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Results: Grid fees for BESS in Germany

Internal Information on results

Agenda

- **Current Situation and Challenge**
- Key Takeaways
- Modelling Assumptions
- Results

Germany's BESS build-out faces make-or-break risk from unquantified grid fees and FCA, prompting AFRY's 2029 case study to define viable tariff design corridors

Situation

- BESS are on track to become the central pillar of flexibility in Germany as rising renewables penetration increases balancing needs
- The current pipeline was partly enabled by favourable grid-tariff treatment without any subsidies; this baseline is now being reassessed under AgNes
- Under the AgNes proposition, BNetzA is transitioning to a cost-reflective tariff regime, in which grid-fee exemptions expire by 2029, BKZ are retained, and static and dynamic grid-fee components are introduced
- In parallel, grid connections are increasingly granted under Flexible Connection Agreements (FCA), imposing binding operational constraints; BNetzA has signaled its intention to standardize FCA going forward
- Together, AgNes and FCA reset the economics under which today's BESS pipeline was developed, with full impact from 2029

Challenge

- BESS economics are highly sensitive, with small changes in grid fees, BKZ, or operational constraints determining economic viability
- Sensitivity is already material today: imposed FCA can push projects to the margin or into uneconomic territory, even without grid fees
- From 2029 onward, risk escalates materially as grid-fee exemptions expire while the level of future static and dynamic grid fees remain unknown
- BNetzA's AgNes papers outline methodologies but not magnitudes, providing no indicative ranges or design parameters for key tariff components
- The resulting uncertainty is already affecting investor confidence and capital allocation, risking a slowdown in Germany's flexibility build-out precisely when it is most needed for transitioning to a decarbonized power system

Solution

- To shed light on the impact of grid fees and FCA on BESS economics, and to inform all relevant stakeholders including BNetzA, AFRY has conducted a case study assessing the effects of established FCA restrictions and a range of potential grid fee components on a reference 4h BESS
- Grid-fee assumptions are benchmarked against neighbouring European markets, recognizing that applying the current German static grid fees applied to other consumers would render the BESS investment case uneconomic
- AFRY's comprehensive analysis was conducted to be used as an orientation and discussion point for the final design and scale of the new tariff structure

*AFRY Base case assumes a German-wide median BKZ of 85 €/kW

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For BESS built post 2029, merchant viability is limited to scenarios without grid fees; to ensure long-term BESS buildout, the design must avoid overlapping instruments

Key takeaway	Description
A 4h BESS with COD 2029 remains economically viable without grid fees, even under moderate FCA's	A 4-hour BESS with COD 2029 remains economically viable on a fully merchant basis in the absence of grid fees. Unrestricted operation achieves ~11.9% IRR, and even under moderate FCA constraints the project continues to clear a ~10% market-wide hurdle rate without subsidies
Static grid fees fundamentally reset BESS economics; the addition of FCA compounds this effect and leaves no viable unsubsidized case	Even low static grid fees with annual charges on reserved capacity (LP) as low as 6 €/kW/a combined with loss-based working prices (AP1/AP2) at 66.5 €/MWh and 266 €/MWh materially erode returns and push IRRs below hurdle rates. The application of FCA compounds this effect and reinforces the non-viability of unsubsidized deployment.
Post-2029 tariff design must avoid overlapping instruments that overburden the BESS case	Simultaneous application of BKZ, static grid fees, dynamic grid fees, and FCA creates interacting cost and constraint effects that make post-2029 BESS viability highly sensitive. The business case can potentially be preserved under specific parameter combinations, with BKZ exemptions delivering a measurable uplift in returns (≈ +2 pp IRR*). Static grid fees remain the dominant cost driver and would need to fall below the lower boundary tested to avoid materially constraining economics. Dynamic grid fees and FCA both reflect grid constraints through dispatch restrictions, and their combined application could materially increase dispatch constraint exposure

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The study is anchored on a reference 4-hour BESS with a COD in 2029, assumed to operate fully unrestricted and exempt from both static and dynamic grid fees

Assumptions of the AFRY base case

	Power	1 MW
	Usable capacity	4.0 MWh
	Round-trip-efficiency	88%
	Average cycles per day	1.5
	Maximum cycles per day	3
	Commercial operation date	January 2029
	Project Lifetime	15 years without repowering
	State of health at EOL	~65%
	Ramping restrictions	40% of rated power per minute
	Target Markets	Spot markets, FCR and aFRR holding
	CAPEX	775 €/kW
	OPEX	25 €/kW (at COD)
	BKZ	85 €/kW*
	Grid fees	-

* Corresponding to the median of Germany-wide BKZ values (Source: AFRY analysis)

Key modelling assumptions

- AFRY gross margins projection are based on key technical parameters shown on the left
- Markets considered for the gross margin evaluation are:
  - Arbitrage (Spot markets)
  - Reserve capacity holding (FCR, aFRR upward and downward)
- Power traded at other resolutions and in other markets may realise different market capture rates
- Financial trades are not included in the modelling
- The economic valuation is based on the calculation of the real unlevered project IRR for a project lifetime of 15 years

The reference 4h-BESS case was stress-tested under a selection of market-typical FCA assumptions and static grid-fee levels inspired by neighbouring markets

Key risk	Key parameter	Choice of parameter	Rationale
Grid fee	**Baukostenzuschuss**	• 85 €/kW	• Market-wide median
	Capacity price on ordered capacity (LP)	• 6 €/kW/a • 42 €/kW/a	• Capacity price in GB • Capacity price in Belgium
	Working price on losses (AP1 and AP2)	• 66.5 €/MWh and 266 €/MWh	• Current reference value for unsubsidised AP
	Dynamic grid fee	• Not assessed	• Not sufficient information on exact design available
FCA	**Ramp rate**	• 10%/min • 6%/min	• Realised in existing pipeline projects
	Ancillary market cap	• 30% eligible capacity • 0% eligible capacity	• Realised in existing pipeline projects
	Feed in restriction	• Not assessed	• Highly location dependent
	Wholesale freeze	• Not assessed	• Not feasible within fundamental foresight approach

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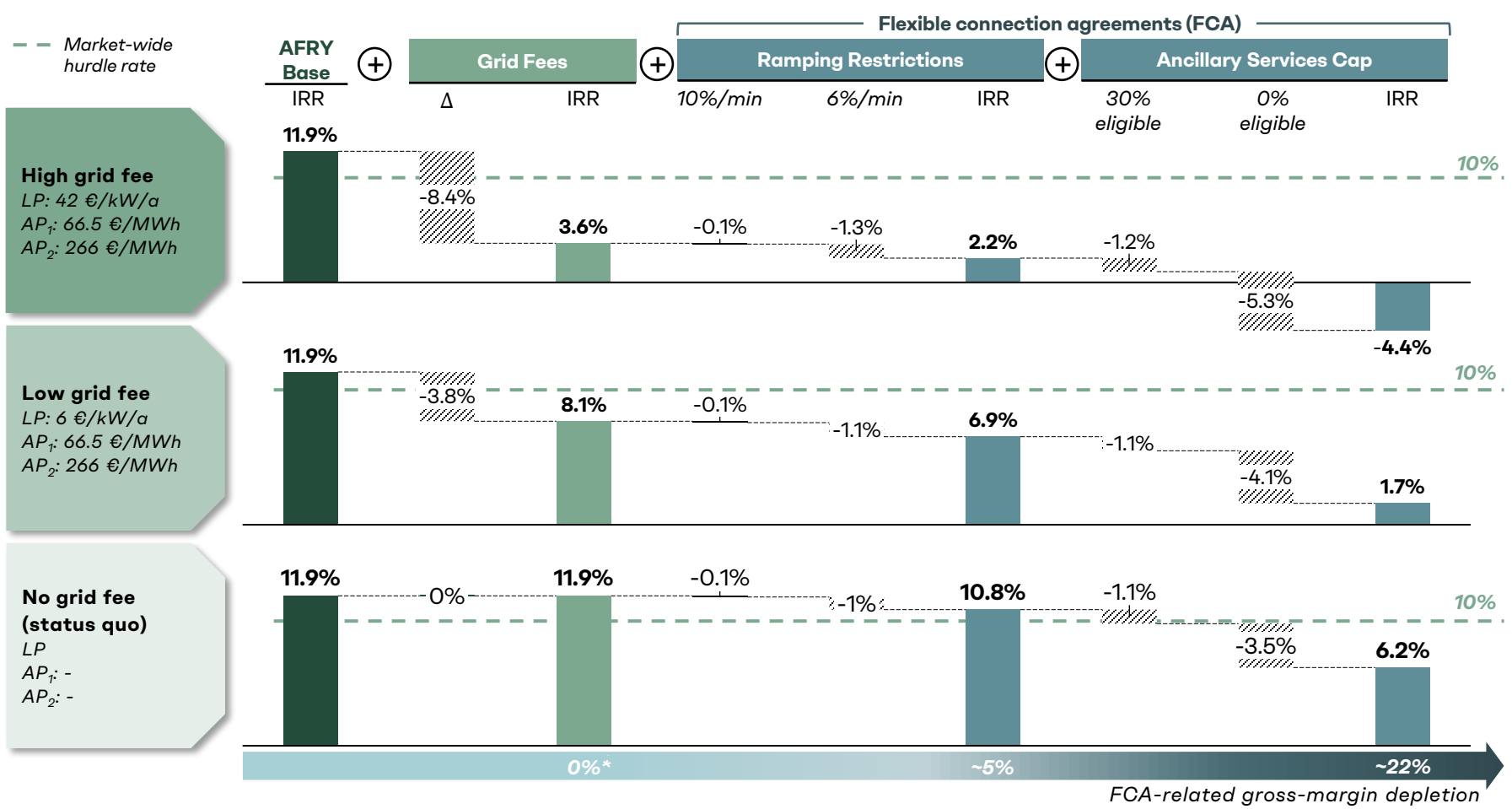
While BESS projects with COD 2029 can remain economically viable under current FCAs, the introduction of static grid-fee components renders all cases unprofitable



Key takeaways

- BESS remain attractive under current conditions, with ~12% IRR for the base case 4h BESS with COD 2029
- FCA alone do not kill viability: even material FCA can clear hurdle rates of 10%, but with very limited headroom
- Static grid fees with both capacity-price and working price are the structural break: even low-capacity charges push returns below hurdles
- Once grid fees apply, projects become non-viable; any additional FCA is prohibitive, with no margin buffer

Key mitigants

- BKZ waivers are a material lever on viability (+2%p increase)
- Only very low static grid fees (below tested regime) without FCA feasible)
- Where dynamic grid fees provide clear grid-friendly dispatch incentives, FCA could be removed to avoid overlapping and counteracting constraints

* For this study, the change in dispatch behaviour due to a AP1/AP2 ratio was not included

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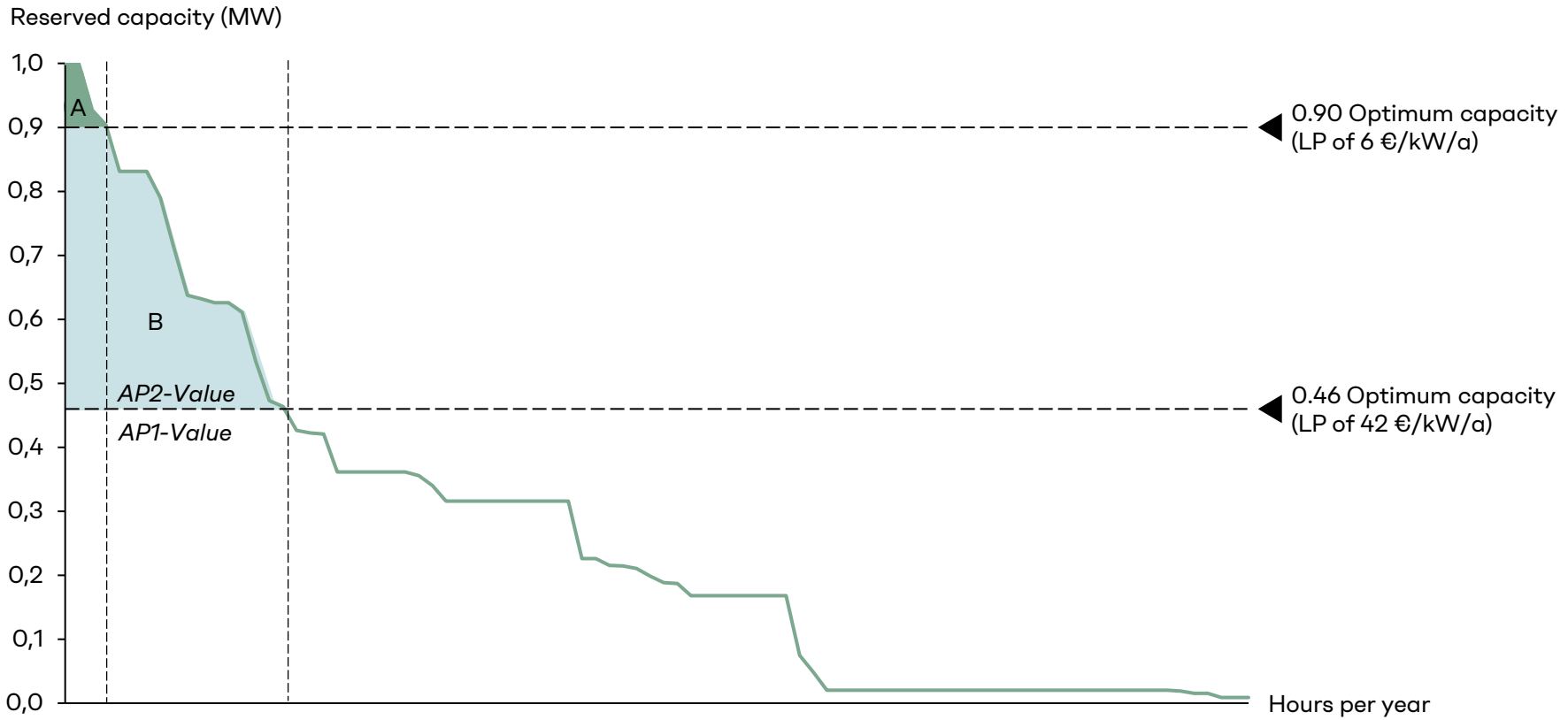
BESS viability relies on minimizing upfront and static grid cost burdens and avoiding overlapping constraint mechanisms, with dynamic grid pricing replacing FCA

Proposed mitigant	Description	Materiality
Exempt BESS from BKZ	— BKZ is explicitly included in the base assessment, reflecting the current lack of a general exemption for BESS median BKZ level of ~€85/kW represents a material upfront cost and materially weakens project economics at COD — Exemption of BKZ would remove a market-wide structural cost burden and materially improve capital efficiency	— Exemption of BESS from BKZ would have a material impact on the case, increasing the IRR by ~2%-points
Set static grid fees (LP and AP1/AP2) below the lower boundary tested	— Assumption of grid-fee levels below the defined "low grid-fee" case, driven by lower LP and reduced AP1/AP2 components — Under these assumptions, grid fees can become economically viable for the asset	— Lowering the LP and AP1/AP2 will materially improve the IRR
Replace FCA with dynamic grid fees, rather than layering both mechanisms	— Dynamic grid fees apply to all procured electricity; the net economic impact depends on regional price spreads, congestion patterns, and charging behaviour — While outcomes are highly location-specific, a well-designed dynamic regime could reward system-supportive dispatch and render the FCA obsolete	— To be determined when dynamic grid fee design is published
Enable additional support mechanisms or complementary revenue streams	— Enable other revenue streams such as potential capacity market participation — Other subsidy-driven support mechanism, if BESS buildout is to be maintained as a key pillar to decarbonization	— Capacity-market participation increases the annual gross margins by ~3% across the BESS lifetime

For the proposed static framework of a split work-price structure, an optimum ordered capacity is chosen by the operator to minimize the total cost

Reserved capacities derived from the charging capacity-duration curve for a 4h BESS



Optimisation results

- The reserved capacity is annually decided by the asset owner by optimizing allocation between AP1 and AP2 priced losses
- For a LP of 6€/kW (low grid fee), the operator choses a high ordered capacity of 0.9 . In this case, only 0.7% of energy losses corresponding to A will be allocated to AP2
- For a LP 0f 42 €/kW, the optimum ordered capacity is much lower (0.46). In this case, the losses allocated to AP2 correspond to AP2 grows to 19% (A+B). In this case, the operator needs to decide at which point they are willing to pay the AP2 on the losses or reduce the charging capacity
- **Note:** It was not clear from the BNetzA position paper whether the AP2/AP1 ratio is evaluated by the charging-capacity duration curve or the charging-and-discharging capacity duration curve

*no feedback loop to gross margin projections included in modelling approach

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