Terms and Conditions for the Second Competition under the Renewable Electricity Support Scheme – Consultation Response

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ISEA
Irish Solar Energy Association

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Executive Summary

The Second Competition under the Renewable Electricity Support Scheme (RESS 2) will be critical for onshore renewables intending to connect by 2024, determining Ireland's mid-decade trajectory towards its renewable electricity targets.

The need for economic bidding into this auction emphasises the importance of the Evaluation Correction Factor (ECF) as it reflects values not captured within the auction strike price. To support our submission, the Irish Solar Energy Association (ISEA) has commissioned AFRY to model an appropriate range of ECFs for solar in RESS 2. Their analysis accompanies this paper.

An ECF is essential to ensure the auction returns least cost outcomes for customers. The updated AFRY modelling, indicates the solar ECF should be 0.75 at the most, which would deliver least cost for the consumer. This number is based on solar being awarded 35% of the auction volumes which broadly reflects the range between the likely RESS 2 volumes and the award volume in RESS 1. AFRY note that ECF number would be lower than 0.75 if project attrition rates from RESS 1 were further factored into the modelling, suggesting that it should be lower to maximise value for Irish citizens.

Strikingly, the updated analysis also finds that solar projects could bid in approximately €83/MWh into RESS 2 across different deployment scenarios, and there would still be a net gain for society.

Hidden value of solar

Solar can accelerate the decarbonisation of the electricity system. The least whole of system cost includes higher levels of solar than currently envisaged in policy. Previous analysis by AFRY into the benefits to Ireland from solar found that where the Government's 2030 renewable electricity targets were met and solar's relative share in our renewables portfolio was substantially increased:

- Ireland improved its power system emissions by an additional 7% by 2030. This finding is crucial as our macro goal is to decarbonise our electricity supply. Renewables are the medium through which we achieve that goal, they are not necessarily the objective in and of themselves.
- Society made a net annual economic gain of €106 million by 2035.

An additional benefit to all system users, including other renewables, would be a two fifths reduction in curtailment levels. Constraint payments to compensate for generator redispatch (including curtailment of renewables) are projected to be €348 million in 2021/2022. As they are recovered from customer bills, this could mean a substantial saving for Irish citizens.

There were two main critiques of the original AFRY analysis that appeared to be grounded in a misunderstanding of the methodology and approach:

- **Merit order coverage** – the paper does capture the impact of merit order effect of different types of renewables, it's just that it was outweighed in the high solar scenario by the impact on consumers from savings in PSO and emissions costs.
- **Participant behaviour** – the model does capture the likely market behaviours of different types of renewables such as: uncontrollable units, negative bidding units that accept

negative prices (e.g. REFIT), zero bidding units (e.g. merchant plant, RESS) which avoid negative prices.

Auction structure and market context

Considering the impact of the delay to the second auction and its importance to helping Ireland meet the renewable electricity targets, ISEA is strongly supportive of the Department increasing the volume to be procured in RESS 2.

We would suggest that the time in which projects are to be delivered should be **at least** equivalent to RESS 1. Assuming the auction is delivered to the current published timeframe, to be consistent, the Commercial Operation and Long Stop dates should at a minimum be in December, not September.

ISEA welcomes the amending of the point at which a party becomes ineligible for future RESS auction participation to Final Auction Results. It should reinforce participant commitment to bids submitted into the auction.

Since RESS 1 there have been a number of international supply chain developments that have significantly impacted solar costs especially.

Issues for consultation

Summarised below are our responses to the twelve Issues for Consultation:

1. **Market Reference Price** – ISEA supports the retention of the existing approach to calculating the Market Reference Price (MRP). We maintain that participants already do face substantial market risk exposure.
2. **Evaluation Correction Factor** – The ceiling for the solar ECF value should at a maximum be set at 0.75, assuming a wind ECF of 1.0.
3. **Eligible Technologies** – the listed technologies seem a reasonable set for RESS 2.
4. **Hybrid Storage Projects** – the provision for hybrid storage projects is a positive step, though a range of regulatory and policy decisions are required from the System Operator and Regulatory Authorities to fully enable participation by such sites.
5. **New project criteria** – the €300 per kW threshold seems an appropriate threshold for participation. We have some reservations about the impact of the "at least 50%" capacity increase provisions on distribution-connected solar.
6. **Indexation** – we note that a significant proportion of solar investment costs are indeed subject to inflation. The equivalent of circa 4.5% of capex is annually spent on opex for Irish solar PV projects.
7. **Financial Questionnaire** – the Department has not sufficiently evidenced why it requires the release of commercially sensitive detailed information on IRR, capex and opex. The text of the state aid approval does not reveal the necessity for said disclosure.

8. **Locational considerations** – ISEA notes that implicit locational signals emanate from the networks and planning processes. We agree that an explicit signal should not be included in RESS 2, though there may be value in a more thorough future review of the matter.
9. **Bid Bond and Performance Security** – ISEA supports the principle of calculating these charges based on output rather than capacity. It aligns the payments with the product being procured and makes the charging regime fairer across different technologies.
10. **Community Category** – post the RESS 2 auction, the Department should assess the extent to which the 100% community ownership precondition has increased community participation.
11. **Community Benefit Fund** – ISEA supports the Department undertaking a lessons learned exercise from the rollout of the RESS 1 Community Benefit Funds (CBF) and greater specificity in the text of the Terms and Conditions on distribution of funds on solar projects.
12. **Citizens' Investment Scheme** – ISEA is committed to engaging on the detail of such a scheme. We would encourage early engagement with the Central Bank and would suggest value in decoupling the design of the Citizens' Investment Scheme from the RESS 2 auction delivery timeframes.

Next steps

ISEA commends our response to the Department. We would welcome the opportunity to discuss the analysis underpinning our response and contents of same.

1 Introduction

The Irish Solar Energy Association (ISEA) was established in 2013 to advance a policy and regulatory landscape promoting solar as a leading renewable energy technology that will decarbonise Ireland's electricity system and contribute to a successful and strong clean economy. As the leading voice for the Irish solar industry, ISEA works closely with stakeholders to advance the solar agenda on behalf of our members. ISEA is committed to delivering at least 5,000 megawatts (MW) of solar in the next nine years to make a significant contribution towards 2030 energy targets and achieve a diverse and clean electricity network. As the trade association for the solar industry in Ireland, ISEA is responding on behalf of our membership of nearly 160 parties currently active in the Irish solar market.

The Second Competition under the Renewable Electricity Support Scheme (RESS 2) will be critical for onshore renewables intending to connect by 2024. It will determine Ireland's mid-decade trajectory towards its renewable electricity targets.

From a policy perspective, it will be the point at which Ireland consolidates the gains from RESS 1. By the time the currently scheduled RESS 2 submission date occurs, we expect a substantial volume of the RESS 1 solar to be fully or partly energised. RESS 2 will be the first truly technology neutral renewable electricity auction, requiring all participants to bid economically.

This requirement for economic bidding emphasises the importance of the Evaluation Correction Factor (ECF) in the auction, as it reflects values not captured within the Strike Price. In order to provide a more substantive view on this topic, ISEA has commissioned AFRY to update and augment the analysis within the *The Value of Solar in the Republic of Ireland* report. AFRY's remit was to assess an appropriate range of ECFs for solar in RESS 2. Their analysis accompanies this submission and supports our response on Issue for Consultation No. 2.

ISEA believes that through diversification of the renewable electricity supply, solar can contribute in a foundational manner to the power system. Analysis of the available data strongly supports the contention that significantly dialling up the volume of solar will result in lower whole of system costs and accelerate the decarbonisation of the electricity system.

The remainder of this chapter sets out some of broader the arguments in support of this position The second chapter considers several structural matters in relation to the second auction and updates on price relevant market trends since the RESS 1 auction. The third chapter addresses ISEA's specific responses to the questions raised in the consultation document.

1.1 Equitable risk exposure

ISEA favour a principle of equitable risk exposure within the design of support mechanisms. Such a position entails seeking to allocate risk to the party best able to manage it and to do so efficiently.

Support mechanisms are intended to sufficiently de-risk project revenues to the extent that projects of an appropriate quality can be financed and delivered. The role of a support mechanism such as the Renewable Electricity Support Scheme (RESS) is not to 100% de-risk an investment in renewable electricity projects. Transferring all risk to customers would result in citizens having to act as the back stop for any project, of any quality, which would be an unreasonable expectation.

RESS contract holders do face significant market risk. As noted in the state aid decision[1] on the RESS, the beneficiaries of RESS must sell the generated electricity in the market and all beneficiaries must face standard balancing responsibility. Support payments are settled against the Day Ahead Market (DAM), and they receive no payments during negative pricing periods. The parties (i.e. the generator and supplier or other offtaker) putting those volumes into the market face a distribution of market risk. Those parties, between them, negotiate the appropriate sharing of that risk under their power purchase agreement (PPA).

If there is a high volume of zero marginal cost generation relative to the overall power demand on that system, and nearly all the output of that generation is correlated, that is a recipe for high volumes of "price cannibalisation". In that scenario prices can regularly be depressed to near zero or into negative territory resulting in a significant exposure for consumers under the Public Service Obligation (PSO) where that technology is already heavily PSO-supported. In addition, it may create challenges for projects to be financed in future. This effect has already manifested in the Single Electricity Market (SEM) with wind capture prices[2] being estimated by AFRY as 11% lower than the wholesale price in 2020[3].

Blending in higher volumes of another zero marginal cost renewable technology whose output does not correlate to the first, spreads that risk. It reduces burden on the PSO, diversifies the supply and really captures the merit order benefit of renewables by maximising the number of times in the day that there are zero marginal cost renewables entering the market.

Ultimately, new renewable electricity projects seeking contracts under RESS should be additive to both wider social welfare and the decarbonisation of our electricity sector. Ireland needs to substantially increase the volume of renewable electricity on its system[4], but it should do so in a manner equitable to participants and as economic as possible for consumers. It is important that market signals for the most efficient renewable plant are not distorted, to ensure that incremental renewables are added at least cost and least risk to the PSO from that point.

RESS 2 will deliver a tranche of that capacity, but it should not deliver that capacity at any cost. Industry should bear some risk to ensure the best price for consumers, and that the better projects are coming through in the auction. It must also be designed to ensure the optimal technology mix is achieved to ensure least cost outcomes.

This second competition will be occurring against the backdrop of the existing SEM rather than any future idealised set of trading arrangements. That market setting will shape Irish renewable investment, so the RESS mechanism needs to be designed to maximise the benefits to Ireland with that setting in mind.

That said, in the medium term ISEA is strongly supportive of a market redesign. Ireland's likely future generation portfolio will be dominated by renewables and sources of flexibility and the current market will struggle with that technology mix. This view was echoed in a recent consultation from

[1] State Aid SA.54683 (2020/N) – Ireland Renewable Electricity Support Scheme (RESS)
[2] Capture prices reflect the average price a generator would expect to receive in the wholesale market.
[3] The Value of Solar in the Republic of Ireland: a report to the Irish Solar Energy Association
[4] To meet the 2030 target would likely require a near trebling of the volume of green electricity we produced in 2020, moving from 12.7TWh up to something of the order 32-35TWh.

EirGrid[5], in which sending the appropriate market signals was envisaged as being crucial to enable decarbonisation.

1.2 Value of solar

In this section, we summarise a range of the benefits accruing to Ireland from significantly increasing solar's net contribution over the next decade. In our response on the ECF (see Section 3.2 and supporting analysis by AFRY), we provide more specific analysis of these benefits as they directly relate to the RESS 2 auction.

Much of the below is based on assessments undertaken by AFRY in the *The Value of Solar in the Republic of Ireland* report which utilised a relatively conservative set of assumptions and hour-by-hour modelling of the Irish power market and system to estimate values across a range of scenarios in which the 70% by 2030 renewable target was achieved. The maximum end of the assessed range was the Higher Solar Ambition (HSA) scenario which modelled the system with 5GW of utility-scale solar. The lowest band was the No Solar Ambition (NSA) which assumed the installation of no further solar beyond the RESS 1 capacity. These scenarios were modelled in 2025, 2030 and 2035.

We also respond to a number of critiques of the AFRY report, which in the main appear to be founded on misunderstanding of the methodology and approach taken.

1.2.1 Lower power sector emissions

A key challenge for the sector is ensuring that the supply of renewables better corresponds to customer demand. As noted by AFRY, Irish wind and solar output profiles are complementary, in that if you layer them over each other, they better represent the shape of demand than either technology in isolation.

The addition of higher volumes of solar results in a change to the merit order during the day. Solar can replace daytime thermal assets that are normally able to run due to higher demand requirements in that period. It is also reducing the need for imports that would be required in a scenario without a high volume of solar. The likely effect is that less efficient thermal assets are displaced in the merit order resulting in a substantial improvement in daytime GHG emissions.

AFRY quantified this effect as emissions from power generation being 7% lower in the HSA scenario as compared to the NSA scenario by 2030. In short, the outcome of dialling up the solar was an improved emissions profile for the same share of renewable electricity generated. This result is an important finding. The overall policy aim is to reduce and ultimately remove carbon emissions from the electricity sector, rather than adding renewable generation *per se*. RESS 2 should be designed to ensure the optimum blend of renewable projects to accelerate decarbonisation.

In the updated analysis by AFRY for RESS 2, this emissions saving is the single largest benefit generated by solar in the scenarios with increased volumes of solar.

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[5] Shaping Our Electricity Future

1.2.2 Lower societal costs

The AFRY report found a potential per annum benefit of €106 million by 2035 when comparing the HSA to the NSA scenario. This benefit emerged from analysis that found the wholesale cost of meeting demand was less than the benefits arising from lower emissions and savings in the cost of supporting renewables, across the scenarios.

Reviewing the impact on the wholesale market[6] and comparing that with the benefits from lower emissions and savings to the PSO (ultimately funded by consumers), provides a reasonably holistic view of the economic impact on consumers.

1.2.2.1 Wholesale cost

As solar is generating during the higher priced periods, the cost of satisfying demand in the wholesale market is higher in the blend of solar and wind scenarios than if adding wind alone. With wind's output profile, especially with the night time output during periods of lower demand, it is depressing wholesale prices more than in a scenario with solar and wind. Wind tends to displace the marginal generator more than solar does in the different scenarios.

This merit order effect was captured in the analysis but was somewhat mitigated by the effect of rising fuel and carbon prices across the scenarios in the AFRY analysis. In effect, the wider market response to pricing carbon risk eats up some of the saving from decreasing power prices

Also, the benefits of a single source of highly correlated generation pushing down wholesale prices diminish in value after a certain point. For example, generating substantial periods of negative pricing which can result in counter intuitive market outcomes. It can make it challenging to attract capital to finance assets if merchant pricing in the market is very low. Also, by driving down the wholesale price, especially at low demand periods, it can create an added burden on the PSO.

In AFRY's updated analysis for RESS 2, by 2040 the net cost of meeting demand in the wholesale market shifts into a benefit in scenarios with increased solar on the system.

1.2.2.2 Savings in cost of support

As the PSO support is calculated on the difference between the wholesale price[7] and the RESS strike price, then that gap may narrow where a technology operates during higher price periods even at a higher strike price. Put another way, lower capture prices can mean higher support costs, as noted in the Department's consultation paper. Key findings from AFRY's original analysis include:

- A substantial decrease in the net cost[8] of the PSO between the HSA and the NSA scenario from €583.9 million to €461.8 million by 2030, and €590.3 million to €402.0 million in 2035.

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[6] Which captures merit order effects and which is ultimately paid for through customer bills
[7] Further adjusted for Capacity Remuneration Mechanism (CRM) revenues where a generator is in receipt of them
[8] The difference between the cost to the PSO of the payments to generators and the payments from generators

- Under different scenarios solar could have an €8-€13/MWh more expensive a strike price, with the cost to the PSO remaining the same.
- PSO cost of supporting existing REFIT-backed renewables could be as much as 5% lower by 2030 if supplementing wind with more solar.

In the updated AFRY analysis, they found that solar could bid into RESS 2 at a price of €83/MWh and still generate a net gain for society.

1.2.2.3 Emissions cost saving

The outputs from AFRY's system dispatch model were modelled and the EU-ETS carbon prices estimated using the base case in National Grid's 2020 Future Energy Scenarios[9]. The output savings were estimated at €13.3 million in 2030 and €21 million in 2035 across the scenarios.

In the attached AFRY assessment of the RESS 2 ECF, they find an annual saving in emissions costs of €6.30-€7.80/MWh for RESS 2 solar

1.2.3 More secure electricity system

The initial AFRY work modelled the impact of curtailment upon the volumes of renewable electricity generated in Ireland across the different scenarios. The HSA scenario resulted in an approximately two-fifths reduction in curtailment (including reductions in same for both onshore and offshore wind) relative to NSA.

However, this analysis did not fully quantify the economic benefits of that reduced curtailment. There are potential additional financial benefits for customers in a higher solar scenario.

The level of curtailment in the NSA scenario as a share of output is more than double the 5.3% curtailment experienced in 2020[10]. That 2020 level of curtailment links to a volume of constraint payments[11] in 2020/2021 estimated at €286 million by the SEM Committee.[12] That constraints payment number increased in 2021/2022 to €348 million.[13] These costs are recovered from suppliers, who fund them via customer bills. Therefore, a saving in this space is potentially valuable.

1.2.4 Comments on methodology

Post publication, there were a number of critiques made of the report; we respond to two of the more common below. They appear to be grounded in a misunderstanding of the methodology and

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[9] Available here
[10] All Island Quarterly Wind Dispatch Down Report 2020
[11] Including costs for redispatch to compensate for curtailed renewables,
[12] Imperfections Charge October 2020 – September 2021 And Reforecast Report October 2018 – September 2019, Decision Paper SEM-20-058
[13] Imperfections Charge October 2021 – September 2022 And Reforecast Report October 2019 – September 2020, Decision Paper SEM-21-061

approach. In both the original paper, and the updated analysis for this consultation, the methodology is described. However, we are happy to arrange a discussion to address any of the more detailed points, should there be outstanding queries.

1.2.4.1 Merit-order effect

One critique of the work was that it failed to capture the “merit order” effect of wind power i.e. its impact on depressing wholesale prices. That is simply not correct.

That effect has already been discussed within this response, but in the interest of clarity:

- The work found that wholesale prices were lower in a wind plus RESS 1 scenario than one with a higher solar installation but the overall impact on consumers was more positive in the higher solar scenario as savings to the PSO and emissions costs outweighed that merit order impact
- AFRY modelled the wholesale market on an hourly basis, capturing pricing dynamics such as the price depressing impacts of zero marginal cost renewables.
- Merit order effects of different technologies are reflected in the resulting capture prices.

1.2.4.2 Participant behaviour

One comment received was in relation to whether the model sufficiently captured behaviour across different categories of participants, which could be important for modelling impacts in calculating ECFs.

For example, different categories of renewable players (e.g. existing renewable units coming out of support, RESS 1 and RESS 2 projects) may wish to avail of non-priority dispatch so they avoid being forced to generate in negative pricing periods. In that scenario, there is a potential for capture prices to be higher. Another example was of non-priority dispatch units actively participating in the Balancing Market, whereby lower cost units (such as those coming out of support or RESS) may be willing to dispatch down at bid prices above those for REFIT units, potentially reducing constraint costs.

While important to consider the behaviours of different participant types, it is incorrect to say the AFRY model does not do so. Their merit order stack for renewables reflects the expected behaviour within the day ahead modelling. The different bidding behaviours of renewables are split into:

- Uncontrollable units, which cannot be curtailed;
- Negative bidding units (e.g. REFIT within support) which accept negatives prices up to their support payments and as a result are barely (if ever) out of merit; and
- Zero bidding units (e.g. merchant plant, units out of support, RESS assets) which seek to avoid the negative pricing periods and are therefore the first to be out of merit.

As a result, the RESS capture prices in the analysis for all units incorporate higher levels of total curtailment (i.e. market curtailment and the Balancing Market). The capture prices across the RESS units are higher than the capture prices for units with priority dispatch, where the uncontrollable and negative bidding units are effectively the priority dispatch units. Therefore, the above first example is already captured within the AFRY analysis.

The second example, we would suggest is not especially material, and was considered within the modelling work. As no final decision has been taken on the treatment of renewables in the Balancing Market, AFRY assumed that all variable renewables (excluding uncontrollable units) were dispatched up or down on a pro rata basis as per the System Operator's Wind Dispatch Tool. As such, the key determinant is the level of System Non-Synchronous Penetration (SNSP) on the system at a given moment. Most of the dispatch down in their analysis was day ahead curtailment rather than Balancing Market curtailment. In the main this was due to improvements in operational constraints (e.g. the SNSP limit is at 95% from 2030) and therefore would not constrain renewables much in the Balancing Market.

2 RESS 2 structure & market developments

This chapter considers structural matters relevant to the RESS 2 auction and several market developments relevant from a cost perspective.

2.1 RESS 2 structural points

2.1.1 RESS 2 volumes

The maximum quantity to be procured (Representative Maximum Quantity or $RMax_p$) in RESS 1 was 3,000GWh. The final competition ratios, once applied, enabled circa 2237GWh to be successful within the 2020 auction.

The Program for Government (PfG)[14] committed to annual RESS auctions. Following the initial auction, no RESS competition is scheduled for 2021. If the RESS 2 volume remains constant, and the next auction occurs in 2022, in effect RESS 2 has been cancelled and the Department is skipping to RESS 3, meaning a delay in that renewable electricity being delivered onto the system and potentially jeopardising the 2030 targets.

Activity within the development market has continued, encouraged by the strong commitments made in the PfG, meaning the volume of projects eligible for the auction is continuing to rise. Due to the RESS eligibility criteria, ECP2.2 projects will also become eligible to participate in RESS 2 in 2022. Initially the market forecasted that this batch of grid applicants would participate in RESS 3 at the earliest.

There are realistic mitigations that can be applied through the design of RESS 2 to reduce the impact that the sequential auction delay will have on the wider industry. Increasing the scale of RESS 2 (RMaxp - All Projects Category) is an accessible mechanism that will partially mitigate the artificially distorted volume eligibility levels that this delay has inadvertently created. It will also signal intent to the industry and their investors who have structured their operations and associated strategies for annual RESS auctions. This can be done whilst maintaining higher levels of competitive tension on all auction participants i.e. onshore and solar, than the levels of competitive tension applied on most participants through the auction design in RESS 1. Utilising an effective competition ratio and a meaningful ECF (Technology Correction Factor) reflecting the net benefit of solar on the system, will provide adequate competitive tension for all technologies within the auction.

In terms of the RES-E 2030 target, and the associated interim targets, an increase to the volume of RESS 2 should also be viewed as an excellent opportunity to backfill the renewable capacity that has been delayed due to late delivery of the second RESS auction.

There is also a potential risk of losing the contribution from a range of shovel ready projects. There are a relatively significant number of projects nearing the end of their planning permission term and these projects may not be able to participate in RESS 3.

[14] Programme for Government: Our Shared Future

2.1.2 Delivery times

ISEA believes that the delivery times in RESS 2 should at a minimum be no shorter than the delivery times under RESS 1. The current draft of the Terms and Conditions contains Commercial Operation Date and Longstop Date in September, meaning successful bidders have three months fewer to deliver their projects, if the auction is held in line with the published Auction Timetable

The shortened delivery times in the draft RESS 2 Terms and Conditions and associated Auction Timetable should be reviewed to provide generators with sufficient time to deliver their projects and comply with their obligations under their Implementation Agreement.

2.1.3 Penalties for non-delivery

ISEA welcomes the Department's clarification in the draft Terms and Conditions ISEA that notification of Final Auction Results is the point in time that rules out that project from participation in future RESS auctions for onshore projects. It is consistent with the Department's own *RESS 1 Lessons Learned*. This amendment should help mitigate the risk of speculative bidding in RESS 2, and potentially maximise auction participation from committed projects.

2.2 Market developments

Recent developments such as global supply chain constraints and the impacts of COVID-19 have impacted greatly on solar project economics. The relative impact has been more substantial on solar than many other renewable technologies such as onshore wind. While the duration of these effects is unclear, it will directly impact on the bid price that solar projects can offer into the auction.

A recent detailed analysis[15] of the current solar market and related price changes detailed sharp price rises for solar module components, including polysilicon, wafer, mono cell, silver, copper and aluminium across 2021. External factors such as freight and exchange rates are analysed also. The report gave an overview of the price trends for the various components, and clearly indicates that for the majority, sharp increases in overall module prices have been recorded since July 2020 when the initial RESS auction took place.

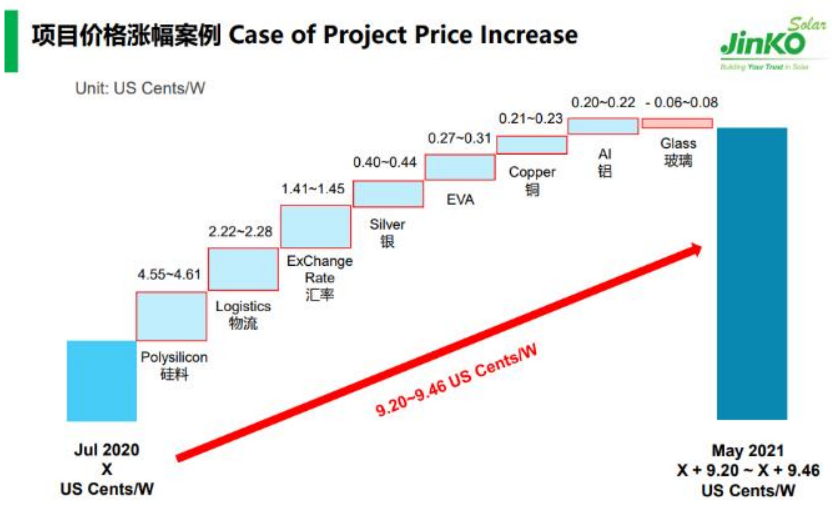

Figure 1: drivers of solar cost increases since RESS 1

BloombergNEF, Windpower Monthly, and the International Renewable Energy Agency (IRENA) have all completed similar

[15] JinKo Solar. May 2021. *Analysis on Impact Factors of Module Price*

analysis for onshore wind looking at the effects pandemic related issues, along with other external global factors, had on onshore Original Equipment Manufacturer (OEM) costs.

In 2020, the global weighted-average LCOE of onshore wind fell by 13%, year-on-year, from $0.045/kWh to $0.039/kWh[16]. The global price average for wind turbines increased slightly due to the smaller nature of wind farms in Western Europe compared other regions such as China and Latin America. However, price decreases were seen, with record-breaking lows in China in 2021. The global average of $830,000/MW for contracts signed in H1 2021 was up 1% over H2 2020, and despite rising commodity prices and logistical issues, turbine prices remained largely the same[17]. Turbine pricing is in the range of $910/kW to $960/kW for orders received in early Q1 2021. Bloomberg predicts 78GW of onshore wind capacity to be installed in 2021, a positive number after a record amount of 91GW in 2020. High demand for newer technology and logistical costs may prevent prices from falling this year.

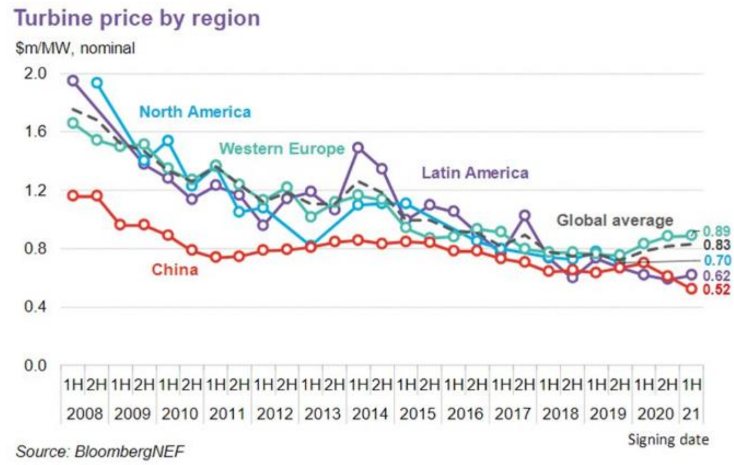

Figure 2: Turbine pricing by region

The main area of concern with regards to onshore wind pricing in RESS 2 are the steep increases in steel pricing. There has been an approximate price increase of 80% since the beginning of 2021[18]. Due to COVID-19 lockdown measures across Europe, several steel manufacturers reduced capacities to balance supply with sharply declining demand throughout 2020. The problems in supply chain were caused by capacity remaining idle too long after demand started to ramp-up following COVID-19 lockdowns. In regard to price however, market sources are showing that, following rapid rises in 2020 and early 2021, prices are expected to normalise in late 2021, providing high levels of confidence in a downward fall in prices in the coming months[19].

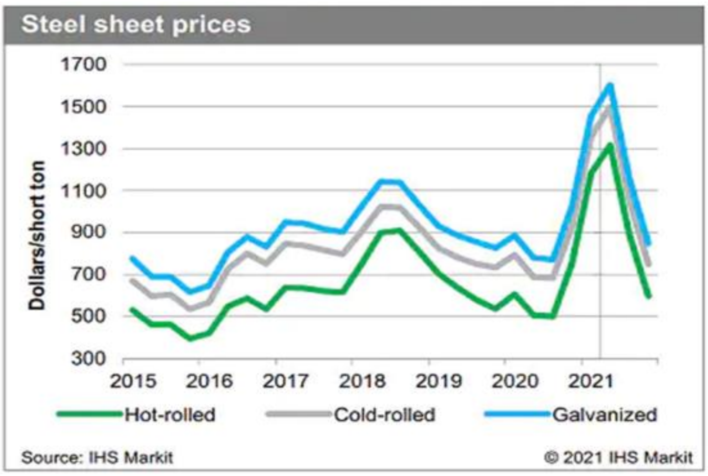

Figure 3: Historic steel prices and forecast

Where recent volatility effects the RESS market is perhaps most prevalent within the transportation sector. Record high shipping costs have been

[16] IRENA. 2021. Renewable Power Generation Costs in 2020
[17] Bloomberg 2021
[18] https://www.bnef.com/insights/26855/view
[19] Steel Price Forecast and Market Outlook | IHS Markit

caused by a combination of factors, including surging demand, backlogs, the Suez Canal incident, as well a shortage of dock workers and haulage operators which was amplified by the pandemic. Also shipping containers are in short supply, all of which has amounted to an increase of 400% in containerised shipping costs from June 2020 to June 2021. The cost of shipping a 40-foot container from Shanghai to Rotterdam has surged to well over $8000 in June 2021, from $2000 in June 2020. According to Bloomberg, from 2008-2021, marine transport for onshore wind turbines averaged at $87,000/MW and overland transport at $77,400/MW. An average of 6% of the cost of onshore wind deployment can be attributed to transportation.

The per unit cost of shipping solar modules has quadrupled from a steady recent average of around $0.005/Wp to $0.020/Wp in 2021. This is a significant cost increase for solar developments, as shipping now equates for approximately 10% of the cost of the module and approximately 5% of the overall cost of deployment of solar. As solar relies on conventional shipping containers as its predominant model of transportation, across longer distances i.e. from Asia to Ireland, solar has been substantially affected by pandemic related transportation costs increases. These increases unfortunately show little sign of normalising in the short to medium term.

It is without doubt that both the solar and onshore wind industry have been hugely affected by the aftermath of the pandemic and the adverse effects it brought about. The future is still uncertain, and how long these effects last for is yet to be seen. However, the studies show that the relative cost impact on the Irish solar industry will be far greater in magnitude to the effects that other onshore renewables will likely experience on a relative pricing basis in the near to medium term.

3 Issues for consultation

Below are ISEA's specific responses to the matters raised within the consultation paper.

3.1 Market Reference Price

ISEA are supportive of DECC's proposal to retain the existing approach to how the Market Reference Price is calculated.

In relation to the "second-order concern" about aligning availability to periods of market scarcity, the consultation paper may not be fully considering the role of the Balancing Market (BM). With all market participants balance responsible, a key feature of all RESS PPA negotiations is the distribution of ownership for balancing risk plus the commercial terms associated with same. All traders of RESS PPAs, are incentivised to trade the renewable volumes under contract in the most efficient manner they can.

Ultimately, ISEA does not see the evidence of sufficient upside to merit an adjustment in the MRP. Currently, further risk should not be added into the price against which RESS settles. "Out of market" risks are more suitably addressed via the ECF.

a. Is the state of market price forecasting in Ireland such that it would be reasonable to require variable projects to accept and price some additional market price risk now or in the foreseeable future?

In keeping with the desire to incentivise economic renewables, we'd note that all projects retain significant exposure to market risk. Participants facing market signals is a fundamental principle of market economics and is important to ensure least cost outcomes for consumers. Strong market signals will ensure the development of the most economically efficient resources for the Irish market and encourage the deployment of technologies enabling decarbonisation such as energy storage, demand side management and others.

The RESS negative pricing provisions ensure projects can earn RESS revenues only when contributing value from the perspective of the market. RESS-supported renewables are already disproportionately exposed to constraint and curtailment, compared to other asset classes within the market, impacting upon their ability to recover revenues within the market.

The lack of clarity on the treatment of constraint and curtailment under the Clean Energy Package (CEP) will be a market risk that developers will have to consider within their bids. For bidders to understand the implications of the CEP decision sufficiently, that decision would need to include not only how constraint and curtailment are to be priced, but market design, firm access policy and a plethora of other areas. That market uncertainty may have an impact on the cost to the PSO.

With increasing renewable build out, we'd expect wholesale capture prices to decrease for renewables (price cannibalisation as discussed in Sections 1.1 and 1.2). Renewables projects are especially exposed to this market price risk in the post subsidy period of their life cycle. Bidders into the auction are already considering this merchant price risk in their bid prices.

While understanding the Department's desire to internalise costs, market price forecasts present a long-term view that is more appropriate for calculating aggregate revenues, than risk exposure. ISEA would suggest that forward curves would not provide a suitable basis on which to price risk as:

- Firstly, no project settles at the curve. In the real world, revenues diverge from the forward view, and those curves are updated regularly, meaning that back casting a risk exposure from delivery versus actual is methodologically challenging. The baseline constantly shifts in response to events in the market, so one cannot apply a future performance for curves purely on how they have done in the past; and
- Secondly, from a solar perspective, there would need to be a number of years of live experience. As it is likely to be 2022 before there is a broader portfolio of utility scale solar connected, it would seem premature to start trying to quantify that risk from theoretical curves.

There is a direct relationship between the level of risk bidders are required to assume and their bid price. For example, asking projects to bear additional price risk would likely inflate auction prices. Conversely, extending contract durations would reduce pricing as it provides more certainty.

b. Are consumers being exposed to potentially excessive PSO support costs by not requiring variable projects to assess and price market price risks?

As noted above, any characterisation that renewable projects do not take market risk is inaccurate. If market price risk increases, the corollary is a likely increase in RESS bid prices, exposing consumers to additional cost under the PSO.

It is worth noting that the design of RESS 2 and PSO does mitigate consumers' exposure to market price risk to some extent:

- The bilateral structure, whereby generators have a payback obligation over the strike price, insulates them against excessive pricing, which is a risk during low wind periods;
- Consumers are not exposed to negative price risk in the market;
- Where the PSO overpays against the market, that money is clawed back through an adjustment; and
- Consumers are currently not exposed to inflation within RESS

c. What ideas do commenters have with respect to introducing exposure to market price risks that would enable a comparison of Strike Prices that better reflects the relative PSO support costs of various bids?

ISEA does not support additional market price exposure. Renewables' relative exposure to the market is greater on many parameters than conventional generation. Variable generators have greater balancing costs to consider than non-variable thermal plant. Their options in terms of varying output in response to market conditions are more limited than fossil fuelled generators.

Capture price discounts of specific technologies could be considered in the determination of the ECF. However, capture prices will vary over time and are dependent on a range of external factors including supply and demand, build out rates, interconnector capacity, and scheduling/trading rules for interconnection and renewables. Therefore, it may not be appropriate to consider the capture price discount at a single point in time to determine the auction hierarchy. A projection of the discount curve could be used to inform the ECF calculation, though the methodology and impacts would require careful consideration.

d. Does maintaining the MRP determination structure from RESS 1 place at risk the continued use of technology neutral auctions?

ISEA would not see a contradiction between technology neutrality as an enduring organising principle of the auction and the use of the DAM as the MRP. The Department justifiably has mechanisms within the auction design to enable flexibility and capture value not addressed within the strike price.

3.2 Evaluation Correction Factor

To help inform the Department's selection of an appropriate ECF for solar PV, appended is an updated analysis by AFRY to support this submission. This supporting analysis models a range of renewable capacity mixes in the RESS 2 auction specifically: 100% wind, 65:35 wind/solar, 50:50 wind/solar, and 100% solar.

The 65:35 wind/solar scenario is seen as being the closest to the likely RESS outcomes as it is broadly representative of:

- The previous **RESS 1 auction** in which 34.3% of awarded energy volumes came from solar and 65.7% of awarded energy volumes came from wind; and
- The **eligible pipeline** – currently ISEA estimate a RESS 2 eligible pipeline of approximately 2GW solar and 1GW wind. That translates to a Deemed Energy Quantity (DEQ) percentage of approximately 40% solar and 60% wind.

The output ECF from this analysis was 0.75 relative to an ECF of 1.0 for wind[20]. However, project attrition has an impact on that number, potentially reducing it further. The AFRY analysis did not account for the RESS 1 project attrition since the final results were published in that auction. As AFRY state in the attached:

> *"In the absence of publicly available post-auction attrition rates, all RESS 1 capacity is deployed. If attrition had been considered, the ECF for solar would have been lower."*

Overall the detailed analysis supports a conclusion that the 0.75 number should be seen as a ceiling for the solar ECF, rather than a floor, and that the final ECF should be lower than that number. This updated analysis would also suggest that the 0.85-1.05 range in the consultation is not adequately capturing the benefits from solar.

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[20] The ECF is a relative measure within the context of the competitive auction and in modelling its impact across a mixed portfolio of assets.

3.3 Eligible Technologies

The listed technologies appear a reasonable list for RESS 2. At a high level, making an allowance for hybrid site participation is a positive development within RESS. ISEA would suggest though, that a range of regulatory matters may need urgent work if hybrid sites are to be involved at scale in RESS auctions (see Section 3.4 for examples).

3.4 Hybrid Storage Projects

The provision for hybrid storage projects is certainly a step in the right direction and ISEA welcomes the implication that by proposing different models the Department is attempting to be flexible. For these sites to meaningfully participate however, there are a range of regulatory and technical decisions required across the following areas *inter alia*:

- DS3 or system service design;
- SEM and the Trading and Settlement Code;
- Grid Code; and
- Connection practice

There are some key regulatory areas undergoing review at this moment in time. These topics are particularly pressing in terms of RESS 2 participation and include:

1. Dynamic sharing of MEC between technology types
2. Multiple legal entities (MLE's) behind a connection point
3. Oversizing of total generator capacity levels relative to a connection point MEC (120% over install rule)

With no meaningful Flextech Working Group outputs in 2020 or 2021, or resolution to the above issues, hybrid sites will not be able to participate with sufficient certainty in the upcoming RESS 2 auction. ISEA would welcome these agenda items progressing further and with urgency.

In relation to the two hybrid options proposed in the consultation, ISEA feels that neither of these options are sufficient to facilitate the meaningful inclusion of hybrids, or to unlock the potential for hybrid storage sites in RESS. ISEA have identified three key principles that should be included in implementing battery storage hybrids:

1. The battery storage asset should have the ability to contract for ancillary services and capacity remuneration market revenues.
2. The battery storage asset should be permitted to charge via the RESS asset and the grid connection.
3. The RESS asset should receive subsidy support for all exported energy, whether directly to the grid or to the battery storage asset.

3.5 New project criteria

ISEA is broadly comfortable with the €300 per kW investment threshold and the clarification of its point of application post Implementation Agreement. It seems a reasonable border at which eligibility for support should take effect.

We would note that there are scenarios for distribution-connected solar in which the "at least 50%" capacity increase could be unduly restrictive, and that a precedent should not be set at this time that may affect existing/soon to be built solar farms participating in future RESS auctions. For example:

- The maximum capacity available at a 38kV distribution level substation is c.50MW depending on the line ratings. In the future, if a 40MW solar farm seeks an extension at a connection point where spare capacity of 10MW is available, it would have to apply for a minimum of 20MW, which would bring total installed capacity to 60MW, which cannot be facilitated at that connection voltage. The proposed 50% threshold could restrict a generator in maximising efficient use of existing infrastructure. The incremental cost to the existing generator of acquiring this extra capacity and increasing renewable generation on the system would come a lower cost to the consumer than that of new generator, that in turn may never be built anyway due to the small scale of capacity being added.
- Similarly, if the same solar farm was connecting at 38kV at a 110/38kV node, the 50% threshold (20MW in this case) could also potentially trigger transmission level reinforcement works, making the additional capacity unduly expensive to add. Whereas, if the 40MW solar farm could add a lesser capacity within the limits permissible of the existing infrastructure, additional capacity can be added to the system in a cost-effective manner at a lower strike price and cost to the consumer.

3.6 Indexation

RESS solar project costs are substantially influenced by longer term inflation. In assessing the relative profile of capex to opex in Irish solar projects, we find significant operational costs which are liable to inflation uplift. Excluding community benefit and major maintenance that is required throughout the project lifecycle, circa 4.5% of capex is spent on opex annually on solar PV projects. Over the lifetime of the project, or even the RESS support period, this number equates to a substantial share of the total project cost.

Unlevered project IRR[21] on solar projects is especially sensitive to opex increases. Typically every £1k/MW increase in opex causes a decrease in unlevered project IRR by circa 0.3%, while a comparable £1k/MW increase in capex causes a decrease of circa 0.01% in unlevered project IRR. Therefore, uncertainty in long term opex can be seen to increase risk and potentially impact on investor confidence.

We also would note that the claim that the CRM is not indexed is neither totally accurate, nor does it fully reflect the functioning of the mechanism.

[21] Unlevered IRR or unleveraged IRR is the internal rate of return of a string of cash flows without financing.

- While the awarded contract under the CRM is not directly indexed, a number of the key parameters within the auction are determined by the Cost of New Entry (CONE) values. These parameters drive pricing outcomes. These factors include inflation values across a range of areas[22] including business rates, nominal WACC which assumes an inbuilt inflation rate, and market yield rates.
- While the CRM directly provides a per MW payment, it also enables a participant to retain all traded revenues in the Day Ahead, Intraday and Balancing Market(s) up to the value of €500/MWh. The obligation to pay back is when the market price is in excess of that threshold. Therefore, there is far more headroom to deal with cost changes such as inflation under the CRM than under RESS.

3.7 Financial Questionnaire

The Financial Questionnaire's request for more detailed information on IRR, Capex and Opex is problematic. There are organisations prevented from providing this information by covenants, existing agreements and procedures.

It is also commercially sensitive information, and it is not clear as to why organisations should release this information when the Department has not clarified for what purposes it will be used. Given that such information is linked to the specifics of an individual transaction, it is also not clear that it can be meaningfully used by a third party.

The Department has not evidenced the requirement for this specific information beyond an assertion of a need to do so in line with the state aid approval. Reviewing the state aid clearance document does not clarify as to why the information is required. We would request that the Department revisit this requirement.

3.8 Locational considerations

ISEA are supportive of the stated position that locational signals should not be explicitly factored into RESS 2. We would be of the view that the network already issues implicit locational signals through the constraint regime, the regional variations in use of system charging, and the generator-specific means of accounting for losses through Transmission Loss Adjustment Factors (TLAFs).

In addition, the planning system makes decisions upon the appropriate location of renewable energy development through the process by which proposed projects apply for planning permission.

The implementation of Article 12 and 13 under the Clean Energy Package (CEP) is under consideration by the SEM Committee, so it is very difficult to assess potential risk from not applying explicit locational signals in RESS 2. That decision is not due until the first half of 2022, and there is currently no clarity on an associated range of enabling measures. ISEA suggests there is insufficient certainty to enact an explicit locational signal for RESS 2.

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[22] Updated Cost of New Entrant Peaking Plant and Combined Cycle Plant in I-SEM

ISEA is open to a conversation on setting explicit locational signals in future, though we would urge caution and suggest a full review would be required to assess any unintended consequences. A state-level renewables auction may not be the appropriate mechanism through which to send locational signals. Issues that might need consideration include:

- **Path dependence:** as the RESS preconditions require planning and grid (both of which include implicit locational elements as discussed above) essentially a locational signal would be rewarding project owners for locational decisions taken potentially 5-10 years in the past. However, there could be value in seeking to accelerate projects near demand centres, for example.
- **Equity:** following on from the "path dependence" point, the fairness of a locational signal would need review if it is rewarding decisions taken in the past when the explicit signal was not present rather than encourage the correct outcomes in the future. That said, the need for green generation in the right part of the network may outweigh some of those concerns.
- **Appropriateness:** there is an element of ensuring the use of the most appropriate tool for sending an economic signal. If the goal of a locational signal is to ensure sustainable land use and projects are in appropriate areas, then the planning system would appear to be the most suitable means. If the objective is to encourage location within specific areas of the grid, then network charging mechanisms would seem more aligned with driving that outcome. In contrast, the implicit locational signals could be argued to be diffuse and perhaps insufficiently targeted to drive the preferred outcome.
- **Dilution and complexity:** the benefits of locational signals tend to erode over time, and may just become an uncertainty that has to be priced into a RESS bid. In a system with many moving parts and signals that are not always aligned, another incentive-linked dynamic may just make matters more complicated. That addition of complexity and an uncertain bid element would have to be weighed carefully against any potential accrued upside .

3.9 Bid Bond and Performance Security

We support the principle of shifting to charging on the basis of output (MWh) rather than nameplate capacity (MW). It aligns the auction bond and security payments with the product that is being procured, namely energy.

In addition, there is an equity principle, that charging on the basis of capacity risks discriminating between different technology types on the basis of capacity factor, i.e. the relative payment by a technology being lower or higher because of its innate characteristics. It seems fairer to charge different technologies on a level playing field, based on how much they produce.

3.10 Community Category

ISEA would suggest that the Department review the uptake levels under the community preference category in RESS 2 and consider whether it would be appropriate to revisit the requirement for 100% community ownership as a precondition for future auctions.

3.11 Community Benefit Fund

ISEA would be supportive of DECC undertaking a lessons learned exercise from the rollout of the RESS 1 Community Benefit Funds (CBF). It could be helpful to review the design and structure against the lived experience of delivered projects.

The Terms and Conditions would benefit from more specificity in relation to the distribution of funds on non-wind sites such as solar. Specifically at issue is Clause 7.2.6, paragraphs a-d. In the published RESS CBF Good Practice Principles Handbook, there is a clarification that:

> *"For onshore solar farms, category (a) and "near neighbour payment" elements of (d) do not apply."*[23]

In the interests of consistency, ISEA would suggest that the Terms and Conditions themselves should be specific on the distribution of funds for solar. At a minimum, ISEA suggests that something comparable to the above clarification should appear in the Terms and Conditions. We would also suggest that the Terms and Conditions could set out some degree of payment for homes close to solar projects, as they may be most impacted by the development activity.

ISEA suggest amending (or adding to) 7.2.6.a to specifically reference projects that nominate as Solar technology being required to contribute €2 per MWh to the Community Benefit Fund and distribute Community Benefit Funds on the following basis:

a) 50% of the balance of the fund shall be paid to the households located within a distance of 200 metre radius from the RESS 2 Solar Project with each household receiving a payment of €500. Whereby there are a greater number of houses in the 200m radius area than the 50% of the fund allocation can be distributed amongst, those houses which are in closer proximity to the Solar Project should be given priority for the €500 payment.

During the construction phase ISEA believe that it is important projects are able to spend funds, which can be recouped later, for example to establish the CBF committee, commence community action planning and initialise a funding round. Projects may impact the most in communities during construction and being able to contribute funds to the community at this phase of the project is beneficial. Commencing a CBF up to 18 months after the construction period is complete and three years after construction has commenced would be too late given the real impact the relevant projects would have had on the communities in the locality of the project. The establishment of Fund Committees is also a considerable endeavour, and it would be prudent to begin establishing it as early as possible following a RESS auction

Noting the above workload, ISEA is also supportive of increasing the administration allowance up to 15%, as the likely outlay will exceed the allowance permitted on many projects in the country.

ISEA would also be interested in garnering the Department's views on the potential for offsetting the value of development contributions against the CBF. The majority of councils require a development contribution, which is spent in communities for their benefit similarly to what is intended under the CBF provisions. There could be value in exploring this option.

[23] Renewable Electricity Support Scheme - Good Practice Principles Handbook for Community Benefit Funds

3.12 Citizens' Investment Scheme

Our association and its members stand ready to engage on the structure and operation of a Citizens' Investment Scheme. We note the potential interaction of such a structure with the regulations overseen by the Central Bank and would recommend the Department engage with them on detailed design.

Given the likely steps antecedent to operating such a scheme (e.g. regulatory approvals, set up of functions), it is likely that its detailed design would need to be well advanced at this point, to be delivered by the current RESS 2 timeline. If the scheme has not progressed to an advanced stage, then the Department should consider decoupling the design of the Citizens' Investment Scheme from delivery of RESS 2.

We are in a climate crisis, and it is imperative that we urgently progress projects to decarbonise our power system. Any further delay to the RESS 2 auction should not be countenanced by the Department.

4 Conclusion and Next Steps

The solar industry is primed to compete in the next round of the RESS auction and look forward to the Department finalising the RESS 2 Terms and Conditions. It is essential the correct decisions are made to drive the decarbonisation of our electricity system at least cost and least risk to consumers. We would welcome the opportunity to meet to discuss our response and allow the Department the opportunity to interrogate both our thinking and the updated modelling from AFRY.