CORNWALL INSIGHT
CREATING CLARITY

NORTHERN POWERHOUSE
HM Government

European Union
European Regional Development Fund

Unlocking Clean Energy Greater Manchester Energy market modelling

16 June 2023

Tom Andrews & Tom Edwards

About Cornwall Insight

Established in 2005, Cornwall Insight is one of the most respected voices in the energy industry. We provide research, analysis, consulting and training to businesses and stakeholders in the Great British, Irish and Australian energy markets.

Our insight

Our independent experts work across the energy market and provide high quality and actionable insights on which to base your business decisions. We look to facilitate positive market and policy change, whilst also advising customers on how to navigate and comply with energy market dynamics, rules and regulations.

Our expertise

Our experts in-depth working knowledge of energy market design, including policy and regulatory changes, means we are perfectly placed to advise on changes to the future market design and help businesses achieve their net zero goals.

Tom Edwards
Senior Modeller
t.edwards@cornwall-insight.com

Tom Andrews
Senior Consultant
t.andrews@cornwall-insight.com

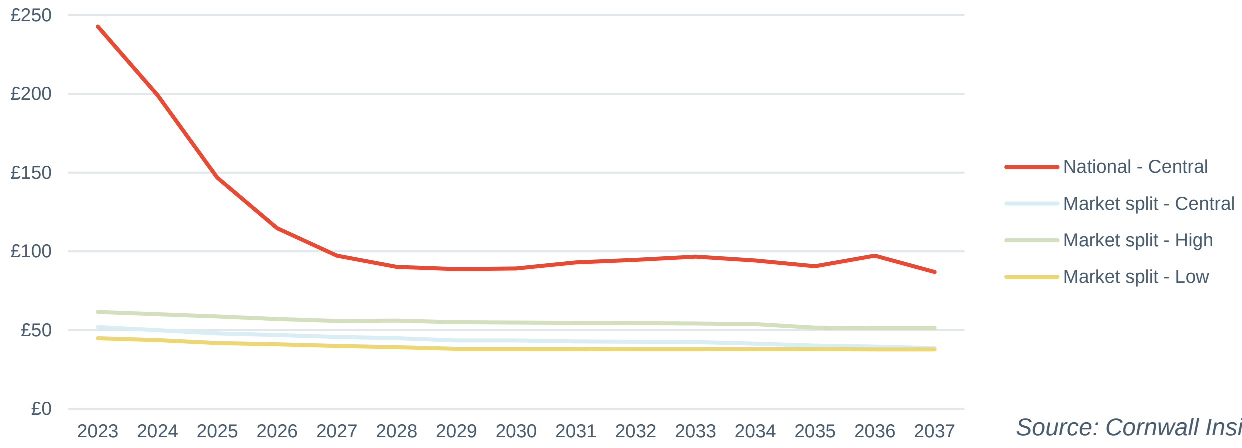
Introduction

- As part of the Unlocking Clean Energy Greater Manchester (UCEGM), the Energy Systems Catapult (ESC) has commissioned Cornwall Insight to deliver network and energy market modelling for assets in the UCEGM region
- Nationally, the modelling team took our existing wholesale power price forecasts and developed two new models: a locational marginal pricing model, and a market splitting model, to reflect two possible future GB energy market paradigms
- Regionally, the modelling team mapped out the UCEGM, including the precise network assets in the region, demand and generation sources, and then introduced new generation and electricity storage assets to test the economic benefits of deploying these
- This report, and the accompanying data book, provide key takeaways from this modelling exercise

Executive summary – wholesale markets

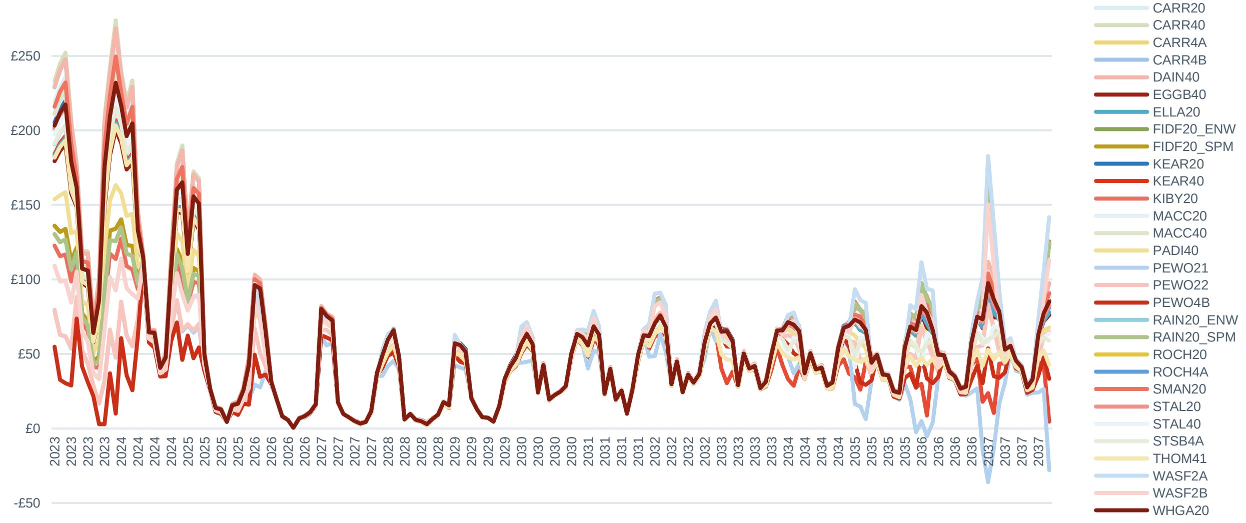
- We modelled three types of wholesale market:
  - National markets, on the current paradigm of a single price for all generation and consumption
  - Locational Marginal Pricing (LMP), looking at electricity prices for each of the ~380 Grid Supply Points (GSPs) with these differing during times when connection between the points
  - Split markets, with a base/ fixed price for intermittent renewable generation and marginal prices for renewable generation
- Prices were modelled to an hourly granularity
- Generator revenues and consumer costs for wholesale power are the same, with network charges and other third-party costs (TPCs) modelled separately
- These prices are fed into the regional network model to inform generation revenues and consumption costs
- The results of Locational Marginal Pricing are particularly interesting, with short-term pricing and long-term pricing dependent on GSP to a much greater extent than we would have expected
  - This is due in the short term largely to whether the GSP is more gas-linked or renewables link
  - In the long term, this is due to increasing constraints on the network as demand grows past the planned transmission reinforcements

Wholesale prices under National and Market Splitting pricing scenarios



Source: Cornwall Insight

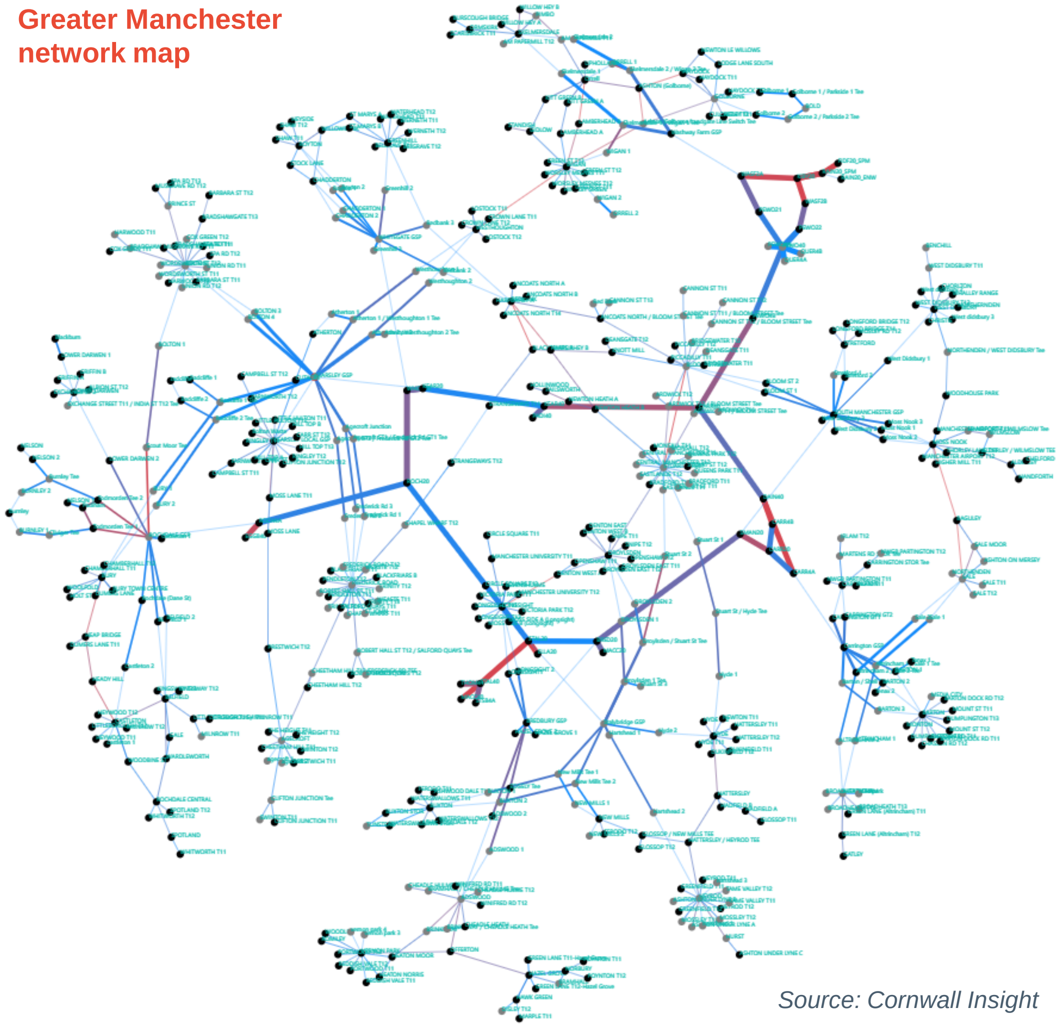
Wholesale prices under Nodal/ LMP pricing scenario



Executive summary – regional modelling

- Our regional modelling focused on constraints in the local networks, which drive different behaviour for users and generators
- This includes, under the LMP pricing model, different costs for consuming and revenues for generating power at different network nodes
  - These nodes are based on transformers, down to the HV level, which may not be the implementation decided on even if LMP is introduced
  - There may also be differentiation between types of user, for example, generation and consumption may see different price zones/ nodes
- The network map created shows several key points of constraint. These include at the boundaries of Greater Manchester, where imports may require upgrades to the transmission network, and some internal constraints including core areas of Rochdale, Wigan and Staylbridge
- We also note that some of the example sites used to model generation and consumption may not be appropriately sited or sized: in particular, the Swinton Road depot site sees EV charging consumption much larger than can be sustained by the local network
  - This provides a case study of why network operators control the users which are permitted to connect in different regions

Greater Manchester network map



Source: Cornwall Insight

Executive summary – Key takeaways

- Our forecasts of average retail costs for the pricing scenarios are set out opposite. This excludes the impact of constraints and the benefits of generation and batteries
- Average annual revenues are also shown. The standalone solar generation sites (Chamber House Farm and Kenyon Way) see lower returns than sites with co-located demand
- The more highly constrained sites, Swinton Road and Grande Central, also see lower returns than the other sites of the same time (depots and leisure centres respectively), whereas low level of constraint boost revenue
  - This is a result of the ability of the assets to mitigate small amounts of constrain, whereas high levels interfere with the ability of the assets to operate and prevent them achieving revenues
  - In reality, many of the severe constraints we forecast will be addressed by the DNOs, with the marginal constraints providing the opportunity for local flexibility to earn higher returns
- The sites modelled have very little impact on regional constraint. The size of, and forecast growth of, power consumption in the region is significant enough that these sites make up only a tiny proportion of overall power needs
  - This remains true of the LA demand portfolios, which each range between 7.7GWh/year and 63GWh/year (average 23.2GWh/year) versus total generation of ~9.6GWh/year

Average retail prices under market pricing scenarios, 2023-24 to 2037-38

	Central	High	Low
National	£156	£175	£137
LMP	£94	£110	£84
Market splitting	£117	£133	£109

Average Central, Equal-size battery £/kWp/year revenues at each site under different markets

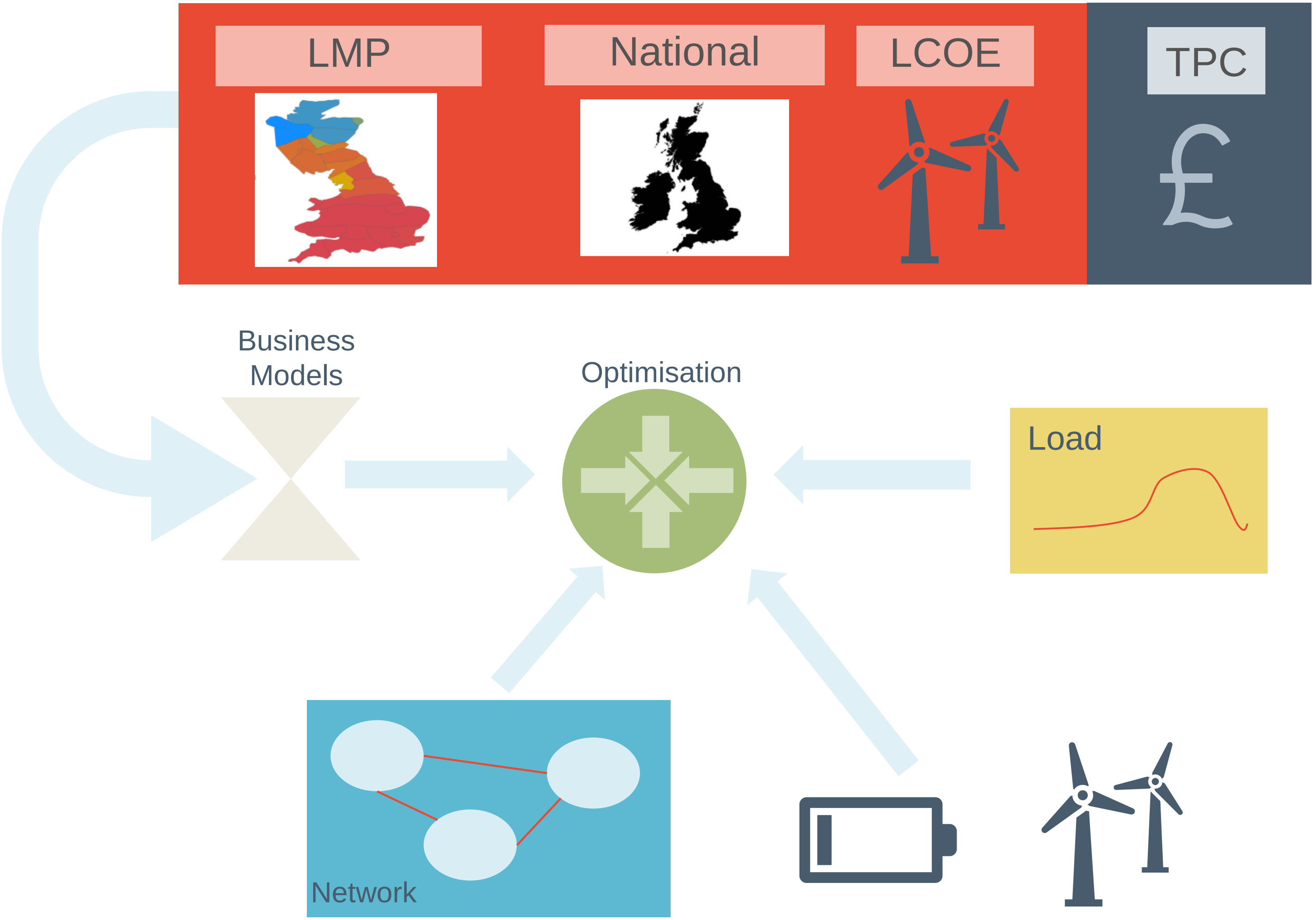
	National		LMP		Market splitting	
	Solar	Battery	Solar	Battery	Solar	Battery
Turnpike	£114	£67	£68	£49	£54	£26
Swinton Road	£125	£53	£108	£44	£63	£38
Chamber House Farm	£85	£81	£38	£35	£55	£177
Kenyon Way	£79	£78	£32	£30	£53	£205
Robin Park	£138	£77	£97	£60	£66	£30
Grande Central	£102	£55	£55	£31	£51	£26

Source: Cornwall Insight

Methodology

Modelling method

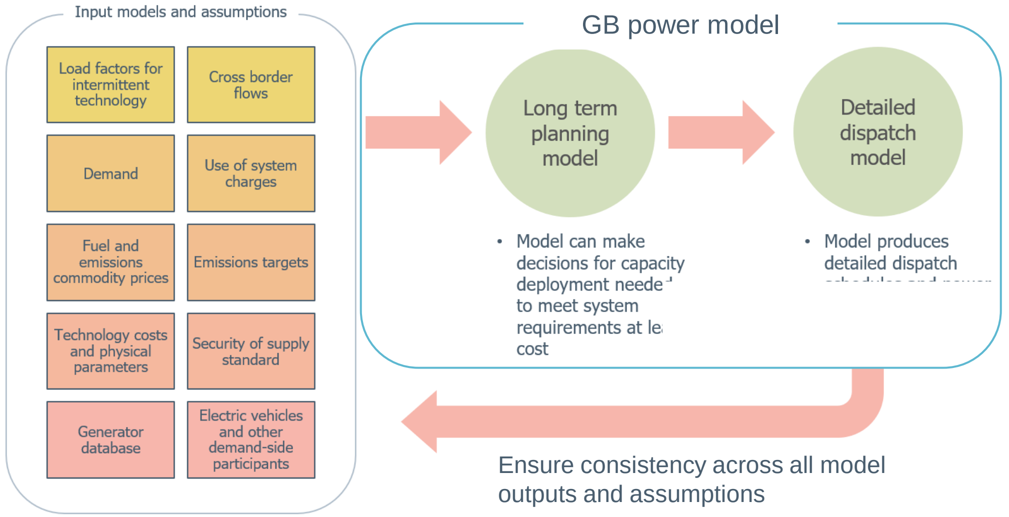
- Our modelling methodology two stages: gathering of key data elements…
  - Creation of wholesale price curves, and establishing non-commodity costs (Third-Party Charges (TPCs))
    - For National, Location Marginal Priced, and Levelised cost of energy (LCOE) split market paradigms
  - Creation of demand and generation (load) curves for the local area and, in particular, the relevant LA estates
  - Mapping of the local network and constraints
- …and optimisation of the region through the prism of business models, to understand:
  - Local network constraints
  - User costs
  - Generation profits
  - Storage revenues



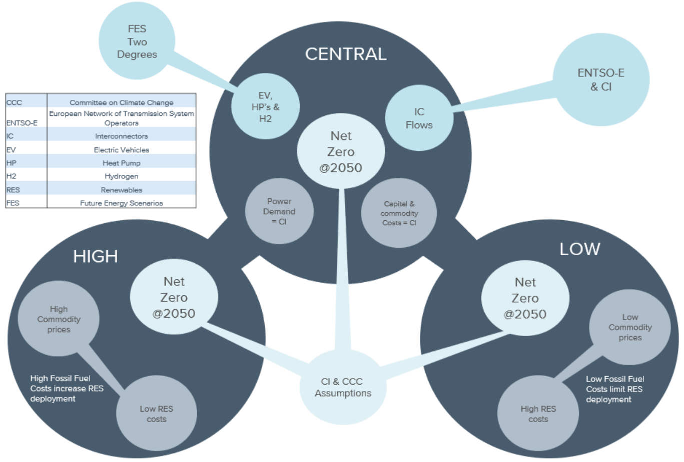
National wholesale price modelling

- CI's wholesale price forecasting tool, the Benchmark Power Curve (BPC), provides hourly power prices for a 30-year time horizon under three scenarios:
  - Central scenario is our expected view of commodity prices and the capital cost of different technologies
  - High scenario provides a view of high commodity prices and low costs for variable renewables technologies
  - Low scenario provides a view of low commodity costs and lower costs for firm low-carbon capacity such as BECCS, nuclear and CCUS
- The model forecasts changes to demand, new generation buildout, and system operation to deliver hourly power prices for the GB national wholesale market
- This models the existing market paradigm, assuming no regulatory reform beyond code modifications which are in train – particularly, this excludes potential REMA impacts (which we model under the other two power price paradigms)
  - See our attached BPC report for more information on relevant regulatory and policy developments

Three main modules – external inputs, long term planning and detail dispatch



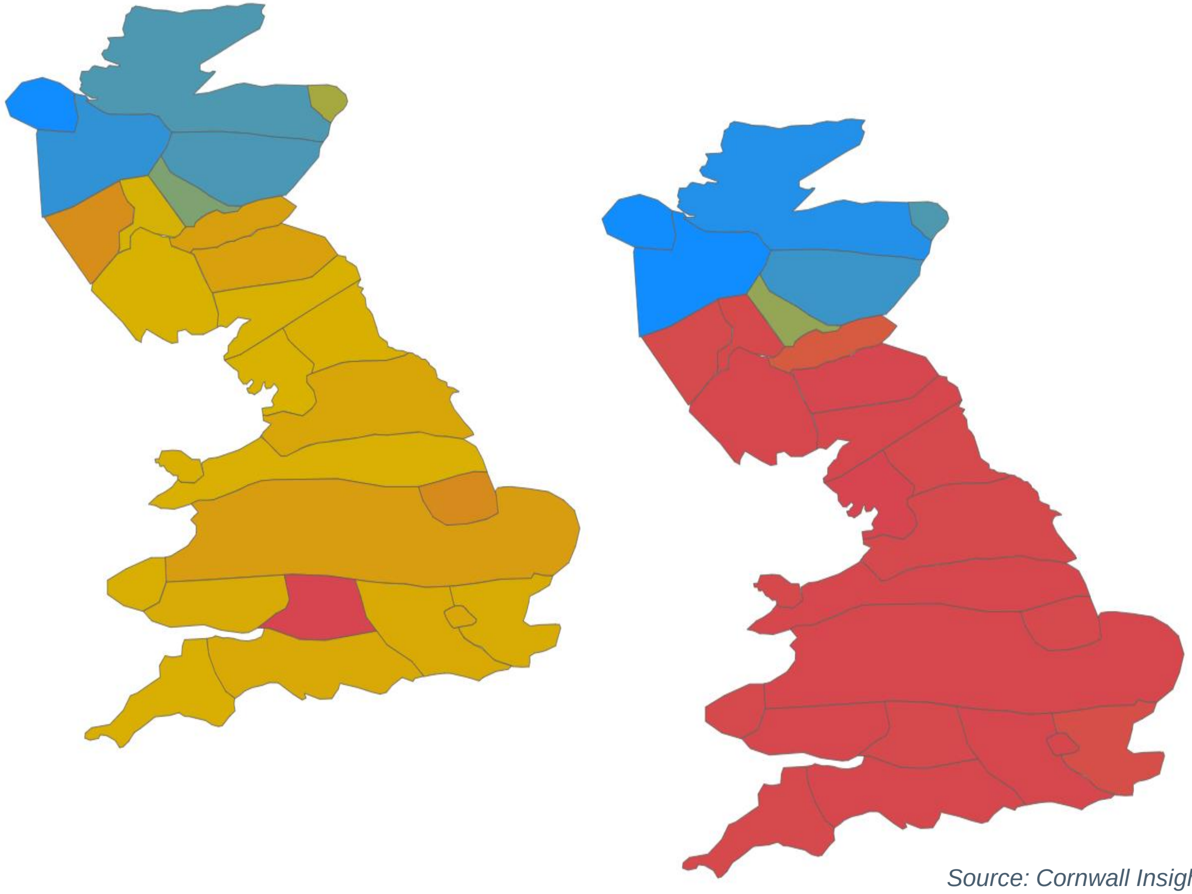
Cornwall price curves overview



Locational Marginal Prices – National

- The diagram opposite illustrates one possible implementation of LMP in GB – at the level of TNUoS zones, which creates 27 regional prices. This implementation might be suitable for generators, as it reflects the historic differences in costs on the national transmission system
- The colours indicate relative average wholesale power prices, with blue being the lowest and red the highest prices
- This analysis was conducted based on financial year 2023-24 (1 April to 31 March), from our Q4-22 BPC results. The transmission system and generation system are modelled as expected during that period.
- The impacts of the current wholesale price paradigm, with extremely high prices, are clearly reflected in results and LMP variances should be considered on the this light
- Government, Ofgem and National Grid Electricity System Operator have not yet given an indication what, if any, LMP model may be implemented in GB
- *Note that this is not the implementation of LMP which we have provided for the UCEGM region, which is granular to network nodes in order to provide price differentials within the UCEGM region. This approach is explained on the next slide*

Relative view of average wholesale prices by TNUoS zone, summer 2023 (left) and winter 2023-24 (right)

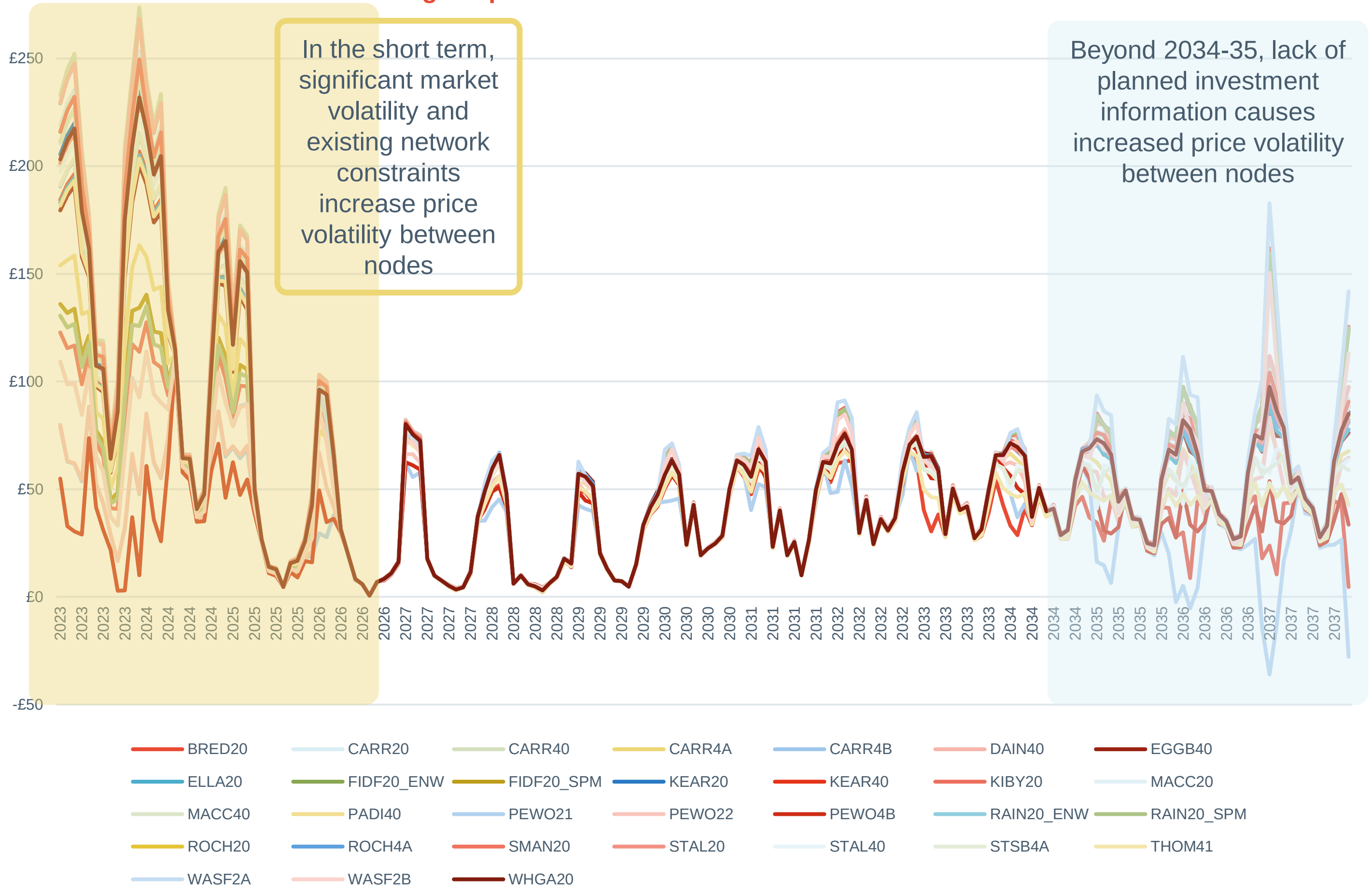


Source: Cornwall Insight

Locational Marginal Prices – Manchester

- CI's locational marginal pricing (LMP) model for UCEGM has been developed to project possible regional prices under one possible LMP implementation
- Existing generation and demand is mapped against network nodes across GB
  - These nodes, which are also used to allocate prices, are based on the Electricity Ten Year Statement – there are 1,061 nodes in total
- New demand and generation capacity to be deployed is taken from the BPC model, with this allocated:
  - For demand, by increasing demand in each region in proportion to existing demand
  - For short-term projects, according to CI's Renewable Asset Planning Database
  - For longer-term projects, by increasing the size of regional generators in proportion to existing capacity
- The existing and planned buildout of the GB transmission network was also mapped, to identify possible points of constraint
- The LMP model outturns hourly prices according the levels of generation and demand and transmission network constraints in GB; these are shown for UCEGM nodes in the chart opposite
- Although various implementations are possible, in our modelling consumers are directly exposed to these prices with no shielding. This is not unlikely for larger consumers, though no details of potential LMP implementation have yet been published

Greater Manchester locational marginal prices

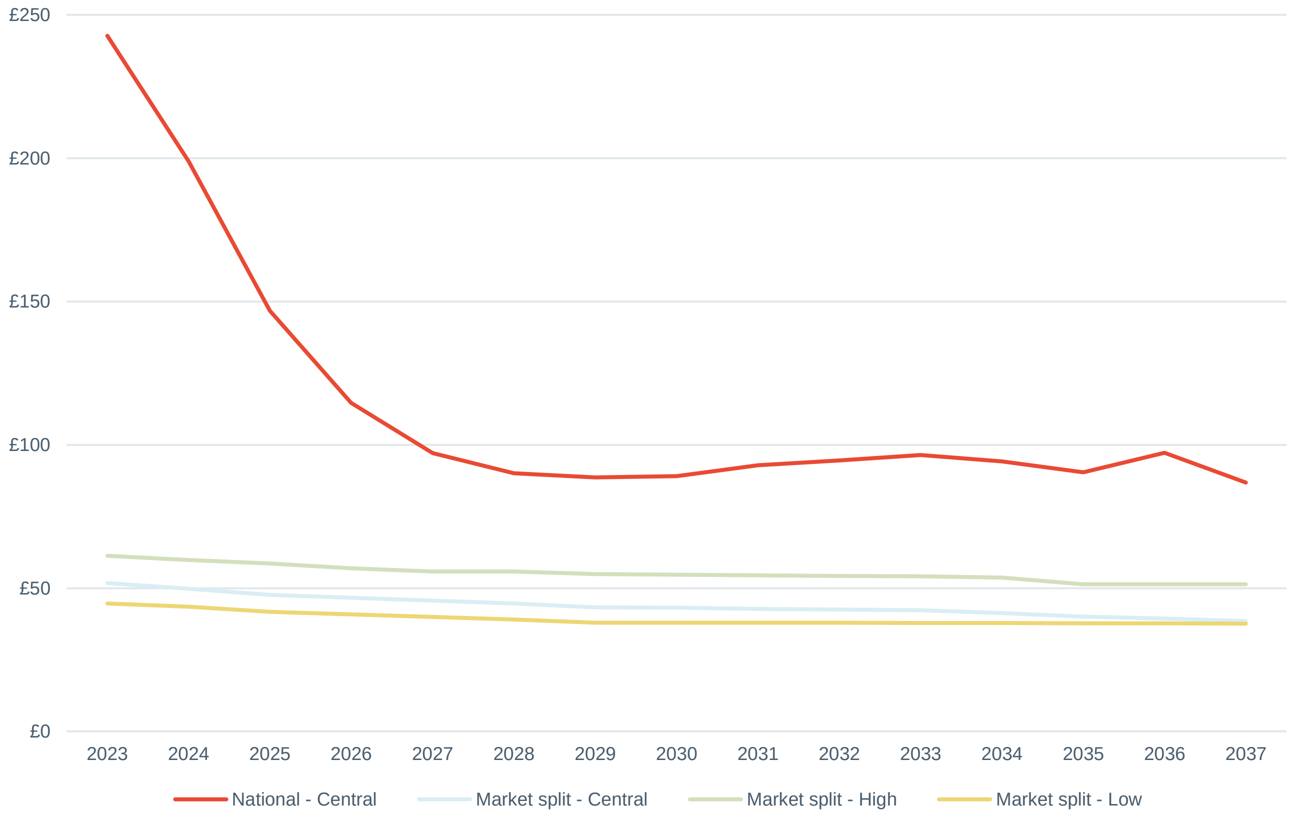


Source: Cornwall Insight

Wholesale market splitting

- The market splitting paradigm would see renewable technologies (e.g., solar, wind, hydro) separated into a different market to dispatchable/ fuelled technologies (e.g., gas, biomass, storage)
- This would see intermittent renewables compensated for generation at a long-run marginal cost of generation
  - It is not yet clear how this would be set – e.g., for all generators, new generation that year, via auction, via accreditation, compulsory or voluntary
  - It is represented in our modelling by the Levelised Cost of offshore wind for new assets, as the most expensive intermittent technology
  - This embeds a similar mechanism to the CfD for all GB renewable generation, setting a fixed income per unit of power exported
  - Central, High and Low forecasts are shown in the chart opposite
- Dispatchable generation would continue to be priced under the existing marginal pricing paradigm – the National Price in the chart opposite is our Central forecast of this
- The price point would continue to be set on a national basis, but this paradigm would increase the value of flexibility in the GB markets
- It reduces revenues to renewable generation, but provides stability and predictability, which creates a more investible business case for renewable generation, which may be preferred by investors
- The wholesale price paid by consumers is, for each hour, a split between the National price and the Market Splitting price
  - The split set as the share renewable versus fuelled generation available on the system

National and market-split wholesale prices (£/MWh)

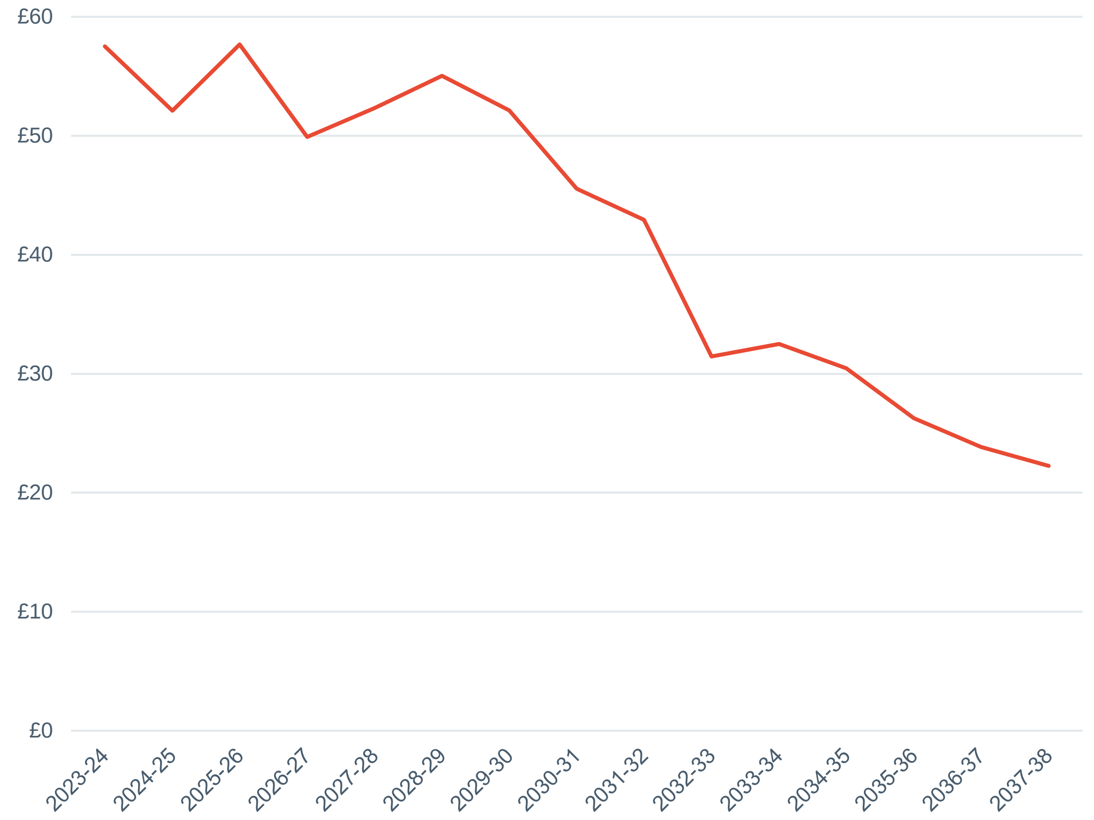


Source: Cornwall Insight

TPCs

- Third Party Charges are the non-commodity costs of importing power from the public networks
- They include network charges and policy levies
- We have used CI's forecasts of these costs, and included:
  - Transmission network charges (volumetric only, and zero for this area)
  - Distribution network charges (volumetric only)
  - Balancing services charges
  - Assistance for Areas of High Electricity Distribution Costs charges
  - Renewable Obligation levies
  - Feed-in Tariff levies
  - Contracts for Difference levies (currently negative and forecast to be so for most of the forecast period)
  - Capacity Market levied (only charged for peak demand periods, 4-7pm during Nov-Feb)
  - Climate Change Levy
- TPCs generally decrease over the period
- Note that we have not included possible future levies, such as hydrogen and CCUS subsidy costs

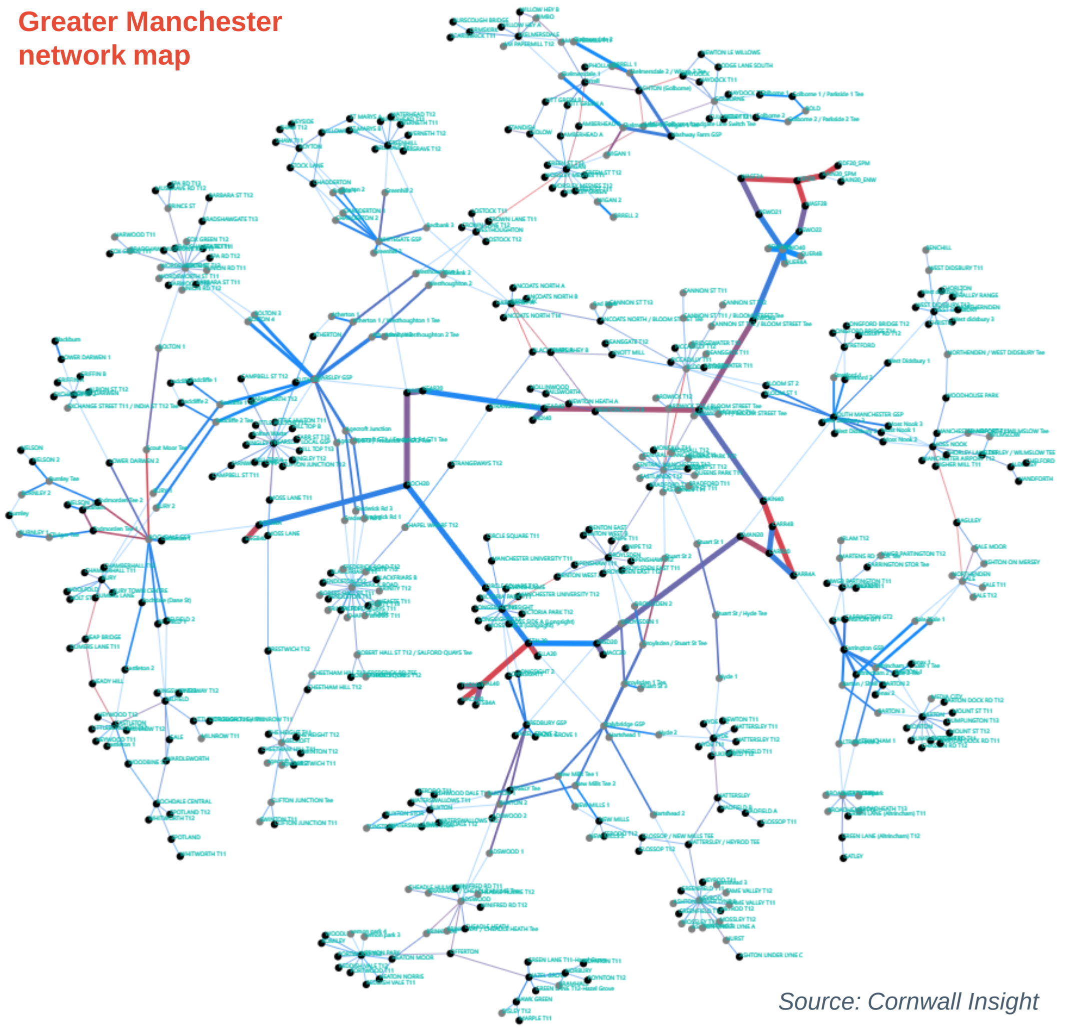
Total average TPCs per year (£/MWh)



Source: Cornwall Insight

Network modelling

Greater Manchester network map



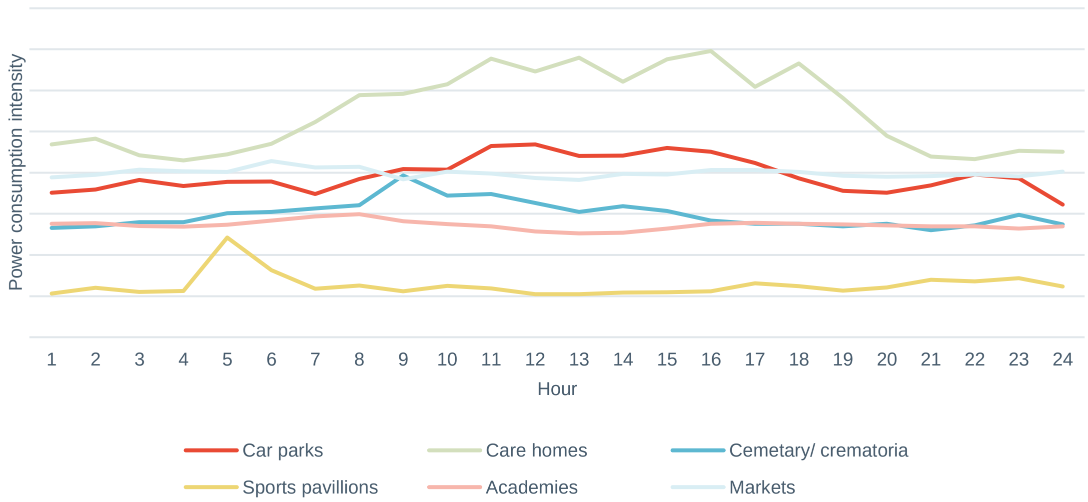
Source: Cornwall Insight

- We modelled the network in the Greater Manchester region, based on the reporting of the local Distribution Network Operator (DNO), Electricity North West (ENW)
- This required mapping the transmission and distribution substations and cables across the region, and allocating generation and demand to these substations on a time-of-use basis, with hourly granularity
  - These are represented in the graphic opposite by the thickness of the lines (cables) and the size of the dots (substations)
  - Cable loading is represented by line colour, with blue lines experiencing lower and red lines higher levels of constraint
  - We also simplified the network, by combining substations where there were no forecast constraints between these
- We included the planned network development from ENW's Long Term Development Statement. We also included information on the expected locational growth of demand, as well as our wider and longer-duration forecasts of demand growth
- As can be seen, the transmission system is mostly ring-based, while the distribution system is radial
- Note that our network model only factors in active power, not reactive power. Customers are not able to impact on reactive power to affect their charges

Demand modelling

- ESC and the UCEGM LAs provided data to include in the models. Data provided was:
  - Oldham – half-hourly consumption data
  - Salford – annual consumption data
  - Manchester City – half-hourly consumption data
  - Rochdale – half-hourly consumption data
  - Stockport – annual consumption data
  - Wigan – half-hourly consumption data
- We also received some data on the estates of Greater Manchester Combined Authority, Transport for Greater Manchester, and various blue light services (police, fire, ambulance)
- We used the categories of the sites (e.g., schools, offices) to create average energy intensities profiles based on the half-hourly data received. These were applied to sites for which we only received annual data, to create half-hourly profiles to feed into modelling
- For the purpose of modelling, these profiles are assumed to continue level, though in reality we would expect usual energy efficiency deployment to reduce, and deployment of electrified heating to increase, consumption
- ESC supplied details of six key sites where solar generation, solar carports and EV chargers, and in some scenarios battery energy storage systems, would be deployed
- ESC also supplied data on forecast EV charging load at the solar carport sites. This grows over time, by a significant amount
- For generation, we used Cornwall Insight's standard technology profiles from our Benchmark Power Curve

Example half-hourly demand profiles for winter off-peak day



Total LA demand per year (MWh)

LA (or other public body)	Total annual demand (MWh)
Manchester City	63,128
Oldham	29,793
Rochdale	7,723
Salford	14,533
Trafford	3,355
Wigan	20,801

Source: Cornwall Insight, from LA and ESC data

Business models & optimisation

- We have included several different business models/ technology set-ups and sensitivities
  - Business-as-usual: local growth, without UCEGM assets built
  - UCEGM asset set-ups: stand-alone ground-mount solar, solar located behind demand meters, co-located solar with EV chargers, batteries co-located with each solar installation
  - Sensitivities on adding batteries at different sizes – 50% of solar generator size, 100%, and 200% (all 2 hour duration)
- Business models:
  - Sale of power to grid/ sleeved PPA – profits of generators and costs to consumers are the same irrespective of the presence or absence of a sleeving deal, noting that savings to consumers are balanced by lower generation income
  - Behind the meter co-location – generation (and batteries) behind the meter and offsetting energy imports
  - EV supply – similar to the above, but with additional demand from EVs which grows over time according to profiles supplied by ESC
  - Local energy markets – selling energy from ground-mount solar (and potentially other exports from assets) to other LA consumption sites in the immediate area, without paying TPCs to carry energy over networks
    - Note that this model is discussed under ground mount solar arrays only, as these are the only ones where this model is relevant due to minimal exports from other sites over time
- The optimisation process takes an hourly approach to modelling

- Demand, solar generation, wholesale power prices, and TPCs are assessed for each network node and each of the specific UCEGM sites on an hourly basis
  - The specific sites are those being considered under Workstream 1 of UCEGM
  - These are modelled neither as recommendations nor as statements of district's intended approaches, but as useful potential examples
- Generation and demand show how much needs to be imported
- If batteries are included, these follow the following behaviour:
  - Charge during lowest cost periods
    - From excess solar at wholesale prices
    - Form import at wholesale price plus TPCs
  - Export during high cost periods, to offset import and – if prices rise high enough – to earn from wholesale arbitrage
  - Cycles are limited to 3 per day, to preserve the capacity of the batteries, and the assets will dispatch at their maximum capacity to charge or discharge
  - Overall operation is targeted to minimise costs to the site and, for LMP runs, overall wholesale costs at the node
    - Both approaches maximise economic benefits to the site, and to the wider

Site	Demand type	Solar (kW)	Battery (kW)	EVs?
Turnpike	Depot	469	234.5 / 469 / 938	Yes
Swinton Road	Depot	173	86.5 / 173 / 346	Yes
Chamber House Farm	PV only	5,500	2,750 / 5,500 / 11,000	No
Kenyon Way	PV only	2,532	1,266 / 2,532 / 5,064	No
Grande Central	Leisure centre	210	105 / 210 / 420	No
Robin Park	Leisure centre	280	140 / 280 / 560	No

Key assumptions

- The region modelled is all connections to the following Grid Supply Points: Bold, Bredbury, Carrington, Harker, Hutton, Kearsley, Kirby, Macclesfield, Paidham, Penwortham, Rochdale, South Manchester, Staylbridge, Washway Farm and Whitegate
- Demand grows according to our own forecasts (based in part on National Grid Electricity System Operator's forecasts)
  - New demand is allocated as growth to existing demand sites
  - Demand for EVs at specific LA sites is based on data supplied by ESC
- We have used annual demand volumes for each site in LAs profiles, based on data provided by each LA
  - Half-hourly metered data was provided by some LAs, with which we created consumption profiles
  - These profiles were categorised by type and applied to all buildings with specific half-hourly data in other LA portfolios
- Network (transmission and distribution) network buildout is as set out in Long-Term Development Statements; this runs out in around 10 years and network constraint tends to increase from this point as demand continues to increase
- Several sites are heavily constrained under some of the scenarios, with prices at or near the Value of Lost Load (£6,000/MWh). We have edited results to remove these, as they present a false picture of returns for batteries and solar, which can assess these prices
  - As analysis of results shows, limited constraint is better for solar/battery revenues than no constraint, as these assets can access value by acting to mitigate these constraints and control costs
  - Severe constraint, however, prevents users accessing power and drives lower returns due to blackouts and disconnections, and is negative for value. In the real world, networks would invest in wires to mitigate severe constraint, while looking to markets to manage moderate constraint
- Location of new generation is important to signal the balance of generation and demand at each network node, in future periods. Individually allocating all new generators is too complex for the scope of this project
- Under the Locational Marginal Pricing scenario, new generation is allocated:
  - In the short term, based on our renewable energy pipeline tracker, which identifies new generation build locations
  - In the long term, to the same locations as existing generation of the same technology
- Retirement of existing (and future-build) fossil fuel plant is modelled on an economic basis in our BPC model, including all costs and revenue streams; generation is retired on a locational basis
- Under all market paradigms, EV growth is allocated to all residential regions equally. No brand-new nexuses of EV growth are included
- No large-scale electrolytic production of hydrogen in this area is expected
- Import costs presented in £/kW terms relate this to the size of the solar array. As these arrays are sized according to expected build, rather than size of peak demand, these values should only be compared within a site, not between sites, and do not provide useful data if compared between sites
- In terms of income, it is likely that a PPA would need to be agreed for the site with an offtaker (an energy supplier or trader). This would include a discount, with generators currently retaining around 93-97% of revenue on average, depending on the terms (e.g., duration) of the deal struck
- Similarly, LAs currently typically strike one or two year fixed-term contracts for buying energy
  - Neither is not modelled here, where we assume that LAs will be exposed to underlying power prices on a time-of-use basis, to illustrate the benefits (or otherwise) of exposure to directly to energy markets

Validation

- The outputs of the model have been validated in three ways:

Results do not show network lines overloaded in the short term, or severely overloaded within the planned network reinforcement of the local DNO

Results do not show consumers unable to access power (lost load) in the short term

Results demonstrate behaviours expected in the short term, and with forecast behaviours demonstrated in our other forecasts and previous modelling projects conducted over the longer term

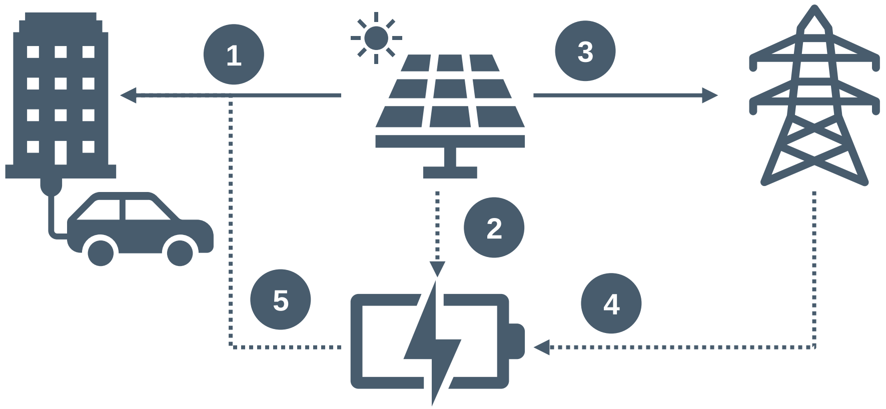
Modelling results – UCEGM sites

Note that additional results are presented in the attached databook, including High and Low scenarios

Solar carports – site details

- We modelled two sites with solar carports – awnings above carparks with solar arrays mounted – and co-located EV chargers
- Charging of EV fleets are expected to increase at these sites over time, and make up large volumes of consumption: far larger than the onsite power generation
- Turnpike has a 469kWp of solar generation, while Swinton Road has 173kWp
- The business model for these assets is to supply power to any existing load onsite, and to EV chargers installed onsite, exporting the remainder to the grid
  - Revenues are better for power consumed onsite, which is assumed to displace import (which would also incur TPCs), than for power exported from the site
- Both sites see considerable EV load, developing over time according to a profile supplied by ESC. This is expected to be a mix of domestic charging and potentially fleets of LA vehicles

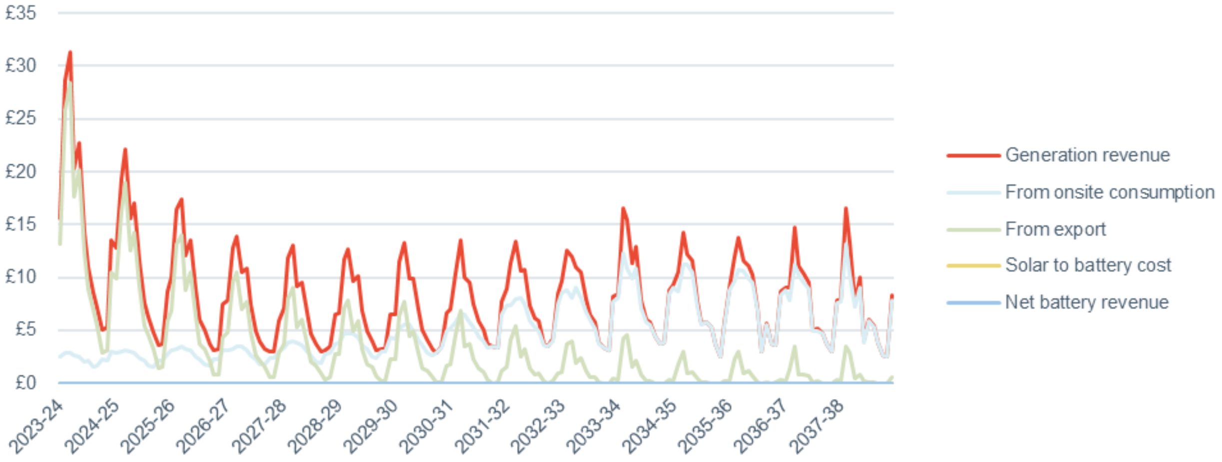
- We added batteries matched to the size of the solar arrays, and sensitivities at half and double this size. Each is modelled at 2-hour duration
  - These are modelled to optimise value
  - Charging from solar (costed at wholesale price) or importing from the networks (wholesale plus TPCs and losses)
  - Discharging to supply onsite consumption to charge EVs (valued at wholesale plus TPCs and losses) and to export to the networks (valued at wholesale price)



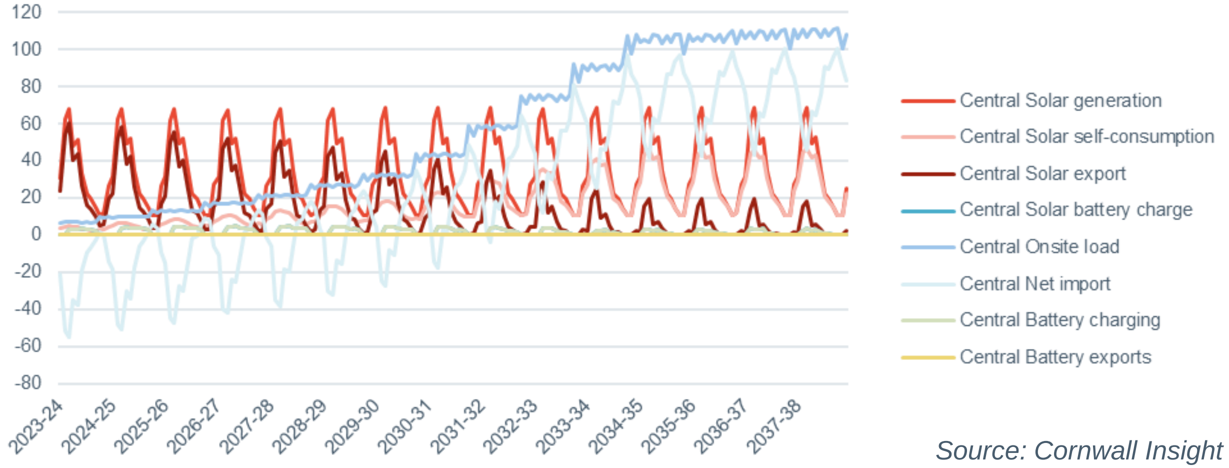
Solar carports – Turnpike results (no batteries)

- The Turnpike site is the larger of the two, with 469kWp of solar. This initially results in significant exports from the site, as there is excess energy generation
- As EV demand builds, exports fall and imports increase to supply this load. This sees site costs increase as a result
- The site is not in a constrained region, and therefore no issues with added EV chargers and demand are expected despite the disparity between total EV demand and onsite generation
- The average sales revenue for the solar array, over the modelled period, is £101/kWp/year
  - This is derived by dividing total revenue by the kWp size of the generator
  - Revenue arises from sales to the grid (export), power consumed onsite, and power used to charge any battery assets onsite
- This does fall over the period, mostly due to the general fall in wholesale prices in the short term. Value over the longer term is supported by supplying to the EV charges
  - This provides additional value to the solar by offsetting TPCs for importing power
- There is no curtailment of the solar expected at this site

Revenues in £/kW/month – Turnpike – National Central



Volumes in MWh/month – Turnpike – National Central



Source: Cornwall Insight

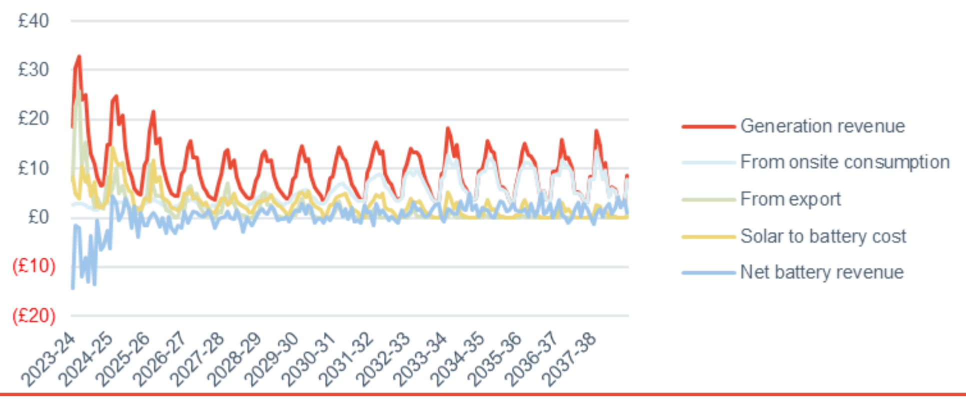
Solar car ports – Turnpike results (with batteries)

- Adding batteries to the site increases generation revenues, and adds a further revenue line for batteries
  - Under the National Central scenario, adding an equal-sized battery provides an additional £25/kW/year of revenue on average; export revenues drop while value is created by charging the battery
  - A double-sized battery provides £19/kW/year on average
- Around half of the power generation onsite continues to be immediately consumed by the onsite load, with 30% used to charge the battery and 20% exported
- While the battery revenues are not always positive, the total site revenue does increase

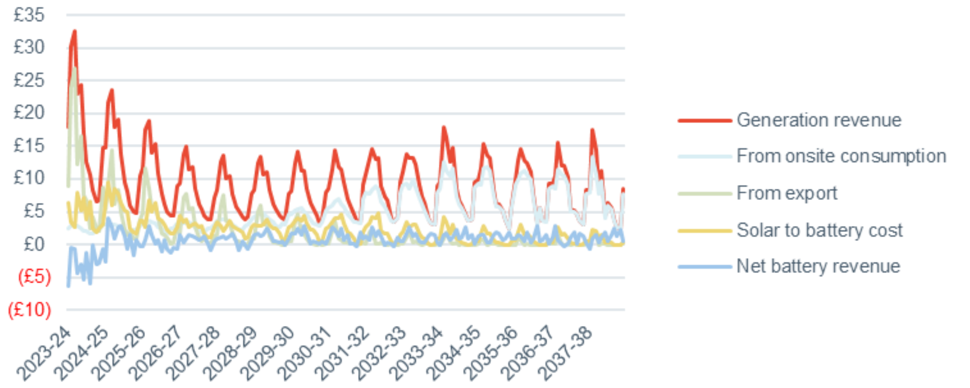
Average revenues in £/kW/year – Turnpike – National Central – entire period

Revenue, £/kW/year	Generation revenue (onsite)	Generation revenue (export)	Generation (battery charging)	Net battery revenue
None	£60	£41	£0	£0
Equal	£62	£24	£28	£9
Double	£63	£21	£32	£4
Half	£62	£29	£20	£9

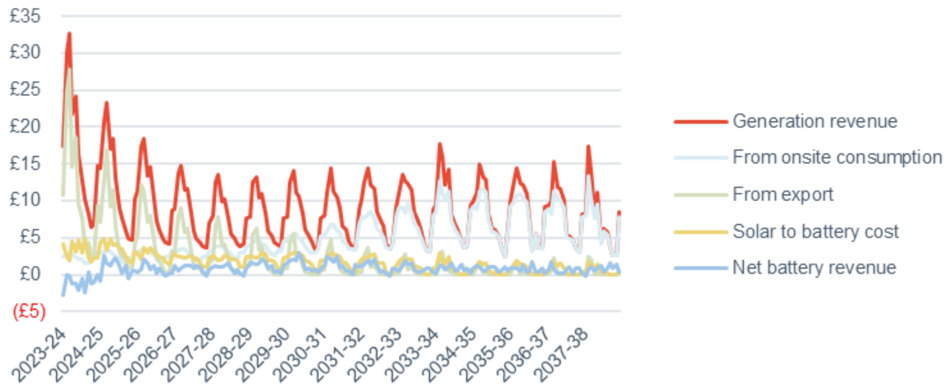
Revenues in £/kW /month – Turnpike – National Central – Double battery



Revenues in £/kW/month – Turnpike – National Central – Equal battery



Revenues in £/kW/month – Turnpike – National Central – Half battery



Source: Cornwall Insight

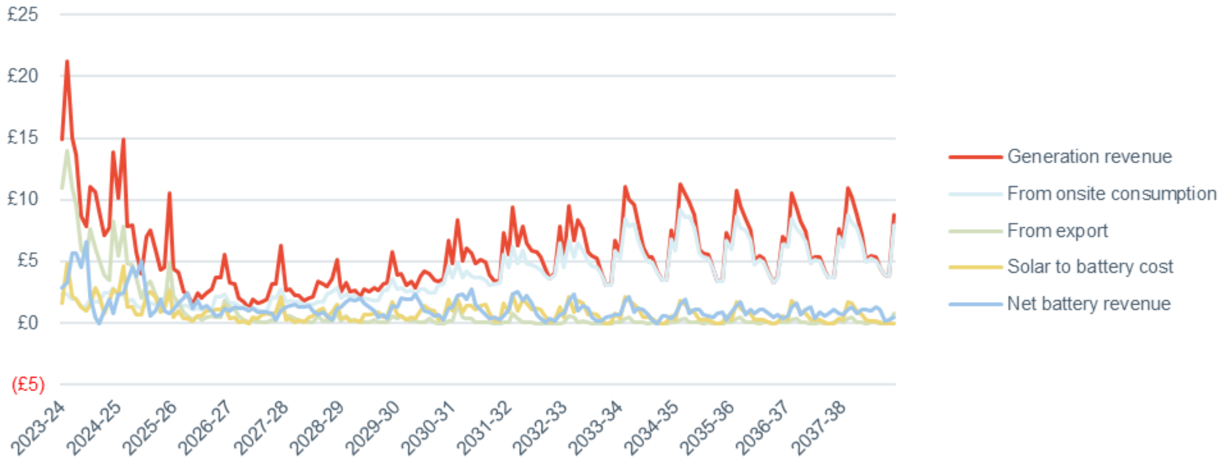
Solar car ports – Turnpike results (other scenarios)

- As the area is not significantly constrained, the site sees best revenues under the existing market paradigm, with revenue falling under other scenarios
- Though import costs also fall under these scenarios, the net position for the additional assets is negative for the site in both cases
  - The market splitting produces much lower revenues for generators as these are tied to a relatively low average market price and there is very little arbitrage opportunity in this scenario
  - Import costs are also relatively low, as in the near term much of the demand is supplied by the onsite generator (at the low cost), and in long-term, by the time import due to EVs has increased to require significant impacts the renewable share of generation on the sider system has increased sufficiently to minimise costs
- This provides an important learning for unconstrained sites in the region in general – where there is onsite generation and storage – being less constrained is net positive for the assets and scarcity rents due to constraint are not positive for the investment case
  - This view is complicated by the Robin Park site, discussed later, which sees that small amounts of constraint (over peak periods only) as net positive for asset income, as these assets act to mitigate this constraint

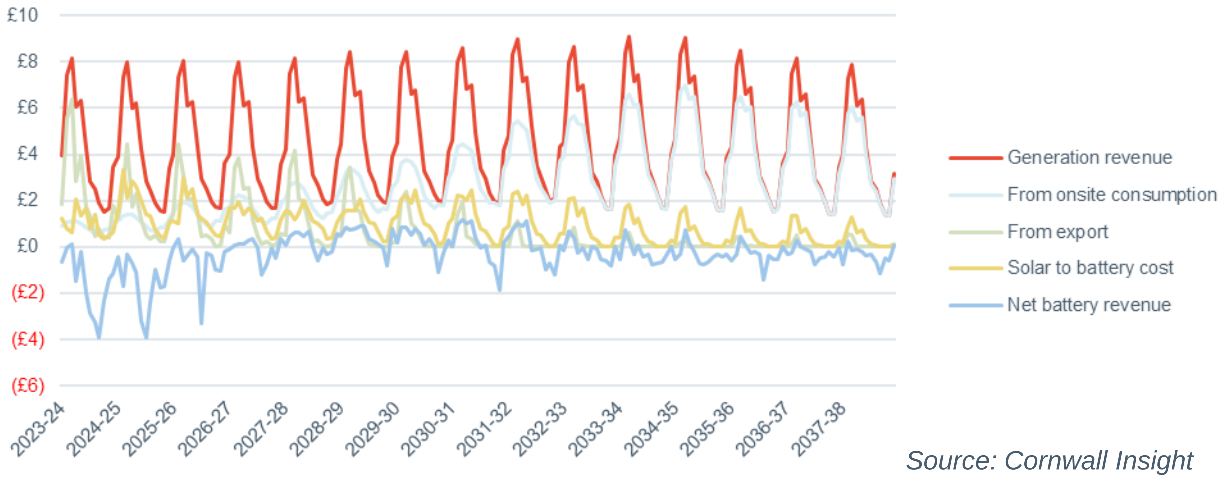
Average revenues in £/kW/year – Turnpike – Central – Equal battery

Revenue, £/kW/year	Generation revenue	Net battery revenue	Total benefits
National	£114	£9	£123
LMP	£68	£15	£83
Market splitting	£54	-£3	£51

Revenues in £/kW /month – Turnpike – LMP Central – Equal battery



Revenues in MWh/month – Turnpike – Market splitting Central – Equal battery

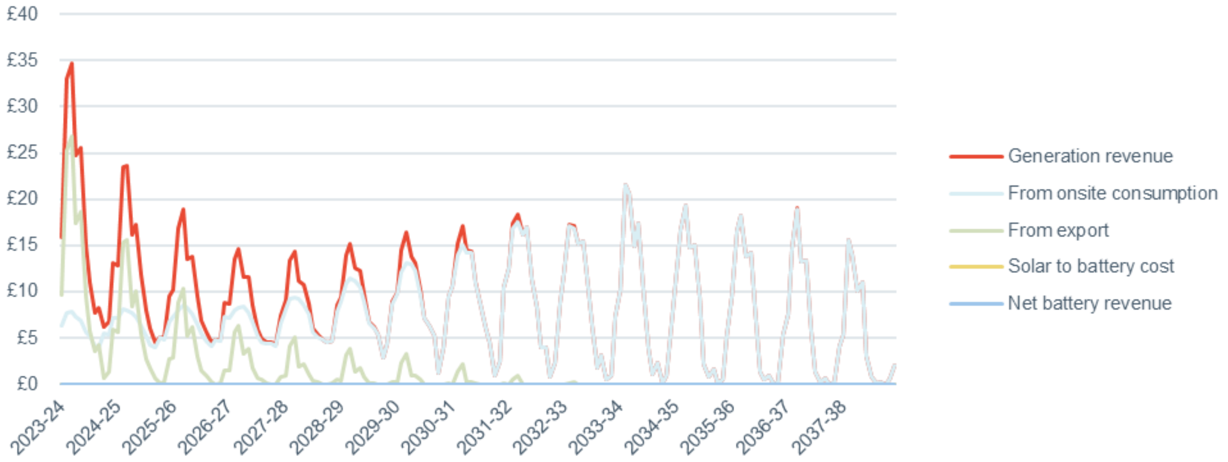


Source: Cornwall Insight

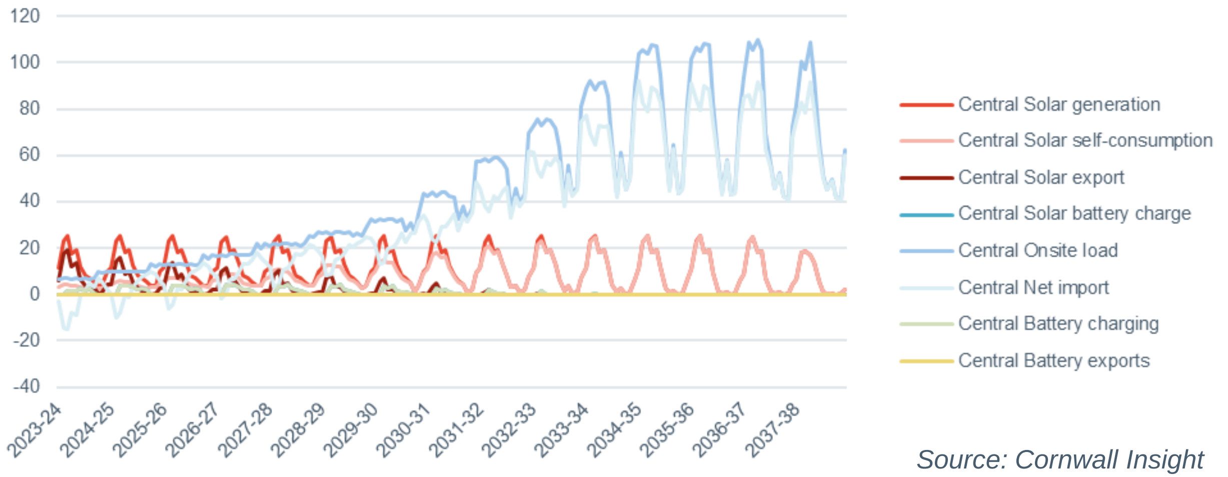
Solar carports – Swinton results (no batteries)

- The Swinton Road site has a much smaller generator and battery, but the same EV load profile. It is also connected to a constrained part of the network
- In early years, power is exported from the solar, but as EV demand grows this trend ceases, with an end in 2031-32
- This has a significant impact on ability to consume power from the networks, and results in the model out-turning prices at the Value of Lost Load: £6,000/MWh
  - We have removed the most extreme of these results (over £400/MWh) from the data presented here, in order to present information relevant to investments in assets
  - In the real world, we would expect that the DNO would invest to alleviate these serious constraints
  - Even following removal of VoLL prices, the import costs at Swinton Road are extremely high, reflecting the severe constraint
- Solar generation revenue over the period is £111/kWp/year, 10% higher than the Turnpike site, reflecting the higher level of solar self-consumption in early years, before both sites are consuming virtually all generation onsite
- As the majority of solar is consumed onsite, there is no constraint of exports – the node is restricted to import, and mostly due to the site's load, rather than other consumers
  - The constraint does not appear in the immediate data as it is not the connection to the neighbouring node which is constrained, but higher in the system

Revenues in £/kW/month – Swinton Road – National Central



Volumes in MWh/month – Swinton Road – National Central



Source: Cornwall Insight

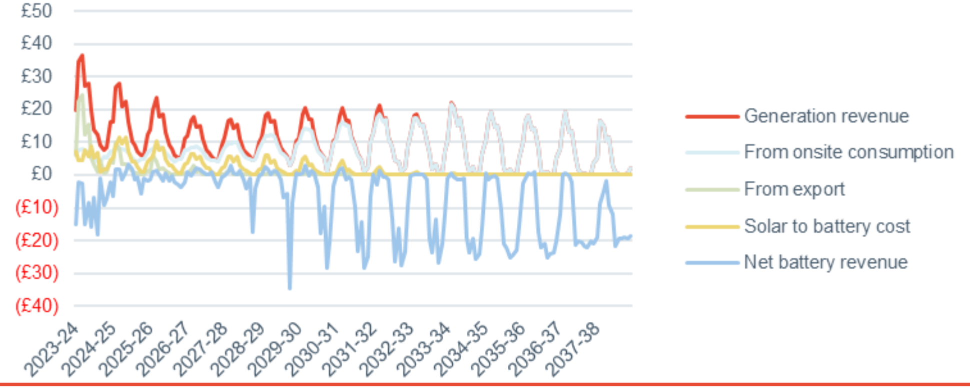
Solar car ports – Swinton Road results (with batteries)

- The extremely high demand at the Swinton site overwhelms all other market signals, even under the National pricing paradigm.
  - Detailed investigation of the behaviour of the model is correct, but the natural losses in the battery and the (planned) tendency for the battery to occasionally trade incorrectly result in overall net additional costs
  - In practice, either no battery would be operated, or a much larger battery would be installed onsite
- Ultimately, this may indicate that this site is not suitable for development as an EV hub – though under the current network operational paradigm, if a connection can be secured from the DNO, it would become the DNO's concern to reinforce (and pay for the reinforcement of) the network to meet this demand

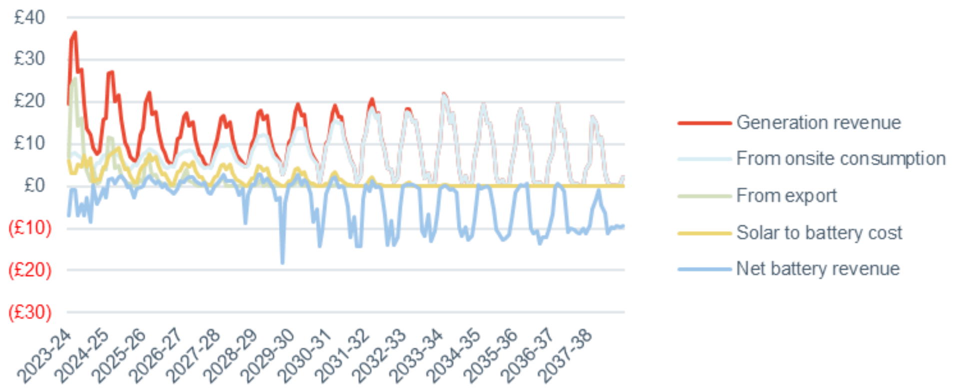
Average revenues in £/kW/year – Swinton Road – National Central – entire period

Revenue, £/kW/year	Generation revenue (onsite)	Generation revenue (export)	Generation (battery charging)	Net battery revenue
None	£91	£20	£0	£0
Equal	£93	£13	£19	-£43
Double	£93	£11	£22	-£92
Half	£92	£17	£14	-£19

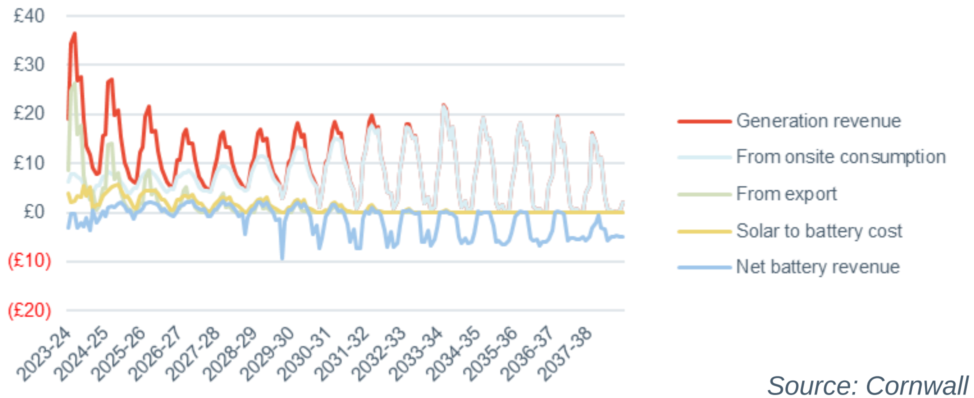
Revenues in £/kW/month – Swinton Road – National Central – Double battery



Revenues in £/kW/month – Swinton Road – National Central – Equal battery



Revenues in £/kW/month – Swinton Road – National Central – Half battery

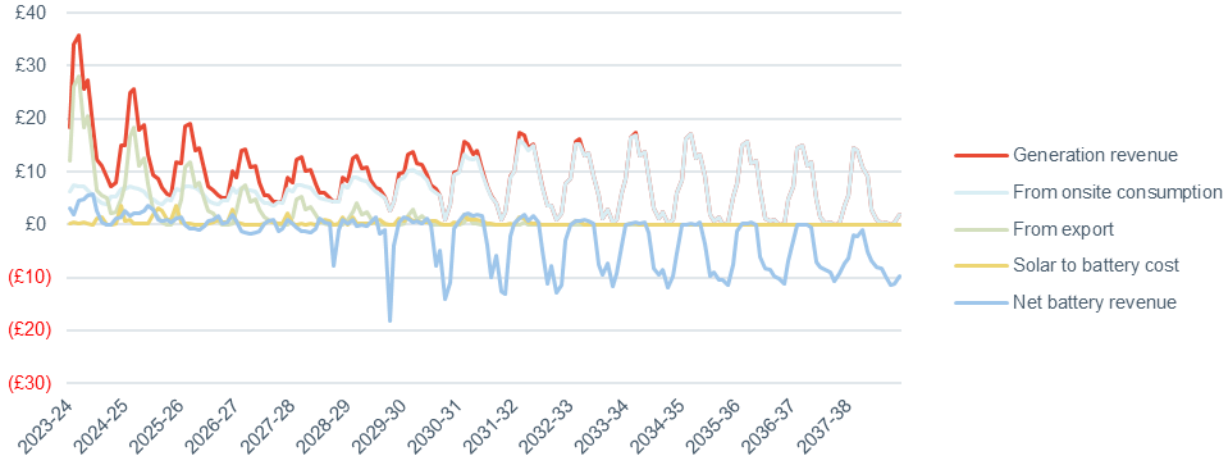


Source: Cornwall Insight

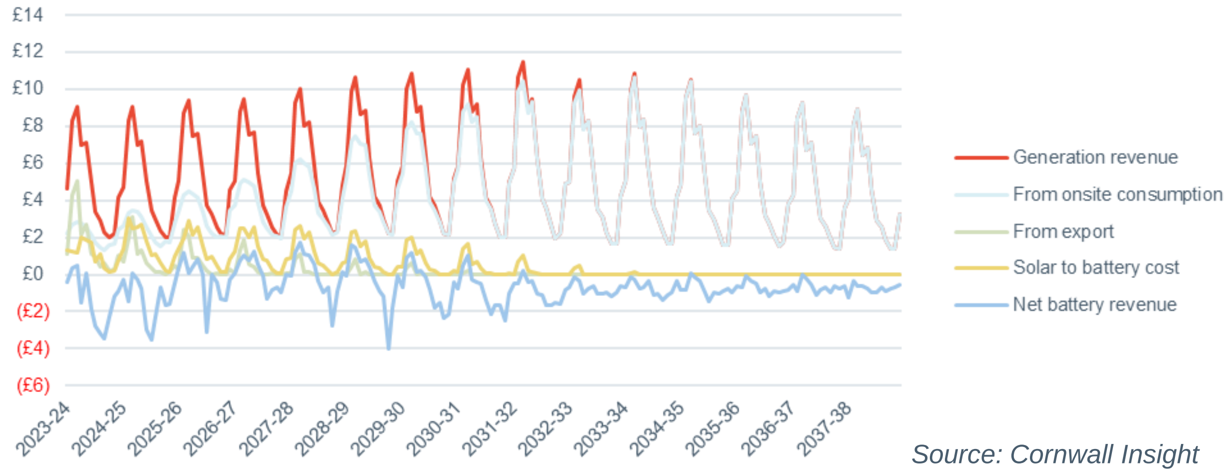
Solar car ports – Swinton Road results (other scenarios)

- Comparing the market scenarios, Swinton Road has some of the highest costs we see overall, due to the outsized demand
- The removal of VoLL pricing is more impactful on the LMP scenario, which have more natural variation, and results in a slightly lower price than the National scenario
- The site does provide a useful comparator to Turnpike under the Market splitting scenario, where import costs are much higher. This is partially due to the VoLL pricing concerns, but also due to the earlier date at which EV demand overtakes solar generation
  - This is happening consistently from 2025-26
  - It exposes the site more heavily to the dispatchable element of the power price, which drives up import costs compared to Turnpike
- Again, under these scenarios there is simply too much demand, compared to the size of the generation and flexibility assets, to enable efficient operation of batteries at the site

Revenues in £/kW/month – Swinton Road – LMP Central – Equal battery



Revenues in £/kW/month – Swinton Road– Market splitting Central – Equal battery



Source: Cornwall Insight

Average revenues in £/kW/year – Swinton Road – Central – Equal battery

Revenue, £/kW/year	Generation revenue	Net battery revenue	Total benefits
National	£125	-£43	£82
LMP	£108	-£31	£77
Market splitting	£63	-£8	£55

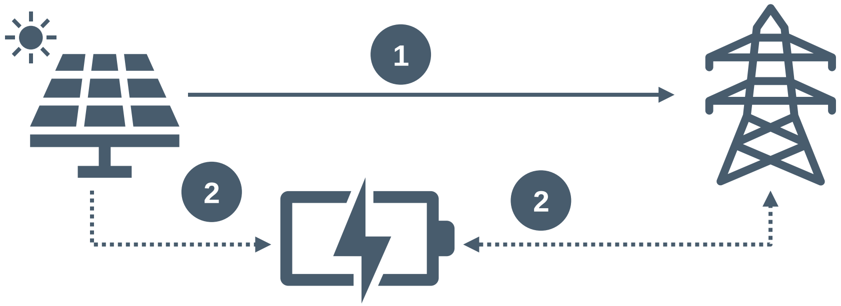
Solar carports – key takeaways

- Rather than charging from the solar, the batteries primarily import from the grid during low-priced overnight periods. This leaves the solar to export during peak midday generation periods. This is because the with-day variation in prices is favourable to this behaviour, with much higher demand during the day driving generally higher prices than overnight
  - This is typical of co-located solar-and-storage, though the addition of demand does increase the share of solar which will be used to charge the batteries due to the marginal increase in value caused by avoiding TPCs, particularly in the short-term when TPCs are higher
  - This is not true at all times, and solar is used to charge the batteries in scenarios where this is not immediately absorbed by the onsite load
  - In these instances, the batteries will often still charge from the grid during midday peaks, as avoiding the evening peak is overall economically beneficial
- In practice, the network operator will be unwilling to grant large network connections or connection upgrades in a region where constraint is expected, particularly for high-load consumers like EV chargers. They may alternatively pass on the cost of network reinforcement in the wider area
  - Reform to reinforcement charging rules has restricted the amount which users can be billed for wider reinforcement work, but "high cost" upgrades over a certain threshold (£1,720/kW in 2022-23) are still chargeable
- These sites particularly illustrate the value of considering the future of the network, where potential changes are being considered to market and charging structures which might impose the costs of the system on individual users of the network
- It also indicates that consideration should be given to scaling up the generation and storage assets, as electricity demand onsite grows

Ground-mounted solar – site details

- Two ground-mounted solar arrays were modelled; Chamber House Farm, at 5,500kWp, and Kenyon Way at 2,532kWp
- These assets have been modelled initially with a business model of selling power direct to market
  - This is 100% export, at the prevailing market rate for each of the wholesale pricing scenarios
  - This covers the sale to market and sleeved PPA business models
- Secondly, we have implemented a model assuming sale to local LA consumption at the same node – this would avoid the payment of Third Party Charges and improve the revenues of the asset
  - This covers the private wire and local energy market business models, with the difference being the need to build a private wire, versus use the public network
  - We assume that, as the LA owns both generation and consumption, the sharing of TPC savings between these entities is not material to value creation
  - Outturn results are discussed at the end of this section

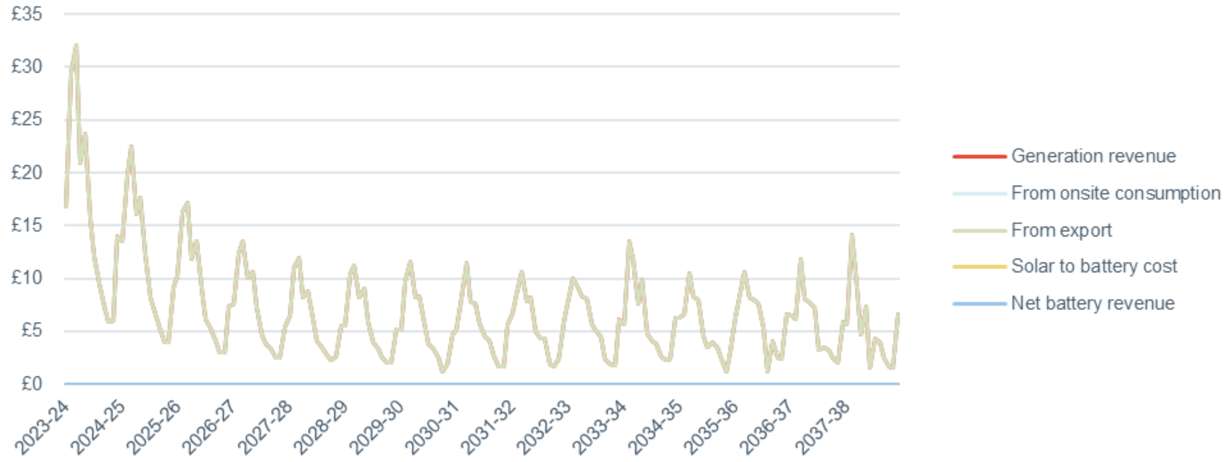
- We added batteries matched to the size of the solar arrays, and sensitivities at half and double this size. Each is modelled at 2-hour
  - These are modelled to optimise value
  - Charging from solar (costed at wholesale price) or importing from the networks (wholesale plus TPCs and losses)
  - Discharging to supply onsite consumption (valued at wholesale plus TPCs and losses) and to export to the networks (costed at wholesale price)
- Note that no revenue from ESO or DSO services is assumed
  - ESO service revenues (e.g., from Dynamic Containment) are in the process of falling rapidly. They are forecast to make up under 1% of the revenue stack over the lifetime of a battery
  - DSO service revenues are short-term, locational and highly uncertain. The LMP scenario provides a proxy for these values



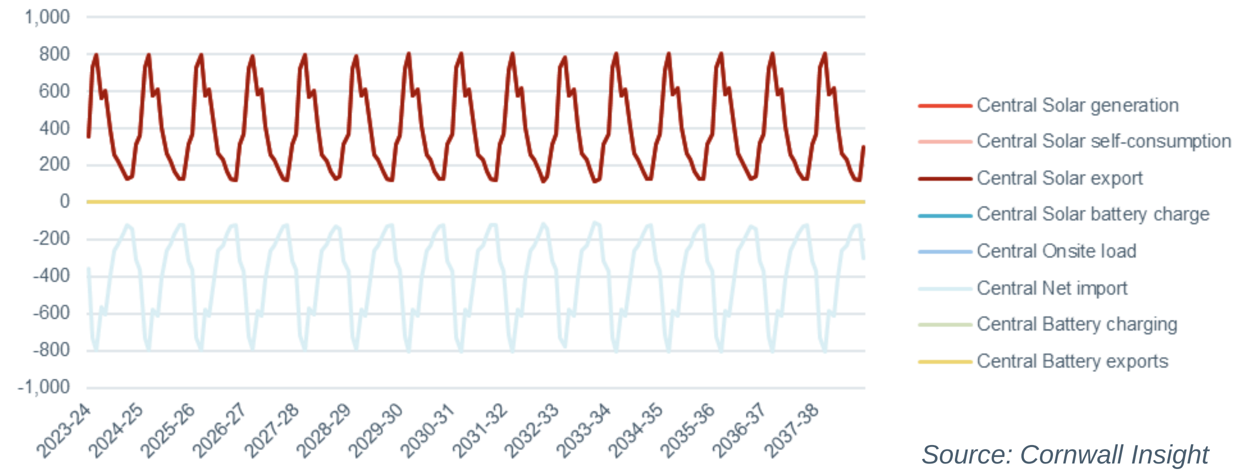
Ground-mount – Chamber House Farm results (no batteries)

- Chamber House Farm is the larger of the two solar standalone generators, at 5.5MW
- Its business model is simpler than other assets, selling power to the grid
- Average solar generation revenue is £85/kWp/year
  - There is no onsite consumption, so no opportunity to earn higher revenues by displacing import (which is priced at a higher cost due to non-commodity costs)
- Revenue tends to decrease over time, as the average wholesale price decreases

Revenues in £/kW/month – Chamber House Farm – National Central



Volumes in MWh/month – Chamber House Farm – National Central



Source: Cornwall Insight

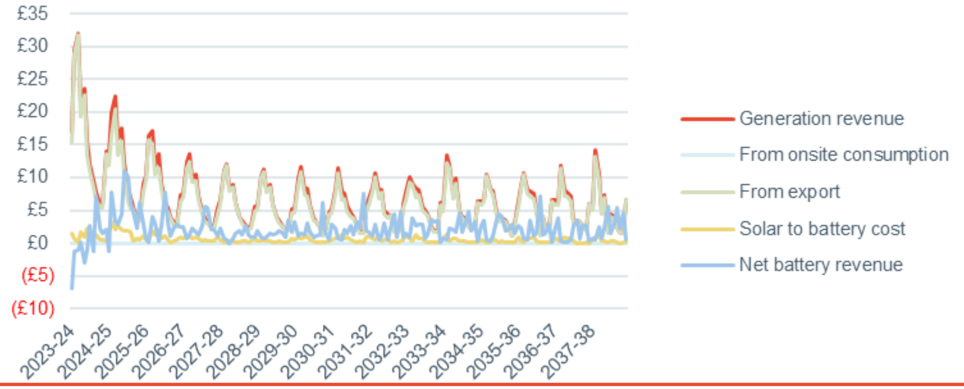
Ground-mount – Chamber House Farm results (with batteries)

- The batteries at the generation-only sites are able to deliver relatively superior value as they can import power without paying TPCs on this power. This enables them to cycle more frequently and have more opportunities to arbitrage energy prices
  - Note that the TPCs are still listed on the results datafile as these are used to calculated the potential LEM uplift – see slide
- The batteries may also be able to access opportunities in the Balancing Mechanism, in order to further uplift revenues
- However, with no onsite demand, there is no opportunity to increase solar self-consumption, which would in many cases provide higher value than wholesale arbitrage

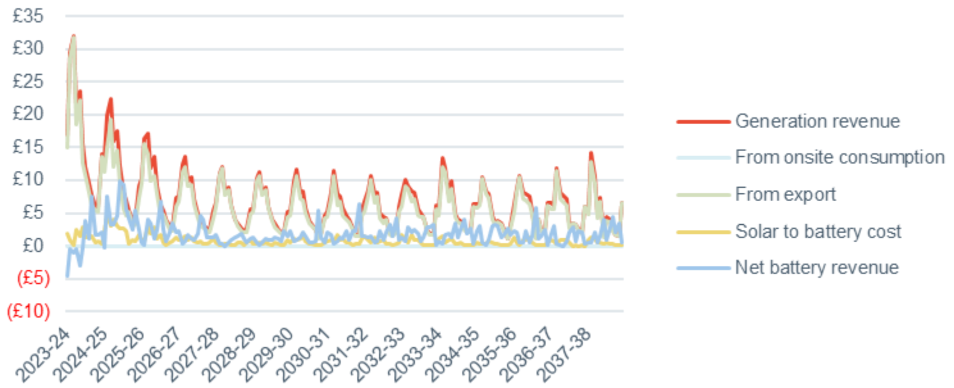
Average revenues in £/kW/year – Chamber House Farm – National Central – entire period

Revenue, £/kW/year	Generation revenue (onsite)	Generation revenue (export)	Generation (battery charging)	Net battery revenue
None	£0	£85	£0	£0
Equal	£0	£76	£9	£22
Double	£0	£78	£7	£26
Half	£0	£73	£13	£17

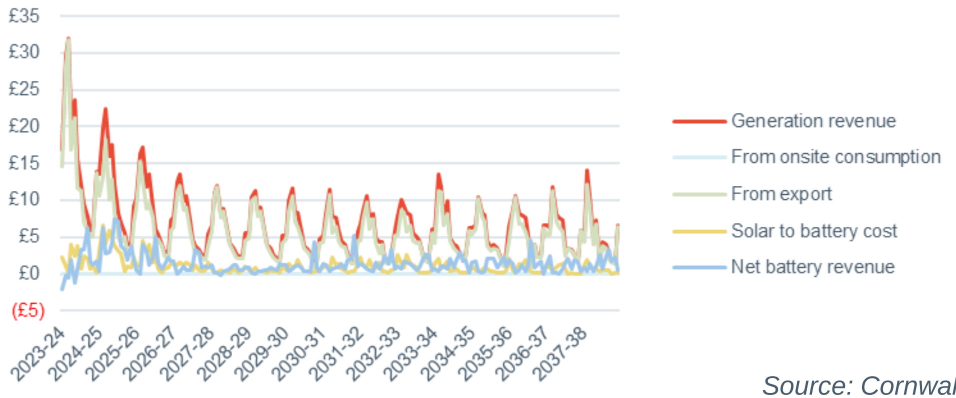
Revenues in £/kW/month – Chamber House Farm – National Central – Double battery



Revenues in £/kW/month – Chamber House Farm – National Central – Equal battery



Revenues in £/kW/month – Chamber House Farm – National Central – Half battery



Source: Cornwall Insight

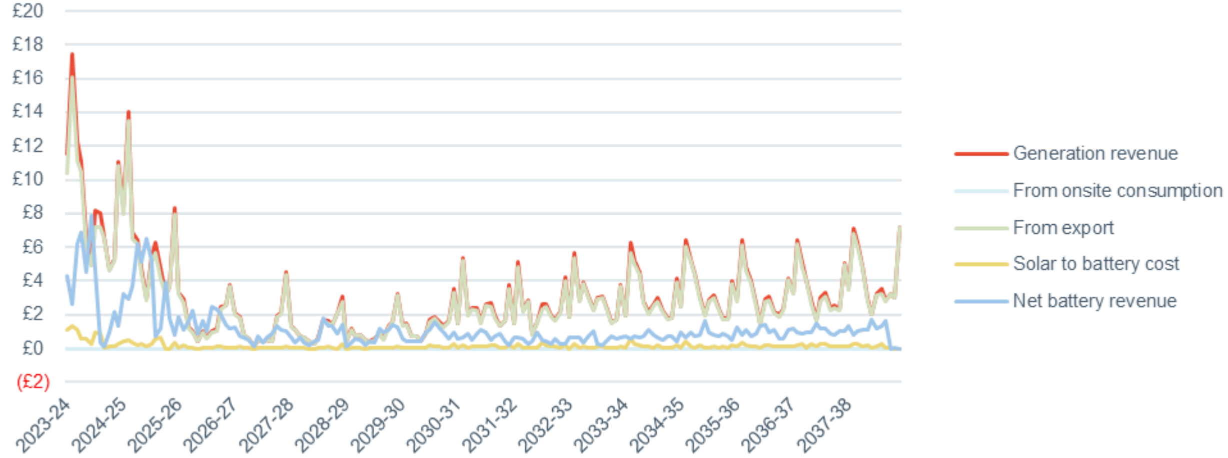
Ground-mount – Chamber House Farm results (other scenarios)

- The site sees value drops significantly under both the LMP and Market Splitting scenarios – though more in the former case, as the site is unconstrained
  - Because power can flow freely to local demand users, the neither the solar generator nor the battery drives congestion rents under the LMP scenario
- However, because the generator can turn intermittent solar generation under a fixed-marginal cost pricing model into dispatchable power under the variable pricing model, the site can deliver relatively high value under the market-splitting scenario
  - It is not yet clear whether this would be allowed under a reformed market, but we assume that it would be as it would encourage development of the storage assets necessary to balance the system
- Under both scenarios, the battery is able to increase revenues, but the revenue decreases versus trading nationally

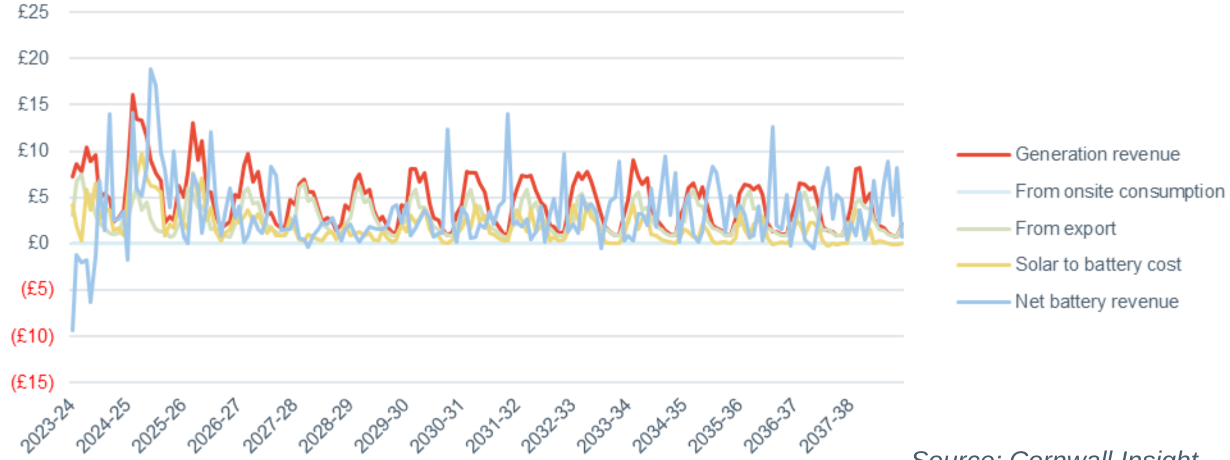
Average revenues in £/kW/year – Chamber House– Central – Equal battery

Revenue, £/kW/year	Generation revenue	Net battery revenue	Total benefits
National	£85	£22	£107
LMP	£38	£14	£52
Market splitting	£55	£40	£96

Revenues in £/kW/month – Chamber House Farm – LMP Central – Equal battery



Revenues in £/kW/month – Chamber House Farm – Market splitting Central – Equal battery

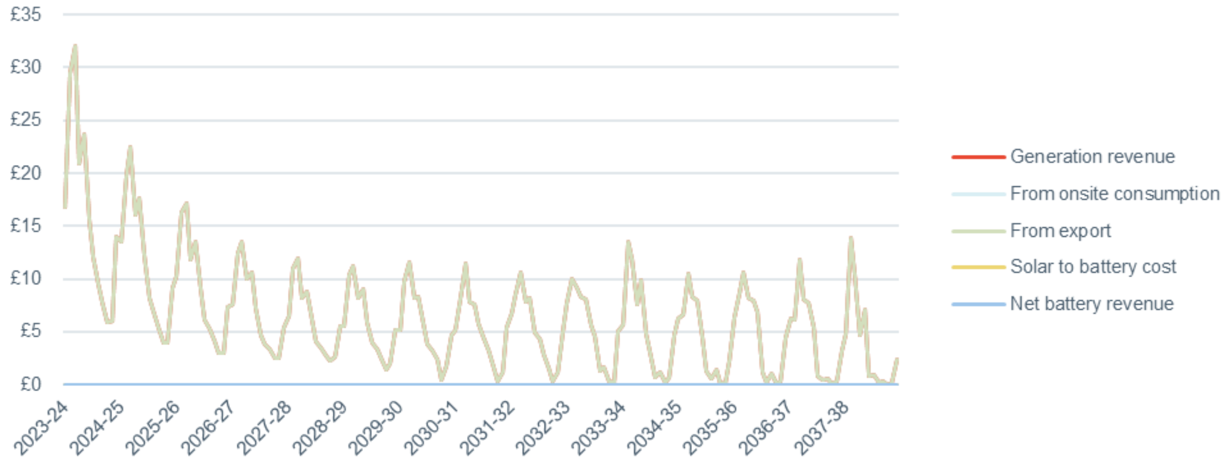


Source: Cornwall Insight

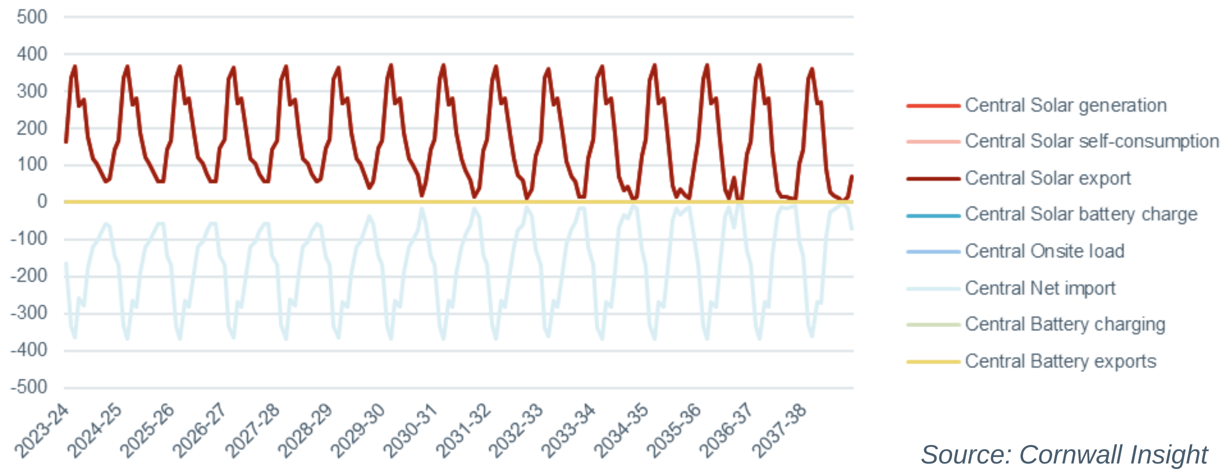
Ground-mount – Kenyon Way results (no batteries)

- The Kenyon Way site is smaller than Chamber House, at only 2.5MW, but is located in a constrained region
  - This constraint appears for exports, later in the modelling period
- Again, the site sells power to the grid, at the prevailing price, under the baseline scenario
- Revenue is £79/kWp/year, slightly lower than the other site, due to the constraint later in the modelling period
- Revenue could be increased if linked with a local consumer, with TPCs shared between parties
- If the sites were linked physically with a private wire, the parties may be able to avoid constraint as well as reduce exposure to TPCs

Revenues in £/kW/month – Kenyon Way – National Central



Volumes in MWh/month – Kenyon Way – National Central



Source: Cornwall Insight

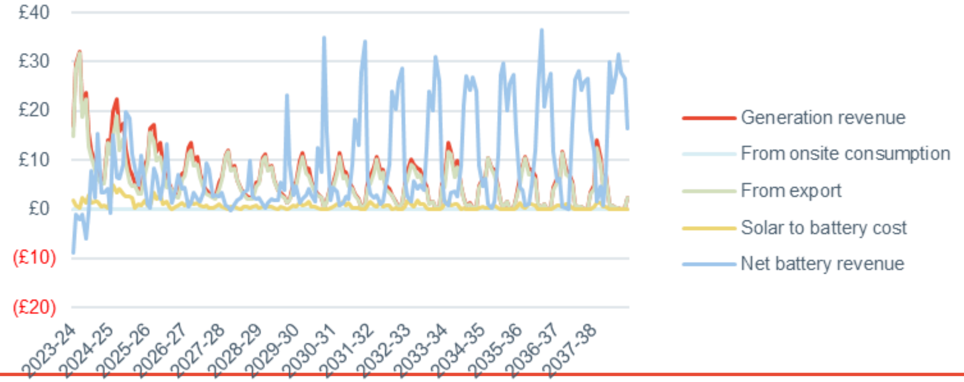
Ground-mount – Kenyon Way results (with batteries)

- Batteries connected to the system away from consumption are not exposed to TPCs, and the returns are typically higher, as the batteries are not paying TPCs for energy imported and later exported to the grid
- Kenyon Way sees the highest level of battery revenue of any site for the batteries. This is partially driven by the limited constraint on the site, which allows tapping of low-cost solar which would otherwise not be produced
- However, the level of constraint on the grid is preventing the asset from trading effectively and driving extensive losses from the batteries. It is likely that the location simply is not suitable for deployment of battery assets

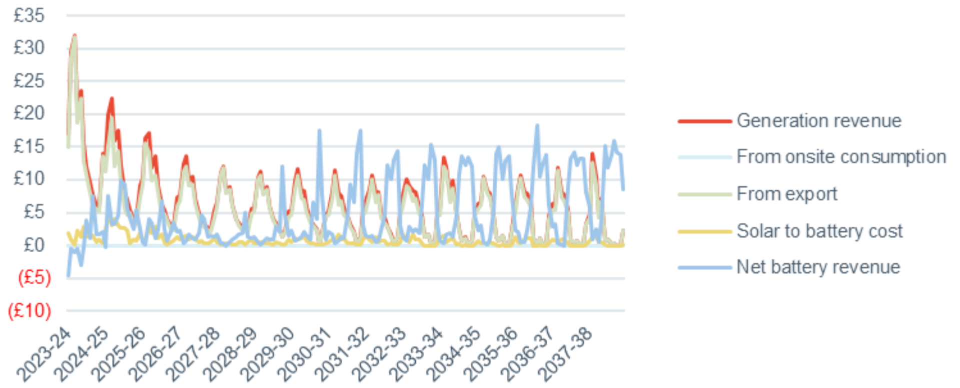
Average revenues in £/kW/year – Kenyon Way – National Central – entire period

Revenue, £/kW/year	Generation revenue (onsite)	Generation revenue (export)	Generation (battery charging)	Net battery revenue
None	£0	£79	£0	£0
Equal	£0	£70	£9	£57
Double	£0	£70	£9	£113
Half	£0	£71	£8	£29

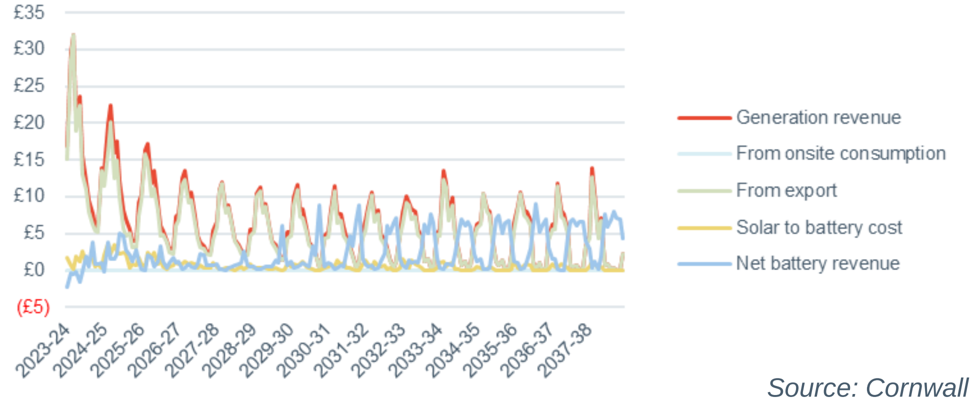
Revenues in £/kW/month – Kenyon Way – National Central – Double battery



Revenues in £/kW/month – Kenyon Way – National Central – Equal battery



Revenues in £/kW/month – Kenyon Way – National Central – Half battery

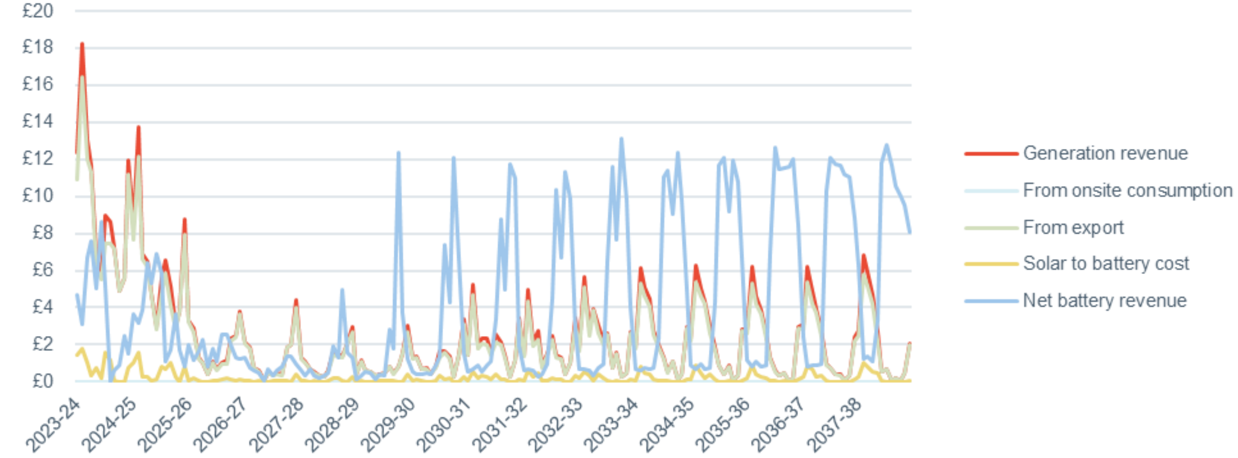


Source: Cornwall Insight

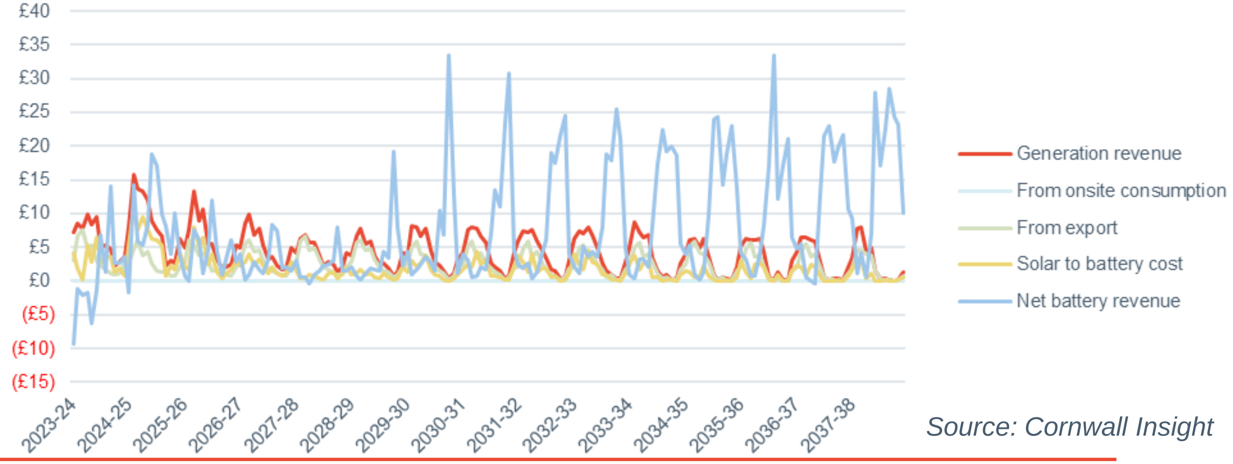
Ground-mount – Kenyon Way results (other scenarios)

- Kenyon Way sees the highest value of any site under the LMP scenario and the Market Splitting scenario
- This is due to the low level of network congestion, with the battery assets able to operate efficiently and sell power out to the network at the optimum times
- Again this demonstrates that limited network constraint can deliver additional value, even though higher levels of long-term constraint is negative for the investment case

Revenues in £/kW/month – Kenyon Way – LMP Central – Equal battery



Revenues in £/kW/month – Kenyon Way – Market splitting Central – Equal battery



Average revenues in £/kW/year – Kenyon Way – Central – Equal battery

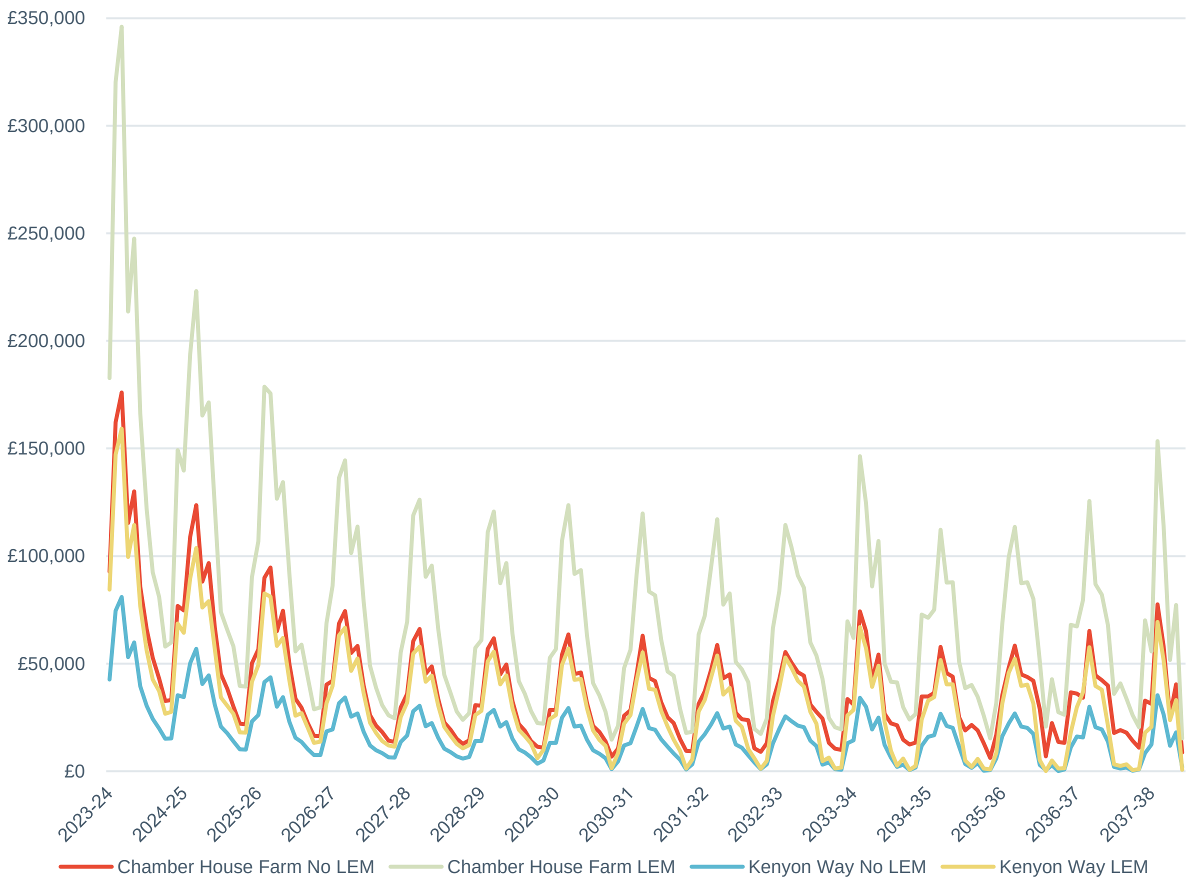
Revenue, £/kW/year	Generation revenue	Net battery revenue	Total benefits
National	£79	£57	£136
LMP	£32	£49	£81
Market splitting	£53	£92	£144

Source: Cornwall Insight

Ground-mount solar – Local Markets

- The ground-mount arrays export large volumes of energy, which can be sold to other users under Power Purchase Agreements
- As electricity is passed over the public networks, this exposes consumers to TPCs. Avoiding some of these TPCs under a "Local Market" model creates additional value which can be shared between parties
  - We assume that, as both generation and consumption are owned by the LA, the internal share of these is irrelevant, and have tracked the additional value with an uplift to the generation revenue
- The additional TPC value is modelled as the avoidable TPCs (the policy as opposed to network elements) multiplied by the units of electricity exported from the generators
  - The policy element initially makes up ~85% of TPCs, falling to ~64% over the modelling period
  - The LAs consumption portfolios are of sufficient size to absorb all electricity generated, across all regional sites
- Uplift is significant, particularly in the years before TPCs start to fall in the late 2020s. As avoidable TPCs fall, the benefit reduces. The average uplift is nearly double for both sites (91-92% uplift)
- However, note the government's statement in the *Powering Up Britain* policy document released March 2023, suggesting that "significant progress" will be made by end-2024 in rebalancing policy levies from electricity to gas
  - This could reduce the local market uplift considerably, by reducing the potential to avoid costs through a local market
  - It would also reduce the value of behind-the-meter generation

Revenues in £/month – ground-mount sites – National Central – Equal battery – with and without Local Market revenues



Source: Cornwall Insight

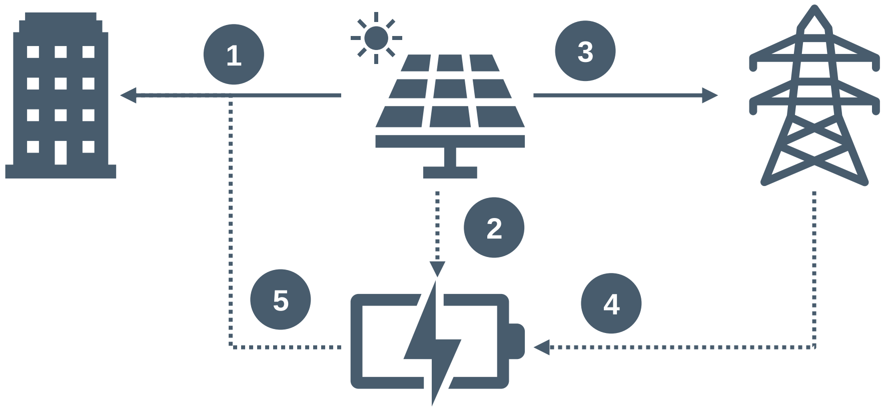
Ground-mount solar – key takeaways

- The constraints on the ground-mount arrays are primarily due to behaviour in the wider system, rather than the sites themselves. This does leave some room for operation and trading on the local node
  - This indicates that the sites are less likely to be liable for network reinforcement costs on deployment, as reinforcement would be required higher up the voltage levels
  - Despite constraint, the assets continue to make decent income on the markets, in line with or above other sites
- Revenues are significantly lower for the new market paradigms for both sites, though these standalone sites deliver much higher value than other sites. In the Market splitting scenario, this is compensated for by revenue stability and these standalone sites are delivering higher value by moving power from the long-run marginal cost market to the (more volatile) dispatchable market, which is assumed not to be possible for the more complex sites where generation is co-located with consumption
  - The opposite is true under the LMP scenario with lower revenues forecast
- There is currently significant potential value in local markets, where power supplied over the local network remains exempt from some policy charges. This could allow LAs to access cost-savings on consumption which enable an approximately 90% upside to generation revenues (though this value would in practice need to be shared between generator and consumer)
  - However, reform of these charges is expected to rebalance policy levies between the electricity and gas bills. This may dramatically reduce this value over the next two years – potentially by 50%. This in turn may make the establishment of these markets non-viable

Rooftop solar – site details

- We examined two example rooftop solar arrays, both installed on leisure centres: Grande Central (210kWp solar) and Robin Park (280kWp solar)
- The primary objective of these arrays is to produce power to be consumed onsite, displacing imports from the networks. This offers a higher marginal value for power than exporting power to the networks
  - Any excess generation will be sold to the networks

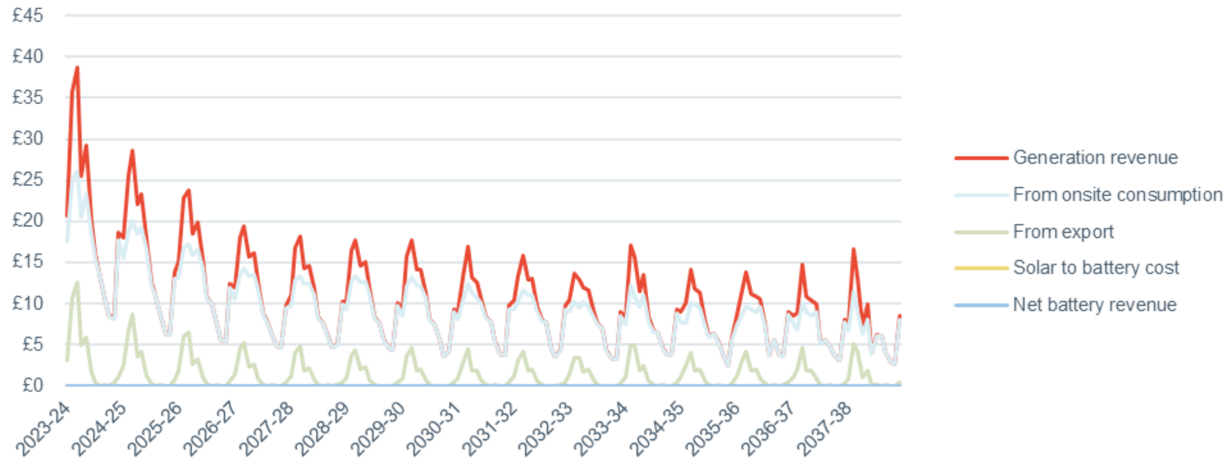
- We added batteries matched to the size of the solar arrays, and sensitivities at half and double this size. Each is modelled at 2-hour
  - These are modelled to optimise value
  - Charging from solar (costed at wholesale price) or importing from the networks (wholesale plus TPCs and losses)
  - Discharging to supply onsite consumption (valued at wholesale plus TPCs and losses) and to export to the networks (costed at wholesale price)



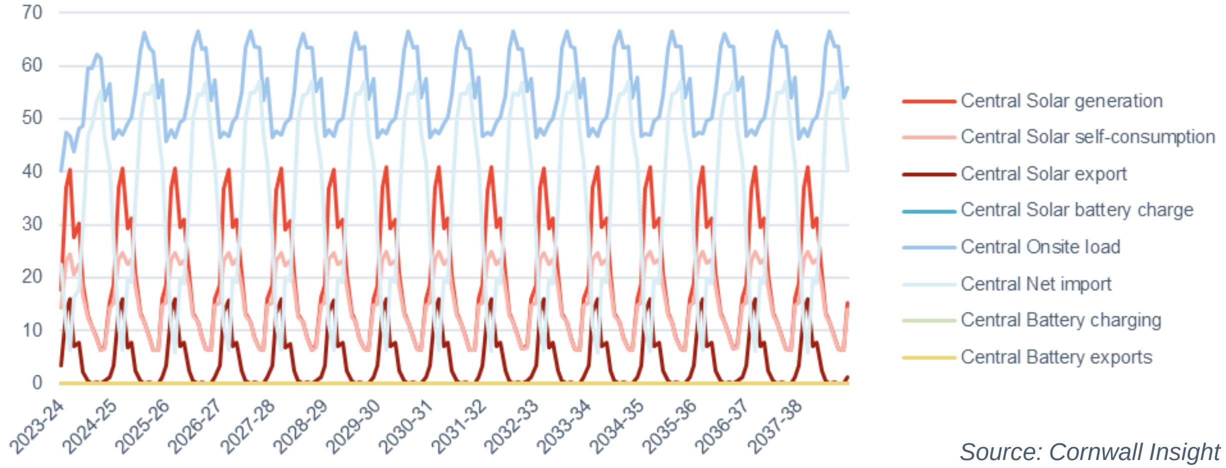
Rooftop solar – Robin Park results (no batteries)

- Like Turnpike, Robin Park is in an unconstrained area of the network; without EVs it also does not see demand increase to the same extent as the carport sites
- The consumption is nevertheless significant and above the expected generation from the solar arrays, however on an hourly basis, during solar peak generation periods large amounts of power are exported. This reduces average solar generation revenues per kWp
  - This is concealed in the monthly average results, only being apparent due to the lower solar generation revenue compared to sites with higher self-consumption percentages
- Average import costs decrease over the period as wholesale prices return closer to historic averages and TPCs decrease. They are lower in the summer, when solar generation produces more power and onsite load (e.g., heating load) is lower, than in the winter
- Average generation revenue over the period is £129/kW

Revenues in £/kW/month – Robin Park – National Central



Volumes in MWh/month – Robin Park – National Central



Source: Cornwall Insight

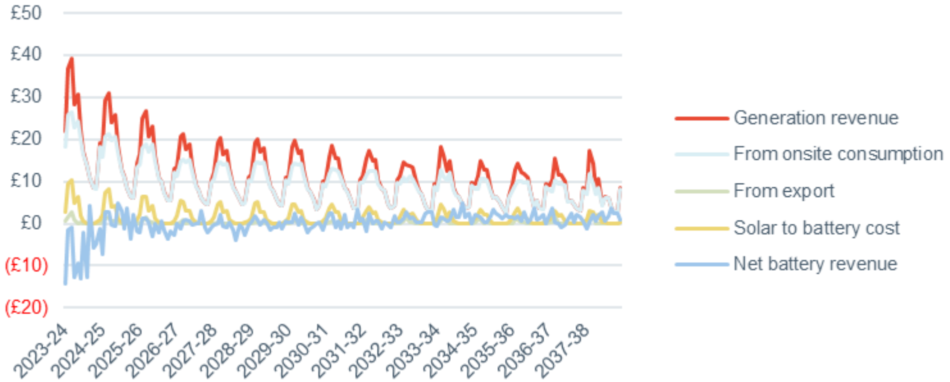
Rooftop solar – Robin Park results (with batteries)

- Due to the export constraints on the site, the batteries are able to offer a slight uplift in revenues – this is minimal in terms of the energy volumes (around 17% total, though not all of this is due to constraint), but provides a large impact on revenues due to the high prices at these times
- Note that this congestion exists wider in the system than the immediate node, and does not appear in volumes as congested solar

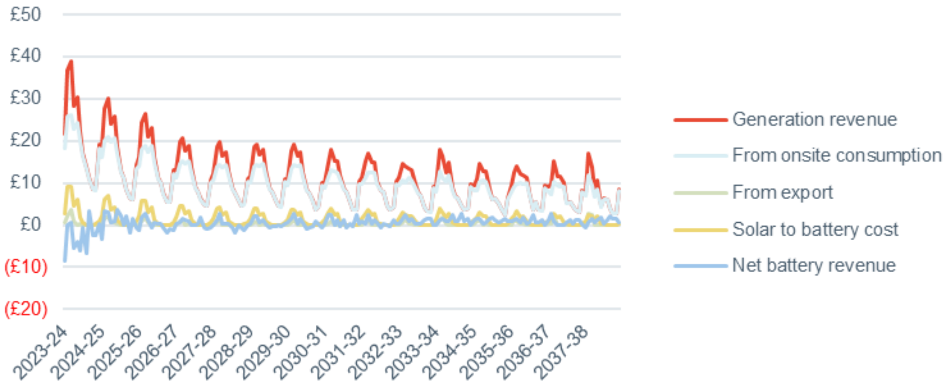
Average revenues in £/kW/year – Robin Park – National Central – entire period

Revenue, £/kW/year	Generation revenue (onsite)	Generation revenue (export)	Generation (battery charging)	Net battery revenue
None	£112	£18	£0	£0
Equal	£118	£3	£17	£6
Double	£118	£3	£18	£1
Half	£116	£17	£12	£7

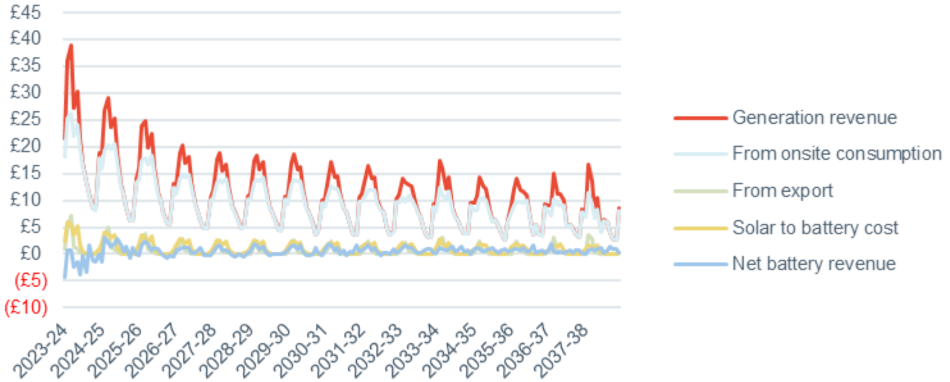
Revenues in £/kW/month – Robin Park – National Central – Double battery



Revenues in £/kW/month – Robin Park – National Central – Equal battery



Revenues in £/kW/month – Robin Park – National Central – Half battery



Source: Cornwall Insight

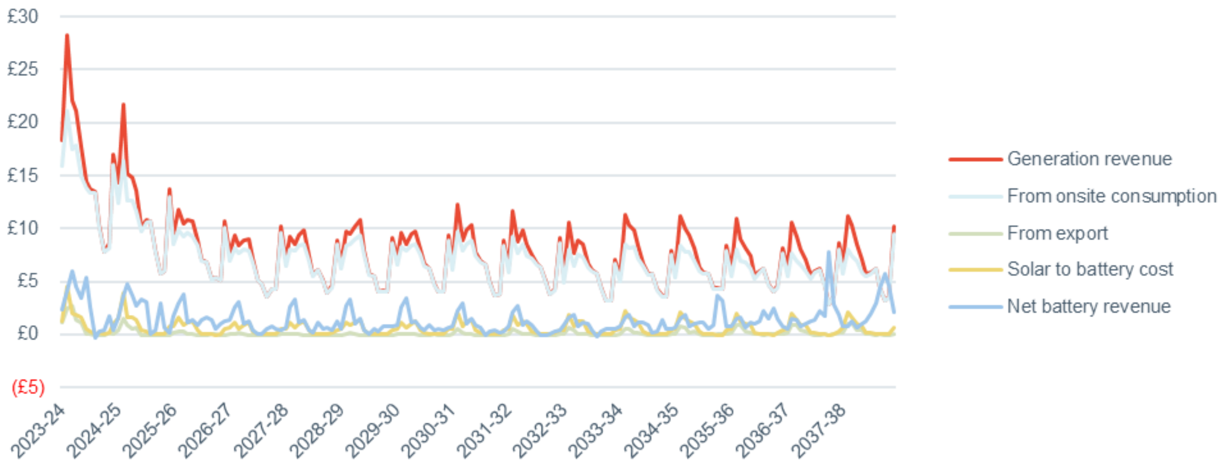
Rooftop solar – Robin Park results (other scenarios)

- Robin Park does see a small amount of network constraint, though this is a lot lower than for the Swinton Road EV hub
- Some constraint emerging at the end of the period provides an uplift to battery revenues, but also a small increase in costs to power the site – which is a much larger element than the revenues
  - This signals that small amounts of constraint are beneficial, as the onsite assets can act to mitigate this and shift load throughout the day
  - Large-scale constraint, where insufficient power is available for all users over substantial periods of the day, is what harms network users
- The Market Splitting scenario sees negative battery returns, as there is minimal arbitrage revenue available in this scenario
  - We assume that the site would earn export revenues as an intermittent, generator, rather than moving revenue to dispatchable, due to the complexity of the sites

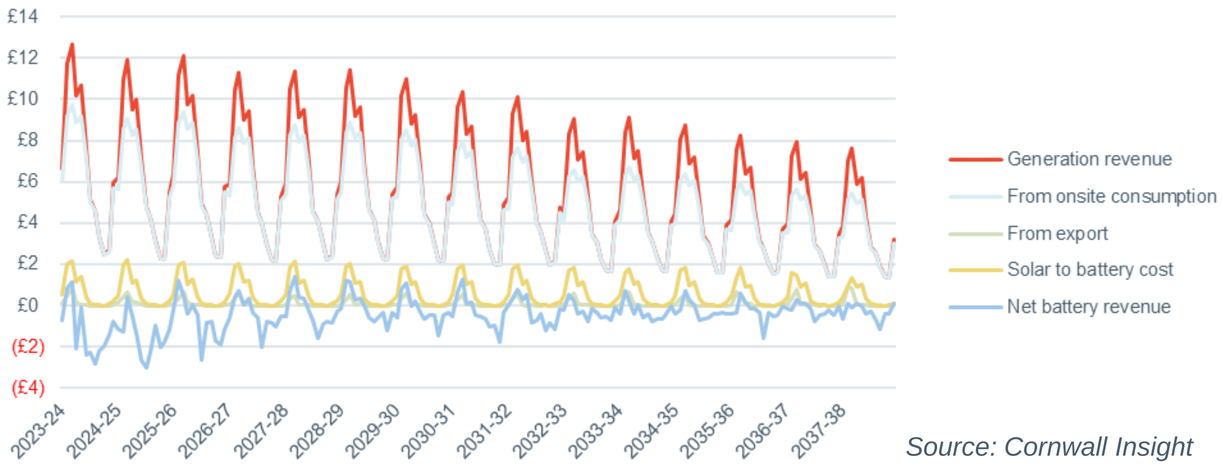
Average revenues in £/kW/year – Robin Park – Central – Equal battery

Revenue, £/kW/year	Generation revenue	Net battery revenue	Total benefits
National	£138	£6	£144
LMP	£97	£17	£114
Market splitting	£66	-£5	£61

Revenues in £/kW/month – Robin Park – LMP Central – Equal battery



Revenues in £/kW/month – Robin Park – Market splitting – Central – Equal battery

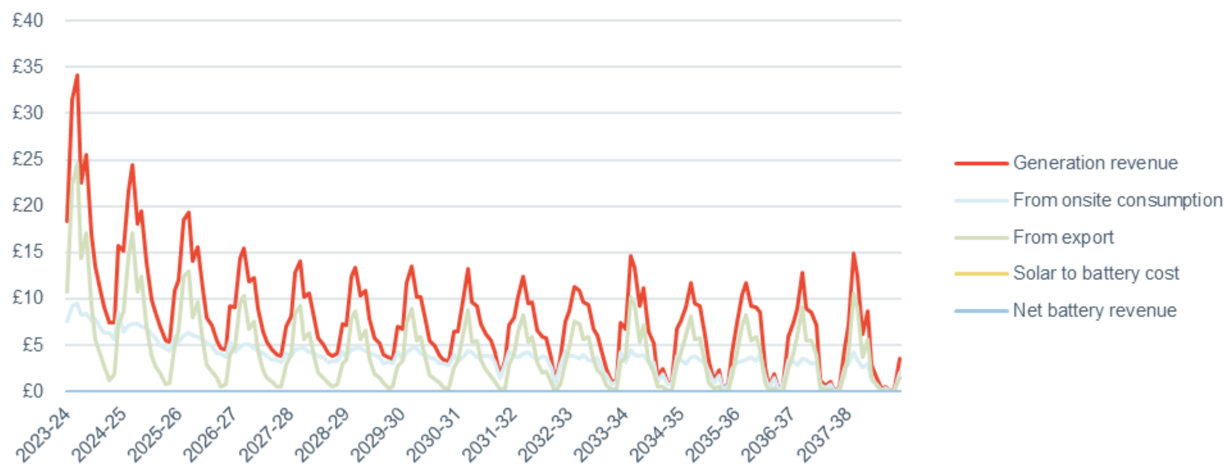


Source: Cornwall Insight

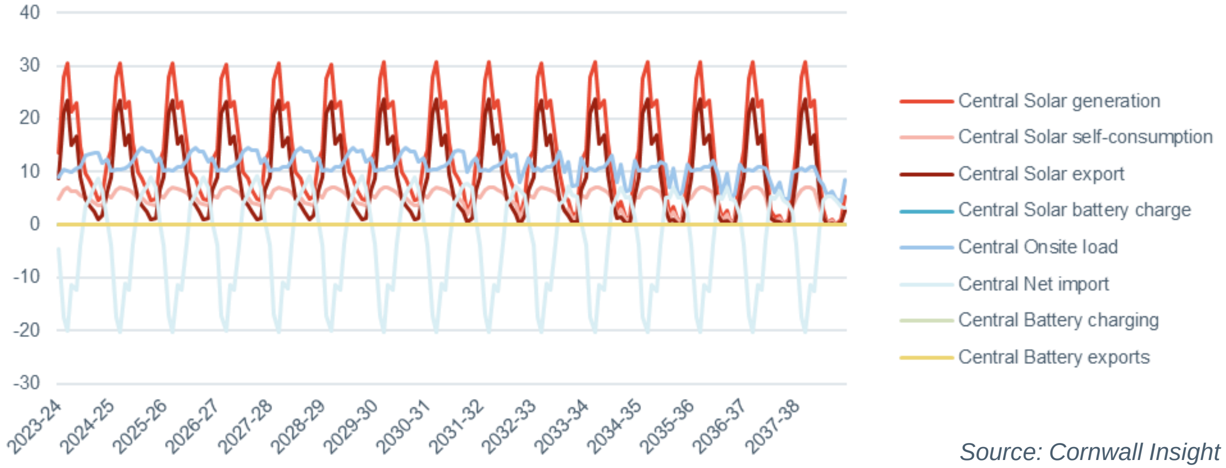
Rooftop solar – Grande Central results (no batteries)

- The Grande Central leisure centre site is in a constrained area of the region. Load remains steady over the period, but growth in demand from the rest of the region drives this constraint
  - This increases generation income, versus the Robin Park site where there is much less extensive constraint, as it is receiving some congestion rents
  - It will also not interfere as greatly with the operation of the batteries as some other sites
- As generation volumes are larger than import (averaging 14MWh/month versus 11MWh/month), while the import cost does rise, profits rise further in times of constraint
- Average generation income is £97/kW/year

Revenues in £/kW/month – Grande Central – National Central



Volumes in MWh/month – Grande Central – National Central



Source: Cornwall Insight

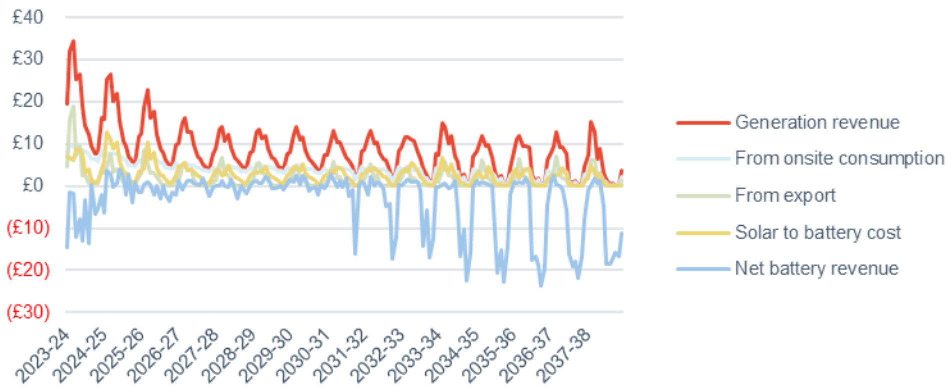
Rooftop solar – Grande Central results (with batteries)

- Adding the batteries improves the ability of the site to deal with constraint and reduce the impact of congestion. This increases solar revenue slightly as well as providing battery revenue
  - However, the level of constraint drives peak prices which are cut out of the results due to being excessively high
  - Benefits can be seen, as the value of the generation is higher with batteries deployed is higher than the value without (£97, £102, £106 and £100 for no battery and an equal, double and half-sized battery respectively)

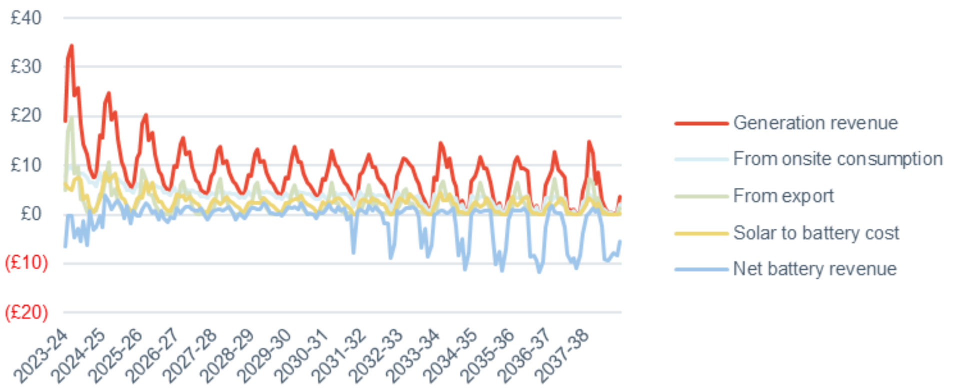
Average revenues in £/kW/year – Grande Central – National Central – entire period

Revenue, £/kW/year	Generation revenue (onsite)	Generation revenue (export)	Generation (battery charging)	Net battery revenue
None	£45	£52	£0	£0
Equal	£47	£27	£28	-£15
Double	£48	£24	£34	-£42
Half	£46	£32	£22	-£3

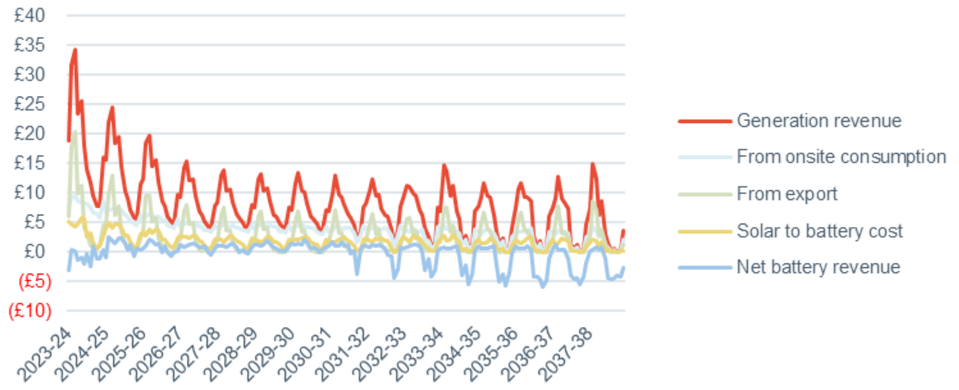
Revenues in £/kW/month – Grande Central – National Central – Double battery



Revenues in £/kW/month – Grande Central – National Central – Equal battery



Revenues in £/kW/month – Grande Central – National Central – Half battery



Source: Cornwall Insight

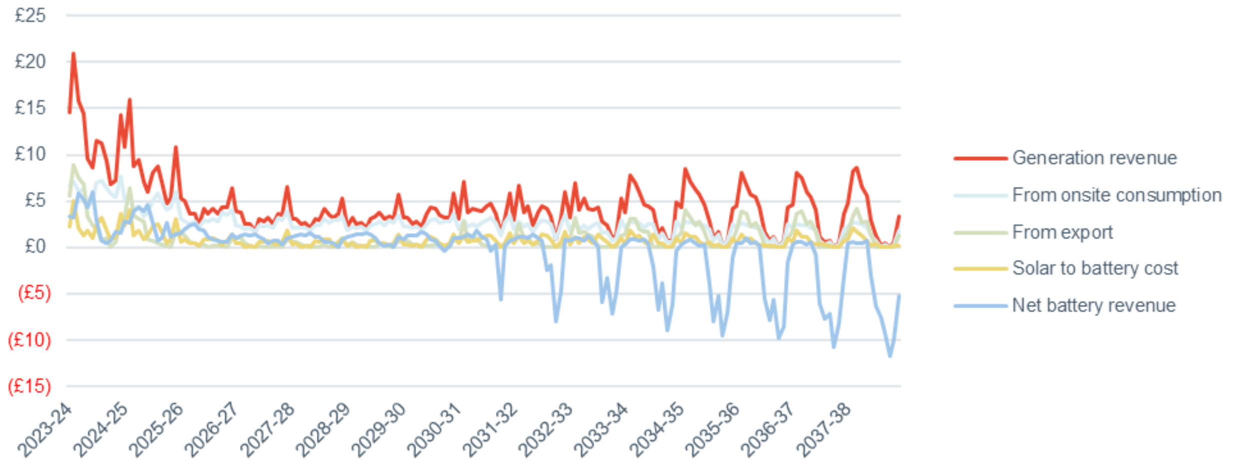
Rooftop solar – Grande Central results (other scenarios)

- The LMP scenario for Grande Central is one of the most interesting, as the wider node is constrained for import and this drives up local wholesale prices, increasing generator and battery revenue
  - Battery revenue is driven to such levels that it is cut out in the model as these prices are excessive and would result in network upgrade, and have therefore been cut out of the modelling results as discussed at the top of this section
- As the site is a net exporter of power, it is able to take advantage of this benefit, using much more of the solar generation to charge the batteries than would usually be the case (around 50% rather than the 30-35% of a behind-the-meter site, or 10-15% for a site with no onsite consumption), and profiting from this behaviour
  - However, the solar does not generate sufficient power to supply both the onsite load and the battery, so overall, revenues are down versus the less constrained Robin Park site

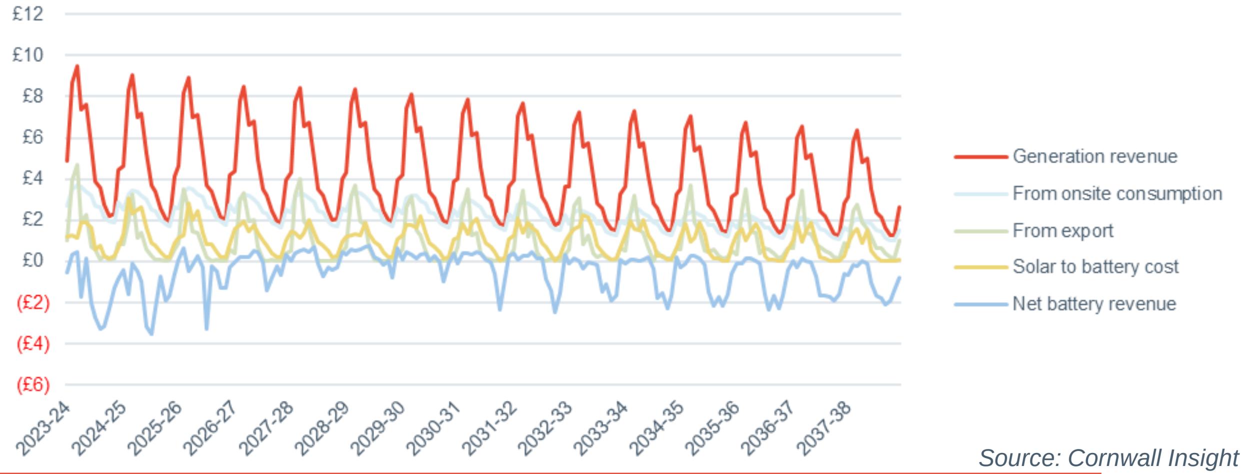
Average revenues in £/kW/year – Grande Central – Central – Equal battery

Revenue, £/kW/year	Generation revenue	Net battery revenue	Total benefits
National	£102	-£15	£87
LMP	£55	-£5	£50
Market splitting	£51	-£6	£45

Revenues in £/kW/month – Grande Central – LMP Central – Equal battery



Revenues in £/kW/month – Grande Central – Market Splitting Central – Equal battery



Source: Cornwall Insight

Rooftop solar – key takeaways

- Rooftop solar acts to both provide generation revenues and to mitigate import costs. Value is typically higher for sites which maximise self-consumption of power, rather than exporting this
  - Power consumed onsite reduces imports, which are higher priced than exports due to third-party charges
- Excess generation is may be beneficial to the Grade Central scenario under the LMP model, as it allows provision of more power to the local node, at marginal prices higher than the average price
  - However, the overall level of the local constraint is too high for this to be a net benefit, with generation and battery revenues lower than the Robin Park site
- As with other sites, the alternative market paradigms see lower returns for generation at the sites, due to lower power prices in the region (LMP) and for intermittent generation (Market splitting)
  - Overall costs for the LAs do decline under these market structures, but the investments in generation and storage are more difficult to justify in economic terms
- Again, increasing the size of generation and storage assets to keep them in scale with the onsite consumption would deliver more value to the sites

Modelling results – wider Manchester region

Constraint

- Our results show the effects of constraint in two ways: unserved energy (i.e., consumers who are not able to access power); and under the LMP pricing scenario, changing wholesale prices
  - We conducted a run under "business as usual" scenario, where the UCEGM assets are not built, to show the marginal impact of building the assets
  - Noting the relatively small size of the asset base under consideration (in the range 9-10MW of generation and 4.5-18MW of battery storage), this has only a small impact on the overall pattern of demand in Manchester, which is forecast to grow from around 43TWh/year in 2021 to around 76TWh/year in 2051
- There are several lines, such as Daines to Carrington and Rochdale to Scout Moor Tee, which are also heavily loaded, but these areas are also connected by other, less loaded. This mitigates the potential for constraint
- Several key areas of constraint can be identified:
  - The Stalybridge GSP and connected areas
  - The Rochdale GSP and Todmorden circuit
  - Kirkby and areas such as Fiddler's Ferry, on the edge of the region
  - Wigan and the adjacent area
  - Heady Hill and Heap Bridge area
- Other lines which connect Greater Manchester to the wider system are also heavily loaded, such as the connection to Eggborough
  - This indicates potential need for reinforcement of the transmission system to enable electrification, as the landscape of Manchester may not be suitable to deploy the scale of generation needed to mitigate need for reinforcement of transmission lines
- While behavioural changes such as deployment of flexible consumption, deployment of generation, and deployment of energy storage, can all mitigate the immediate need for reinforcement, this is to be considered mostly in the context of making reinforcement more efficient, not replacing it entirely

Line loading in Greater Manchester region

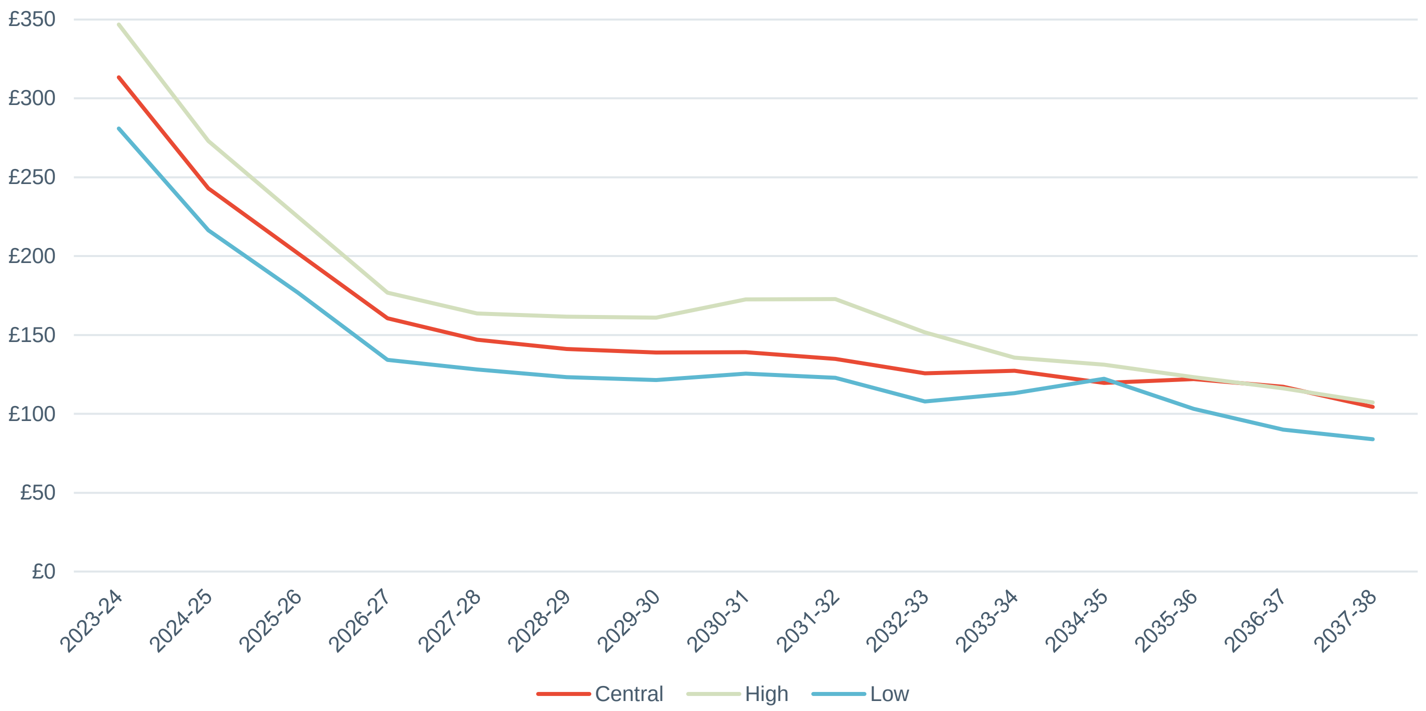
From Substation or busbar name	To Substation or busbar name	Average line loading
MOSS NOOK	BAGULEY	100.00%
SALE	BAGULEY	100.00%
REDBANK	BLACKFRIARS A	100.00%
CARR4A	DAIN40	100.00%
CARR4B	DAIN40	100.00%
DENTON WEST A	LONGSIGHT	100.00%
LAMBERHEAD B	Orrell	100.00%
FIDF20_SPM	RAIN20_SPM	100.00%
ELLA20	STAL20	100.00%
MACC40	STAL40	100.00%
STAL20	STAL40	100.00%
BLOOM STREET	STUART STREET	100.00%
KIBY20	WASF2B	100.00%
WIGAN	WESTHOUGHTON	100.00%
KIBY20	RAIN20_SPM	99.36%
Scout Moor Tee	ROCHDALE GSP	97.68%
KIBY20	RAIN20_SPM	96.56%
KIBY20	WASF2A	96.33%
HAYDOCK	ASHTON (Golborne)	95.19%
Ashton/Golborne/Landgate Line Switch Tee	ASHTON (Golborne)	92.85%
BURY	HEAP BRIDGE	91.06%
EGGB40	ROCH4A	90.91%
HEADY HILL	CASTLETON	88.32%
HARPURHEY B	REDBANK	87.45%
MOSS LANE T11	KEARSLEY LOCAL GSP	85.14%
Ashton/Golborne/Landgate Line Switch Tee	WIGAN	83.93%
ROCHDALE GSP	Todmorden Tee 2	81.74%
ROCHDALE GSP	Todmorden Tee 1	81.71%
CARR20	SMAN20	80.94%

Source: Cornwall Insight

Offtake/ Retail prices for LAs – National

- Under the National pricing scenarios, retail prices are the same for all UCEGM Local Authorities
- We have forecast these as the cost of the wholesale power, plus cost of TPCs, plus a 5% allowance for supplier costs
- In the Central scenario, this cost falls from around £315/MWh (31.5p/kWh) during 2023-24, to just over £110/MWh (11.1p/kWh) over the forecast period
- Average values are:
  - Central: £156/MWh
  - High: £175/MWh
  - Low: £136/MWh
- TPCs make up a variable element of the total retail bill, from 18% in the short term, to a peak of 36-37% at the end of the current decade, and then falling to around 20% in the mid-2030s
- This forecast assumes LAs are exposed to an average cost of wholesale power and TPCs across the year, rather than securing a hedged contract with a supplier

Retail prices under National wholesale pricing scenarios

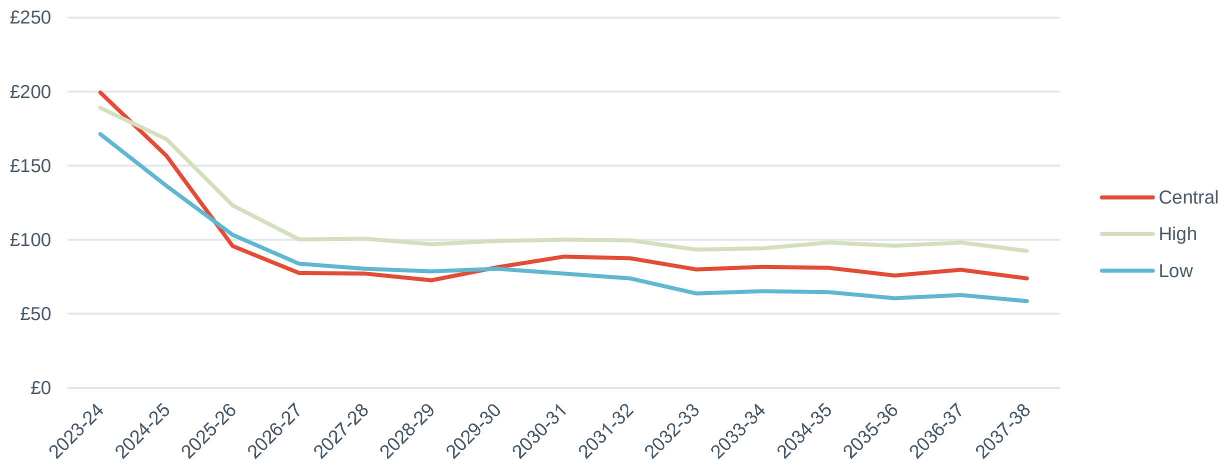


Source: Cornwall Insight

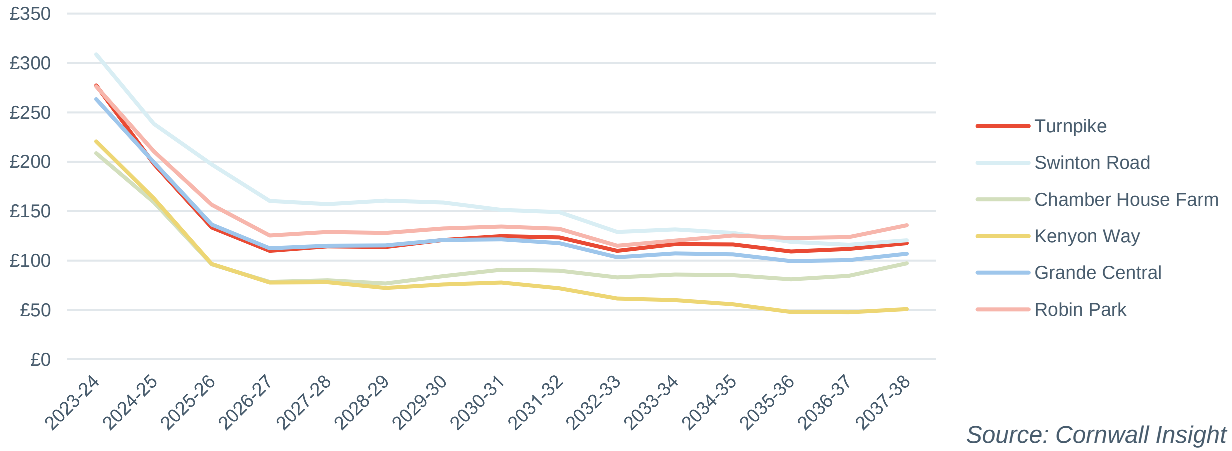
Offtake/ Retail prices for LAs – LMP

- Under the LMP scenario, retail prices are dependent on the LMP wholesale price at each relevant node, plus the TPCs
- Each LA has different consumption portfolio across the nodes and is exposed to a different combination of wholesale costs
- The charts opposite show the forecast:
  - Average import prices across the Greater Manchester nodes (top)
  - The average retail price forecast to be paid by each of the six individual modelled sites (bottom)

Retail prices under average LMP wholesale pricing scenarios



Average retail price for each site under Central LMP wholesale price scenarios

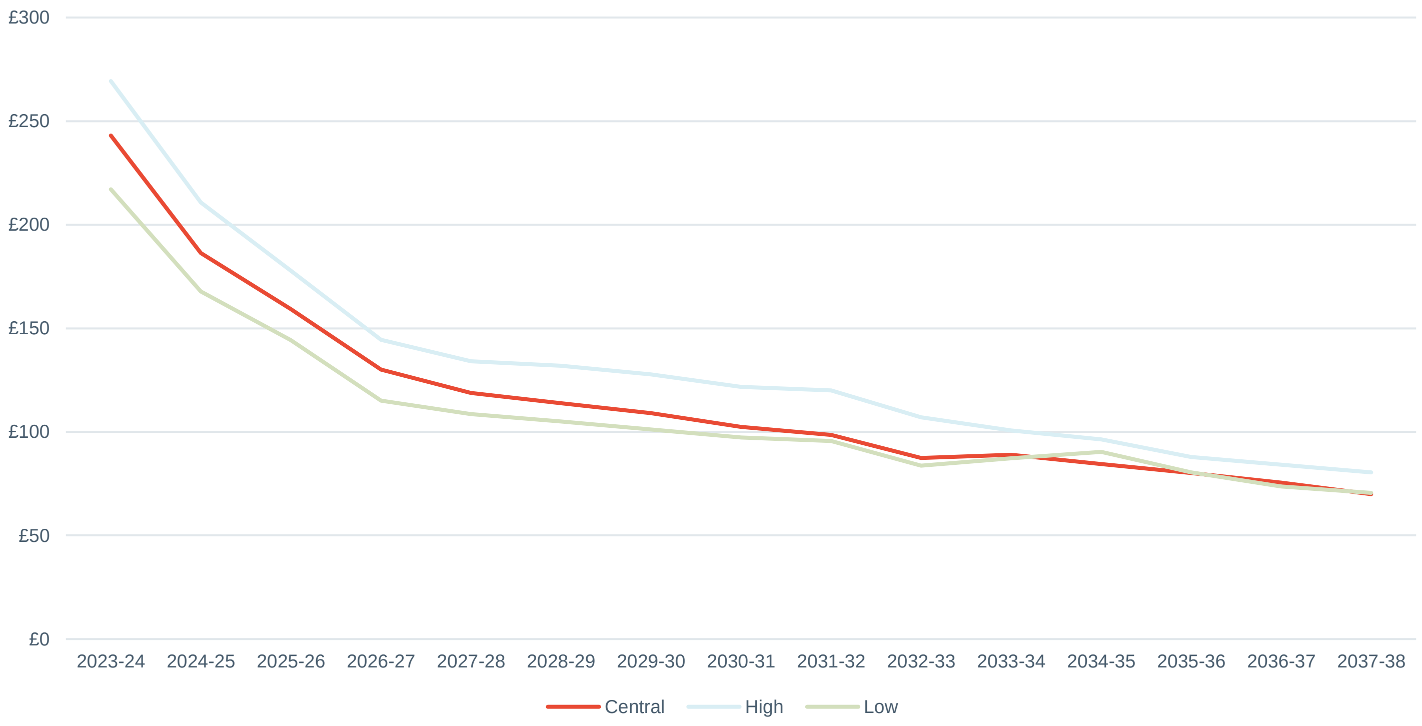


Source: Cornwall Insight

Offtake/ Retail prices for LAs – Market splitting

- Under the Market splitting pricing scenarios, retail prices are the same for all UCEGM Local Authorities
- We have forecast these as the cost of the wholesale power, plus cost of TPCs, plus a 5% allowance for supplier costs
- The Market splitting forecasts are made up of a share of the intermittent market price – modelled as the cost of offshore wind – and a share the national price
  - This share is set at the split of intermittent renewable generation and dispatchable generation
  - In the chart opposite, this is conducted on an annual average basis; in the model runs, this was tracked on an hourly basis
- Average values are:
  - Central: £117/MWh
  - High: £133/MWh
  - Low: £109/MWh
- TPCs make up a variable element of the total retail bill, from 18% in the short term, to a peak of 36-37% at the end of the current decade, and then falling to around 20% in the mid-2030s
- This forecast assumes LAs are exposed to an average cost of wholesale power and TPCs across the year, rather than securing a hedged contract with a supplier

Retail prices under Market splitting wholesale pricing scenarios

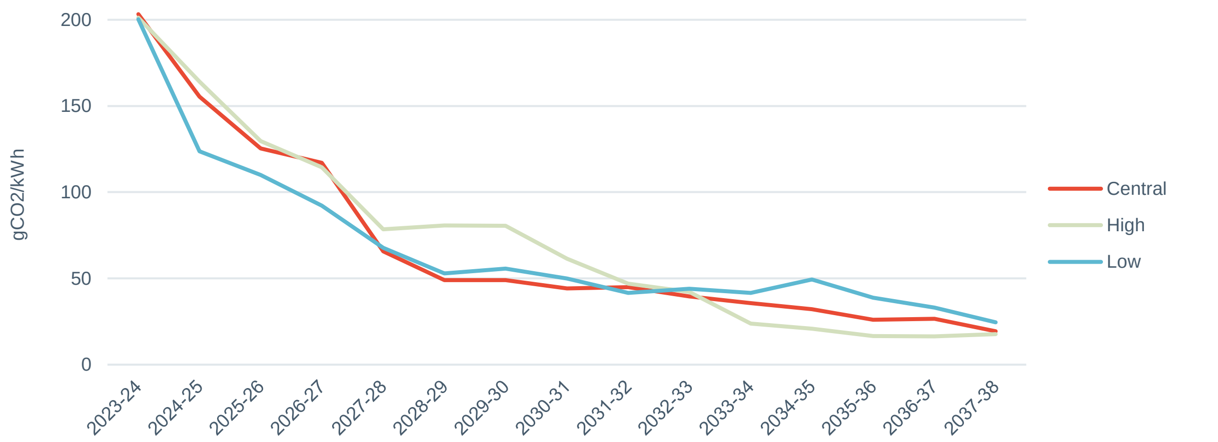


Source: Cornwall Insight

LA carbon emissions

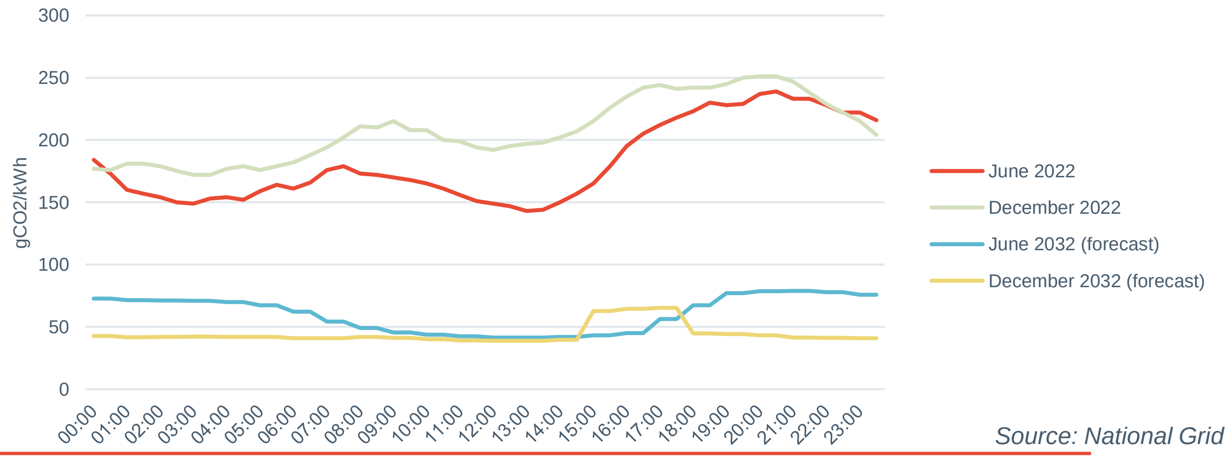
- Power drawn from the public system results in carbon emissions as-per the carbon intensity of the grid
  - REGOs can be used to legislatively reduce emissions, by claiming green power generation for the LA's portfolios. This is zero impact on actual emissions, however
- Average power sector carbon emissions are forecast to fall over the future period, reaching net zero in 2040-41 under the High and Low scenarios, and 2041-42 under the Central scenario
- However, hourly emissions are more variable, and when in the day power is consumed will say more about the actual emissions than annual averages
- By building solar arrays, LAs reduce emissions for power during the day, but do not reduce demand during peak demand periods (winter evenings), when grid emissions are highest
- By building batteries, LAs may have a more active role in reducing emissions, as they will reduce (import) demand during peak periods, which is likely to reduce emissions. They replace this with imports overnight or during peak solar generation periods, when grid imports are lower carbon
  - Batteries could be operated to maximise economic benefits, or carbon emission reductions
  - However, we note that due to the relative marginal costs of renewable and dispatchable power generation, low carbon and low cost periods tend to be heavily aligned
- The differences are currently relatively small – 20-30% – but are forecast to grow over time as the renewable element of the power mix increases
  - For example, in winter 2032, our forecast shows that the evening peak has emissions around 50% higher than emissions over the rest of the day, while during the summer, daytime emissions are only 55-60% of overnight emissions

Carbon intensity forecast – average gCO_2/kWh by year



Source: Cornwall Insight

Carbon intensity – example gCO2/kWh by half hour, Summer and Winter 2022-23 and 2032-33



Source: National Grid

Appendix & reference

Battery Capex

- The cost of developing batteries varies depending on size, duration and site details
- Technology costs have been steadily decreasing over time as the technology has matured and learning rates applied, and this is expected to continue over the longer term, albeit at a reduced rate. Looking ahead this is expected to be driven by economies of scale from manufacturing and supply chain improvements
- However, in the short term battery capex costs are seeing significant increases – driven by the wider global macro-economic environment, including manufacturing reductions from Covid lockdowns, shipping cost increases and material and labour inflation. The increases vary by site, with ranges of 10-80% reported, with 25% seen as a 'central' assumption
  - This is expected to be a temporary reversal of the enduring decreasing capex trend, and is assumed to resolve by the mid/late 2020s as energy prices, shipping costs, the geo-political situation returns to in-line with historic norms
- Prior to these price spikes, the average 'all in' cost for a 1hr battery was ~£400/kW with 2hr durations being around 25-30% more expensive, recognising some costs (e.g. network connections and some site and development expenses) are constant across duration
  - Given the existing network connections on site, this may reduce capex by around 20-30%
- Batteries degrade steadily over time, before eventual replacement. Operators may opt to replace the full site once reaching a degrading threshold, or to swap out individual units as they degrade
- These decreasing capex costs factor into battery operation considerations, with higher learning rate assumptions favouring more aggressive trading strategies and therefore sooner replacement

Retail prices under average LMP wholesale pricing scenarios

Source: Cornwall Insight

Contact us

Tom Edwards

Senior Modeller

t.edwards@cornwall-insight.com

01603 542150

Tom Andrews

Consultant

t.andrews@cornwall-insight.com

01603 542118