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Future-proofing Japanese utilities: The case for grid-scale battery investment

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1. Executive Summary

Ramping up investment in grid-scale batteries is an untapped opportunity for Japan's incumbent electric utilities. With price and technological barriers tumbling, the strategic deployment of grid-scale batteries offers utilities long-term earnings resilience and a much-needed evolution of business models.

Japan's incumbent electric utilities ("Japanese utilities"), which include the 10 electric power companies with regional monopolies (EPCOs) and the largest wholesale generator J-POWER, are increasingly misaligned with Japan's decarbonising energy system. Their business models are built around centralised baseload generation and predictable demand, whereas the grid is increasingly driven by variable renewables and decentralised supply, and customer expectations are changing.

Investor reticence about the challenges facing Japanese utilities is reflected in the deep discount-to--book value that the group average trades at. These companies are also highly leveraged, underscoring the need to reduce debt over time through more prudent capital allocation.

Battery projects are increasingly attractive investments globally due to rapidly declining costs. The global battery storage levelised cost of electricity (LCOE) dropped from US$300/MWh in 2018 to US$104/MWh in 2024 and is projected to halve again to US$53/MWh by 2035. In Japan, battery projects can achieve an expected internal rate of return (IRR) of more than 10% with the support of currently available government subsidies, while the cost of building and operating new batteries in Japan will soon be cheaper than the cost of running existing LNG plants.

Japan needs more energy storage capacity. Variable renewable energy (VRE) is scaling up, and with it, rates of curtailment – wasted renewable energy. Batteries' millisecond response capability provides the flexibility to store excess renewable energy until it is needed. When equipped with grid-forming inverters, batteries can mimic the stabilising role of traditional turbines, which help set and maintain the grid's frequency and voltage.

Japanese utilities are uniquely placed to deploy grid-scale batteries. Their local operational expertise and strong regional presence give them a clear competitive advantage. They also have, for now, first-mover advantage. While major utilities – including the EPCOs and J-POWER – have yet to meaningfully scale their participation, given the strong business case for batteries it is only a matter of time before there is broader commercial uptake.

Investors in Japanese utilities should be asking their companies if batteries are factored into decarbonisation and capital allocation strategies. If the answer is no, the question is - why not?

Key Findings

Japan's incumbent utilities – the 10 EPCOs and J-Power – are under pressure to evolve their business models and investing in batteries can help utilities adapt to the energy transition. Business models built around centralised baseload generation and predictable demand are increasingly misaligned with Japan's decarbonising energy system. (Section 4)

Incumbent Japanese utilities have a competitive advantage in the battery market, as they own most generation assets and grid infrastructure while having regional operational expertise, giving them relative knowledge and cost-competitive advantages. They can install batteries at retiring coal plants; co-locate with existing and new VRE assets; and site batteries near constrained transmission corridors and/or substations. (Section 2)

Utilities should act now and secure first mover advantages. There is a narrowing window for early movers to benefit from government subsidies and secure strategic locations ahead of broader commercial uptake. (Section 5)

Grid-scale batteries can support Japan's national energy security and clean energy transition. As distributed renewable generation grows, batteries can help stabilise the grid, reduce curtailment and ease congestion, as well as reducing the grid's need for the use of imported LNG. (Section 3)

Deploying batteries will help Japan make the most of its growing wind and solar energy. Existing storage capacity provided primarily by pumped hydro is no longer sufficient to meet Japan's increasing renewable needs (Section 3). Markets forecast a significant scale up of batteries, with BloombergNEF estimating a tenfold increase in storage volume from 2023. (Section 5)

Battery costs are plummeting. Global battery storage levelised cost of electricity (LCOE) has dropped from US$300/MWh in 2018 to US$104/MWh in 2024 and is projected to halve again by 2035 (Section 2). The cost of building and operating new batteries will soon be cheaper than the cost of running existing LNG plants. (Section 3)

Batteries are already commercially viable in Japan. There are opportunities to earn above 10% IRR via multiple revenue streams - capacity payments, energy arbitrage and ancillary services payments - supported by government subsidies. (Section 5)

Regions that are constrained in importing or exporting electricity provide greater opportunities for battery investment. Import-constrained demand centres and export-constrained, high-VRE regions need dispatchable storage capacity like batteries to maintain system reliability and stability[1] while reducing curtailment. (Section 6)

[1] Batteries support system reliability & stability. System reliability refers to the grid's ability to deliver electricity consistently and meet demand. System stability refers to the grid's ability to maintain correct voltage and frequency during disturbances.

Recommendations

Japanese utilities have a timely opportunity to deploy grid-scale batteries. Their local operational expertise and strong regional presence give them a competitive advantage to act now. Utilities can target high impact regions where they can maximise system value, capture stronger returns and secure first-mover advantages, creating future shareholder value.

A strategically important window is now open for investors to push Japanese utilities on battery investment. Falling costs, supportive policies, rising curtailment and IRRs of more than 10% have created favourable conditions for batteries to scale. This alignment of market and policy drivers may be temporary before broader commercial uptake, which makes timely investor engagement critical to ensuring that utilities act and capture the current financial and decarbonisation benefits.

From an energy transition perspective, battery investment can:

- enable greater VRE uptake by shifting generation to higher-value time periods and reducing curtailment
- displace LNG peaking generation with zero-emissions energy
- enhance the credibility of transition plans.

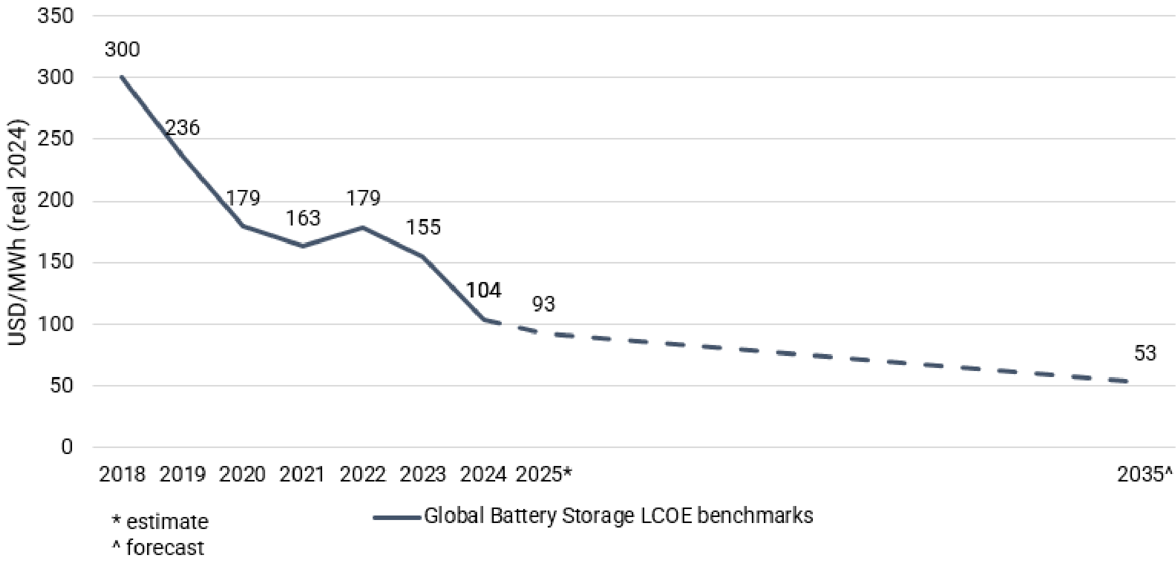
Key engagement questions for investors:

- Do you think battery storage will play an important role in Japan's energy transition?
- How do batteries fit into the company's broader decarbonisation and capital allocation strategies?
- What is the company's strategy for deploying batteries in demand centres and high-VRE regions? How will this strengthen decarbonisation and financial performance via capacity payments for firming, arbitrage returns and ancillary services payments?
- Are you advocating for streamlined approval processes to unlock investment and accelerate the deployment of viable battery projects?
- Do you see batteries as one option that can enhance the shareholder value of utilities in Japan, particularly considering that utilities face long-term structural risks from the energy transition?
- What, so far, has held back more aggressive investment into battery storage? What role does the company see themselves having in the build out of battery storage in the Japanese grid?

2. A strategic opportunity for utilities to deploy batteries now

Japanese utilities have a strong opportunity to deploy grid-scale batteries before broader commercial uptake, thanks to falling battery costs[2] (see Chart 1) and the availability of multiple, viable revenue streams supported by government subsidies.

Chart 1: Global battery LCOE is already plummeting and expected to decline further



Source: BNEF

Japan's incumbent utilities have a competitive advantage in the battery market because:

- They own most generation assets and grid infrastructure, while having regional operational expertise. Compared to foreign or smaller developers, they can more effectively forecast prices, optimise battery charging and dispatch.
- As large-cap, listed companies, they have the financial scale and capacity to invest in flexible, transition-aligned assets – like batteries – that can strengthen portfolios and deliver long-term shareholder value.

Utilities in Japan can leverage these strengths by deploying batteries where they deliver greater system value and higher revenue, such as by installing batteries:

- **at retiring coal plants –** This enables fast, cost-effective redevelopment by using existing grid infrastructure to support reliability.

[2] BNEF, Levelized Cost of Electricity Update 2025, p. 6 & 8. (Client access only).

- **co-located with variable renewable energy (VRE) –** Pairing with solar and wind assets mitigates price cannibalisation[3] by shifting output to higher-price periods, particularly under the feed-in-premium (FIP) scheme, which incentivises generation during high demand periods through storage.[4] This also improves the bankability, internal rates of return (IRR) and project flexibility of new VRE projects.
- **near constrained transmission corridors or substations –** By leveraging utilities' regional operational expertise[5] to relieve congestion, increase line utilisation and delay or reduce the need for costly upgrades.

Utilities operating in import-constrained demand centres and export-constrained, high-VRE regions are particularly well-placed to invest in batteries. They can generate strong returns by earning:

- **capacity payments** in regions that require local firm supply to meet peak demand
- **arbitrage returns** in constrained regions where rising curtailment and low-pricing intervals are driving greater price volatility
- **ancillary services payments** in regions with unmet reliability gaps, where fast-response reserves are urgently needed to maintain frequency stability.

Utilities can secure first-mover advantages and establish a competitive edge as flexible, clean capacity providers in a decarbonising grid by:

- capturing early strong returns while current government subsidies remain available[6]
- deploying batteries in the most attractive sites – demand centres and high-VRE regions.[7]

Some utilities are already acting. For example:

- Kansai Electric Power Company (KEPCO) has announced plans to construct the Tanagawa Energy Storage Plant, a 99 MW/396 MWh battery project in the Osaka prefecture that will earn revenue solely from energy arbitrage. Commercial operation is expected in 2028.
- Kyushu Electric Power Company (Kyuden) has announced a smaller 2 MW/8 MWh battery project that is scheduled to start operating in the Fukuoka prefecture (Kyushu region) from 2026. It will generate revenue from arbitrage, ancillary services and the capacity market.[8]

These are encouraging developments and as VRE penetration increases, the scale and speed of deployment is expected to accelerate. This presents a window of opportunity for utilities to secure first-mover advantages.

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[3] BNEF, Japan's Rising Renewables Capacity Hits Revenues, April 2025. (Client access only).
[4] RatedPower, Japan's FIP scheme and battery storage subsidy are driving forces to boost renewables, May 2023.
[5] Under Japan's legal unbundling rules, a utility's transmission arm is generally prohibited from owning or operating generation assets - including battery storage, which is legally classified as generation under the Electricity Business Act.
[6] For more detail, please see Section 5.2.
[7] Region-specific analysis of the most attractive sites is in Section 6.
[8] Energy Storage News, Japan: Electric utilities KEPCO, Kyuden, make progress in emerging battery storage market, May 2025.

3. Batteries' role in Japan's clean and secure energy future

Batteries can enhance energy security by reducing the grid's use of imported LNG to meet peak demand and firming needs, simultaneously reducing emissions. As distributed renewable generation grows, batteries also offer the flexibility needed to stabilise the grid, reduce curtailment and ease transmission congestions.

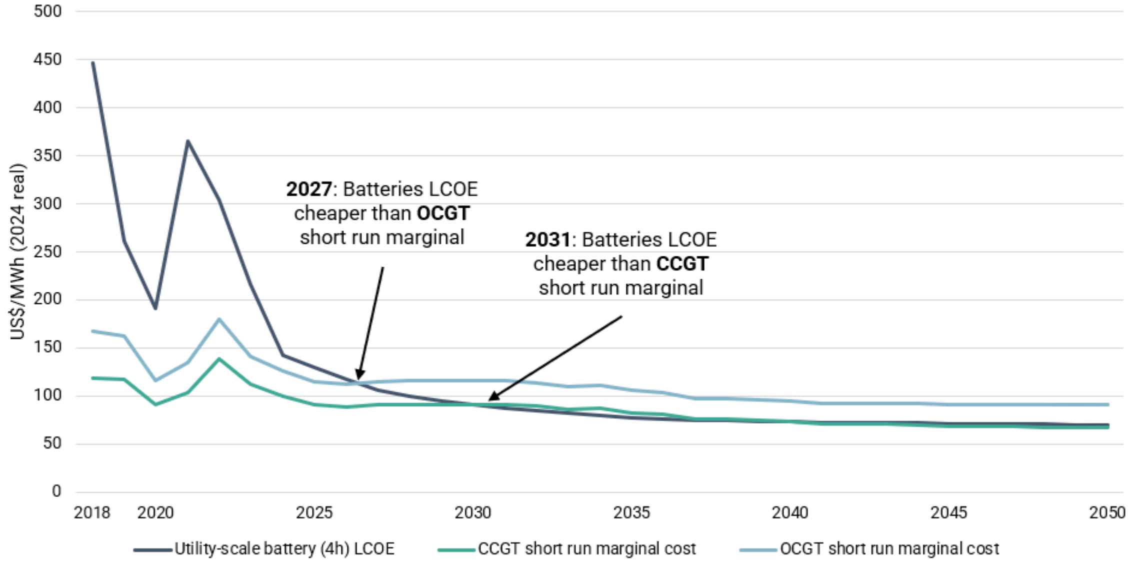
3.1 Batteries support energy security by reducing reliance on imported fuels

Batteries can enhance the grid's energy security by reducing its reliance on imported fuels and its exposure to volatile fuel prices. As Japan decarbonises its grid, this will be key to strengthening energy security. Batteries offer a clean, cost-effective[9] alternative to LNG peakers, as they firm variable renewables and support peak demand without emissions.

Building and operating new grid-scale batteries will soon be cheaper than the cost of running existing LNG plants. Some utilities, such as JERA, plan to use LNG plants to firm renewables,[10] [11] but batteries could meet the same need more cheaply without creating emissions. According to Bloomberg NEF's (BNEF) 'mid-scenario', the levelised cost of electricity (LCOE)[12] from a typical 4-hour battery[13] in Japan is expected to fall below the short-run marginal cost[14] of operating open-cycle gas turbines (OCGT) by 2027 and combined-cycle gas turbines (CCGT) by 2031 (Chart 2).[15] This is likely to occur even sooner if existing government subsidies are accounted for.[16]

[9] Batteries avoid fuel and emissions costs, benefit from declining capital costs and can earn revenue across multiple markets. In contrast, LNG peakers face ongoing fuel and carbon costs. As battery deployment scales and subsidies lower capex, batteries are expected to deliver lower long-run system costs than LNG for firming and peaking.
[10] Japan Wire, Japan's Jera pledges stable power supply by using LNG-fired plant, May 2025.
[11] The generation assets of TEPCO and Chubu EPCO were consolidated under JERA in 2015, a 50-50 joint venture between the two companies.
[12] LCOE is the average cost to *build and operate* a power source (like a battery or gas plant) over its lifetime, divided by the total electricity it produces. It helps compare different energy technologies on a per-unit basis (e.g. yen/kWh).
[13] BNEF provides LCOE data for 1-hour and 4-hour batteries only. We have used 4-hour battery LCOEs, as this is the typical project type in Japan.
[14] Short-run marginal cost is the cost of generating one more unit of electricity from an *existing* power plant, mostly made up of fuel and operating expenses. For gas plants, this reflects how much it costs to run them - not build them.
[15] BNEF, 2025 LCOE: Data Viewer Tool, February 2025. (Client access only).
[16] BNEF's LCOEs exclude subsidies or tax-credits.

Chart 2: Cost of building and operating new batteries is expected to be cheaper than the cost of running existing LNG plants as soon as 2027



Source: BNEF, ACCR

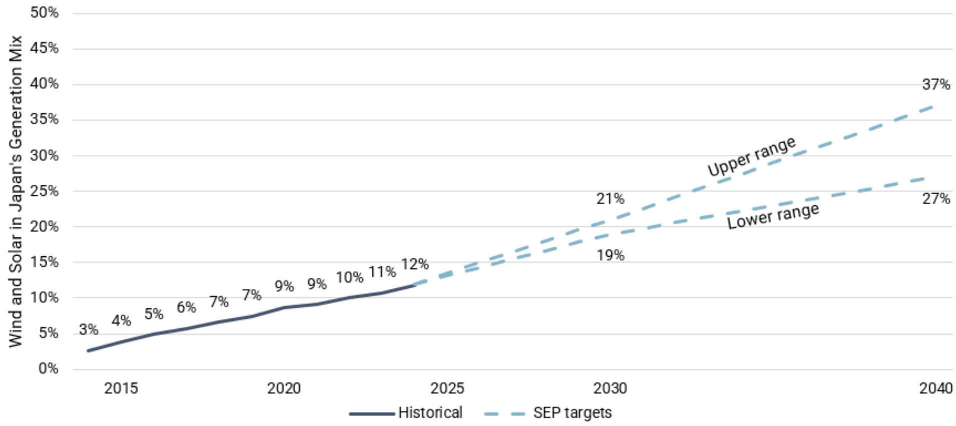
3.2 Japan needs dispatchable storage capacity beyond pumped hydro to unlock its renewable potential

As Japan continues to expand renewable generation, its grid requires more dispatchable storage. The current dispatchable storage mix, dominated by pumped hydro, is no longer sufficient for meeting Japan's evolving storage needs as distributed solar and wind capacity grows. In this context, grid-scale batteries represent a viable near-term opportunity for utilities to strengthen grid reliability and stability.

Japan's variable renewable energy (VRE) share is forecast to grow as the country works towards its 2030 and 2040 generation mix targets. Primarily driven by solar, VRE has risen from a 2.6% share of the mix[17] in 2014 to nearly 12%[18] in 2024, supported by falling costs[19] and strong policy support.[20] Japan's most recent Strategic Energy Plans (see Chart 3) project VRE to make up 19-21% of the generation mix in 2030[21] and 27-37% in 2040.[22] [23] [24]

[17] IEA, Japan Electricity, Evolution of electricity generation sources in Japan since 2000.
[18] OCCTO, Aggregation of Electricity Supply Plans for Fiscal Year 2025, June 2025, p. 26-27. (Japanese version).
[19] METI, 太陽光発電について, December 2024, p. 34.
[20] IEA, Japan 2021 Energy Policy Review, March 2021, p. 104-105.
[21] METI, 6th Strategic Energy Plan (Outline), October 2021, p. 12. (Japanese version).
[22] METI, 7th Strategic Energy Plan (Outline), February 2025, p. 14. (Japanese version).
[23] METI, 6th Strategic Energy Plan (Outline), October 2021, p. 12. (Japanese version).
[24] METI, 7th Strategic Energy Plan (Outline), February 2025, p. 14. (Japanese version)

Chart 3: Growth in wind and solar is expected to continue to meet 2030 and 2040 targets

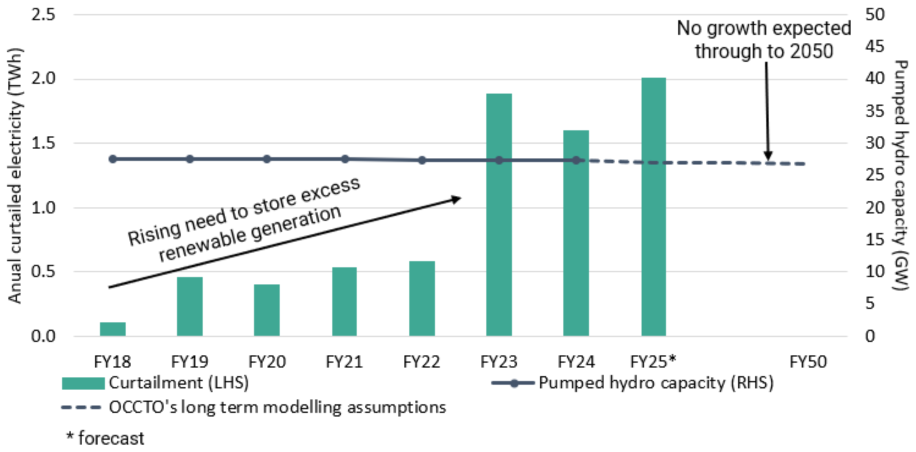


Source: IEA, Organisation for Cross-regional Coordination of Transmission Operators (OCCTO) and METI.

Japan needs more energy storage capacity. Curtailment has grown from just 0.1 TWh in FY18 to 1.6 TWh in FY24 (see Chart 4), with Kyushu region's curtailment rate projected to reach 6.1% in FY25.[25] [26] This trend highlights the need for more storage capacity, even though Japan already has a sizeable 27 GW pumped hydro fleet (8% of national capacity).[27] However, most remaining potential hydro sites are considered uneconomic[28] and OCCTO projects no further growth in pumped hydro capacity through to 2050.[29] [30] [31]

[25] METI, 再生可能エネルギー出力制御の長期見通し等について, June 2025, p. 5.
[26] All fiscal year references in this report refer to the most common measure of the Japanese corporate fiscal year – 1 April to 31 March of the following calendar year. In this instance, fiscal year 2025 covers 1 April 2025 to 31 March 2026.
[27] OCCTO, Aggregation of Electricity Supply Plans for Fiscal Year 2025, June 2025, p. 20. (Japanese version).
[28] 脱炭素技術センター, なぜか伸びない水力発電の謎?, April 2025.
[29] OCCTO's compiled data is based on a mechanical aggregation of capacity figures submitted by electricity generators. These are not scenario-based projections but input values used for system modelling purposes.
[30] OCCTO, Aggregation of Electricity Supply Plans for Fiscal Year 2025, June 2025, p. 20. (Japanese version).
[31] OCCTO, 広域系統長期方針(広域連系系統のマスタープラン)<別冊(資料編)>, March 2023, p. 45.

Chart 4: Rising curtailment signals the need for new storage beyond pumped hydro



Source: OCCTO & METI data

Batteries are currently underutilised, with around 1 GW deployed as of September 2024[32] (Chart 5). Despite this, batteries offer Japanese utilities significant potential because they can:

- reduce curtailment by storing excess renewable energy and shifting supply to meet peak demand
- ease transmission congestions when sited near demand centres and congestion points
- enhance grid stability through fast frequency response, voltage control and synthetic inertia (i.e. the ability to mimic the stabilising role of traditional turbines) when equipped with grid-forming inverters
- provide location flexibility with less geographical constraints – as modular systems can be sited closer to where they are most needed to help manage intraday variability and firming renewables across a decentralised grid.

[32] METI, 定置用蓄電システムの現状と課題, March 2025, p. 2.

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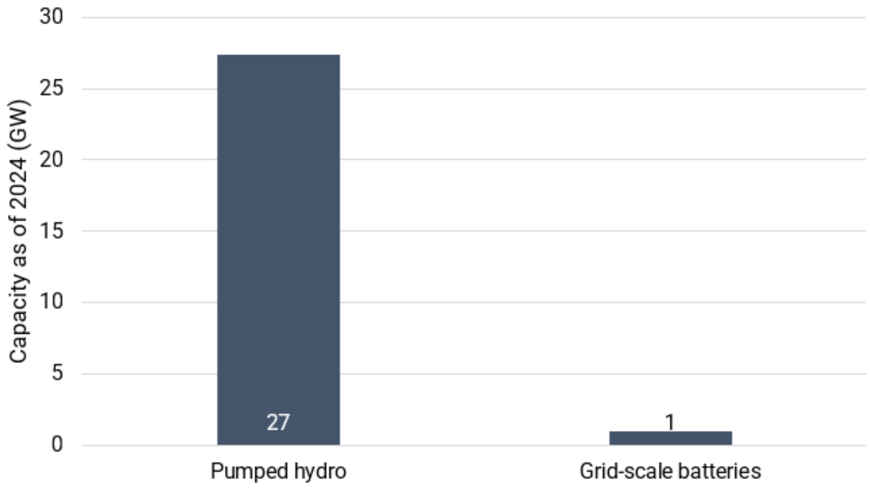
Chart 5: Japan's dispatchable storage mix highlights major growth opportunity for batteries



Source: OCCTO

Other solutions to increase grid flexibility like transmission upgrades, green hydrogen and virtual power plants (VPPs) that coordinate distributed energy resources[33] for demand response will support Japan's decarbonisation. However, grid-scale batteries stand out as an immediately viable investment for utilities.

[33] Such as behind-the-meter battery storage, solar panels and electric vehicles.

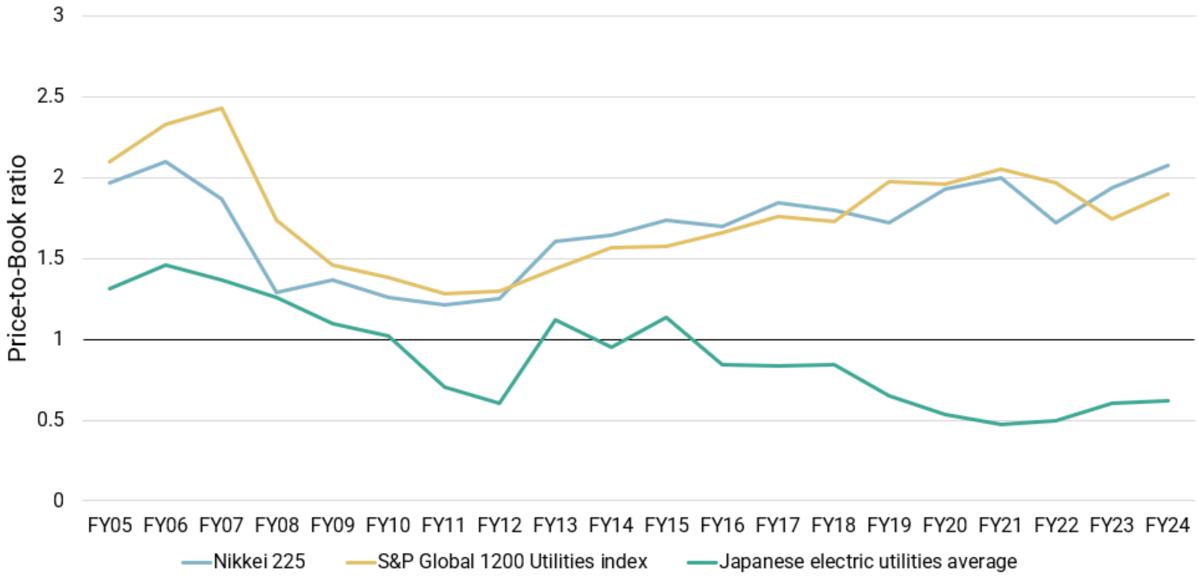
4. Batteries are an opportunity for Japan's utilities to adapt

Japan's incumbent electric utilities are under growing pressure to adapt their business models as the country's energy system transitions. Investing in grid-scale batteries is an opportunity to do this while delivering stronger returns. Investors can explore opportunities to strengthen long-term returns by engaging utilities on strategic battery deployment – which could enhance earnings resilience, capture new revenue streams and support decarbonisation goals.

Business models built around centralised baseload generation and predictable demand are increasingly misaligned with Japan's decarbonising energy system. The grid is increasingly driven by variable renewables and decentralised supply, while customer expectations are changing.

Currently, there is investor scepticism about the ability of Japanese electric utilities to deliver long-term returns above the cost of capital, as reflected in the deep discount-to-book value multiple that the group average trades at. On average, the group has traded below their own book value since FY16.[34] Relative to domestic and global peers, over the past two decades they have traded at a discount to the Nikkei 225 and the S&P Global 1200 Utilities Index (Chart 6), as shown by their relative price-to-book ratios.[35]

Chart 6: On average, Japanese incumbent electric utilities traded at a persistent discount to global peers, the domestic market and their book value

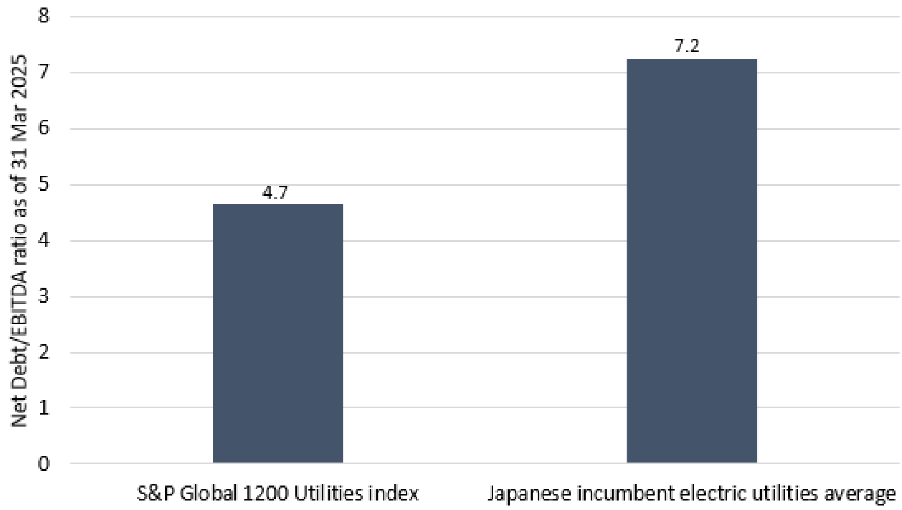


Source: Bloomberg Finance L.P.; Used with permission of Bloomberg Finance L.P.

[34] The Japanese corporate fiscal year 2016 covers 1 April 2016 to 31 March 2017.
[35] P/B ratios shown for Japanese utilities represent a simple average across the 11 listed companies in the sector.

As Japanese utilities are highly leveraged companies, prudent capital allocation is important. As of 31 March 2025, the utilities reported an average net debt-to-EBITDA ratio of 7.2x[36] - significantly higher than the 4.7x average among global utility peers (see Chart 7). Considering these businesses face long-term structural risks, it may be a priority to reduce debt over time through more prudent capital allocation, as longer-term cash flows from emissions intensive assets are not necessarily dependable through the energy transition.

Chart 7: Japanese utilities are more highly leveraged than global peers



Source: Bloomberg Finance L.P.; Used with permission of Bloomberg Finance L.P.

To meet policy, market and investor expectations, utilities will need to adapt to the decarbonising grid and develop credible transition strategies. Table 1 summarises the implications for incumbent electric utilities if they continue with business-as-usual operations.

Table 1: Transition risks for the traditional utilities' business models

Risk	Description	Implications for investors
Asset underperformance	Continued reliance on emissions-intensive generation (e.g. coal-fired) with declining utilisation.	Lower asset productivity, value impairment, earnings pressure.
Capital misallocation	Missed investment opportunities in future-proof infrastructure such as renewables and grid flexibility assets (e.g. storage, demand response).	Missed growth opportunities, declining competitiveness, weak long-term earnings outlook.
Policy misalignment	Business models fail to adapt to Japan's evolving policy settings and targets.	Regulatory exposure, reduced access to incentives, reputational risk.

[36] The average net debt/EBITDA ratio for Japanese utilities is calculated as a simple average across the 11 listed companies in the sector.

Over-leveraged business	High debt levels constrain balance sheets, leaving less room to invest in low-carbon technologies.	Higher cost of capital, credit rating pressure, constrained reinvestment capacity, reduced investor confidence.
Overreliance on unproven technologies	Strategic reliance on unproven or commercially uncertain technologies for decarbonisation (e.g. ammonia co-firing, CCS).	Delayed returns, cost overruns, weaker investor support for long-term plans.

4.1 Battery investment can help utilities adapt

Battery investment can help utilities adapt to a system increasingly shaped by renewables and be rewarded for flexibility to support system reliability and security, ultimately creating long-term shareholder value.

Utilities in other markets are already making similar shifts. For example, Australian utilities are moving toward direct battery ownership as falling costs and stronger revenue streams reshape their business models.[37]

If Japan's utilities delay battery investment, the risks in Table 1 may become more immediate and pronounced:

- **Missed decarbonisation targets –** Prolonged fossil dependence would make it harder to meet decarbonisation targets, weakening the credibility of transition strategies.
- **Stranded asset risk –** Failure to adapt portfolios to the energy transition would leave utilities increasingly exposed to stranded assets over the long-term.
- **Higher exposure to fuel and carbon costs –** Continued reliance on LNG[38] would increase vulnerability to volatile fuel prices and growing carbon liabilities, especially with mandatory carbon pricing commencing in FY26.

[37] BNEF, 2025 Australia Energy Storage Update: Business Models, April 2025. (Client access only).
[38] The IEA's Low Battery Case suggests that in advanced economies committed to phasing out unabated coal, insufficient battery deployment could result in a continued reliance on natural gas to offset the shortfall in solar PV generation. IEA, Batteries and Secure Energy Transitions, April 2024, p. 128.

5. The scale and economics of the opportunity

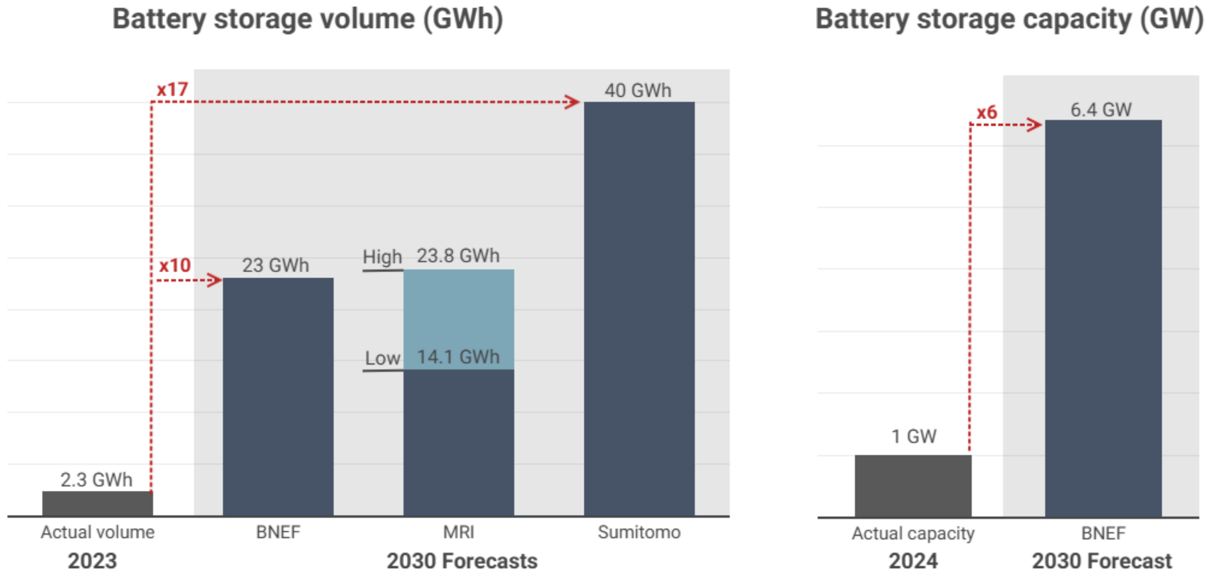
As renewables grow in Japan's energy system, a significant scale-up of grid-scale batteries is expected, presenting a major opportunity for utilities to lead deployment. Batteries are already commercially viable, with both capacity market-backed and subsidised merchant models[39] offering revenue sources with internal rates of return (IRRs) above 10%.

5.1 The expected scale-up of grid-scale batteries presents an opportunity for utilities

Market forecasters expect the energy volume[40] (GWh) and power capacity[41] (GW) provided by batteries to expand significantly. By 2030:

- BloombergNEF (BNEF)[42] and the Mitsubishi Research Institute (MRI)[43] project a tenfold increase in Japan's battery energy storage volume from 2023 levels,[44] while trading house Sumitomo[45] projects a 17-fold increase.
- BNEF projects a sixfold increase in battery power capacity[46] from 2024 levels[47] – see Chart 8.

Chart 8: Significant scale-up is expected from current battery levels in Japan



Source: METI, BNEF, Reuters

[39] Merchant battery projects refer to storage investments whose revenues come primarily from market activities (e.g. arbitrage, ancillary services) without guaranteed income from long-term contracts (e.g. capacity payments).
[40] Energy volume (GWh) determines how long batteries can continue supplying electricity. Higher energy volume is essential for managing prolonged periods of low renewable output or high demand.
[41] Power capacity (GW) reflects how much electricity batteries can deliver at any given moment. Sufficient power capacity ensures the system can respond instantly to peak demand or sudden shortfalls without being constrained by output limits.
[42] BNEF, 1H 2025 Energy Storage Market Outlook, April 2025, p. 25. (Client access only).
[43] MRI, 定置用蓄電システムの普及拡大に向けた調査, December 2023, p. 8.
[44] METI, 定置用蓄電システムの現状と課題, March 2025, p. 1.
[45] Reuters, Sumitomo aims to install 500 MW battery storage in Japan by early 2031, June 2024.
[46] BNEF, 1H 2025 Energy Storage Market Outlook, April 2025, p. 25. (Client access only).
[47] METI, 定置用蓄電システムの現状と課題, March 2025, p. 2.

5.2 Three revenue sources from grid-scale batteries

There are two types of battery projects: capacity market-based projects, where revenue is generated via capacity payments; and merchant projects, where revenue is generated via energy arbitrage and/or ancillary services payments (Table 2). Both project types can be commercially viable today, offering battery projects an IRR above 10% – exceeding the typical developer hurdle rate of 8-10%[48] generally required to justify investment in Japan.

Table 2: Two battery project types in Japan

	Capacity market-backed projects	Merchant projects	
Primary revenue stream/s	**Capacity payments** 20-year payments received in exchange for committing capacity to be available when needed	**Energy arbitrage** Charging when prices are low and discharging when prices are high	**Ancillary services payments** Payments received for providing fast-response support to maintain grid stability
Commercially viable (>10% IRR) today?	Yes	Yes, achievable with existing subsidies	
Commercially viable (>10% IRR) *without* subsidies?	N/A	Not yet - ACCR estimates this could occur as early as 2029	
Special requirements	- Must return 90% of profits received from other revenue sources - Not eligible for national and Tokyo subsidies	- National subsidy covers 50% of capex - Tokyo Metropolitan Government subsidy covers up to two-thirds of capex	

Source: ACCR, OCCTO, BNEF

5.2.1 Revenue via the capacity market

Japan's capacity market provides long-term revenue certainty for battery projects through 20-year capacity payments awarded via the Long-Term Decarbonisation Auction (LTDA), giving developers predictable cash flows regardless of short-term market volatility.[49] Battery operators receive these payments in exchange for making their capacity available to the grid, even if it is not used. Under current rules, projects receiving capacity payments must return 90% of any profits earned from other

[48] BNEF, 2025 Japan Energy Storage Economics: A Balancing Game, February 2025, p. 13. (Client access only).
[49] This stable income stream helps de-risk projects and attract financing, particularly from lenders seeking predictable cash flow.

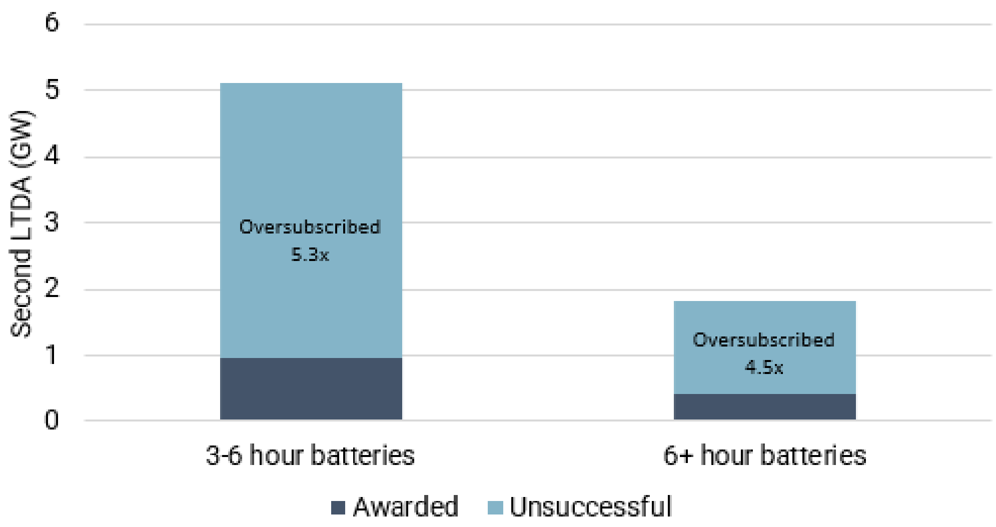
revenue streams to prioritise system reliability support. They are also not eligible for additional government subsidies.[50]

Battery projects are already commercially viable and achieving strong returns under the LTDAs, with the first two auctions driving a surge in developer interest. For example, BNEF modelling shows that a battery project in the Tokyo region could reach an IRR of 32% at the current auction price cap.[51]

These projects also remain commercially viable under more competitive conditions. The most recent LTDA awarded 1.4 GW of battery capacity and was significantly oversubscribed (see Chart 9).[52] However, BNEF estimates that even if clearing prices[53] fall to half the regional price cap, battery projects could still achieve IRRs above 10%.[54]

Despite this momentum, the major utilities – including the EPCOs and J-POWER – are yet to scale up their participation meaningfully, and were not awarded battery projects in the first[55] or second[56] LTDA.

Chart 9: Intense battery competition for capacity payments in the second LTDA



Source: OCCTO and BNEF

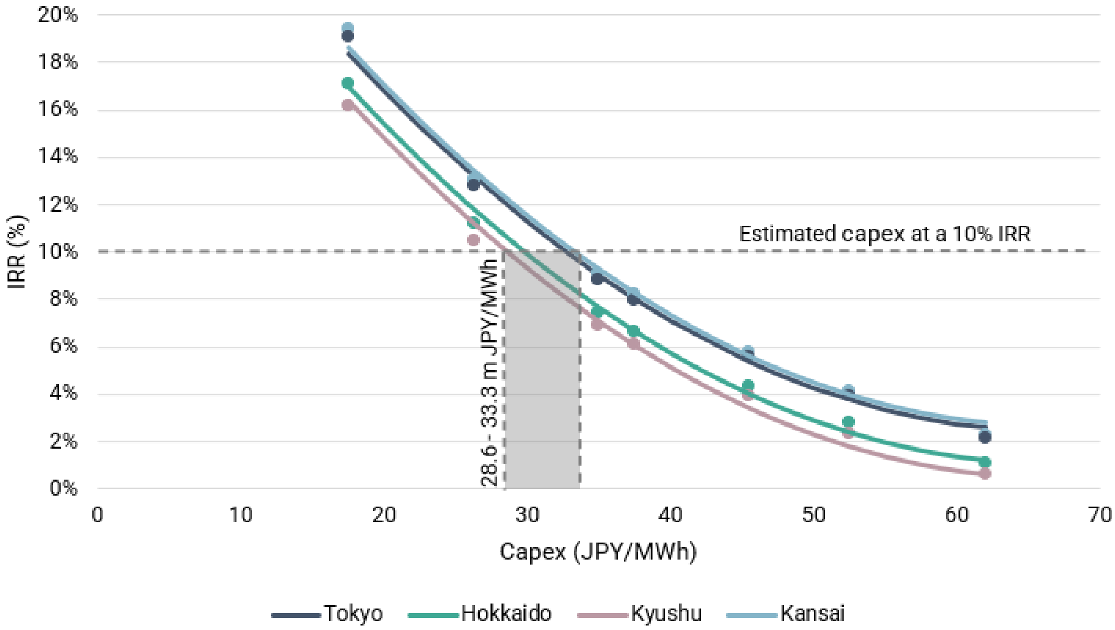
[50] BNEF, 2025 Japan Energy Storage Economics: A Balancing Game, February 2025, p. 8. (Client access only).
[51] BNEF, 2025 Japan Energy Storage Economics: A Balancing Game, February 2025, p. 1. (Client access only).
[52] BNEF, Battery, Nuclear Gain as Hydrogen Muted in Japan Auction: React, May 2025. (Client access only).
[53] OCCTO doesn't disclose auction clearing prices.
[54] BNEF, Battery, Nuclear Gain as Hydrogen Muted in Japan Auction: React, May 2025. (Client access only).
[55] OCCTO, 容量市場 長期脱炭素電源オークション約定結果(応札年度:2023年度), April 2024.
[56] OCCTO, 容量市場 長期脱炭素電源オークション約定結果(応札年度:2024年度), April 2025.

5.2.2 Revenue streams for merchant projects

Merchant battery projects that participate in energy arbitrage and the balancing market are commercially viable today with the support of government subsidies.[57] As capital costs continue to fall and policy support increases,[58] revenue streams for merchant projects – energy arbitrage and ancillary services payments – will play an increasingly central role in battery economics.

Although no merchant battery project in Japan can meet a 10% IRR without subsidies yet,[59] ACCR analysis suggests that merchant battery projects could be commercially viable without subsidies as early as 2029, as battery costs continues to fall. According to BNEF,[60] merchant battery projects can achieve 10% IRR once capex falls below between 28.6-33.3 million JPY/MWh - depending on the region (see Chart 10). Using BNEF's 2023 benchmark capex of 52.5 million JPY/MWh for a typical 4-hour battery system as a starting point,[61] and assuming a 10% annual decline,[62] these breakeven levels could be reached by 2029.

Chart 10: Estimated breakeven capex for merchant batteries to achieve 10% IRR



Source: BNEF, ACCR

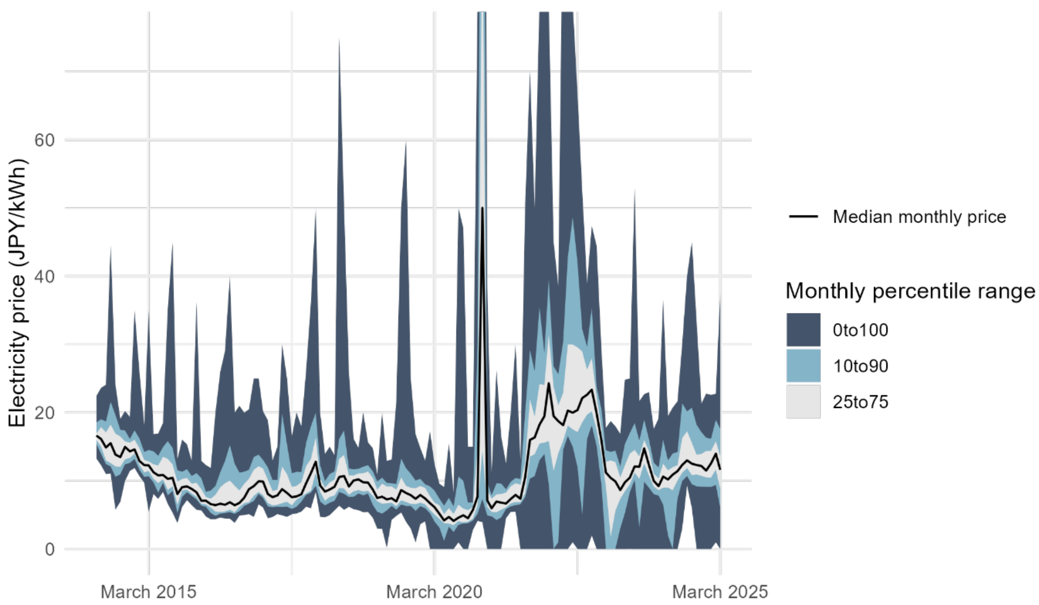
[57] Japan offers two major subsidy programs that cover a large share of grid-scale battery project costs. A national subsidy from METI covers 50% of capex, while a Tokyo-specific program covers up to two-thirds. Projects awarded in the LTDA, however, are not eligible for these subsidies. BNEF, 2025 Japan Energy Storage Economics: A Balancing Game, February 2025, p. 9. (Client access only).
[58] Renewable Energy Institute, Unlocking the Potential of Grid-Scale Battery Storage Business: Current Status and Challenges, August 2025, p. 8.
[59] BNEF, 2025 Japan Energy Storage Economics: A Balancing Game, February 2025, p. 1. (Client access only).
[60] For further detail on this analysis, see Appendix 1.
[61] BNEF, 2025 Japan Energy Storage Economics: A Balancing Game, February 2025, p. 10. (Client access only).
[62] BNEF, Levelized Cost of Electricity Update 2025, p. 8. (Client access only).

Revenue via energy arbitrage

As Japan's renewable share has grown, price volatility has increased, creating more frequent arbitrage opportunities for battery owners. Energy arbitrage involves charging batteries during low-pricing periods in the spot market (such as periods with abundant solar generation) and discharging at higher prices during high demand or low supply periods.

ACCR analysis (Chart 11) shows that the average daily price range has more than doubled – from 6.8 yen/kWh (FY15-FY19) to 15.7 yen/kWh (FY20-FY24). This trend is expected to continue, with BNEF forecasting sustained volatility through FY25-FY26.[63] [64]

Chart 11: Electricity price volatility is increasing in Japan



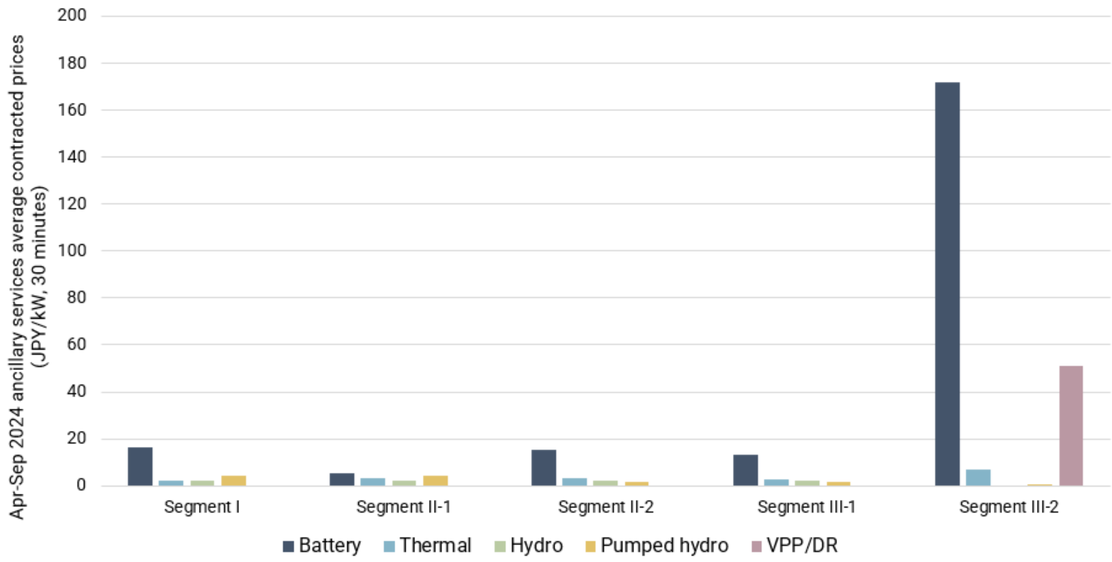
Source: Japan Electric Power Exchange (JEPX), ACCR

Revenue via providing ancillary services

Battery operators providing ancillary services in the balancing market can receive payments for delivering fast responses that stabilise fluctuations in frequency and imbalances in supply-demand. This has become a strong revenue stream for subsidised battery projects in Japan, particularly following the April 2024 introduction of new market segments (I, II-1, II-2) that better align with battery capabilities. Across all segments, batteries have secured significantly higher contracted prices than other technologies (see Chart 12),[65] reflecting their competitive advantage in delivering fast-response services.

[63] BNEF, Japan Power Market Outlook 1H 2025: Fuel Costs Drag Prices, April 2025, p. 7. (Client access only).
[64] The Japanese corporate fiscal year 2025 covers 1 April 2025 to 31 March 2026.
[65] BNEF, 2025 Japan Energy Storage Economics: A Balancing Game, February 2025, p. 6. (Client access only).

Chart 12: Batteries secure higher prices than other technologies in all ancillary service segments



Source: BNEF (adapted by ACCR)

Short-term returns are especially strong in Hokkaido, where BNEF modelling shows that a 30 MW/ 4-hour battery commissioned in 2024 could recover nearly 60% of its capital costs in the first year of operation, with a payback period of just 1.8 years.[66] Subsidised projects in Segment I (Frequency containment reserve) can achieve IRRs of up to 19% in this region,[67] fuelling strong developer interest. As of April 2025, 8.4 GW of battery projects are applying for grid connection in Hokkaido.[68]

However, long connection lead times of up to two years remain a barrier.[69] A surge in applications – some seemingly speculative and aimed at reselling project rights – has strained transmission and distribution services operators (TDSOs), extending project timelines and raising costs for battery developers.[70] Streamlining approval processes could unlock investment and accelerate viable projects. METI is working on temporary measures that will allow early grid connection for batteries without transmission system upgrades.[71]

Future market reforms are set to further improve battery economics. OCCTO plans to shift all ancillary service settlement to day-ahead by FY26, allowing technologies like batteries to participate more flexibly.[72] METI is considering a simultaneous energy-ancillary services market and a three-part bidding system by FY28[73] to improve price signals.

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[66] BNEF, Jackpot for Batteries in Japan's Hokkaido Builds Up Queue, May 2025. (Client access only).
[67] BNEF, 2025 Japan Energy Storage Economics: A Balancing Game, February 2025, p. 14. (Client access only).
[68] Hokkaido Electric Power Co., 発電等設備の受付状況に関する情報・出力制御区分の内訳. (Accessed on 11 June 2025).
[69] BNEF, Japan's Energy Storage Uptake Challenged by Policy Risks, June 2025, p. 4. (Client access only).
[70] REI, Unlocking the Potential of Grid-Scale Battery Storage Business, August 2025, p. 12.
[71] METI, 系統用蓄電池の迅速な系統連系に向けて, March 2025.
[72] Electric Power Reserve eXchange, 第６回 （一社） 電力需給調整力取引所 運営委員会 議事録, May 2025.
[73] Japan Energy Hub, METI's study group releases interim report on simultaneous market design, October 2024.

6. Location matters: How grid constraints shape battery revenue potential

Strategically placed batteries can meet the grid's need for greater local flexibility and stability by responding almost instantly to local shortfalls, stabilising frequency and balancing supply-demand fluctuations. Batteries are likely to unlock stronger revenue opportunities in regions where the grid is currently constrained, and where future renewable flows are likely to be located.

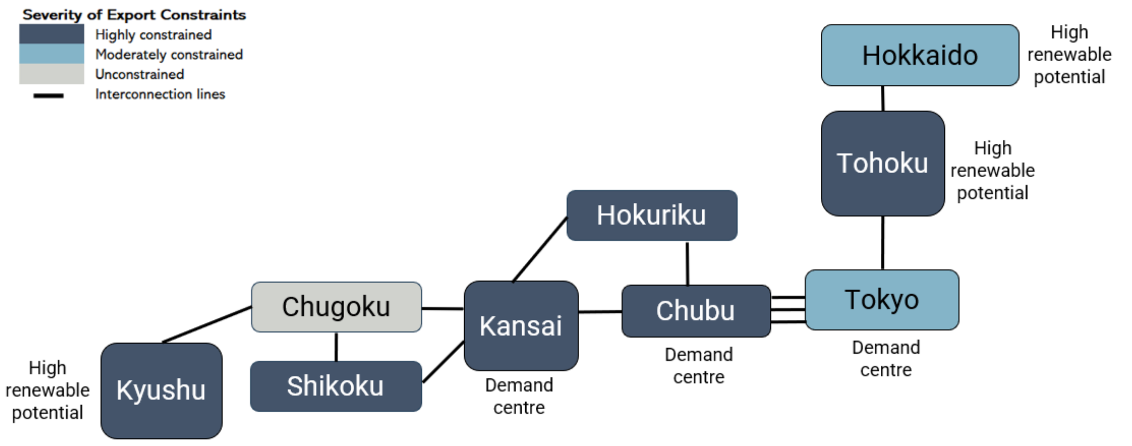
6.1 Greater need for dispatchable storage in constrained regions

There is a greater need for dispatchable storage, such as batteries, in transmission bottlenecks – regions where limited transmission capacity restricts electricity imports or exports. Dispatchable storage is most needed to support system reliability and stability in:

- major demand centres that struggle to import power to meet peak demand
- regions where renewable generation exceeds local demand but faces export constraints.[74]

In FY23, most regions experienced export constraints, as data from the Organisation for Cross-regional Coordination of Transmission Operators (OCCTO)[75] shows. We assessed the severity of these export constraints and categorised the nine regions as either highly constrained, moderately constrained or unconstrained (see Chart 13).[76]

Chart 13: Current transmission constraints and future renewable flows from high-potential regions



Source: ACCR, OCCTO

[74] OCCTO's 2050 Master Plan identifies future energy flows from remote regions with high renewable potential to major demand centres. OCCTO, Long-term Transmission Network Expansion Plan in Japan for Achieving Carbon Neutrality Goals towards 2050, September 2023, p. 3.
[75] OCCTO, Outlook for Electricity Supply–Demand and Cross-regional Interconnection Lines: Actual Data for Fiscal Year 2023, November 2024, p. 36-41. (Japanese version). The Japanese corporate fiscal year 2023 covers 1 April 2023 to 31 March 2024.
[76] For more detail on our methodology, please see Appendix 2.

Deploying batteries can help in:

- **demand centres that struggle to import energy to meet peak demand** – by storing electricity during low demand periods and releasing it during peak demand, reducing reliance on imports and meeting local peak needs.
- **remote, high-variable renewable energy (VRE) regions that can't export most of the time** – by storing energy for local use at another time, displacing generation from heavy-emitting power plants and reducing curtailment.
- **remote, high-VRE regions that can't export some of the time** – by storing excess renewable power during congested periods and releasing it when transmission lines are uncongested, increasing the use of existing transmission capacity.

6.2 Grid constraints highlight regional revenue opportunities

Regions facing grid constraints tend to offer greater revenue opportunities. This section outlines how regional dynamics impact the value that batteries can generate from capacity payment, energy arbitrage and ancillary service payments.

6.2.1 Revenue opportunities from the capacity market

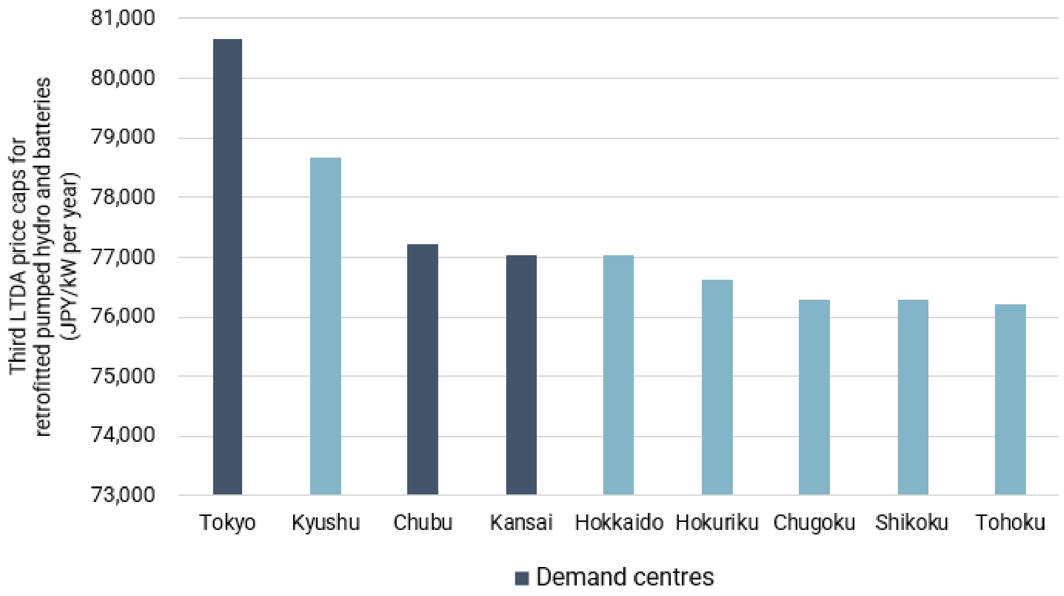
In the capacity market, batteries are likely to secure higher payments when they are deployed in import-constrained demand centres; or in export-constrained, high-VRE regions:

- Import-constrained demand centres (Tokyo, Chubu & Kansai) often require local firm capacity to meet peak demand and maintain reliability, driving up the need for reserved dispatchable capacity to be available when needed.
- Export-constrained, high-VRE regions like Kyushu face greater supply volatility and curtailment risk, increasing the value of batteries that can provide firming capacity and local supply-demand balancing.

This is reflected in the price caps which OCCTO has set for Japan's upcoming third LTDA. The highest price caps are in demand-heavy regions, indicating OCCTO's intention to attract more local dispatchable capacity to maintain system reliability (see Chart 14).[77] Higher price caps have also been set in high renewable regions such as Kyushu, likely reflecting OCCTO's intention to attract more flexible local capacity like batteries to support reliability and reduce curtailment.

[77] BNEF, Japan Capacity Market 2025 Update: New Rules, New Tech, September 2025, p. 9. (Client access only).

Chart 14: Demand centres (Tokyo, Chubu & Kansai) and Kyushu have higher LTDA price caps for batteries and retrofitted pumped hydro



Source BNEF, OCCTO

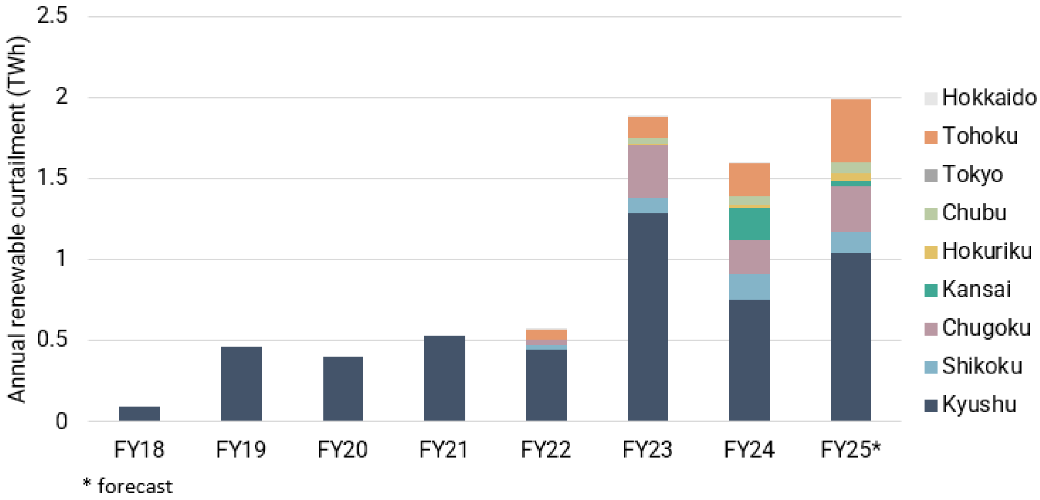
6.2.2 Revenue opportunities from energy arbitrage

Energy arbitrage revenue opportunities are greater in regions where surplus renewable generation drives frequent low-pricing periods, allowing batteries to charge cheaply and discharge at higher prices. Renewable curtailment has surged in the last five years across multiple regions, creating a growing need for more dispatchable storage.

Curtailment of renewable energy nearly quadrupled from an average of 0.5 TWh per year between FY19-FY22 to 1.9 TWh in FY23, remaining elevated at 1.6 TWh in FY24.[78] High levels are expected to continue into FY25 (see Chart 15).[79] Curtailment is highest in Kyushu and is increasing in other regions, including Tohoku, Chugoku and Shikoku.

[78] METI, 再生可能エネルギー出力制御の長期見通し等について, June 2025, p. 5.
[79] METI, 再生可能エネルギーの出力制御に関する短期見通し等について, January 2025, p. 5.

Chart 15: Curtailment has surged since FY23 and is spreading beyond Kyushu

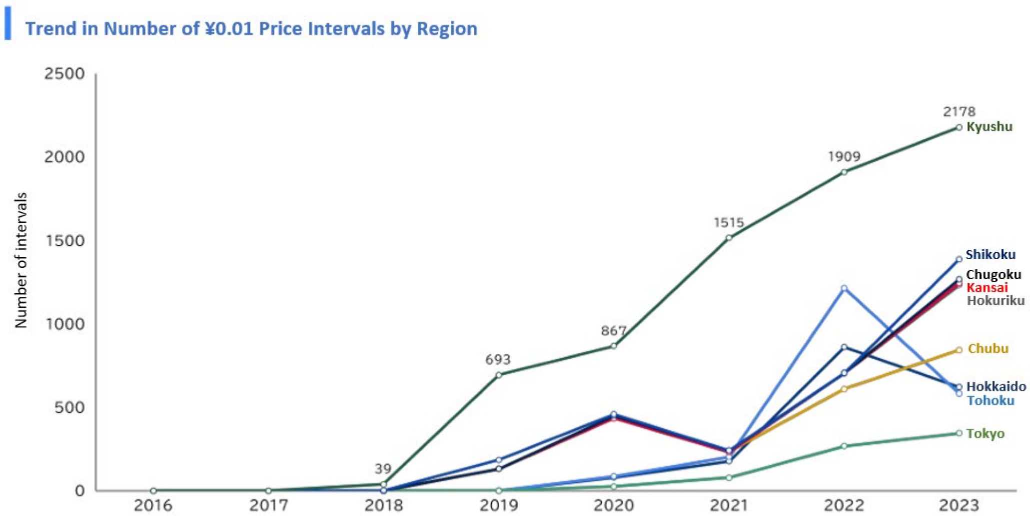


Source: METI

METI's 2034 long-term outlook projects worsening curtailment rates across all regions, reaching 30% in Hokkaido, 22% in Kyushu, and 16% in both Tohoku and Chugoku.[80] [81]

The growing frequency of low-pricing intervals[82] also creates greater arbitrage potential in certain regions. In 2023, Kyushu traded at the market floor (0.01 JPY/kWh) for 12.4% of the year – equivalent to one in every eight intervals. Similar trends are emerging across other regions (see Chart 16).[83]

Chart 16: Low-pricing intervals have increased across all regions



Source: METI (adapted by ACCR)

[80] METI, 再生可能エネルギー出力制御の長期見通し等について, June 2025, p. 15.
[81] FY24 curtailment rates: 0.04% in Hokkaido, 4.8% in Kyushu, 1.3% in Tohoku and 2.3% in Chugoku.
[82] Electricity is traded in 30-minute intervals in the JEPX. The Japanese corporate fiscal year 2024 covers 1 April 2024 to 31 March 2025.
[83] METI, ２０２４年度 定置用蓄電システム普及拡大検討会の結果とりまとめ（案）, January 2025, p. 49.

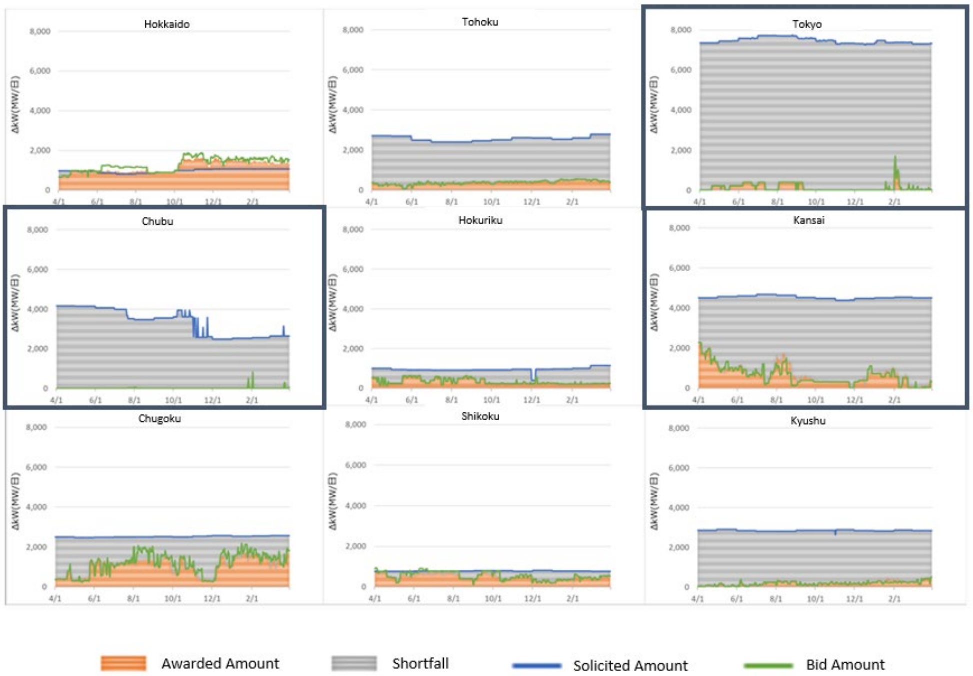
6.2.3 Revenue opportunities from providing ancillary services

Large procurement shortfalls in Segment I ancillary services signal an untapped market potential for batteries. Participating battery operators have already secured significantly higher contracted prices than other technologies across all segments, indicating their competitive advantage.

Batteries are likely to deliver higher returns in regions where there is a greater need for stabilising services, with persistent shortfalls in the supply of fast-response reserves. Demand centres (Tokyo, Chubu and Kansai) and high renewable regions (Kyushu and Tohoku) have a greater need for stabilising services like frequency control, creating strong opportunities for batteries to provide critical grid support and capture stronger revenue.

There is a structural shortfall in the fast-response reserves of demand centres and high-VRE regions. FY24 data shows persistent procurement gaps in Segment I ancillary services, particularly in demand centres (Tokyo, Kansai and Chubu), followed by remote, low demand regions with high renewables (Kyushu, Tohoku). These regions show large gaps between what the system needs and what the market can currently deliver (see Chart 17).[84]

Chart 17: Demand centres (Tokyo, Chubu and Kansai) showed the largest unmet need for fast-response capacity in FY24



Source: ERPX (adapted by ACCR)

Batteries are well placed to fill this gap. Utilities that act early in these regions can help provide crucial stabilising services and fast-response capacity while capturing higher revenue.

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[84] EPRX, 2024年度の取引実績について, June 2025, p. 9.

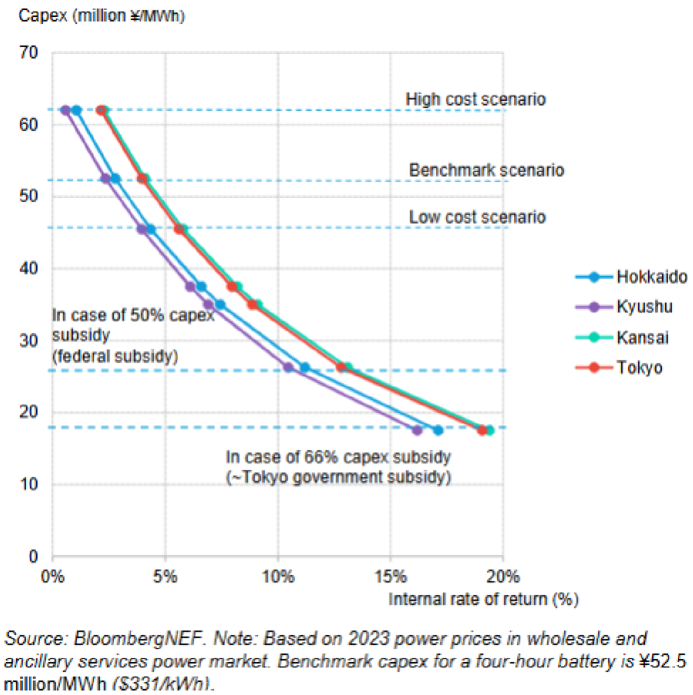
Appendix 1: Methodology for IRR curves interpolation

We estimated the capex required for merchant battery projects to achieve a 10% internal rate of return (IRR) – the typical target for developers in Japan.

We took BNEF analysis of the relationship between merchant battery project capex and IRR for four Japanese regions,[85] and applied a quadratic regression model (n=28, see Chart A1), with IRR as the response variable and capex as a numerical predictor. We also included location as a categorical predictor to account for regional differences. No interaction term between the two predictors was included, given the relationship between capex and IRR is consistent across all regions. The resulting model had an R^2 of 0.995. We then attained the estimated capex, resulting in a 10% IRR for each region using the model equation (Chart 11 – in the report).

To determine when merchant battery projects will achieve a 10% IRR, we used BNEF's 2023 benchmark capex of 52.5 million JPY/MWh for a 4-hour battery system.[86] We assumed a 10% annual decline in capex, which aligns with BNEF's projections of battery storage capex.[87]

Chart A1: BNEF analysis of changes in IRR based on capex for a 4-hour lithium-ion battery project by region



Source: BNEF

[85] BNEF, 2025 Japan Energy Storage Economics: A Balancing Game, February 2025, p. 14. (Client access only).
[86] BNEF, 2025 Japan Energy Storage Economics: A Balancing Game, February 2025, p. 10. (Client access only).
[87] BNEF, Levelized Cost of Electricity Update 2025, February 2025, p. 8. (Client access only).

Appendix 2: Methodology for interpreting OCCTO data and categorising the extent of regional export constraints

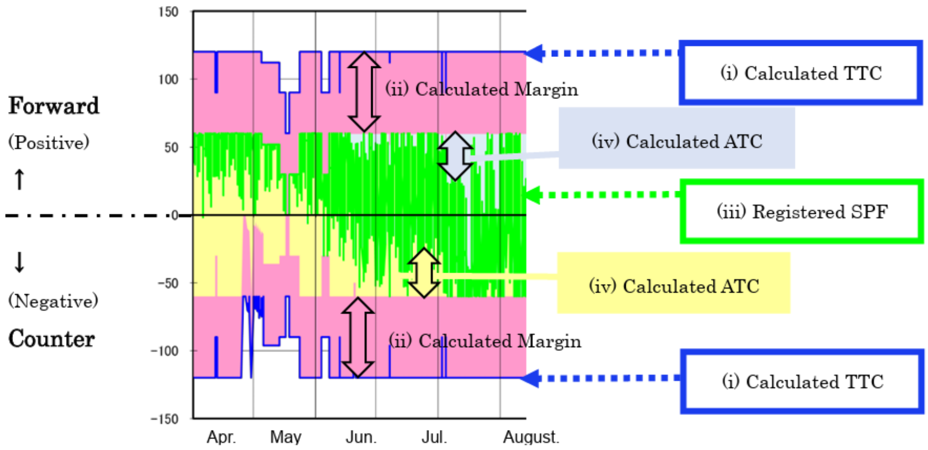
We categorised each of the nine regions by the severity of their export constraints to neighbouring regions using FY23[88] interregional transmission data published by the Organisation for Cross-regional Coordination of Transmission Operators (OCCTO).[89] The extent of export constraint was assessed by examining how often actual power flows approached or reached the line's physical capacity or reserved margin.

OCCTO provides definitions for each component of the transmission chart (see Chart A2),[90] which can be summarised as:

- **Total transmission capacity/TTC (Blue) –** The physical maximum capacity of the interconnection under ideal conditions.
- **Reserved margin (Pink) –** Capacity reserved by OCCTO for grid stability and emergencies, reducing the amount of capacity available for trading.
- **Registered scheduled power flow/SPF (Green) –** Actual net power flow, representing the offset between forward and reverse flows.
- **Available transfer capacity/ATC (Yellow/Grey) –** The remaining capacity available for additional transfers. When low or absent, this indicates congestion.

[88] The Japanese corporate fiscal year 2023 covers 1 April 2023 to 31 March 2024.
[89] OCCTO, Outlook for Electricity Supply–Demand and Cross-regional Interconnection Lines: Actual Data for Fiscal Year 2023, November 2024, p. 36. (Japanese version).
[90] OCCTO, Outlook for Electricity Supply–Demand and Cross-regional Interconnection Lines: Actual Data for Fiscal Year 2023, November 2024, p. 36-41. (Japanese version).

Chart A2: OCCTO's guidance on how to interpret the transmission flow charts



Source: OCCTO

ACCR categorised each of the nine regions of the grid based on the severity of their export constraints:

1. **Highly constrained** - Exports to at least one neighbouring region reached maximum transmission capacity or reserved margins for most of the year. We categorise a region as highly constrained if it faces export limits to at least one neighbouring region with high electricity needs, even if transfers to other neighbours are unconstrained.
2. **Moderately constrained** - Exports to at least one neighbouring region reached maximum transmission capacity or reserved margins for parts of the year.
3. **Unconstrained** - Exports to neighbouring region(s) did not reach maximum transmission capacity or reserved margins, for most of the year.