Modelling 24/7 Carbon Free Electricity (CFE) in Asia

Results for Japan

July 2025

Report authors

Alex Luta
Lead (East Asia)

Dan Welsby
Modeller (Japan)

Joel Yap
Analyst (East Asia)

Additional contributors

We gratefully acknowledge the contributions of colleagues across TransitionZero — both current and former — who supported this work through communications, analysis, modelling infrastructure, and operational coordination. These include Alice Apsey, Ollie Bell, Duncan Byrne, Khandekar Mahammad Galib, Matthew Gray, Michael Guzzardi, Tim Haines, Anna Hartley, John Heal, Simone Huber, Thomas Kouroughli, Alex Luta, Aman Majid, Grace Mitchell, Irfan Mohamed, Joe O'Connor, Sabina Parvu, Handriyanti Diah Puspitarini, Abhishek Shivakumar, Stephanie Stevenson, Isabella Söldner-Rembold, Isabella Suarez, and Thu Vu.

Acknowledgements

This work was made possible through the funding from Google.org.

Our methodological approach is focused on the assessment of system-level costs and benefits of 24/7 Carbon-Free Electricity (CFE) procurement in Japan, India, Singapore, Taiwan, and Malaysia. It builds on a robust body of literature and cutting-edge modelling tools.

TU Berlin and affiliated researchers:

- *Riepin, I., & Brown, T. (2022). System-level impacts of 24/7 carbon-free electricity procurement in Europe. Zenodo.* https //doi.org/10.5281/zenodo.7180098
- *Riepin, I., & Brown, T. (2023). The value of space-time load-shifting flexibility for 24/7 carbon-free electricity procurement. Zenodo.* https //doi.org/10.5281/zenodo.8185850

Princeton University (ZERO Lab):

- *Xu, Q.,Manocha, A.,Patankar, N., and Jenkins, J.D., System-level Impacts of 24/7 Carbon-free Electricity Procurement, Zero-carbon Energy Systems Research and Optimization Laboratory, Princeton University, Princeton, NJ, 16 November 2021.*
- *Xu, Q., & Jenkins, J. D. (2022). Electricity System and Market Impacts of Time-based Attribute Trading and 24/7 Carbon-free Electricity Procurement. Zenodo.* https //doi.org/10.5281/zenodo.7082212

International Energy Agency (IEA):

- *Regional insights and sectoral analyses*
- *IEA (2022), Advancing Decarbonisation through Clean Electricity Procurement, IEA, Paris.* https //www.iea.org/reports/advancing-decarbonisation-through-clean-electricity-procurement

Our in-house modelling leverages PyPSA (Python for Power System Analysis), an open-source framework for simulating and optimizing energy systems. This platform enables high-resolution, hourly modelling of decarbonised power systems, adapted for our country-specific analyses. We are grateful to all contributors in the open modelling community, whose tools and insights strengthen the analytical foundation for achieving global CFE goals.

We thank the reviewers who provided valuable feedback and insights during the development of this work: Kimiko Hirata (Climate Integrate), Kaname Ogawa (METI), Jubair Sieed (RITE), Masahiro Sugiyama (University of Tokyo), Kae Takase and colleagues (REI), Shinya Ueoka (METI), You Yasuda (University of Strathclyde). We also extend our sincere thanks to the reviewers who chose to remain anonymous but whose insights were invaluable in shaping the final report. Contribution to and review of this study does not imply an endorsement by either the individual or their organisation. Any mistakes are our own.

Table of Contents

Matthew Gray
Co-founder & CEO
TransitionZero

Foreword

In February 2025 the Japanese government formalised its Seventh Strategic Energy Plan, under which it set itself the goal to raise the share of renewables to 40-50% of its total electricity generation by 2040. Along with this near doubling of renewables' share relative to the present, the government also has ambitious goals regarding nuclear restarts and thermal generator decarbonisation. Japan is the world's fourth largest economy, with a high per capita income, animated by high-tech industrial sectors whose exports are admired all over the world. This presents the country with both opportunities and challenges as it transitions to an electricity grid predominantly supplied by low-cost variable renewable energy (VRE).

At the heart of this transition could be Japan's ability to produce 24/7 carbon free energy (24/7 CFE) at scale, to meet the expectations of international consumers buying the country's high value-add exports. As the Japanese decision makers grapple with integrating more VRE, and as corporates and developers adjust their strategies in response to the forthcoming Greenhouse Gas Protocol (GHGP) accounting updates, the key questions are: what is 24/7 CFE and what does it cost?

24/7 CFE means matching every hour of electricity use with generation from carbon-free sources. It ensures that clean power is actually available when it is needed, all day, every day, instead of buying clean energy certificate on an annual basis. This approach is especially important for heavy industry and cloud computing, whose electricity demand is typically flat around the clock, making it essential for their long-term decarbonisation – especially when the output of VRE, the prime source of CFE in the future, constantly fluctuates. This aligns such large-scale consumers' interests with those of grid planners, who must balance electricity demand in real time while ensuring that long-term grid expansion occurs at the lowest possible cost. Shifting to this approach is a central focus of the GHGP, which governs how companies account for emissions from purchased electricity, and is in the process of a multi-year revision of its standards. However, while hourly emissions accounting is emerging as the preferred accounting method, the GHGP does not set targets or grade performance.

Our analysis shows that transitioning from annual to hourly matching can offer a 'no regrets' options for Japan's energy planners, grid operators, and corporates. The national benefits are nearly identical under annual matching or when across the year as much as 90% of all electricity consumed in each hour is CFE delivered through PPAs: Japan as a nation saves annually around US$1.8 billion in fuel costs and cuts emissions by more than 11.MtCO$_2$e However critically, our work shows that under this 'CFE 90' scenario corporates cut the emission intensity of their electricity consumption by nearly 74% compared to annual matching – and do it at unit costs that in real terms are below the average of the annual wholesale market prices witnessed since 2019.

We also appreciate that in recent years the uptake of VRE in Japan has slowed down, and we note that the government, with a view towards long-term energy security and decarbonisation, has simultaneously started pouring support into innovative thermal technologies, like gas-fired generation with Carbon Capture and Storage or co-firing of ammonia and hydrogen with coal and gas, respectively. Our analysis recognises that planners must balance carefully VRE's cheap unit costs against the potential advantages of thermal plants. But it bears mentioning that in our analysis we have found that these advantages seem highly sensitive to untested assumptions, making them susceptible to competition from new forms of storage – or indeed other sources of CFE that one might wish to investigate.

We hope this analysis helps Japan's energy planners and market participants better understand the challenges and opportunities associated with 24/7 CFE, and supports the Japanese government's goal of achieving up to 50% of generation from renewable sources by 2040.

About TransitionZero

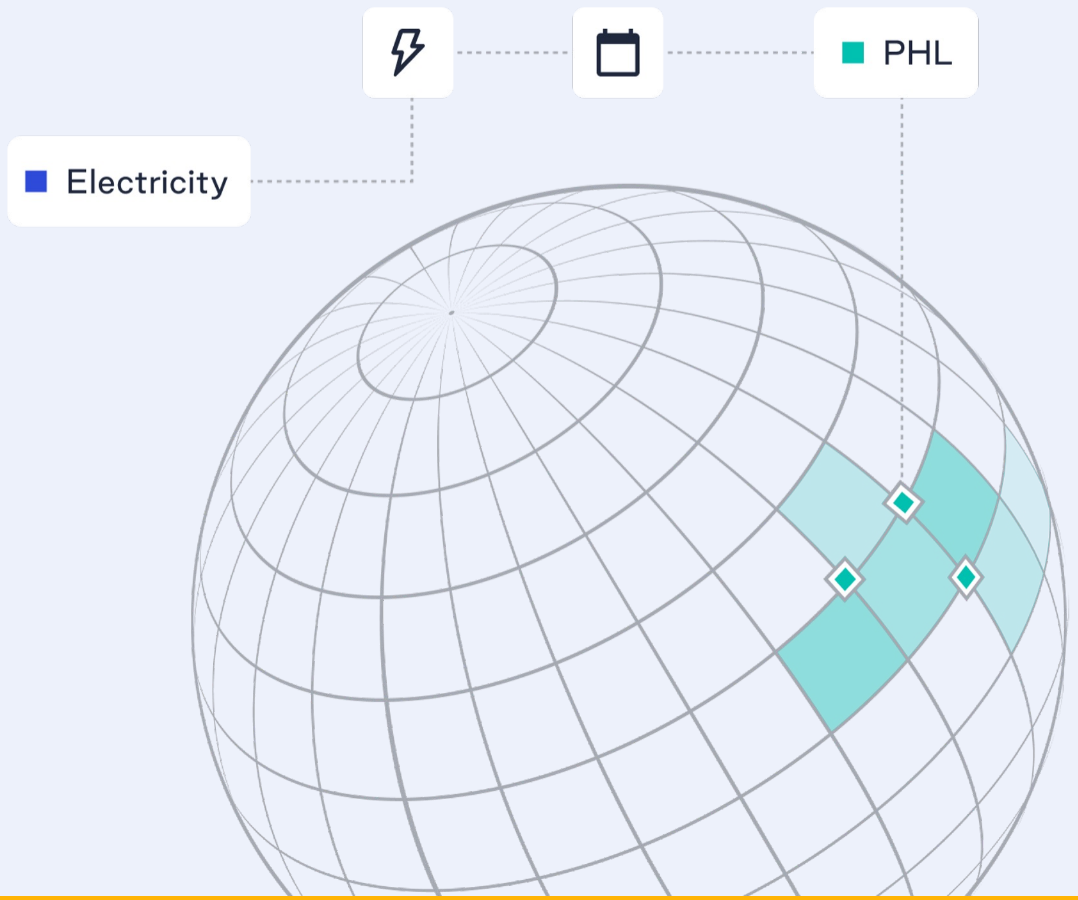
Open software, data and insights for energy transition planning

We help governments and their partners plan for the transition to clean, and more reliable electricity

Visit our website

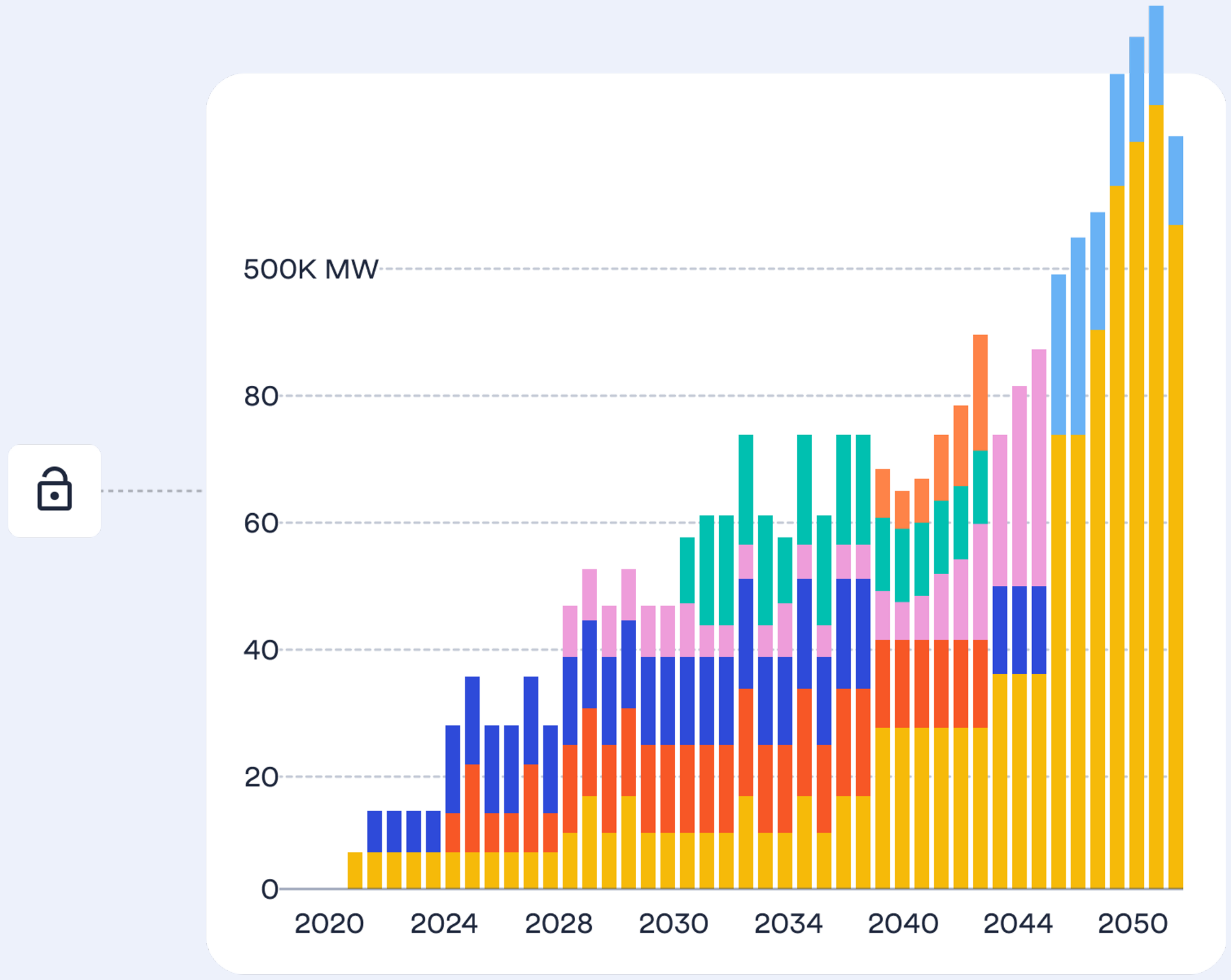
Accessible software

Our accessible system modelling software and technical training enables more efficient, effective energy transition planning.



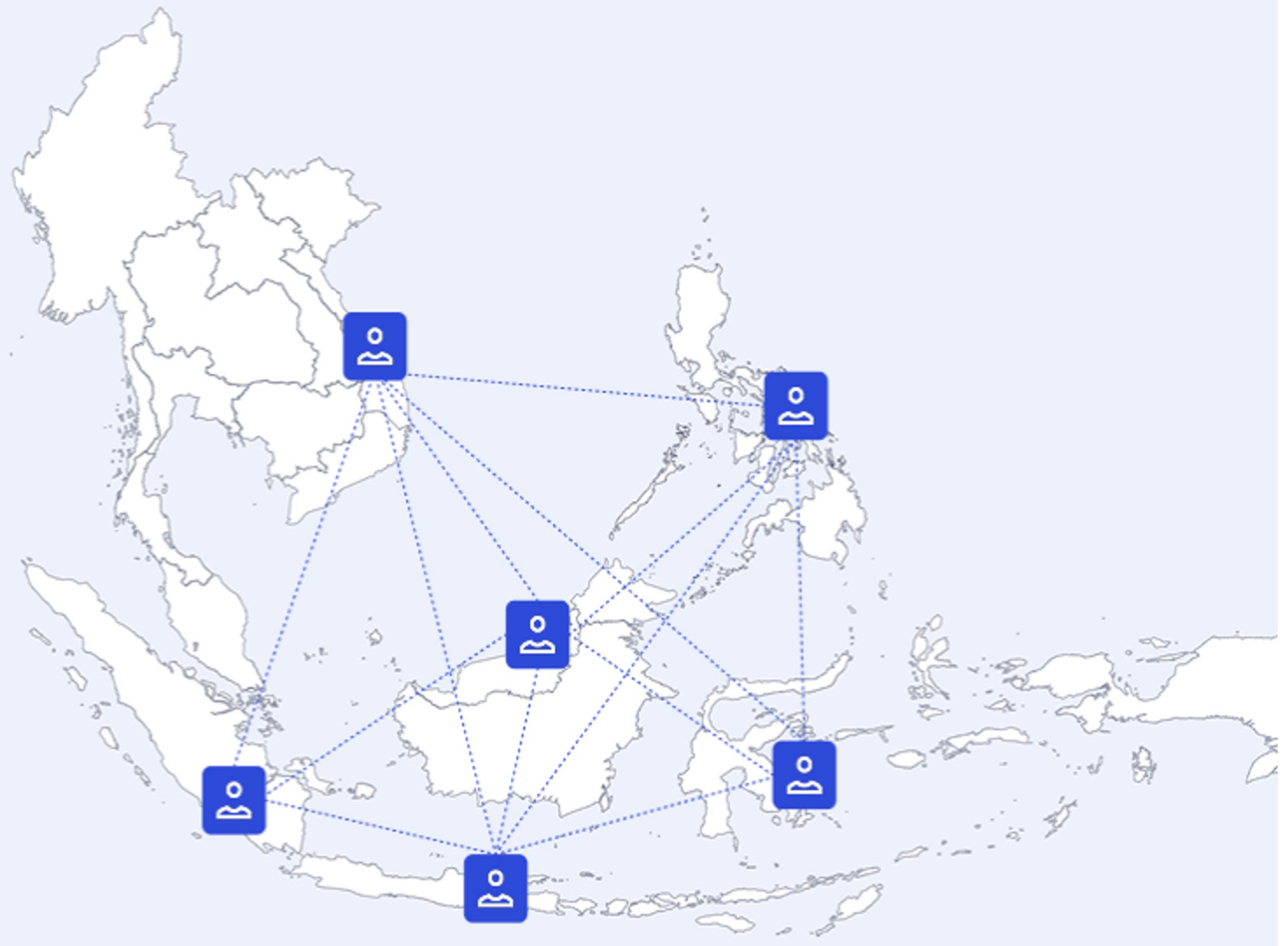
Open data

Combining AI with in-country expertise, our open datasets support high-quality system modelling.



Market analysts

Our analysts help decision-makers build the skills and knowledge they need to better understand energy transition risks and opportunities.



Funded by
SEQUOIA CLIMATE FOUNDATION
Google.org
Bloomberg Philanthropies
Quadrature Climate Foundation

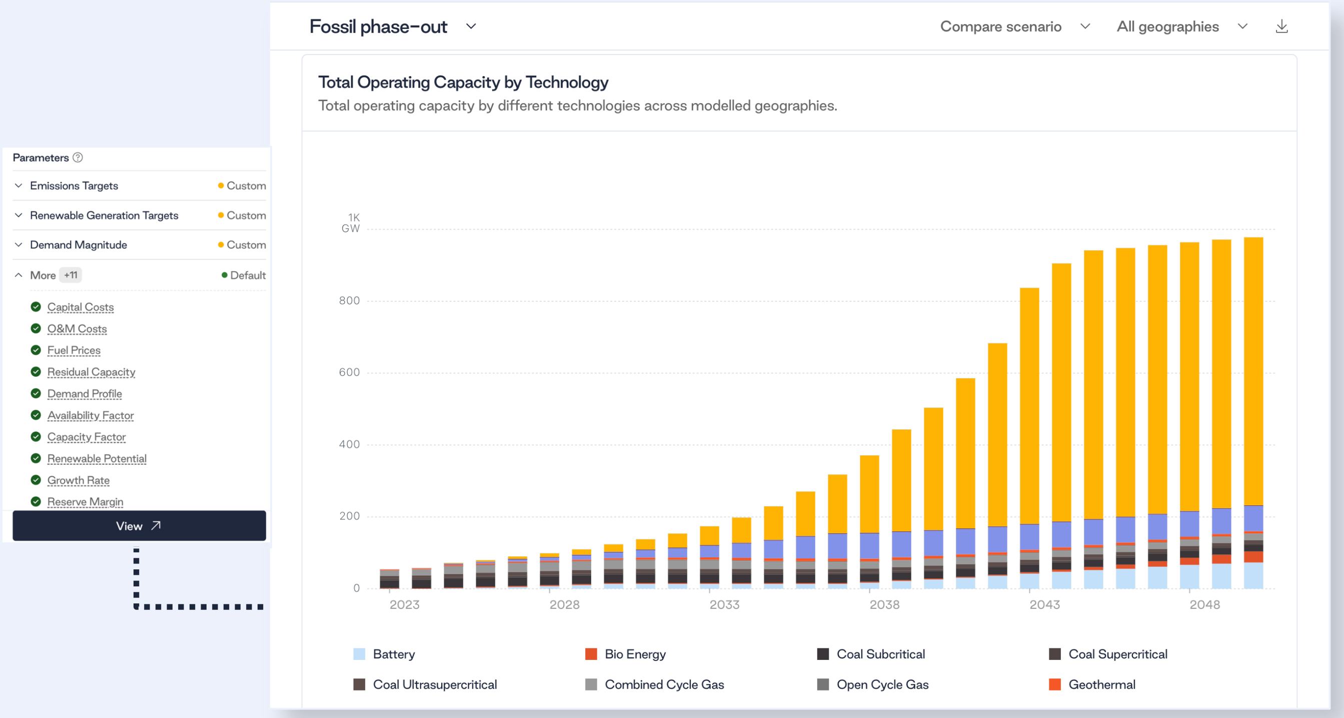
TransitionZero products

Our software and data products make energy transition planning more accessible and transparent

Explore products

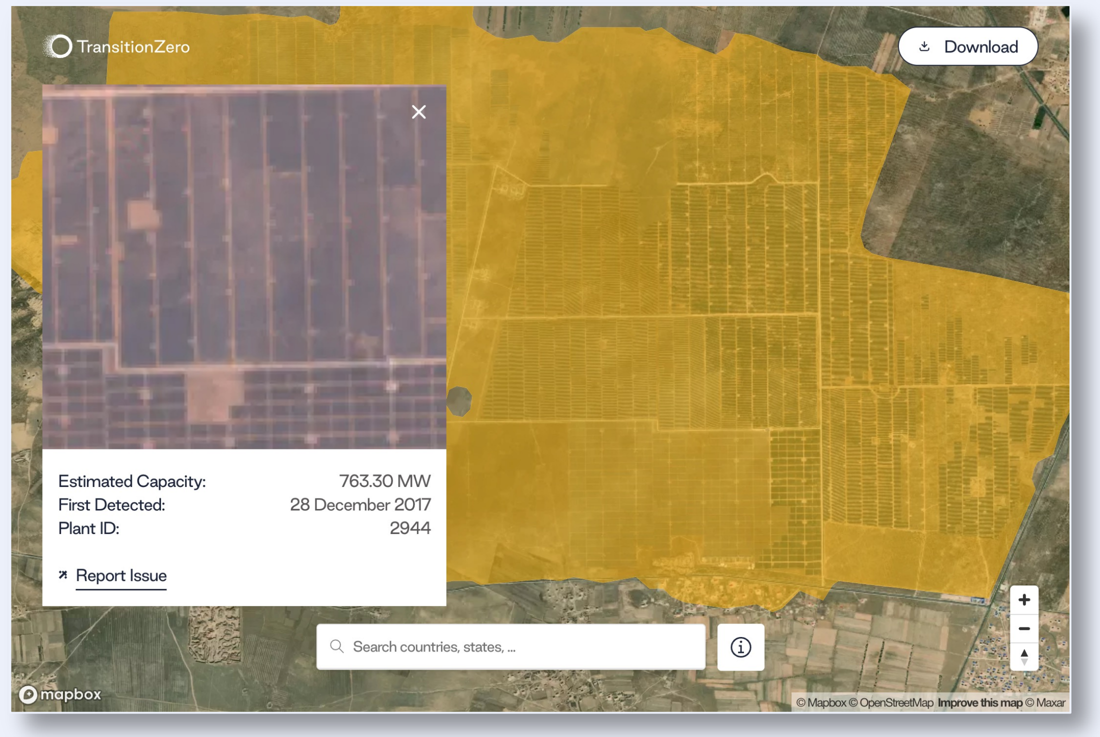
Scenario Builder

TZ-SB is free, no-code modelling platform that allows analysts working on energy transition planning to build, run, and analyse results from electricity system models – quickly, transparently, and at scale.



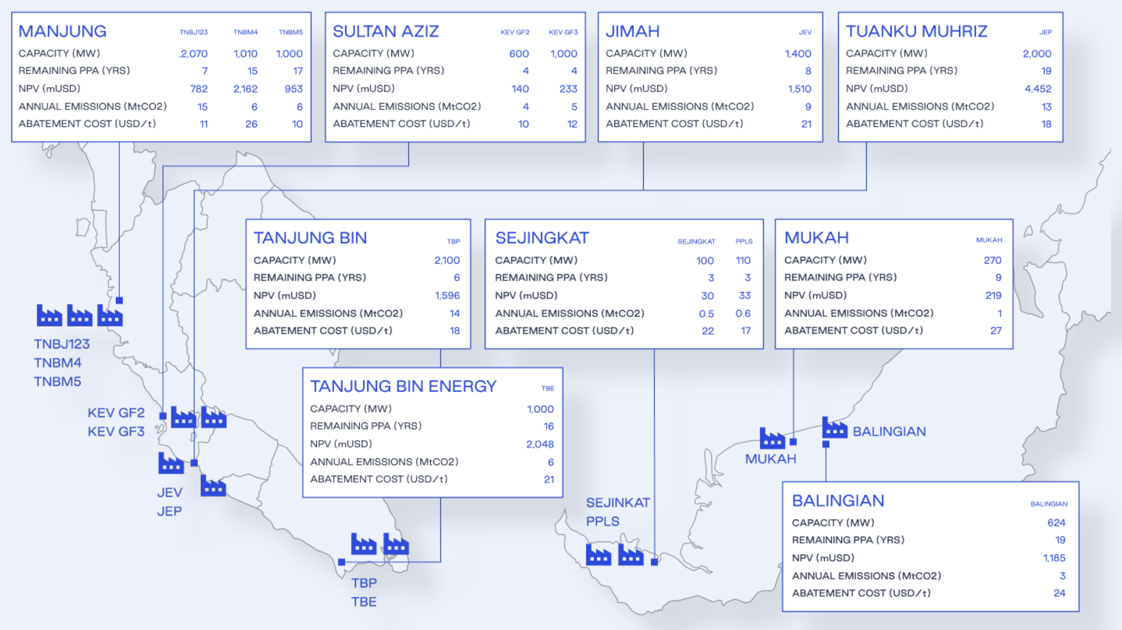
Solar Asset Mapper

TZ-SAM is an open access dataset of solar facilities, powered by machine learning and geospatial data. Tracks 100,00 solar assets across 200 countries, with ~100 GW of capacity added each quarter.



Coal Asset Transition Tool

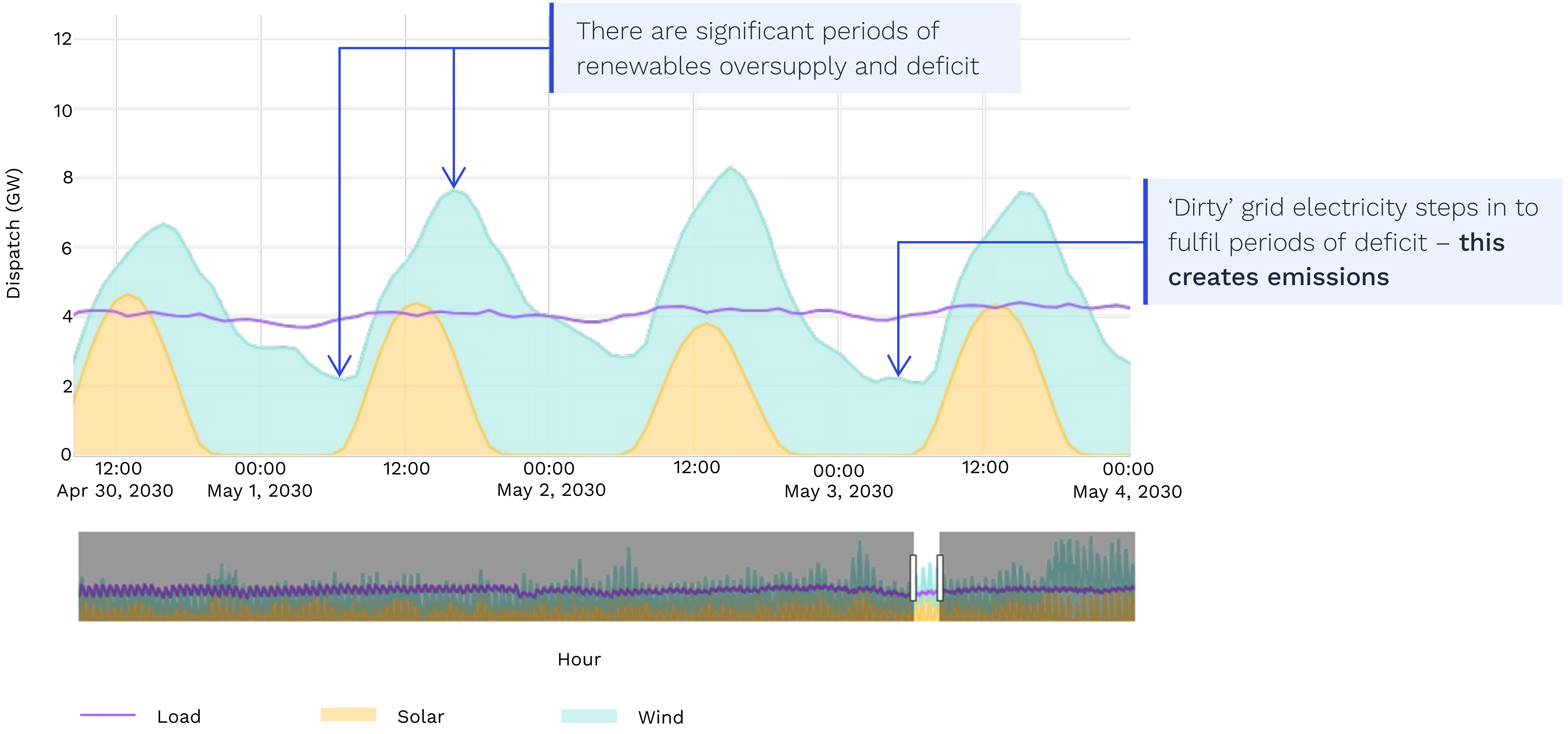
TZ-CAT is an open data product that supports the refinancing and replacement of coal plants in an affordable, just way. TZ-CAT is currently available for the Philippines, Indonesia, and Malaysia.



Background to Carbon Free Electricity (CFE)

Power consumers are grappling with mismatches between the generation and consumption patterns of clean electricity

What does an annual matching regime look like?

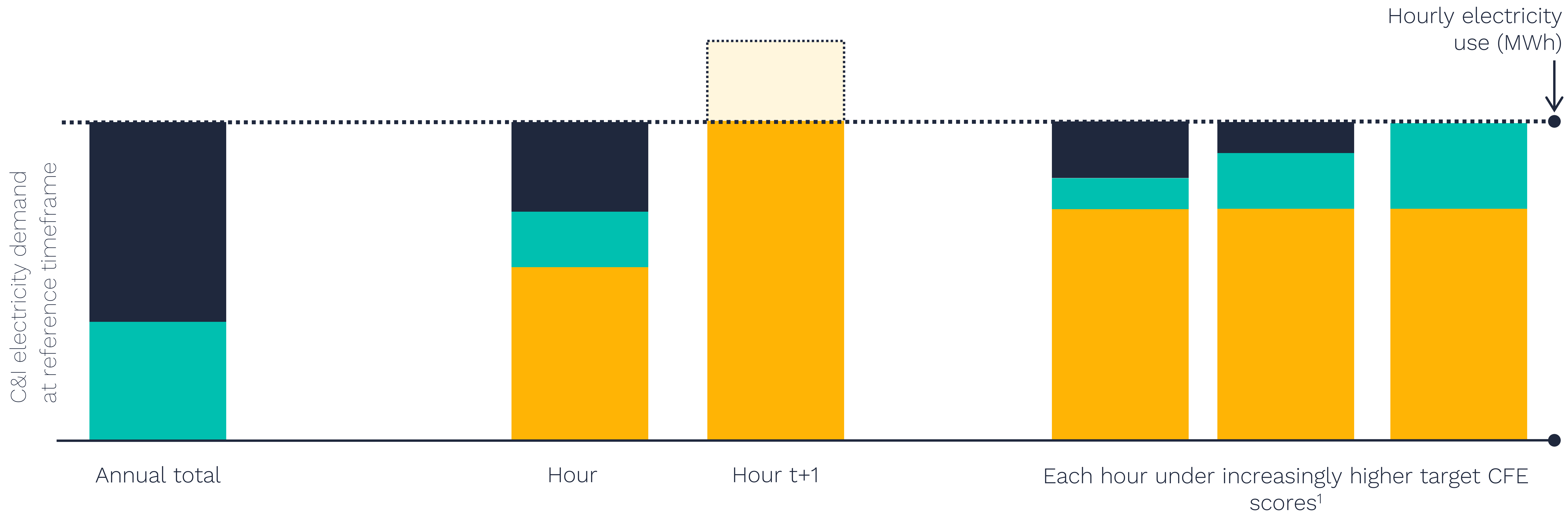


Key points

- Commercial and industrial (C&I) consumers face pressures to reduce their consumption of polluting electricity.
- Reliance on 100% annual matching through renewables PPAs results in cycles of oversupply and deficit, where only some hours truly benefit from CFE.
- When there is a deficit between procured clean energy and demand, consumers must rely on carbon-emitting system electricity.
- Matching consumption to generation hour by hour ("24/7 CFE") seeks to maximise CFE reliance round the clock.

Shifting guidance on emissions reporting

The GHG Accounting Protocol is evolving, and may require companies to report Scope 2 emissions based on hourly accounting



Situation 1:
Do nothing

C&I consumer's electricity consumption is met only by the regional grid, which is for the most part carbon-based.

Situation 2:
Annual matching (current common practice)

C&I consumer's electricity consumption is only partially matched, resulting in either a shortfall or an oversupply of CFE.

Situation 3:
24/7 CFE

Electricity use is fully matched with CFE. We can use a blended approach, in which some of the demand is matched by a PPA, while the remainder can be imported from the grid, provided it meets CFE threshold.

Key points

- A consumer's CFE score is the average of Situation 3 across all hours of the year.
- Principles that CFE should meet are to be locally sourced (from the same grid zone), time-matched (ideally hour by hour), and resulting from additional investments.
- CFE includes, by definition, a commitment to technological neutrality.

- Carbon-based grid supply
- CFE from grid supply
- CFE PPA consumed
- Excess CFE PPA (not counted towards CFE score)

[1] Note that at 100% CFE C&I consumers can rely on the grid only if the grid itself is also 100% CFE. A grid that features emitting generators can also be relied upon if the consumers seek to reach a lower CFE score.

How is Carbon Free Electricity measured?

The CFE score includes PPA-procured generation, and the cleanliness of the wider grid

- The CFE Score is a percentage score which measures the degree to which each hour of electricity consumption is matched with carbon-free electricity generation. We follow the methodology set out by Google[1].
- This is calculated using both carbon free electricity provided by through PPA contracts, as well as CFE coming from the overall grid mix. It is calculated as:

$$\text{CFE Score \% (h)} = \frac{\text{Contracted CFE MWh} + \text{Consumed Grid CFE MWh}}{\text{C\&I Load MWh}}$$

where:

$$\text{Contracted CFE MWh} = \text{Min (C\&I Load MWh, CFE Generation MWh)}$$

$$\text{Consumed Grid CFE MWh} = [\text{C\&I Load MWh} - \text{Contracted CFE MWh}] \times \text{Grid CFE \%}$$

- The Grid CFE % is calculated by looking at the what percentage of the generation comes from carbon free sources. In the case of Japan, this considers each of the five grid zones as having distinct hourly CFE % scores.
- The contracted CFE score is capped at 100%, even if there is excess CFE that is exported back to the grid.

An example calculation

Participating C&I load =	*100 MWh*
Contracted CFE generation =	*65 MWh*
Grid Imports	*100 - 65 = 35 MWh*
Grid CFE	*45%*
CFE Score =	*[65 + (35 x 0.45)] ÷ 100 = 81%*

Here, the participating C&I consumer has a load of 100 MWh which is participating in CFE/round-the-clock matching.

In this example hour, they have procured 65 MWh of clean generation through PPAs (e.g. some combination of solar and batteries) and must import the remaining 35 MWh from the grid to meet the load.

The grid at that hour has a CFE score of 45% (i.e. only 45% of generation is from CFE sources). This results in an overall CFE score for the C&I consumer of 81% in that hour.

[1] *Google 2021, "24/7 Carbon-Free Energy: Methodologies and Metrics"*

Key questions

Stakeholders need to better understand the implications of this shift

What are the implications in markets with high levels of fossil generation when a significant share of C&I consumers shift from annual to hourly matching?

What are the costs and benefits of hourly matching at the system level, i.e. the Japanese power sector and the actors involved in generation, storage, transmission, and distribution?

What other implications of hourly matching are there for both the wider system and C&I consumers?

To what extent are nascent technologies (storage or innovative thermal generation) needed for higher shares of hourly matched CFE?

To what extent can a wider palette of CFE technologies affect system-wide costs and benefits?

Technology palettes

We explore how additionality and technological choice affect system costs and benefits arising from greenfield investments

Technology	Palette 1	Palette 2	Palette 3
Onshore wind and solar	✓	✓	✓
Battery storage	✓	✓	✓
Long-duration energy storage[1]	✗	✓	✓
Gas with CCS	✗	✗	✓
H_2/NH_3 co-firing	✗	✗	✓

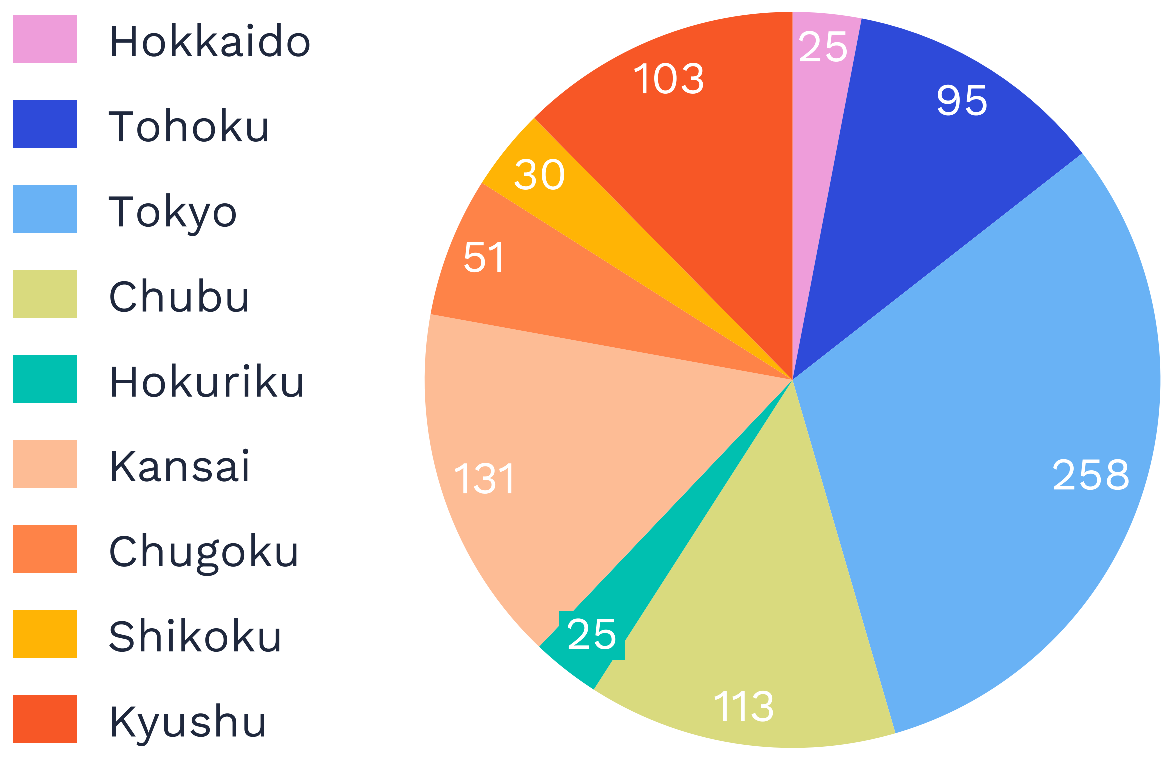
[1] Liquid air storage.
[2] For H_2/NH_3 only generation from the non-fossil share is accounted as CFE (10% and 20% respectively). For CCS we consider a 70% CO_2 capture rate, with the remaining 30% of unabated generation not accounted for as CFE.

A wider range of technologies should lower system costs

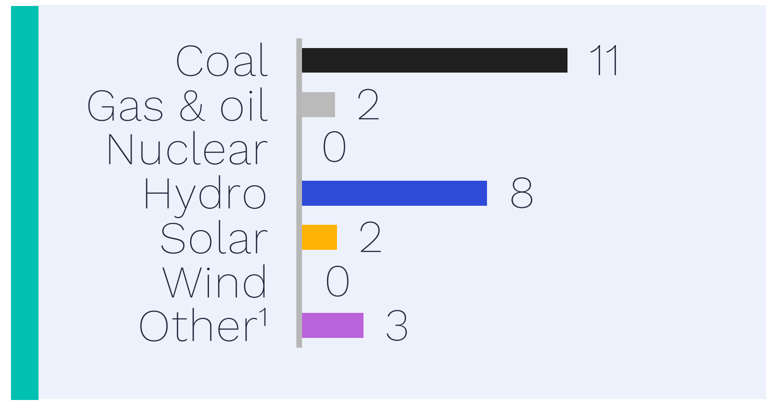
- The 'brownfield' capacity mix in our Reference Scenario will include CFE sources of low additionality (pre-existing nuclear, hydro, renewables plants, as well as pumped and battery storage) and CFE plants likely to be built under business-as-usual conditions – all of which will contribute to the CFE score of the local grid.
- In our annual and hourly matching scenarios, C&I consumers can procure additional generating capacity in the 'greenfield' through PPAs with technologies restricted to these palettes.
- Palette 3 also considers the non-conventional parts of innovative thermal plants[2] as additional.

Overview of the Japanese power sector [1]

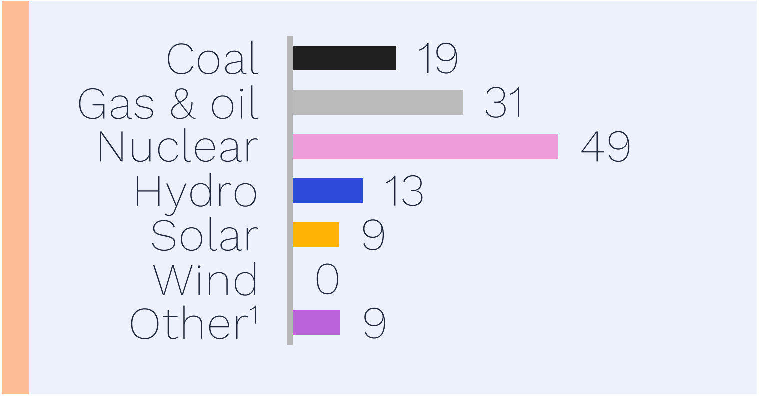
Generation by grid zone as of 2024 (TWh)



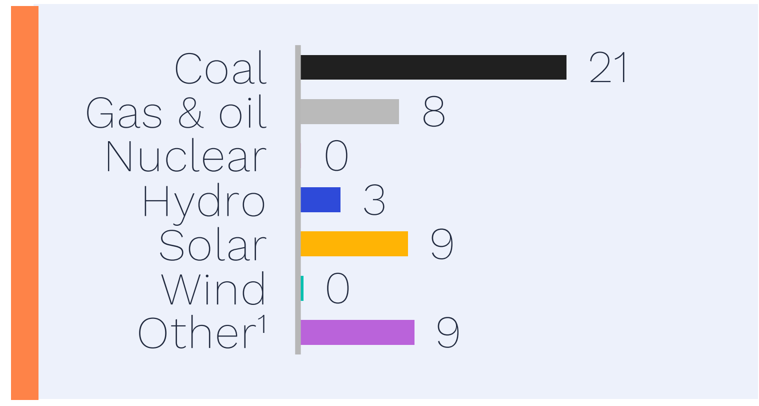
Hokuriku (25 TWh)



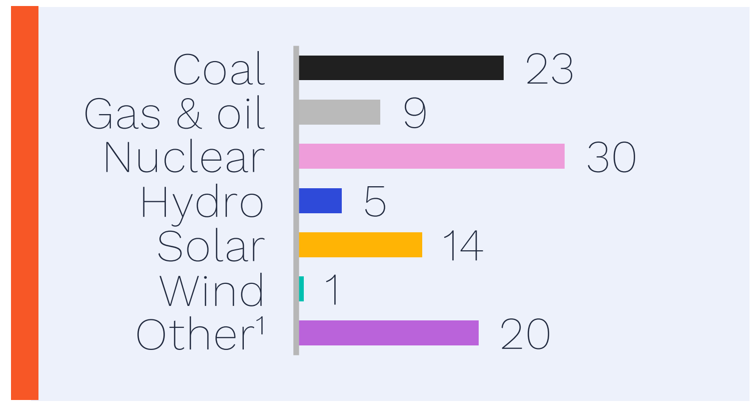
Kansai (131 TWh)

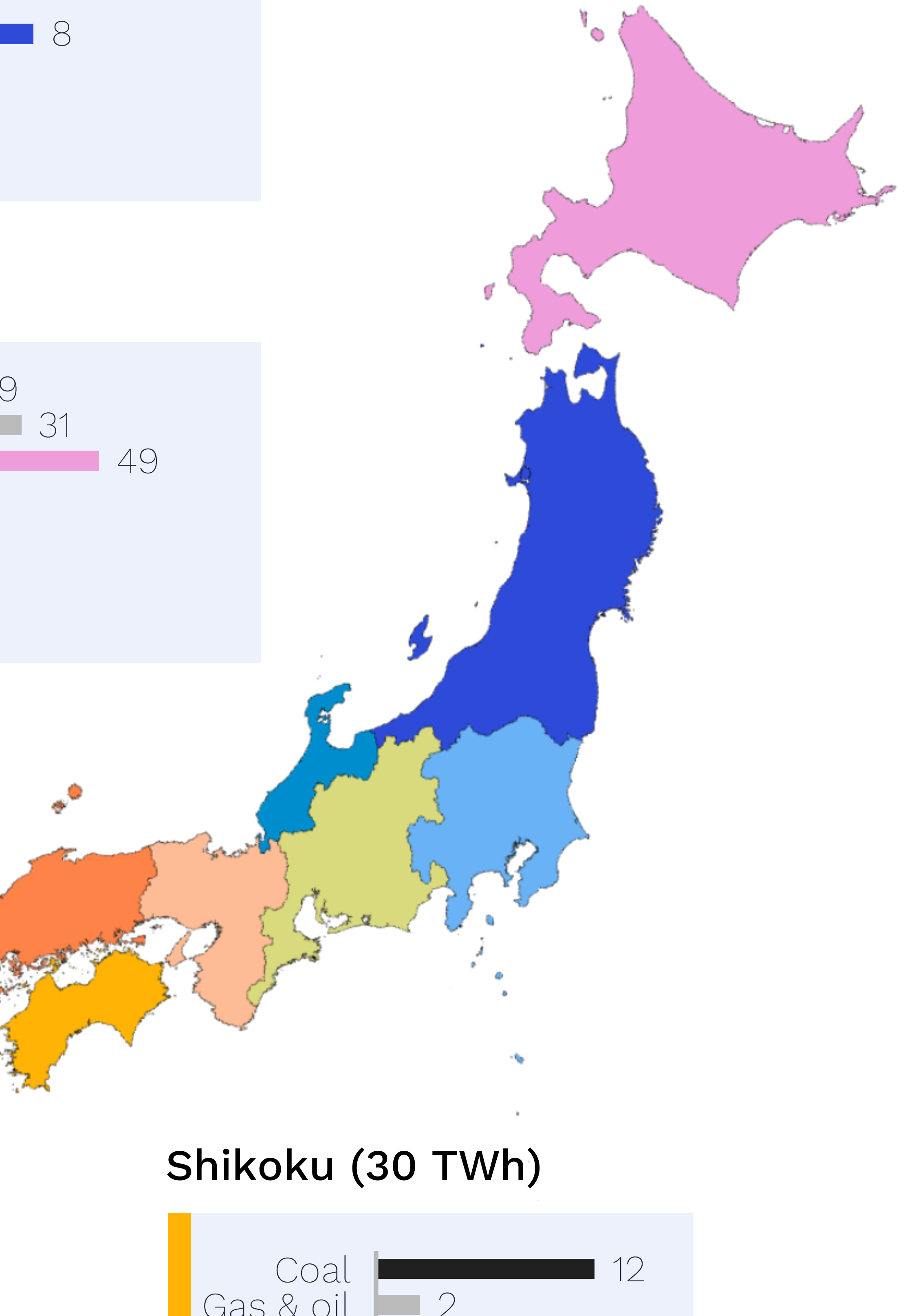


Chugoku (51 TWh)

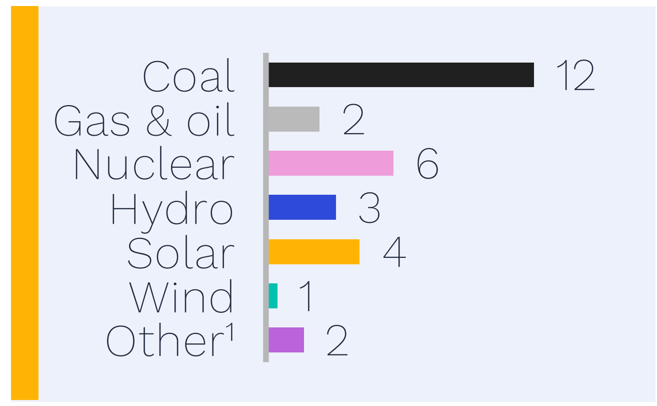


Kyushu (103 TWh)

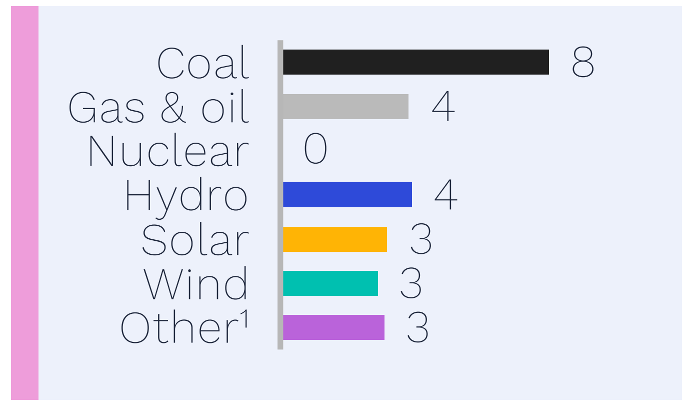




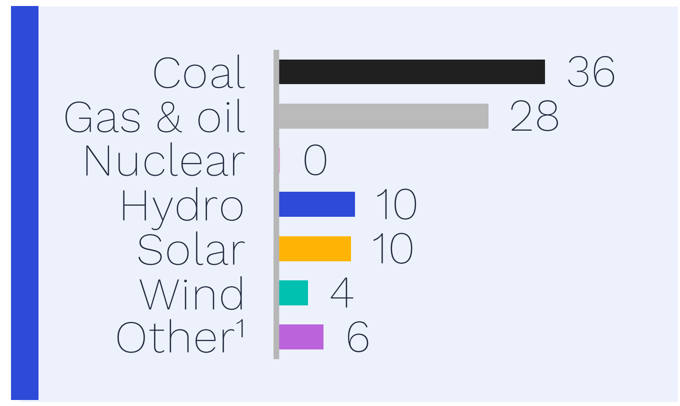
Shikoku (30 TWh)



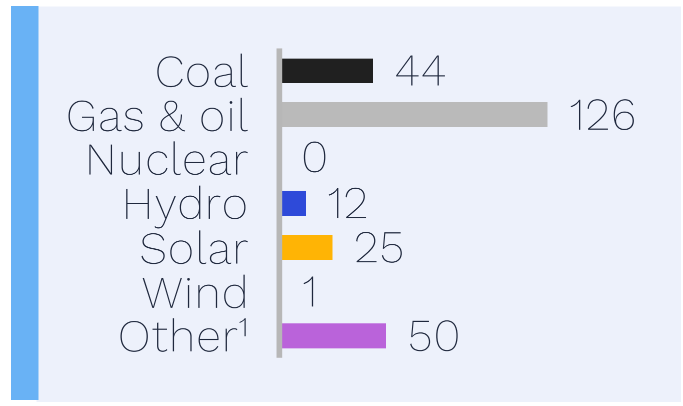
Hokkaido (25 TWh)



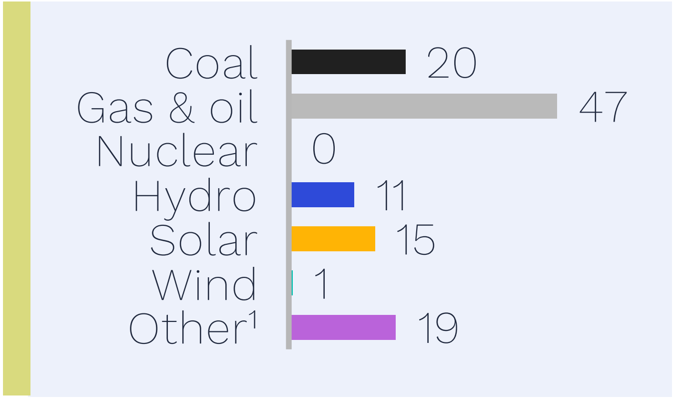
Tohoku (95 TWh)



Tokyo (258 TWh)



Chubu (113 TWh)



327 GW
Total nationwide capacity

846 TWh
Total nationwide demand[1]

65%
Unabated thermal generation share

25%
Renewables generation share

2.7 GW
Solar capacity added in 2024

[1] Including Okinawa (not shown on map due to small size and not being connected to the mainland).
[2] Includes biomass, geothermal, interconnectors, and generation from storage.

Source: OCCTO (preliminary values for 2024).

Overview of the Japanese power sector [2]

A brief look into real-world and modelled CFE procurement strategies

C&I consumers currently have 4 procurement options for carbon-free electricity (CFE) in the Japanese electricity market. All of them involve so-called Non-Fossil Certificates (NFCs), which is a government scheme that enables the trading of environmental attributes of electricity. In short, the government issues NFCs to generators, who can then gain revenue when consumers interested in CFE eventually buy some form of certified electricity. The four options are:

1. **On-site PPA:** Consists of an investment into CFE capacity on the consumers' premises, with consumers keeping the NFCs produced on-site.
2. **Off-site PPAs, which can be 'physical' and 'virtual':** Japanese law requires a retailer as a third party to link CFE consumers with CFE generators.[1] All 'off-site PPAs' involve the transfer of NFCs from generators to consumers, but there are two forms:
    a. **'Physical PPAs'** source the CFE from a specific generator,
    b. **'Virtual PPAs'** bundle NFCs from a specific generator with conventional electricity purchased from the wider wholesale market, without attribution to the CFE generator originating the NFCs.
3. **Green tariffs:** Retailers procure through various means electricity and NFCs, which they sell in a bundled manner without tracking to consumers.

In our modelling we approximate a hybrid of physical and virtual PPAs that is starting to emerge in Japan. We do this to acknowledge that practically speaking when a consumer wishes to meet 100% of its load with CFE, a variable renewable energy source, even when equipped with storage, may not be able to meet that load. Therefore, retailers interfacing with consumers need the flexibility to procure both electricity and NFCs (ideally attributed directly to a CFE asset) to supplement any momentary shortfalls. Conversely, when the contracted asset over-generates, it is useful to have the flexibility to sell that CFE to other consumers – either as CFE (the approach in this study) or as unbundled electricity and NFCs (not explored in this study).

There are several steps that the Japanese authorities could take to better align this system with the ideal of 24/7 CFE. At present, not all NFCs are tracked to specific generators; as of August 2025, NFCs are reported with daily—not hourly—granularity; there is no centralised registry to track use and origin; and the previous unbundling of NFCs from electricity (pursued in the name of flexibility) may produce confusion in the future. We hope that this study will demonstrate the need for an upgrade of the NFC system, to enable 24/7 CFE to flourish in Japan.

[1] In practice, some developers choose to obtain a retailer license to circumvent this rule.

Selected moments in Japan's renewable procurement journey

2017 — **NFCs created**
Created to ensure that retailers would procure a rising share of Japan's non-fossil electricity

2022 — **NFCs to consumers**
Following initiatives such as RE100, consumers gain the right to purchase certain categories of NFCs

2022 — **H_2 & NH_3**
Electricity generated from hydrogen and ammonia recognised as eligible for certification, with CCS expected to follow

2024 — **Tracking upgrade**
The Japan Electric Power Exchange (JEPX) adds tracking about origin and plant age to NFCs

2025 — **Price ceiling reached**
NFCs earmarked for retailer use reach maximum price on two consecutive auctions

TransitionZero

Executive summary

Key takeaways from our CFE modelling in Japan

An overview of our study approach

How we modelled carbon free electricity in Japan in 2030

We developed a representative 2030 grid and created a dispatch model with hourly granularity to model Mainland Japan at the grid zone level (9 zones). We tested different clean electricity policies to see the impact of these interventions on costs, emissions and other key system metrics.

Our step-by-step process is as follows:

01

We cycle through each grid zone and assign 3% of the total grid zone demand to C&I consumers participating in clean electricity matching. This 3% is representative of general C&I demand moving towards decarbonisation.

02

This 3% of demand is modelled as following either an annual matching or an hourly matching scheme (testing between 70-100% hourly CFE). C&I consumers procure PPAs from additional clean generators to supply this clean electricity, which are built and optimised by our model.

03

We then aggregate grid zone level results together to assess the nationwide impact of these schemes for both the C&I consumer as well as the wider system, i.e. the Japanese power sector and actors involved in generation, storage, transmission, and distribution.

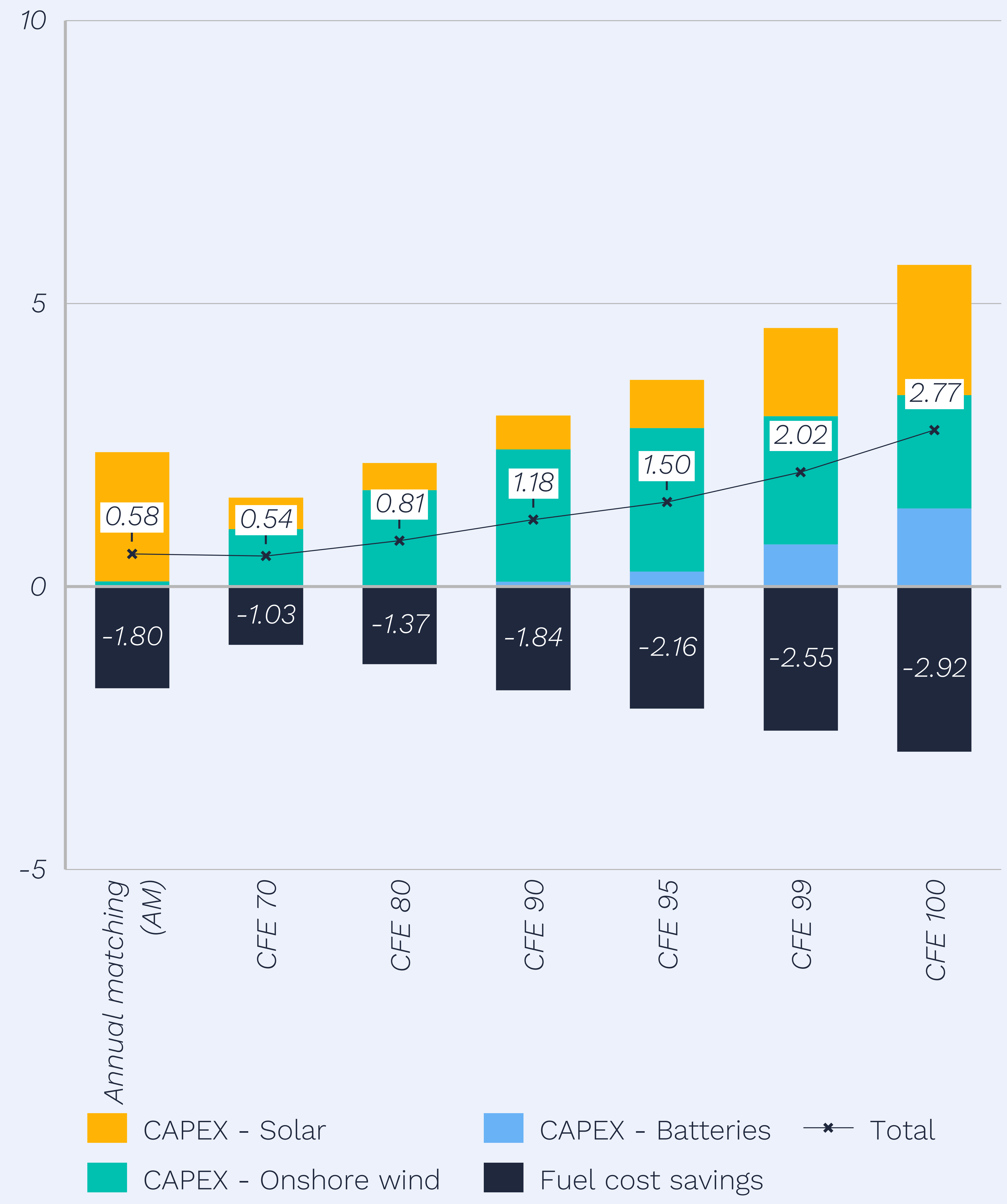
Savings under hourly matching start at $1 billion per year

While offtakers' investment costs escalate towards higher CFE scores, moving beyond CFE 70 also increases fuel savings by up to $3 billion

1. **Wind is the optimal VRE resource in Japan.** It pads out hours when the C&I offtakers cannot rely on either their solar PPA resources or on the regular grid to achieve CFE. However, hybrid systems relying on solar and battery storage start becoming necessary at the highest CFE scores, where every hour counts but the grid can no longer be completely relied on.
2. **Storage CAPEX rises exponentially under the highest CFE scores.** Looking at nationwide totals, the CAPEX from the extra storage alone required for going from CFE 90 to CFE 100 nearly equals the original costs of reaching CFE 90 itself. Storage is in fact so expensive that relying on it heavily in CFE 100 prompts substituting some of the wind resource – with high capacity factors but also high costs – with solar, featuring lower capacity factors but also lower costs.
3. **Excess renewable generation cuts fuel costs.** On occasions that PPA assets' generation exceeds offtakers' CFE demand, the excess can be sold on the wholesale market, displacing thermal generation through the merit order. Conventional generators on the mainstream grid save between $1.03 billion under CFE 70 up to $2.92 billion in CFE 100. The impact of these savings in terms of lowering overall system costs can be as much as 49% under CFE 100.
4. **Annual matching is financially inefficient.** While fuel savings are higher than under CFE 70, offtakers' CAPEX is notably higher, making overall system costs 7% higher under annual matching.

System-wide costs and benefits[1]

Costs/savings to the Japanese power sector (USD billion)



[1] These comprise all capital, operational, and fuel expenditure of the entire system, including PPA assets. CAPEX figures are annualised.

Source: TZ modelling.

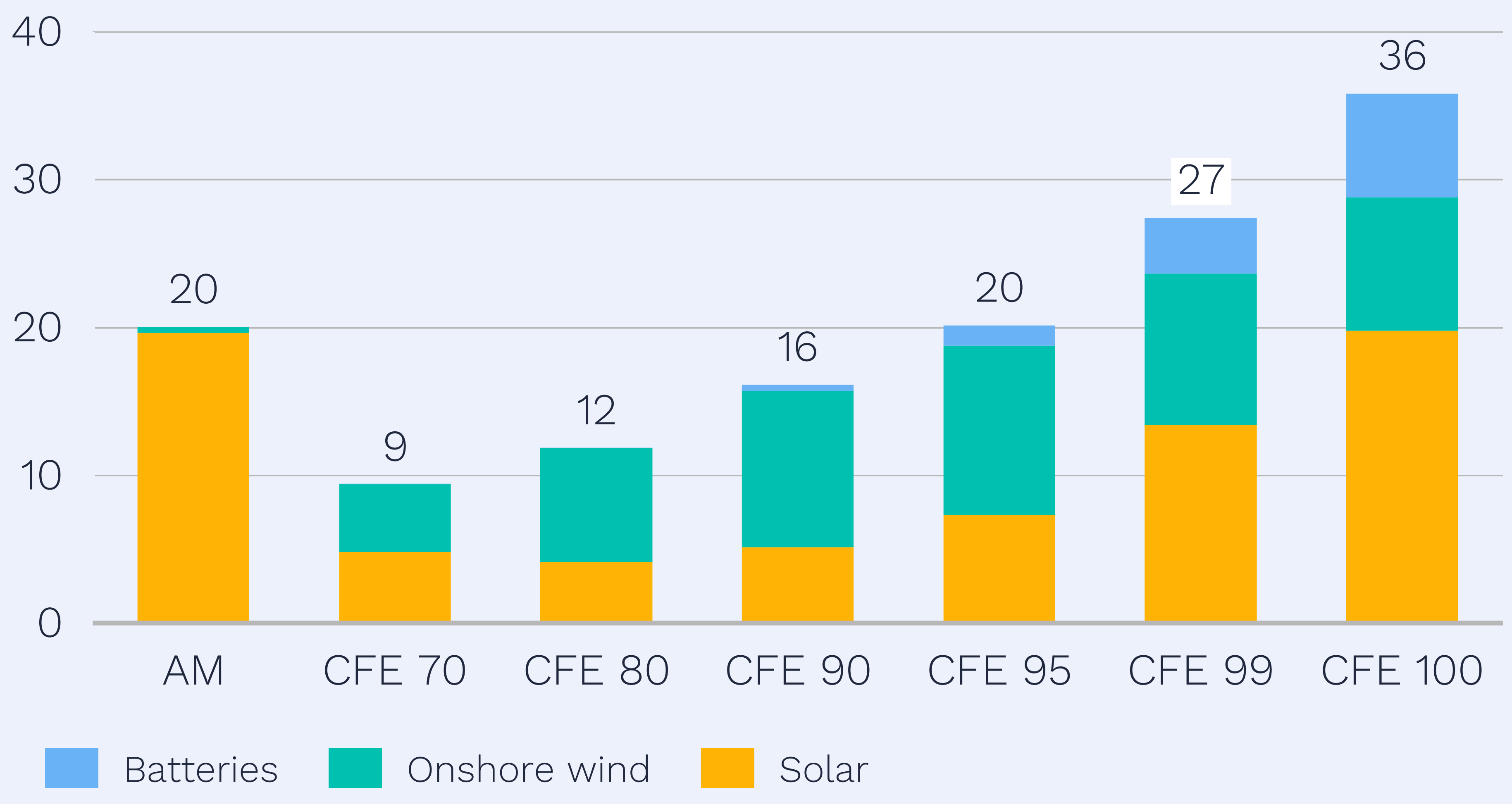
Hourly matching is better for abatement

At 70% hourly matching, emissions intensity falls 20% below annual matching

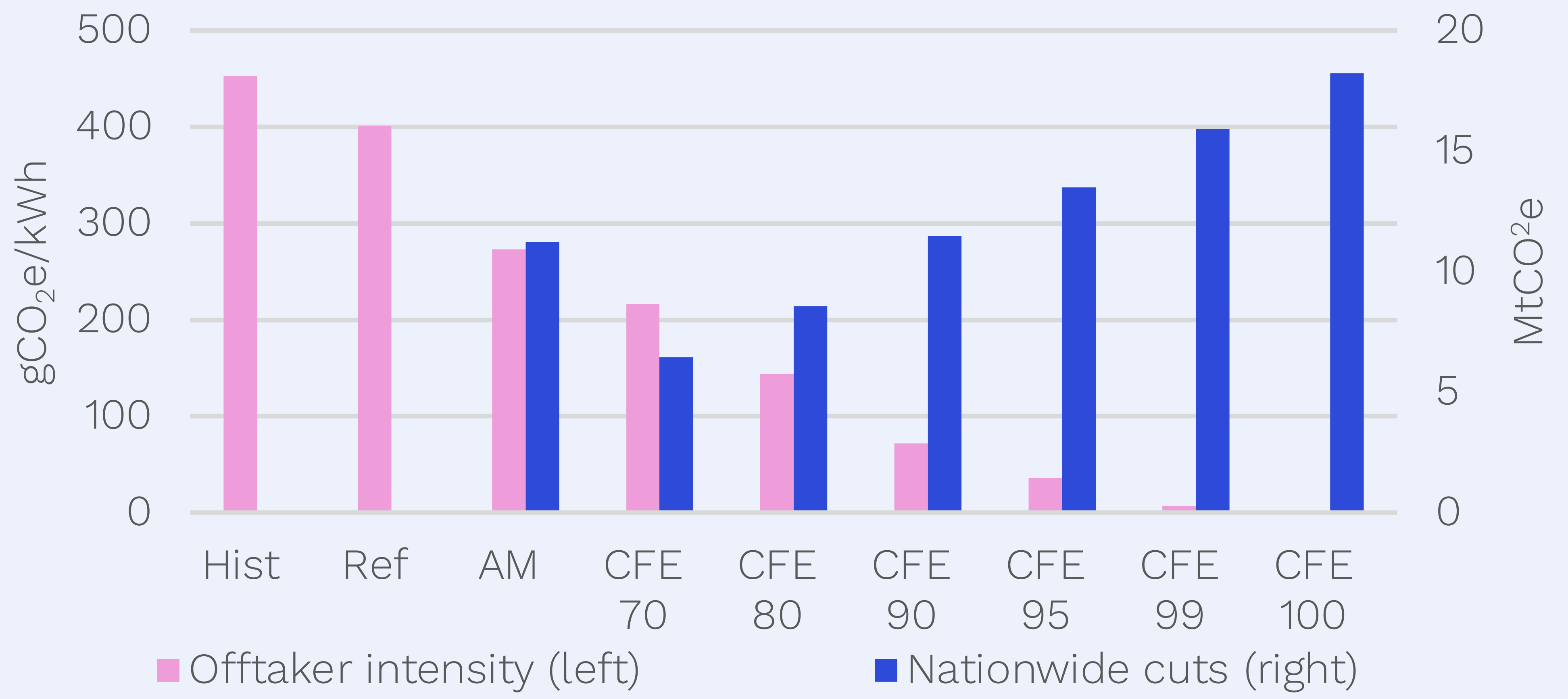
1. **Even at the lowest hourly matching threshold, offtakers' emission intensity falls below the annual matching regime.** This underscores the effectiveness of hourly matching in minimising emissions per unit of electricity generated.
2. **From CFE 90 onward hourly matching cuts more system-wide emission than annual matching.** At lower levels, annual matching achieves greater nationwide emissions reductions, because of the substantial export of clean electricity from overbuilt assets, and because at CFE 70 and CFE 80 the desired volume of CFE is lower than under the annual matching scenario. However, from CFE 90 onwards, hourly matching closes the gap, delivering over 18 $MtCO_2e$ in emissions savings by CFE 100, more than 60% above the 11 $MtCO_2e$ that annual matching achieves.
3. **CFE 95 cuts significantly more emissions than annual matching both in absolute and emissions intensity terms.** Although both approaches require a similar buildout of approximately 20 GW, CFE 95 delivers around 20% more nationwide emissions reductions and does so with 74% lower emission intensity for offtakers. This difference is largely driven by the greater reliance on wind in CFE 95, as wind generation, unlike solar, is not limited to daytime hours. This makes it more effective and better aligned with the temporal needs of hourly matching, in contrast to annual matching where solar dominates as hourly matching is not required.

Buildout by 2030 (GW)

Generation & storage requirements rise along with stringency…



…and by 90% hourly matching abatement is clearly stronger than under annual matching

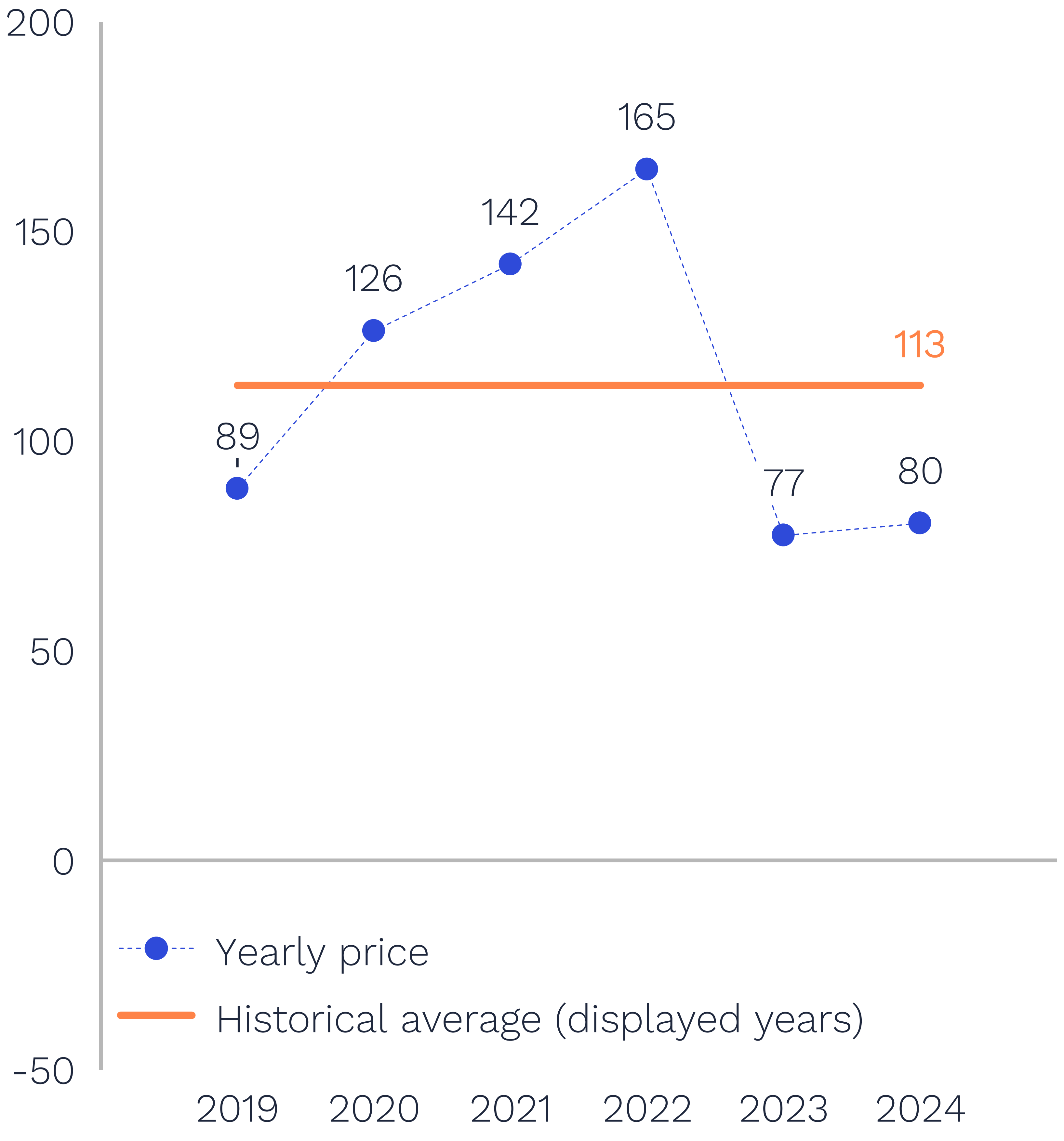


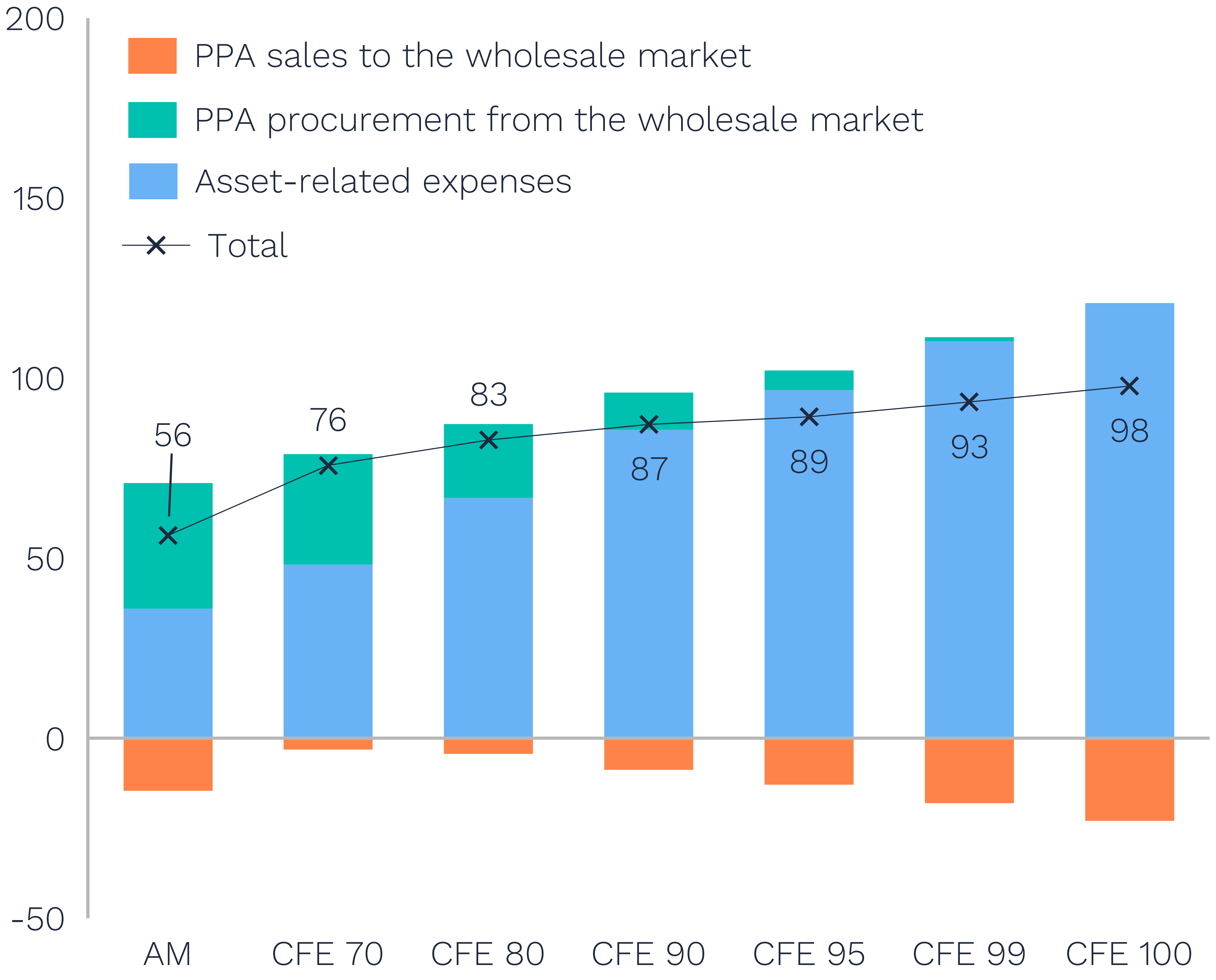
Source: TZ modelling.

Costs in context

The cost of even the highest levels of hourly matching is comparable to historical wholesale market prices

Historical wholesale market price[1] against national weighted average of PPA unit costs (USD/MWh)





Notes

- While total nationwide capacity requirements increase 4-fold in the transition from CFE 70 to CFE 100, unit costs borne by off-takers increase just under 30% over the same range, with the biggest increase seen in going from CFE 99 to CFE 100.
- Imports from the regular grid account for half of the unit cost under annual matching, but, along with the transition to hourly matching regimes with progressively stricter CFE score requirements, they gradually decline.
- In contrast, under hourly matching export revenues from PPA assets selling back to the regular grid increase along with the CFE score.
- When compared to the last six years of historical wholesale market prices, the unit costs of participating in any matching regime is below the average of all annual wholesale market prices recorded as far back as the pre-COVID year of 2019. This reflects the fact that wholesale market prices are set by natural gas, whereas the CAPEX of renewables and storage remain comparatively low.

[1] 30-min interval wholesale market prices data sourced from JPEX Day Ahead Market across all 9 grid regions and each aggregated at the yearly average level. Nominal JPY values are converted to USD and then denominated to the 2023 real USD base year.

Source: TZ modelling.

Technological neutrality can help

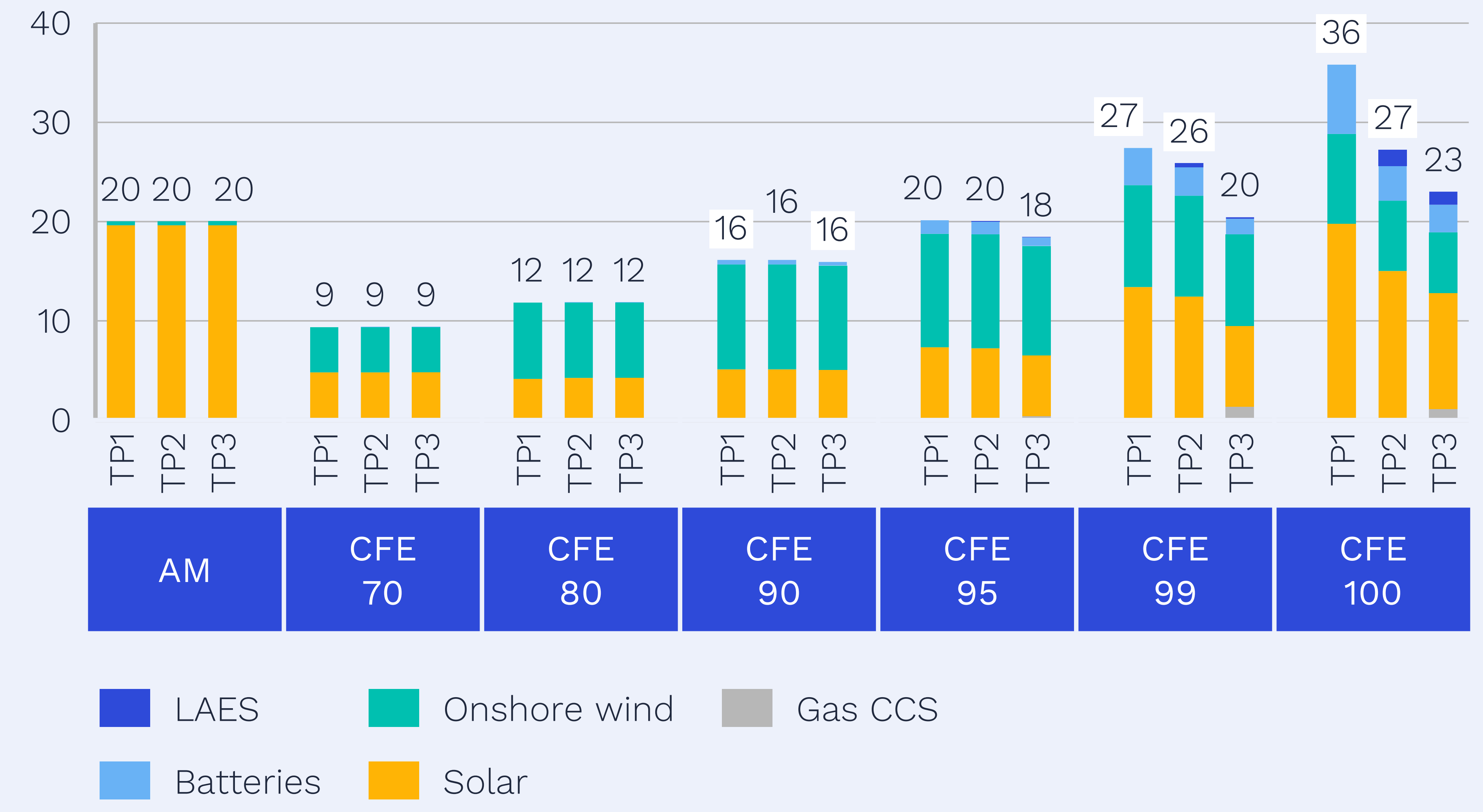
Emerging technologies can reduce the build-out rates for renewables and storage

1. **The new-build capacities required by 2030 for the most stringent interpretations of additionality under Tech Palette 1 (TP1) are significant.** Assuming that participating C&I demand is around 3% of the national total (see input slides for details), at CFE 70, new solar is 7.3% of the installed capacity in 2023, while new onshore wind is at 103%; whereas for CFE 100 the values are 26% and 343% respectively, with an additional 88-fold expansion of batteries.
2. **Adding liquid air energy storage (LAES) in Tech Palette 2 (TP2) displaces nearly half of battery capacity from TP1.** With a storage duration of 1 week compared to batteries' 6 hours, LAES is useful to cover long stretches of low renewable generation. Just as in TP1, the cost optimal choice for reaching CFE 100 is to expand storage capacity and reduce relatively expensive wind capacity – however under TP2 the superior capabilities of LAES reduce the need for wind even more. LAES also promotes the uptake of solar, which in CFE 99 and CFE 100 must, just like in TP1, expand materially above the level seen under more modest CFE scores.
3. **Gas CCS is the preferred innovative thermal technology.** In Tech Palette 3 (TP3) we considered CCS along with co-firing of blue hydrogen and ammonia, in line with the stated objectives of the Japanese government. However, expected prices in 2030 for natural gas, hydrogen and ammonia render CCS the most attractive option. CCS enters the market starting CFE 90 due to its high potential capacity factor, reducing reliance on renewable and storage capacity even more than TP2 when moving to higher CFE scores. (See detailed output slides for an explanation of the dynamics involved.)
4. **LAES is stiff competition to CCS at high CFE scores.** Within TP3, CCS capacity contracts by nearly 17% between CFE 99 and CFE 100, whereas LAES capacity rise nearly by a factor of 9. Nevertheless, compared to TP2, there is 21% less LAES under CFE 100 in TP3, highlighting that, across scenarios, the two technologies remain quite evenly matched.
5. **The alternative palettes cut national emissions slightly less than TP1.** TP2 reduces national emissions less because the long-duration storage soaks up excess CFE in many hours, releasing it later for C&I consumers' use, rather than releasing it for immediate consumption by brownfield consumers. The gross cuts in emissions from the regular grid under TP3 are more modest relative to the previous palettes because the joint presence of CCS and LAES lowers renewable build-out further than under TP2, and the net impact is lower still because offtakers are now directly responsible for leaked emissions from the PPA CCS plants.

Source: TZ modelling.

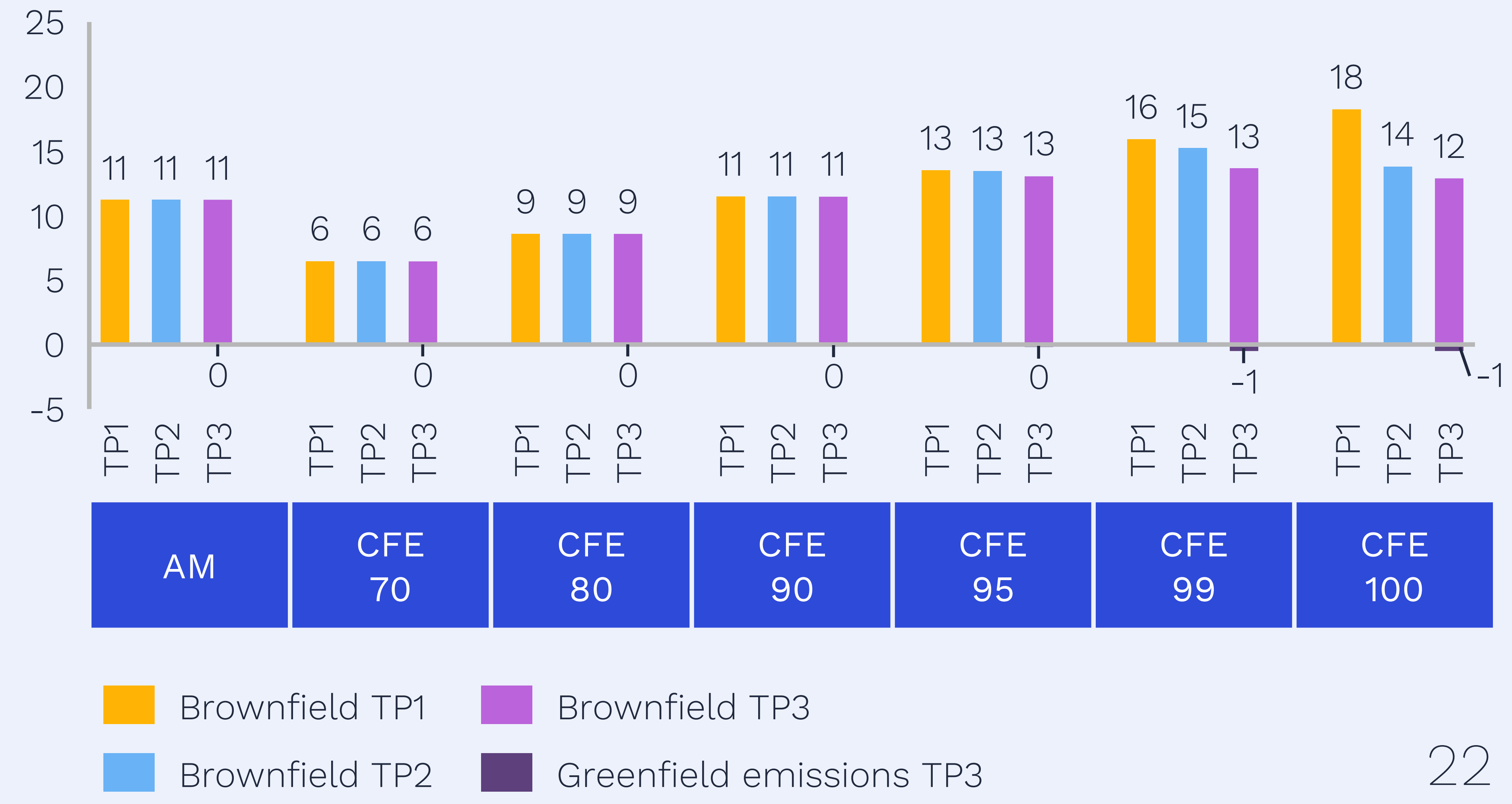
Buildout by 2030 (GW)

Dispatchable technologies reduce the need for overbuilding for low renewable output hours…



National emissions impact (Mt)

…while still delivering emission cuts nationally



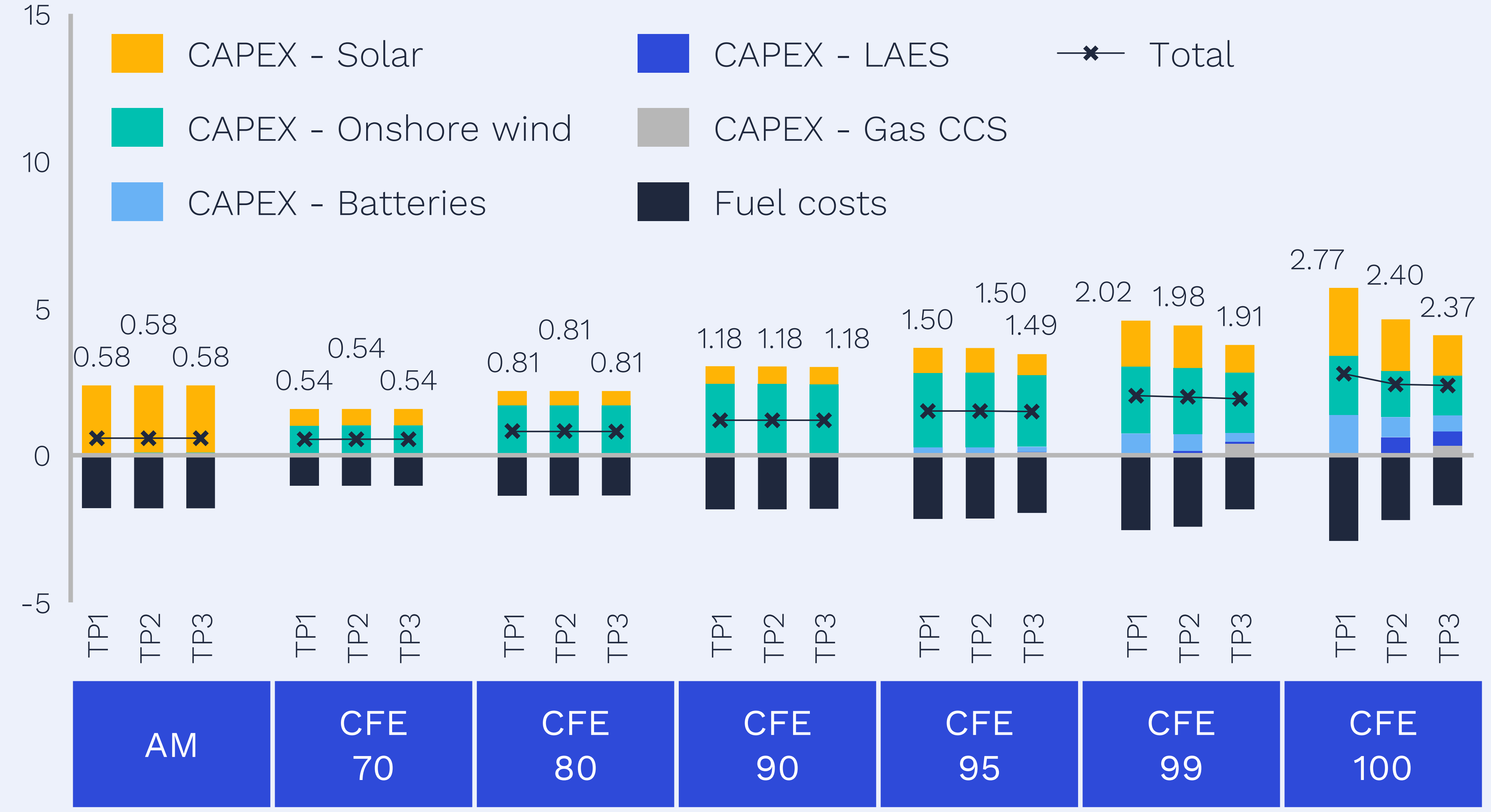
Technological neutrality has benefits

Technologies that can be dispatched more efficiently reduce the CAPEX from renewables and storage overbuild

1. **System costs escalate much less at higher CFE scores.** At CFE 100, TP2 is 14% cheaper than TP1, and TP3 is 15% cheaper. This is due to the reduction of capacity for first conventional batteries, followed by wind, then solar.
2. **Fuel savings on the regular grid remain a very important component of system-wide cost cuts.** However, these benefits contract as the flexible technologies reduce the availability of excess renewable generation. Moreover, under TP3, the CCS plants consume additional gas compared to the Reference Scenario, so fuel savings decrease even further.
3. **PPA unit costs rise above TP1 under the highest CFE scores.** TP2 starts becoming more expensive than TP1 in CFE 99, and TP3 at CFE 95. While CAPEX does fall as highlighted above for system costs, there are two further factors at play. First, with the advent of LAES more renewable generation is stored for the offtakers' use rather than being sold off to the regular grid. This can be quite beneficial in systems like Japan, where siting for new renewables can be difficult, but it does diminish revenue and therefore pushes up net PPA unit costs. Second, the additional fuel costs of TP3 raise costs even further compared to TP2.

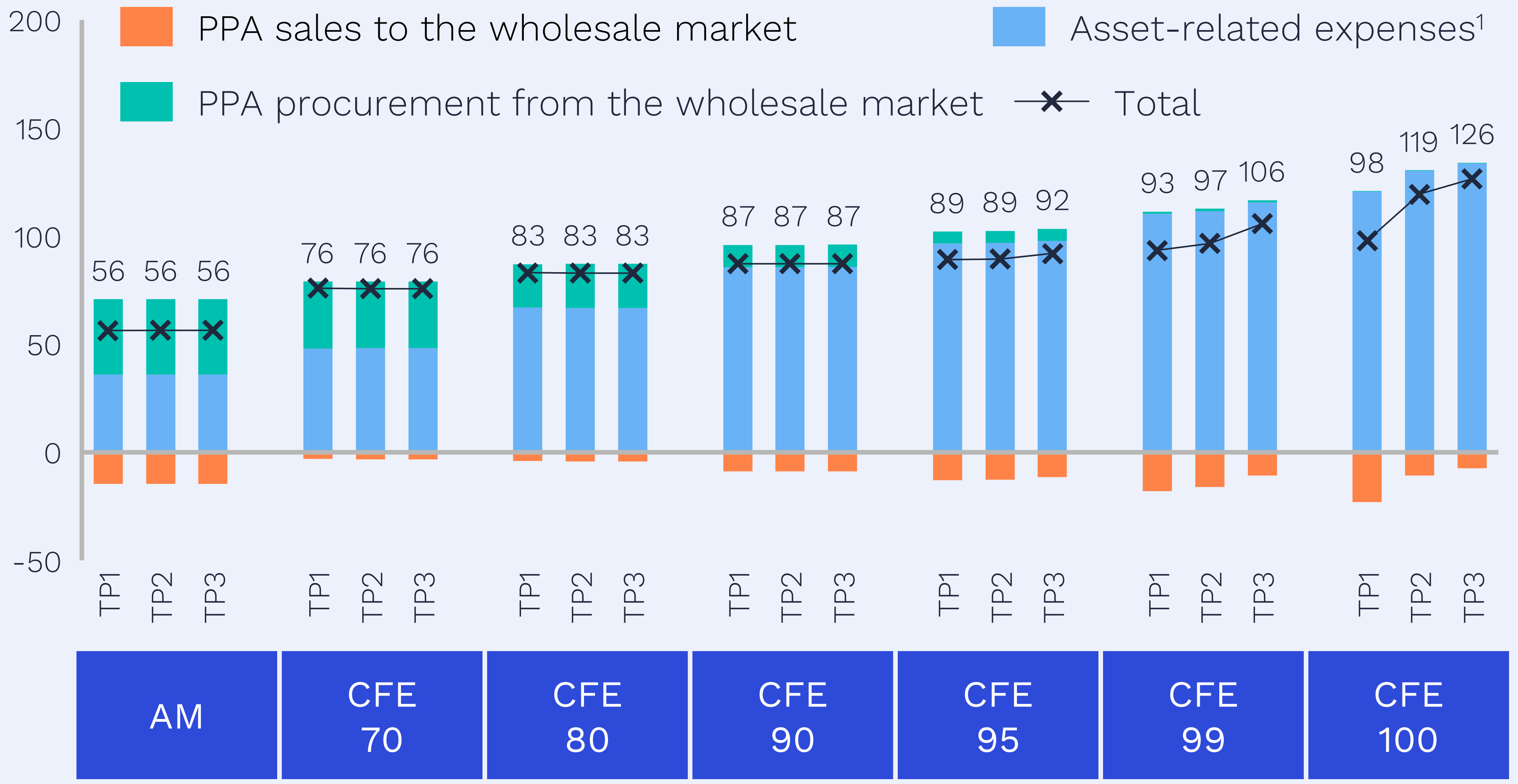
System-wide costs (Billion USD)

Emerging technologies reduce costs driven by overbuild



PPA unit cost (USD/MWh)

...and the less offtakers have to pay



Source: TZ modelling.

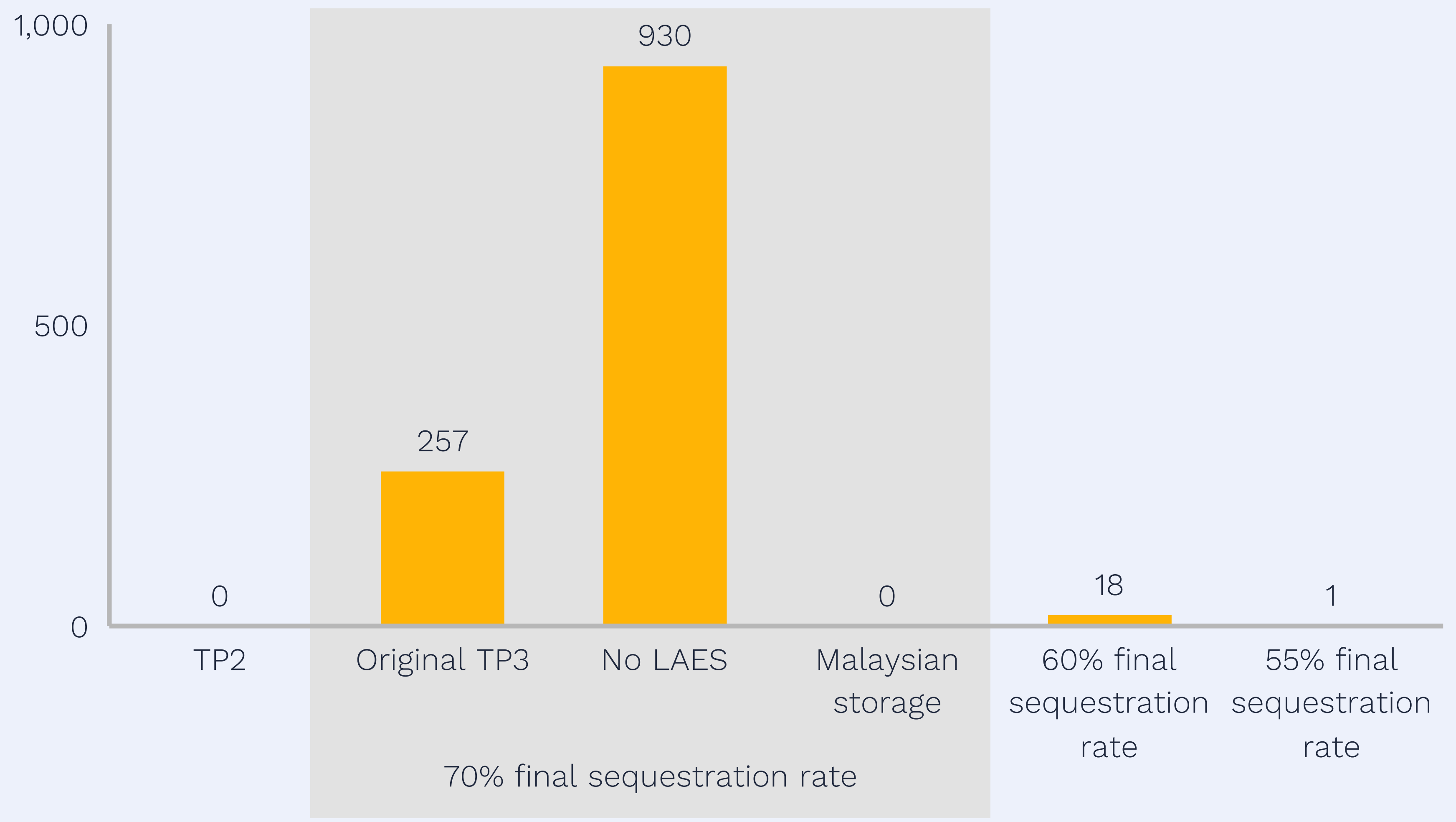
Technology risk

There are many unknowns behind CCS that can radically alter its usefulness for the highest CFE scores

1. **CCS uptake is particularly sensitive to two variables: final sequestration rates[1], and storage & transportation costs.** To test this, we ran sensitivities for deployment in the Tokyo region, using our standard TP3 assumptions: namely, 70% of all CO_2 caused by electricity generation is permanently stored underground, and the storage site is in Japan on average 1,000 km away from the CCS plant and reachable by boat.[2]
2. **CCS uptake in TP3 is highly sensitive to competition from storage.** As a dispatchable technology with a high-capacity factor and more appealing economics than hydrogen or ammonia co-firing, CCS has, under our standard assumptions, a lower levelised cost than hybrid renewables-and-battery systems. If LAES is removed from consideration, CCS uptake nearly quadruples under CFE 100 – entirely at the expense of solar capacity (-14%) and mildly offset by an increase in wind and battery capacity (+1% and +14% respectively).
3. **CCS is adopted only when the final sequestration rate exceeds 55%.** Below this threshold, renewables and LAES remain the more economically attractive option and CCS uptake is nil. This is concerning, because in its 2025 guidance for the Long-term Decarbonisation Power Source Auctions, METI specifies a minimum capture rate of 20% and a minimum sequestration rate of 70%, implying a final sequestration rate of 14% – at which point CCS no longer provides any CFE cheaply enough to be of value.
4. **Our sensitivity analysis indicates that to be economically viable, CCS requires storage in Japan.** Japan's current Memoranda of Understanding for carbon storage in Malaysia assumes an average shipping distance of 5,000 km. However, under these conditions, CCS is not competitive enough to see any build-out.
5. **The emission impact of CCS is limited.** Because it eats into renewable generation, excess generation is reduced and therefore the activity of thermal plants on the regular grid is impacted less. Furthermore, under the assumptions here CCS is leaky, so the more it is used, the more the CFE PPA itself becomes an emissions source.

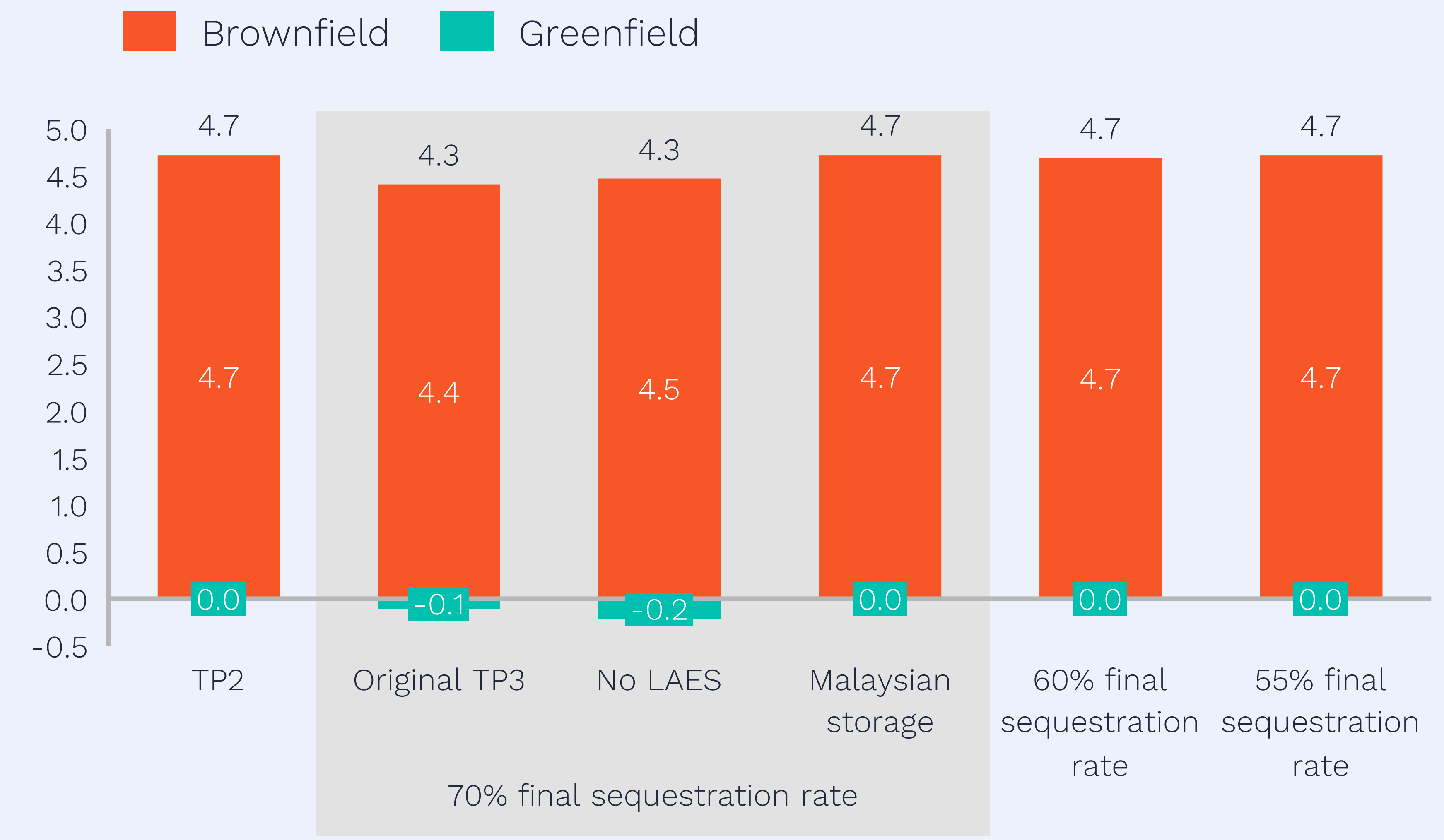
CCS uptake (MW) – Tokyo CFE100

Projected capacity is sensitive to assumptions…



National emissions impact ($MtCO_2e$)

…and leaks affect its emission impact



Source: TZ modelling.

[1] *Defined as the capture rate of CO_2 resulting from fuel combustion, times the sequestration rate for the captured CO_2.* [2] *The project economics for pipeline transport did not affect CCS uptake during initial runs due to insufficient differentiation from other competing CFE technologies.*

Build requirements in context

Meeting CFE demand at low to medium scores is not challenging in peripheral zones, but high-load zones would struggle compared to historical performance

Required build-out[2] against present-day reference values (MW)   CFE 70   CFE 80   CFE 90   Reference value[1]

Notes

- Having a higher capacity factor than solar PV makes onshore wind the preferred technology for C&I consumers at the lowest hourly matching regimes tested.
- Fortunately, Japan benefits from a massive untapped stock of onshore wind projects that have been licensed under the old Feed-in Tariff law but have not yet been commissioned.
- Access to sufficient renewable capacity is problematic in the Tokyo, Chubu and Kansai regions, emphasising the need to rely on regional interconnectors that would allow tapping into renewable resources further afield.

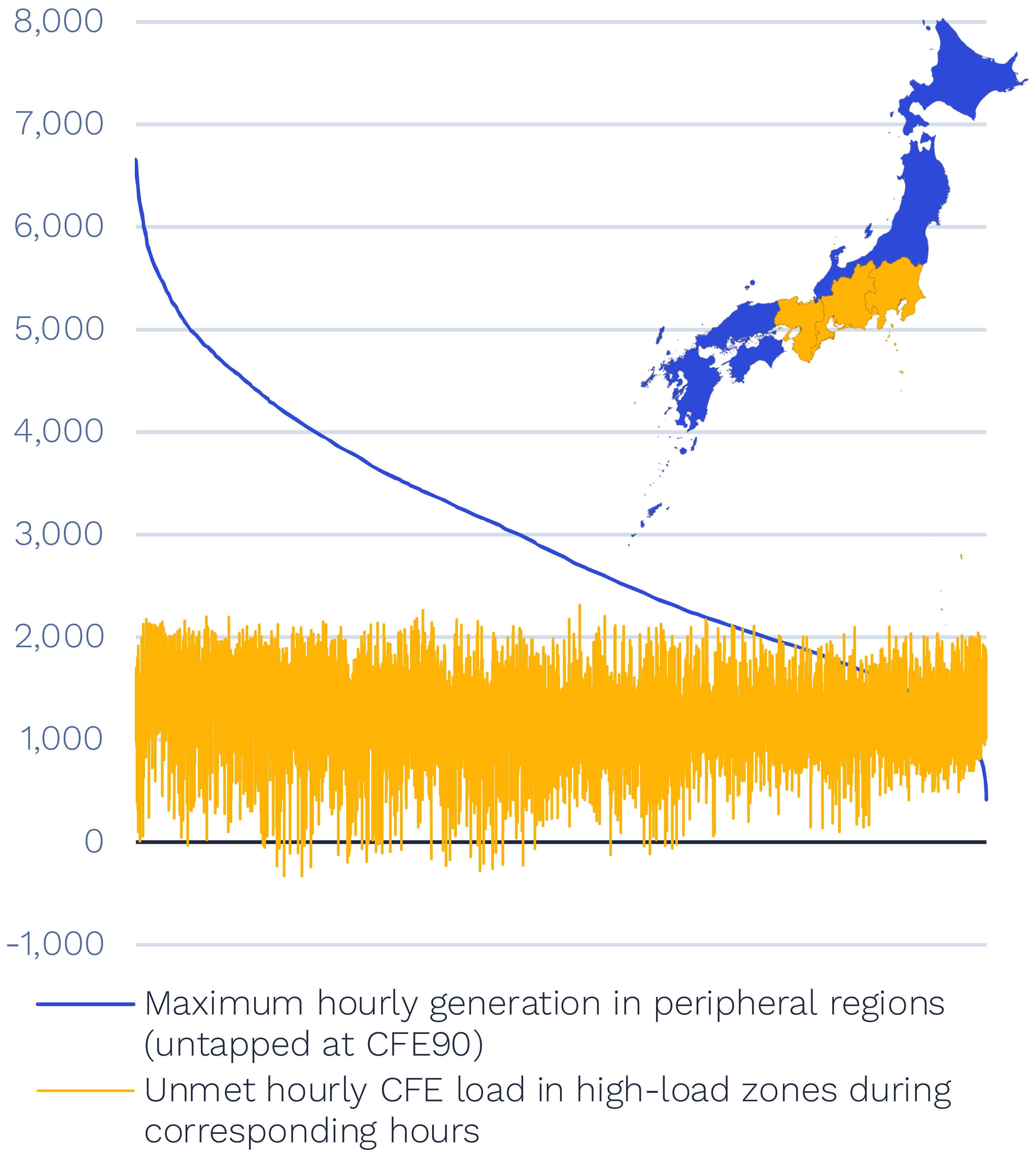
[1] For solar: average yearly licensing rate over past 7 years. For onshore wind: cumulative stock of licensed projects by 2024.
[2] Single-node modelling approach: In our study, we have applied CFE participating demand to one grid zone at a time and then aggregated the results together, ignoring potential inter-zone effects on CFE demand and behaviour. This is because of current modelling limitations of solving multiple adjacent grid zones at a time. A study where CFE participating demand is simultaneously applied to all grid zones may show different outcomes.

Source: TZ modelling.

Benefits of regional interconnectors

At CFE 90, renewable potential and interconnector capacity seem adequate to realistically meet demand in high-load centres

Potential to service high-load zones (MW)



Ordered spare interconnector capacity[3] for Tokyo (MW)

Ordered spare interconnector capacity[4] for Chubu (MW)

Ordered spare interconnector capacity[5] for Kansai (MW)

[1] Tokyo, Chubu, and Kansai. [2] Hokkaido, Tohoku, Hokuriku, Chugoku, Shikoku, and Kyushu. [3] Tohoku to Tokyo. [4] Hokuriku to Chubu. [5] Chugoku to Kansai, Hokuriku to Kansai, and Shikoku to Kansai. [6] For solar: average yearly licensing rate over past 7 years. For onshore wind: cumulative stock of licensed projects by 2024.

Notes

- The chart on the left explores what would happen throughout Japan under CFE 90 in TP1 if renewables expanded exactly up to their historical reference values.[4]
- In 95% of all hourly periods the CFE demand that cannot be met in the high-load zones[1] can be more than met with generation from other parts of the country.[2]
- The charts on the right show that the interconnectors bringing electricity from peripheral zones into high-load zones (one direction only), even after accounting for everyday utilisation, will almost always have spare capacity to handle some CFE flow. Chubu, the region with the least interconnection to peripheral regions (Hokuriku only), might use its interconnectors to Tokyo and Kansai to indirectly access other peripheral regions it does not directly border on.
- More careful modelling is required to explore hour-by-hour to what extent battery capacity can help paper over the 5% of hours when generation in the periphery cannot fully supply CFE demand in high-load zones, and when interconnector capacity becomes too tight.
- Likewise, further modelling is required to investigate what would happen under higher CFE scores. It may be possible that at the highest CFE scores, it may become necessary to loosen the boundaries of this study, e.g. allow more technologies or permitting PPAs with assets on the brownfield.

A realistic reference point

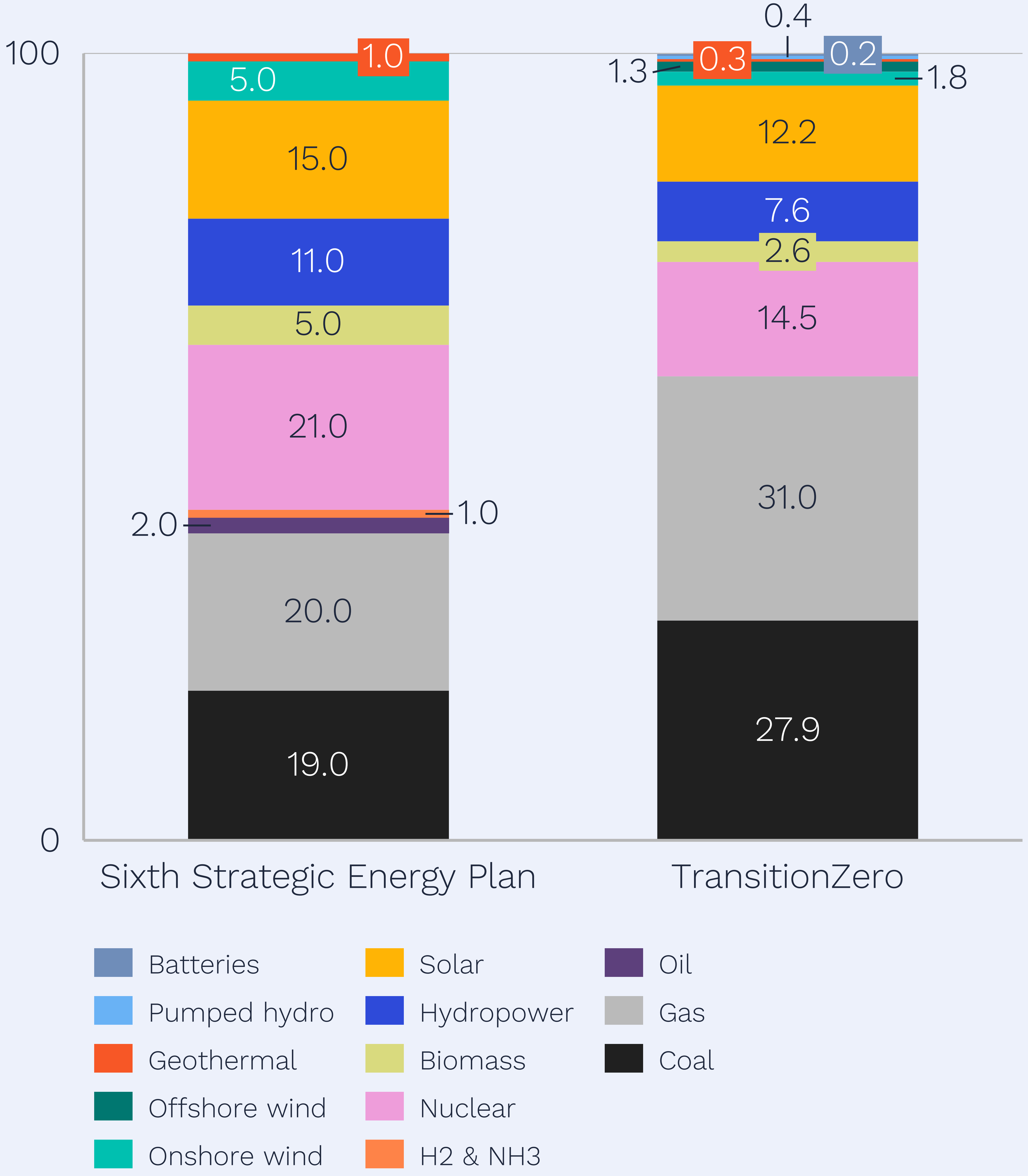
Our Reference Scenario for 2030 includes deviations from government plans that reflect market realities and historical trends

- We acknowledge that in the Sixth Strategic Energy Plan of 2021[1] the government had envisioned substantial changes to the Japanese energy mix by 2030, but we do not use these policy targets as modeling constraints to guide outputs.
- We expect several constraints on the expansion of nuclear and most forms of renewables. (For details see our inputs section.)
- In contrast, the introduction of several kinds of auctions since 2021 will bring on sources not addressed in the Sixth Energy Plan, like batteries and offshore wind – though not enough to compensate for the above contraction.
- Accordingly, coal and gas generation increases relative to the government plan, because these are comparatively cheap fuels, whereas oil and innovative thermal are too expensive to be dispatched.

[1] *We avoid any reference to the Seventh Strategic Energy Plan from 2025 because it refers to the year 2040, it does not provide any information for any intervening years, and does not provide a more granular split among technologies beyond the high-level categories of renewables, nuclear, and thermal.*

2030 generation mix

Share of total generation (%)



Source: TZ modelling.

Methodology

How we modelled CFE in Japan

Key modelling design features

Relevant parameters of the 24/7 CFE model

- **Year of analysis:** 2030.
- **Time steps:** 8760 hours/year, i.e. hourly.
- **Modelling framework:** PyPSA open-source linear optimisation of dispatch in copper-plated zones without intra-zone power flows.
- **CFE demand:** country-specific subset of demand from emerging sectors.
- **CFE demand profile:** Proportional to overall demand profile in each grid region.

Modelled nodes by country

Country	Grid regions	Interconnectors	
		Domestic	*International*
India	5	6	3 [1]
Japan	9 [2]	10	-
Malaysia	3	1	3
Singapore	1	-	2 [3]
Taiwan	1	-	-

[1] Modelled as generators due to their low demand/supply levels.
[2] The analysis only covers the 9 interconnected price zones of the Japanese Mainland.
[3] Represents one existing and one planned interconnector, reflecting a conservative estimate of the import capacity that may be available to Singapore by 2030.

Common inputs

Our models utilise the full suite of inputs required for power systems modelling

Technology

- Capacities
- Maximum build-constraints
- Renewable profiles
- Efficiencies
- Emissions factors

Financial

- Cost of capital
- CAPEX
- OPEX (FOM/VOM[1])

Demand

- Nodal hourly demand
- Commercial & industrial demand

National policies [2]

- Planned expansions
- Capacity mix targets
- Decarbonisation targets
- Transmission plans

[1] VOM also covers here fuel costs and carbon penalties.
[2] We will apply a delay of up to 5 years on policies that do not seem realistic, in consultation with our Working Group partners.

We run three sets of scenarios to test both supply and demand for CFE in 2030

Reference Scenario

A brownfield grid accounts for

Existing Grid and Generators in 2023

+

Transmission Capacity Expected by 2030

+

Generation Capacity Expected by 2030

+

Model-built Generation Capacity

Carbon-Free Electricity Scenarios

Where 2 different technology palettes are available

Technology Palette 1

Technology Palette 2

Technology Palette 3

Model-optimised capacity:
Annual Matching Regime

Where additional solar, wind, battery storage can be built to meet 100% of participating C&I demand for the whole year

Model-optimised capacity:
Hourly Matching Regimes

% of CFE hours matched is tested

Where 5% of national demand must be met with CFE on average throughout the year ×

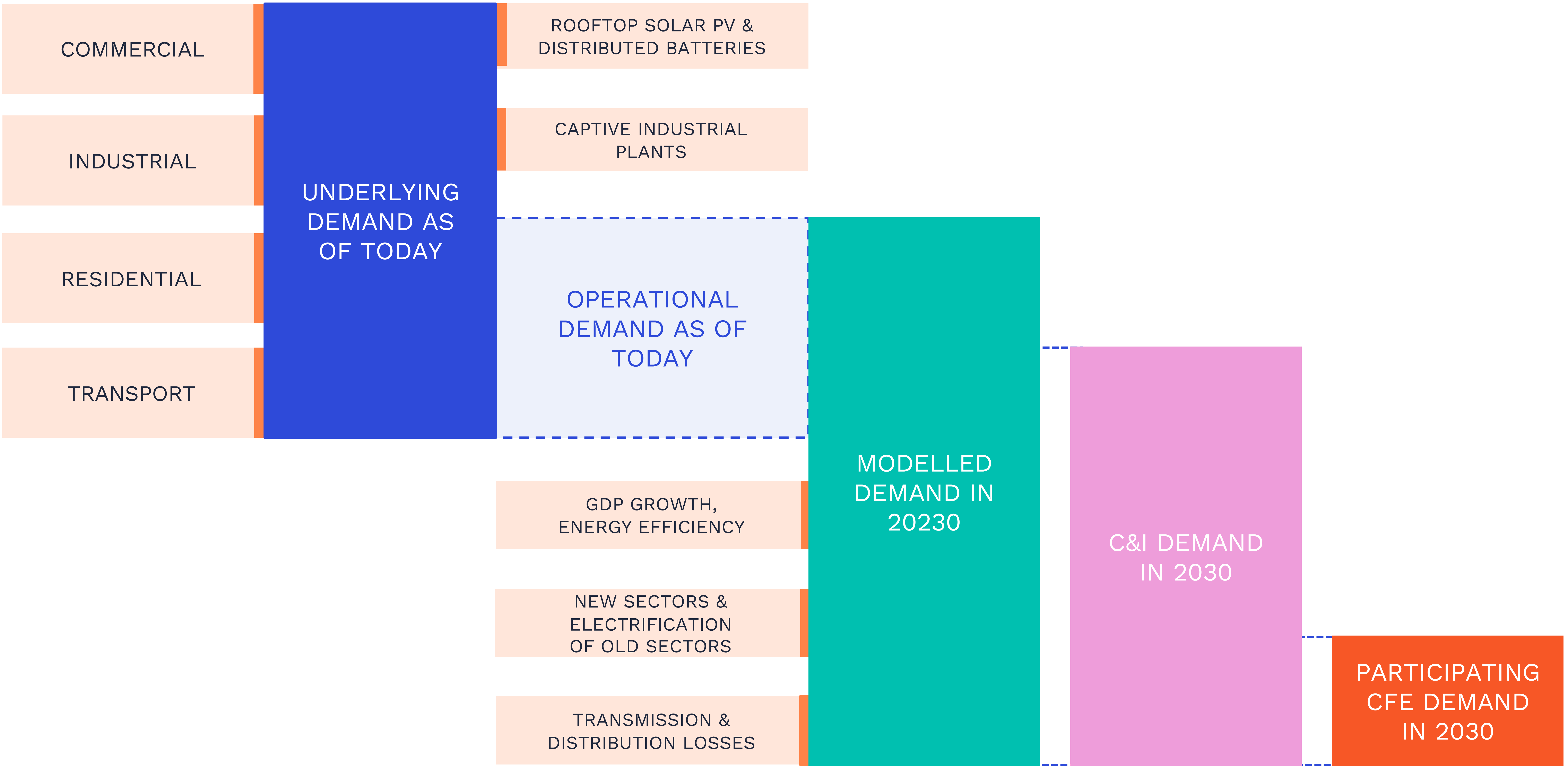
70%
80%
90%
95%
99%
100%

Notes

- CFE scenarios meet the participating C&I demand either on an annual or an hourly basis by building additional capacity (equivalent to procuring additional capacity through PPAs).
- Before modelling any CFE scenarios, we run a Reference scenario, allowing new-build on the brownfield bus only.
- For each technology palette the first CFE scenario is the Annual Matching Regime, which we run only once.
- We then run Hourly Matching Regimes starting with a CFE share of 70% and then rising to 100% for a total of 6 runs (see infographic on left).
- The total number of runs is 22, made up of 1 Reference Scenario and 7 matching regime runs each for each technology palette.

Demand in 2030

Our model considers both demand for both conventional electricity and CFE



[1] In-house projection for Japan only.

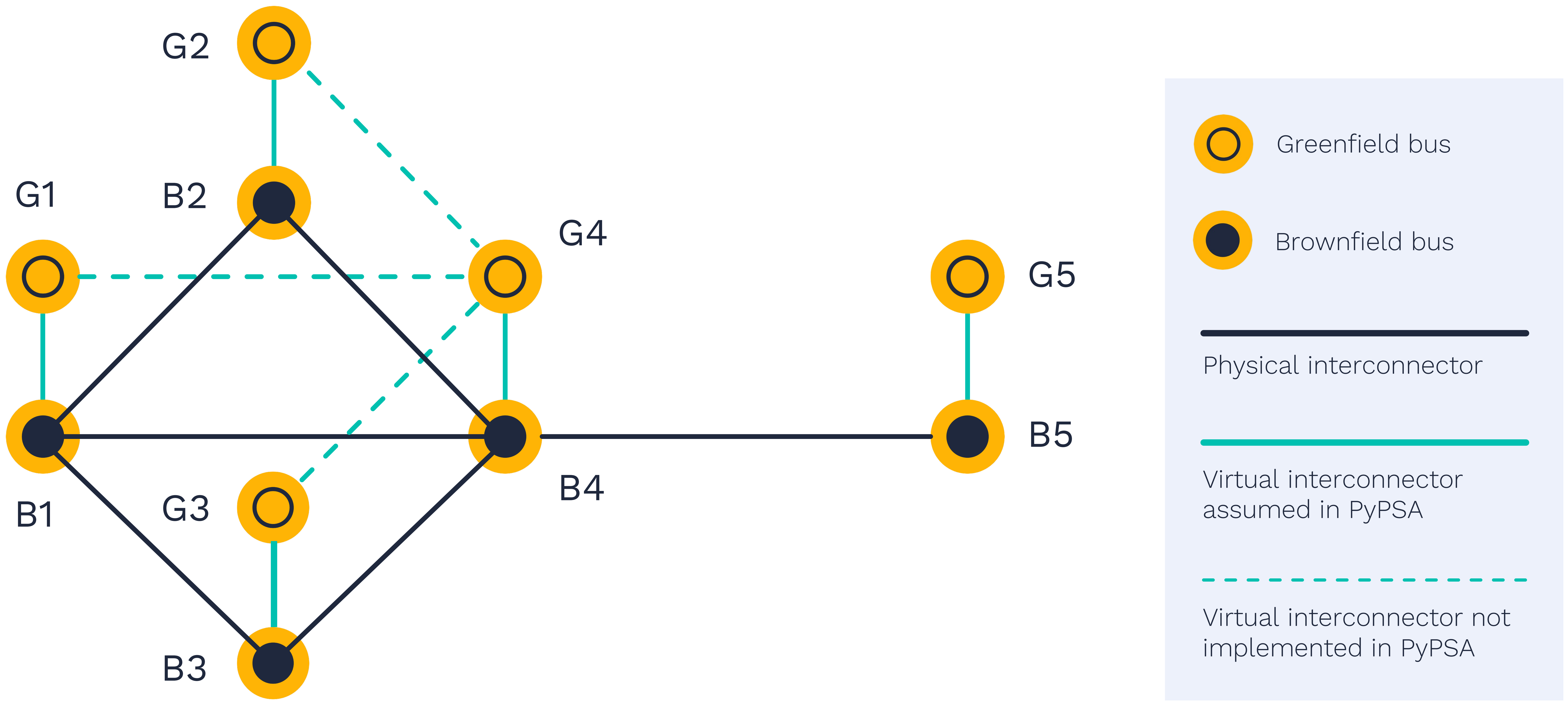
Notes

- Our demands for 2030 account for several sources of change from the present – either explicitly through in-house modelling[1] or by incorporating projections made by local authorities.
- In our Reference Scenario the model only seeks to meet demand for conventional electricity.
- In our CFE scenarios we expect that a certain share of C&I consumers switch to consuming only CFE, thereby triggering PPA developers to build new capacities.
- We derived a reasonable expected share for CFE demand relative to total demand through consultations with local stakeholders. The values are accordingly specific to each country.
- Actual CFE demand in each model run depends on the CFE% targeted in each Hourly Matching Regime.

Market	CFE volume [TWh]	CFE % [relative to 2030 demand]
India	122 TWh	5%
Japan	29 TWh	3%
Malaysia	15 TWh	5%
Singapore	3.5 TWh	4%
Taiwan	16 TWh	5%

Connections among buses

We break down complex markets featuring multiple zones connected through interconnectors into multiple linked buses

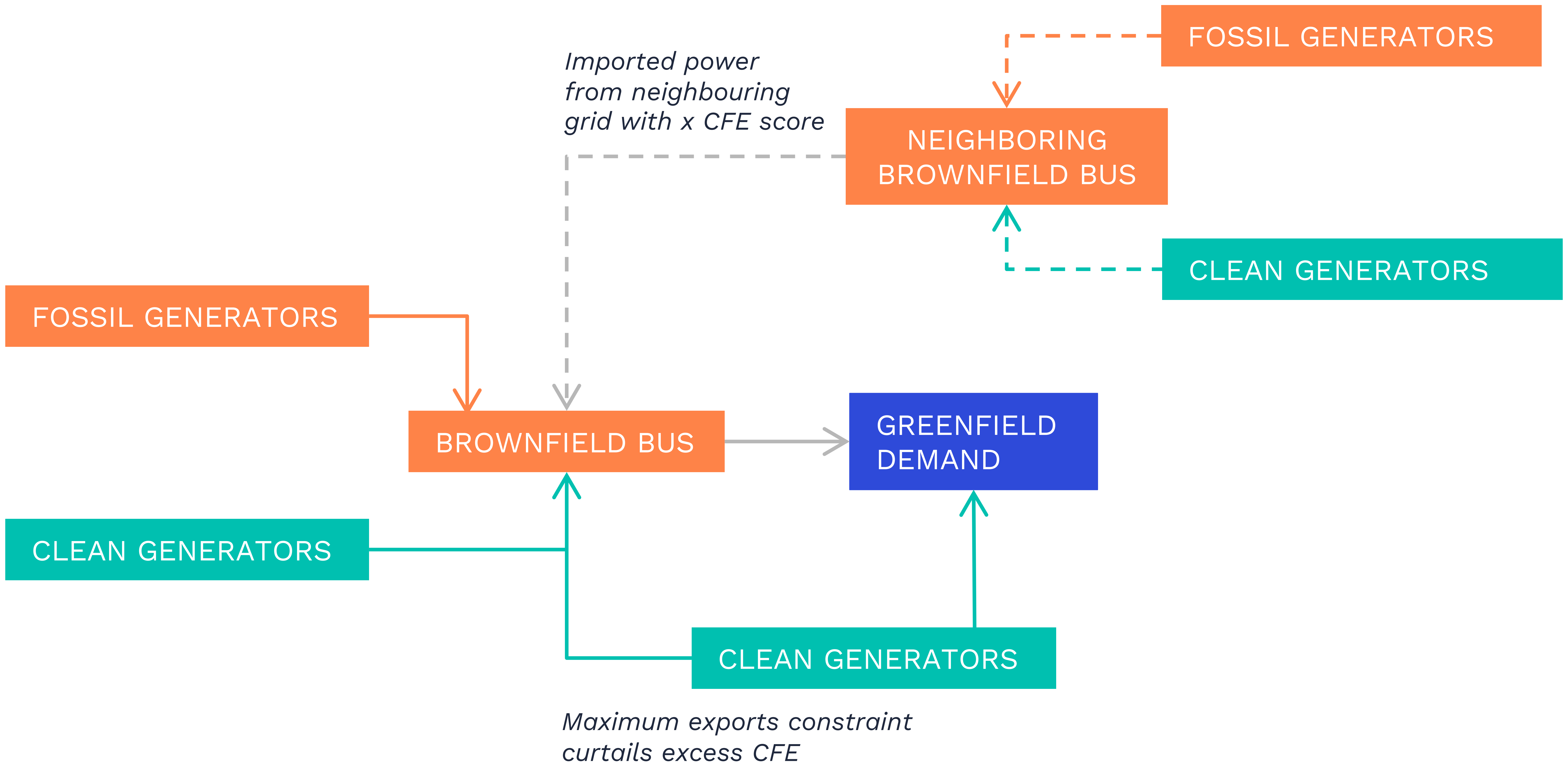


Notes

- In PyPSA we implement brownfield buses connected through links in a topology that reflects real-world grid zones and the interconnectors between them
- The brownfield buses contain the same generators and loads as in the real world
- To each brownfield bus we attach a single virtual greenfield bus to house generators financed through the CFE PPAs by interested C&I consumers located in the original grid zone
- In this project greenfield generators can only supply C&I consumers on the brownfield bus they are directly connected to, i.e. there are no links to other greenfield or brownfield buses

Procurement across links between buses

Our model allows for bi-directional trade between the greenfield and brownfield buses



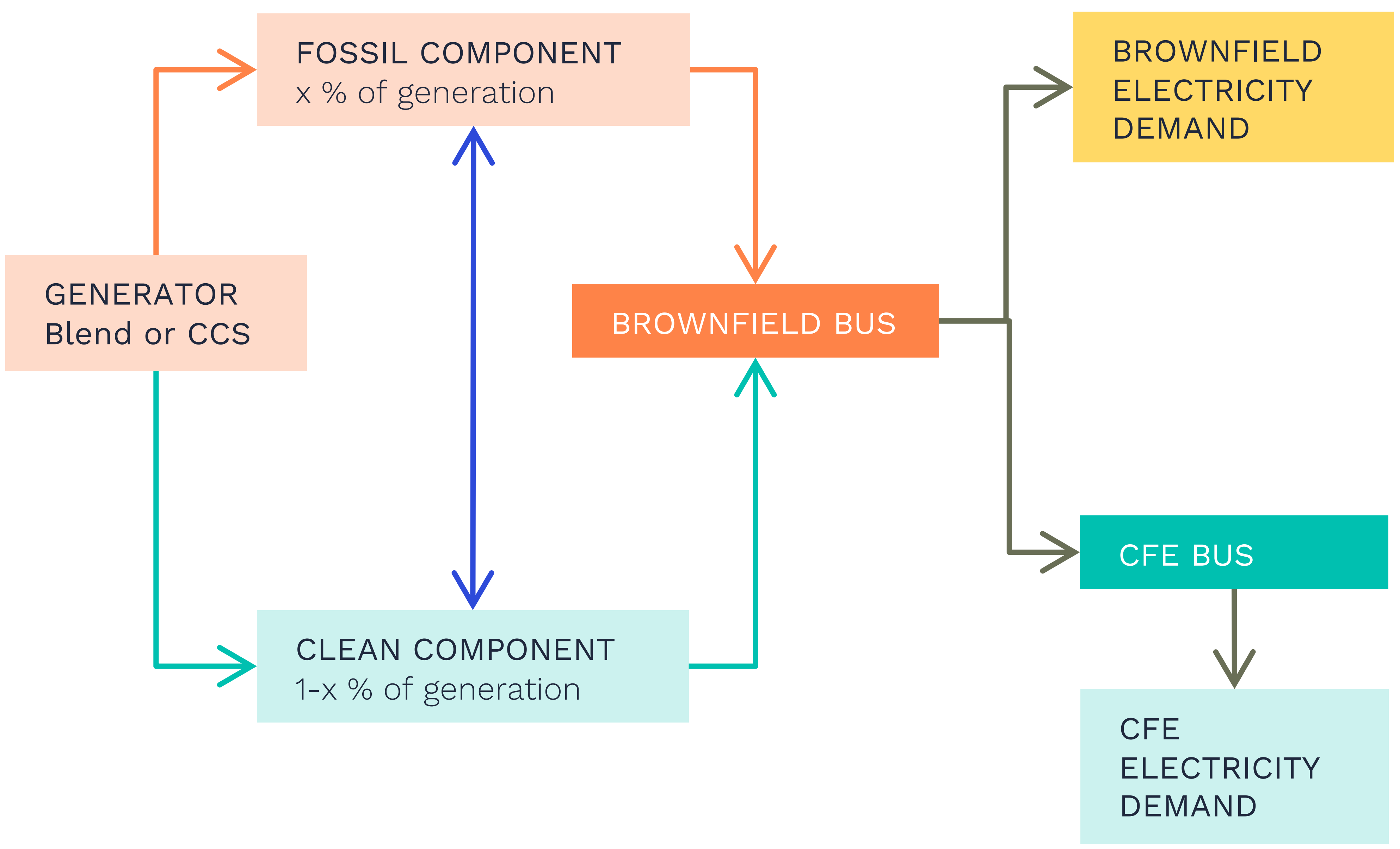
Notes

- C&I consumers can use brownfield procurement to top up insufficient PPA generation.
- If their local grid is interconnected with another grid, then the CFE score of their brownfield procurement will be affected by the CFE score of the net imports from that other grid.
- For certain countries, we allow exports **of excess generation back to the grid**, reflecting a conservative assumption based on grid technical constraints in handling additional exogenous generation at both hourly and annual scales.
- This maximum sell-back is set at 20% of C&I load for hourly CFE in India, and 15% in Malaysia and Singapore.
- Reflecting local market conditions this limit is set to 100% of C&I load in Japan and Taiwan. In Japan new renewable plants are increasingly encouraged by the government to sell their generation on the wholesale market, whereas in Taiwan Taipower buys up generation at fixed feed-in tariffs.

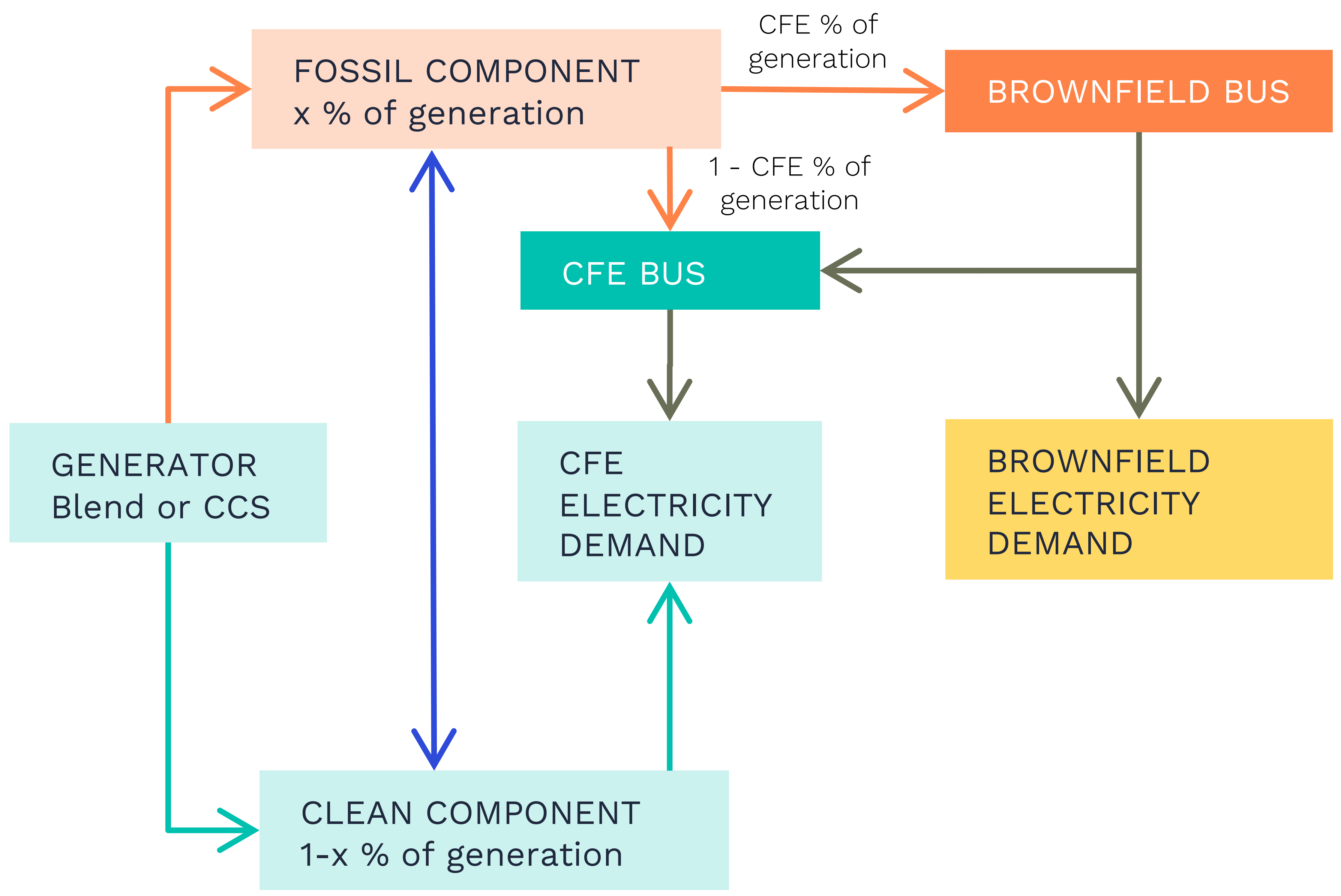
CFE scoring for TP3's innovative thermal plants

We ensure that only an appropriate share of generation from low-carbon generators can be used to meet CFE demand

Built on the brownfield



Built on the greenfield



CFE ratio of generation | CFE generation | Non-CFE generation | CFE share of brownfield mix | Non-CFE share of brownfield mix

[1] Expressed as the CFE share of the hourly matching regime.
[2] For the 100% CFE hourly matching regime the model will allow only CFE consumption on the CFE bus, but for lower matching regimes some emitting generation is permitted.
[3] As a share of energy, derived from policy objectives of the Japanese authorities. Technologies available for TP3 differs per country.

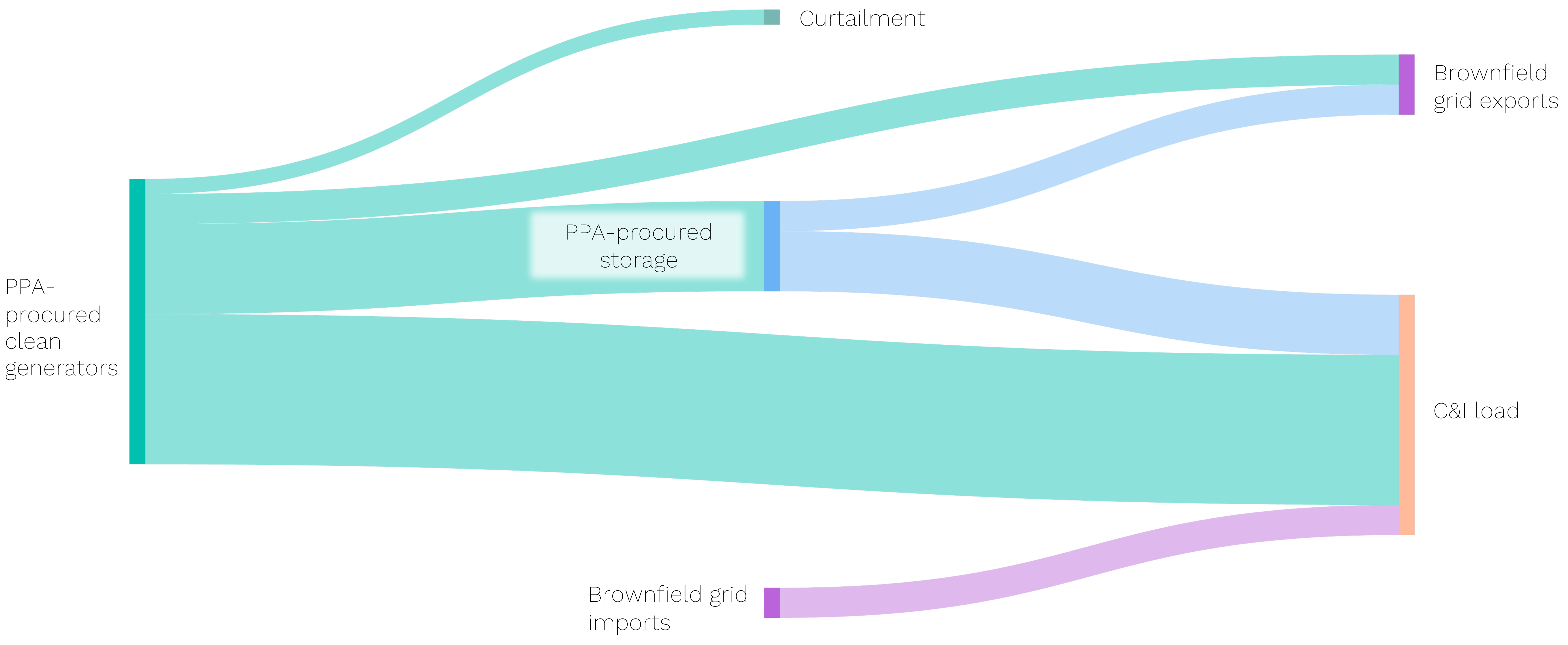
Notes

- Whereas loads on the brownfield bus consume any kind of electricity, consumers on the CFE bus want to meet a minimum share of their consumption from CFE[1].
- The generation from plants that blend fossil and non-fossil fuels and CCS plants with imperfect capture rates cannot be said to be 100% CFE.
- For each such plant we implement a CFE generation ratio that is fixed at all time steps.
- For plants on the brownfield bus (present in the Reference Scenario) their generation mingles with all other pre-existing plants' generation, affecting the CFE % of the brownfield, and this total generation may then flow into the CFE bus depending on the target matching regime.[2]
- For plants on the greenfield bus (present in technology palette 3) the non-CFE share of their generation flows immediately to the brownfield bus, from where it may return to the CFE bus depending as in above point on the target matching regime.

Asset class	CFE share[3]
Coal-ammonia co-firing	20%
Gas-hydrogen co-firing	10-30%
CCS	70%
Coal-biomass co-firing	15%

Energy flows and costs for the C&I load

Sankey diagram showing indicative energy flows between clean generators, storage units, the grid, and the C&I load



Relevant formulas

- In calculating the unit cost of electricity supplied to the C&I consumer, the C&I consumer could handle the grid imports themselves, and the PPA manager handles the PPA supply and export revenue from excess supply. This would lead to the following unit cost calculation:

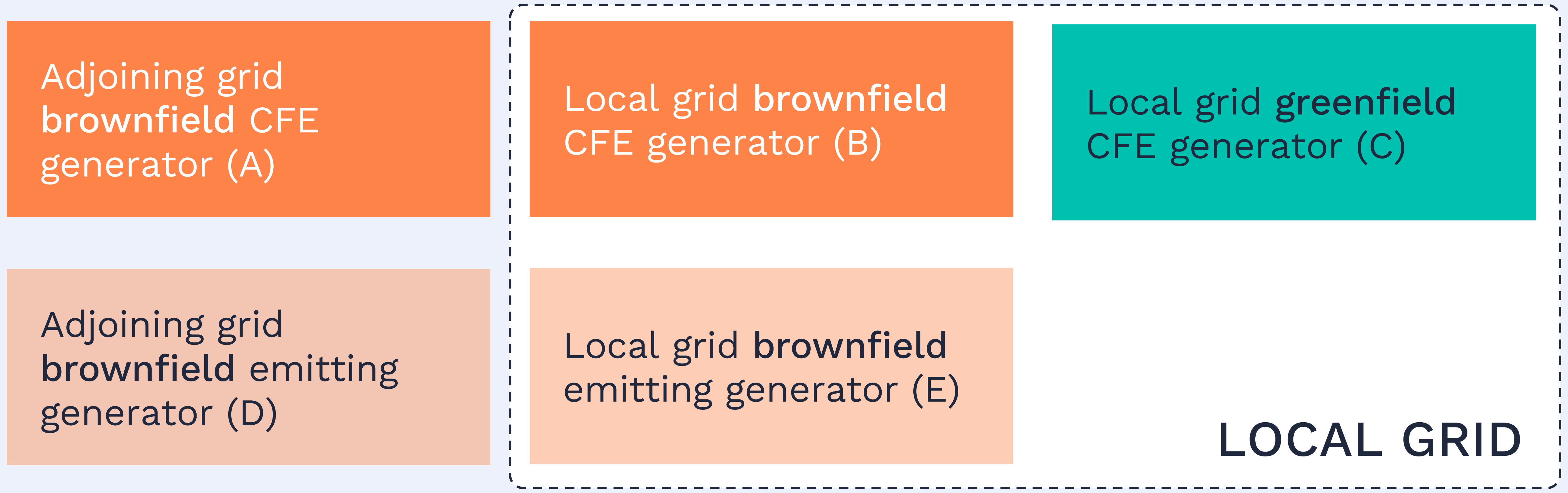
$$\text{Unit cost} = A \times \frac{\text{capex + opex + grid export revenue}}{\text{C\&I load} - \text{grid imports} + \text{grid exports}} + (1-A) \times \frac{\text{grid import costs}}{\text{grid imports}}$$

$$\text{Where } A = \frac{\text{C\&I load - imports}}{\text{C\&I load}}$$

- This splits the electricity supply into the two components which come from the PPA supply and the grid respectively, which are then weighted by the proportion by which they supply the C&I load.

Grid CFE score

We iterate to avoid the CFE build-out in adjoining grid zones from creating a nonconvex modelling problem



$$ImportCFE_t = \frac{A_t}{A_t + D_t}$$

$$CFE_t = \frac{B_t + ImportCFE_t * import_t}{B_t + E_t + import_t}$$

- To determine whether C&I consumers can use the brownfield grid to meet their target CFE score we calculate a ‘grid CFE score’, showing what ratio of all brownfield generation comes from CFE sources.
- When C&I consumers use brownfield procurement to top up insufficient PPA generation, if their local grid is interconnected with another grid, then the CFE score of their brownfield procurement will be affected by the CFE score of the net imports from that other grid.
- However, because all grids are building out CFE capacity to meet matching regime requirements, this creates a nonconvex modelling problem.
- We avoid this problem by treating the grid CFE score as a parameter that is iteratively updated, with convergence expected after 2 iterations.

Limitations of the study

We have taken several decisions to simplify the scope of our study

Considerations	Decision
Multi-period investment optimisation	Not included: We only model one step from the calibrated base year of 2023 to the target year of 2030
Trading of Energy Attribute Certificates	Not included
Demand shifting (in time and space)	Not included
Impact of asset age on additionality	We are not exploring the RE100 guidance to treat all renewable assets younger than 15 years as additional
CFE status of discharges from storage assets on brownfield buses	Not included

TransitionZero

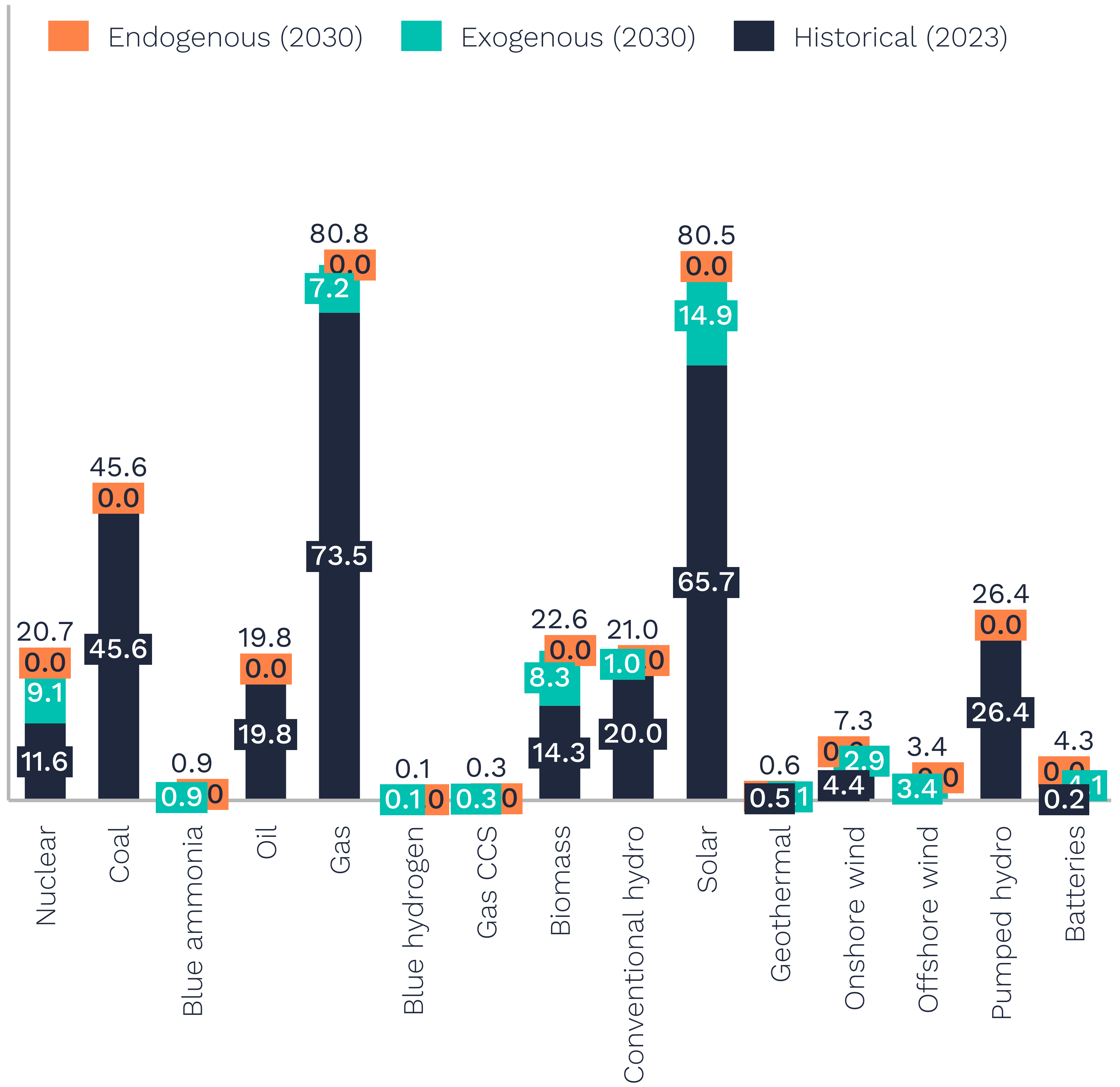
Modelling results

Deep-dive analysis into the national and grid-zone level findings

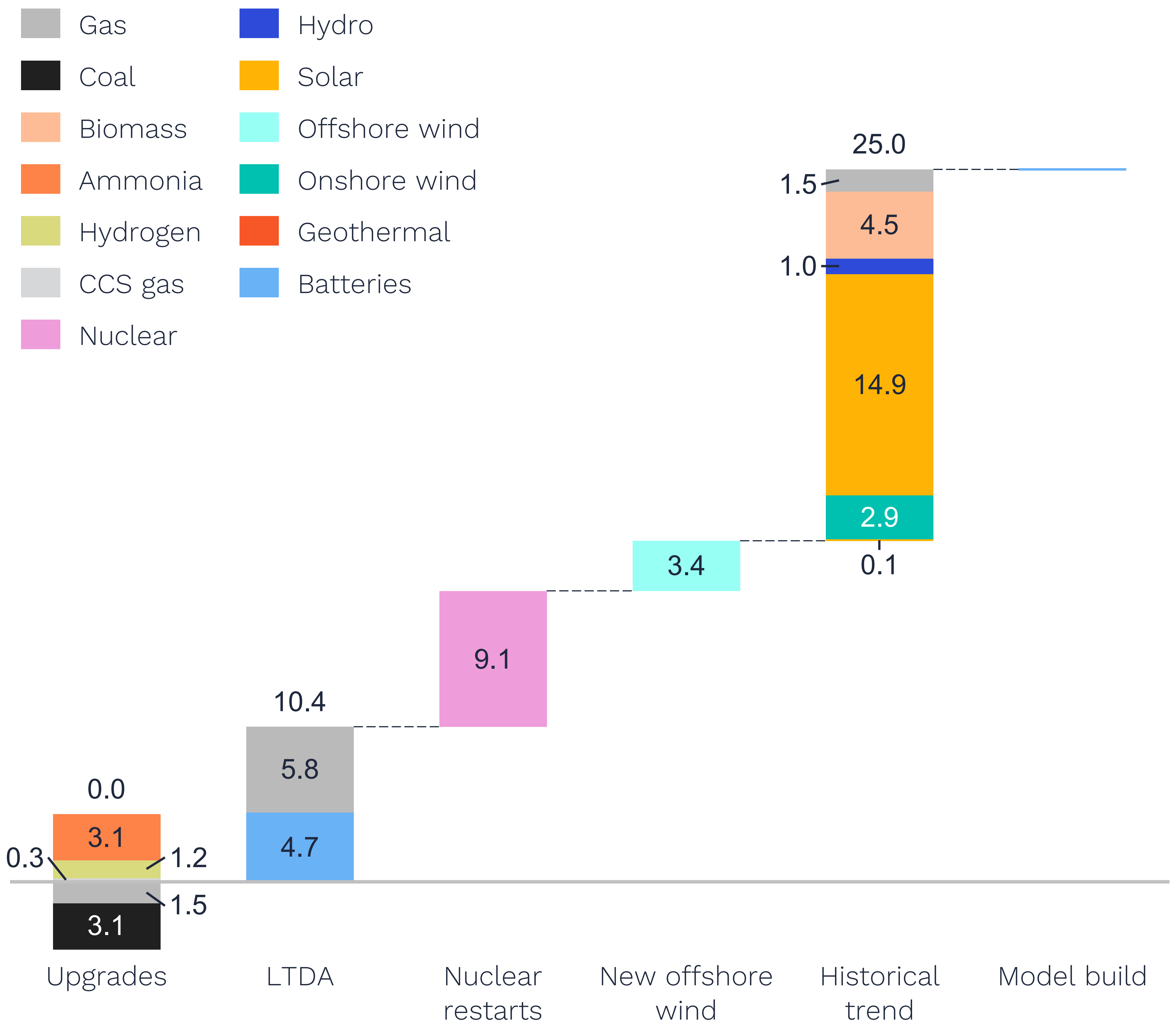
Reference Scenario: Generators and storage capacities

Our analysis starts with the composition of the power system before any CFE demand

Installed capacities[2] (GW)



Breakdown of 2030 exogenous capacities (GW)



Notes

- In our approximation of the current Japanese power system, we have used the capacity mix as presented in OCCTO's 2024 Aggregation of the Electricity Supply Plans.
- We have split present-day national capacity totals into capacities for 9 brownfield buses[1].
- We have topped up present-day capacity with expected new capacity based on historical trends, news accounts, and expected capacity from various auctions[2].
- We have also allowed PyPSA to endogenously build new capacity, but the capacity assumed to be present by 2030 is sufficient to meet projected 2030 demand.

[1] In the future we hope to populate our model with bottom-up information of Japanese plants. [2] Long-Term Decarbonisation Auctions (LNG, batteries), site auctions (offshore wind).

[2] Single-node modelling approach: In our study, we have applied CFE participating demand to one grid zone at a time and then aggregated the results together, ignoring potential inter-zone effects on CFE demand and behaviour. This is because of current model limitations of solving multiple adjacent grid zones at a time. A study where CFE participating demand is simultaneously applied to all grid zones may show different outcomes.

Source: TZ modelling and desk research.

Reference Scenario: Generation mix

Our Reference Scenario is cleaner than the present but does not achieve the 2030 target in the Sixth Strategic Energy Plan from 2021

Generation[2] across different technologies and scenarios (TWh, % of total generation, % of year[1])

Notes

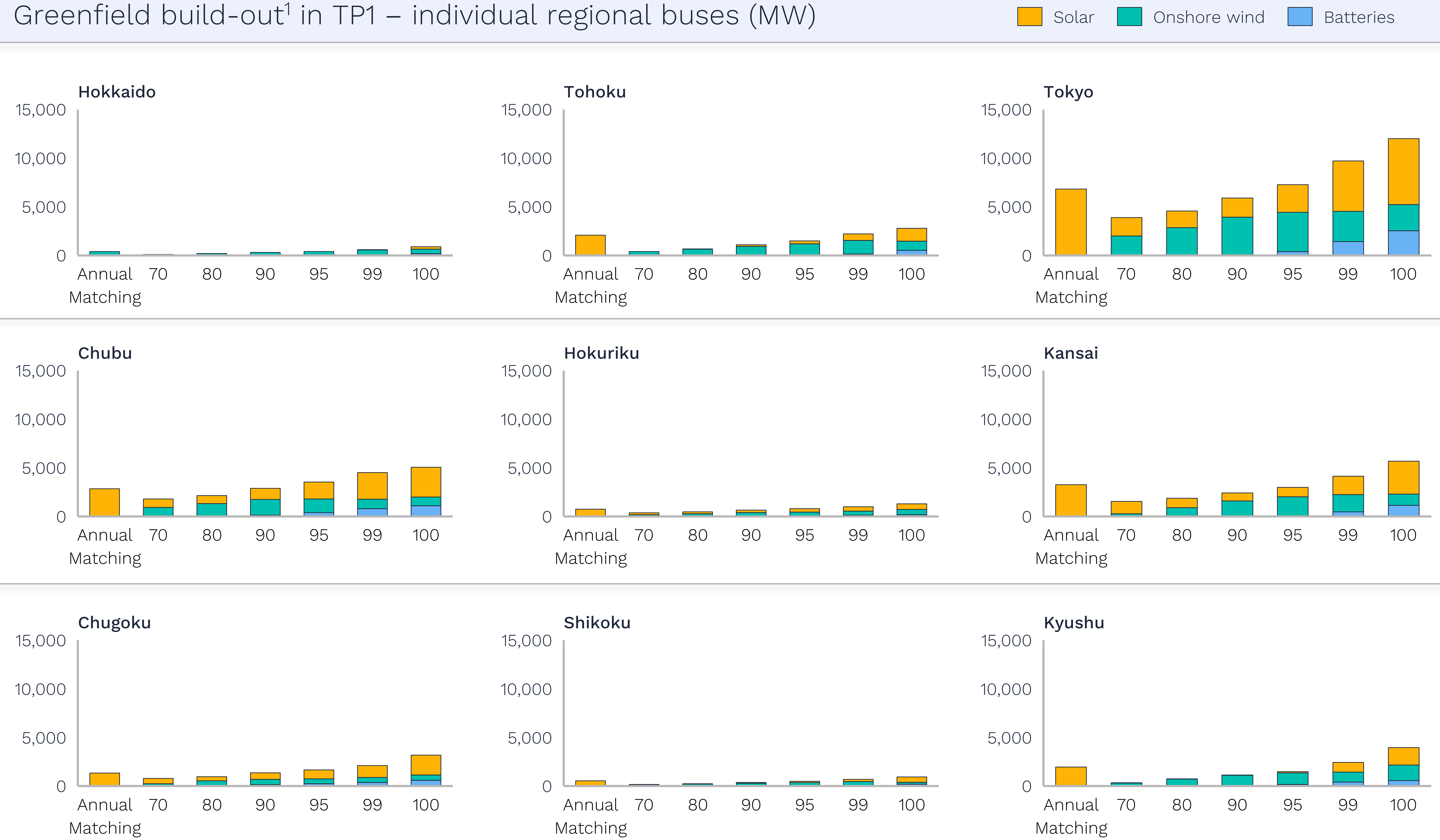
- We acknowledge that in the Sixth Strategic Energy Plan the government had envisioned substantial changes to the Japanese energy mix by 2030, but we do not use these policy targets as modeling constraints to guide outputs.
- We do however employ historical data from 2023 to calibrate the model to mimic real-world generation patterns for thermal plants.
- Given the constraints on the expansion of nuclear and renewables, gas and coal fail to fall.
- Thermal capacity forced onto the system (oil and innovative thermal) does not actually run endogenously.

[1] Capacity factors listed as "Government plan" are from the OCCTO Annual Report for 2021, projecting for 2030. [2] Single-node modelling approach: In our study, we have applied CFE participating demand to one grid zone at a time and then aggregated the results together, ignoring potential inter-zone effects on CFE demand and behaviour. This is because of current model limitations of solving multiple adjacent grid zones at a time. A study where CFE participating demand is simultaneously applied to all grid zones may show different outcomes.

Source: TZ modelling, METI, OCCTO.

Our model determines build-out by optimising one region at a time

Greenfield build-out[1] in TP1 – individual regional buses (MW)



Notes

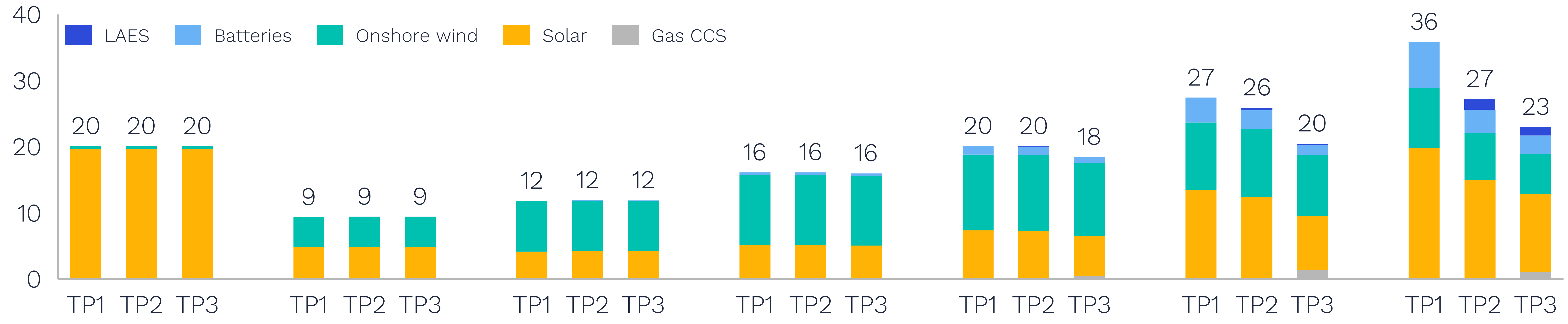
- The ratio between solar and onshore wind build-out is a function of the relative capacity factors within each zone.
- The trend towards more storage at higher CFE scores is observed in all regions.
- Areas of high demand receive more investment under our current model design.
- However, under an alternative a model design where CFE consumers could use interconnectors to tap into renewable resources in other regions, the distribution of new-build across all nodes could be quite different.

[1] Single-node modelling approach: In our study, we have applied CFE participating demand to one grid zone at a time and then aggregated the results together, ignoring potential inter-zone effects on CFE demand and behaviour. This is because of current model limitations of solving multiple adjacent grid zones at a time. A study where CFE participating demand is simultaneously applied to all grid zones may show different outcomes.

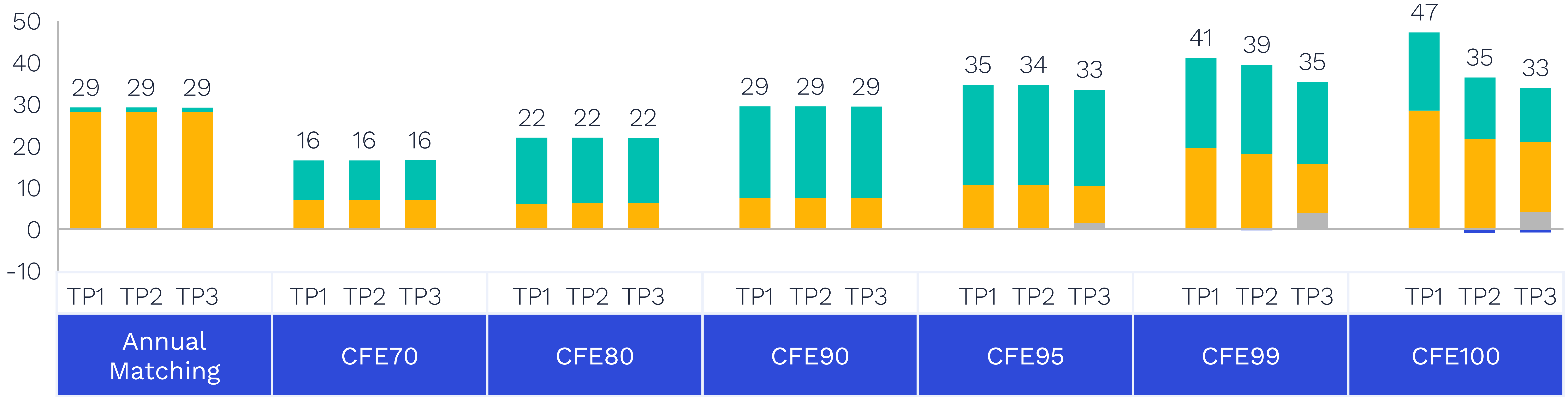
Source: TZ modelling.

Solar and batteries must grow exponentially to go beyond CFE 95 – unless other technologies are present to contain this capacity expansion

Greenfield build-out – national total[1] (GW)



Greenfield generation – national total[1] (TWh)



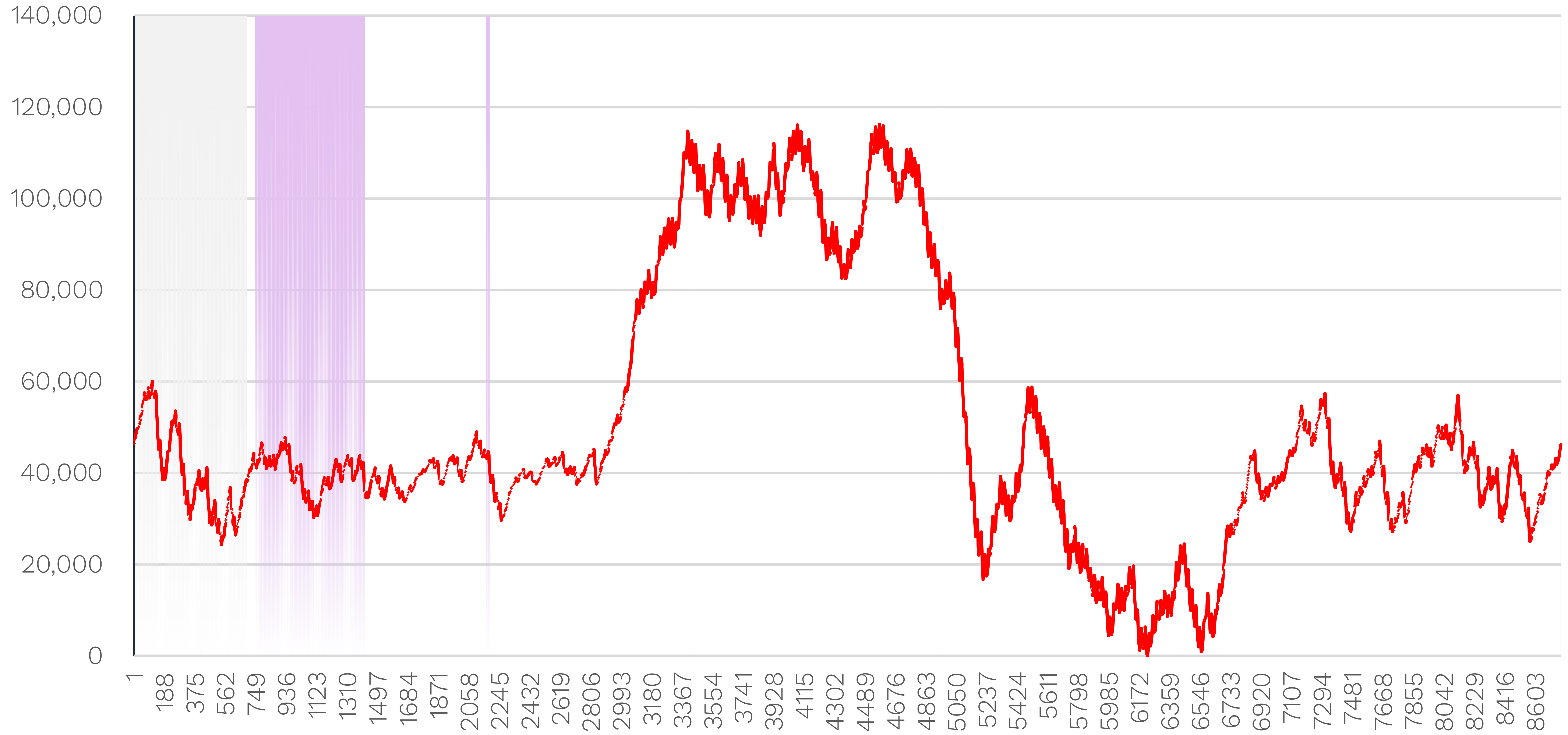
Notes

- The strong preference for solar in the annual matching regime occurs because solar is cheap and hourly matching is not required.
- Wind is preferred at lower CFE scores because unlike solar its generation is not restricted to daytime hours.
- Storage makes an appearance once CFE scores rise to 90% and above, when the brownfield grid and wind alone can no longer provide enough CFE.
- In the most challenging CFE scores it is cheaper to add solar + storage hybrid systems than to rely on wind – to the point that wind capacity actually starts decreasing.
- Adding liquid air energy storage (LAES) in TP2 significantly reduces the need for batteries due to the longer storage duration of the former, although in CFE 100 solar must still expand materially above the level of CFE 99.
- Of the three considered innovative thermal technologies, Gas CCS proves attractive because it produces much more CFE. Due to its ability to dispatch flexibly its starts noticeably reducing reliance on solar and storage capacity from CFE 95 onwards.

[1] Single-node modelling approach: In our study, we have applied CFE participating demand to one grid zone at a time and then aggregated the results together, ignoring potential inter-zone effects on CFE demand and behaviour. This is because of current model limitations of solving multiple adjacent grid zones at a time. A study where CFE participating demand is simultaneously applied to all grid zones may show different outcomes.

The additional energy storage in Tech Palette 2 stores energy for up to a week, assisting with seasonal demand peak management

LAES hourly state of charge in Tokyo under CFE 99 (MWh)



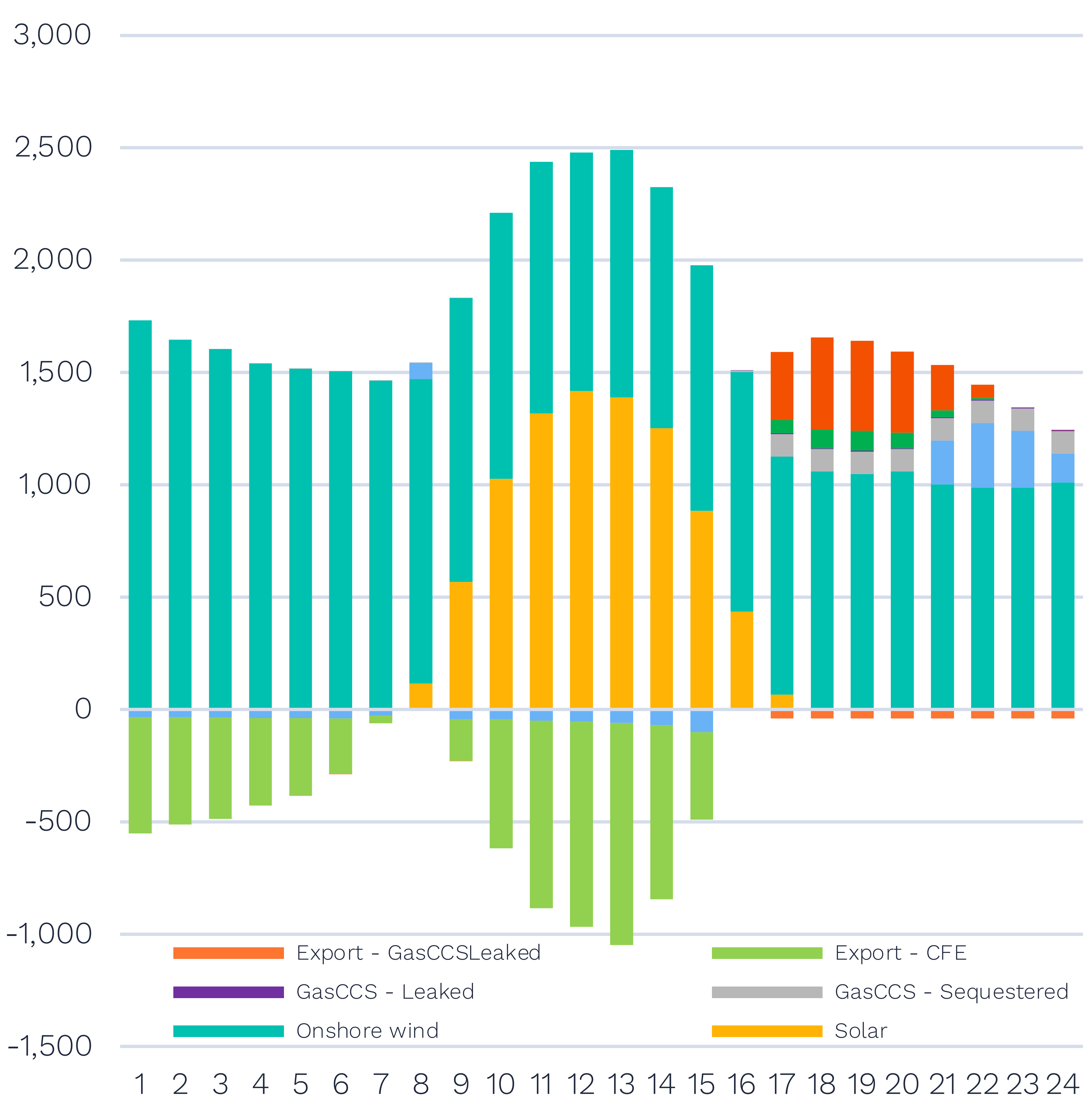
Notes

- In this project we assume that the consumption profile of consumers interested in 24/7 CFE matches that of other consumers, but if the two diverge, the utilisation profile of long-duration energy storage may shift considerably

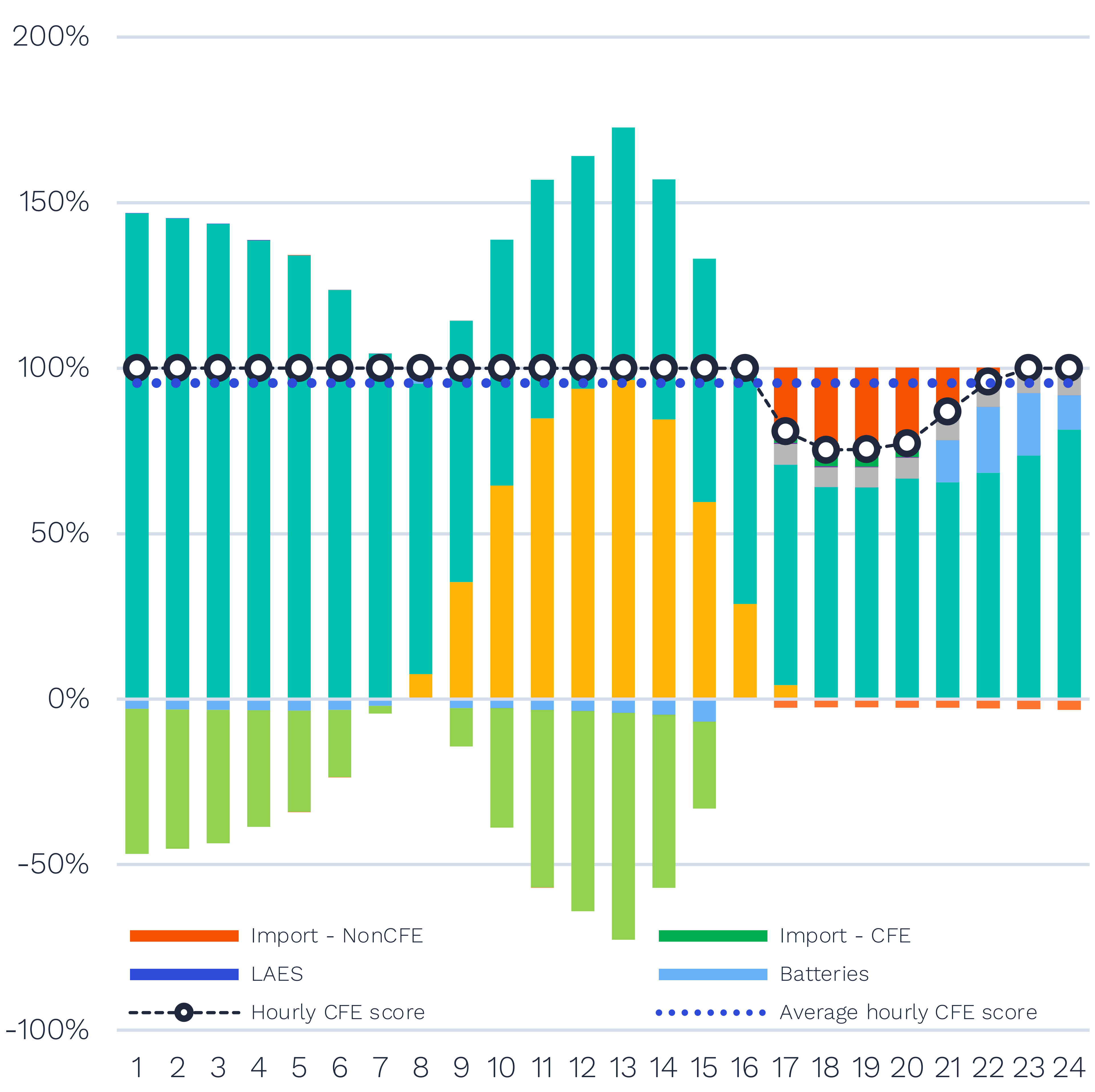
Source: TZ modelling.

In Tech Palette 3 innovative thermal technologies can still contribute to CFE scores despite causing some emissions

Hourly generation breakdown (MW)



Hourly generation share breakdown (%)



Notes

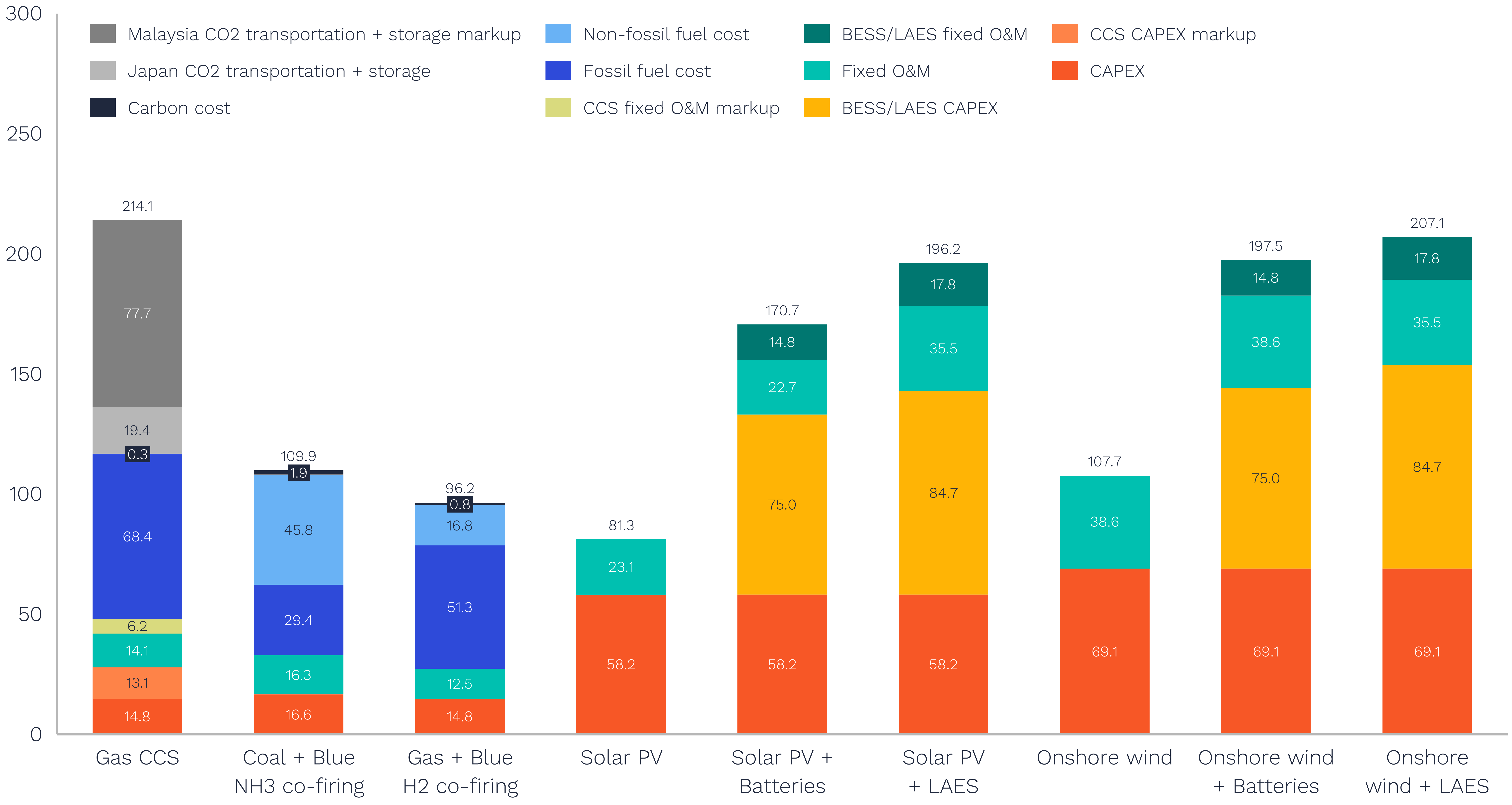
- The charts show the activity on the greenfield, including trade with the brownfield, under CFE 95 for the Tokyo region during 24 hours of a representative day.[1]
- Under this scenario the model chooses to build very few batteries, so when the renewable generation is insufficient, grid electricity along innovative thermal (here: gas CCS) compensates.
- Imports cover most missing electricity demand, but to ensure that the average CFE score stays at 95% despite the presence of emitting electricity in the imports from the brownfield, the model also chooses to build CCS.
- Much of the non-CFE component of CCS generation must be immediately exported to the brownfield, leaving the PPA offtaker to consume only the CFE component, so that the target average CFE score of 95% is respected.
- This need to offload non-CFE generation becomes more stringent under higher CFE scores.

[1] *25 January 2030..*

Source: TZ modelling.

While widening technological scope adds flexibility, the resulting capacity mix is very sensitive to cost assumptions

LCOE by technology[1] (USD/MWh)



Notes

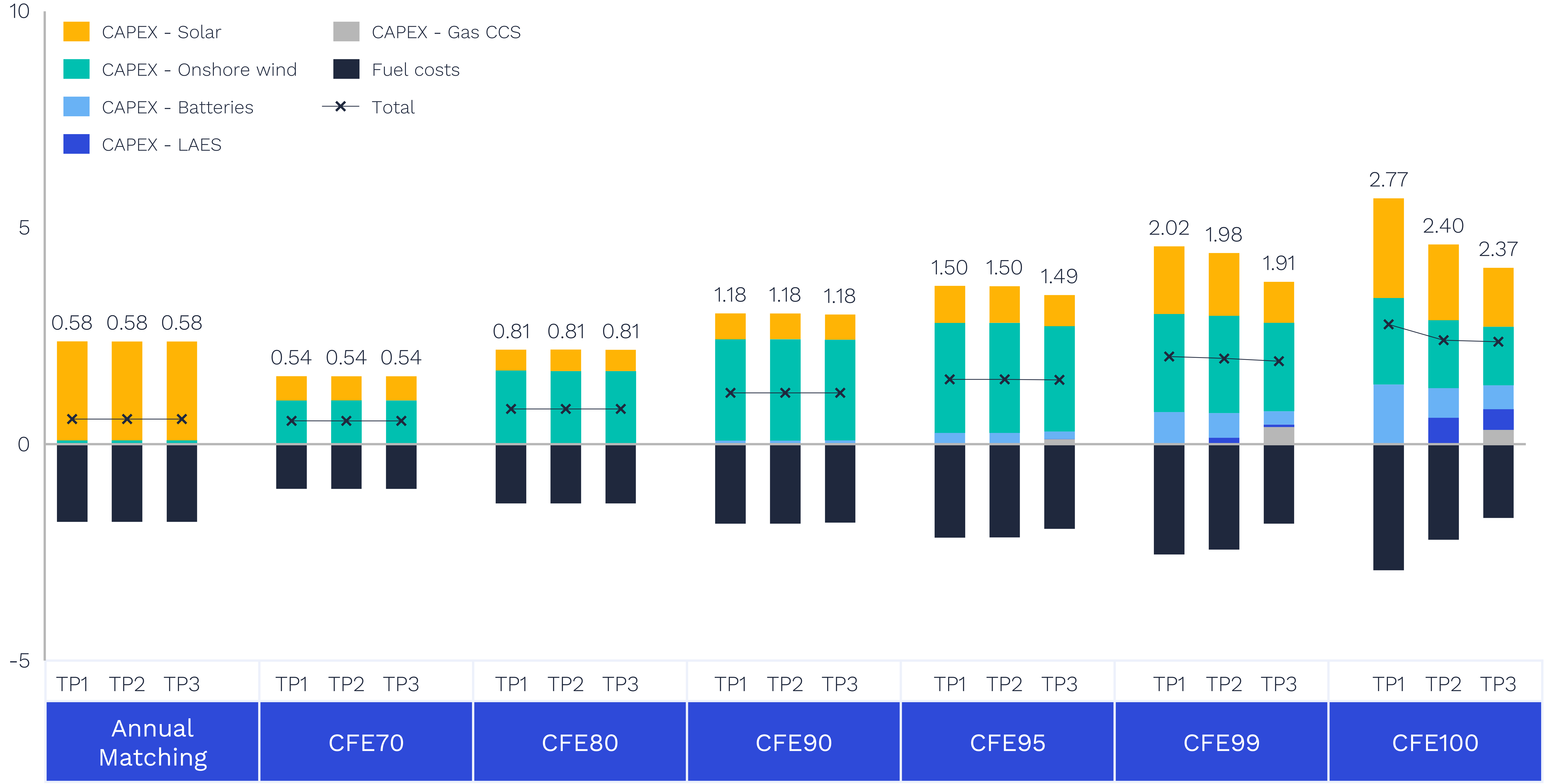
- At standard capacity factors[1] the technologies with the lowest levelised cost of electricity (LCoE) are solar PV and onshore wind, even after adding storage to form hybrid plants.
- Of all innovative thermal technologies, gas CCS is the only one that can compete with hybrid plants on cost; however, our model findings show that transporting the CO2 out of Japan can have a material negative impact on the competitiveness of CCS.
- One factor beyond LCoE affecting technology uptake is the ability to meet greenfield electricity demand while minimising costs. The model may prefer higher LCoE technologies that are freely dispatchable to cover lulls in renewable generation that cannot be cheaply covered by storage.
- An additional factor is a technology's ability to contribute to the target CFE score. This checks the uptake of innovative thermal technologies like ammonia and hydrogen co-firing. For these technologies, the non-CFE component makes their LCoE more expensive while simultaneously not contributing towards offtakers' CFE consumption. Low sequestration rates for CCS likewise negatively affect its competitiveness.

[1] Maximum 70% for the thermal technologies including gas CCS, coal-ammonia, and gas-hydrogen cofiring, in our LCOE calculation. In addition, we have applied capacity factors of 16% for solar and 24% for onshore wind (Tokyo region). Maximum capacity factors of 25% for batteries and 35% for LAES according to observed model run results.

Source: TZ modelling.

CAPEX[1] is the main driver of costs, which long-duration storage can help mitigate – and under some circumstances CCS can too

Breakdown of economic costs and benefits by category[2] (USD Billion)



Notes

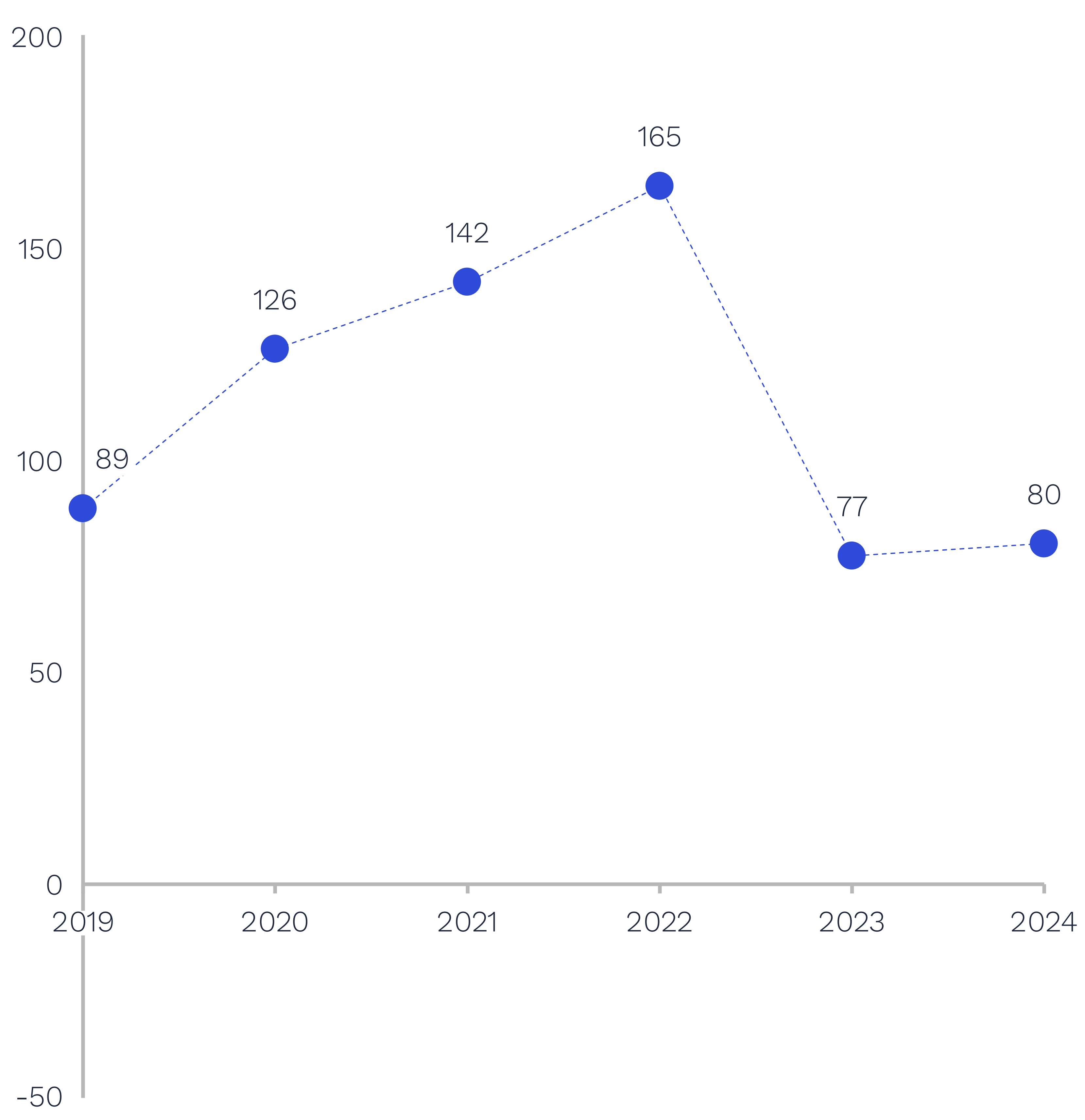
- Storage requirements rise along with CFE scores: looking at nationwide totals, the annualised CAPEX from the extra storage alone required for going from CFE 90 to CFE 100 (USD 1.3 billion) exceeds the original total system costs of reaching CFE 90 itself.
- The availability of dispatchable LAES or and gas CCS strongly reduces overall system costs by cutting CAPEX on renewables and storage – although there are much more modest fuel savings. This is because excess renewable generation is absorbed for later use, and because the CCS plant does itself consume natural gas.

[1] CAPEX figures shown are annualised, based on the assumed lifetime of individual assets and discounted to present value.
[2] Single-node modelling approach: In our study, we have applied CFE participating demand to one grid zone at a time and then aggregated the results together, ignoring potential inter-zone effects on CFE demand and behaviour. This is because of current model limitations of solving multiple adjacent grid zones at a time. A study where CFE participating demand is simultaneously applied to all grid zones may show different outcomes.

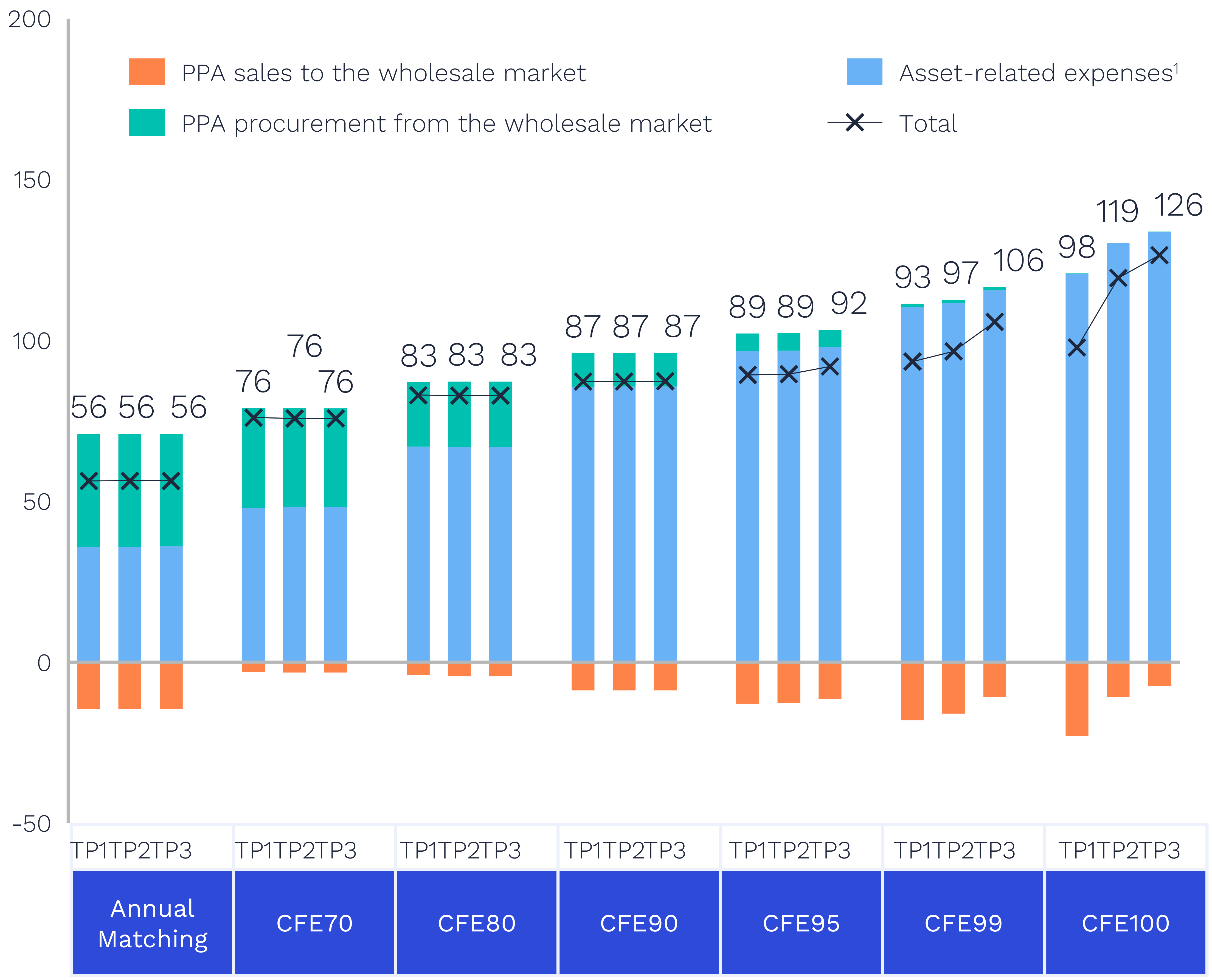
Source: TZ modelling.

Consumer costs rise alongside CFE scores, though not as sharply as capacity requirements

Historical wholesale market price[3] - national average weighted by regional CFE load[2] (USD/MWh)



PPA unit costs - national average weighted by regional CFE load[2] (USD/MWh)



Notes

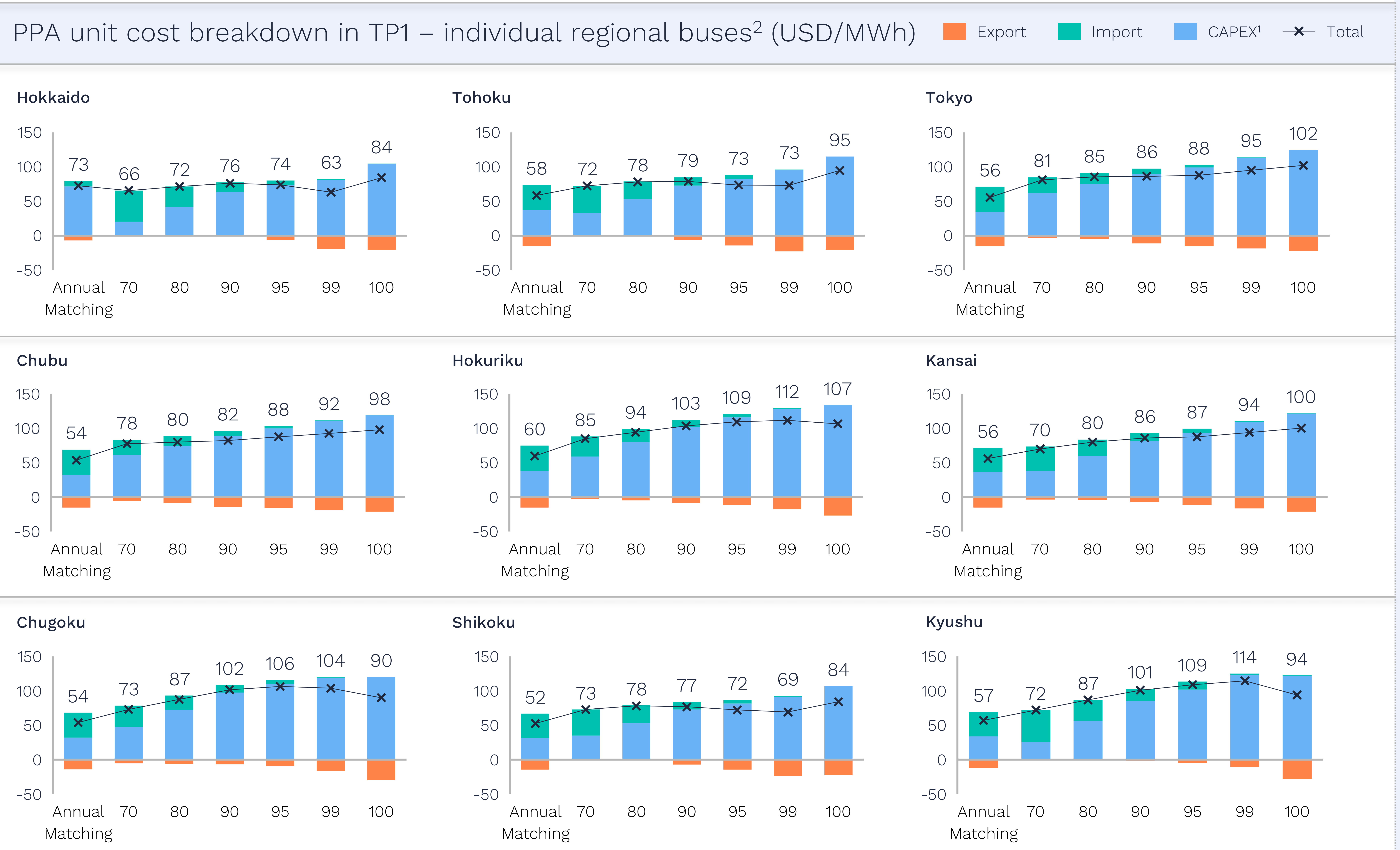
- While total nationwide capacity requirements increase up to 4-fold in the transition from CFE 70 to CFE 100 in TP1, unit costs borne by offtakers escalate by less than 30%.
- At the highest CFE scores PPA unit costs rise across palettes because while CAPEX expenditures fall, the amount of electricity generated falls faster. In TP3, PPA offtakers must also pay for the fuel being used in CCS plants.
- PPA unit costs still compare favourably to wholesale prices in recent years.

[1] The CAPEX component of the asset-related expenses shown are annualised, based on the assumed lifetime of individual assets and discounted to present value.
[2] Single-node modelling approach: In our study, we have applied CFE participating demand to one grid zone at a time and then aggregated the results together, ignoring potential inter-zone effects on CFE demand and behaviour. This is because of current model limitations of solving multiple adjacent grid zones at a time. A study where CFE participating demand is simultaneously applied to all grid zones may show different outcomes.
[3] 30-min interval wholesale market prices data sourced from JPEX Day Ahead Market across all 9 grid regions and each aggregated at the yearly average level followed by conversion to USD using corresponding year average exchange rate and denominated to 2023 real money base year.

Source: TZ modelling.

The better the wind resource, the cheaper the PPA unit costs

PPA unit cost breakdown in TP1 – individual regional buses[2] (USD/MWh)



Notes

- All regions need onshore wind to compensate for the hours when solar and batteries can no longer provide CFE.
- Strong capacity factors for wind correlate with lowered PPA unit costs, making Hokkaido the cheapest region within which to set up a PPA and reach CFE 100.
- Despite enjoying high solar potential, Kyushu is one of the most expensive places in the country to reach high CFE scores, because onshore wind capacity factors are notably worse than elsewhere in the country.
- The unit prices for other regions reflect this relationship between relative onshore wind capacity factors and PPA unit prices

[1] CAPEX figures shown are annualised, based on the assumed lifetime of individual assets and discounted to present value.

[2] Single-node modelling approach: In our study, we have applied CFE participating demand to one grid zone at a time and then aggregated the results together, ignoring potential inter-zone effects on CFE demand and behaviour. This is because of current model limitations of solving multiple adjacent grid zones at a time. A study where CFE participating demand is simultaneously applied to all grid zones may show different outcomes.

Source: TZ modelling.

More stringent matching regimes and higher renewable output raise interconnector utilisation

Yearly power flow – national total[1] (TWh)

Notes

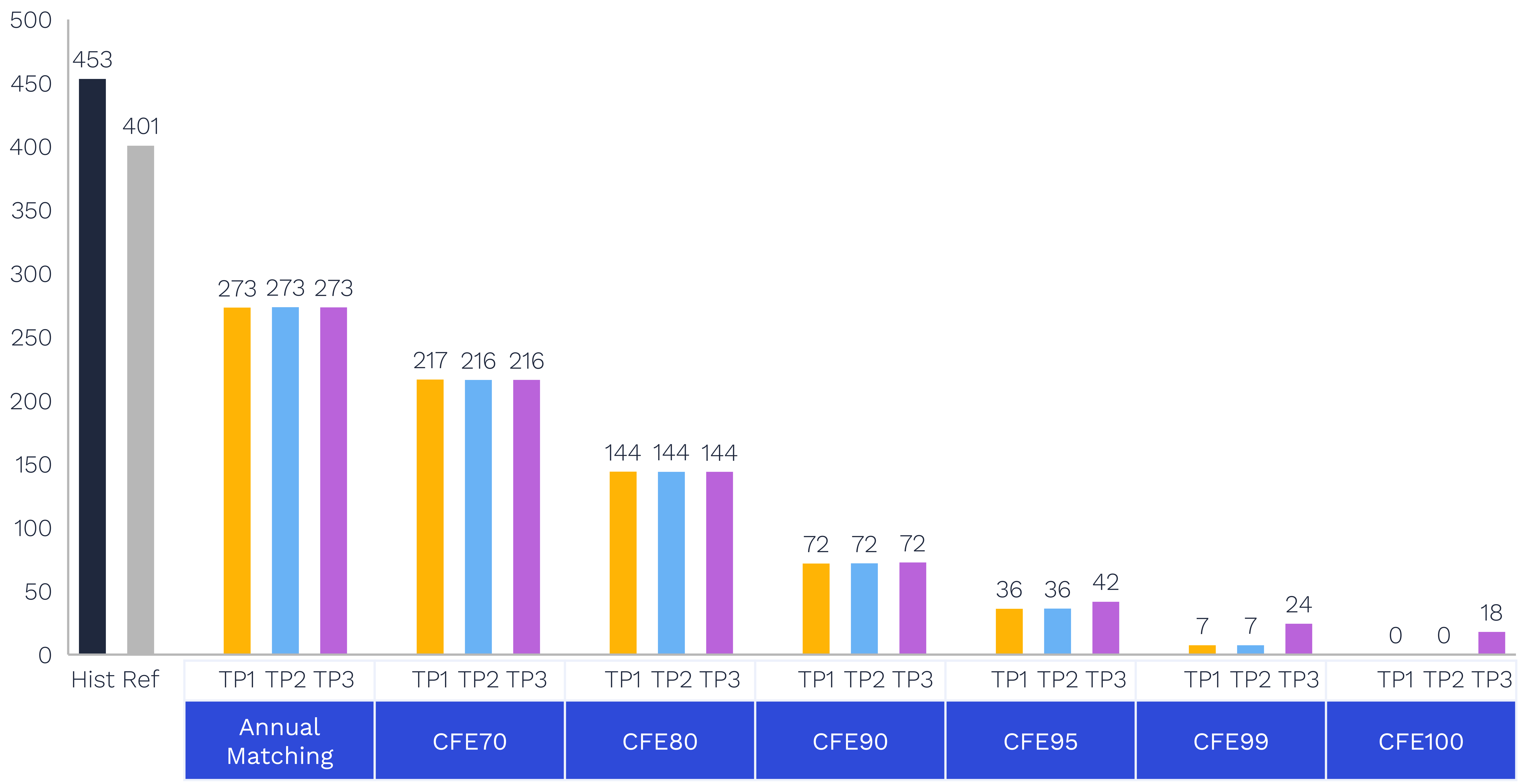
- Regardless of the technology palette and scenario, the majority of CFE generation comes from renewable energy sources, which frequently generate in excess of demand.
- Excess CFE generation is first stored on the greenfield to satisfy CFE demand at a l ater date or, when storage is uneconomical, sold to the brownfield. Here, it displaces thermal generation not only in the local brownfield but also in neighbouring zones, thereby increasing interconnector utilisation.
- The effects are more muted in the technology palettes 2 and 3, where much less excess renewable capacity is required, and therefore less excess generation is present.

[1] Single-node modelling approach: In our study, we have applied CFE participating demand to one grid zone at a time and then aggregated the results together, ignoring potential inter-zone effects on CFE demand and behaviour. This is because of current model limitations of solving multiple adjacent grid zones at a time. A study where CFE participating demand is simultaneously applied to all grid zones may show different outcomes.

Source: TZ modelling.

As more of the C&I load is met with CFE, Scope 2 emissions are progressively eliminated

Emission intensity of C&I electricity consumption[1] – national average weighted by CFE load (gCO_2e/kWh)



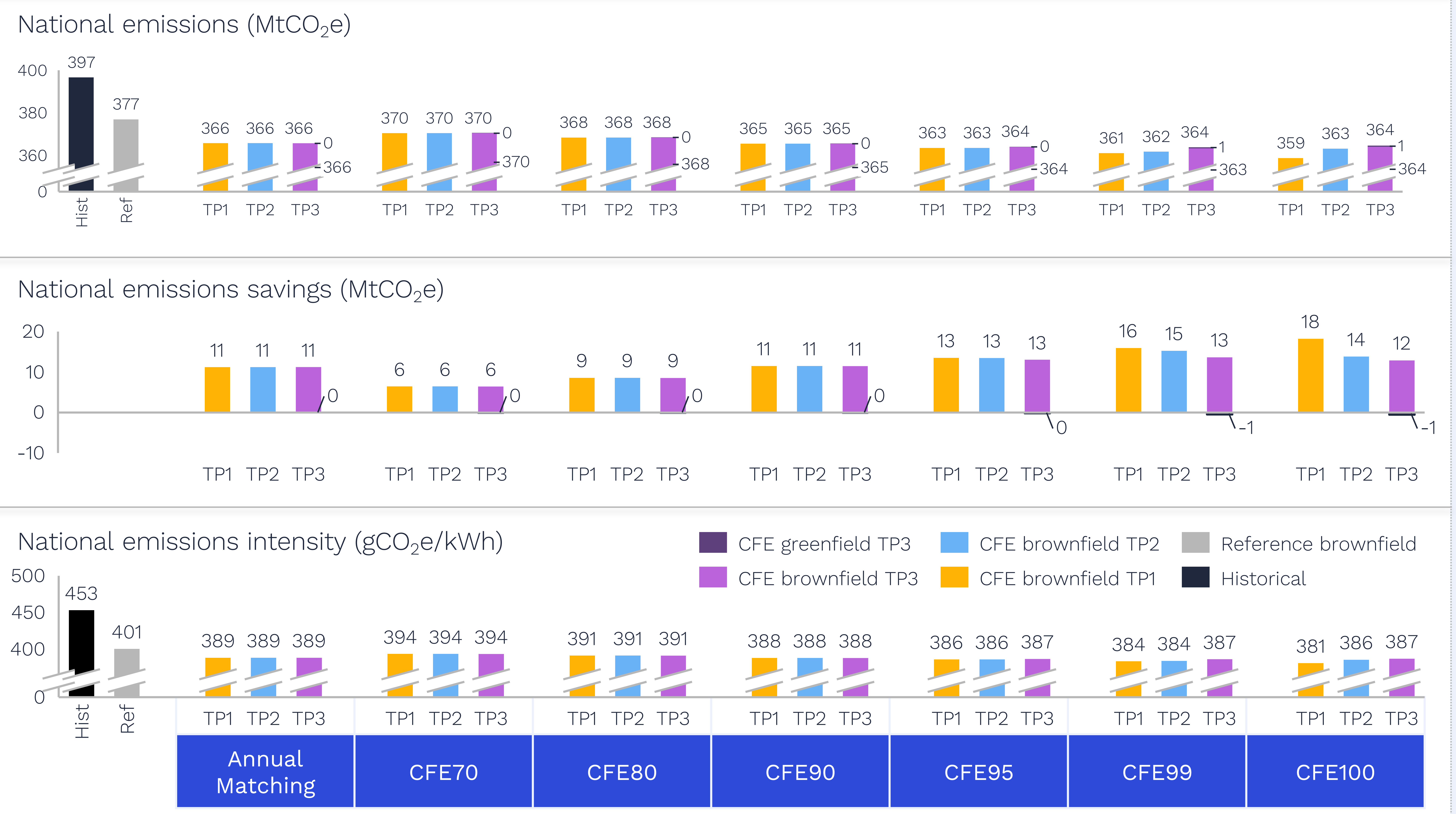
Notes

- Any CFE regime is better than annual matching for reducing the emissions intensity of C&I consumers' Scope 2 emissions, because under annual matching they must rely on many hours on non-CFE grid electricity.
- The emissions impact is lowest at CFE 70 because here C&I consumers continue to rely the most on grid electricity, which continues to be powered by the same generators as in the Reference Scenario.
- As CFE scores increase, the emissions impact of excess CFE generation sold back to the brownfield grid further pushes up the emissions impact.
- The presence of leaked emissions from innovative thermal plants under TP3 means that even under CFE 100 it is impossible to reduce emissions intensity to zero.

[1] Single-node modelling approach: In our study, we have applied CFE participating demand to one grid zone at a time and then aggregated the results together, ignoring potential inter-zone effects on CFE demand and behaviour. This is because of current model limitations of solving multiple adjacent grid zones at a time. A study where CFE participating demand is simultaneously applied to all grid zones may show different outcomes.

Source: TZ modelling.

The benefits of 24/7 CFE extend beyond neutralising the climate impact of new demand



Notes

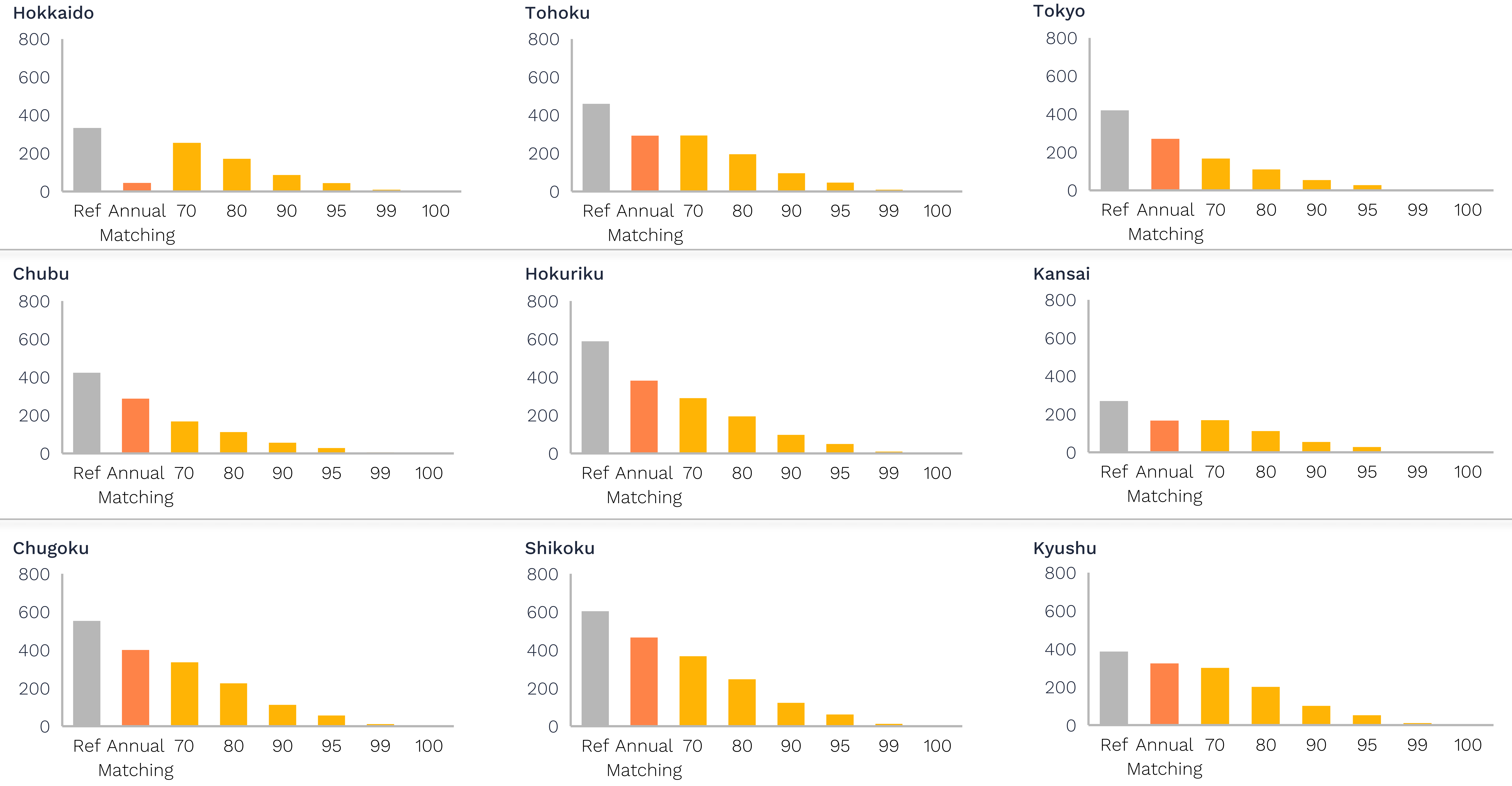
- Any CFE matching regime, even the annual one, will eliminate emissions that would have resulted from consuming brownfield electricity, which contains thermal generation.
- Annual matching regime impacts national emissions more than CFE 70 or 80 because this regime must generate the CFE equivalent to the full volume of C&I consumers' demand, just like CFE 100.
- Given our assumption that new CFE load in 2030 would be about 3% of Japanese power demand, the emissions impact from annual matching (11 $MtCO_2e$) compared to the power sector total for the Reference Scenario (377 Mt) represents the expected impact of neutralising the climate impact of new load.
- However, under CFE 100, the emissions impact is higher because the push towards hourly matching incentivises more generation capacity than under annual matching, which accordingly results In the higher CFE generation that delivers the abovementioned higher emissions savings.
- Tech Palette 2 reduces national emissions less than Tech Palette 1 because long-duration storage soaks up excess CFE in many hours, releasing it later for C&I consumers' use, rather than releasing it for immediate consumption by brownfield consumers.
- Tech palette 3 provides only modest emissions cuts relative to the previous palettes, although with the proviso that offtakers are now directly responsible for leaked emissions.

[1] Single-node modelling approach: In our study, we have applied CFE participating demand to one grid zone at a time and then aggregated the results together, ignoring potential inter-zone effects on CFE demand and behaviour. This is because of current model limitations of solving multiple adjacent grid zones at a time. A study where CFE participating demand is simultaneously applied to all grid zones may show different outcomes.

Source: TZ modelling.

All grid zones except Hokkaido show stronger cuts in off-takers emissions intensity when moving from annual matching to hourly matching beginning at CFE 70 or CFE 80

Emissions intensity of C&I electricity consumption (gCO_2e/kWh)



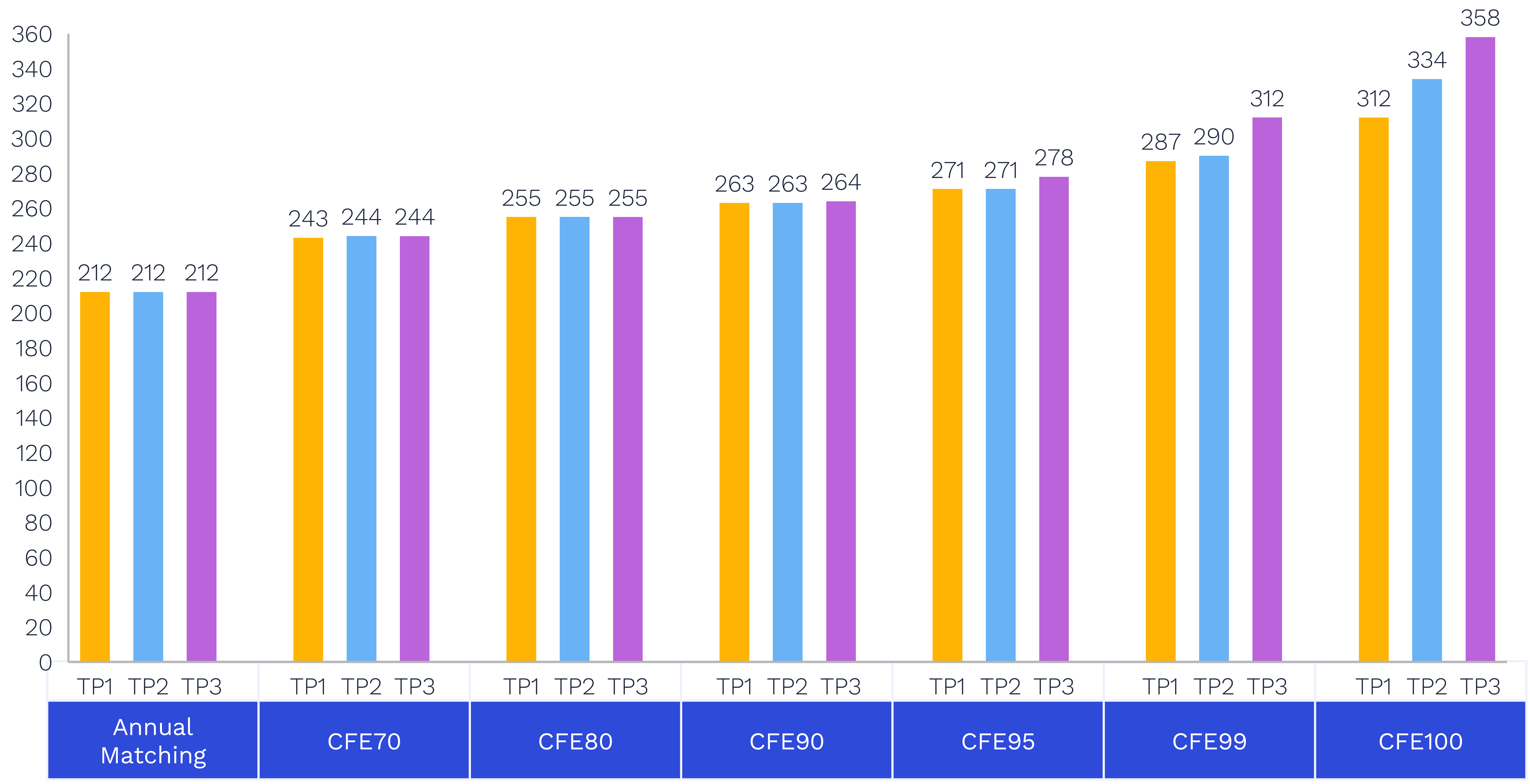
Notes

- The emissions intensity of C&I consumers is strongly influenced by the underlying grid's cleanliness and the availability of local wind resources. Since emissions are largely driven by imports from the existing grid, regions with cleaner grids and higher wind potential tend to see lower off-takers emissions. Unlike solar, wind generation is not limited to daylight hours, making it more effective in reducing reliance on brownfield imports.
- In Hokkaido, where onshore wind resources are abundant, off-takers emissions intensity is already low under annual matching. This performance is only matched by hourly matching at CFE 95 and above primarily because C&I consumers in Hokkaido can meet all of their demand using overbuilt wind capacity and do not rely on the existing grid at all.

Source: TZ modelling.

Abatement cost increase by about a third for offtakers moving from annual matching to hourly matching at CFE 100

Abatement cost born by all offtakers[1] (USD/tCO_2e)



Notes

- The abatement costs expressed here are national total costs, across CAPEX and OPEX (including fuel consumption from thermal plants on the greenfield) for PPA assets, divided by total variation of emissions (including leaked emissions from thermal plants on the greenfield).
- In Tech Palette 1, we see the doubling of the abatement cost during the transition from annual matching to hourly matching at CFE100.
- Broadening the tech palette reduces the total required CAPEX and OPEX that the offtaker must pay, but it also diminishes the emissions savings. The latter effect is due to the reduction of excess renewable generation.
- In the Japanese context, CAPEX and OPEX decrease more slowly than the emissions reduction do. As a result, the offtaker bears a higher abatement cost when moving from TP1 through TP2 to TP3.

[1] Carbon abatement cost is calculated as the CAPEX and OPEX expenditures of all PPAs divided by tCO_2e of nation-wide system emissions savings.

Source: TZ modelling.

Conclusions

Incorporating CFE 24/7 into Japan's energy transition

Carbon free electricity can bring benefits to both the system and C&I consumers

Supporting policy and clear price signals are needed to further incentivise CFE procurement

01

Targeting 90% CFE for C&I consumers provides multiple benefits for the power sector in 2030.

Hourly matching at 90% CFE is comparable to annual matching both in terms of nation-wide emissions cuts and savings on fuel utilisation for the Japanese power system but allows C&I consumers to achieve 74% lower emission intensity than annual matching does.

If they trade excess generation from CFE assets, PPA offtakers can still enjoy high levels of CFE at a PPA unit cost often cheaper than the average of annual wholesale electricity prices for all years since 2019, which is in turn often set by fossil gas.

02

Widening the technological palette allows a more efficient use of limited renewable resources.

Much of the soaring investment costs involved in the material expansion of renewables and battery storage required for achieving the highest CFE scores can be avoided by drawing on emerging technologies.

The innovative thermal technologies that the Japanese government is interested in seem able to compete with long-duration storage in a limited set of circumstances, but results are sensitive to untested assumptions, and not all C&I consumers will approve of the emissions that will inevitably still occur in 2030.

03

Interconnectors can enable remote renewable resources from low-demand areas to be delivered to high-demand load centres.

The slow-down in renewables uptake throughout Japan means that an unprecedented turn-around of capacity expansion must take place if each zone is to meet its CFE demand locally.

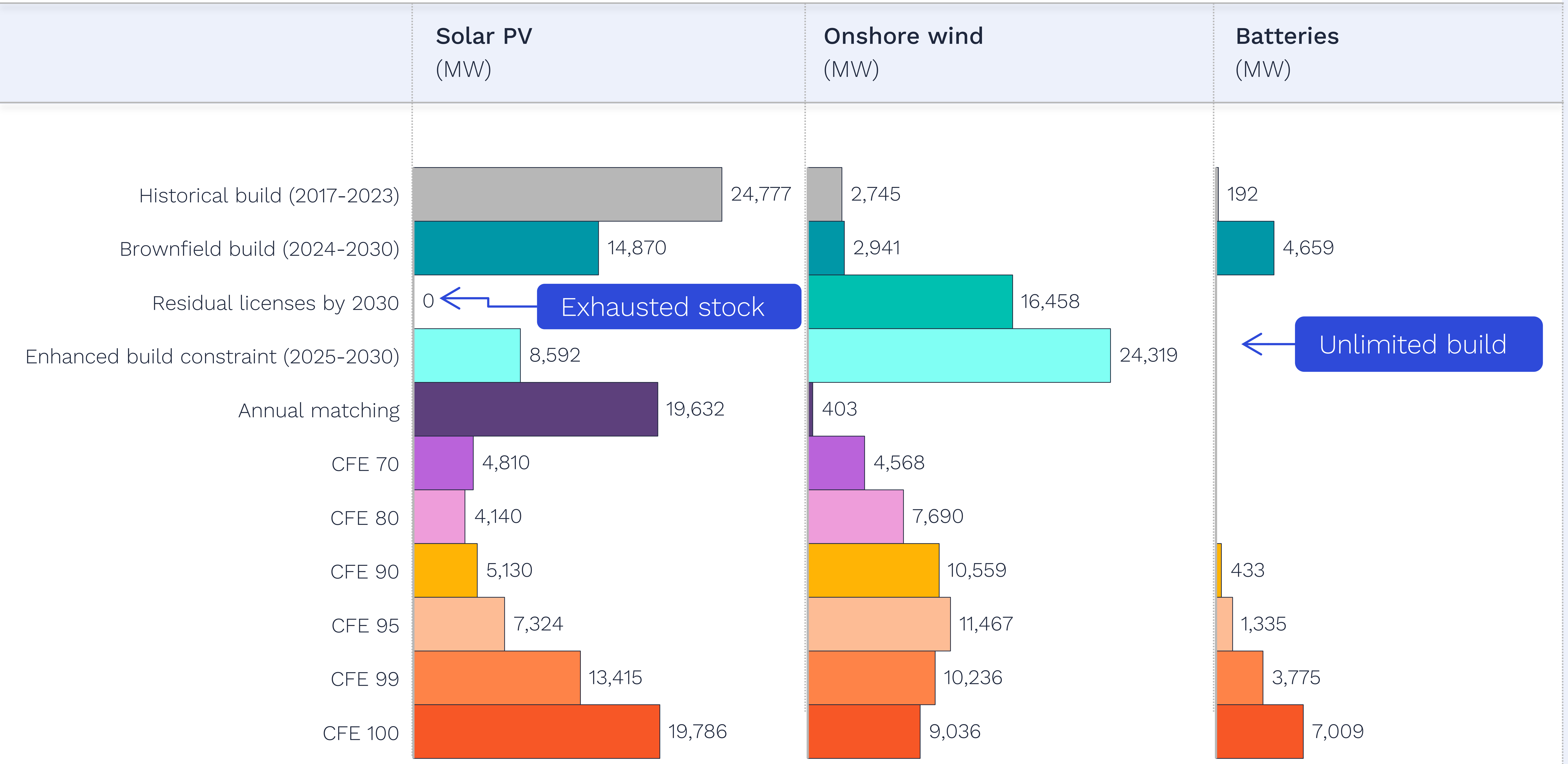
However, because many low-demand zones have a great untapped potential for renewable generation, it is advisable to facilitate an increased utilisation of interconnectors to bring this remote CFE to the C&I consumers who desire it.

Sensitivity analysis

What happens with alternative assumptions?

Strain under Tech Palette 1

For CFE scores beyond 95% build-out rates must overcome the recent slump for solar, and must materially exceed current ambitions for batteries



Notes

- In our Reference Scenario we include ex ante an expected expansion of renewable capacity that continues historical trends until 2030; in contrast for our PPA assets we allow the model to build capacity without any constraints.
- However, in Japan the commissioning of solar has outpaced licensing of new sites, so even accounting for new licensing at historical rates until 2030 the business-as-usual expansion exhausts all new sites before any CFE scenarios.
- Any additional solar capacity therefore requires an expansion at a licensing rate faster than the recent past – but we decided to tolerate this in our first analysis because we wished to explore just how much more capacity 24/7 CFE would require.
- To model the realistic pull that additional CFE demand would have on renewable supply chains we decided to explore how the system would take advantage of a doubled licensing rate in each zone, imposed as a hard constraint.
- To allow the model to reach a feasible solution, we keep build-out for batteries, liquid air energy storage, and innovative thermal plants completely unconstrained, while acknowledging the strain this would place on supply chains.

[1] *Average for past 7 years, accounting for the gap between our calibrated base year of 2023 and our target year of 2030.*

Source: TZ modelling.

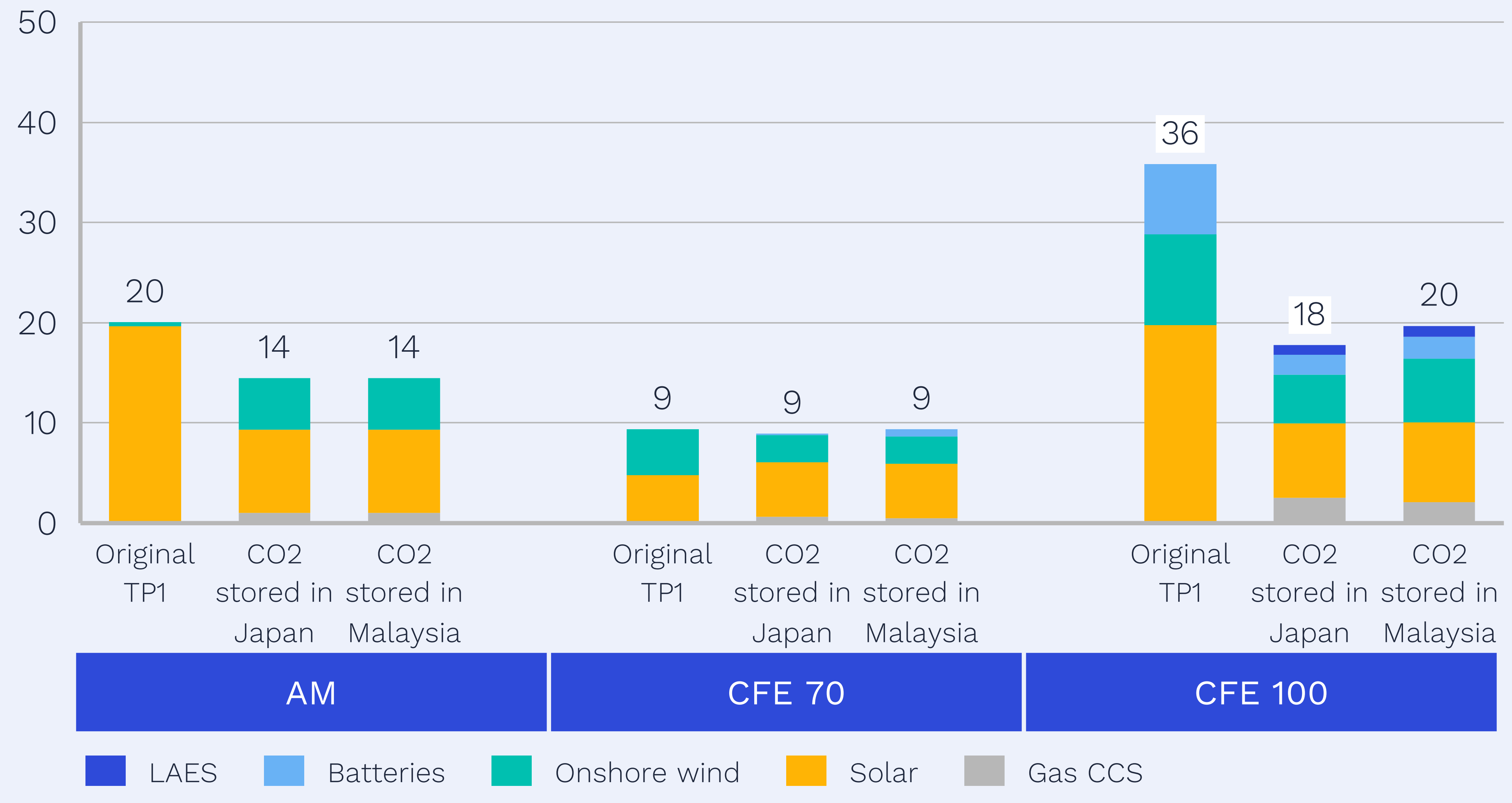
Constraining renewables (1/2)

Alternative technologies quickly emerge even with higher renewable build limits

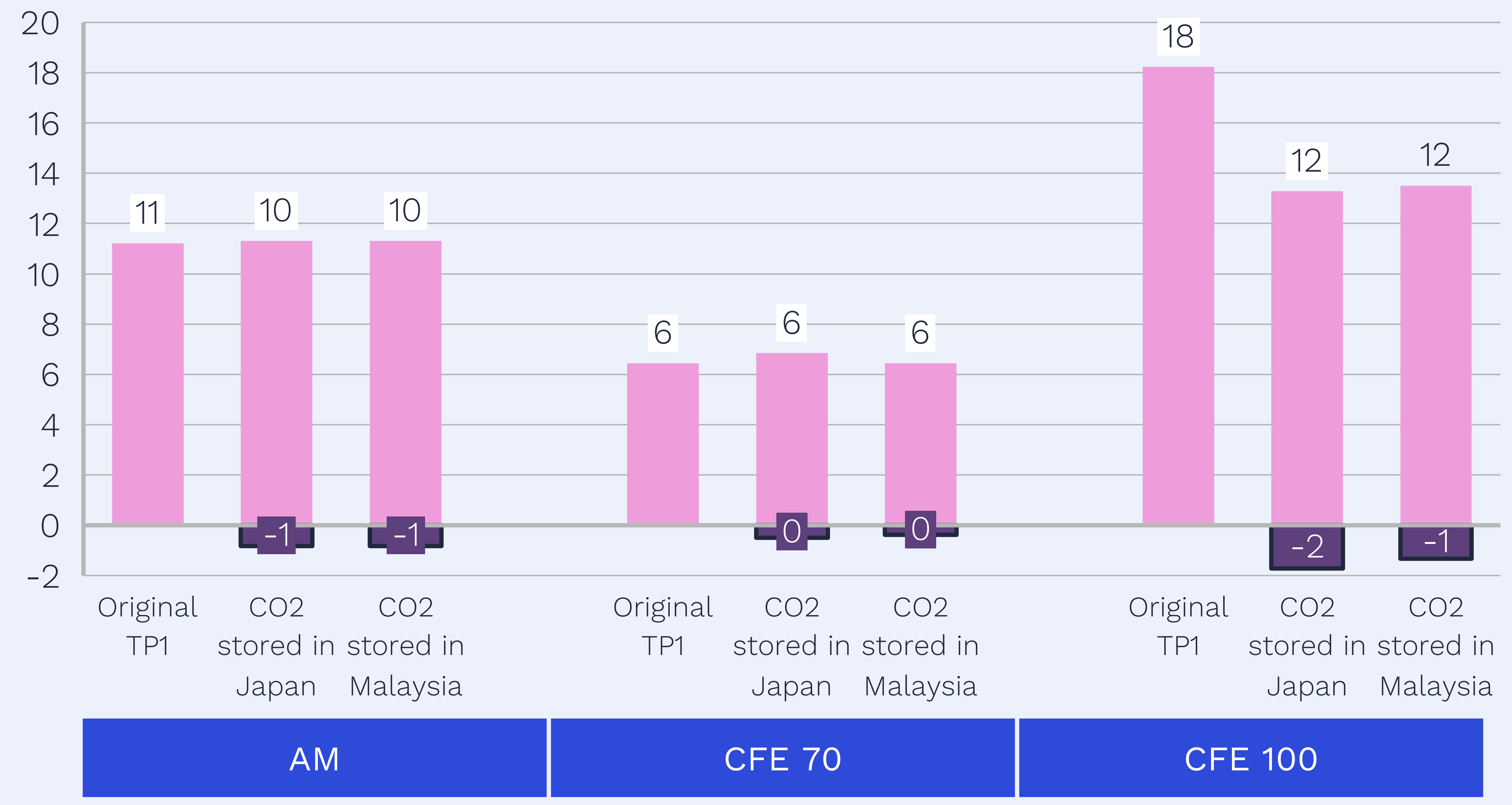
1. **To account for limits on maximum renewable capacity we allowed the model to build all technologies.** The build constraints for renewables were set loosely, equal to a doubled licensing rates for solar and onshore wind in each region relative to the past 7 years. The intention was to represent a more favourable business environment, characterised by more demand for assets and more favourable policies for siting new projects. Batteries, liquid air energy storage, and CCS face no build constraints.
2. **We explored a wide range of costs for innovative thermal.** Having observed earlier that restricting CO_2 storage to Malaysia eliminates CCS from the capacity mix when renewables build-out is unlimited, we decided to explore storage both in Japan and in Malaysia as sensitivities.
3. **Innovative thermal competes with renewables from the start.** As each zone has it's own constraints on both solar and onshore wind, alternative technologies become quickly necessary – even under annual matching. The cost assumptions for innovative thermal options and liquid air energy storage generally favour CCS, regardless of the storage option made available. However, a different technology palette composition (e.g. geothermal, brownfield assets, etc.) or a more flexible examination of the role of interconnectors may reduce the role of CCS.
4. **The main competition is between storage and innovative thermal.** With less renewable capacity, storage also diminishes. However, imposing more expensive transportation and storage in Malaysia reduces CCS capacity and adds storage. Compared to TP1, the preferred storage option is liquid air energy storage, due to its superior duration relative to batteries. Nevertheless, conventional batteries also still emerge in considerable volumes.
5. **The required investment levels appear more achievable.** Nationwide CCS levels are 2.1-2.5 GW, while storage is 2.9-3.2 GW — comparable to LNG and battery investment sought over 3 years under the Long-term Decarbonised Power Auctions.
6. **This technological flexibility dents national emission reductions.** The increased role of liquid air energy storage soaks up excess renewable generation for the use of the offtaker, limiting the reduction in fossil fuel use on the regular grid. Furthermore, leakages from CCS produce their own emissions.

Buildout by 2030 (GW)

Dispatchable technologies reduce the need for overbuilding for low renewable output hours



National emissions impact (Mt)



Source: TZ modelling.

Constraining renewables (2/2)

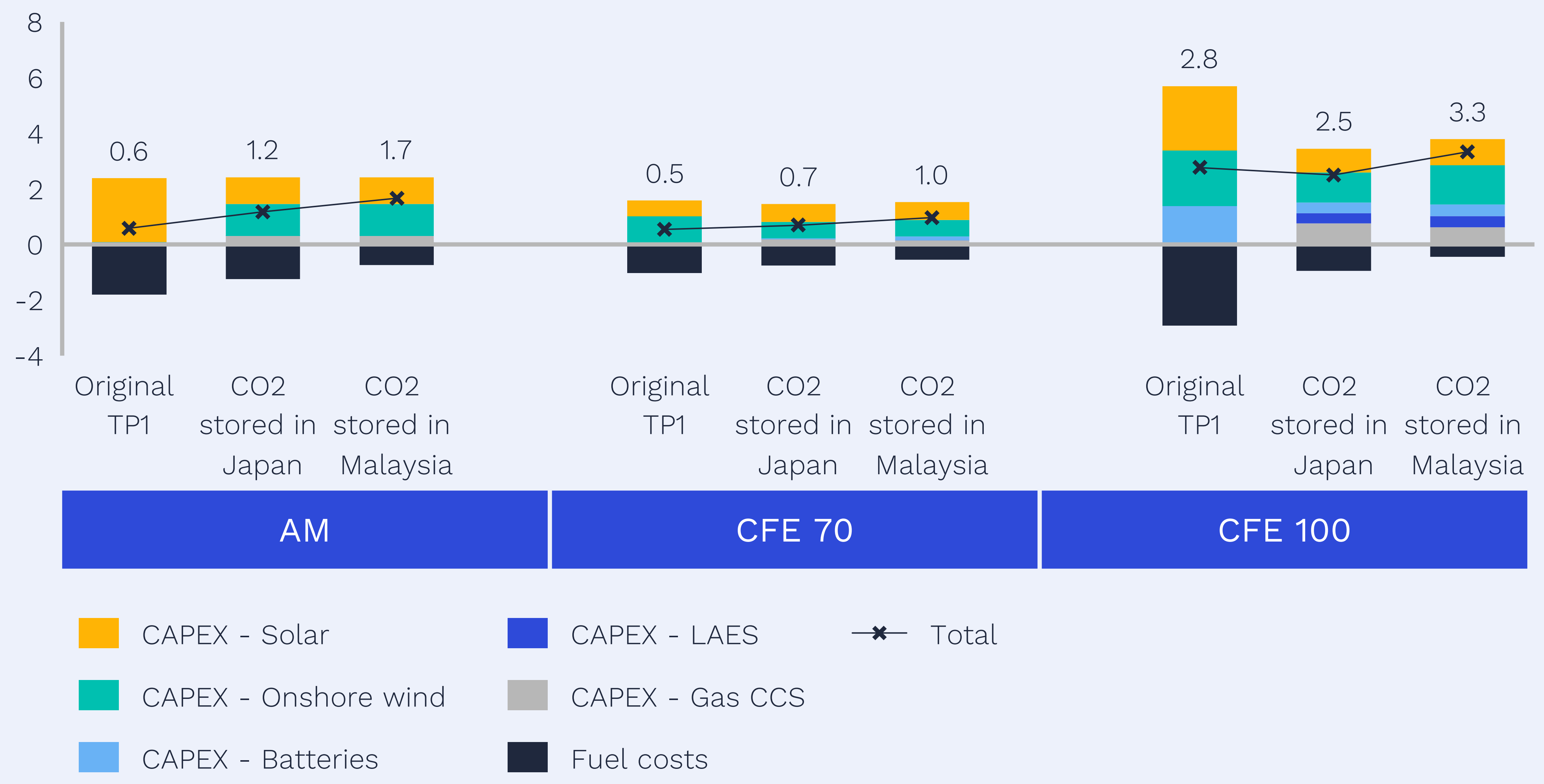
Once cheap renewables are exhausted, costs climb quickly

1. **Higher CAPEX raises total system costs in all scenarios.** As individual zones reach their maximum solar build constraints, they must reach for more expensive technologies– first wind, then technologies from other palettes. Thanks to it's lower costs and ability to freely dispatch, CCS outcompetes storage under CFE 70, but under CFE 100 both batteries and liquid air storage step in to limit the escalation of costs that more CCS would cause.
2. **Fuel cost savings contract in all scenarios, further raising total system costs.** Less renewable generation translates into less exports to the brownfield, thereby suppressing fuel savings for pre-existing generators. Additionally, expenditure on fuel use in the new greenfield CCS plants constitutes a positive cost.
3. **More demanding matching regimes discourage investment in expensive CO_2 shipping.** Shipping to Malaysia is obviously much more expensive than transporting it to a storage location within Japan, so CAPEX on CCS goes down by 25% in CFE 70 and 20% in CFE 100. The additional shipping expense also drastically reduces fuel savings, as it constitutes a material increase in positive costs associated with gas use. Therefore, the optimisation prefers building cheaper renewables instead.
4. **PPA unit costs rise faster than total system costs.** This is first driven by the diminished ability to export excess renewable generation to the brownfield, and second by the need to pay for fuel costs in CCS plants – with shipping costs to Malaysia constituting a material additional impact.

Source: TZ modelling.

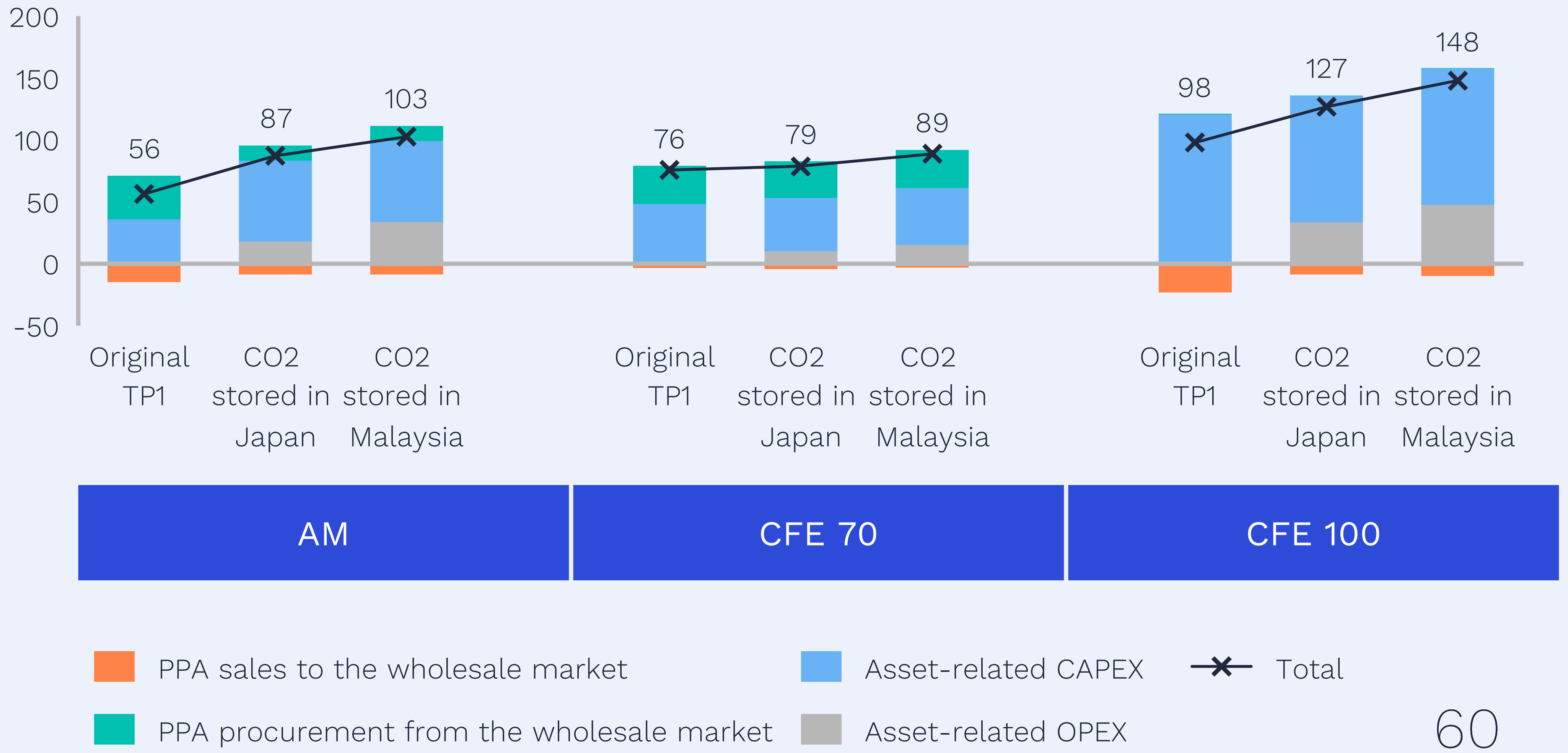
System-wide costs (Billion USD)

Constraining renewables lowers offtakers' overall expenditures…



PPA unit cost (USD/MWh)

…but burning gas and transporting CO_2 further away ends up costing offtakers more per MWh



Annex

Further information, data and assumptions

Glossary (1/3)

Term	Definition
Brownfield generators	Total CFE and non-CFE capacity mix forming the basis of our Reference Scenario, required by 2030 to meet overall electricity demand, resulting from a mixture of present capacity and new-build to account for variations in demand, retirements of current plants, and restart of idled plants
Brownfield procurement	CFE procured by C&I consumers from brownfield generators from the same grid zone when contracted same-zone greenfield generators are insufficient to cover CFE demand
C&I	Commercial and Industry
CFE	Carbon-free electricity, including renewables, nuclear power, the emission-free part of innovative thermal plants, and electricity discharging from storage technologies [after being charged up from generation from the previous categories]
Consumer CFE score	Hourly share of CFE from a consumers' total electricity consumption, resulting from both greenfield and brownfield procurement
DISCOM	Distribution Company

Glossary (2/3)

Term	Definition
Grid CFE score	Hourly share of CFE within all brownfield generation from a single grid zone
Grid zones	The nine regional grid zones in Mainland Japan, i.e. Hokkaido, Tohoku, Tokyo, Chubu, Hokuriku, Kansai, Chugoku, Shikoku, Kyushu.
Imports	Flows across interconnectors from adjoining grid zones to satisfy demand for electricity generally or CFE specifically
Innovative thermal	Thermal plants that are either equipped carbon capture (capacity adjusted for leakage) or are co-firing fuels deemed to emit no CO_2 at the point of combustion (hydrogen, ammonia, biomass)
Interconnector	Transmission-level power cables connecting two countries or two grid zones within a country
Matching regime	Modelling constraint forcing C&I consumers to reach a specified CFE score, matched either against total annual consumption or across each hour of the year
Palette	Scenario-specific combination of technologies deemed eligible for CFE status

Tech build constraints

We seek to impose sensible limits on what type of capacity expansion we allow in the Reference Scenario

Tech name	Planned new-build	Modelled additional build
Coal	✗	✗
Oil	✗	✗
Gas	✓	✓
Biomass	✓	✓
Grid-scale solar	✓	✓
Conventional hydro	✓	✗
Pumped hydro	✗	✗

Tech name	Planned new-build	**Modelled additional build**
Nuclear	✓	✗
Offshore wind	✓	✗
Onshore wind	✓	✓
Green/Blue hydrogen	✓	✓
Green/Blue ammonia	✓	✓
Gas CCS	✓	✓
Batteries	✓	✓

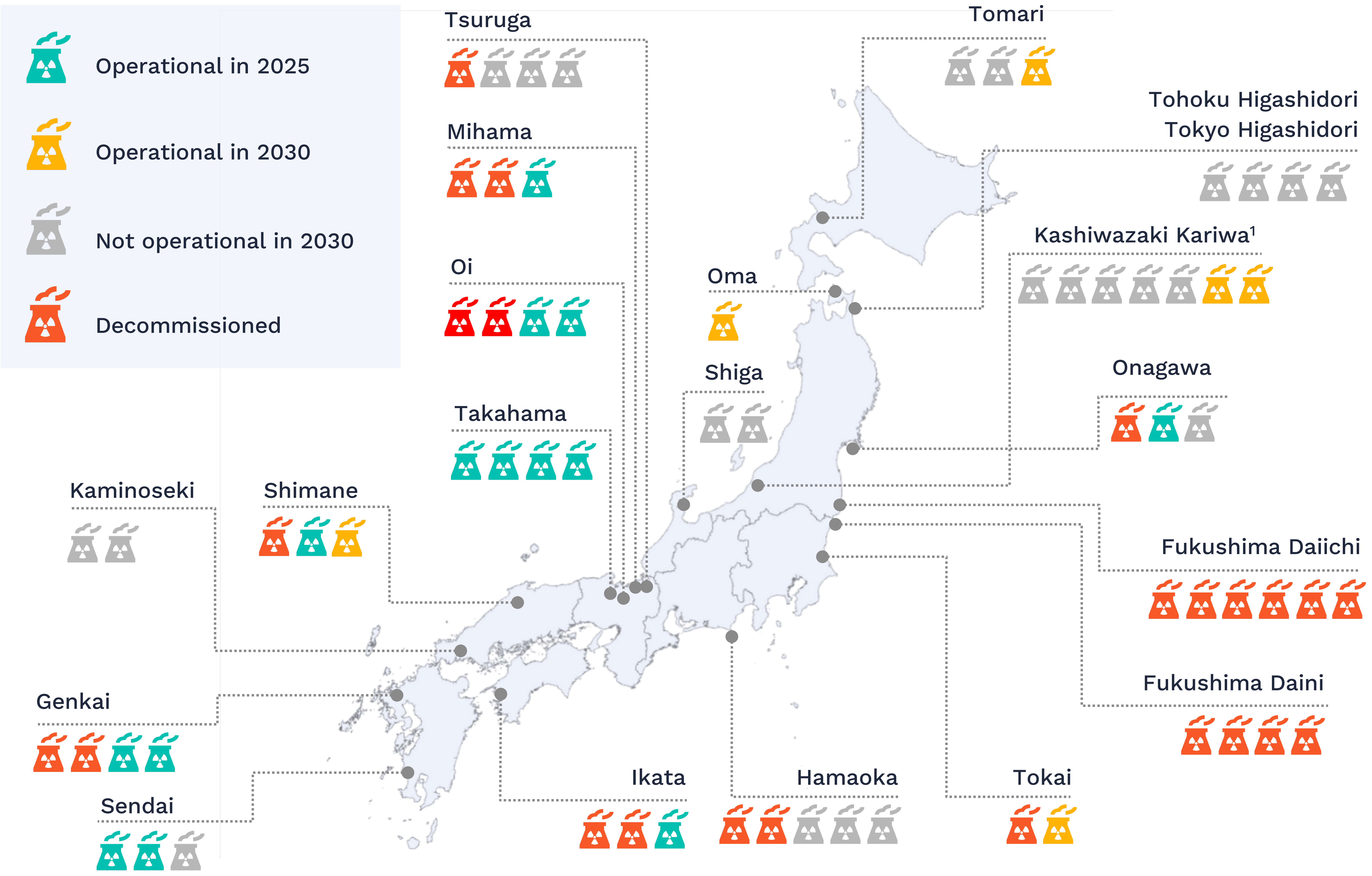
Notes

- New capacity for nuclear power and offshore wind is added exogenously to reflect restarts and auctioned wind farms expected by 2030 – but the model is not allowed to build new capacity endogenously due to siting limitations.
- Additional capacity for thermal co-firing or CCS[1] is imposed exogenously, while the model to build further capacity endogenously
- To reflect the long-term decarbonisation auctions, new gas and batteries capacity is imposed exogenously, but no additional capacity for fossil-fired or pumped hydro plants is permitted – either exogenously or endogenously
- Conventional hydro is expanded exogenously to reflect already licensed small-scale hydro

[1] For co-firing we allow only blue hydrogen and blue ammonia, but endogenously the model can build both blue or green capacity

Source: TZ modelling.

Nuclear power



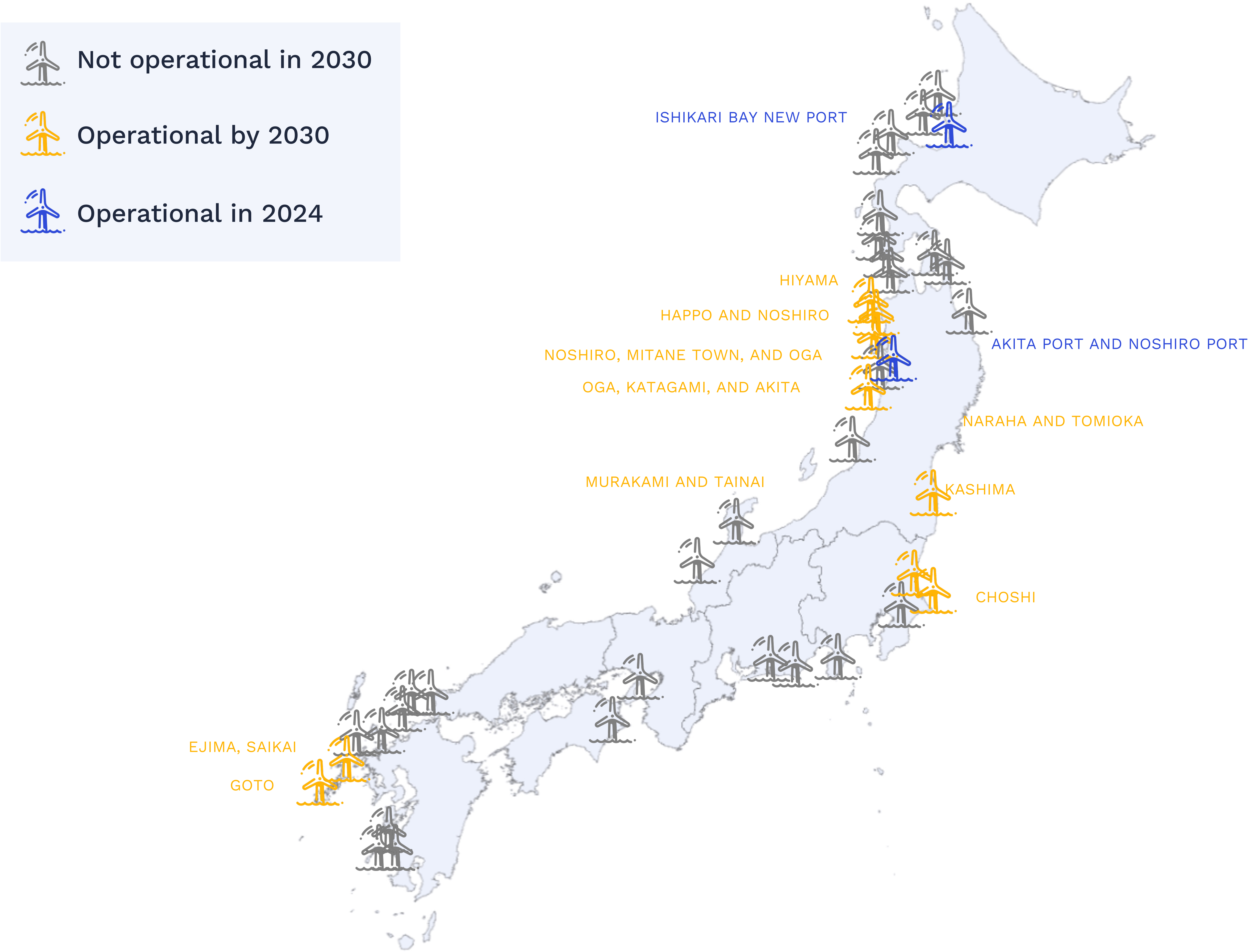
Notes

- We expect all reactors running as of May 2025 to still be running in 2030.
- We derive our expectations around reactor restarts by 2030 from media reports, adding 2 years to their restart date to account for further potential delays – thereby delaying the restart of Tomari-1 and Tomari-2 beyond our focus year
- We expect 2 reactors still under construction to be turned on by 2030: Oma-1 and Shimane-3.
- We do not expect several reactors under planning to be active in 2030: any at the Tokyo Higashidori, Kaminoseki and Tsuruga complexes, and Sendai-3.

[1] *A Tokyo EPCO complex, despite being geographically located in Tohoku.*

Source: TZ desk research.

Offshore wind



Notes

- In addition to offshore wind projects that are already up and running, we have also added most projects that have already been awarded contracts in the 2030 model
- This includes both the projects that have won in the explicit auctions run by the government and ones that have been independently developed[1]
- However, we exclude projects that list December 2030 as their expected start of operation, thereby eliminating the Sea of Japan South, Yuza, and Yurihonjo projects from the scope of analysis

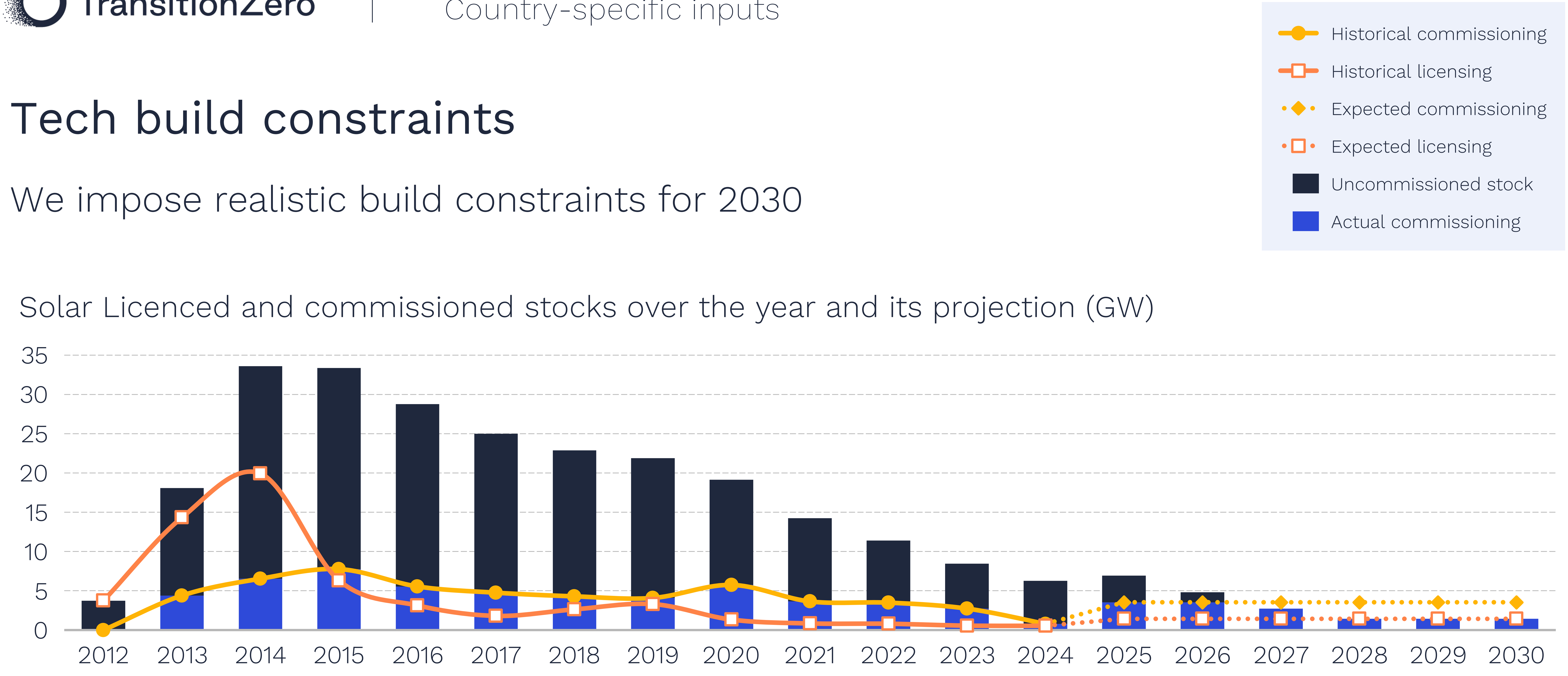
[1] In this latter category we include the early project at Goto, Ishikari New Port, Akita Port and Noshiro Port, Naraha and Tomioka, and Kashima.

Source: TZ desk research.

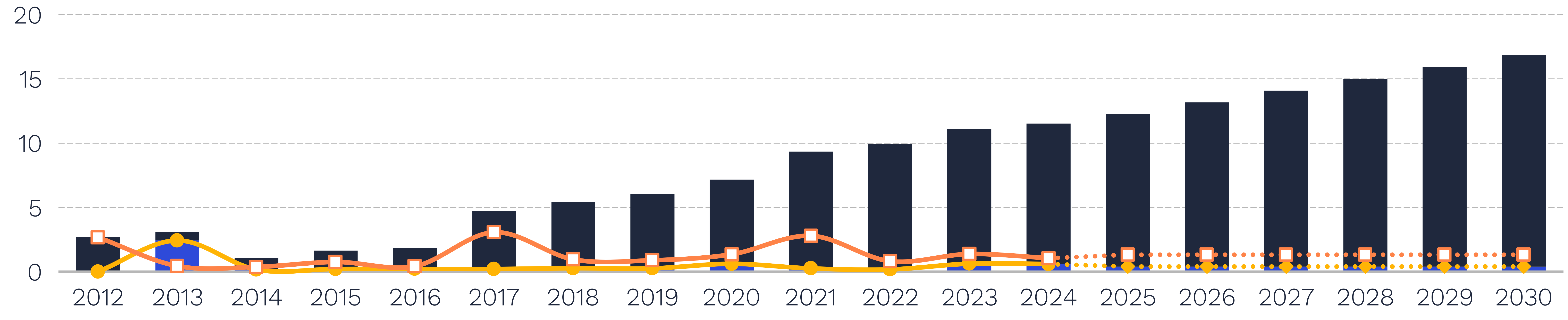
Tech build constraints

We impose realistic build constraints for 2030

Solar Licenced and commissioned stocks over the year and its projection (GW)



Onshore Wind Licenced and commissioned stocks over the year and its projection (GW)



Notes

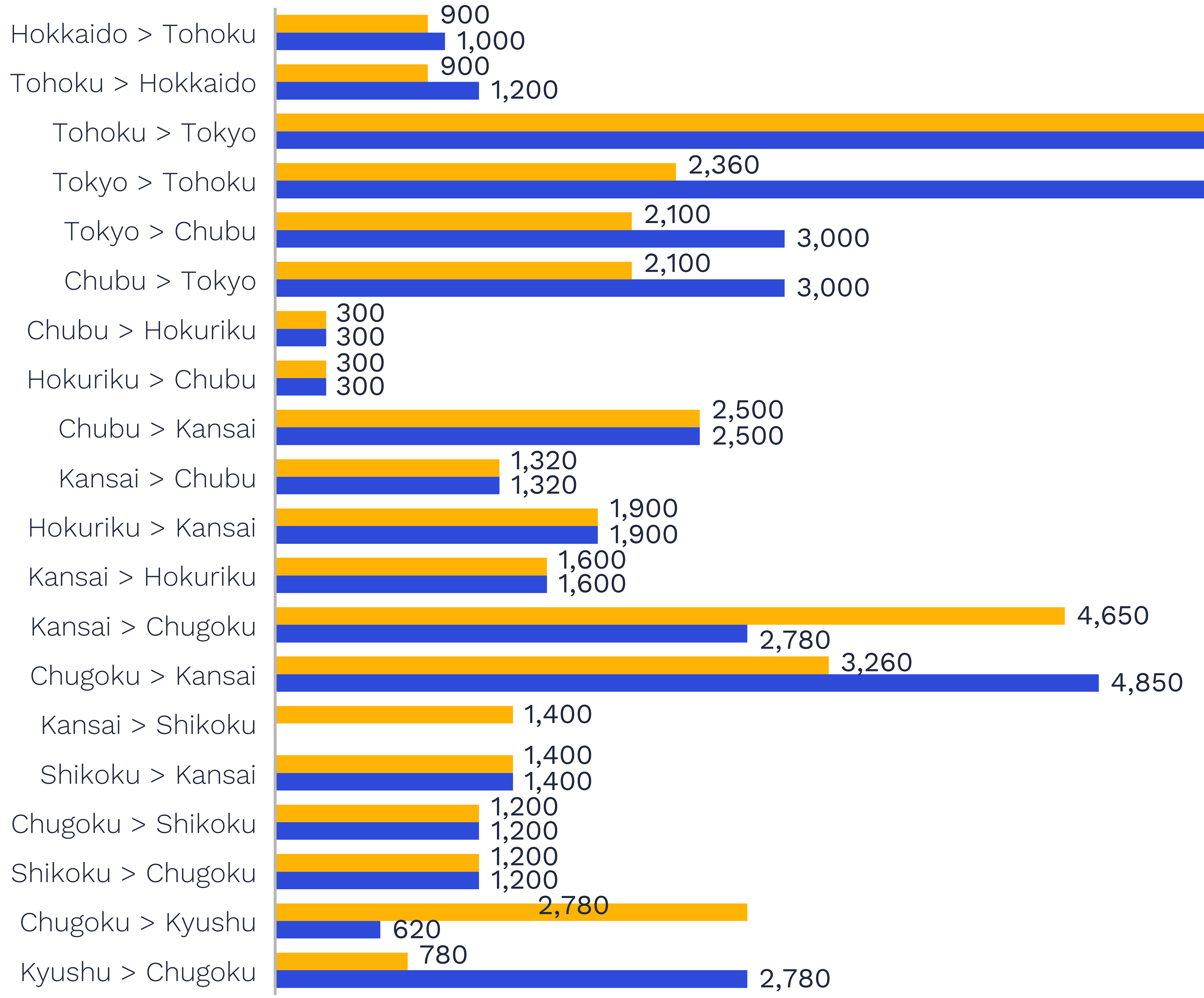
- For renewables, we consider whether the licensing of new sites over the next 7 years[1] can keep pace with the average pace of commissioning new sites over the upcoming 7 years
- For asset classes like solar, even where accounting for the current stock of licensed but not yet commissioned plants, continuing at the average past rate of commissioning would outpace the capacity that can reasonably be expected to be licensed by 2030. Therefore we restrict build-out to the latter volume
- For all other renewable asset classes we permit the average rate of commissioning to continue
- Among conventional thermal plants we only allow gas to expand – at the average rate of replacement of existing capacity over a 40-year lifetime

[1] Accounting for the 7 years to 2030 after our calibration base year of 2030, and measured as the average licensing rate over the previous 7 years.

Source: FiT Portal.

Interconnector capacities

Our study reflects OCCTO's capacity expansion plans for the year 2030



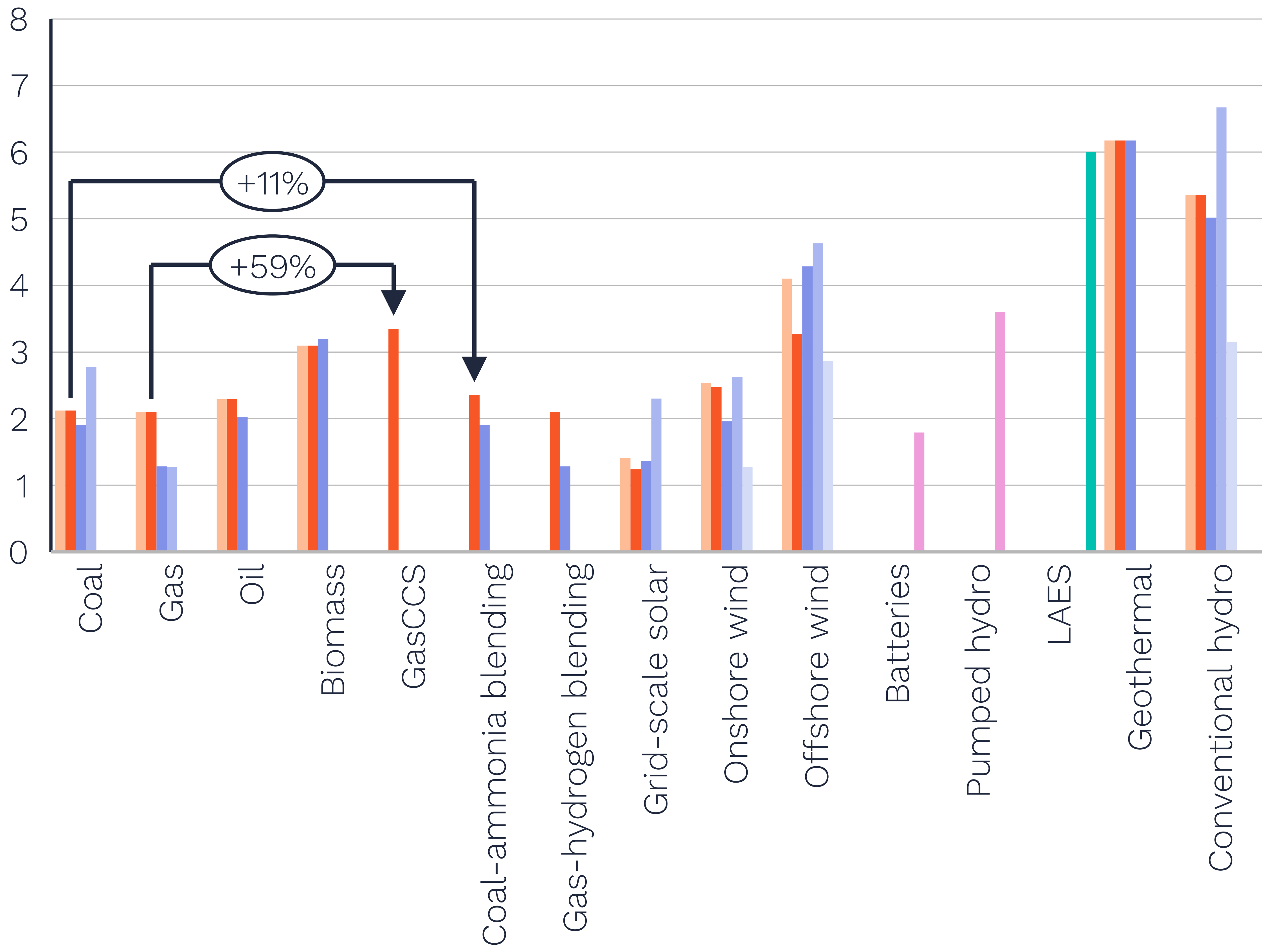
Notes

- We split Japan into the 9 grid regions of Mainland Japan, without exploring non-interconnected Okinawa
- We utilise the interconnectors' operational capacities as presented in OCCTO's reports ("2025-2034" for 2030, and "2023-2032" for 2023)
- For the fences between Hokuriku-Kansai-Chubu regions we are using the capacities reported by OCCTO from outflow from one region into the other two, split by the ratio between the historical flows during the past ten years between the source region on the one hand and either of the destination regions on the other

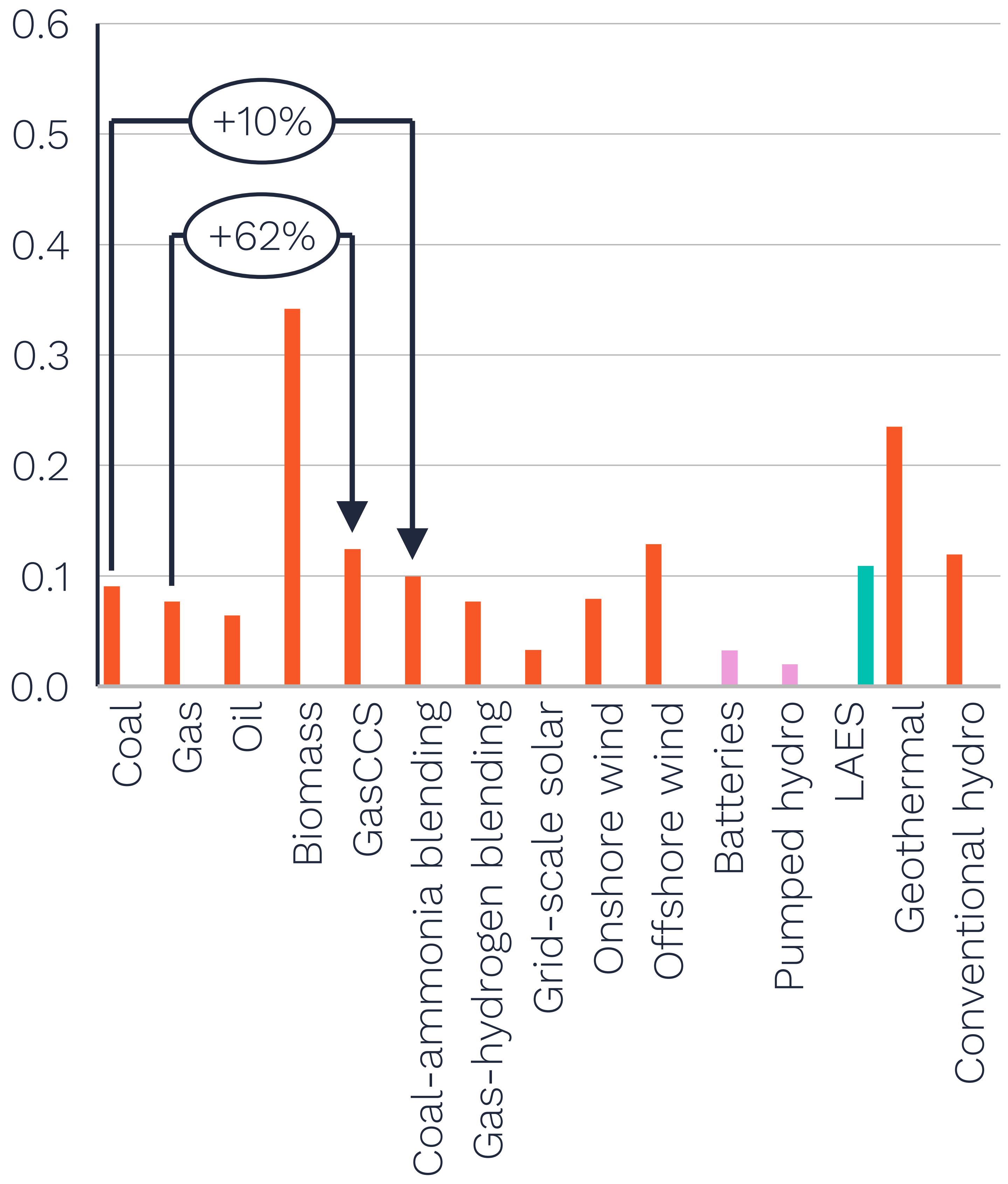
Technology characteristics

We employ the Japanese government's most recent technology cost projections

Technology CAPEX (Million USD/MW)



Technology OPEX (Million USD/MW)



- Historical 2023 - METI (2024)
- 2030 Projection Used - METI (2024)
- 2030 Alternative Reference - METI (2021)
- 2030 Alternative Reference - IEA Japan (2020)
- 2030 Alternative Reference - DNV OECD Asia (2023)
- 2030 Projection Used - NREL (2024)
- 2030 Projection Used - Desk research (2025)

Notes

- Taking note of the 2024 report from METI's Generation Cost Verification Working Group, we decided to contextualise it against other sources.
- With the report focusing on the years 2023 and 2040, we first derived an inferred CAPEX value for 2030 from the METI data through linear interpolation.
- Having found that the derived value is roughly aligned with other sources, we decided to adopt it as a modelling input.
- For OPEX, we observed that the report assumes costs remain constant from 2023 through 2040, and we have adopted this assumption in our 2030 reference year's modelling inputs.
- For CCS we slightly adapt METI's costs by splitting out its 'CCS cost' category into components covering CAPEX, OPEX and variable fuel costs (see following slides).
- For ammonia, we also adapt METI's costs by incorporating BNEF observations[1] that relative to conventional coal it should receive an 11% mark-up for CAPEX and a 10% mark-up for OPEX.
- For storage technologies, we followed NREL's cost projection for batteries and did our own literature review for LAES given its relatively lower tech readiness and market maturity.
- To convert to USD, we used the average exchange rate of 2023 of 140.53 JPY/USD.[2]

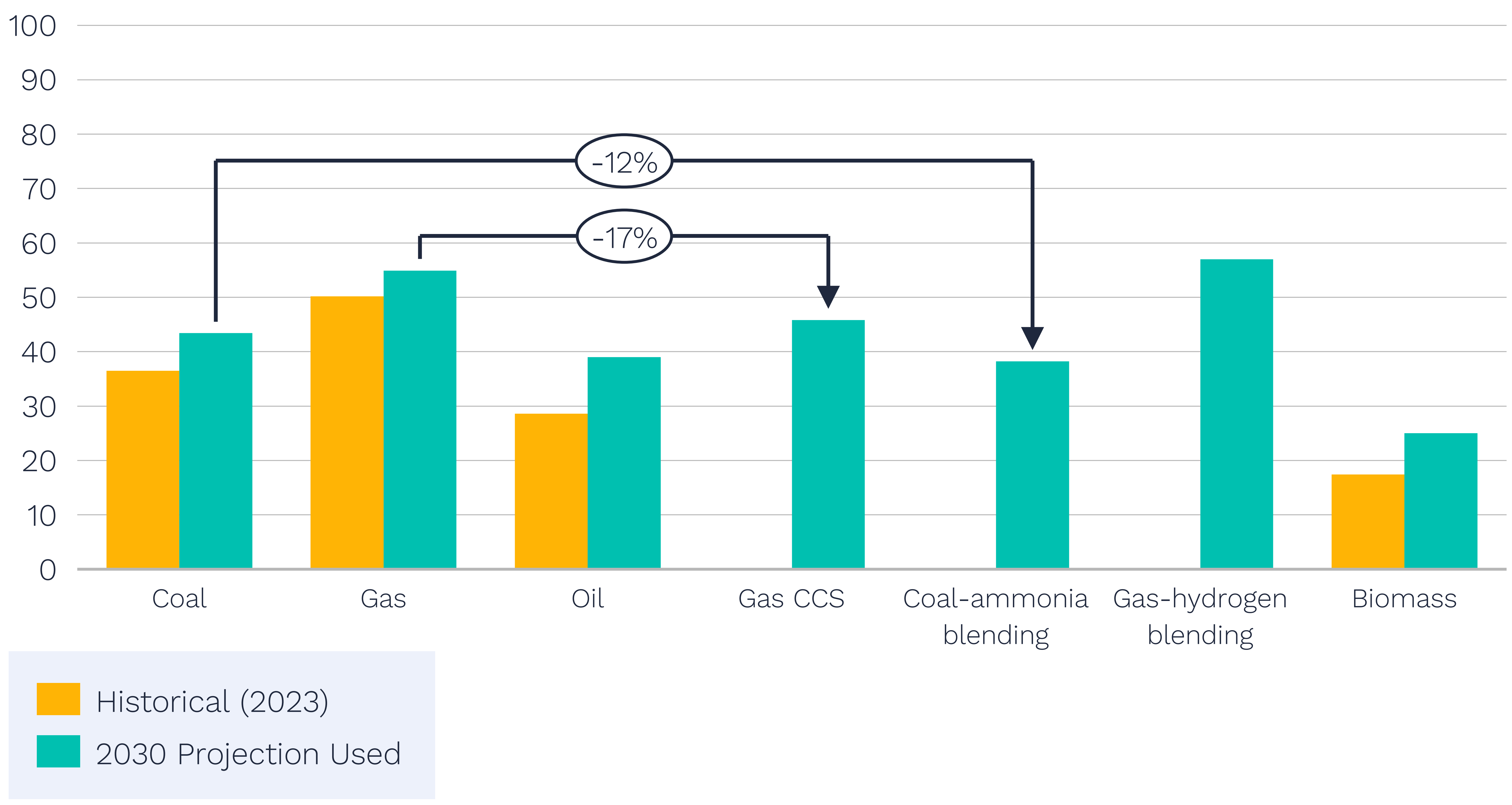
[1] See Bloomberg NEF, 'Japan's Costly Ammonia Coal Co-Firing Strategy' (28 September 2022).. [2] We assumed the CAPEX values presented by METI to be in the 2023.base year.

Source: METI..

Technology characteristics

For thermal plants we employ the Japanese government's most recent conversion efficiencies

Efficiency by technology (%) – Ranked highest to lowest



Notes

- For our model calibration of the year 2023 we derived average thermal efficiencies for the existing generation fleet from METI statistics on total primary energy supply
- For plants built between the present and 2030 we mostly relied on efficiencies from the 2024 report from METI's Generation Cost Verification Working Group
- For CCS we adopt a cut to efficiency of one sixth relative to Combined Cycle Gas Turbines, in line with the guidance from the Danish Energy Agency's Technology Catalogue.
- For ammonia we incorporate BNEF observations[1] that relative to conventional coal its efficiency should drop by 12 percentage points.
- For biomass we also decided to diverge from the METI value (43.4% for 5% co-firing of biomass with coal), because desk research suggested that thermal efficiencies for pure biomass are in the range of 15-30% and because in our modelling of 2030 we only allow mono-firing of biomass instead of co-firing of biomass with coal

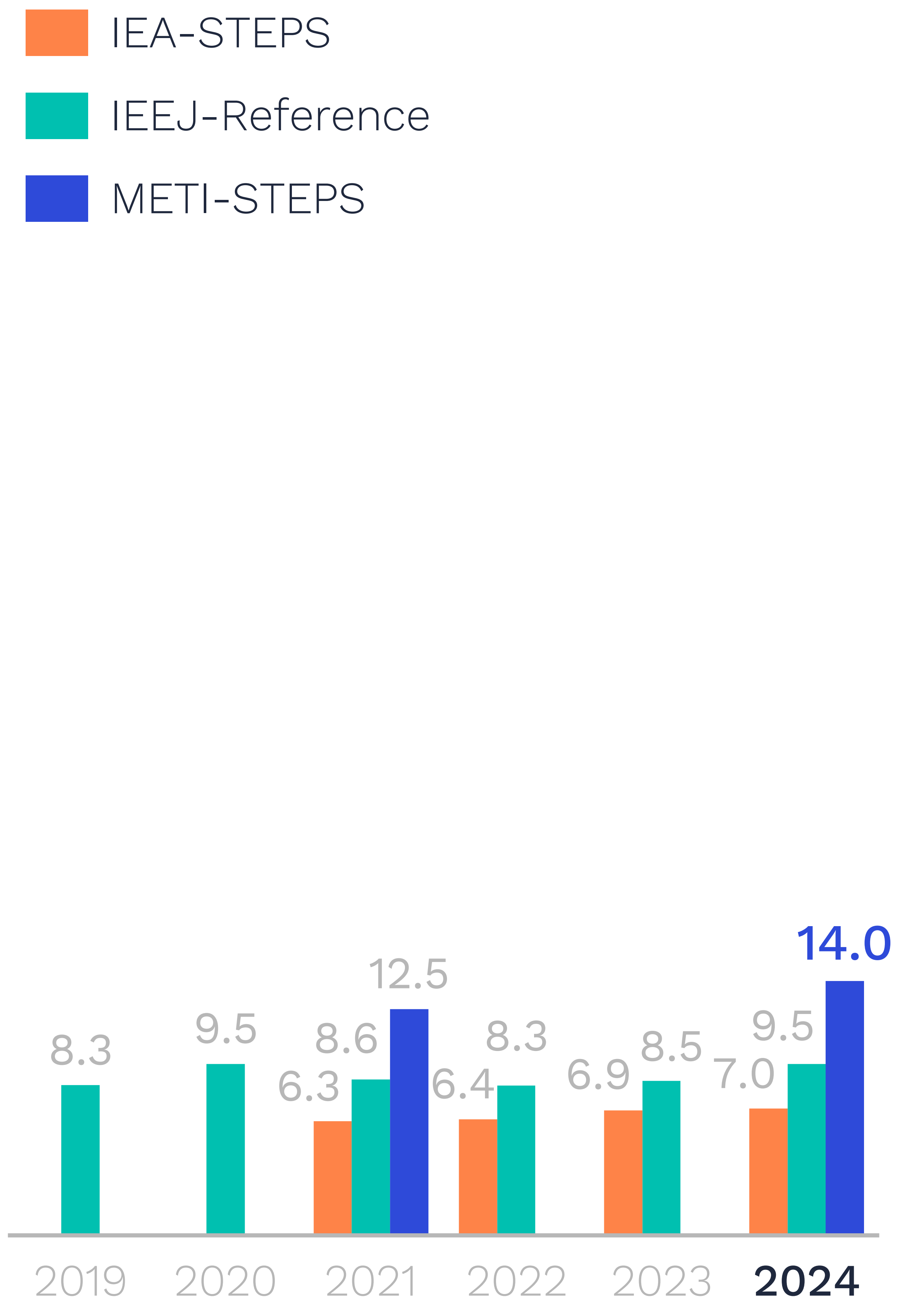
[1] See Bloomberg NEF, 'Japan's Costly Ammonia Coal Co-Firing Strategy' (28 September 2022)..

Source: METI..

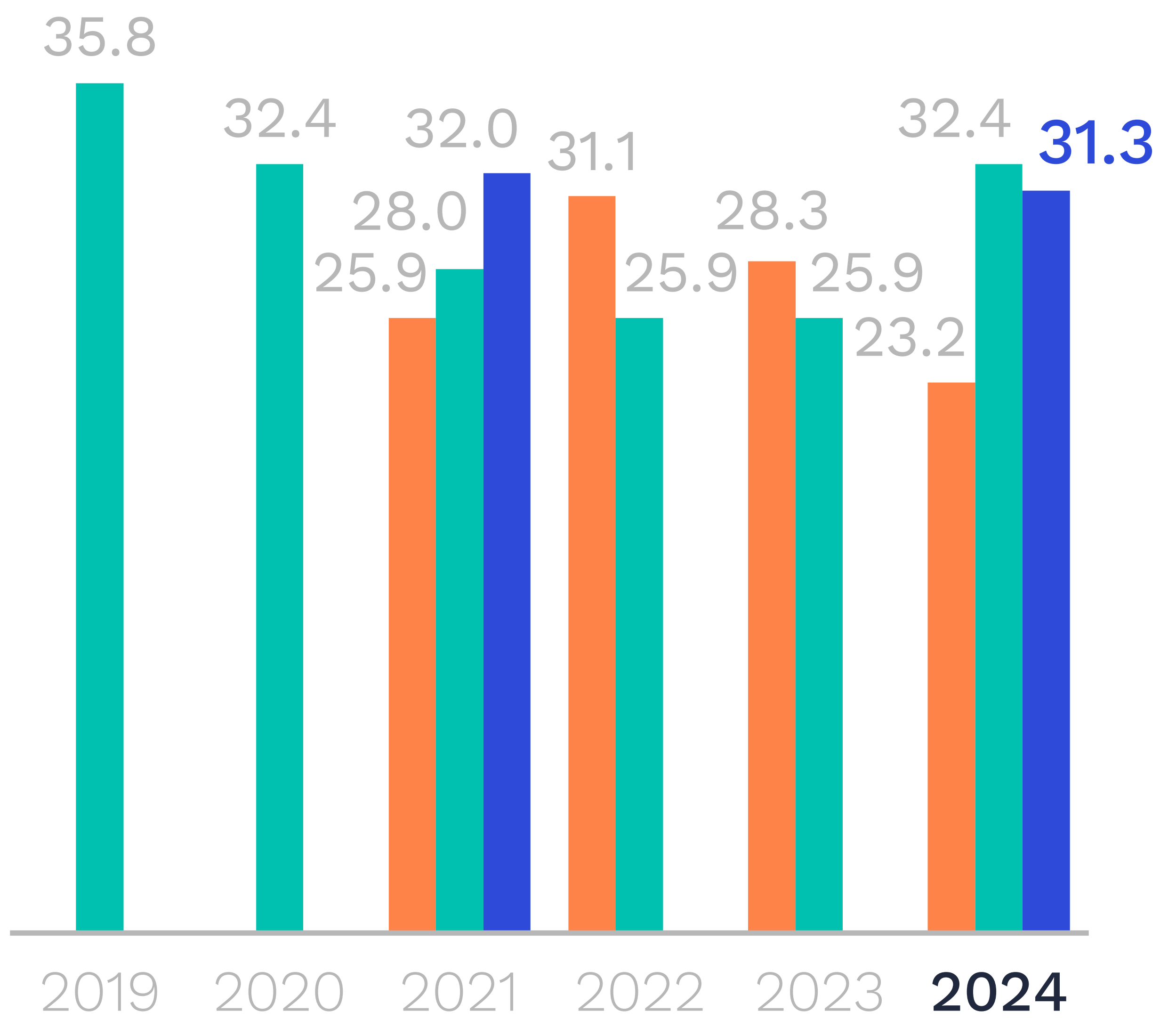
Fuel prices

We derive our fossil fuel costs from figures proposed by METI in 2024

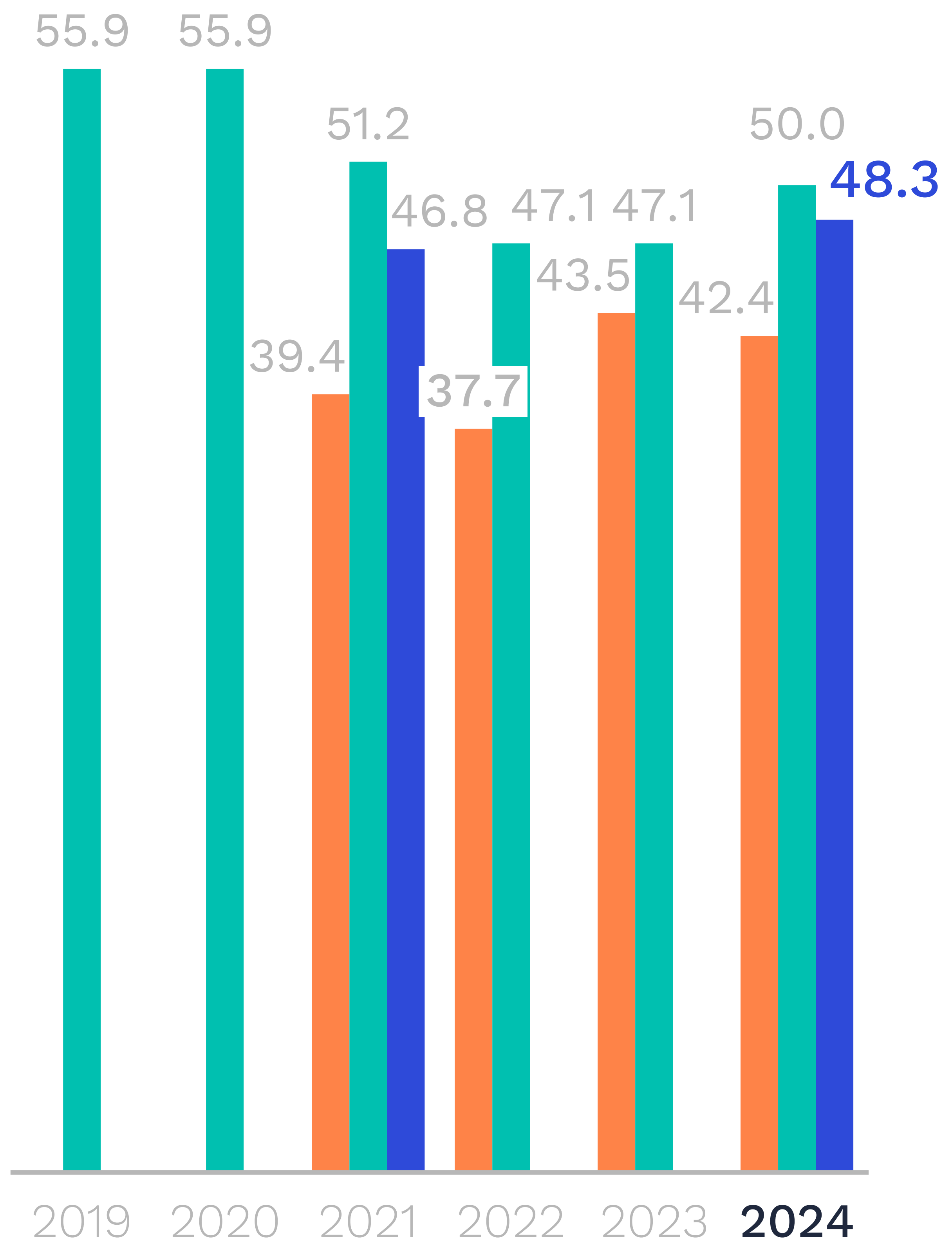
Coal prices by different sources and vintage year (USD/MWh)



Gas prices by different sources and vintage year (USD/MWh)



Oil prices by different sources and vintage year (USD/MWh)



Notes

- We tracked how 3 organisations' projections[1] for commodity prices in 2030 have evolved over the past 5 years
- We observed that Japanese sources consistently exhibit a mark-up relative to IEA values, so we decided to employ local data instead
- Noticing little discrepancy between IEEJ and METI gas and oil projections, we decided to use the data used in the official government documents
- For consistency, we decided to also use METI figures in the case of coal

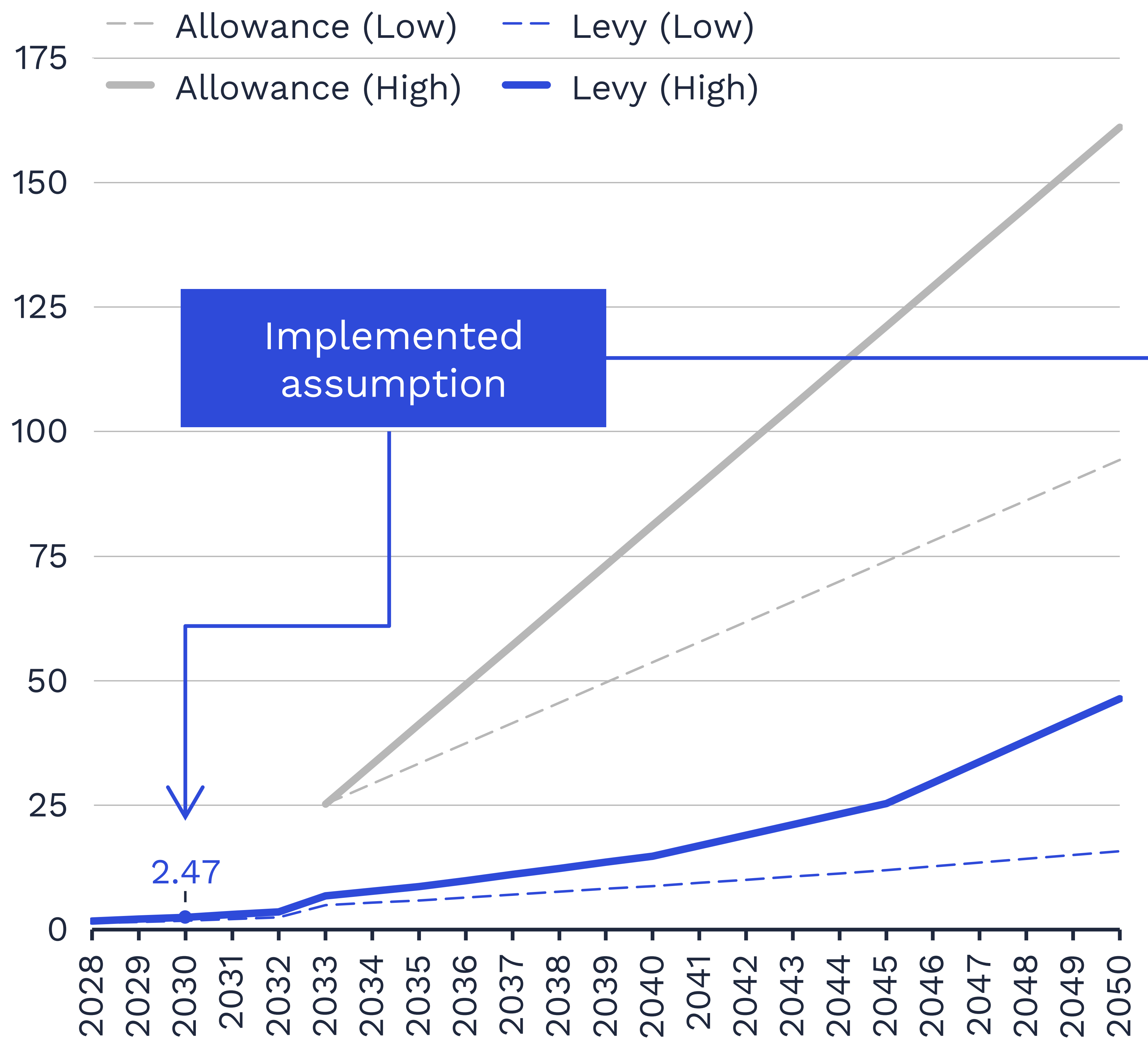
[1] The IEAs Stated Policies Scenario (missing 2030 in the first two years), the Reference Scenario in IEEJ's yearly Outlook, and METI's Base Scenarios from the Generation Cost Verification Working Groups in 2021 and 2024.

Source: IEA, IEEJ, METI.

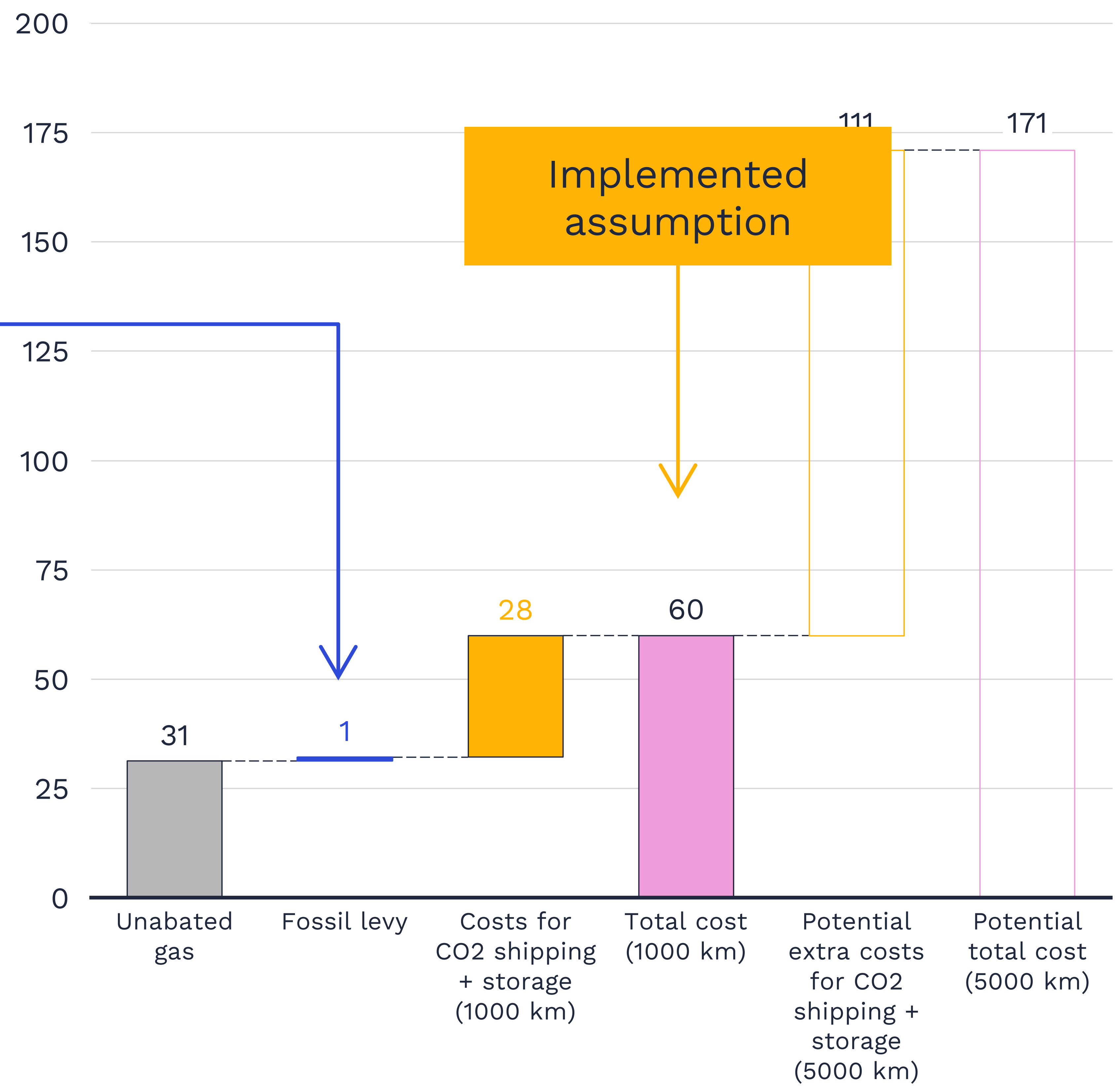
Carbon pricing and CCS

The shape of carbon pricing policy and arrangements around CCS burden sharing have material impacts on the utility of innovative thermal plants

Carbon price (USD/tCO_2e)



Generation cost components for gas with CCS (USD/MWh)



Source: METI, IEEJ.

Notes

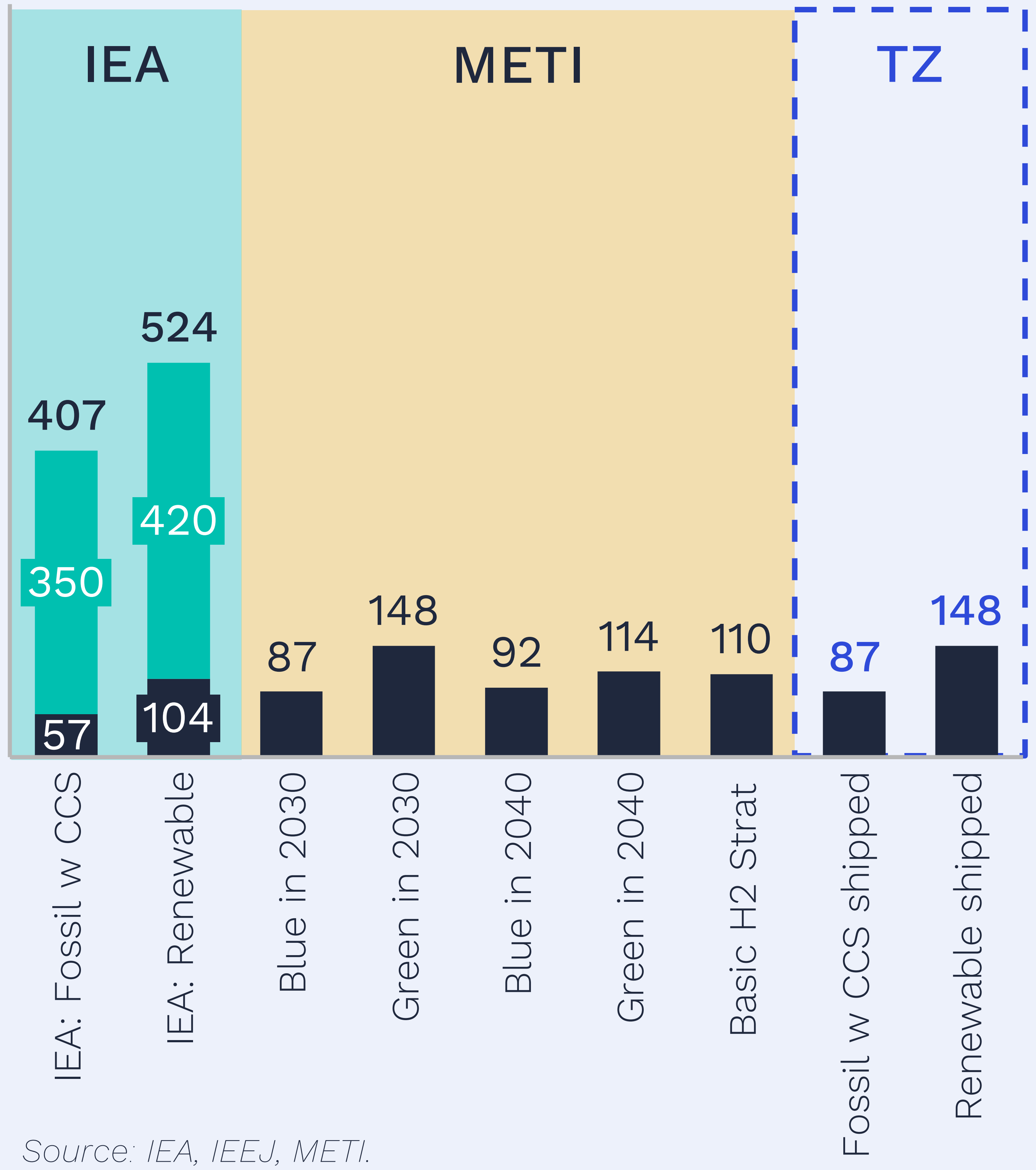
- Japanese carbon policy is in flux, but the government has decided to utilise carbon pricing to pay off Green Transition bonds by means of a carbon levy, foreseen to be imposed on fossil fuel imports starting 2028, and an emissions trading scheme for large emitters such as power plants, with auctions foreseen to start in 2033.
- Amid uncertainty about the exposure of the power sector to carbon pricing in 2030, we have decided to apply in our modelling a mark-up to the cost of natural gas equivalent only the carbon levy, employing domestic projections estimating the pricing required for repaying the bonds.[1]
- Assuming a leakage rate of 30%[2] and an escalation of carbon pricing, the impact on the cost of electricity generation in the medium term could quickly escalate.
- Further costs affecting CCS arise from the need to ship and store the CO2 once it has been captured, for which activity we have assumed the standard estimation shared by METI for storing CO_2 after it has been shipped by boat out of the country 1000 km away.[3]
- It bears noting that, while there are some sites within Japan where storage is available for cheaper, it is not a given that C&I consumers interested in a CFE PPA will have access to these, and that sites for which the Japanese government has signed Memoranda of Agreement for are much further away.[4]

[1] IEEJ estimate from July 2023, aiming at 90% by 2050 relative to 2013, yielding 224 JPY/tCO_2 in 2028. [2] 70% of annual emissions is the minimum required by METI for the 2025 round of the Long-Term Decarbonisation Auctions. [3] Estimated at a mark-up of 3.9 JPY/kWh to CCS generation costs in METI's 2024 Generation Cost Verification Working Group. [4] For instance the distance to the depleted Petronas M3 field near the Bintulu LNG terminal in Malaysia is roughly 5000 km, depending on the port of departure in Japan..

Fuel prices

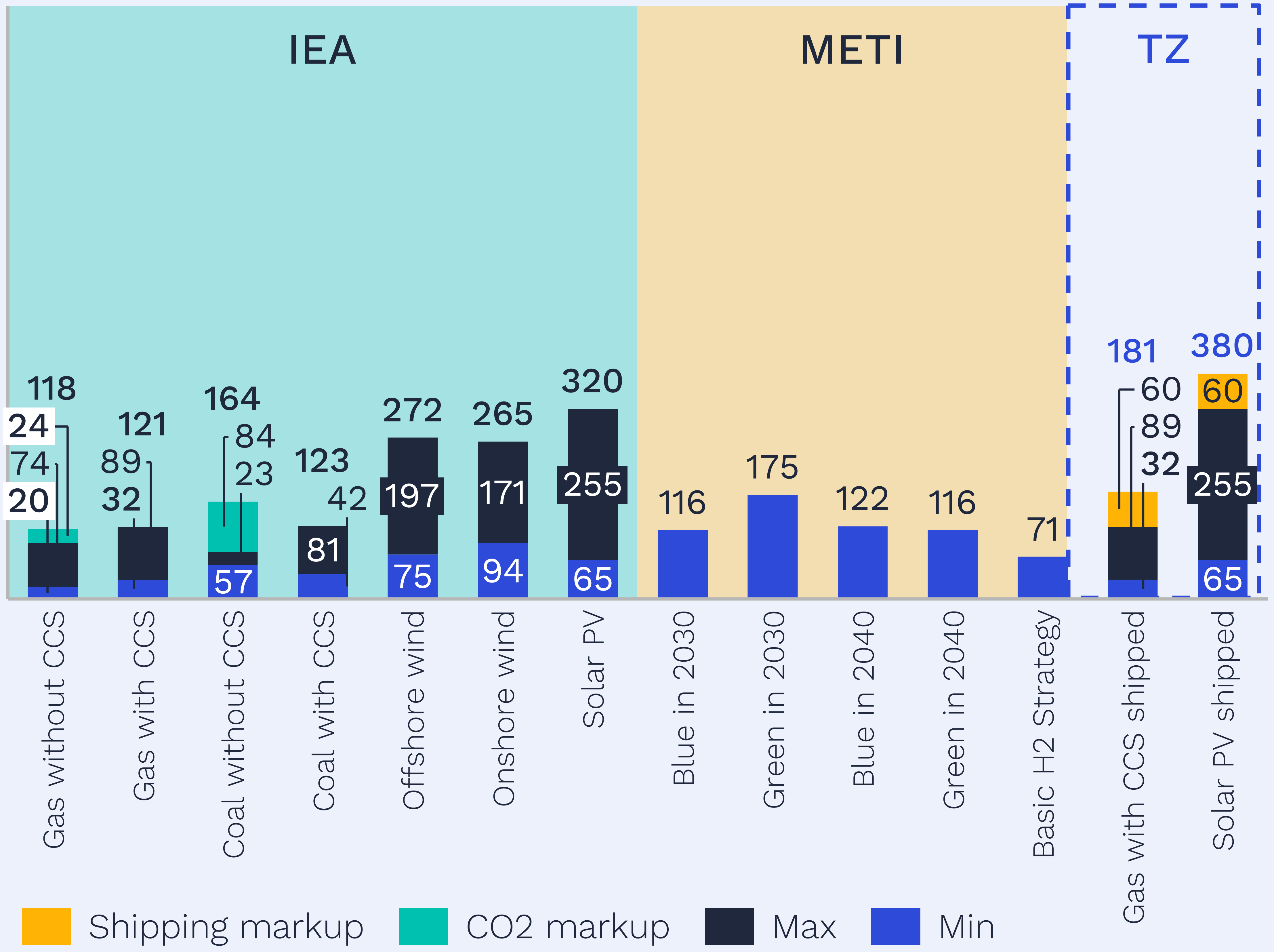
We derive hydrogen and ammonia prices from production costs plus shipping

Ammonia prices by different sources (USD/MWh)



Source: IEA, IEEJ, METI.

Hydrogen prices by different sources (USD/MWh)



Notes

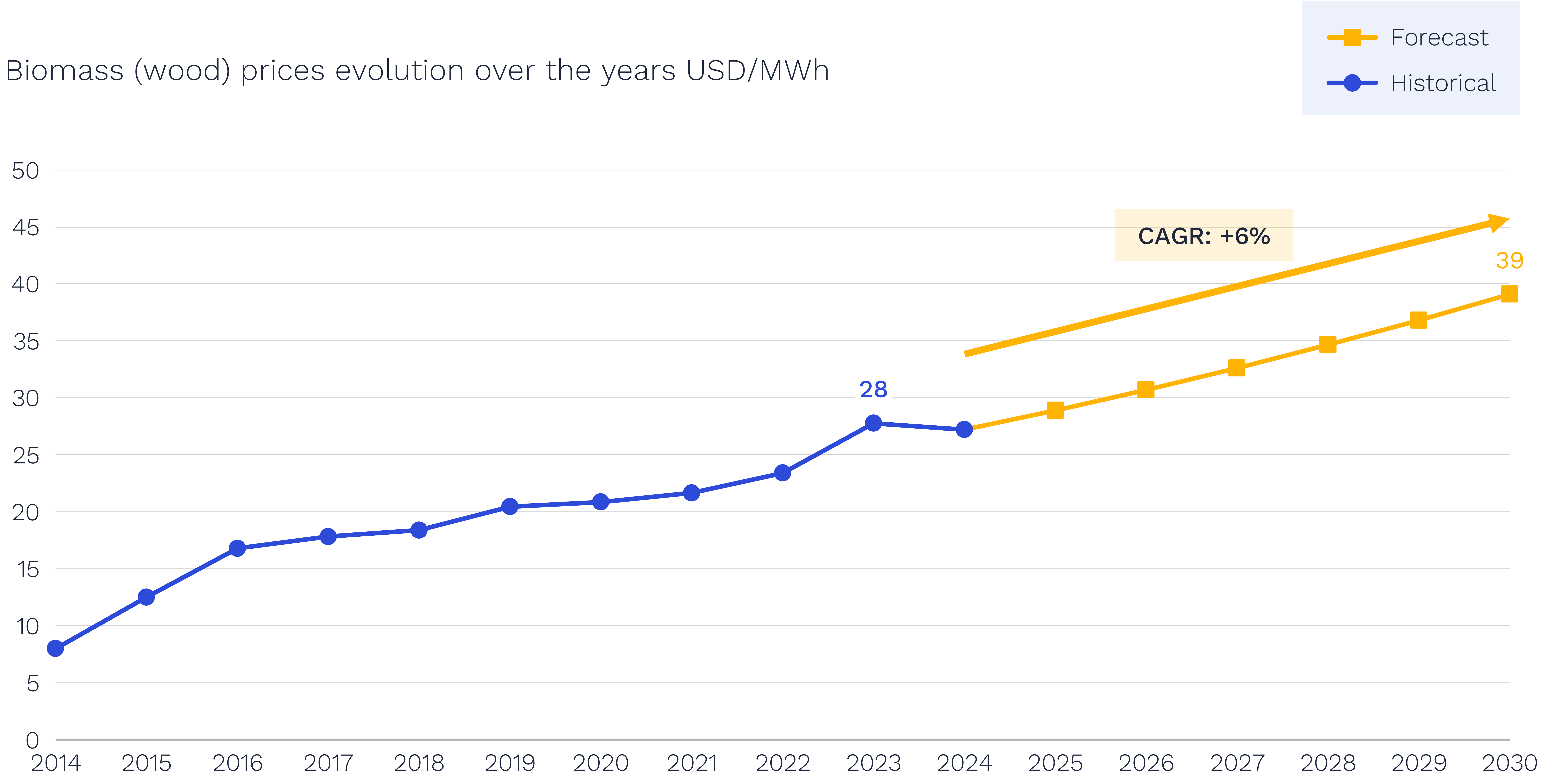
- To derive price projections for hydrogen and ammonia we compared production costs estimated by the IEA in its 2024 Global Hydrogen Review with expected costs of delivery from several METI documents[1]
- For blue hydrogen, given that Japan is a price taker on gas, we decided to use the upper bound of the IEA's projection for production from gas with CCS, and then apply shipping costs[2]
- For green hydrogen, we used the IEA's maximum price for production from electrolysis powered by solar power, marked up by the same shipping costs
- For ammonia we decided to respect METI's 2021 report, as it aligns with 2025 news accounts that Middle Eastern blue ammonia production costs being 3-400 USD/t (circa 58-77 USD/MWh), marked up with a shipping add-on of 40 USD/t (circa 8 USD/MWh)
- All fuel prices here refer to pure hydrogen and ammonia, prior to blending with gas and coal respectively

[1] Projections for 2030 are from the 2021 report of the Generation Cost Verification Working Group. Projections for 2040 are from the 2024 vintage of the same report. Projections from the 2023 Basic Hydrogen Strategy are for 2030.
[2] For hydrogen we used the estimated cost of shipping liquid hydrogen from the IEA's 2024 Global Hydrogen Review assuming shipment from Darwin, Australia, while for ammonia we used the 2019 IEEJ ' Feasibility Study on the Supply Chain of CO2-Free Ammonia' .

Fuel prices

We expect the price of biomass to continue to rise

Biomass (wood) prices evolution over the years USD/MWh



Notes

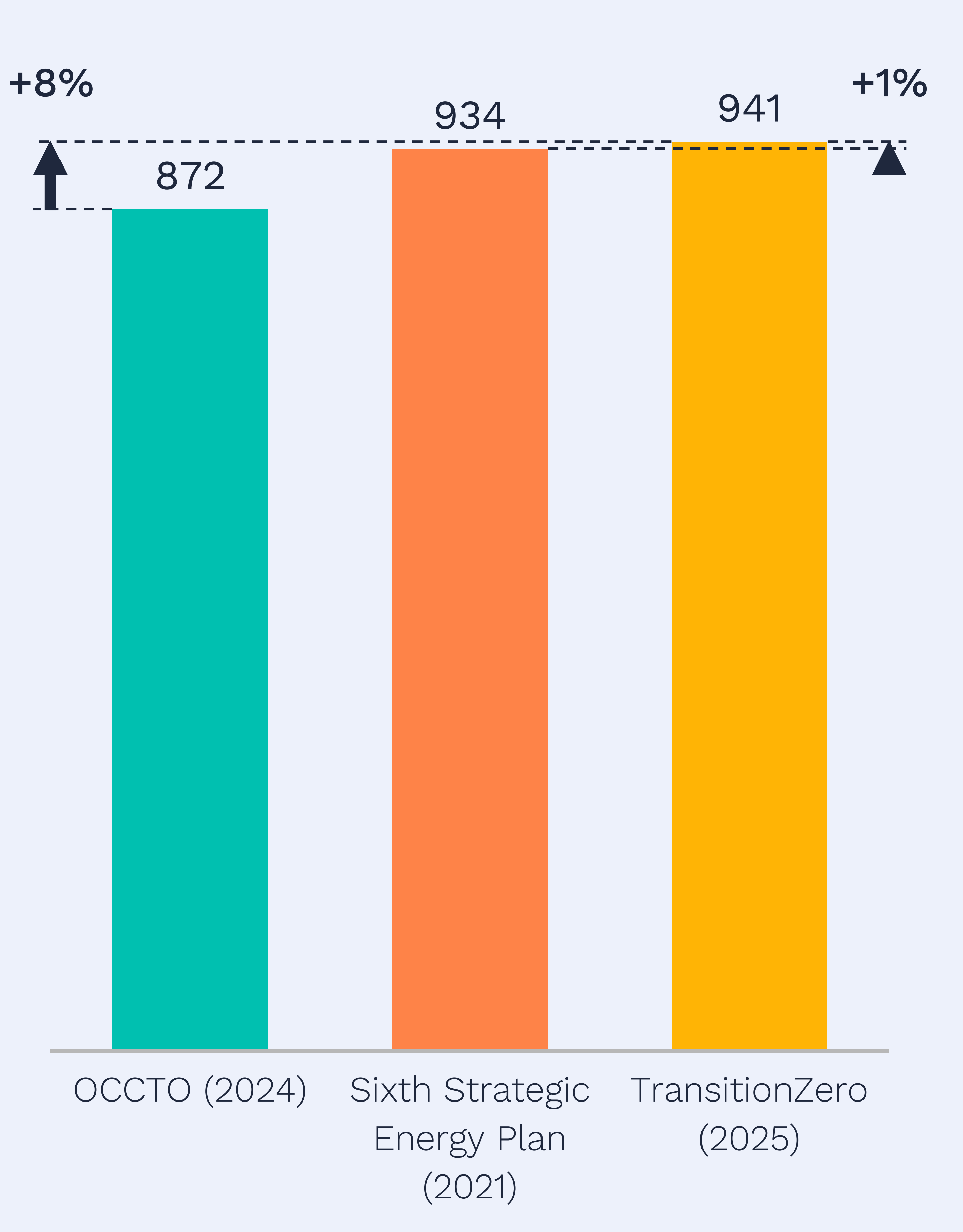
- Analysis of data provided by the FiT Level Committee shows that the fuel costs of wood have been on a consistent gently rising trend since 2016
- We continue the historically witnessed CAGR of 6% linearly to 2030

Source: FiT Level Committee..

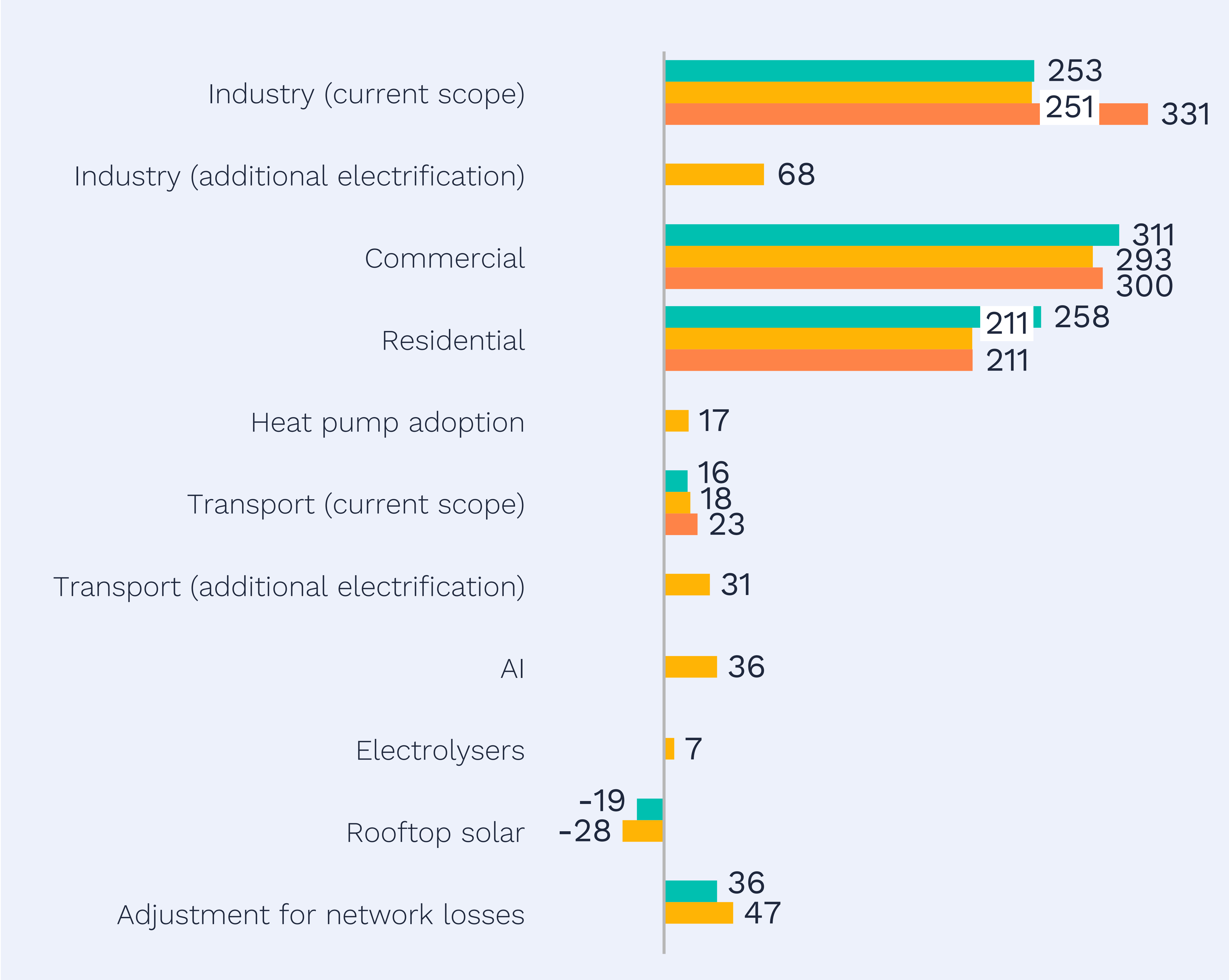
Demand

We produce our own demand projection for 2030 in-house

2030 National Demand Projection (TWh)



2030 Demand Breakdown (TWh)



2023 historical values
2030 - Sixth Strategic Energy Plan[1]
2030 TZ projection

Notes

- We assume that several new sources of electricity demand may arise between the present and 2030 from electrification in various segments: industrial boilers, building heating through heat pump adoption, the spread of EVs, the introduction of electrolysers for the domestic production of green hydrogen, and the uptake of technologies linked to the expansion of AI.

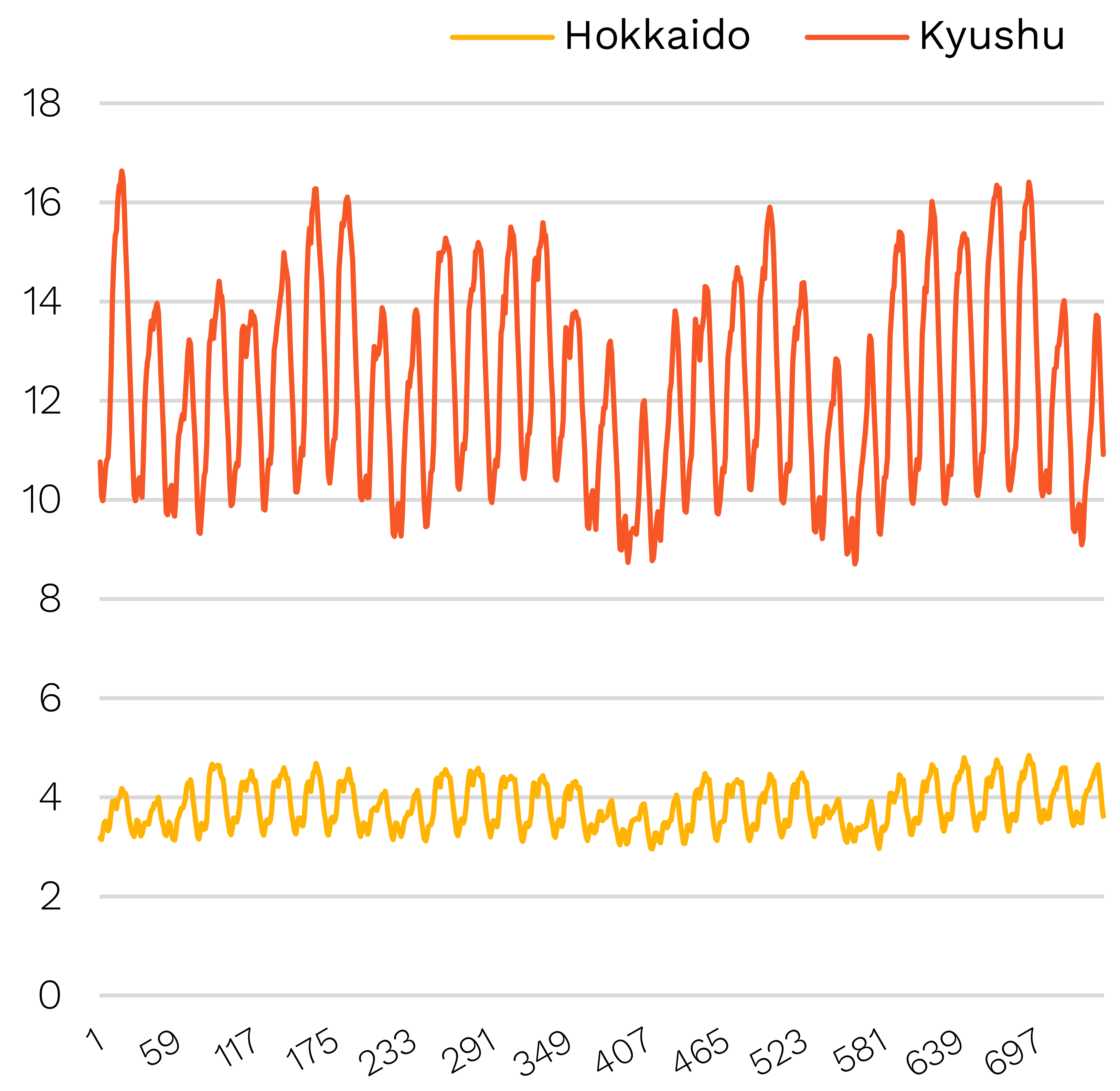
[1] *The demand breakdown projections from the Sixth Strategic Energy Plan are based on post-efficiency adjusted values.*

Source: METI, OCCTO, TZ modelling.

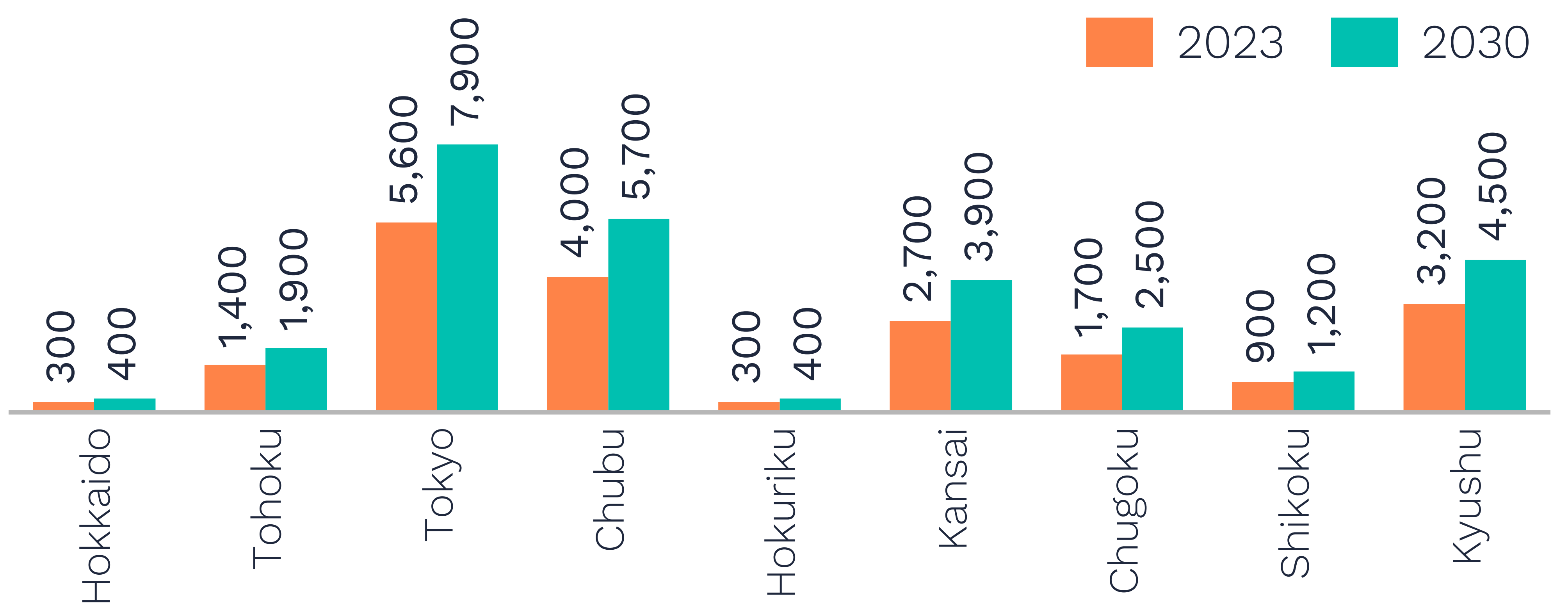
Demand

We utilise hourly regional profiles for demand and rooftop solar generation

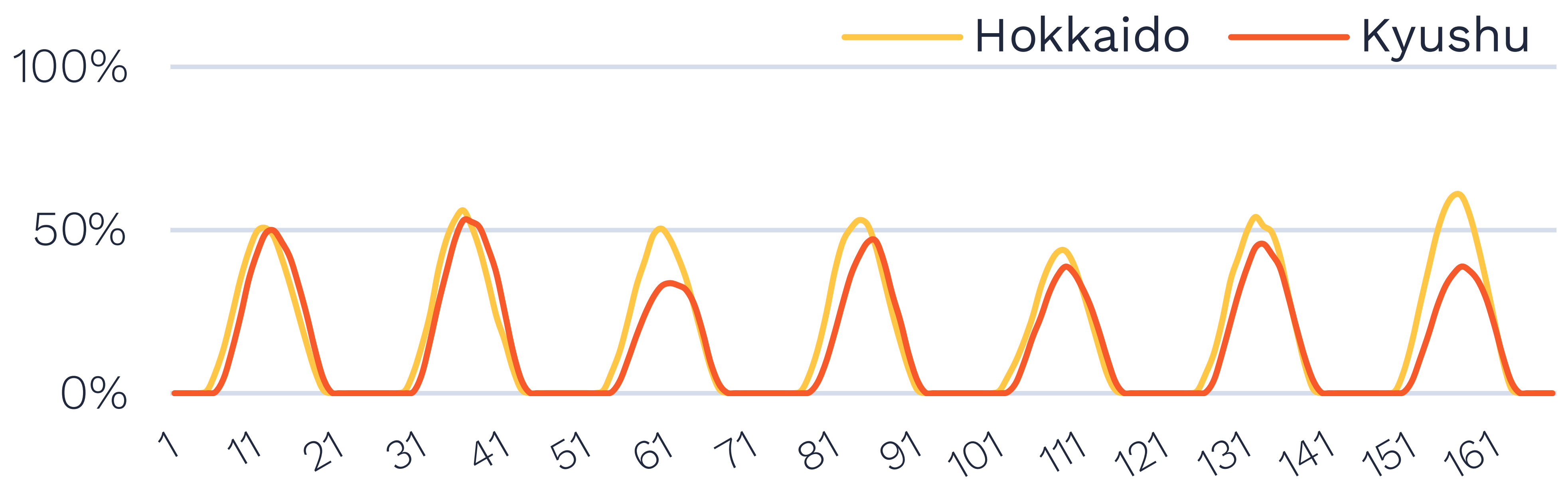
2030 hourly demand profile of the representative July month for Hokkaido and Kyushu (GWh)



2030 behind-the-meter demand projection across different regions (GWh)



2030 solar hourly generation profile of the representative first week of July for Hokkaido and Kyushu (%)



Notes

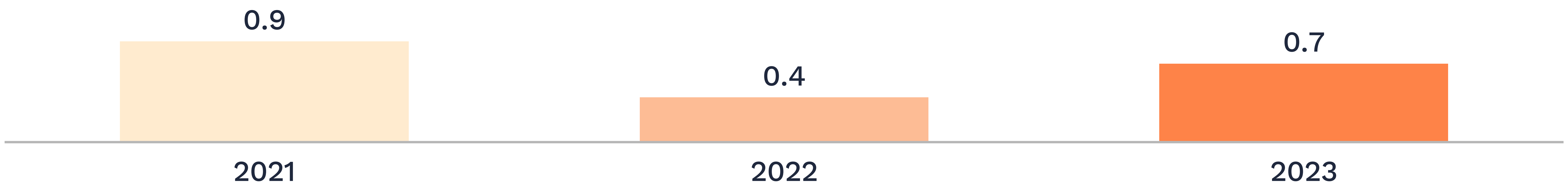
- On each brownfield bus we implement the 8760-hour demand profiles observed historically in each individual grid zone
- To account for the future spread of rooftop solar, we split our projections for Behind-the-Meter capacity across our 9 buses and apply to them generation profiles based on region-specific observed data

Source: OCCTO..

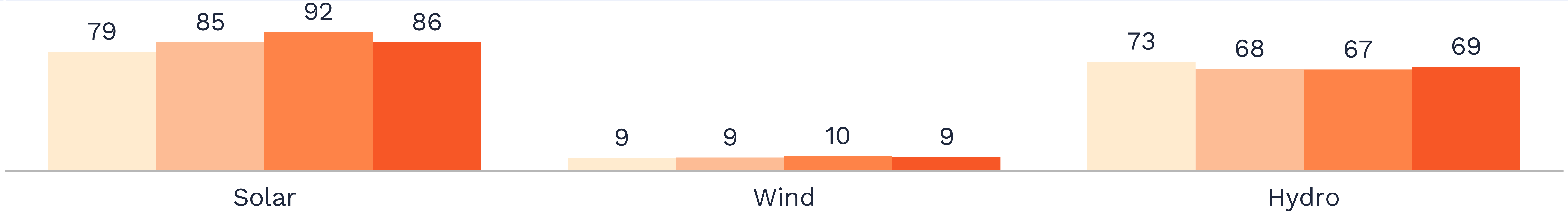
Demand

We conduct variance analysis on both demand and supply sides when selecting weather year

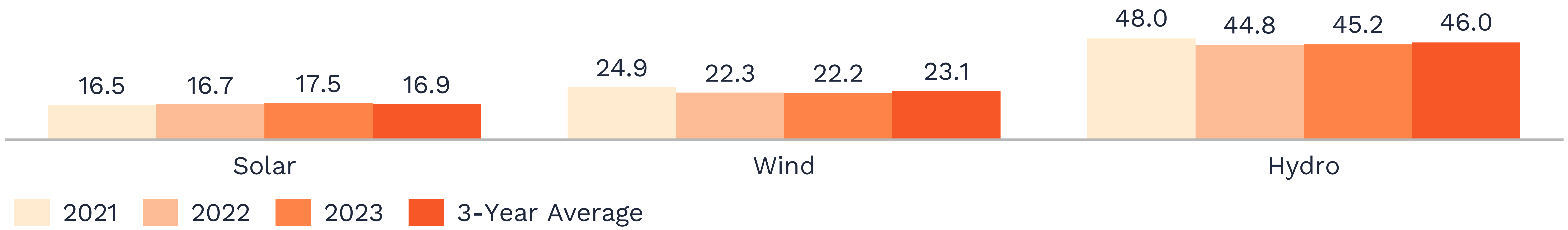
Variation from average normalised demand across different years (%)



Power generation across different years and intermittent renewables (TWh)



Yearly capacity factor across different years and intermittent renewables (%)



Notes

- Based on our variance analysis, we selected 2022 as the representative weather year for the model's hourly demand profile, as it showed the lowest deviation, 0.4%, from the 3-year average normalized demand.
- On the intermittent supply side, 2022 was average across the major forms of renewable generation – solar, wind, and hydro.

Source: OCCTO..

Attribution

To cite this document and the larger body of CFE work from TransitionZero, use the following:

> *Luta, A., Mohamed, I., Puspitarini, H. D., Suarez, I., Shivakumar, A., Yap, J., & Welsby, D. (July 2025). System-level impacts of 24/7 Carbon-Free Electricity (CFE) in India, Japan, Malaysia, Singapore, and Taiwan. TransitionZero.*

The modelling in this report is based on TransitionZero's country-level 24/7 CFE framework, built using the PyPSA (Python for Power System Analysis) platform. The model and methodology will be released under the AGPL-3.0 open-source license in September 2025. This license requires that any public use or adaptation of the model be shared under the same terms. Documentation and data files can be downloaded at: transitionzero.org/cfe.

TransitionZero

Contact

Alex Luta
East Asia Lead Analyst

alex.l@transitionzero.org