%	12.43
Industry_rooftop_250kW	18.94%	195,597	90,325	16,001	(37.71)	2.75	40,235	1,105	22,629	12.37%	9.04
Industry_rooftop_250kW_battery	10.41%	285,816	157,578	8,681	(16.42)	2.75	21,828	599	24,685	7.22%	13.34
Warehouse_rooftop_250kW	92.33%	195,597	90,325	78,000	0.16	2.75	196,135	5,384	2,141	8.23%	11.76
Warehouse_rooftop_250kW_battery	72.93%	285,816	156,955	59,603	6.65	2.75	149,875	4,114	7,309	4.10%	17.51
Public_rooftop_325kW	44.21%	254,276	117,422	48,550	(10.48)	2.75	122,082	3,351	20,248	11.02%	9.81
Public_rooftop_325kW_battery	31.67%	371,561	204,573	34,092	1.64	2.75	85,724	2,353	24,309	6.22%	14.46
Industry_rooftop_625kW	18.91%	488,992	225,812	39,942	(23.17)	2.75	100,435	2,757	46,399	10.17%	10.53
Industry_rooftop_625kW_battery	10.39%	714,540	393,945	21,655	12.92	2.75	54,451	1,495	50,610	5.33%	16.00
Export_ground_999kW	100.00%	2,787,241	747,117	382,828	23.55	2.75	962,636	26,427	-	-2.42%	n/a
Export_ground_999kW_battery	100.00%	3,147,757	1,012,448	369,333	30.32	2.75	928,702	25,495	-	-4.31%	n/a
Export_ground_4000kW	100.00%	5,585,367	2,449,770	2,069,342	2.75	2.75	5,203,440	142,849	-	6.00%	14.04
Onshore_wind_4000kW	100.00%	12,194,156	8,121,389	4,292,688	5.86	2.75	10,424,400	286,179	-	3.11%	17.57

Table 56: Policy option 2 - 2023

Archetype technology	Export level	System cost - 2023 installation	Lifetime operating cost - 2023 installation	Total lifetime subsidy	ViaGap after CEG - 2023 installation	FiP level	1st year export - 2023 installation	1st year subsidy - 2023 installation	1st yr bill saving	IRR	Payback (incl. subsidy)
	%	€	€	€	c/kWh	c/kWh	kWh	€	€		yr
Commercial_rooftop_60kW	21.95%	96,445	28,934	18,927	20.71	11.68	11,190	1,307	7,986	5.00%	15.84
Commercial_rooftop_60kW_battery	12.83%	125,895	51,021	10,909	96.00	11.68	6,449	753	8,794	1.60%	24.75
Agriculture_rooftop_100kW	12.35%	155,719	46,716	18,633	14.87	11.68	11,016	1,286	15,689	5.79%	15.01
Agriculture_rooftop_100kW_battery	9.86%	174,104	60,505	14,820	46.85	11.68	8,762	1,023	16,073	4.33%	17.67
Public_rooftop_100kW	34.48%	148,346	44,504	49,561	11.68	11.68	29,300	3,421	11,172	6.00%	13.98
Public_rooftop_100kW_battery	24.39%	165,861	57,640	34,509	26.03	11.68	20,401	2,382	12,690	4.28%	17.15
Industry_rooftop_250kW	18.94%	302,275	90,683	68,059	(7.43)	11.68	40,235	4,698	34,555	8.28%	11.82
Industry_rooftop_250kW_battery	10.41%	424,980	182,711	36,922	60.68	11.68	21,828	2,549	37,695	3.58%	19.29
Warehouse_rooftop_250kW	92.33%	302,275	90,683	331,765	6.34	11.68	196,135	22,902	3,270	9.72%	9.55
Warehouse_rooftop_250kW_battery	72.93%	424,980	182,711	253,515	17.86	11.68	149,875	17,500	11,161	3.54%	15.84
Public_rooftop_325kW	44.21%	392,958	117,887	206,503	2.47	11.68	122,082	14,255	30,920	8.73%	10.93
Public_rooftop_325kW_battery	31.67%	552,474	237,525	145,004	27.15	11.68	85,724	10,010	37,121	3.57%	18.44
Industry_rooftop_625kW	18.91%	755,688	305,821	169,888	10.99	11.68	100,435	11,728	74,825	6.09%	14.34
Industry_rooftop_625kW_battery	10.39%	1,062,451	534,865	92,105	97.14	11.68	54,451	6,358	81,617	1.55%	25.01
Export_ground_999kW	100.00%	3,336,017	1,076,382	1,628,312	31.65	11.68	962,636	112,404	-	-1.83%	n/a
Export_ground_999kW_battery	100.00%	3,826,346	1,439,074	1,570,911	40.69	11.68	928,702	108,442	-	-4.58%	n/a
Export_ground_4000kW	100.00%	7,107,593	3,363,105	5,345,337	7.09	7.09	5,203,440	368,995	-	6.00%	12.86
Onshore_wind_4000kW	100.00%	12,702,967	8,566,598	10,974,474	7.02	7.02	10,424,400	731,632	-	6.00%	12.39

Table 57: Policy option 2 - 2030

Archetype technology	Export level	System cost - 2030 installation	Lifetime operating cost - 2030 installation	Total lifetime subsidy	ViaGap after CEG - 2030 installation	FiP level	1st year export - 2030 installation	1st year subsidy - 2030 installation	1st yr bill saving	IRR	Payback (incl. subsidy)
	%	€	€	€	c/kWh	c/kWh	kWh	€	€		yr
Commercial_rooftop_60kW	21.95%	62,408	18,722	252	(17.88)	0.16	11,190	17	5,230	8.60%	11.91
Commercial_rooftop_60kW_battery	12.83%	84,061	34,962	145	11.84	0.16	6,449	10	5,759	5.22%	16.21
Agriculture_rooftop_100kW	12.35%	100,763	30,229	248	(48.71)	0.16	11,016	17	10,274	10.19%	10.53
Agriculture_rooftop_100kW_battery	9.86%	114,281	40,367	197	(41.00)	0.16	8,762	14	10,526	8.55%	11.95
Public_rooftop_100kW	34.48%	95,992	28,798	659	(11.07)	0.16	29,300	45	7,316	8.74%	11.81
Public_rooftop_100kW_battery	24.39%	108,870	38,456	459	(9.87)	0.16	20,401	32	8,310	7.54%	13.04
Industry_rooftop_250kW	18.94%	195,597	90,325	904	(37.71)	0.16	40,235	62	22,629	11.91%	9.37
Industry_rooftop_250kW_battery	10.41%	285,816	157,578	491	(16.42)	0.16	21,828	34	24,685	7.05%	13.62
Warehouse_rooftop_250kW	92.33%	195,597	90,325	4,409	0.16	0.16	196,135	304	2,141	6.00%	15.24
Warehouse_rooftop_250kW_battery	72.93%	285,816	156,955	3,369	6.65	0.16	149,875	233	7,309	2.91%	21.04
Public_rooftop_325kW	44.21%	254,276	117,422	2,744	(10.48)	0.16	122,082	189	20,248	9.96%	10.79
Public_rooftop_325kW_battery	31.67%	371,561	204,573	1,927	1.64	0.16	85,724	133	24,309	5.71%	15.50
Industry_rooftop_625kW	18.91%	488,992	225,812	2,258	(23.17)	0.16	100,435	156	46,399	9.72%	10.99
Industry_rooftop_625kW_battery	10.39%	714,540	393,945	1,224	12.92	0.16	54,451	84	50,610	5.16%	16.40
Export_ground_999kW	100.00%	2,787,241	747,117	21,639	23.55	0.16	962,636	1,494	-	-3.33%	n/a
Export_ground_999kW_battery	100.00%	3,147,757	1,012,448	20,876	30.32	0.16	928,702	1,441	-	-5.14%	n/a
Export_ground_4000kW	100.00%	5,585,367	2,449,770	2,069,342	2.75	2.75	5,203,440	142,849	-	6.00%	14.04
Onshore_wind_4000kW	100.00%	12,194,156	8,121,389	9,160,061	5.86	5.86	10,424,400	610,671	-	6.00%	12.69

A2 Policy costs

The table below shows the policy costs per option by year.

Figure 21 Policy costs by year for CEG and policy options 1-3 in million EUR

Policy option	Uptake	Implementation year								
		2023	2024	2025	2026	2027	2028	2029	2030	Total
CEG*	**Low**	7.47	37.28	8.06	10.98	103.55	110.07	57.24	0.74	**335.38 ***
CEG*	**High**	111.62	72.79	145.76	186.23	568.13	653.56	351.16	37.97	**2,127.22 ***
1**	**Low**	5.68	26.04	3.26	3.90	34.24	30.64	13.08	0.13	**116.97**
1**	**High**	94.39	50.93	65.72	73.40	192.94	187.46	82.72	7.07	**754.63**
2**	**Low**	5.68	20.77	3.05	3.06	36.41	32.62	13.99	0.01	**115.59**
2**	**High**	62.17	40.39	71.44	82.92	229.93	238.32	114.05	11.27	**850.48**
3**	**Low**	5.68	26.04	3.26	3.90	34.24	30.64	13.08	0.13	**116.97**
3**	**High**	94.39	50.93	65.72	73.40	192.94	187.46	82.72	7.07	**754.63**

*These costs are borne by the supplier. There is no cost to the state for the CEG policy.

**Please note that policy costs for options 1, 2 and 3 are excluding CEG as these are listed separately.

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