INFORMING THE REMA DEBATE

International Learnings on Investment Support for Clean Electricity

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Energy Systems Catapult was set up to accelerate the transformation of the UK's energy system and ensure UK businesses and consumers capture the opportunities of clean growth. We are an independent, not-for-profit centre of excellence that bridges the gap between industry, government, academia and research. We take a whole system view of the energy sector, helping us to identify and address innovation priorities and market barriers to decarbonise the energy system at least cost.

1. EXECUTIVE SUMMARY

The British government has set an ambition of a fully decarbonised electricity system by 2035. Such a system would rely primarily on renewable generation technologies – wind and solar – whose output cannot be controlled in the way fossil-fuelled generation has been. To keep the costs of such a system manageable and avoid unacceptable supply interruptions, responsiveness or 'flexibility' needs to come from dedicated assets (storage) and demand response. The Review of Electricity Market Arrangements (REMA) presents an important opportunity to design a system that supports large volumes of both renewable generation and flexibility in mutually supportive ways.

To date, debate around the REMA consultation and related work on energy market reforms[1] has tended to present a conflict between investment in renewable generation and investment in flexibility. Proponents of the former favour keeping market arrangements broadly unchanged, particularly with regard to renewables' exposure to price signals. Proponents of the latter favour the introduction of sharper price signals in time and space. This short report seeks to bridge the gap between these two extreme positions by drawing on insights from international markets.

We reviewed the evidence from markets across the US and in New Zealand that use locational marginal pricing (LMP), as well as European markets that use zonal pricing. While no electricity system can be said to have fully solved the challenge of how to integrate high volumes of intermittent renewables, we make general observations that are relevant to the GB debate.

First, **LMP is not an obstacle to large-scale investment in renewable generation**. US markets vary considerably in the strength of decarbonisation policy drivers, but have generally seen high levels of investment in renewables – for example, New York and California have seen 2.2GW and 3.5GW of wind capacity, respectively, have come online since those markets introduced LMP.[2] US markets have adopted different structural approaches to incentivising investment in clean energy with no equivalent of the centralised procurement approach to those observed in the UK and across Europe. Investment in renewables in those US markets has tended to rely on tradeable renewable energy certificates to place a value on environmental attributes. There are also examples of merchant renewables investment and ongoing development of contracting and hedging approaches. This highlights the importance of designing support schemes for renewables that work together with the underlying market design (e.g. LMP in the wholesale market) but do not distort the underlying price signals.

We were not able to find conclusive evidence that sharper price signals in LMP markets increased the cost of capital for generators, despite some commentators making that link. Establishing causality is difficult because of the differences across jurisdictions in macroeconomic conditions, decarbonisation policies and supporting policies for renewable generation. Renewable generators' exposure to sharper price signals could also be diversified (for example, by investing in or contracting with flexibility) or managed through the design of support schemes.

Second, **the GB electricity market could benefit from a different technology mix that would emerge under LMP markets**. For example, US markets with LMP have typically seen more deployment of storage than European markets with zonal or uniform prices. This observation cannot be attributed entirely to nodal price signals – mandates on storage deployment (in California) and overlays such as a capacity market (in PJM) likely played a role. Nevertheless,

[1] Including Ofgem's review of locational price signals; National Grid ESO's Net Zero Market Reform programme, and Energy System Catapult's Rethinking Electricity Markets.

[2] California has also seen a huge investment of 14GW in solar PV over the same time period.

storage is disproportionately located in US markets that use LMP:[3] despite only making up 58% of grid capacity in the US, those markets make up 74% of large-scale battery storage power capacity (GW) and 72% of energy capacity (GWh). There is also emerging evidence from US markets of storage being co-located with renewable generation – allowing intermittent renewables to behave like price-responsive assets in LMP.

Third, **the regulatory model that governs the recovery of network investment in GB seems to have a better record of supporting investment in grid** capacity than a number of the international jurisdictions we have reviewed. While recognising that there is room for improvement in the GB regulatory model (RIIO) to enable the volume of network investment that is required,[4] the lesson here is that reform should focus on the areas where we could best learn from what has worked internationally while retaining what has worked best about the current approach in GB.

Overall, we find that Britain does not need to choose between a market that works for investors in renewables and a market that works for investors in flexibility – both can be successfully accommodated by learning from international experience.

[3] Those markets are overseen by independent system operators (ISOs) or regional transmission organizations (RTOs).
[4] National Grid ESO's Holistic Network Design projects annual transmission reinforcement of £12bn, compared to an average of around £1bn per annum across the RIIO-1 (2013/14-2020/21) period.

2. CONTEXT

The UK has committed to a hugely ambitious target of fully decarbonising the electricity sector by 2035. Huge progress has been made with investment in renewable generation, but there is a growing awareness of the need to think afresh about the policy framework to deliver 2035 target.[5] Broadly, the debate covers:

- **What role, if any, should LMP have in the design of the wholesale electricity market**. LMP is intended to provide stronger locational signals for real time operation of grid-connected resources, as well as stronger locational signals for siting decisions of investment in grid-connected resources.
- **What additional mechanisms would best complement the design of the wholesale market to create a framework that enables a smart, flexible electricity system.** This began with a specific emphasis on enabling greater flexibility, but has since extended into a consideration of whether the contracting mechanisms designed to support investment in generation[6] are capable of bringing forward a cost-efficient mix of resources for a net zero system by 2035.

This debate is currently playing out in the REMA process that is being undertaken by BEIS. REMA aims to inform the market framework that would facilitate the achievement of the 2035 target.

It is crucial that a joined up approach is taken to develop thinking on market reform. There are interactions between price signals in spot markets and longer run decision making around investments in resources that have attributes (in terms of ability to deliver or regulate the flow of electrons in time and space) that are valuable to the system. These are also linked to questions around how to make decisions about major investments in electricity grid infrastructure.

Markets around the world are adapted to their particular challenges and circumstances. There is no objective ‘global leader’ in electricity market and policy design for a net zero electricity system. Nevertheless, the UK has a chance to learn from experience of other jurisdictions.

The aim of this paper is to draw on international experience, and to summarise what can be drawn from the evidence around the performance of different market designs and policy interventions in enabling investment in clean electricity – specifically:

- low carbon generation;
- storage and flexible resources; and
- grid investment.

In particular the paper considers the experience of markets which have either:[7]

- implemented much stronger price signals through LMP;[8]
- adopted more demand-led approaches to incentivising the decarbonisation of the generation mix; or
- both.

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[5] Energy Systems Catapult (2021) Rethinking Electricity Markets – The case for EMR 2.0

[6] The capacity mechanism intended to support security of supply, and contracts for difference intended to support decarbonisation of generation capacity.

[7] We also reviewed the experience of other European markets where zonal pricing has been implemented, while recognising the very different resource endowments and ownership configurations of many of these markets compared with the UK (e.g. NordPool in Scandinavia).

[8] LMP has been successfully implemented across most of North America, including planned implementation in Ontario. New Zealand was also an early adopter of this market design.

3. INVESTMENT SIGNALS FOR CLEAN ENERGY

Wholesale market design – and the price signals that provides to generators, flexibility providers and other market participants – forms the foundation of a market framework. There is extensive literature on the relative merits of uniform, zonal and nodal (LMP) pricing,[9] which we do not revisit in this note. Instead, we think it is useful to start by characterising the different types of policy interventions that supplement the wholesale market to achieve particular outcomes – security of supply, decarbonisation of generation capacity, etc.

3.1. Theoretical background

Proponents of energy-only markets have long argued that free operation of markets can provide the investment signals that would be sufficient on their own to encourage investment in generation capacity. For example, high price periods are seen as a necessary market condition to remunerate flexible generation that needs to be available at times of system stress.

The alternative view has been that specific mechanisms need to be in place to reward capacity / resource adequacy. These views are informed by the idea that prices in energy-only markets would need to rise to politically unacceptable level in order to sufficiently reward flexible capacity.

It is now conventional across nearly all energy markets in developed countries to have in place some form of explicit means of remunerating capacity, although there are varied designs in play. Some are effectively long-term contracts with a central authority, and some are conceived as purchasing/contracting obligations or requirements imposed on market players.

From a decarbonisation perspective, a similar debate exists about the role of market signals in driving a fully decarbonised generation mix. On one side is the assumption that carbon pricing could be sufficient to incentivise decarbonisation of the electricity mix. On the other side is a concern of diminishing returns from incremental carbon price increases as the carbon intensity of the power mix declines – i.e. the carbon price may have increasingly limited influence on the merit order.[10]

3.2. Characterising the types of investment signals

The mechanisms used to achieve system policy outcomes such as security of supply and decarbonisation of the generation mix fall into two broad categories:

- **Centralised contracting:** mechanisms that "overlay" wholesale electricity markets to provide either additional or stabilised revenues to support investment. Targeted at the inputs (e.g. amount of flexible firm capacity on the system; investment in new zero carbon generation capacity).
- **Outcome based purchasing requirements:** mechanisms that are designed to "modify" the demand functions of players in wholesale electricity markets, such that they value certain attributes (e.g. a target level of reliability; the emissions intensity of their contracted generation mix) in their purchasing.

There have been different ways of distinguishing between those two categories of mechanisms, as summarised in the figure below.

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[9] See, for example: FTI Consulting (2022), Net Zero Market Reform: Phase 3, Assessment of market design options

[10] Energy Systems Catapult (2021) Rethinking Electricity Markets – The case for EMR 2.0, Annex 5

Figure 1: Mechanisms for supporting investment in clean energy

	Nature of support provided	How is cost efficiency sought?	Examples
Centralised contracting	'Supply push' – investment support for key technologies judged to be required for a decarbonised electricity system	'Competition *for* the market' - project developers compete for access to long term investment support contracts for defined technology categories	• Capacity Market (GB, Belgium) • Strategic Reserve (Germany; Sweden) • Contracts for Difference / Feed-in-Premium (GB, Italy, Spain)
Outcome based purchasing requirement	'Demand pull' – leaves the responsibility for contracting with the purchasers of electricity	'Competition *in* the market' - market players compete for revenues in wholesale markets on the basis of the combination of technology cost and performance characteristics, including their carbon content	• Capacity Obligation Mechanism (France) • Retailer Reliability Obligation (Australia National Electricity Market) • Renewables Certificate Schemes (Norway, Sweden) • Renewable Portfolio Standards (New York, California, etc.)

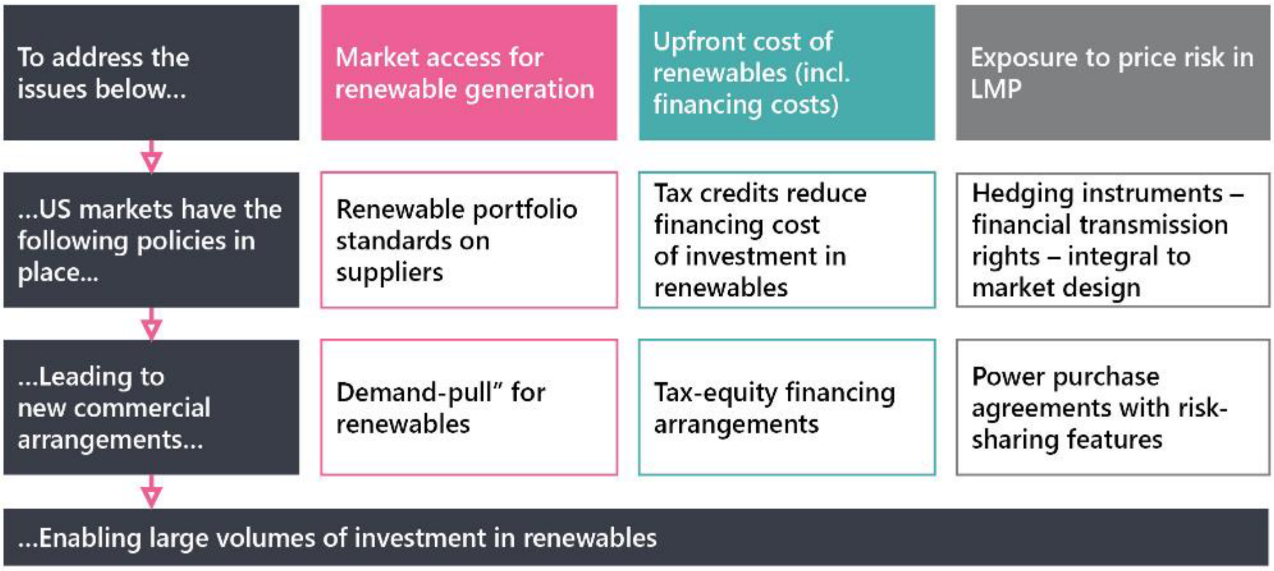
4. EVIDENCE ON MARKET PERFORMANCE

In this section we summarise the lessons for GB from international markets that adopted LMP and/or outcome-based (demand-pull) policy mechanisms. We discuss the impact on each of the following in turn: (i) low carbon generation, (ii) storage and flexible resources, and (iii) grid investment. We also present case studies from Italy – a zonal electricity market whose renewable generation technology potential (i.e. wind and solar PV) is broadly comparable to GB.

4.1. Investment in renewable generation capacity

There is considerable growth in renewables across the US – including in some states where decarbonisation policies are weak. How has this been achieved? Most/all have adopted different structural approaches to incentivising investment in renewable energy, with no equivalent of the centralised contracting / feed-in-tariff approach of the UK. Tradeable renewable energy certificates, which place a value on environmental attributes of renewables – alongside tools to help manage price risk in LMP – have led to new commercial approaches to support investment in renewables.

Figure 2: Overview of policy mechanisms and to support renewables in US LMP markets



4.1.1. Policy approaches

Two policy support approaches for renewables appear to be prominent in the US markets that we reviewed.:

- Demand-pull 'renewable portfolio standards' on investor-owned utilities – determined by individual states.[11]
- Tax credits for generators – set at the federal level.[12]

In Italy, tax credits are used for smaller scale installations while a centralised contracting approach has been adapted to the zonal market design to support new renewable generation capacity.

The US federal tax credits for renewable energy projects include the Renewable Electricity

[11] These utilities are typically vertically integrated (generation, network and retail), but play a similar consumer-facing role to suppliers in the GB market.
[12] Federal tax credits have recently been extended under the Biden administration Inflation Reduction Act which gained senate approval in August 2022.

Production Tax Credit (PTC), the Investment Tax Credit (ITC), the Residential Energy Credit, and the Modified Accelerated Cost-Recovery System (MACRS).[13] Production tax credits effectively subsidise each MWh of output from qualifying renewable energy projects for a defined time period (e.g. 10 years). Alternatively, investors can elect to take investment tax credits worth 25-30% of qualifying project costs.

Generally, the PTC and ITC require co-investment from large financial entities (e.g. banks or insurance companies) to ensure all the credits can be used – giving rise to the concept of 'tax equity financing'. The financial entity invests in a renewable energy project in place of paying a portion of its tax liabilities. In that sense, tax credits can be considered equivalent to a cash subsidy offset against the financial entity's tax liability.

> "Tax-equity investors are typically profitable tax-paying entities such as banks, insurance companies, and certain utilities and corporate entities. [...] tax-equity investors generally invest alongside a developer who cannot make efficient use of the tax benefits associated with the underlying asset. Tax-equity financing structures are driven by tax laws that are unique to the United States."[14]

Tax equity finance will generally need to be combined with other sources of finance.

> "Generally, tax equity will only cover around 35 to 40 per cent of the total capital cost for solar developments and 50 to 60 per cent of the total capital cost for wind developments, so sponsors need to complete the capital stack with sponsor equity or debt (or both). [...] Some creditworthy sponsors may be able to fill the entire capital stack with sponsor equity or corporate debt without seeking project finance debt but, for many developers, that is not an option or is not the preferred option (for economic or other reasons)." [15]

There are range of tax equity financing structures and this is a complex area – strongly shaped by the detailed rules and criteria around the ITC and PTC policies and how the risks associated with qualifying for various levels of tax credits are managed between financing parties. However, this approach to subsidising renewable generation has undoubtedly brought a range of investors into the market for renewable energy assets across US electricity markets.

Use of tax credits in a zonal market: Italy's EcoBonus

Italy is one European country that has used a similar approach to the US federal tax credits to support investment in renewables. This mechanism has been specifically targeted at solar PV installation, and comprises of:

- a fiscal subtraction equal to 50% of the costs incurred up to a maximum cost of €96,000;
- a one-off "super-bonus" for PV power plants installed in the period 1 July 2020 - 31 December 2021, set at a fiscal subtraction equal to 110% of the costs incurred.

The "super-bonus" of 110% is also granted to PV installations related to refurbishment projects.

Sources: Council of European Energy Regulators[16], PV Europe[17]

[13] U.S. Energy Information Administration, Renewable energy explained – Incentives. Accessed 1 September 2022
[14] The Law Reviews, The Project Finance Law Review: Tax-equity Financing. Accessed 1 September 2022
[15] The Law Reviews, The Project Finance Law Review: Tax-equity Financing. Accessed 1 September 2022
[16] CEER (2021), Status Review of Renewable Support Schemes in Europe for 2018 and 2019
[17] PV Europe, Italy introduces tax deduction for residential PV-systems. Accessed 1 September 2022

The tax credit approach used in the US helps reduce the financing cost of renewable generators – similar to the aim of contracts-for-difference in GB - but it retains generators' exposure to LMP signals. The exposure to locational price differences creates strong incentives at the margin for investors in new renewable generation assets to:

- locate in higher price locations;
- invest in complementary assets that enable them to manage price risk (e.g. storage); and
- contract with other market players who either wish to manage an opposing exposure to market variability, or who are themselves investing in assets or business models that seek to exploit price arbitrage opportunities.

In the sub-sections that follow we explain how market designs and participants' contracting approaches have evolved in response to the above incentives.

4.1.2. **Hedging mechanisms to manage price risk in LMP markets**

Investors in electricity generation assets generally seek to manage their exposure to risk arising from variability in electricity wholesale prices. Across most major electricity markets this gives rise to long-term contracting arrangements such as multi-year power purchase agreements (PPAs) and/or contracts for difference. In LMP markets, wholesale price exposure is more differentiated. This means that market players are motivated to manage their exposure to variation in prices across space (i.e. price differences across nodes) as well as through time.

US markets have developed a wide range of contracting structures and approaches to manage risks around renewable energy projects. In many LMP markets, Financial Transmission Rights (FTRs) are auctioned to enable market players to manage their exposure to locational price risks.[18]

The Rocky Mountain Institute has published detailed guidance on risk mitigation, PPAs and Virtual PPAs aimed at local government (e.g. cities) purchasing clean electricity.[19] The paper identifies six different broad categories of risk (price, basis, non-energy market, shape, operational and volume) and outlines risk mitigation strategies for all through the detailed structuring of PPAs. From a practitioner's perspective – taking EDF Renewables as an example of a market participant in the US – it has executed PPAs with risk-sharing structures, including: PPA prices that adjust based on market conditions, permissible extensions to targeted commercial operation dates, regulatory risk sharing and basis risk sharing.[20]

PPAs and FTRs may only be defined or offered at 'trading hubs' and this means that investors in generation assets frequently have to accept a residual amount of basis risk. This risk generally relates to the price differences between a specific node and the trading hub against which the hedge is secured. Basis risk features prominently in industry courses for project developers and finance professionals in US markets. This indicates that it is a live consideration in analysing and assembling finance for project investments. However, exposing generators to this risk can allow for new market-led hedging instruments to emerge. EDF Renewables argues that, in some contexts, basis risk has become unsustainable for it to be borne entirely by sellers, so:

> "Developers are pushing back and seeking partners willing to share in the risks of the project during the tenor of the PPA. EDFR has worked with offtakers to limit the total basis cost that can be borne by the seller in any contract year. Without this risk

[18] Different nodal markets in the US different terms to mean broadly the same type of hedging mechanism. For simplicity we refer to these broadly as FTRs in this report.
[19] RMI (2021), A Local Government's Guide to Off-Site Renewable PPA Risk Mitigation
[20] EDF Renewables, Delivering Success Through Innovative Approaches to PPA Risk Sharing. Accessed 1 September 2022

> protection, projects can become cashflow negative and risk failure. When the total cost is exceeded, the PPA settles at the project's node which absolves seller of basis risk for the remainder of the contract year."[21]

An alternative to PPAs has emerged in ERCOT (Texas), which is known as a 'physical fixed-volume hedge'. This hedge involves a renewable generator selling its actual output at the prevailing nodal price, while buying a fixed quantity of electricity at the hub price. The latter is sold to the hedge counterparty at a fixed price. This has the effect of converting floating revenue into fixed revenue for the generator, thus supporting investability of the project – including using project finance approaches.[22,23]

The demand for renewable energy is also being driven to a significant degree by companies motivated to demonstrate their commitment around Environmental, Social and Governance issues (ESG investing).[24] In this context, corporate buyers of energy want to reduce their carbon footprint by purchasing clean energy and are motivated to enable renewable energy projects to be built and financed. This is an important driver of the demand for renewable energy in the US, but also motivates new approaches to risk sharing (e.g. around basis risk) between generators and purchasers.

Support schemes in zonal markets: Italy's feed-in-premium

The support schemes in Italy for renewable electricity generation have gone through several iterations over time, but the essential elements are as follows:

- The regulator *Autorità di Regolazione per Energia Reti e Ambiente (ARERA)* defined a **reference price** (€/MWh) and expected plant lifetime for eligible technologies, which are: PV solar, onshore wind, hydro-electric and energy-from-waste.
- A two-way contract-for-difference (feed-in-premium) is available for generator schemes of at least 250kW (previously 500kW) in the eligible technologies.[25]
- For generators between 250kW and 1MW, the feed-in-premium payment is calculated as the respective **reference price less the hourly zonal electricity price** in the zone in which the generator is located.
- For generators larger than 1MW, a reverse auction is used. The generators that offer the larger discount relative to the reference price – up to the target amount of capacity being procured – become eligible for the feed-in-premium. The feed-in-premium is then calculated as each generator's **discounted reference price less the hourly zonal electricity price** in the zone in which the generator is located.

The reference price and the target generation capacity – by type – are both defined at a national level. Because access to the feed-in-premium for larger generators (i.e. >1MW) is via a discount

[21] EDF Renewables, Delivering Success Through Innovative Approaches to PPA Risk Sharing. Accessed 1 September 2022
[22] Norton Rose Fulbright, Lending to hedged wind and solar projects. Accessed 1 September 2022
[23] The Texas energy crisis of February 2021 – in which some wind generators made very large profits while other made large losses – has highlighted some of the limitations of hedges in extreme conditions. Subsequently, some commentators have proposed an alternative model called a proxy revenue swap. See: J. Bartlett, Texas Power Crisis Exposes Problems with Financial Risk–Mitigation Strategies in Renewable Energy Projects, Resources.org, 21 March 2021. The proxy revenue swap is somewhat similar to the 'yardstick CfD' proposed for the GB market. See: D. Newbery (2021), Designing an incentive-compatible efficient Renewable Electricity Support Scheme, EPRG Working Paper 2107.
[24] Wood Mackenzie, US renewables project finance: five things to know. Accessed 1 September 2022
[25] The feed-in-premium is suspended in incidences in which the zonal electricity price is zero or negative for more than 6 consecutive hours.

offered to the reference price, the mechanism implicitly favours generators located in areas with more favourable conditions (e.g. better capacity factor, lower connection costs, etc.).

Sources: Council of European Energy Regulators[26], Dentons[27], Gestore dei Servizi Energetici S.p.A. (GSE)[28]

4.1.3. Implications for the cost of capital for renewables

The cost of capital represents the financial return that a project or an asset must achieve to justify investment. Investors in projects take a view on the risks associated with the investment.

The weighted cost of capital (WACC) is affected by variations in the overall macro-economic and business environment, tax regimes, business culture, a wide range of features of the policy mix and the approach to corporate structures and strategies. There are, therefore, major challenges in (a) making comparisons across different jurisdictions about the cost of capital, and (b) in drawing conclusions around causality from those comparisons.

The need for caution in comparing cost of capital estimates and drawing conclusions is highlighted by looking at the International Energy Agency's (IEA) relative WACC estimates for solar PV projects.

Figure 3: Business models and indicative WACCs of solar PV projects, 2019 (IEA)

		Revenue supported (Feed-in tariff, contract for difference, long-term PPA, bilateral agreement)				Merchant risk (Market-based revenue)	
		Europe	United States	China	India	Europe	China
Revenue risk:	Price	Low	Medium	Low	Low	High	High
	Volume	Low	Medium	Medium	Medium	Medium	Medium
	Off-taker	Low	Low	Medium	High	-	Medium
Debt base rate after tax (%)		0.3	1.5	2.4	4.8	0.3	2.4
Debt risk premium after tax (%)		1.9	1.3	1.4	1.8	1.9	1.4
Cost of equity (%)		5.3 - 10.9	4.5 - 7.3	7.0 - 9.0	14.0 - 18.0	10.9 - 14.5	9.0 - 15.1
Share of project debt (%)		75 - 85	55 - 70	70 - 80	70 - 80	40 - 50	40 - 50
WACC nominal, after tax (%)		2.6 - 4.3	3.3 - 5.0	4.4 - 5.4	8.8 - 10.0	6.5 - 9.6	6.4 - 6.9
WACC real, pre-tax (%)		2.4 - 4.0	2.9 - 4.5	3.4 - 3.6	5.0 - 6.6	5.9 - 8.8	4.9 - 8.9

Source: IEA[29]

Taken at face value, the IEA's estimates would seem to suggest that support schemes had no effect on default risk of solar PV investments in Europe (debt risk premium of 1.9% for both supported and merchant generators). It also seems to suggest demand-side mechanisms in the US resulted in lower cash flow risk (implied by the range on the cost of equity) and lower default risk than supply-side mechanisms in Europe. Without further details on how these estimates were derived, both of these conclusions seem counter-intuitive.[30]

[26] CEER (2021), Status Review of Renewable Support Schemes in Europe for 2018 and 2019
[27] Dentons (2020), Italy: The 2019-2021 incentives regime for renewable energy plants
[28] GSE, ACCESSO AGLI INCENTIVI, accessed 7 November 2022
[29] IEA, World Energy Outlook 2020, Table 6.1
[30] For example, analysis conducted for BEIS on the WACC of different generation technologies in GB found that generators supported by a contract-for-difference would have a lower WACC than an identical generator not eligible for

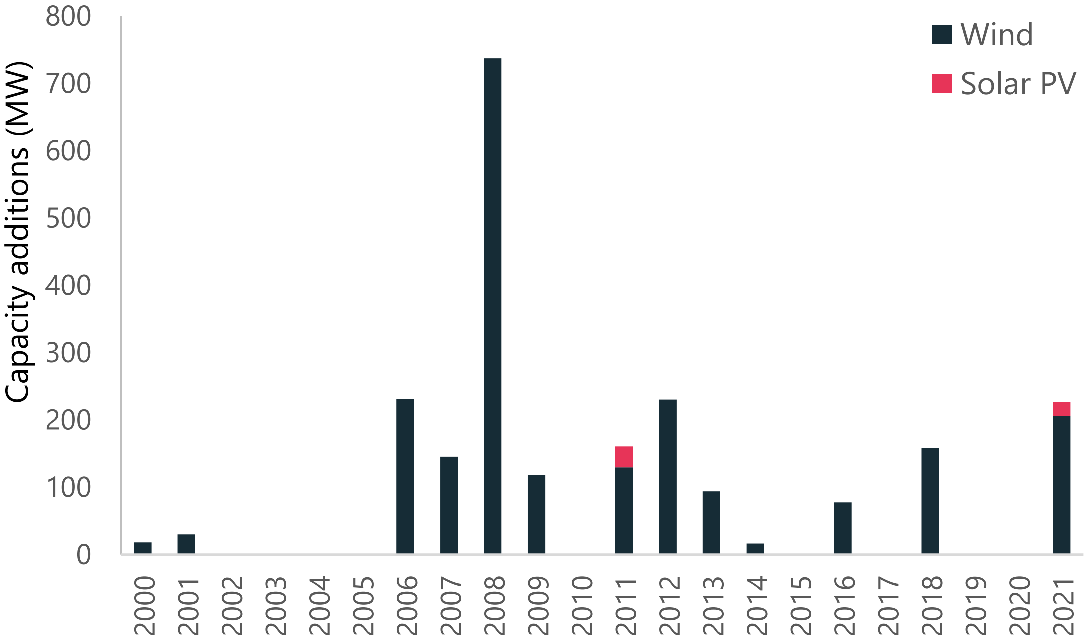
One trend that has been observed consistently across the UK and US markets is a drop in the cost of new renewable generation projects over time. Berkley Lab reported dramatic drops in PPA prices for utility scale solar across all regions of the US since 2008, with the fall continuing (although more slowly) post 2017.[31] This reflects the trend of lower financing costs for renewable generation – similar to the impact that has been attributed to contracts-for-difference in GB.[32]

4.1.1. Impact on investment in generation capacity

US markets vary considerably in the strength of decarbonisation policy drivers, but have generally seen high levels of investment in renewables. We have not identified evidence that the introduction of LMP has negatively affected the pace of investment in variable renewables – wind and solar PV.

There was no wind generation capacity on the system operated by NYISO before LMP were introduced in 1999. Since then, 2.2GW of wind have been added to the system (as well as 52MW of solar PV).

Figure 4: Wind and solar PV capacity additions in the NYISO system



Source: ESC analysis of NYISO data[33]

In California, wind accounted for 3.9% of generation capacity and there was only 13MW of solar PV on the system when CAISO switched from zonal pricing with self-dispatch to LMP with central dispatch in 2009. Since then, 3.5GW of wind have been added to the system – doubling wind's share in generation capacity. Nearly 14GW of solar PV have been added over the same time period – taking solar PV's share of generation capacity to 17%.

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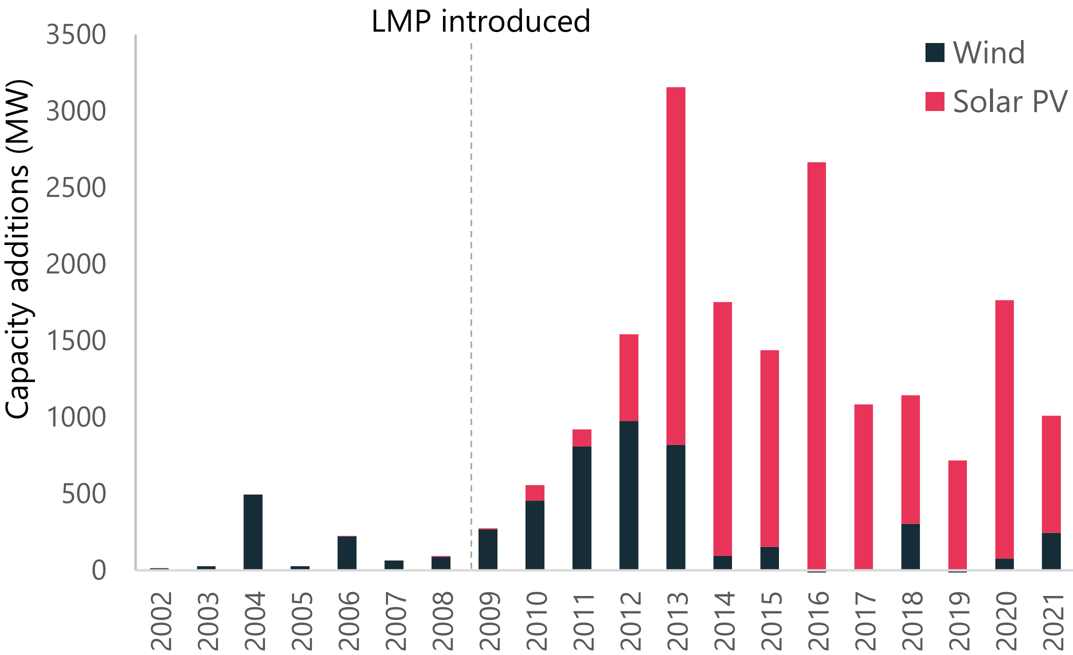
support. See: Europe Economics (2018) Cost of Capital Update for Electricity Generation, Storage and Demand Side Response Technologies

[31] Berkeley Lab (2019) Utility Scale Solar: Empirical Trends in Project Technology, Cost, Performance and PPA Pricing in the US

[32] The decline in investment costs in both the UK and US may not be entirely attributable to the support mechanisms, Other relevant factors may include declining interest rates over the period, and investor familiarity with renewable technologies and comfort with their risk profile.

[33] NYISO, 2022 Load and Capacity Data Report (Gold book), 2022 NYCA Existing Generating Facilities, Table III – 2a NYISO Market Generators. Accessed 18 November 2022

Figure 5: Wind and solar PV capacity additions in the CAISO system



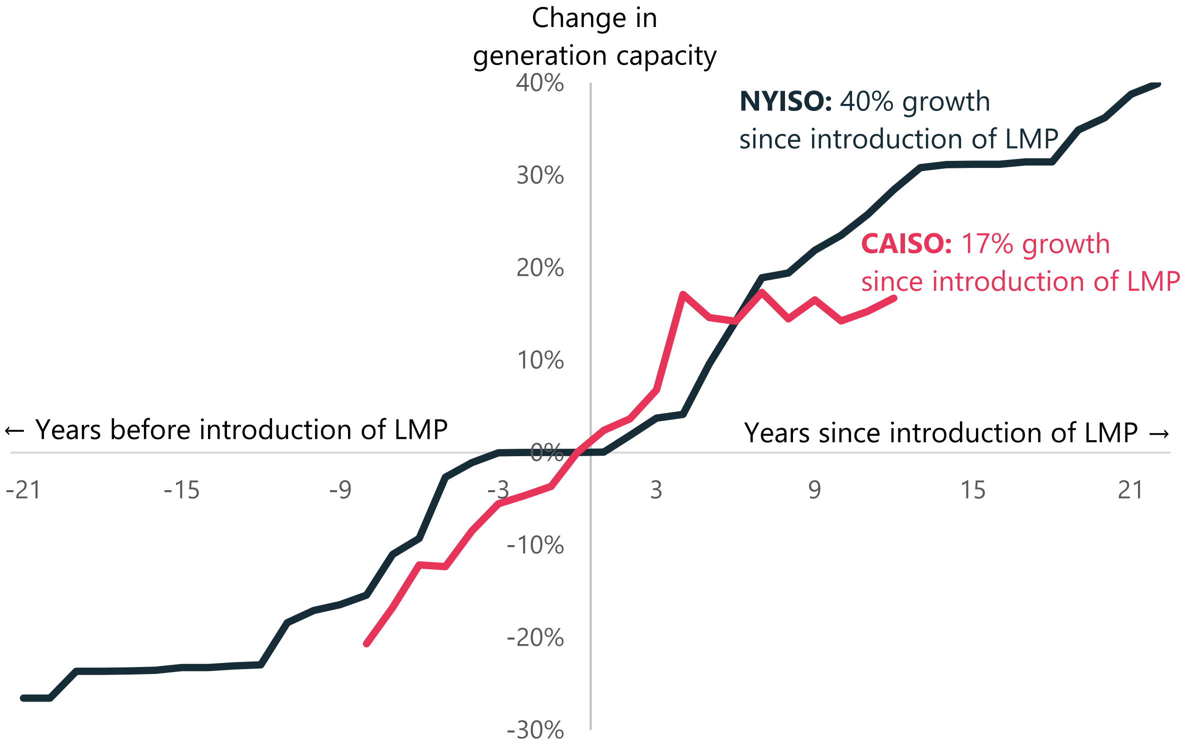
Source: ESC analysis of California Energy Commission data[34]

If anything, the pace of investment in those technologies appears to have ramped up since the introduction of LMP. While that may be due to factors that are not directly related to electricity market design, it is clear that neither LMP nor the absence of centralised contracting for renewables (such as contracts for difference) have hindered large-scale investment in renewable generation in these US markets. A similar observation has been made with respect to ERCOT.[35]

Looking more broadly at generation technologies, there has been a near doubling of the annual rate of capacity additions in NYISO in the 22 years since LMP were introduced compared to the 22 years that preceded the introduction of LMP. In California, the pace of net capacity growth has slowed in recent, having initially spiked after the introduction of LMP. This slowing down relates to accelerated retirement of fossil fuel generators – with 9.5GW of gas generation capacity coming offline since 2013.

[34] California Energy Commission, Electric Generation Capacity and Energy, Installed In-State Electric Generation Capacity by Fuel Type (MW). Accessed 18 November 2022
[35] National Grid ESO (2022), Net Zero Market Reform - Phase 3 Assessment and Conclusions

Figure 6: Percentage change in generation capacity in NYISO and CAISO



Source: ESC analysis of NYISO and California Energy Commission data[36,37]

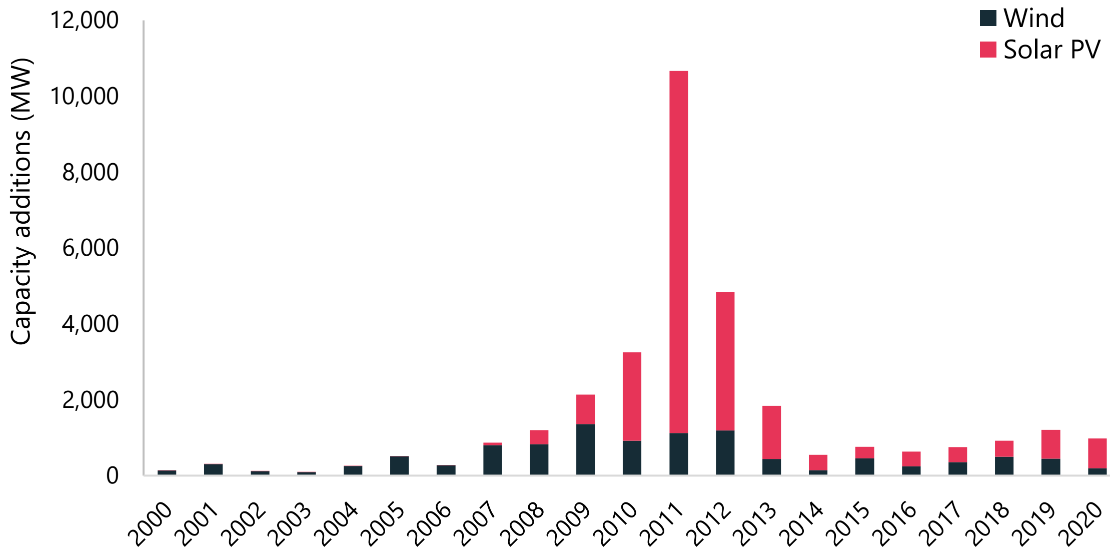
[36] NYISO, 2022 Load and Capacity Data Report (Gold book), 2022 NYCA Existing Generating Facilities, Table III – 2a NYISO Market Generators. Accessed 11 November 2022

[37] California Energy Commission, Electric Generation Capacity and Energy, Installed In-State Electric Generation Capacity by Fuel Type (MW). Accessed 18 November 2022

Renewable generation investment in Italy

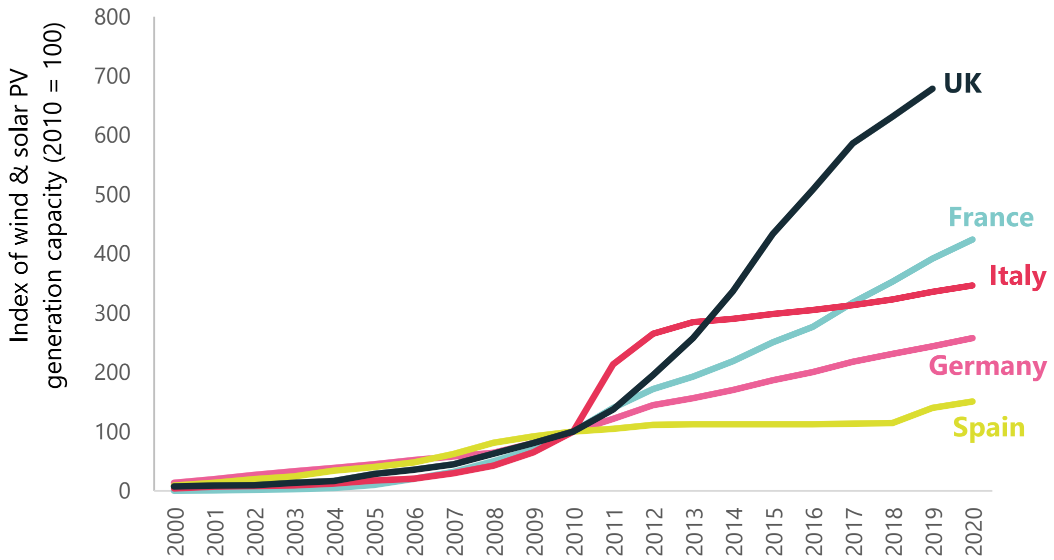
Italy's electricity system combines zonal pricing, feed-in-premiums for renewable generation that are calculated against the respective zonal price, and tax breaks for smaller scale installations. It has seen a steady rate of investment in both solar PV and wind generation (see Figure 7) that has generally ranked around the middle of comparable European states (see Figure 8). There was a notable spike and short-lived spike in investment in solar PV around 2011 – an unintended effect of the government's decision to reduce the level of support offered to solar PV installations after 2011.

Figure 7: Wind and solar PV capacity additions in Italy



Source: ESC analysis of Eurostat data[38]

Figure 8: Comparison of wind and solar PV capacity additions in Italy to comparable European states



Source: ESC analysis of Eurostat data[39]

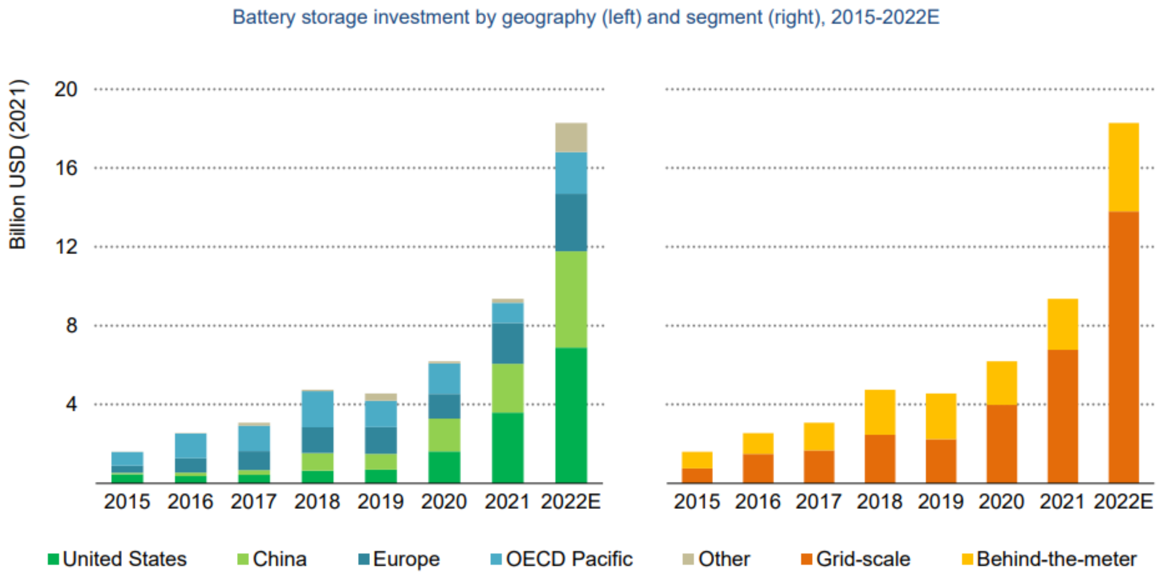
[38] Eurostat, Electricity production capacities for renewables and wastes. Online data code: NRG_INF_EPCRW. Accessed 1 December 2022.

[39] Eurostat, Electricity production capacities for renewables and wastes. Online data code: NRG_INF_EPCRW. Accessed 1 December 2022.

4.2. **Investment in flexible capacity**

US markets have generally seen larger levels of investment and deployment of storage technologies than European markets – as illustrated in the figure below.

Figure 9: Recent trends in battery storage investment (IEA)

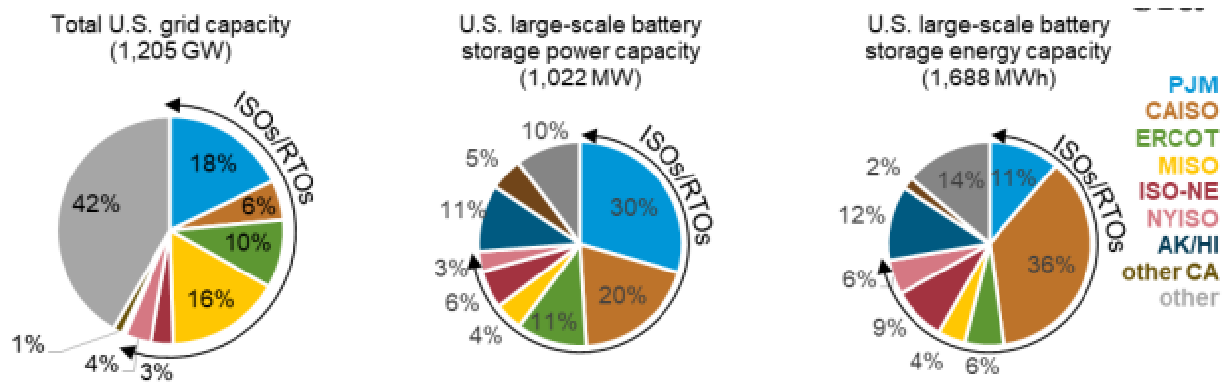


Source: IEA[40]

When examining the trend in storage investment more closely, there is reason to conclude that the granular price signals offered by LMP were influential in enabling the higher levels of investment in storage observed in the US. For example, storage is disproportionately located in US markets that are covered by independent system operators (ISOs) or regional transmission organizations (RTOs)[41] – the markets that use LMP:

- ISOs and RTOs account for 58% of grid capacity in the US; but
- the LMP markets operated by ISOs and RTOs account for 74% of large-scale battery storage power capacity (GW) and 72% of energy capacity (GWh).

Figure 10: Large-scale power and energy capacity by region in 2019 (US EIA)



Source: US Energy Information Administration[42]

[40] IEA, World Energy Investments 2022, p. 54

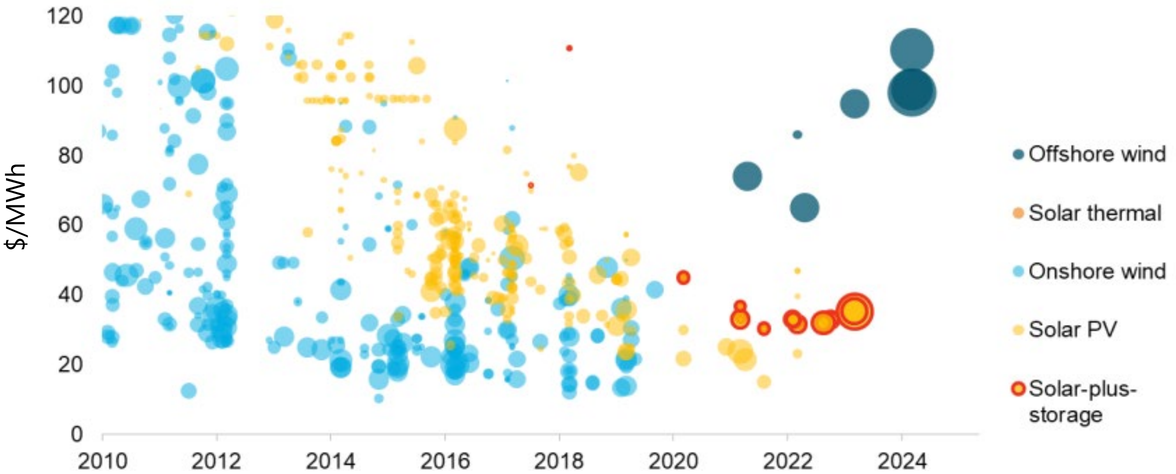
[41] The distinction between RTOs and ISOs is fairly subtle – both perform similar functions but a FERC-recognised RTO must meet some additional requirements (MISO, ISO-NE, PJM and SPP are currently recognised as RTOs).

[42] U.S. Energy Information Administration, Battery Storage in the United States: An Update on Market Trends, August 2021, Figure 1

The LMP algorithms used by ISOs and RTOs have evolved over time, and in recent years improvements have been made to account for specific bidding formats of storage and DSR.[43]

There is also emerging evidence from US markets of storage co-locating with renewable generation – allowing intermittent renewables to behave price-responsively in LMP markets.

Figure 11: PPAs for renewable energy projects, by operation year (Bloomberg NEF)



Source: Bloomberg New Energy Finance[44]

Demand response in an LMP market: PJM

Demand in the PJM market is treated on a zonal basis (whereas generation is treated on a nodal basis); nevertheless, PJM is considered one of the largest markets for demand-response. 'Economic Demand' participates in the energy and ancillary services market by bidding – via an intermediary called a Curtailment Service Provider – into the LMP algorithm.

However, given the limited value available as a result of not being able to access the nodal price, the vast majority of demand response is contracted through the capacity market. The design of the capacity market has evolved over time, but installed capacity committed to provide response has been relatively stable and has averaged around 8GW since 2010. The value accessed by demand response – largely through the capacity market – was just over $500 million in 2021. Over the last 5 years, the share of demand response from distributed energy resources has also been relatively stable around the 15-16% of demand response mark.

Shielding demand from nodal prices is done in a number of LMP markets – typically owing to concerns about distributional impacts. Such concerns were prominent when US markets transitioned to nodal pricing 10-20 years ago. But the improvements in the technology and cost of demand side flexibility since then means that there are now potentially very large savings to be made by exposing demand to nodal prices. These savings could then be redistributed to address any distributional concerns that result from the exposure to nodal prices.

Sources: PJM[45], Monitoring Analytics[46]

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[43] U. Helman (2021) Demand response in the US wholesale markets: recent trends, new models, and forecasts. *Variable Generation, Flexible Demand*, Elsevier, pp. 211–257

[44] Bloomberg NEF, Global Energy Storage Outlook, Presentation for Macquarie Group, 11 August 2021, p. 23

[45] PJM, Demand Response fact sheet, 13 October 2022. PJM, Load Management and Price Responsive Demand Performance Report 2020/2021, August 2021, Figure 1. PJM Demand Side Response Operations, 2021 Distributed Energy Resources (DER) that participate in PJM Markets as Demand Response, February 2022, Figure 1

[46] Monitoring Analytics, 2021 State of the Market Report for PJM

4.3. **Investment in grid capacity**

Grid investment decision-making in US markets is generally planned and mediated by the ISOs and RTOs. RTOs/ISOs assume the transmission planning function (in addition to setting up and running markets for wholesale power and ancillary services, and ensuring overall reliability of the grid), setting up arrangements to work with stakeholders to develop overall plans for new transmission that is needed to meet demand and facilitate efficient operation of the grid.[47]

Each RTO/ISO runs processes to plan and coordinate investment in transmission infrastructure. For example, PJM runs a Regional Transmission Expansion Planning process that takes account of feasibility and reliability studies, new generation capacity and generator retirements.

Midcontinent Independent System Operator (MISO), which covers a number of states in central US and Manitoba in Canada, develops a Transmission Expansion Plan annually an inclusive process with stakeholders. MISO has established the following guiding principles for its Transmission Expansion Planning:[48]

- Develop transmission plans that will ensure a reliable and resilient transmission system that can respond to the operational needs of the MISO region.
- Make the benefits of an economically efficient electricity market available to customers by identifying solutions to transmission issues that are informed by near-term and long-range needs and provide reliable access to electricity at the lowest total electric system cost.
- Support federal, state, and local energy policy and member goals by planning for access to a changing resource mix.
- Provide an appropriate cost allocation mechanism that ensures that costs of transmission projects are allocated in a manner roughly commensurate with the projected benefits of those projects.
- Analyse system scenarios and make the results available to federal, state, and local energy policy makers and other stakeholders to provide context and to inform choices.
- Coordinate planning processes with neighbours and work to eliminate barriers to reliable and efficient operations.

Expert commentators in the US have observed a shift in transmission planning from being purely reliant on LMPs to assess the economic benefits of transmission projects to finding the least cost transmission solution to assumed policy goals (state/federal). This is being given effect to formally through a proposed rule change by the Federal Energy Regulatory Commission (FERC). The rule change would require ISOs and RTOS to include state clean energy driven scenarios and to lengthen the planning time horizons used in transmission planning.[49]

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[47] ISOs/RTOs are not-for-profit and are regulated by FERC, not by the states. Membership in an ISO or RTO by any entity is voluntary. Including Texas (which is technically outside of FERC's jurisdiction), there are seven ISOs/RTOs in the U.S., covering about half of the states and roughly two-thirds of total U.S. annual electricity demand. Each ISO/RTO establishes its own rules and market structures, but there are many commonalities. ISO/RTO decision-making is governed by a "stakeholder board" consisting of various electric sector constituencies. In some cases, the RTO can implement policy unilaterally without approval by the stakeholder board, but this is generally rare. All policies must, however, be approved by FERC.
ISOs/RTOs do not own any physical assets – they do not own generators, power lines or any other equipment and do not sell electricity to retail customers. They purchase power from generators, resell it to electric distribution utilities, who then resell it again to end-use customers.

[48] MISO, Transmission Expansion Plan. Accessed 1 September 2022

[49] FERC, Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection, Notice of proposed rulemaking, Docket No. RM21–17–000, 4 May 2022

To an extent, the US can be seen to be catching up to GB in this sense, where decarbonisation policy has long informed transmission planning by National Grid ESO through the process involved in preparing the Future Energy Scenarios (FES), Network Options Assessment (NOA) and Holistic Network Design (HND). While there is a need to ramp up investment – the 2022 HND sets out a need for £12 billion of annual transmission reinforcement to 2030,[50] compared to an average of around £1 billion per annum across the RIIO-T1 period (2013/14-2020/21) – the *ex ante* approach to funding network investment is generally regarded as having been more effective at enabling efficient levels of transmission reinforcement than the *ex post* approach used in the US.

[50] National Grid ESO (2022), Pathway to 2030: A holistic network design to support offshore wind deployment for net zero

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