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Future market design options for electricity markets with high RES-E

Lessons from the Irish Single Electricity Market

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Abstract: Variable renewable electricity generation presents challenges for traditional power markets. The island of Ireland has high levels of renewable generation by international standards with even higher levels envisaged and so must address these challenges. Market design is informed and constrained by EU policy and progress to date has been mixed. A qualitative review finds that market redesign is advised to address price cannibalisation, reveal consumer preferences for security and protect vulnerable households. Options for market design are presented and recommendations for short and medium term policy action are made.

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1 Introduction

The Programme for Government [1] envisions challenging changes to the energy sector. The goal to decarbonise energy production requires several milestones, including a target of 70% renewable energy by 2030. The steps towards a greener energy sector imply more electricity demand but also more and different sources of renewable energy and fuels. The electrification of heating and transportation will significantly change the composition of energy sources. The Programme also plans facilitating additional grid connection, incentivising offshore wind capacity, engaging the demand side and increasing the penetration of green hydrogen. Together these actions could provide the electricity needed and the flexibility to maintain a reliable grid. To-date the market design has performed well in a fossil fuel dominated energy sector but to make the 70% renewables target a reality, it is imperative that in conjunction with the physical changes in the energy sector mentioned above that the design of energy market is also revisited.

The worldwide move towards decarbonisation requires that power systems move rapidly towards low-carbon technologies, with widespread deployment of variable renewable technologies such as wind and solar power. The European Union's (EU) Renewable Energy Directive (2009/28/EC) establishes a target that requires the EU to fulfil at least 32% of its total energy needs with renewable energy by 2030, though a recent EU Commission impact assessment concludes that the 2030 share of renewables will need to reach 38-40% to allow for a gradual transition to a climate neutral EU economy by 2050 [2]. While there is no binding EU target for renewable electricity, investment in renewable generation is expanding rapidly. Within the EU Denmark, Ireland and Portugal have the highest shares of power generation from wind [3]. Ireland has already seen high levels of variable RES-E generation (40% of power in 2020) and so faces many of the technical and economic challenges of widespread variable RES-E integration that other power systems will face in the coming years. Across Europe the average share of power generation from wind is 15%, with half of European countries at 9% or less [3]. Thus Ireland is a helpful case study for examining electricity market design for high levels of variable RES-E.

The Clean Energy for all Europeans Package (CEP) [4], which is a set of legislative acts, includes establishing a new electricity market design to allow more flexibility and integrate a greater share of renewables. In a review of the CEP legislative framework, Boscán [5] concludes that CEP legislation removes fundamental barriers for consumer participation but that several unresolved issues remain. Among the challenges are "making competition effective, striking the right balance between the verticality and horizontality of the future retail market and confronting market reconfiguration". Much of the academic literature on electricity market design has focused on whether the wholesale market design is fit-for-purpose. Peng and Poudineh [6] suggest that the CEP has a misplaced emphasis on a short-term energy-only design, which may impact on future capacity investment. Additionally, while the CEP does address some market misalignments it does not resolve issues surrounding the distortive effect of generation-based subsidies, concerns with central auction procurement, missing money, and missing markets.

Qualitative studies on electricity market redesign generally focus on stylised markets [e.g. 5–10]. The general conclusion of this literature is that the sustainable integration of high levels of renewable generation is feasible in the context of market redesign. There is also a view that electricity market redesign should be considered within wider energy market design, as future renewable heating, green gas and liquid fuel markets will influence the electricity market and vice versa [11]. Several challenges and principles for good market design are recommended [e.g. 5, 8, 10, 12, 13] but renewables integration does not change the fundamental principle that markets need to adequately price all resources and externalities. As MacGill and Esplin [13] note, discussions of electricity market design often focus on wholesale spot markets whereas in reality a key part of market design is the interface between multiple markets so that they can perform efficiently. van der Veen and Hakvoort [14] examine the full extent of the design challenge in the context of the inter-linkages between the balancing market and the wider electricity market.

For reasons of computational feasibility, quantitative studies examining market design issues tend to concentrate on large, strongly interconnected power systems and abstract from individual power system idiosyncrasies [e.g. 15–18]. For example, Brouwer et al. [17] consider six regions (Germany & Benelux, Scandinavia, British Isles, France, Iberian peninsula, Italy & Alpine states) with just eight interconnectors. Interconnection between separate power systems within regions (e.g. Ireland and Great Britain, Spain and Portugal, etc.) is not considered. Whereas in the study by Zappa et al. [18] focusing on Central Western Europe (France, Belgium, The Netherlands, and Germany) neighbouring interconnected markets are simply modeled with a single operator per generator type. Even within these modelling limitations, the scenario results suggest that planned market redesigns with high levels of variable renewable generation lead to unsustainable market outcomes, for example, with zero electricity prices for up to 17% of time and revenue gaps for generators both of which undermine future investment [17, 18]. Adding power system idiosyncrasies, such as market power, low interconnection to neighbouring markets, or small island power systems, the ability of CEP's electricity market redesign to deliver cost-effective, secure and affordable electricity to EU customers will be tested.

This paper contributes to the literature in three ways. First, it identifies some of the challenges facing power systems with growing shares of renewable generation, including some issues that can arise on small, isolated power systems such as the SEM, which recent EU legislation on electricity market design has little cognisance. Second, as variable RES-E rises to 70% and beyond, the likely trajectory of investment and operation in the SEM under the current market design. Specifically, the consequences on revenue streams from energy services, negative electricity prices, interconnection, support schemes and parallel or sequential optimization of energy and system services. Third, it outlines options for new electricity market design that address these challenges while respecting the principles of good market design. Seven key principles are outlined for the design of electricity markets, accommodating high levels of RES-E and minimising non-market redispatch.

2 Examining the past and future direction of European market design and identifying relevant applications and issues for the SEM.

A retrospective examination of the implementation of EU and Irish energy policy in the Irish electricity market reveals lessons and insights that are relevant for future design of the market. While existing EU energy market policy is unlikely to change in the short-term, it is instructive to review both the historical design and how it has been applied in Ireland to date focusing particularly on academic and technical documents that are of most relevance for high RES-E systems, and the implications for renewable and conventional technologies, as well as for consumers.

2.1 Regulatory and policy documents

The most recent EU legislation to impact on electricity markets is the Clean Energy for all Europeans Package [4], adopted in 2019. The Clean Energy Package consists of eight legislative acts, which include electricity market design and renewable energy targets. Key points in the Clean Energy Package (CEP) relating to market design follow from previous EU energy market policy. In particular, there is a strong desire for RES-E to be integrated via market mechanisms. In practice, this means removing priority dispatch for RES-E installations above a certain minimum installed capacity, scheduling RES-E according to general market schedule rules and rendering RES-E balance-responsible. Deviations from the market schedule should treat RES and non-RES generators equally. The Single Electricity Market Committee (SEMC) have stated that RES-E is already balance responsible in the SEM and so does not envisage market change on this score [19], but does lay out a roadmap to implementing the CEP in general [20].

Previous EU regulations regarding electricity market design have shown a lack of cognisance of the particular issues that can arise on small, isolated power systems. This pattern is also observed in some aspects of the CEP. First, there is an ever-present focus on interconnection to facilitate flexibility and seamless trading, allowing an efficient dispatch across a wider geographical area. While interconnection is certainly a useful tool for system operators, it is limited in its ability to address both the technical and economic issues that can arise on small, isolated synchronous power systems with ever increasing levels of RES-E. This is discussed in greater detail in section 2.2.1.

A new feature of the CEP is to restrict capacity payments to generators with emissions below specific thresholds. This new restriction stems from the reticence that the European Commission has shown towards capacity payments historically, preferring to rely on energy-only markets with sufficiently deep and liquid forward markets. While this solution may address adequacy concerns in sufficiently large and flexible markets, small isolated power systems are far more likely to exhibit the market failures that require specific interventions to ensure capacity adequacy. In this context, capacity markets correct a market failure. Legitimate concerns can be raised around capacity markets acting as a barrier to trade, especially when the design of capacity markets is not aligned in neighbouring markets. However, the CEP sees, and indeed explicitly refers to capacity markets, as a subsidy, suggesting that the objection to capacity markets is at a more fundamental level. While not commenting on the appropriateness of the specific policy of restricting capacity payments to low-carbon generators, this is an example of a lack of understanding of the particular issues that can arise on small, isolated power systems with high RES-E.

There are several particular issues that have arisen in implementing the CEP to date, prompting specific responses from the SEMC [20, 21]. In particular, issues around dispatch and redispatch are of relevance to the SEM. A key priority of the CEP is that redispatch should be "market-based", and that non-market based redispatch should be accompanied by compensation for generators. While theoretically sound, the practical differentiation between market based and non-market based redispatch is crucial and yet is unclear.

Furthermore, there are several aspects of Regulation (EU) 2019/943 that are opaque regarding the treatment of RES-E. While the Regulation clearly states that "the redispatching of generation and redispatching of demand response shall be based on objective, transparent and non-discriminatory criteria", it goes on to state that system operators shall "guarantee the capability of transmission networks and distribution networks to transmit electricity produced from renewable energy sources or high-efficiency cogeneration with minimum possible redispatching", but explicitly does allow redispatching up to 5% of annual electricity generated, unless it is provided by a "Member State in which electricity from power-generating facilities using renewable energy sources or high-efficiency cogeneration represents more than 50% of the annual gross final consumption of electricity". System operators "must also take appropriate grid-related and market-related operational measures in order to minimise the downward redispatching of electricity produced from renewable energy sources". The Regulation also states that RES-E shall face downward dispatch for non-market reasons only if there is no alternative source available. There are several other examples where there is explicit reference made to prioritising RES-E, in spite of the over-arching commitment to technology neutrality. The implementation of these opaque and potentially contradictory elements of the Regulation may lead, at a minimum, to market uncertainty and potential legal challenge, and should be be approached with caution by the SEM Committee.

The CEP mandates that the System Operator provide information to the Regulator on the extent and reasons for non-market dispatch on at least an annual basis. This is a positive development. The extent of non-market dispatch, and the reasons for same, especially over time and relative to other markets will be a key metric for system and market operators, as well as policy makers.

The procurement of system services or ancillary services is increasing in relevance, with the EU Commission issuing the EBGL regulation [22]. The SEM Committee published a scoping paper on the topic in July 2020 [23], whose eventual aim is to "map an overall end to end process for the competitive procurement of system services in a manner which enables an open and transparent route to auctions, which may be considered to be the favoured approach to competitive procurement, and which also aligns with European legislation". Given the considerable heterogeneity in ancillary service market design and procurement across the EU, the EBGL regulation is limited in specificity, but makes several relevant distinctions. The SEMC has interpreted these distinctions to mean that frequency based services cover balancing capacity products, while non-frequency based services cover "inertia and voltage based products that do not align with the definitions for any standard balancing products". The EBGL specifies that services must be procured in a transparent, non-discriminatory and market based manner. In response, daily auctions for system services have been proposed by the SEM, although they leave open the option to procure system services via fixed contract arrangements. The rationale for this is to incentivise entry of new technologies and provide some revenue certainty. Investment certainty is also raised as a relevant issue for system service procurement. One consideration missing from the document is the fact that cost structures of system service provision vary based on the technology - at least some system services can be provided by different generators at zero fixed or variable cost. As such a single auction that procures services on the basis of incremental provision will suit some technologies more than others, versus procuring a contract to provide services as required. The fact that most RES-E technologies have a fixed cost structure and face variation in their output renders revenue certainty particularly important. These considerations could be better reflected in both EU and SEM documents.

A final consideration is the fact that small isolated power systems have specific challenges when it comes to mitigating market power. Furthermore, the particular market structure of the SEM is best characterised as a monopoly/oligopoly with a competitive fringe, while most other EU markets are best characterised as a pure oligopoly. The optimal market power mitigation measures are determined by the market structure: competition can be enhanced and hindered by the same policy in separate markets (see de Frutos and Fabra [24] as an example of the impact of mandatory forward contracting under different underlying market structures). See Di Cosmo and Lynch [25] for a discussion of competition and market power as applied to the design of I-SEM to comply with the EU internal electricity market. The main conclusion to be drawn at this point is that when it comes to market design, it is preferable to include market power mitigation measures at design phase, rather than as an “add-on" once any new market design has been determined.

2.2 Principles of good market design

There is a wide literature on electricity market design in general, and a specific focus on market design for high RES-E markets has also emerged in recent years. Newbery et al. [8] is a recent analysis of market design for high levels of variable renewable generation in Europe. They outline several principles of efficient market design:

- correcting as directly as possible the market failures in current market designs
- allowing for appropriate cross-country variation in market design
- using price signals and network tariffs to reflect the value of all electricity services
- collecting network fixed costs in as efficient and equitable a way as possible
- de-risking low-carbon investment

- retaining the flexibility to respond to new information on the attractiveness of different low-carbon technologies

Newbery et al. also outline the principles of market completeness: in order for a market to be efficient, all products and services must be efficiently priced to reflect their economic cost and value. In particular, markets must be complete across three dimensions: time (prices determined at very granular level for decades to come), space (prices vary at granular spatial level) and externalities (all external costs are reflected in the price). In reality, electricity markets fail on all three criteria: they are of insufficient temporal and spatial granularity, forward markets are insufficiently deep and liquid to allow trading far enough into the future and external costs of carbon in particular are not properly captured. The paper also concludes that a “radically different" future market design may emerge, based on experimentation, as the current incomplete market design simply cannot support the levels of RES-E anticipated.

Newbery et al. also suggest that RES subsidies should be designed on a capacity rather than energy basis. This follows the principle that fixed costs should be compensated via fixed remuneration rather than variable remuneration, and echoes the point earlier regarding the varying cost structures of different technologies when designing system services procurement. However, maintaining the link with the energy/ancillary services market, which is required in order to ensure efficiency based on market dispatch mandated by the CEP, is challenging. Potential solutions include a contracts for differences approach, which has been implemented in the Renewable Energy Subsidy Scheme in the SEM. In the long run, as RES-E reaches ever higher levels, such subsidy scheme designs may lead to unintended consequences within the market, particularly given that RES-E depresses market prices.

In addition to these EU-level considerations, there are features of small, isolated power markets that Newbery et al. does not expand on. For example, they place a high emphasis on interconnection as a means of ensuring efficient dispatch across wide geographical areas, stating that “with high variable RES shares, the real-time supply and demand balancing of national electricity systems across the EU is thus typically no longer economically sensible". However, in the case of the SEM, there is no alternative to national balancing in at least some circumstances.

There is a paucity of discussion in Newbery et al. on the manifestation of the various market failures identified in day ahead, intraday and balancing markets. Given insufficient temporal granularity in particular, one would expect a shift in market activity to the balancing market, all else equal. Indeed, system imbalances are rising in both Great Britain and Belgium as RES-E increases. The requirement for the balancing market to play a greater proportional role, relative to the day ahead and intraday markets, on small isolated power systems is underexplored, both in the literature and by the regulatory authorities. For example, it would be instructive if ACER’s market monitoring reports included activity in each market across Europe.

Finally, Newbery et al. categorises system services as power quality — markets with higher levels of system services lead to less instabilities and lower probabilities of black outs and brown outs, and so contribute to the quality of the energy provided. However, this is a simplistic understanding of the complex interdependence of energy and system service provision. Crucially, as variable RES-E increases, the requirement or demand for system services also increases, which is not analogous to good service quality in most other markets.

2.2.1 Issues arising for small, isolated power systems

One of the most prevalent features of the Clean Energy Package, along with previous regulations and legislation on electricity market design, is the continued importance of interconnection to resolve balancing problems and to facilitate both the integration of renewable energy and an efficient dispatch according to marginal costs, resulting in the cost-minimising solution. Thus, harmonisation of bidding and scheduling across the EU is required in order to facilitate optimal operation of interconnectors, which in turn facilitates optimal transmission and dispatch of renewable (and all other) generation.

Interconnection is indeed an important mechanism for ensuring efficient dispatch, particularly as variable RES-E increases. Furthermore, the benefits of interconnection itself increase as RES-E penetration increases. At present, system constraints on characteristics such as non-synchronous penetration (SNSP) and inertia can lead to redispatch for technical reasons, as opposed to correcting imbalances in supply and demand close to realtime. These technical constraints limit the potential for interconnection to balance the system. However, at very high levels of RES-E where the system has sufficient non-energy services that can enable system operation at close to 100% SNSP, interconnectors can operate far more flexibly than they do at present, balancing supply and demand in close to realtime, and overcoming the challenges posed by high variability in renewable supply. Thus the marginal benefit of interconnection may increase in RES-E penetration.

The above notwithstanding, interconnection alone is not guaranteed to overcome the various challenges that arise from increased variable RES-E, which means in practice that many of the market challenges that arise as RES-E levels increase to very high levels may remain even at high levels of interconnection. In particular, the availability of sufficient interconnection, along with harmonised market bidding and clearing rules, can only lead to an efficient dispatch under two conditions: firstly, there must be sufficient interconnection to render the costs of congestion less than or equal to the costs of building new interconnectors. Secondly, prices and quantities must be able to adjust in a continuous, linear manner.

Neither of these assumptions holds for small, isolated power systems with high levels of RES-E. The assumption of sufficient interconnection is rendered untrue by definition on an isolated power system. Case studies on interconnection from Ireland, all of which assume lower levels of variable RES-E than is targeted for 2030, find that the optimal interconnection capacity is greater than the 900MW of existing and 1200MW of planned interconnection capacity [26–29]. This means that periods of congestion can be expected where exports from the Irish power system will be lower than would otherwise be the case.

The second assumption of the possibility of adjusting prices and quantities in a continuous linear manner rests on the assumption that discontinuous costs, such as start costs and no load costs, are sufficiently low as to prove negligible in determining the optimal dispatch. To a first approximation, this will be the case if the average size of power plants that have start and no load costs is small relative to system demand. While this holds for large interconnected power systems, it is less likely to be the case on small power systems, and so these discontinuous costs make up a larger portion of total costs. Furthermore, these costs increase as a proportion of total costs, as variable renewable generation rises [30]. In order for prices and quantities to adjust in a continuous linear manner, it must also hold that deviations from the market schedule, which arise as a result of either local or technical constraints, must also be low enough to render any impact on the market schedule negligible. However, as documented in Newbery et al. [8] and elsewhere, these deviations increase as renewable penetration increases.

It could be argued that sufficiently deep and liquid forward markets for electricity will overcome the challenges posed by non-linearities in the cost structures of power generation. However, the evidence suggests that forward markets have not proven sufficiently deep or liquid in the SEM to date (see Di Cosmo and Lynch [25] for a review of forward markets and competition in the SEM) and the reasons for this have not been established. Whether they stem from the fact that the market structure in the SEM is that of a legacy monopolist rather than that of an oligopoly, or whether they are due to the SEM being a small, isolated power system and so forward markets simply cannot overcome these non-linearities is an open question. In any event, forward markets can be considered a “missing market" in the SEM [31], further undermining the assumption of prices and quantities adjusting in a continuous, linear manner.

In summary, small isolated power systems, such as the SEM, experience lower market prices than would be the case if the optimal level of interconnection were available (as excess demand for export puts downward pressure on SEM prices), and will also see higher deviations from market schedules due to departures from the optimal dispatch for technical reasons.

Finally, there is an open question as to whether the higher discontinuous costs that arise as variable RES-E increases can provide an opportunity for even further exploitation of market power. Di Cosmo and Lynch [25] discuss this possibility, but modelling these effects is currently not feasible given the available solution algorithms for equilibrium models. In particular, discontinuities can be included in cost-minimisation or welfare maximisation models, but have yet to be successfully incorporated into equilibrium formulations that model the strategic interaction of several players, such as mixed complementarity models. The lack of both a theoretical framework or any empirical evidence on this question means market power monitoring is particularly important.

2.3 Examples from other jurisdictions

As pointed out in Newbery et al. [8], insufficient spatial granularity in pricing, leading in practice to zonal prices, hinders efficiency and also poses a significant strain on the future of resource adequacy. Maintaining zonal prices throughout the increasing integration of the pan-European energy market may translate into artificial out-of-market re-dispatching and uplift costs. Zonal pricing removes the potential for allowing physical network limitations to be reflected in prices, and leads to the unintended effect of rendering increased interconnectedness of markets a mechanism for cross-border out-of-merit re-dispatching [32].

Nodal pricing is the efficient economic solution, as nodal pricing allows market participants to respond to locational signals in both the short and long run. Market participants have an incentive to consider location in their investment and operational decisions, which decreases the necessity to redispatch units on the basis of locational constraints. However, nodal pricing also increases complexity and decreases transparency in determining market prices, and may also create opportunities for the exercise of local market power, which may outweigh the benefits of nodal pricing.

Experiences of nodal pricing in other markets are generally positive. Tsai and Eryilmaz [33] and Zarnikau et al. [34] analyse the impact of market structural change, assessing the effect of nodal pricing and a single zonal price in ERCOT, the Texas electricity market. The change happened gradually, starting with a single zone until 2002, 5 zones until 2010 when the Public Utility Commission of Texas instructed ERCOT to transition to a nodal operation. Zarnikau et al. [34] performs a regression analysis on the first two years after nodal pricing was introduced. The results suggests that wholesale prices paid by load serving entities and large industrial energy consumers reduced by 2%, with the reduction attributable to the market change rather than changes in gas prices. In addition, there is evidence of a negative correlation between increased wind power penetration and the procurement of ancillary services. This is attributable to a modification of the dispatch frequency after the structural change. Initially, the SO dispatched on a 15 minute interval whereas in the nodal market the Security-Constrained Economic dispatch is solved every 5 minutes.

Notwithstanding the benefits of nodal pricing in various US markets, a full shift to nodal pricing in the EU remains an unrealistic option at present (although attitudes towards nodal pricing may be shifting as per Newbery et al. [8] and also EU Commission [35]). However the principles of zonal vs nodal pricing are of relevance for market based versus non-market based redispatch. In particular, a market schedule that is arrived at while ignoring locational constraints cannot by definition reflect locational signals in prices or quantities. It follows that a redispatch decision that is necessitated as a result of a local constraint cannot be considered a market based redispatch. This principle should be acknowledged in the definition and application of market based and non-market based redispatch decisions, and is of increasing importance as variable RES-E increases.

2.4 Conclusions from the review of the adaptation of the SEM in response to EU market design to date

There are several points of relevance for small, isolated power systems with high levels of variable renewable energy adapting to comply with EU market design rules.

One practical implication is the need for clarity and certainty in both the definition and application of market-based and non-market-based deviations from the market schedule. The experience to date suggests this clarity could be improved. In particular, it is important to maintain consistency in the treatment of redispatch decisions that reflect local rather than system-wide constraints, as discussed in the preceding section. If a market based dispatch is to be considered as such, it should be possible to link the definition and application of the redispatch to the market dispatch schedule itself. Similarly, if redispatch is required on the basis of a constraint that was not taken into account in determining the market dispatch, such as a local constraint, it is not consistent to consider this a market based redispatch, either in definition or application.

The international literature is quite clear that capacity markets are required as a result of market failures, specifically the lack of participation by the demand side in realtime dispatch and the inability of consumers to economically signal their desired level of reliability to the market. Variable RES-E, which has a low short-run marginal cost, has also contributed to the need for capacity revenues. Thus, a market that rewards technologies with a fixed and variable cost structure alike on the basis of variable prices that reflect short-run marginal costs has in part driven this market failure. However, EU market design legislation makes it clear that capacity markets are considered a subsidy rather than a correction of a market failure. The same dynamic may arise in designing future energy markets. In order to prevent this, market design principals should incorporate the importance of having remuneration reflect the wide range of cost structures, rather than having remuneration reflect short-run marginal cost only.

Market power dynamics that can arise as a result of a legacy monopolist rather than an oligopolistic structure are generally ignored in the EU's market design regulations. Market power arises both in energy and capacity markets, and as the energy market becomes less concentrated due to the addition of RES-E, the capacity market becomes more so. This is driven at least in part by the fact that RES-E is for the most part unable to participate in the capacity market, and certainly its participation to date has been low. This is not a market failure but rather is reflective of the difficulty in determining the ability of RES-E to contribute reliably to system adequacy. For example, Bothwell and Hobbs [36] find that applying various US definitions of capacity credit to the same wind and solar resource sees capacity credit awarded at anything from 11% to 33%, which shows that even with sophisticated power and capacity markets across the United States, the contribution of RES-E to system adequacy is not a settled question.

Given the ongoing level of market concentration in the SEM and the fact that RES-E can play little to no role in mitigating market power in the capacity market in particular, the continued reliance by EU policy makers on interconnection and coordinated market clearing to ensure competition is worrying. Future SEM designs should acknowledge this shortcoming and include market power mitigation measures at, rather than after, design phase.

The lack of market completeness in both space and time outlined by Newbery et al. [8], along with the positive outcomes from the international experience of increasing the spatial and temporal granularity of market dispatch, highlights two gaps in the EU market design. As long as temporal resolutions remain at hourly level, balancing market volumes and redispatch (both market based and non-market based) will increase as RES-E increases. Again, this applies particularly in the case of small, isolated power systems. As long as prices cover wide geographic areas, non-market based redispatch will increase, even with high levels of interconnection. A comparison of the marginal cost of increased interconnection with the net benefit of moving to greater spatial granularity of pricing should be considered in the context of EU market design.

3 Potential direction of key market metrics under the current SEM design at high levels of RES-E

In this section, we consider the likely trajectory of investment and operation in the SEM under the current market design, as variable RES-E rises to 70% and beyond. As outlined above, RES-E has very low or zero short-run marginal costs, which is not the case for conventional generation, and furthermore the demand for system services will increase in both quantity and complexity as RES-E increases. Both of these features mean that the SEM is moving into unknown territory at ever higher levels of RES-E, and therefore historical data to date is of limited utility in predicting future market trends and outcomes. However, some inferences can be made based on historical data as well as economic theory.

3.1 Revenue streams from energy, capacity and system services

As discussed earlier, revenues accrue to electricity generators from energy, capacity and ancillary services markets. These markets are linked both explicitly (e.g. via the design of Reliability Options) and implicitly (as generation firms bid into the various markets taking their total expected profits from all revenue sources into account). Thus, as prices in any one of these markets shifts, the final balance of revenues between the three sources of revenue in equilibrium will also shift.

The CEP and other EU market design documents foresee energy markets remaining the primary source of revenue for generators for the foreseeable future. Economic theory suggests, and empirical studies confirm, that variable RES-E with a short-run marginal cost of zero depresses energy prices [37–40]. This is known as the price cannibalisation effect. In a perfectly competitive market, generation firms' revenues will be sufficient to cover their costs without allowing for anti-competitive profits. Thus, under perfect competition, a reduction in revenues from energy markets will lead to an increase in revenues from capacity and system services markets, all else equal. This represents a shift of revenues away from an energy market with variable prices towards capacity and system services markets with fixed prices.

The current design of the capacity market is of particular relevance here. In order to ensure system adequacy, the capacity market must procure sufficient capacity to cover expected peak demand (plus a margin), and the design is such that participation from variable RES-E generators in the capacity market is negligible and likely to remain so. Thus, conventional generators, who are targeted to provide 30% of energy or less by 2030, must provide 100% of the capacity procured, and must cover their fixed costs while facing a de facto price cap in the energy market (due to the strike price nature of the reliability options design). This means such generators will require higher capacity revenues, leading to higher capacity clearing prices - prices that variable RES-E is unlikely to be able to avail of.

On average, energy prices faced by RES-E generators are likely to be depressed to a greater degree than those faced by conventional generators, as by definition they only earn revenue when renewable generation is positive [37]. It is important to note here that this is not a market failure but is a natural consequence of the characteristics of RES-E [41]. This, coupled with the lack of capacity revenues for

RES-E, means that under the current market design RES-E is likely to depend on the RESS support scheme, or successor schemes, for the vast majority of its revenues. This pushes the cost structure from the energy market to the public service obligation (PSO) in the absence of a market redesign.

For RES-E generators that no longer qualify for subsidy support, a reduction in energy prices and an inability to participate in capacity markets will lead to increased reliance on system services revenues, all else equal. Given the fixed nature of the cost base of RES-E, maintaining flexibility in the design of system services revenue streams may be advantageous, particularly if it allows RES-E generators to incorporate greater certainty into contracts for system service provision. Greater revenue certainty would in turn reduce risk for older RES-E generators. In the absence of revenue certainty, there is the potential for market exit by these projects, or RES-E generators may find themselves with a perverse incentive to repower their sites prematurely in order to qualify for entry to a new subsidy scheme. Long term power purchase agreements (PPA) with electricity supply companies is an alternative option for older RES-E projects. In this case, the strike price for such PPAs will in general be bounded from above by the RESS price (plus some margin to allow for the costs of repowering). While any scheme that reduces variability in RES-E revenues can reduce the cost of capital for RES-E, and therefore can allow investment in low carbon technologies at the lowest possible cost, there are implications for consumers from moving from a variable to a fixed cost base of electricity provision. These implications will be discussed below.

In short, maintaining the current market design means RES-E is unlikely to earn sufficient revenue to cover its costs under a perfectly competitive market with inelastic demand due to the price cannibalisation effect. This necessitates a market redesign if long-run reliance of subsidisation of RES-E is to be avoided.

The question of revenue sufficiency has been raised many times in the literature, and the possibility of variation in the level of competition, demand side activity, interconnection levels, and market liquidity, particularly in forward markets, to address the issue have been proposed. We discuss the potential impact of these variables on the equilibrium levels of energy, capacity and system services revenues below.

3.1.1 Market power

In a scenario where firms exercise market power, market equilibria are less certain compared to the case of perfect competition. In general, firms that exercise market power in the energy market will bid higher prices, tempering the impacts of depressed energy prices discussed earlier. The possibility of some market power being efficient by allowing firms to recoup their fixed costs has been raised in the literature, but the most comprehensive examination of this issue to date finds that this is not a technology-neutral option [41]: renewable generators are unable to exploit this effect. Thus, market power in energy markets may not mitigate the price cannibalisation effect described above. While market power in capacity markets is less researched, an *ex ante* analysis of the SEM capacity market finds that strategic behaviour may lead to 40-100% higher procurement costs in the capacity market compared to a competitive baseline scenario [42]. New entry does not mitigate these effects.

Should market power increase equilibrium capacity prices in the SEM, this may shift the balance of revenues further away from the energy market and may even give generators an incentive to suppress energy prices to uncompetitively low levels, as the incumbents benefit from uncompetitive rents in the capacity market. However, this hypothesis is untested with no examination of the implications of market power in both energy and capacity markets available in the published literature to date.

In short, market power in either the energy or capacity markets is unlikely to overcome the price cannibalisation problem identified earlier. Given the costs to efficiency from market power, a new market structure should seek to address the price cannibalisation problem without exacerbating market power.

3.1.2 Demand side activity

Economic theory suggests that as prices in any market are depressed, demand will increase. *Ex ante* analyses that consider the role of demand response (DR) in electricity markets find that DR can change market equilibria in several markets, including reserve and capacity markets [43, 44]. While RES-E has reduced wholesale prices to date, it is naive to assume that this effect will continue uninterrupted *in extremis* to a scenario in which the price of electricity is zero for a high proportion of time as such a scenario ignores the potential for increased market participation by the demand side. It is certainly the case, however, that at present the demand side faces an inability to properly signal their desired level of reliability of electricity supply to the market [45], which represents a market failure. Thus new market design options should include facilitation of demand response as a means of addressing the price cannibalisation problem which arises in part due to this market failure.

The literature on the ability of demand response to depress prices is sparse, possibly because the endogeneity of demand and prices renders this a difficult problem to analyse empirically. Several *ex post* analyses of the impact of DR programmes in electricity markets exist, but focus for the most part on the impact of DR on investment rather than prices - see for example [46–48].

There is therefore insufficient evidence to determine the likely future ability of the demand side to mitigate the depression of energy prices at high levels of variable RES-E. Sufficiently deep and liquid forward markets can assist the demand side in influencing energy prices. However, even across Europe, forward markets cannot be considered complete either in time or space [8], and forward markets in Ireland have been particularly illiquid compared to other European markets [25]. This exacerbates the scenarios outlined above: revenues will shift from variable to fixed markets more than is economically desirable, and the balance of revenues between energy, capacity and system services will not be efficient.

3.1.3 Interconnection

Given the lack of the demand side integration, increased flexibility on the supply side is particularly important to allow prices to adjust in real-time and avoid unsustainable low energy prices. As discussed above, the CEP envisages greatly increased interconnection as the main mechanism of ensuring supply side flexibility. This will allow power to flow from high-priced to low-priced areas and encourage price harmonisation. In the absence of any physical or technical constraints, the wholesale price in each price zone will be determined by the marginal cost of meeting electricity supply in each zone, which would include an adjustment for losses if the marginal generator is located in another node. This means equilibrium prices in areas of excess supply will be higher than they would be in the absence of interconnection, as excess supply can be exported to a more expensive region. Thus wholesale markets themselves can provide revenue adequacy provided fixed and non-linear costs are sufficiently low.

However, as discussed above, increased interconnection is unlikely to prove sufficient to overcome these market failures in the context of a small isolated power system such as the SEM, particularly at the very high levels of RES-E envisaged, as fixed and non-linear costs account for a higher proportion of total costs and interconnection levels are insufficient. Storage and/or transmission can play a role as other sources of supply-side flexibility, with recent planning studies suggesting that these are complementary [49]. However, even if these supply side flexibility mechanisms are sufficient to counter the depression of energy prices, they would shift the cost base of the power system from a variable to a fixed basis. In general, with high levels of variable RES-E, the greater share of generators' revenues will shift from energy to capacity and system services markets. Increased demand response, supply side flexibility, or market power are unlikely to fully mitigate this effect. Therefore a new market design that addresses the problem of price cannibalisation is likely to prove necessary if renewable generators are to recoup their fixed costs without ongoing reliance on subsidisation.

3.1.4 Consumer impacts

The primary implication for consumers of a move from variable to fixed revenues is a decline in the variable tariff and an increase in the fixed components of their electricity bill, including the PSO portion. It is widely recognised that such a change will be regressive, as less affluent households spend a higher proportion of their income on electricity, and so moving tariffs from a variable to a fixed basis disproportionately impacts lower income households. In addition, a reduction in variable tariffs erodes incentives to invest in energy efficiency and micro-generation, by both households and businesses. The payback time for low carbon technologies increases as variable tariffs decline. Electrification and efficiency are two key pillars of the Climate Action Plan, and the ability to meet these goals at ever-decreasing electricity tariffs is particularly challenging.

There are several other variables that can impact the final equilibrium values of various market metrics. In the following subsections, we trace out some potential impacts of several variables: negative pricing, increased interconnection, RESS designs and separately vs co-optimised energy and reserve markets.

3.2 Negative prices

The growth of negative prices in wholesale power markets across many jurisdictions is a reflection of the current transitional phase of power generation. Negative prices are an unintended consequence of

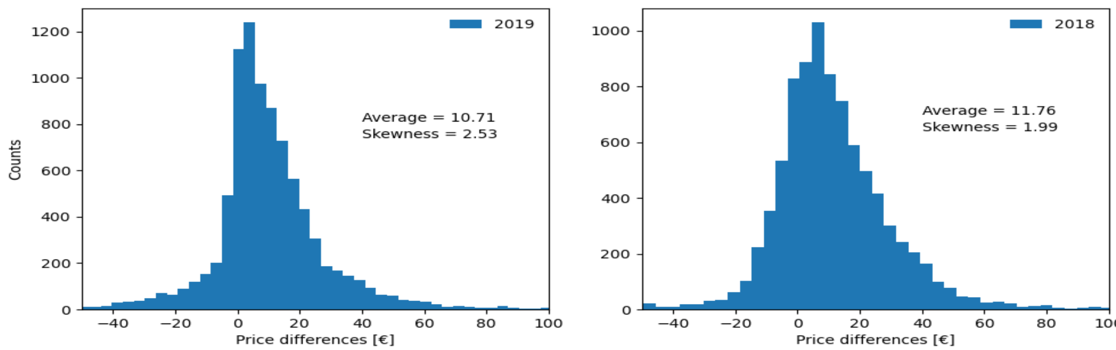

Figure 1: **Histograms of the 2019/18 Day-Ahead price difference between Ireland and France. Source ENTSO-E.**

renewable support policies; as a natural outcome of power systems that lack flexibility [50]; and as an economically efficient response to market dynamics. Negative pricing is a release valve within operational constraints of priority dispatch for renewable generation, an increasing share of variable renewable power, must-run conventional base-load plant, and low demand side participation among other things. Negative pricing also signals the difficulty of maintaining an energy-only market, particularly as variable RES-E increases. At least some of theses sources of negative pricing arise from the SNSP cap and so higher SNSP limits, eventually reaching 100%, could reduce negative pricing. Price floors have been implemented in some markets as a remedial measure [20, 51], and while potentially helpful in the near-term, price floors are not sustainable in the longer term. The market failure rather than the symptom needs attention. All elements of electricity services (energy, capacity, and system services) need to be adequately and efficiently remunerated to ensure financial sustainability plus signal investment opportunities.

Negative pricing that arises as a result of market signals is efficient, while negative pricing that arises as a result of the particulars of renewable subsidisation may not be. For this reason, in the SEM, RES-E is prohibited from negative bidding, in an attempt to preclude this inefficient source of negative prices. However this is not a good long term strategy. The ideal would be to design both subsidy mechanisms and market dispatch to remove incentives for inefficient negative pricing, and then to remove restrictions on negative bids by renewable (and indeed all) generators. This may not be feasible as long as limits on SNSP remain, but removing negative pricing limitations once SNSP limits are removed should be a long run goal of market designers.

3.3 Interconnection

The CEP envisages that greater levels of interconnection will facilitate improved flexibility across markets, seamless trading, and efficient dispatch across a wide geographical area. While this is undoubtedly true in general, interconnection is limited in its ability to address all the technical and market challenges unique to a small, isolated synchronous power system such as the SEM, as discussed earlier. Nonetheless, greater interconnector capacity is beneficial. For example, Di Cosmo et al. [29] show that the Celtic

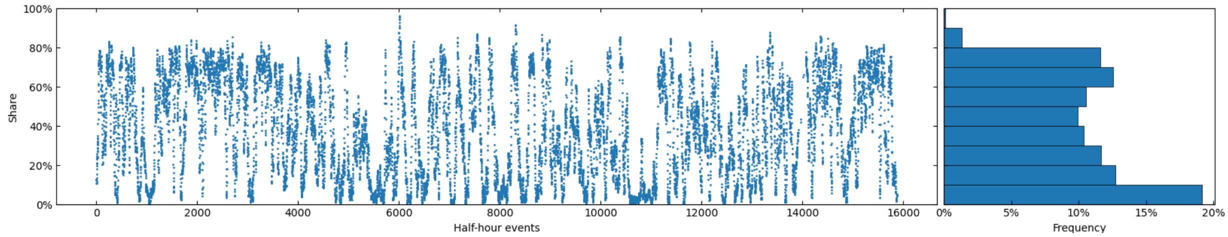

Figure 2: **2020 (Jan-Nov) half-hourly ratio of onshore wind power to demand. LHS: Plot of the onshore wind power to total demand. RHS: Normalized histogram of the events shown in the LHS scatter plot. Source ENTSO-E.**

Interconnector between France and Ireland will have positive impact on welfare in Ireland, though wholesale electricity prices will decline, as well as net revenues of thermal generators. The price differential between the French and Irish markets serves as an indicator of the case for the new infrastructure. The yearly average price differential threshold recommended for considering increasing the connectivity between two bidding zones is €2/MWh [52]. The average yearly price differential in between Ireland and France is close to €11/MWh, as illustrated in Figure 1 based on half-hourly day-ahead Irish-French price differences. Irish prices are higher than the French counterpart, presumably attributable to the large nuclear capacity in the French market. With decommissioning of nuclear reactors already underway [53] there is a future opportunity that net flows on the interconnector could comprise renewable generation from Ireland substituting decommissioned nuclear generation.

Interconnection, specifically AC interconnectors, should be carefully evaluated since in general they should alleviate congestion, in some instances loop flows could unintentional create bottlenecks between countries or regions [54]. In the I-SEM, loop flows are not a concern because existing and proposed interconnectors are HVDC links: the power electronics which control current flows impede unintended usage of the transmission capacity [55–57]. In spite of this, it is also noteworthy that though HVDC interconnectors may avoid loop flows, their use can facilitate other market inefficiencies [58].

3.4 RESS support scheme design

Renewable energy support schemes co-exist and influence the evolution of market outcomes and as such should not be viewed independently to the market. Support scheme designs should not only incentivise delivery of renewable electricity targets but also safeguard a competitive market at the lowest cost possible with sufficient flexibility to adapt to market and technology changes.

In 2012, the REFIT scheme was introduced in Ireland to achieve 40% electricity consumption from renewable sources by 2020. Fig. 2 shows the share of onshore wind power to demand. Almost half of the events registered in 2020 exceeded the 40% target. This evidence suggests that the schemes helped to meet the target at least half of the time. Despite this the current design of both RESS and the market provide little incentive for system optimal location of RES. Without such incentives there is an ongoing potential of developing far from demand centers leading to network congestion. This in turn would require additional transmission infrastructure than could have been avoided if RESS support also included location incentives. Supply-demand imbalances increase both price volatility and generator re-dispatch, while transmission expansion increases the fixed component of electricity costs.

While developing RES capacity is fundamental for achieving the 70% RES-E target, developing sufficient synchronous capacity is also important. Peak demand is estimated to be 20% higher in 2028 compared to 2019 [59]. Furthermore, demand in the Dublin region is anticipated to grow exponentially, largely due to data centres. If all current data centre applications connect to the network their load would be equivalent to 28% of the current all-island system peak demand [59]. In parallel with the RESS scheme for renewable capacity, consideration should be given to whether there is sufficient market certainty that suitable complementary capacity will be developed together with renewable sources to ensure system security. As noted above, the increase in renewable capacity under the present SEM design will depress market prices and increase price variability, which could lead to under investment. The lack of complementary products to RES could lead to a heavy reliance on a scarce and hence expensive balancing market. This underlines the requirement for robust system services markets. Insufficient incentives for system services products could mean more curtailment and out-of-market payments: a more expensive power system with greater market uncertainty.

3.5 Separate vs co-optimised markets

The power mix is still largely composed of synchronous generators that naturally provide enough inertia to autonomously dampen instantaneous load fluctuations. This provides a time buffer for the system operator to prepare other resources in the event that extra measures in addition to the system's inertia are needed. The absence of conventional generators creates a gap between a supply-demand mismatch event and the injection of secondary reserves. Moreover, increased uncertainty from the supply side exacerbates this situation. Thus phasing out incumbent technologies and increasing variability in the long-run will increase demand for reserves and could give place to missing reserves events. The missing reserves would lead to out-of-market actions to maintain the secure operation of the system, with increased curtailment and redispatch events. Both require uplift payments to cover start-up, ramping and curtailment costs, increasing costs for consumers.

Co-optimisation of energy and reserve markets is a potential option to reduce redispatch costs as the output takes into account the opportunity cost of system services. And prevents the need of hierarchical substitution actions. As demonstrated by the results of several market analysis studies, e.g., [60–64] co-optimisation of energy and reserves markets results in more competitive and efficient commitments and schedules, decreasing inconsistencies between market clearing schedules and physical dispatch.

EirGrid and SONI envision five alternatives for the procurement of system services [65]. At a high level the main difference among the five designs is the moment in time in which the procurement auction takes place. The reference auction is the day-ahead market, thus system services can be procured either before, after, through a hybrid approach or together. The after or ex-ante alternative is the one closest to current practices hence it is not surprising that is also the scheme more prone to out-of-market actions, shortages or infeasibilities in real time. On the other hand and despite the complexities, the co-optimization alternative is considered the best procurement option.

In addition to the alternatives outlined above evidence from real market simulations also suggest that the more timely procurement of system services can decrease production costs, congestion rents, services and energy prices while also improving the reliability of the system [66].

4 Options for the SEM design going forward

In light of the analysis above, we identify several general principles of good market design that a future electricity market with high levels of RES-E should follow. We then present various options and features of such a future electricity market, and analyse each option in light of the market design principles presented. Finally, we consider whether there are any low risk or zero risk options that are likely to improve market outcomes given the various uncertainties that exist.

4.1 Principles of good market design

We propose the following principles of market design that should be considered when designing markets for high levels of variable RES-E. Inclusion of any principles on the list is not implying that the principle has not underpinned previous market design, however, as market circumstances evolve and incremental policy or market mechanisms are implemented the extent of compliance with any principles may evolve. It is also the case that the full implementation of some principles is extremely challenging, if not practically infeasible in some instances. Nonetheless, market design consistent with these principles, in as far as is practically feasible, will lead to more efficient outcomes. The list itself is not exhaustive but is informed by electricity market design evolution to date.

1. Completeness across time, space, and externalities. This requires markets to have as high a spatial and temporal granularity as possible, without introducing other distortions (for example, market power). It also requires all externalities to be reflected in the market price. These externalities include not only the cost of carbon, but also whether a particular source of generation incurs extra costs or benefits on the system that fall on other producers and/or consumers (for example, flexibility or the ability to defer transmission investment).

2. Minimisation of cost. Electricity demand should be met at the lowest possible cost.

3. Minimisation of risk. Markets should be designed so as to remove as many sources of risk as possible and allow appropriate risk management for any remaining risk.

4. Allocation of risk to those best able to afford it. In the case of electricity, consumers are best able to bear risk, as they are far greater in number than producers, but the informational asymmetries between producers and consumers mean that strong regulation is required in order to ensure that producers manage their risk appropriately and do not simply shift all risk to consumers.

5. Compensation of fixed costs with fixed revenue streams and variable costs with variable revenue streams. Variable revenue streams in particular should be based on the marginal pricing principle.

6. Flexibility to respond to future events. Market design should recognise the considerable uncertainties that exist regarding future market outcomes and should be flexible to respond and evolve as necessary. Regular redesign of the market itself can lead to regulatory risk and so a design with inbuilt flexibility is preferable.

7. Co-optimisation of various objectives to arrive at a global least cost solution. Equilibrium solutions that simultaneously arrive at the optimal level of energy, capacity, transmission, system services and emissions where possible are preferable to a solution that determines the optimal level of each independently. This allows the optimal level of each to be reflected in market prices with minimum distortions.

4.2 Options for future market design

Given the principles above, the following is a set of options that may be considered for future market design. These options are not an exhaustive list, but rather a set of possible remedies for the challenges identified in Section 3. The general challenge is to ensure sufficient revenue for all generators while maintaining dispatch on the basis of short-run marginal cost, taking into consideration the implications of a natural shift from a power system dominated by variable costs to one dominated by fixed costs for consumers in particular. In particular, energy markets must:

- Provide a price signal for generators that can operate more flexibly, *ceteris paribus*.
- Guard against potential shortfalls in supply.
- Include market signals that can respond to excess supply.
- Incentivise efficient market participation by the demand side.

The above are not independent goals but interact with and reinforce each other. For example, a market that provides efficient price signals for flexible operation will naturally incentivise market participation from the demand side, which will in part manifest as a response to excess supply.

1. **Move to a higher frequency of market dispatch, e.g., fifteen minute or five minute dispatch** Higher frequency of dispatch would be valuable in day ahead, intraday and especially balancing markets. High resolution of dispatch in energy markets has been applied in some of the most sophisticated markets in the United States, with dispatch frequencies as high as every five minutes [8].

Higher frequency of dispatch mitigates the potential source of inefficiencies arising from the mismatch in the balancing market between the dispatch and settlement periods. As it stands the imbalance settlement price is the average of 6 consecutive 5 minute dispatch periods. This gap can be exploited by bid gaming, in particular by large and peak generators, strategically withholding capacity in a single 5 minute settlement period to manipulate the average settlement price. The strategic bidder would still receive a payment for the energy supplied in the early periods albeit withholding capacity late in the half-hour. Aligning dispatch and settlement could incentivise flexible loads and fast response power sources and hence variable generation.

This market redesign option has several attractive features. It moves towards the principle of market completeness across time, allowing generators to naturally address the imbalances between supply and demand that arise on a sub-hourly basis. It also gives more opportunity to flexible generators and other market players such as interconnectors and storage operators: generators that can adjust their output at higher time frequencies have an advantage over generators that require more time to adjust their output. This increases the ability of the market itself to award flexibility and reduces the requirement for out-of-market mechanisms to provide investment signals for more flexible operation. More frequent dispatch would also address the price cannibalisation problem to some degree by allowing higher prices for shorter periods of time, set by units with higher short-run marginal costs but faster response times. In contrast, dispatching over longer time periods, such as an hour, allows units with lower marginal costs and longer response times more opportunities to set the market price. Borggrefe and Neuhoff [67] discusses this phenomenon in more detail.

2. **Allow explicit compensation for flexibility**

   While a move to a higher frequency of dispatch will go some way towards compensating flexibility within the market, only a move towards continuous realtime dispatch will allow full completeness of energy markets across time. Under existing or lower levels of RES-E, variation in demand and supply is low enough that the flexibility required can be incentivised without continuously adjusting quantities and prices. However, at high levels of RES-E, explicit compensation for flexibility may be required in addition to a higher frequency of energy market dispatch.

   Explicit compensation of flexibility can be conceptualised as solving a market failure in a similar manner to capacity markets. The capacity market solves the market failure of the “missing money" problem that manifests at high net demand hours, where there is insufficient remuneration of peaking plant and therefore a potential capacity shortfall. A similar mechanism would address analogous problems that manifest at hours of low or negative net demand, where there is arguably insufficient remuneration of demand flexibility which in turn leads to excess supply.

   It is during these low net-demand hours where the price cannibalisation problem manifests, eroding prices for all generators but for RES-E generators in particular. A more flexible power system, that can shift supply away from and demand towards such hours, will see fewer of these events, along with fewer low and high price events. This respects the principle of market completeness by ensuring the demand side becomes a more active participant in the market. It also provides a potential revenue stream for storage operators. Battery storage in particular does not have a sufficiently strong business case based on arbitrage revenues alone [8].

There are several ways in which a specific flexibility payment could be implemented. One option is to monitor the outcome of capacity markets in terms of the flexibility of the final portfolio procured, according to some objective predetermined metric, such as Insufficient Ramping Resource Expectation (IRRE) proposed by Lannoye et al. [68]. The flexibility of the portfolio as determined by the capacity market outcomes could then be used to determine whether additional sources of flexibility need to be procured, via the system services market and/or an explicit flexibility procurement mechanism such as an auction.

Another option that can be pursued instead of or as well as a (direct or indirect) flexibility procurement mechanism is to hold an explicit auction for “demand", analogous to the Reliability Options auction. In this auction, players on the demand side bid for the right to have guaranteed supply at a predetermined price. The auction would reveal the market clearing price for this guarantee, which in practice reveals the value placed on secure supply by allocating supply to the player(s) who most value(s) it. This in turn reduces investment risk and directly addresses the price-cannibalisation problem by efficiently allocating demand during periods of over-supply.

An alternative option to the auction proposed above is the proposal by Helm [69] of auctions for equivalent firm power (EFP). This essentially envisages replacing both capacity markets and renewable subsidisation with a mechanism in which variable renewable generators bundle with conventional generators and/or storage operators and compete to hold contracts to provide EFP. Thus, this proposal combines the capacity market, which addresses the problem of shortfalls in supply, with a second mechanism which addresses the challenges of funding renewable investment due to low prices that arise from shortfalls in demand.

The benefits of this proposal are a simplification of the market by reducing the number of compensation mechanisms, providing more certainty for generators and providing a potential revenue stream for older RES operators that no longer qualify for explicit subsidy payments. However, this proposal may also lock generators into inefficient bundles, reducing the potential for innovation, and it is also likely that variable renewable generators bundled with conventional generators or storage cannot compete with unbundled conventional generators that can offer EFP in their own right.

3. **Split markets at wholesale and retail level to allow consumers to choose between conventional and renewable generation.** A more radical market redesign option is outlined by Keay et al. [70], who propose that electricity markets be split into an “on demand" market for dispatchable generation, and an “as available" market for renewable generation. The former clears in a manner

similar to the current wholesale market, and provides price signals for demand response, as well as interconnector and storage operation. The latter clears according to long run contracts determined by auctions, either via a subsidisation scheme such as the RESS scheme, or through purely market-based auctions. Thus the problem of scheduling markets according to short-run marginal cost while providing sufficient revenue to ensure renewable investment is circumvented by simply splitting the market into two separate markets. One clears according to short-run marginal cost, and the other clears according to fixed price auctions that cover fixed costs.

This proposal hinges on the active involvement of the consumer in choosing between sourcing electricity from the dispatchable market, the renewable market, or a combination of the two. In this manner, the consumer can directly reveal their preference for a secure electricity supply. As a further benefit, this reduces the requirement for using metrics such as VOLL to determine conventional capacity targets, as the market-clearing price in the “on demand" market incorporates the value the consumer places on certainty. The difficulties associated with a shift towards service-type contracts, discussed below, are also diminished, as availability in the “as available" market and scarcity pricing in the “on demand" market provide incentives for demand response.

This proposal directly addresses several of the challenges identified in Section 3 above. Demand response is directly facilitated, by having consumers themselves split their demand into a completely elastic portion, that uses energy only when available, and a (relatively) inelastic portion, that uses energy on demand. The price cannibalisation problem is also directly addressed, by separating generation technologies into two separate markets based on their cost bases. Renewable generation no longer operates in a market that clears on the basis of short-run marginal cost, and so the “on demand" market provides price signals that support efficient investment in generation that is available at (almost) all times. Furthermore, renewable generators may participate in the “on demand" market via a mechanism such as the EFP described above, if it proves efficient for them to contract with another generator such that their expected output is sufficiently reliable. This option is therefore complementary to the EFP option.

This proposal has many attractive features on a theoretical level, but would require a radical shift at national and EU level. Furthermore, there is a high degree of uncertainty associated with this proposal as the true shape of the electricity demand curve is currently unknown. The proposal in its current form is qualitative only. There are also equity considerations, where lower income households cannot afford the scarcity prices that arise in the “on demand" market and may have to opt for the “as available" market. This would essentially split the market according to those who can and cannot afford the cost of a secure electricity supply. Substantial further research is necessary to investigate the feasibility of this option in the long run.

4. **Switch RES subsidisation from an energy to a capacity basis**

At present, RES auctions are held on the basis of a price per unit of energy produced. Compensating RES-E on the basis of capacity aligns RES's compensation with its cost structure, respecting the principle of providing fixed compensation for fixed costs, and reduces risk for both producer and consumer. One variant used in China is to support RES on the basis of MWh/MW [71]. This equates to a capacity subsidy, but allows the RES operator to continue to participate in the spot market. In other words, this achieves the goal of maintaining efficient realtime dispatch, whilst providing a stable revenue for RES-E investment.

The design outlined above would continue to incentivise RES generators to locate in areas with a high RES capacity factor. The auction-based format of RESS could be maintained whereby generators compete for a subsidy payment per MW for a given number of MWh/MW. Compensating on this basis also removes the incentive to submit negative energy bids and so any negative bidding is more likely to be driven by market conditions, and so to be efficient. This respects the principle of completeness of markets as the prices reflect true market conditions rather than distortions arising from a subsidy scheme.

The benefits of moving RES remuneration from an energy to a capacity basis hold whether the remuneration is via a subsidisation scheme, such as the RESS scheme, or via purely market-based mechanisms. For example, the option of EFP contracts described above could be designed with the renewable component being compensated on the basis of capacity rather than energy. Alternatively, compensating renewable generators on the basis of capacity rather than energy ties in well with the option to split the market into “as available" and “on demand" markets described above. The renewable generators that operate in the “as available" market would be best compensated via long run contracts determined by their capacity. Remuneration, and therefore consumer charges, for the “as available" portion of energy would thus be largely fixed, while those of the “on demand" segment would be variable, reflecting the cost bases of the technologies.

Any move towards compensating RES on the basis of capacity rather than energy output would be best achieved in tandem with a policy shift from setting RES targets in capacity rather than energy terms. However the benefits of compensating on the basis of capacity should be explored independent of a corresponding policy shift.

5. **Co-optimisation of system services procurement with energy and/or capacity procurement**

   The provision of system services can impact on both investment and operational decisions by generators, and the revenue earned in various markets will also impact on generators' decisions in each market. Ideally, therefore, all three services would be procured using one joint mechanism. In practice, one option for facilitating a move towards the co-optimisation of energy, capacity and system services is for the TSO to facilitate generators in submitting combined bids for capacity and system services, possibly along with a separate (mutually exclusive) bid solely for capacity provision and/or separate participation in system services markets. The TSO could therefore jointly procure capacity and the provision of a specific system service or service(s) where possible, providing a more transparent set of prices that reflect not only the capacity but also the capability of generators. This option is therefore similar to the proposal to monitor the outcome of the capacity market and to contract for system services on the basis of the difference between the capability of the capacity fleet to provide the required level of system services and the required levels, as determined by the System Operator according to some objective criteria.

This joint procurement of capacity and system services amounts to rewarding not only quantities but also capabilities of generation capacity.[1] This allows all generators to compete on the basis of the full set of services they offer to the power system, rather than competing separately on the basis of energy, capacity and service provision. As this option is untested, extensive prior research and testing is necessary.

Any future market design is likely to include system service procurement in addition to energy and/or capacity procurement, and so this option should be considered as complementary to the options outlined above.

6. **Determine capacity requirement on the basis of improved risk criteria**

   In the presence of high levels of variable generation, the new market design should enhance current risk assessment criteria. This supports the principle of minimisation of risk. Presently risk is measured through the Loss of Load Expectation (LOLE) and the Value of Lost Load (VOLL). Until now, in a system composed primarily of synchronous generators that provide enough inertia for fast primary response, planning only for the risk of forced outages was sufficient. But missing inertia and uncertainty in generation makes risk handling more complex. Fast ramping capacity, either up or down, will become crucial in the 2030 power grid. In a power system dominated by RES more sources of uncertainty will play a significant role. To keep the system reliable, avoiding extreme and undesirable events, market design and planning must take into account both risk and uncertainty in all its forms.

   One way to maintain safe operation of the grid is by introducing new quantifiers of uncertainty into capacity markets. The theoretical evaluation of this is outlined by Zachary et al. [73]. The IRRE mentioned above is one possible metric that could be employed. In a similar way to the LOLE, the IRRE quantifies the probability of inadequate capacity to quickly respond to load fluctuation.

   This option should be considered wherever risk metrics feature in the future market, e.g. in any future capacity market. While some of the options outlined above allow the value of secure supply to be determined as a market outcome (specifically the option for contracting for secure supply, and the option to split the market into an “on demand" and an “as available" market), a role for

[1] One could argue that there is already an implicit reward for capability, as more flexible generators are better able to respond to market conditions, and therefore can submit more competitive bids in energy and/or capacity markets. However flexible operation is not fully compensated in existing markets due to the various market failures explored above. See also Lynch et al. [72].

risk metrics in monitoring the system, at a minimum, will remain. These risk metrics should be improved as the literature in this area continues to develop.

7. **Move away from volumetric charges for electricity generation and towards fixed or service type retail contracts**

   Finally, one major prediction of Section 3 is that the cost base of the power system will move from one dominated by variable costs to one dominated by fixed costs. A natural consequence of this is a shift at the consumer level away from volumetric charges and towards fixed retail charges. Such a move respects the principle of compensating fixed costs with fixed revenues, and helps provide certainty for energy companies and reduce risk.

   Under this proposal, instead of paying per unit of electricity, consumers instead pay for electricity as a service, similar to the types of contracts available in the communications sector. Risk-averse consumers benefit from certainty in their energy bills. Various options for implementing this proposal are outlined by Lo et al. [74].

   The major downside of this option is that it may undermine energy efficiency incentives and policy. Even in a future zero carbon power system, where energy efficiency measures have no climate impact, excess demand is suboptimal as it leads to over-investment in generation and grid capacity, which is inefficient. Fixed or service-type retail contracts are also regressive, with less affluent households paying a higher proportion of their income on electricity than more affluent households. A strong regulatory response would be required to protect vulnerable consumers, and new mechanisms to incentivise energy efficiency would also be required.

Table 1 presents a high level summary of these options.

4.3 Additional considerations and remarks

There are considerable uncertainties associated with many of the options above, particularly those that are untested or indeed unresearched. However a move to a greater temporal granularity of markets lends itself well to RES integration and has been successfully implemented in other markets, particularly in North America, and so this option should be considered strongly.

Irrespective of any changes to market design, as outlined in Section 3, increased RES-E will push the cost structure of the power system from variable to fixed. Two of the market design options may naturally arise as a consequence of this shift; namely a move to RES compensation on the basis of capacity rather than energy (at least for RES projects that do not fall under a subsidisation scheme) and a move from volumetric to fixed retail charges. Indeed, a shift to RES compensation by capacity bolsters the case for moving retail contracts from volumetric to fixed. Such a move is, however, known to be regressive, impacting disproportionately on less affluent households [75]. Policy makers and regulators should therefore conduct an analysis on the impacts of this shift, and how best to protect vulnerable consumers.

Design	Principles	Benefits	Challenges
1	1,3,6	Facilitates variable nature of RES-E. Reduces requirement for out-of-market settlement.	Implementation costs. Increased market power.
2a (auction for price guaranteed energy)	1,3,4,5	Addresses price cannibalisation. Provides price signal.	Untested. Auction Design.
2b (monitor flexibility of CM outcome)	2,3,5	Ensures sufficient capability as well as capacity of generation fleet	Metric design. Transition from flexibility requirement to procurement.
2c (contracts for equivalent firm power)	2,3,4,5,7	Simplified market design. New opportunities for storage	Untested. Lack of flexibility. Locking into suboptimal bundles. Market power.
3	1,3,4,5	More marketable products.	Untested. Requires policy shift. Cross border trading.
4	3,4,5	Removes price cannibalisation Reveals consumer demand for reliability	Requires policy shift. Splits market between energy and capacity based RES projects (in the short to medium term).
5	1,3,5,7	Less re-dispatch and out-of-market actions	Untested. Finding equilibrium solution.
6	1,3,7	Increase the scheduling robustness.	Untested. Designing risk metrics. Increased role for TSO in market/auction.
7	3,4,5	Simplified design Provides certainty for consumers	Erosion of smart contracts and energy efficiency. Distributional issues.

Table 1: Summary of market design options

There may be an argument for specific regulation of the fixed and variable portions of consumers' bills, particularly given the move towards time of use pricing and other smart contracts via smart meters.

Given these considerations, a full analysis of the distributional impacts of likely future market shifts, irrespective of any changes to market design, should be undertaken. Ireland has enjoyed limited public opposition to RES subsidisation (by means of the PSO levy) to date; however this may not remain the case and so an examination of the equity implications of high levels of RES-E under both current and potential future market outcomes is advised. It is also recommended that a distributional analysis of any market design options be included as a matter of course at design stage. Furthermore, the equilibrium effects of any proposed countermeasures to mitigate regressive or other undesirable impacts should be considered.

Many of the market changes recommended here would reduce the risks faced by RES-E generators. The form of the current RESS also goes some way to derisking RES-E investment, via a Contracts for Differences structure. It is important that policy remain supportive of these derisking opportunities. Increased temporal granularity of dispatch also provides RES-E with increased opportunity to manage risk. Further specific risks faced by renewable generators can be managed, as argued by Newbery et al. [8], provided the underlying market structure is supportive of risk management. However the costs of risk management are likely to prove higher for RES-E operators, relative to their power output, than their conventional counterparts, which in practice means RES-E faces higher transaction costs. System operators and market designers should therefore ensure that, whatever the final market design, aggregators can operate in the market, both on the demand side and the supply side, allowing RES generators in particular to benefit from diversification and providing them with an additional means of risk management.

While market redesign is likely to be required to fully address the challenges of high RES-E outlined in this paper, system operators must continue to minimise redispatch to the greatest extent possible. This will inevitably require new investment in non-energy infrastructure within the SEM. For example, the construction of the North-South interconnector will facilitate the integration of variable renewable energy and improve system reliability [76]. Infrastructural developments that facilitate more flexible operation of the generation assets on the system will influence the optimal market design in various ways. One possibility is that the advantages of moving towards a higher dispatch frequency may be rendered more efficient by increased infrastructural investment, as the former facilitates and the latter incentivises flexible operation of supply and demand. Another example of the interaction between market redesign and optimal infrastructure development is discussed by Newbery et al. [8], where moving RES remuneration to a MWh/MW basis improves incentives for RES generators to locate in areas with stronger transmission infrastructure, rather than purely locating in the areas with the greatest renewable resource. Furthermore, the appropriate level of infrastructure development can change the calculus of system service provision, which in turn impacts on the incentive for generators to provide not only system services but also energy and capacity. Thus the evolution of market design must be considered in conjunction with the likely evolution of system infrastructure.

Market design should also be cognisant of regulatory risk in neighbouring jurisdictions, as this has implications for market outcomes in the SEM. For example, the “6+ hour negative price event" provision in BETTA can distort outcomes in the SEM.

4.4 Recommendations

While many of the options above feature uncertainty and require further exploration, there are some low- or no-risk actions that can be taken in the short term. Market Design Option 1, for example, is a low-risk option that has been successfully implemented in other markets and brings benefits for all market players with little implementation cost. Increasing the frequency of dispatch should therefore be seriously considered by regulators of the SEM.

Further research on several of the market design options outlined above should be conducted. In particular, market instruments that address the price cannibalisation problem should be examined in advance. One example is Option 2 above, which is in many ways analogous to the Reliability Options capacity market design.

Finally the extent to which supply companies may be incentivised to switch from a variable to a fixed billing structure should be examined as soon as possible. The implications for wider energy and climate policy, particularly energy efficiency, should be identified, and the distributional implications should be determined. These analyses can inform appropriate policies that can be designed before these potential difficulties present themselves.

5 Conclusion

Over the past 25 years electricity markets around the world have evolved immeasurably, moving from markets with vertically integrated monopolies based on thermal generation to competitive markets with independent operators responsible for generation, transmission, and retail with growing shares of renewable sourced generation. Over the next 25 years the transition is likely to be equally as dramatic. Climate policy is driving ambition to decarbonise power generation. Ireland is among the most ambitious with policy targets for renewable generation growing from 36% in 2019 to 70% by 2030. There is also the ambition to achieve a real time operational limit of over 90% System Non-Synchronous Penetration (SNSP) by 2030. Existing electricity market designs are already struggling with the evolving circumstances within electricity markets. Capacity markets have been introduced to address the “missing money" market failure that manifests at high net demand hours, where there is insufficient remuneration of peaking plant and therefore a potential capacity shortfall. In addition, markets for system services and flexibility are also being introduced across various power systems to cope with real-time generation variability and guarantee the reliability of the network.

Furthermore, unintentionally the low short-run marginal costs of renewable sources has created a “price cannibalisation” in the power sector. In spite of this, the depressing of electricity prices has thus far been relatively modest, largely because fossil fuel technologies still dominate in the current power system mix. However, in the longer term when the share of renewable technologies is to be vastly greater than today the financial sustainability of investment will be questionable. With the passage of time the growth in renewable generation will push the cost structure of the power system from variable to fixed, while existing market design largely relies on a variable energy market to remunerate investment in and operation of the power system. The case for redesign of the electricity markets is already apparent and in time will become more acute.

The power system is complex and there is no “off the shelf" solution for a market design that will deliver efficient outcomes in terms of operational management and investment in the power system. The current paper has identified some of the challenges facing power systems with growing shares of renewable generation, including some issues that can arise on small, isolated power systems such as the SEM, which recent EU legislation on electricity market design has little cognisance. Seven key principles are outlined for the design of electricity markets, accommodating high levels of RES-E and minimising non-market redispatch. Several options for future market design are also outlined, some of which are mutually complementary. All options represent substantial change from current market design and necessitate comprehensive examination, research, and design prior to implementation to minimise unintended outcomes. The nature of the marketplace is already evolving, for example, increasing levels of fixed versus variable costs on electricity bills. It is imperative that market redesign anticipates the evolving circumstances and establishes a framework for an efficient and equitable marketplace.

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