AURORA ENERGY RESEARCH

Local Flexibility Markets Analysis

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Details and disclaimer

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Agenda

I. Background and recent activity

II. Revenue stacking for UKPN flexibility contracts

III. Key challenges for LFMs

Local Flexibility Markets have been established in response to growing operational complexities arising from the energy transition

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Market Overview

- With the UK's energy mix becoming increasingly intermittent and decentralised over the last decade, the need for location-specific flexibility services connected to the distribution network has been growing
- Local Flexibility Markets (LFMs) first emerged in 2017 from UKPN and WPD as a means to establish a **Distribution System Operator (DSO)** function which would directly procure flexible, dispatchable capacity to better manage the distribution network
- LFMs specifically help reduce reinforcement and operational risks for DNOs that have increased with the deployment of intermittent generation and uptake of electrified demand

DNO

- Network issues are primarily addressed through traditional network solutions, i.e. wires and substations

DSO

- Competitive markets are used as an alternative to network reinforcement. LFMs are established to procure capacity from various technologies
- Relative to traditional methods, DSO alternative measures can provide:
  - Greater network efficiency and lower consumer costs
  - Market driven price signals for the value of embedded flexibility
  - Revenue stacking opportunities for participants
  - Synergies with other system operators

Service Overview

- In 2020, four standardised services for LFMs were launched across all DNOs in GB, coordinated through the ENA's[1] **Open Networks Project**
- The introduction of standardised contracts aims to reduce complexity and create a level playing field to increase market confidence and encourage participation
- Although contracts are standardised, specific requirements vary by location and range from rolling framework agreements, to 7-year fixed contracts depending on site characteristics. Successful applicants receive both availability and/or utilisation payments

Product overview

1	Sustain	→	Scheduled constraint management
2	Secure	→	Pre-fault constraint
3	Dynamic	→	Post-fault constraint management[2]
4	Restore	→	Restoration Support

1) Energy Network Association 2) The service also serves pre-fault constraints for UKPN

Sources: Aurora Energy Research, Energy Network Association, UK Power Networks

Over 1 GW of capacity has been procured through DNO flexibility tenders in 2020, with total requirements scaling up to 3 GW in 2021

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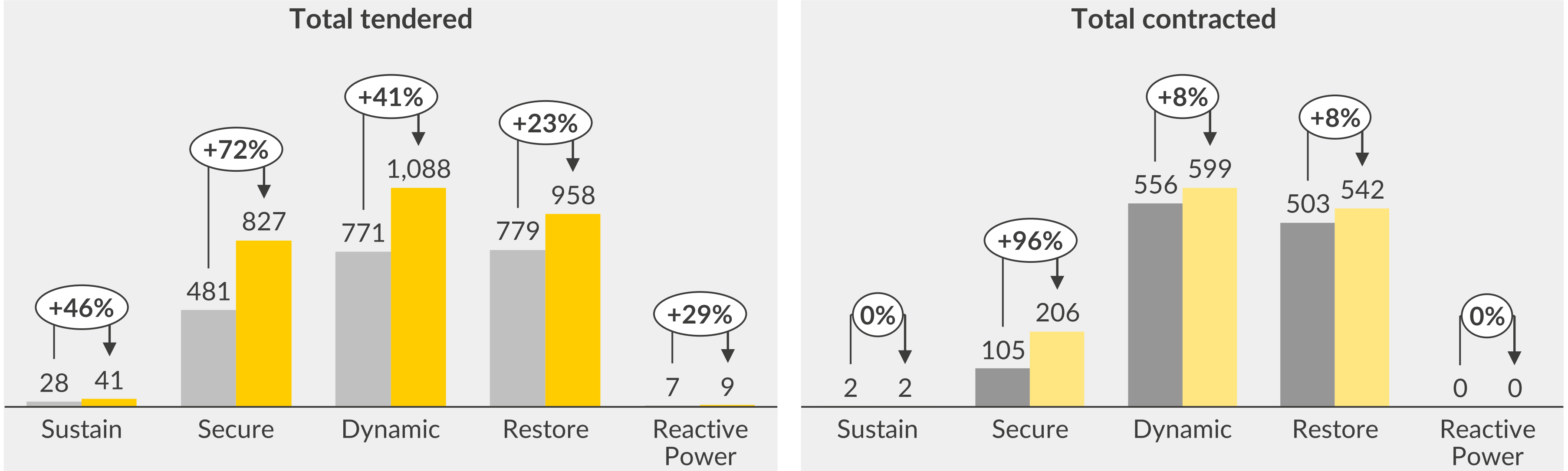
Total tendered and contracted volumes[1] in DNO flexibility tenders in 2020 and 2021
MW (/MVAr for reactive power)



UKPN total flexibility volume by tender round, 2017 – 2021
MW

	2017	2018/2019	2020	Spring 2021
Total tendered capacity	37.6	136	153	387
Total awarded capacity	0.3	19.3	123	350

Tendered for 2020 Tendered for 2021 Contracted for 2020 Contracted for 2021

1) Data published by ENA in February 2021. Different products requirements are counted separately. Includes sustain, secure, dynamic and restore; peak capacity is used (maximum possible capacity required at any point in time)
Sources: Aurora Energy Research, Energy Network Association, UK Power Networks

Comments

- Since 2017, DNOs have been tendering for and procuring various flexibility services at the local distribution network level to solve congestion in the local electricity grids
- The total size of local flexibility markets in 2020 across GB DNOs for all four standard flexibility products has seen a significant increase, with the total contracted volumes amounting to over 1 GW
- DNOs have been scaling up their volume requirements further in 2021, looking to procure ~3 GW across four standardised products, though around 1.3 GW of the total volumes has already been contracted

DNO flexibility services are stackable similar to traditional forms of dispatch, being chiefly compatible with a CM contract

Revenues stacking for standardised local flexibility products by DNOs:

5 Same Time Period	Wholesale	2 Capacity Market	Balancing Mechanism	Replacement Reserve	Ancillary Services	DNO Sustain	DNO Secure	DNO dynamic
DNO Restore	No	Yes	No	No	No	No	3 Yes	Yes
DNO Dynamic	No	Yes	No	No	No	No	Yes	
DNO Secure	1 No	Yes	No	No	No	No		
DNO Sustain	4 Yes	Yes	4 Yes	No	No			

Key considerations:

1 **Wholesale and DNO Secure:** Revenue stackability with wholesale trading varies by DNOs. Some dispatch for the Secure product is instructed in advance (e.g., week-ahead for WPD) so the relevant FP[1] can trade to that position. However, for DNOs where dispatch is closer to real time, revenues are not stackable

2 **Capacity Market:** There is no obligation to export power other than during a system stress event, which carries a penalty for non-delivery[2]. CM rules exempt providers in 'Relevant Balancing Services' (most NGSESO ancillary services) from exporting during stress events. A CM rule change could be raised to extend this to LFMs

3 **DNO products**:

- Assets cannot be dispatched for both Restore and Dynamic or Secure services in the same time period. However, as services (eg. Sustain, Secure and Dynamic) can be across different voltage levels (HV and LV), stacking across services is available if both LV and HV needs are accessible by FPs[1]
- The performance related payment deductions for non-delivery of DNO services is capped at the maximum payment

4 **DNO Sustain**: As scheduled availability is pre-agreed within the contract, FP[1] can trade in the WM/BM outside of the contracted window

5 In general, most services are readily stackable with DNO products **in adjacent time periods**, and less so in the same time period

1) Flexibility providers, 2) Penalties for non-delivery during stress events are capped at twice the monthly revenue per event, total penalties may not exceed the annual contract revenue

Sources: Aurora Energy Research, Energy Network Association, UK Power Networks

Three flexibility services are being offered by UKPN, with contract lengths ranging from 1 to up to 7 years

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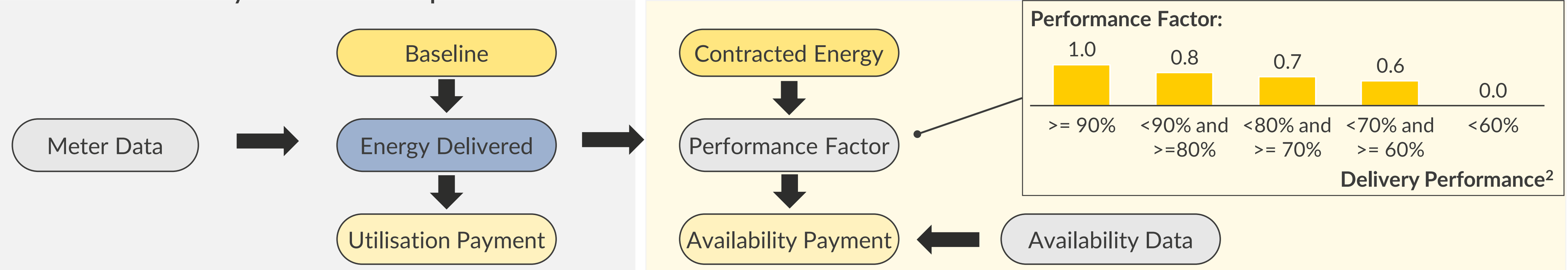
UKPN Flexibility Service Overview:

Secure Increase generation or decrease demand to reduce peak loads on High Voltage (HV) substations	**Sustain** Increase generation or decrease demand to reduce peak loads on Low Voltage (LV) substations	**Dynamic** Increase generation or decrease demand to meet a variety of network needs[1]
FPs[3] paid for availability (£/MW/h) and/or utilisation (£/MWh) as bid	FPs[3] paid a fixed £/MW service fee	FPs[3] paid for utilisation (£/MWh) at a price set by the FP; No Service Windows
Minimum (aggregated) 10kW threshold		
FPs[3] commit delivery >6 months ahead (at contract)	FPs[3] commit delivery 1 month ahead of delivery (option for 1 week)	Optional on FP[3] to accept dispatch instruction
Real-time dispatch	Scheduled dispatch	Real-time dispatch

UKPN payment structure for Flexibility Services - Secure product:



Utilisation Payment (£) = Utilisation Fee (£/MWh) * Energy Delivered (MWh)

Availability Payment (£) = Availability fee (£/MW/h) * Contracted Capacity (MW) * Total Periods Available (h) * Performance Factor (%)

1) E.g. supplement Secure, manage outages 2) Delivery performance is calculated as the monthly ratio of all delivered energy (capped by its contracted energy) to all contracted energy expected during utilisation events. 3) Flexibility Provider

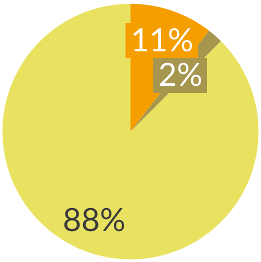
Sources: Aurora Energy Research, UK Power Networks

UKPN's February 2021 Flex Tender awarded 350 MW of capacity at a total cost of £30m across 137 voltage zones

Contract lengths ranged between one and seven years which covered 77 high voltage and 60 low voltage zones have been awarded to 17 companies

In November 2020, UKPN released flexibility requirements of 387 MW covering 138 sites with more than £50m available for the services. Three categories were to be covered: Secure, Sustain and Dynamic. Delivery of the services will start in Winter 2021/22, Summer 2021, Winter 22/23 or Summer 2022

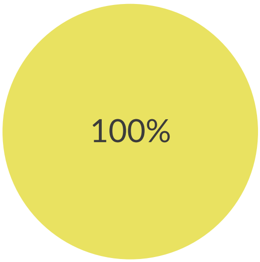
Secure



Total: 81.6 MW

- Reduces HV substation peak load
- Paid for availability (£/MW/h) and utilisation (£/MWh)
- > 6-month ahead commitment

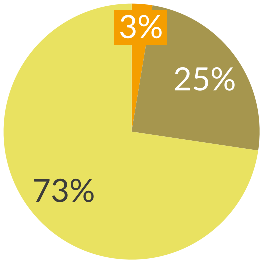
Sustain



Total: 20.4 MW

- Reduces LV substation peak load
- Single fixed service fee (£/MW)
- Month- or week- ahead commitment

Dynamic



Total: 248.1 MW

- Reduces HV and LV substation peak load
- Utilisation payments (£/MWh)
- Real time dispatch which is optional for the provider to accept

Total contract value

£m

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We use UKPN's Secure service to examine the additional value that a LFM contract can provide to batteries and gas recips

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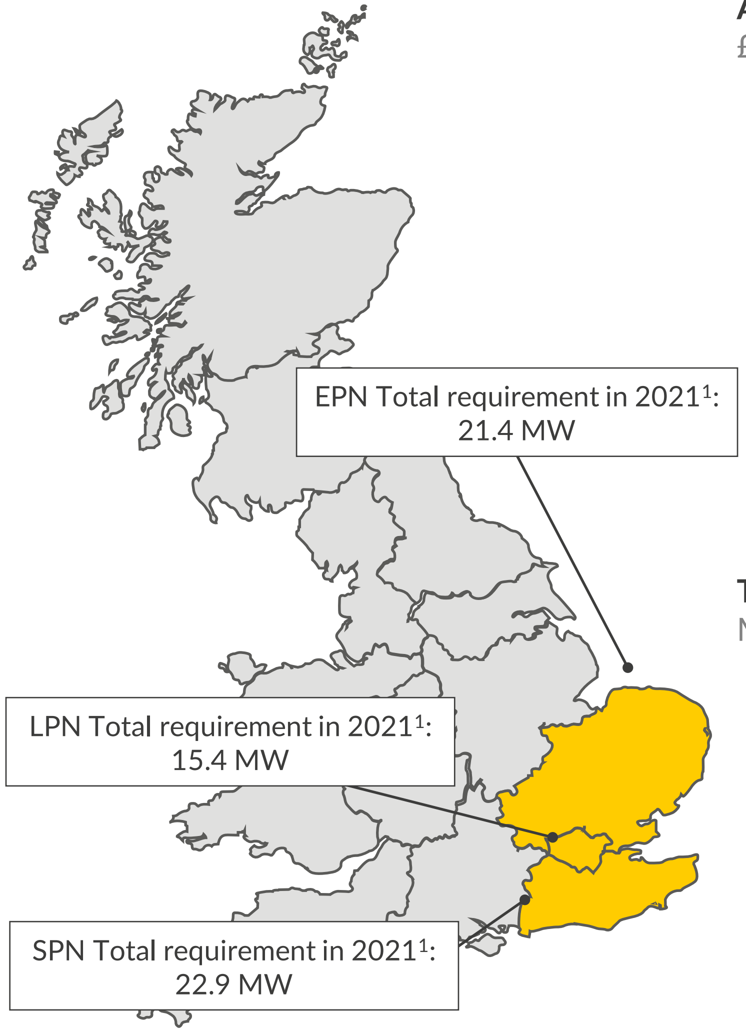
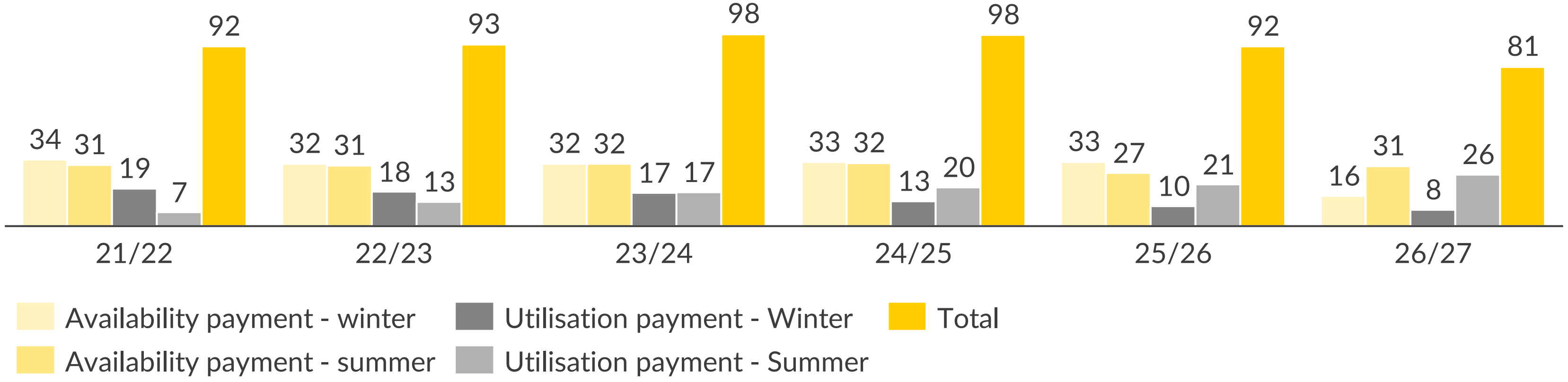


Average availability and utilisation payments from February 2021 tender

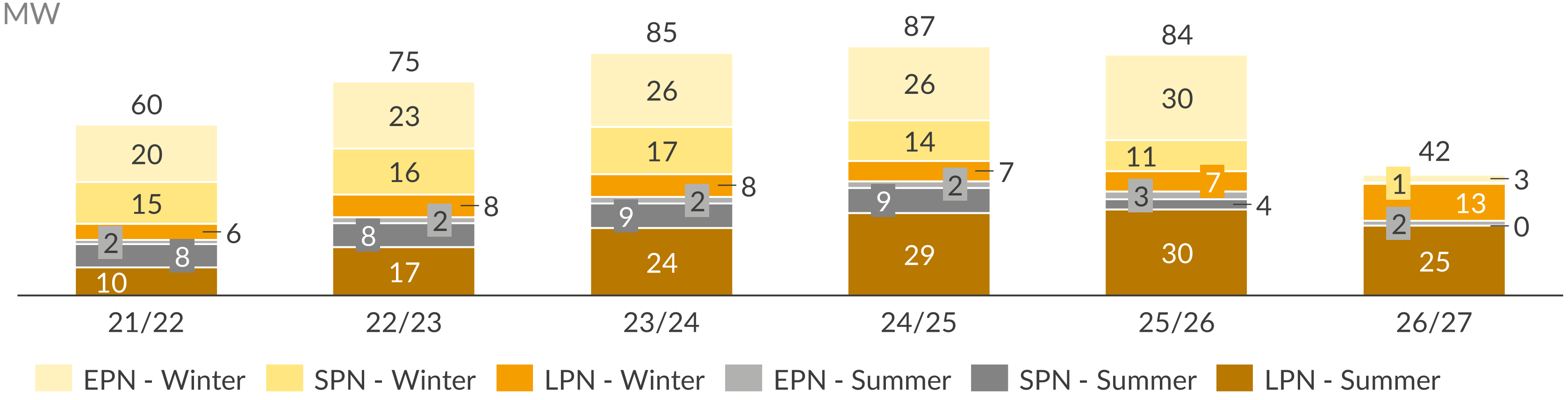
£/kW nominal

Availability Payment[2]: £29/MW/h; Utilisation payment[2]: £174.5/MWh



Total MW requirements across UKPN DNO regions for Secure Product from February 2021 tender

MW



1) Includes total MW requirements in summer and winter 2) Volume-weighted average published by UKPN

Sources: Aurora Energy Research, UK Power Networks

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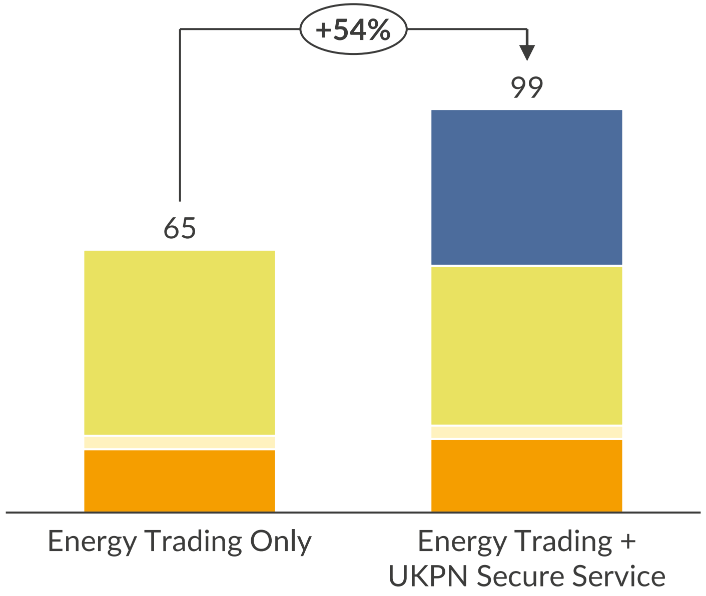
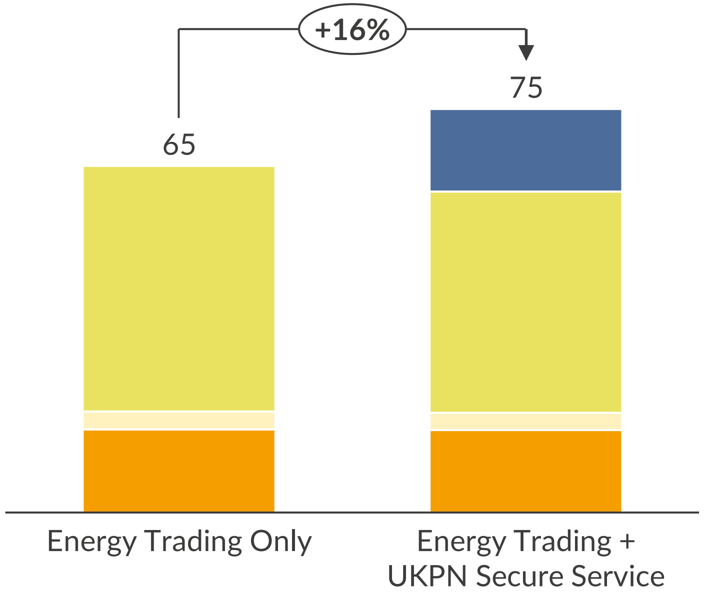
A Winter LFM contract can boost battery gross margins relative to energy trading only, however the gain is higher for smaller assets

Average gross margins from 2021-2027 for a new build 1h battery cycling 1.5x per day with different asset configurations

HV-connected, 1 MW battery
£/kW/year real 2020



HV-connected, 10 MW battery
£/kW/year real 2020



- A 7-year Secure winter contract from UKPN provides a 54% margin uplift for a 1 MW HV-connected battery asset, increasing gross margins by £34/kW/year

- However, due to potentially lower LFM requirements, a 10 MW battery may only be able to obtain a 4 MW LFM contract. In this example, a 10 MW asset would see a smaller gross margin uplift of 16%, £10/kW/year

Embedded Benefit | Capacity Market | Energy Trading | LFM

1) Batteries participating in the service are allowed to export during the availability window (but not import), though a reduced availability payment could apply as a result of a lower performance factor, if assets fail to subsequently meet DNO's dispatch instruction after discharging in the previous period(s).
Sources: Aurora Energy Research, UK Power Networks

Key assumptions:

- Energy trading: battery can trade in the Wholesale and Balancing markets outside of the contracted Secure service availability window (assumes the asset opts out from energy trading between 4-8pm)[1]
- LFM: assumes a 7-year winter contract (Nov – Feb) for UKPN Secure service with a contracted size of 1 & 4 MW for two battery size
- Capacity Market: assets are eligible to stack a CM contract on top of LFM
- Embedded benefits:
  - GDUoS/EET: Eastern England rates
  - Assets are eligible to receive embedded benefits if they export during LFM windows, as network charging arrangements do not distinguish between self-dispatch and instruction by UKPN

Securing a 1 MW 7-year Winter LFM contract from UKPN increases project IRR by 8% for a new build 1 MW HV-connected battery

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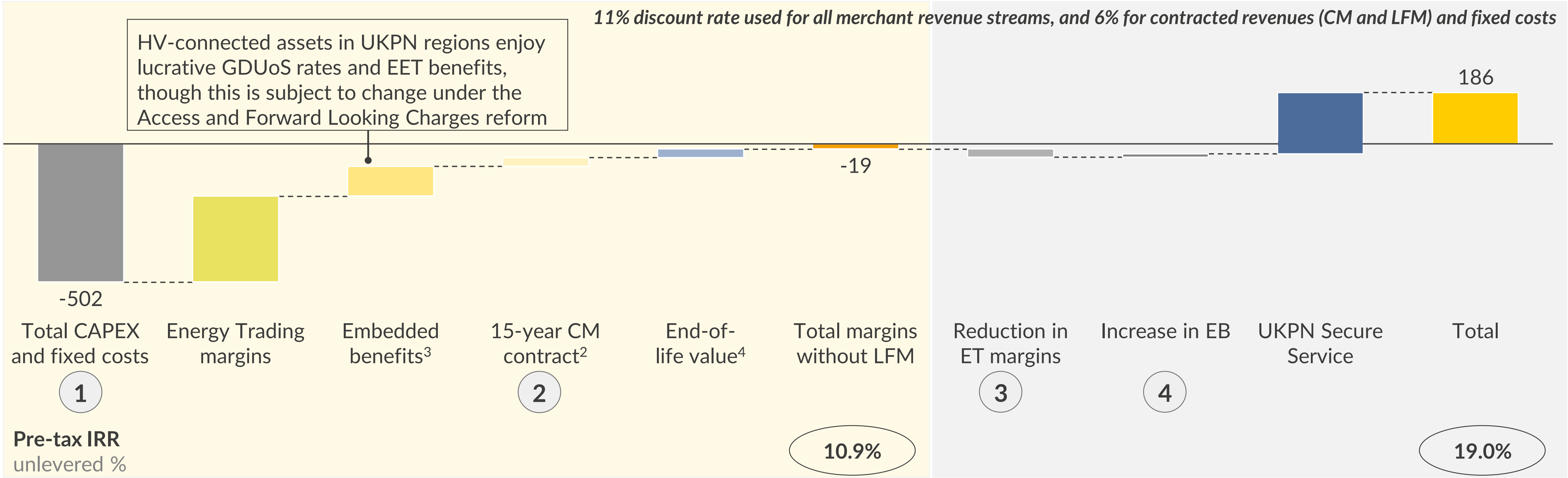
Net Present Value (NPV)[1] for a new build HV-connected 1 MW/1 MWh battery cycling 1.5x per day, 2021 entry
£k real 2020



1 Grid connection costs could be lower/higher than the average assumption. HV sites in UKPN regions can be scarce

2 Asset with 2021 entry requires ~£19/kW to break even mainly as a result of lower CM clearing price and reduced de-rating factor

3 Reduction in trading margins accounts for the additional charging costs (~£3/kW/year) to meet the State of Charge requirement during service window

4 As the asset is eligible for GDUoS payments during service utilisation, embedded benefits see an increase, with average cycling rate increasing by ~0.2 times/day

1) NPV calculated based on discount factors of 6% for CM (15–year) and LFM (7-year) revenues and fixed costs, and 11% for all other revenues and costs over 15-year lifetime 2) We assume asset taking 15-year CM contracts at the price of the entry year 3) Includes Triads EET, BSUoS and GDUoS. Done for an average asset for Aurora Central although in practice, this could differ considerably by individual expectations. 4) Assumes £150/kW for 1 hour battery

Sources: Aurora Energy Research, UK Power Networks

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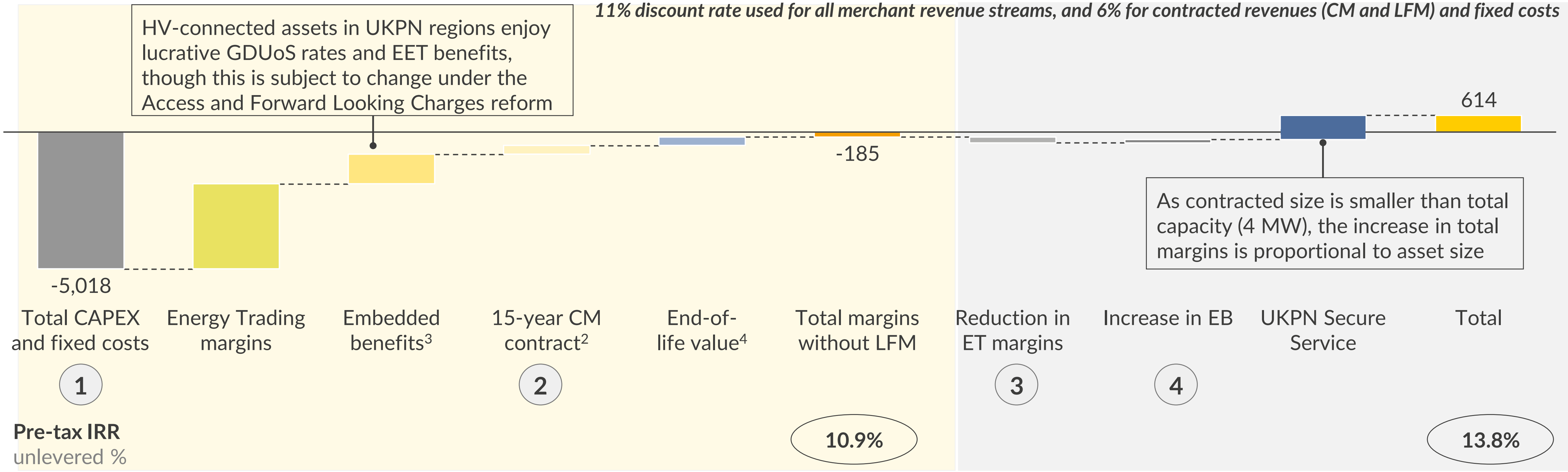
Though smaller, securing a 4 MW LFM contract for a new build 10 MW HV connected battery still increases project IRR by ~3%

Net Present Value (NPV)[1] for a new build HV-connected 10 MW/10 MWh battery cycling 1.5x per day, 2021 entry

£k real 2020



1. Grid connection costs could be lower/higher than the average assumption. HV sites in UKPN regions can be scarce
2. Asset with 2021 entry requires ~£19/kW to break even mainly as a result of lower CM clearing price and reduced de-rating factor
3. Reduction in trading margins accounts for the additional charging costs (~£3/kW/year) to meet the State of Charge requirement during service window
4. As the asset is eligible for GDUoS payments during service utilisation, embedded benefits see an increase of £123k (£12.3/kW), with average cycling rate increasing by ~0.2 times/day

1) NPV calculated based on discount factors of 6% for CM (15–year) and LFM (7-year) revenues and fixed costs, and 11% for all other revenues and costs over 15-year lifetime 2) We assume asset taking 15-year CM contracts at the price of the entry year 3) Includes Triads EET, BSUoS and GDUoS. Done for an average asset for Aurora Central although in practice, this could differ considerably by individual expectations. 4) Assumes £150/kW for 1 hour battery

Sources: Aurora Energy Research, UK Power Networks

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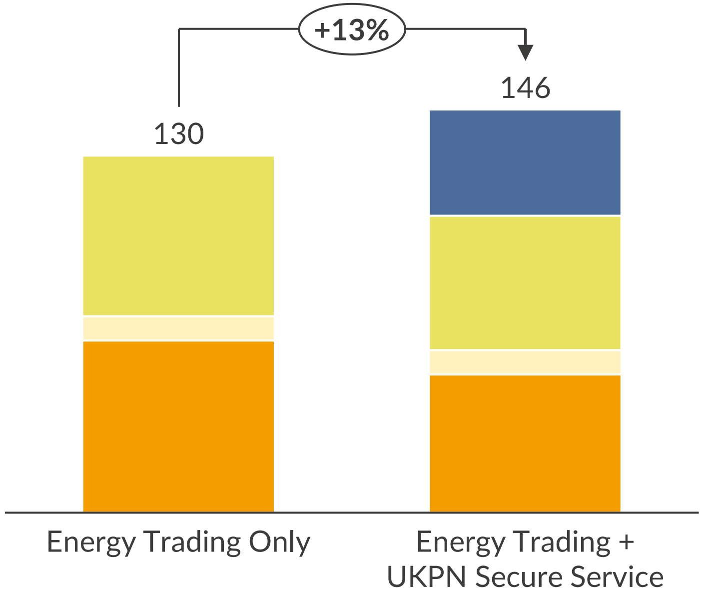
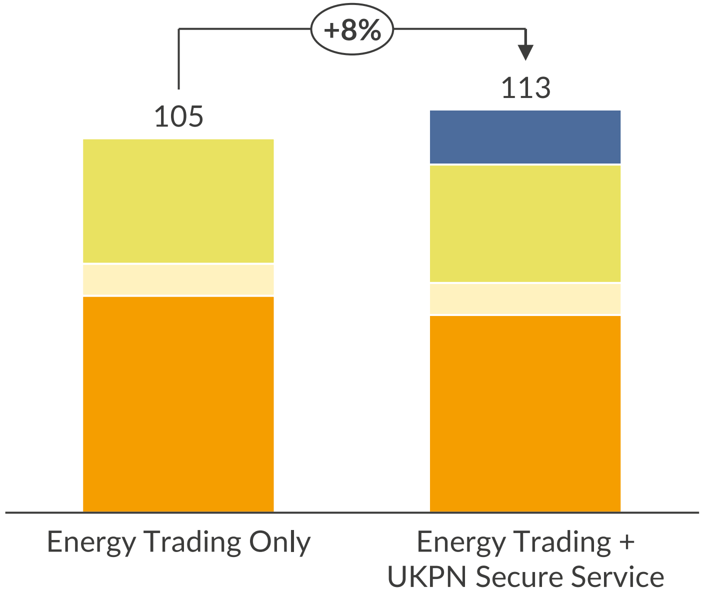
For gas recips, securing a winter LFM contract increases yearly margins by 13% and 8% for 1 MW and 10 MW assets respectively

Average gross margins from 2021-2027 for a new build gas recip with different asset configurations

HV-connected, 1 MW gas recip (35% HHV efficiency, ETS-exempted) £/kW/year real 2020



HV-connected, 10 MW gas recip (38% HHV efficiency, no exemption) £/kW/year real 2020



- A 1 MW asset is ETS exempt under current regulations due to its size, delivering higher energy trading gross margins than a 10 MW asset
- A 7-year Secure winter contract from UKPN provides a 13% margin uplift for a 1 MW ETS-exempted gas recip, increasing gross margins by £16/kW/year

- However, due to potentially lower LFM requirements, a 10 MW gas recip may only be able to obtain a 4 MW LFM contract. In this example, a 10 MW asset would see a smaller gross margin uplift of 8%, £8/kW/year

LFM | Energy trading | Capacity market | Embedded benefits

Key assumptions:

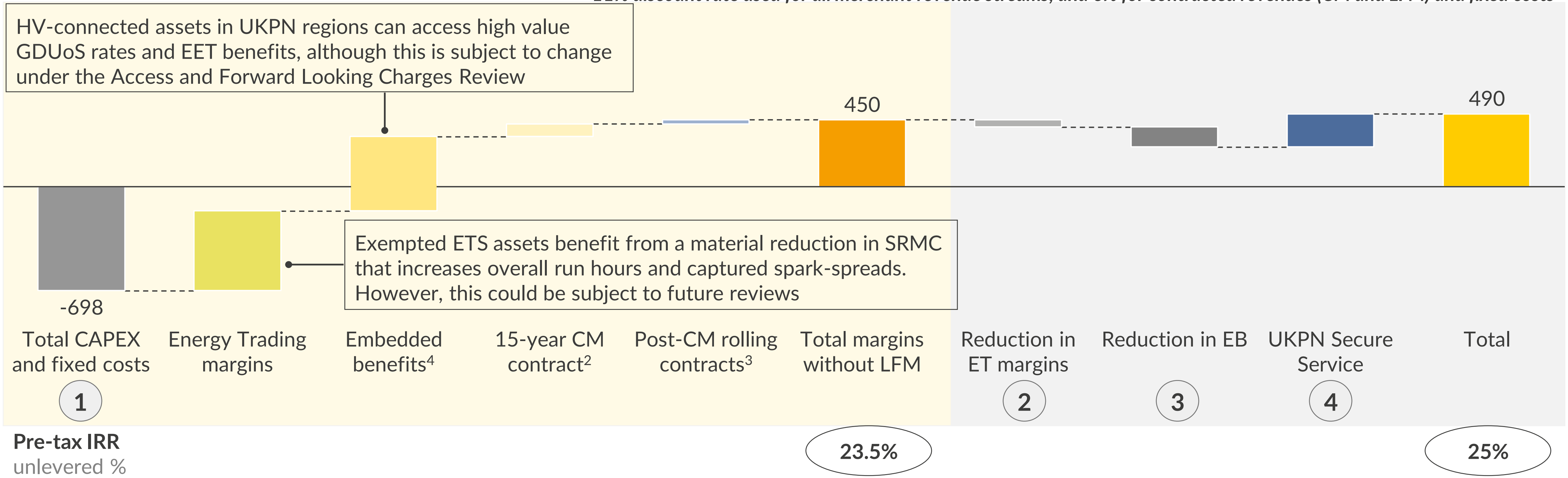
- Energy trading: gas recips can trade in the Wholesale and Balancing markets outside of the contracted Secure service availability window (assumes the asset opts out from energy trading between 4-8pm)
- LFM: assumes a 7-year winter contract (Nov – Feb) for UKPN Secure service with a contracted size of 1 & 4 MW for two battery size
- Capacity Market: assets are eligible to stack a CM contract on top of LFM
- Embedded benefits:
  - GDUoS/EET: Eastern England rates
  - Assets are eligible to receive embedded benefits if they export during LFM windows, as network charging arrangements do not distinguish between self-dispatch and instruction by UKPN

Sources: Aurora Energy Research, UK Power Networks

A 1 MW ETS exempt gas recip sees an increase in project IRR by ~2% by securing a LFM contract

Net Present Value (NPV)[1] for a new build 35% HHV efficiency, HV-connected 1 MW gas recip with ETS exemption, 2021 entry
£k real 2020

11% discount rate used for all merchant revenue streams, and 6% for contracted revenues (CM and LFM) and fixed costs



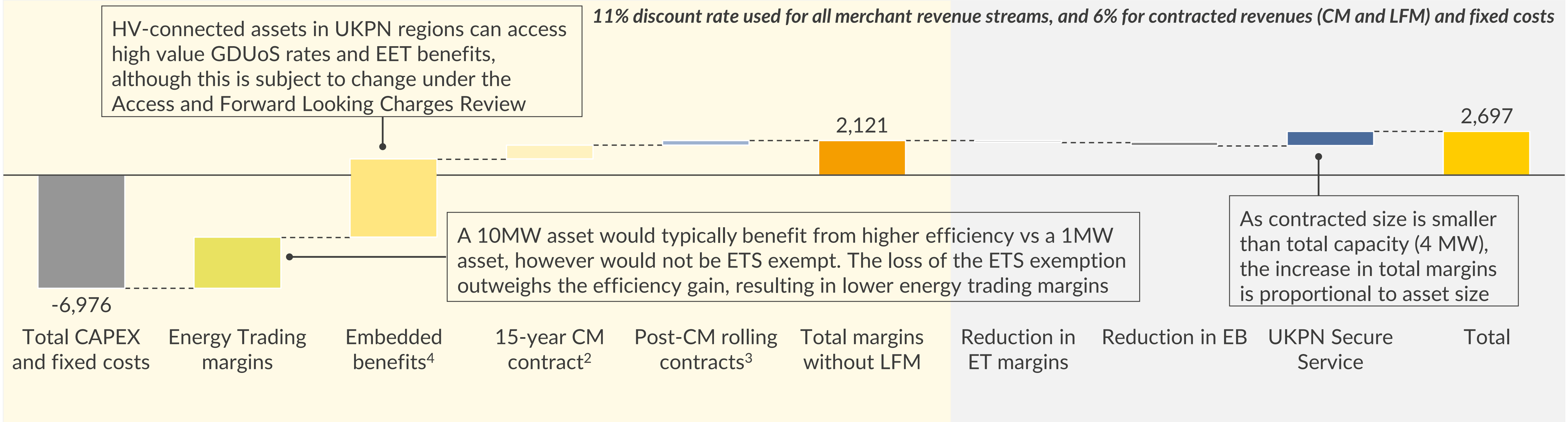
1. Grid connection costs could be lower/higher than the average assumption. HV sites in UKPN regions can be scarce
2. Trading margins sees a reduction of £47/kW as the asset is fully contracted to provide LFM service in winter, thus losing Wholesale and Balancing revenues from evening peaks
3. Asset also sees a reduction in embedded benefits due to reduced export hours during evening peak where HV-connected assets in UKPN regions enjoy lucrative GDUoS red rates
4. However, a 7-year Winter Secure contract (November to February) with UKPN not only counteracts the reduction in trading and embedded benefits, but provides a net increase of £40k (£40/kW) in total NPV for the asset

1) NPV calculated based on discount factors of 6% for CM (15–year) and LFM (7-year) revenues and fixed costs, and 11% for all other revenues over the 25-year lifetime 2) We assume asset taking 15-year CM contracts at the price of the entry year 3) Post-contracts CM revenues assume 1-year rolling contract using H1 Central Forecast 4) Includes Triads EET, BSUoS and GDUoS. Done for an average asset for Aurora Central although in practice, this could differ considerably by individual expectations.

Sources: Aurora Energy Research, UK Power Networks

Similarly, a 10 MW gas recip achieves an increase of 2% in project IRR with a 7-year Winter LFM contract

Net Present Value (NPV)[1] for a new build 38% HHV efficiency, HV-connected 10 MW gas recip with no ETS exemption, 2021 entry
£k real 2020



Pre-tax IRR
unlevered %

Total margins without LFM	Total
18.1%	**19.6%**

1. Grid connection costs could be lower/higher than the average assumption. HV sites in UKPN regions can be scarce
2. Trading margins sees only a slight reduction as the asset is only contracted to provide 4 MW of LFM service, with the remaining capacity able to trade in the WM and BM
3. Similarly for embedded benefits, only a minor reduction is seen as the asset is able to capture GDUoS payments during the service utilisation hours while using its non-contracted capacity to trade in Wholesale and Balancing markets
4. As a result, a 7-year Winter Secure contract (November to February) with UKPN provides a net increase of £576k (£57.6/kW) in total NPV for the asset

1) NPV calculated based on discount factors of 6% for CM (15–year) and LFM (7-year) revenues and fixed costs, and 11% for all other revenues over the 25-year lifetime 2) We assume asset taking 15-year CM contracts at the price of the entry year 3) Post-contracts CM revenues assume 1-year rolling contract using H1 Central Forecast 4) Includes Triads EET, BSUoS and GDUoS. Done for an average asset for Aurora Central although in practice, this could differ considerably by individual expectations.

Sources: Aurora Energy Research, UK Power Networks

Agenda

Whilst DNO LFMs could enhance flexible asset business cases, three main challenges remain

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	Key Challenges	Implications
Size and location	▪ Flexibility requirements for LFMs are highly locational and narrowly defined ▪ Grid connection costs could vary depending on the location, while land availability for HV sites can be scarce	▪ Difficult for assets to participate in these services unless they are already situated in the right locations, or new-builds can source appropriate sites ▪ Potentially useful for DNOs to share more information like UKPN on revenue ranges and availability on grid connection for each region
	▪ Though varying depending on network asset characteristics, LFM requirements are typically small in volumes ▪ For instance, the largest awarded contract size is 3.9 MW from UKPN's April 2020 tender	▪ If LFM requirements are small, it is unlikely to materially enhance project economics greater than 10 MW. Economics would improve in areas with higher LFM requirements. ▪ Developers face additional challenges for smaller assets, such as lower efficiency or higher capex (£/kW) with less economies of scale
Revenue stackability	▪ Uncertainty over how different revenue streams can be stacked with a LFM contract ▪ Ongoing NAFLC[1] reform casts further uncertainty over investment decisions for new-build distributed assets as regions (e.g. UKPN) with high embedded benefits could see large revision depending on the final decision from Ofgem	▪ Although certain revenue stacking has been allowed such as CM and embedded benefits, offering further flexibility for stacking[2] with alignment between ESO and DSO dispatch could encourage more build of assets in the required regions – UKPN are working on this through the Regional Development Programme ▪ Potentially useful for DNOs to publish data on historical utilisation prices and volumes for each region on a more frequent basis
	▪ The opportunity costs of participating in DNO services are determined by value available from energy trading or other ancillary services. For batteries operating in Dynamic Containment (DC), this is currently set at £17/MW/h from 24h contract and the high price has made it difficult for other services to compete in the short term	▪ Though high DC prices currently set the opportunity cost for batteries providing LFM services, DC procurement moving to EFA blocks will allow more flexibility for service stacking. As UKPN winter contract could offer an average of £29/MW/h availability rates during evening peaks, providing LFM during EFA blocks 5&6 would yield higher returns than current DC prices
Visibility of future service requirement	▪ Though high availability and/or utilisation payments are currently being offered in certain regions with high network requirements, uncertainty remains over how static current zonal requirements are and how long these benefits would remain in place	▪ Difficult to make investment decision for new build projects based on LFM revenues as it remains unclear whether future regional will stay the same for each region ▪ Potentially useful for DNOs to share a forward looking plan identifying the most critical areas with need for flexibility. UKPN currently publishes out 7 years

1) Network Access and Forward Looking Charges 2) E.g., allowing battery assets to receive payments from providing both the ancillary/balancing services from NGESO and LFM services from DNOs

Sources: Aurora Energy Research, Aurora LFM survey results, UK Power Networks

Key takeaways

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1. With the UK's energy network becoming increasingly decarbonised and decentralised, Local Flexibility Markets (LFMs) have been increasingly used by DNOs to procure flexibility services at the local distribution network, as part of the transition from DNOs to DSOs. Contracted volumes grew from ~250 MW to over 1 GW in 2020, with further increase in procurement target of up to 3 GW in 2021

2. For batteries, a 7-year winter LFM contract from UKPN's Secure Service can boost battery gross margins relative to energy trading only. The increase in project IRR is significant at ~8% for a 1 MW battery as the asset is able to fully capitalise on the LFM contract, whereas a 10 MW asset sees a relatively smaller increase in IRR at ~3% due to a limit in contract size

3. For gas recips, securing a 7-year winter LFM contract from UKPN's Secure Service increases yearly margins by 13% and 8% for 1 MW and 10 MW assets respectively. Both assets see an increase in project IRRs by ~2% with the revenue stacking with a LFM contract

4. Whilst LFM contracts provide lucrative additional revenues to the flex business cases, three main challenges remain around the current limitation on contract size and highly locational nature of the LFM requirements, uncertainties over revenue stackability and locational benefits being reformed under NAFLC[1], and limited visibility on future service requirements. These issues would need to be addressed to provide better investment signal for the LFMs. UKPN already publish 7 years ahead and are looking to increase visibility. Also, work at the Open Networks project with other DNOs and ESOs aims to tackle the other challenges

1) Network Access and Forward Looking Charges

Source: Aurora Energy Research, UK Power Networks