Carbon Tracker Initiative

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CDP
DRIVING SUSTAINABLE ECONOMIES

LAND OF THE RISING SUN AND OFFSHORE WIND

The financial risks and economic viability of coal power in Japan

Report

October 2019

About Carbon Tracker

The Carbon Tracker Initiative is a team of financial specialists making climate risk real in today's capital markets. Our research to date on unburnable carbon and stranded assets has started a new debate on how to align the financial system in the transition to a low carbon economy.

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About this note

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The principal authors were supported by Durand D'souza, Magali Joseph and Nicolás González-Jiménez from Carbon Tracker. The project economics model was developed by Matt Gray and Durand D'souza. The Levelised Cost of Electricity (LCOE) model was developed by Andrei Ilas who consulted to Carbon Tracker.

The data and analytics from this note are drawn from Carbon Tracker's Global Coal Power Economics Model, a techno-economic simulation model which covers ~95% of global operating capacity and ~90% of capacity under-construction. This model was developed by the Power and Utilities team from 2016 to 2019 and provides current and forward-looking estimates of the short and long run marginal cost, operating cashflow, competitiveness relative to the LCOE of renewables, phase-out year and stranded asset risk in a below 2°C scenario. More information on this data and analytics is available at Carbon Tracker's coal economics portal.

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1 Executive Summary

In this report, we analyse the financial and economic viability of new and existing coal power investments in Japan. In doing so, it aims to shine a spotlight on the risks associated with investing and operating coal power in Japan.

1.1 Carbon conundrum: Paris alignment or coal power?

Japan's policymaking is gradually becoming more ambitious with regards to climate change. Examples include:

- The recent Strategic Energy Plan (SEP) stated for the first time in the history of Japan's energy policy that renewables should become the main source of power and efforts should be made to decarbonize the energy sector by 2050.[1]
- The Long-term Strategy for Decarbonization (LTSD), which was approved by the cabinet and submitted to the UNFCCC in June 2019, states: "The Government will work to reduce CO_2 emissions from thermal power generation to realize a decarbonized society and consistent with the long-term goals set out in the Paris Agreement."[2]

Despite these policy signals, Japan is still investing heavily in coal power. The nation currently has over 11 GW of under-construction, permitted or pre-permitted coal capacity as of September 20, 2019. This capacity could have an overnight capital cost of US$29bn and would need to be closed prematurely to remain consistent with the temperature goal in the Paris Agreement.[3] Regardless of the Paris Agreement, there is a growing expectation that coal will face fierce competition from renewable energy in the future, calling into question not only new investment decisions but the long-term viability of the operating fleet.

1.2 The financial viability of new coal projects is highly sensitive to changing market conditions

Carbon Tracker has developed a project finance model for every planned and under-construction coal unit in Japan. The purpose of these models is to illustrate how, under different scenarios, a coal project could become unviable over its lifetime. In the absence of publicly available information, we developed a breakeven scenario analysis to understand how key variables could compromise project viability. As detailed in Table 1, assuming all else is equal[4], these projects could have a negative Internal Rate of Return (IRR) if the:

- Capacity factor goes below 48%;
- Total fuel price exceeds US$104/t;
- Tariff falls under US$72/MWh; or

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[1] *METI (2018). Cabinet Decision on the New Strategic Energy Plan. Available:* https://www.meti.go.jp/english/press/2018/0703_002.html

[2] *The Government of Japan (2019). The Long-term Strategy under the Paris Agreement. Cabinet decision, June 11, 2019. Available:* https://unfccc.int/sites/default/files/resource/The%20Long-term%20Strategy%20under%20the%20Paris%20Agreement.pdf

[3] *According to the International Energy Agency (IEA), emissions reduction scenarios consistent with a well-below-2°C temperature goal only allow for net-zero or negative emissions from the energy sector. High efficiency and CCS-equipped coal are not net-zero or negative emissions technologies. IEA (2016). Energy Insights 2016. Available:* https://www.iea.org/publications/freepublications/publication/ECCE2016.pdf

[4] *The breakeven analysis assumes the other variables are fixed based on historical data. See Table 2 and 4 of the report.*

- Carbon price increases above US$25/t$CO_2$.

For context, based on publicly available data and Carbon Tracker calculations, in 2018, the:

- Capacity factor averaged 73%;[5]
- Total fuel price averaged US$105/t;[6]
- Tariff prices (based on the Japan Electric Power Exchange) averaged US$87/MWh;[7] and
- Carbon price was US$2.68/t$CO_2$.[8]

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[5] *OCCTO Supply Plan 2019. Available:* https://www.occto.or.jp/kyoukei/torimatome/files/190329_kyokei_torimatome.pdf

[6] *Based on Carbon Tracker analysis. Includes the expenses incurred in buying, transporting, and preparing the coal. See the report for all assumptions.*

[7] *Japanese Electric Power exchange. Available:* http://www.jepx.org/english/market/index.html

[8] *Environment and Economy Division Ministry of the Environment January (2017). Greening of Whole Tax System and Carbon Tax in Japan. Available:* https://www.env.go.jp/en/policy/tax/20170130_greening.pdf

Table 1. Results of the project economics model for planned and under-construction coal units

Project	Parent owner	Forecasted Net Present Value (NPV) (million US$)	Lowest capacity factor to achieve an IRR greater than WACC = 2.5% (%)	Highest fuel price to achieve an IRR greater than WACC = 2.5% (US$/t)	Lowest tariff to achieve an IRR greater than WACC = 2.5% (US$/MWh)	Highest carbon price in 2040 to achieve an IRR greater than WACC = 2.5% (US$/tCO2)
Akita Unit 1	KEPCO, Marubeni	$1,110	49%	$109	$70	$28
Akita Unit 2	KEPCO, Marubeni	$1,110	49%	$109	$70	$28
Hirono IGCC	Mitsubishi (90%), TEPCO (10%)	$539	62%	$95	$75	$21
Hitachinaka Kyodo Unit 1	JERA	$766	50%	$100	$73	$24
Kaita	Chugoku Electric Power (50%), Hiroshima Gas	$65	59%	$85	$78	$10
Kobe Unit 3	Kobelco Power Kobe 2	$1,050	45%	$111	$69	$32
Kobe Unit 4	Kobelco Power Kobe 2	$1,028	44%	$111	$69	$31
Kushiro	IDI Infrastructures F-PowerCoal Mine,	$201	40%	$106	$68	$23
Misumi Unit 2	Chugoku Electric Power	$1,970	42%	$121	$66	$38
Nakoso IGCC	Mitsubishi (90%), TEPCO (5%), Joban Joint Power (5%)	$575	62%	$95	$75	$21
Saijo Unit 1	Shikoku Electric Power	$1,239	42%	$125	$64	$40
Kashima Unit 2	Nippon Steel, J-power	$1,011	47%	$111	$70	$33
Takehara New Unit 1	J-POWER	$1,029	44%	$112	$68	$34
Taketoyo Unit 5	JERA	$1,954	43%	$118	$67	$36
Tokuyama East Power No. 3	Tokuyama, Marubeni, Tokyo Century	$176	57%	$87	$77	$11
Ube Unit 1	J-POWER, Ube Industries	$1,122	43%	$117	$67	$34
Ube Unit 2	J-POWER, Ube Industries	$1,113	42%	$119	$67	$34
Yokkaichi	Mitsubishi	$74	54%	$87	$77	$11
Yokosuka Unit 1	JERA	$5	48%	$76	$82	$4
Yokosuka Unit 2	JERA	$5	47%	$76	$82	$4
Average	**n/a**	**n/a**	**48%**	**$104**	**$72**	**$25**

Source: Carbon Tracker analysis

Notes: Our project economics model is based on a number of high-level assumptions, due a lack of publicly available data. See Table 2 and 4 as well as Section 6 of the report for the modelling assumptions and risks associated with this analysis.

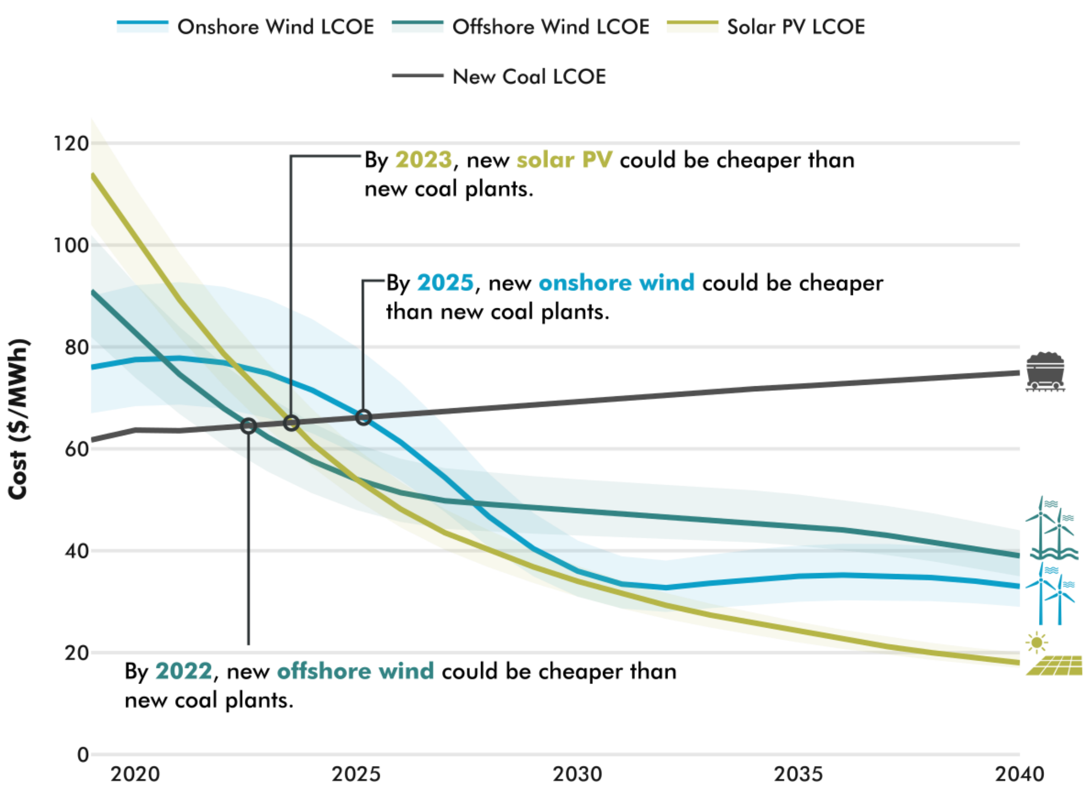
1.3 New renewables cheaper than new coal by 2022 and existing coal by 2025

There are three economic inflections points which will make coal economically obsolete relative to renewable energy:

i. When new renewable energy outcompetes new or under-construction coal;
ii. When new renewable energy outcompetes existing coal; and
iii. When new firm (or dispatchable) renewable energy outcompetes existing coal.

Independent of an additional carbon price or more stringent air pollution regulations, the LCOE of renewable energy in Japan could be lower than the LCOE of coal by 2022. Specifically, the LCOE of offshore wind, utility-scale solar PV and onshore wind could be cheaper than the LCOE of coal by 2022, 2023 and 2025 respectively.

FIGURE 1. THE LCOE OF RENEWABLES VERSUS THE LCOE OF COAL IN JAPAN



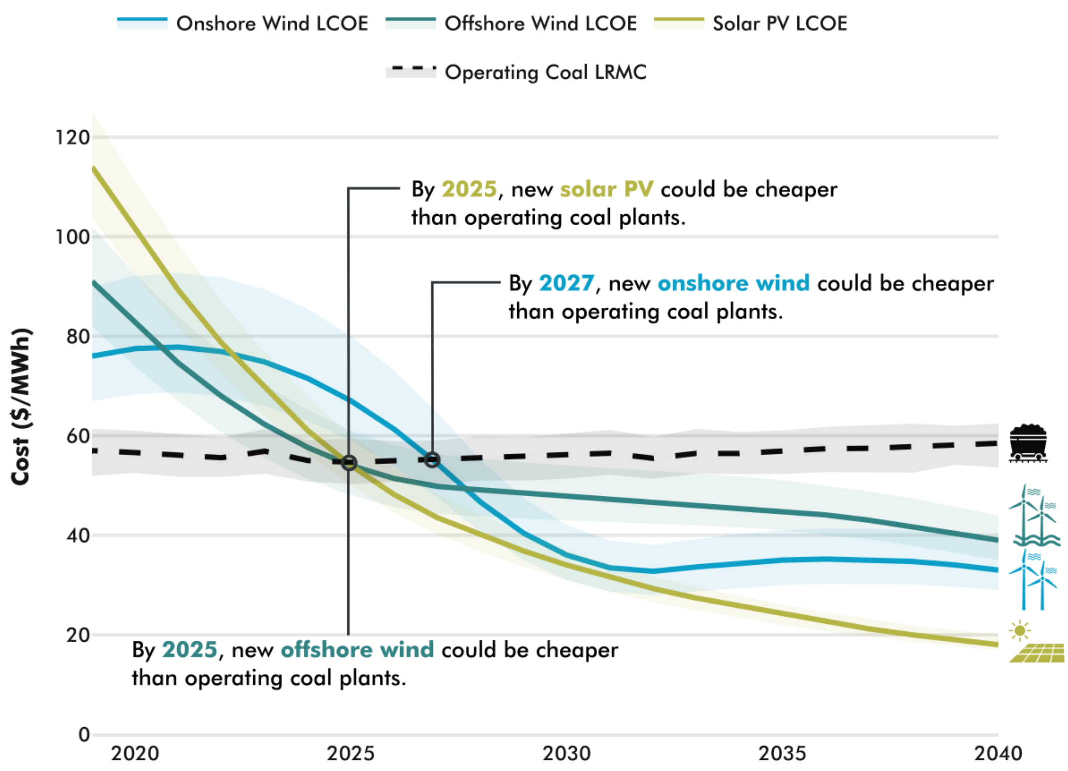
Source: Carbon Tracker analysis

Notes: the key assumptions for onshore wind include: CAPEX of US$2231/KW, O&M of 1.7% of CAPEX, capacity factor of 26%, capacity projection of 30 GW by 2040, real WACC of 3.5%, debt equity split of 80:20, a learning rate of 25%. The key assumptions for solar PV include: CAPEX of US$1932/KW, O&M of 1.3% of CAPEX, capacity factor of 14%, capacity projection of 282 GW in 2040, real WACC of 3.5%, debt equity split 80/20 and learning rate 60%. The key assumptions for offshore wind include: CAPEX of 4135 US$/kW, annual O&M costs 2.5% of

CAPEX, capacity factor of 49%, real WACC of 4.2%, debt equity split of 75:25, capacity projection of 20 GW in 2040 and learning rate of 12%. See Table 2 and the appendix for more information.

Crucially, the LCOE of offshore wind and utility-scale solar PV could be cheaper than the long-run marginal cost (LRMC) of existing coal plants by 2025 and 2027 for onshore wind.

FIGURE 2. THE LCOE OF RENEWABLES VERSUS THE LRMC OF EXISTING COAL IN JAPAN



Source: Carbon Tracker analysis

Notes: Upper and lower bounds for the cost of operating coal units are calculated using several scenarios. Notes: Operating coal cost is capacity-weighted and based on long-run marginal cost, which includes fuel, variable O&M and fixed O&M (SRMC plus fixed operating and maintenance costs). Imported coal is assumed from Australia, Russia and Indonesia. The upper and lower bounds represent the 25% and 75% confidence intervals in the long-run marginal cost given the variance in historical coal prices from the last 10 years. The historical mean coal price is $75/ton. See Figure 1 notes and Table 2 of the main report for other assumptions.

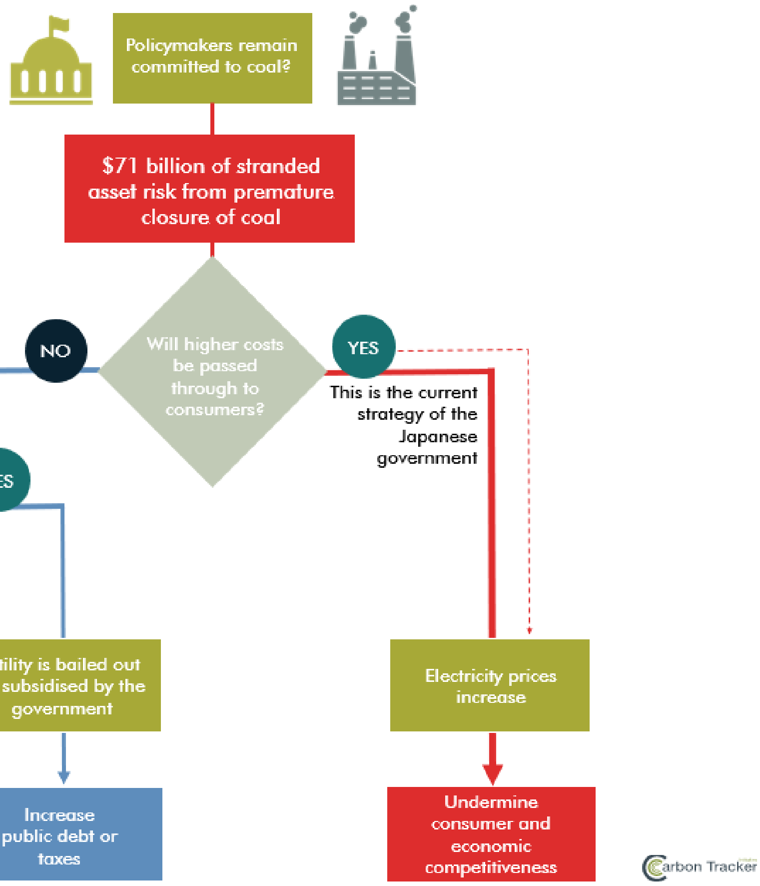
1.4 Without policy reform, the Japanese consumer could pay for US$71bn of stranded coal assets through higher power prices

Our analysis shows that building coal power today equals high-cost power and fiscal liabilities tomorrow. Japan's planned and operating coal capacity is partially protected by regulations that give coal generators an unfair advantage in the marketplace. These regulations include, but are not limited to:

- A baseload power market that includes the fixed cost of mothballed nuclear power and could help shelter coal generators from any future carbon price exposure; and
- An inefficient dispatch that prioritises nuclear before wind and solar and could lead to curtailment of wind and solar in the future.

These regulations are sheltering high-cost coal from significant cost declines in renewable energy. Without policy reform, the Japanese consumer may not be receiving the lowest-cost power possible. In our below 2°C scenario, where planned, under-construction and operating coal capacity is forced to shut down in a manner consistent with the temperature goal in the Paris Agreement, stranded asset risk from capital investments and reduced operating cashflows could amount to US$71bn.[9] Of this US$71bn, US$29bn could be avoided if the Japanese government immediately reconsiders the development of planned and under construction capacity. As detailed in Figure 3, due to Japan's current regulatory environment, this liability could result in higher energy costs for the consumer.

FIGURE 3. HOW STRANDED COAL ASSETS COULD MATERIALISE IN THE JAPANESE ECONOMY



Source: Carbon Tracker analysis

Notes: See the main report for more information.

[9] *This scenario is consistent with government's ambition to reduce CO_2 emissions from thermal power generation consistent with the Paris Agreement. See footnote 2.*

1.5 Policy recommendations

We offer two policy recommendations. Please note that these policy recommendations are high level by design.

1.5.1 Immediately reconsider planned and under construction capacity and develop a retirement schedule for the existing fleet that is consistent with the decarbonisation goal in the Paris Agreement

If Japan intends to meet the temperature goal in the Paris Agreement, it needs to phase-out unabated coal power by 2030.[10] This reality has immediate implications for new coal investments. Both planned and under-construction capacity will unlikely be a least-cost solution over the capital recovery period, which is typically 15-20 years. Our analysis highlights how coal power is losing its economic footing, independent of additional climate change and air pollution policies. As such, Japan should immediately reconsider building new coal. Policy makers also need to provide a clear direction of travel for the existing coal fleet that is consistent with the long term decarbonization goal of the Paris Agreement[11]. Japanese policymakers should develop a retirement schedule based on the LRMC of individual coal units with view to inducing smooth transition from coal. This analysis will allow asset owners to close the higher cost units first and lower cost units last, which should help ensure the end consumer receives the lowest cost power possible.

1.5.2 Accelerate renewable energy through non-discriminatory regulations

Without further reform the Japanese government risks missing the economic opportunity associated with renewable energy and locking-in high cost power. In doing so, the government will likely further compromise energy security, public debt and economic competitiveness. Renewable energy and other supporting technologies – such as battery storage, demand response and high-voltage transmission – are part of a mega trend with no precedent in the 21st century. The benefits from this mega trend will go to those governments who develop a strategy to capture value from the rapid growth of these technologies. Japan has a long track record of technological and engineering prowess that means the nation is well placed to capture value from these technologies as markets mature and product quality commands a price premium. Incentivising renewables begins with seeing these technologies as an opportunity to reinvigorate the nation's industry and economy as well promote energy security. To execute this vision, wholesale changes need to be made to ensure renewable capacity gets built at scale and in manner that maximises its value to the grid. At the heart of these changes is a step change in transparency to avoid discriminatory regulations and potential market abuse.

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[10] *IEA (2017). Energy Technology Perspectives. Available: https://www.iea.org/etp/*

[11] *According to the IEA: i) high efficiency coal technologies are inconsistent with the carbon intensity for power generation under the a 2°C scenario; and ii) 85% to 95% capture rate for CCS is used for IEA modelling, leaving residual emissions that are likely inconsistent with the long-term goal in the Paris Agreement. See: IEA (2016). Energy, Climate Change and Environment. 2016 Insights. Available: https://www.iea.org/publications/freepublications/publication/ECCE2016.pdf*

2 Background

2.1 Context of the report

This report follows previous analysis by Carbon Tracker on the financial risks and economic competitiveness of coal power globally which drew the following conclusions:

- 42% of the global operating fleet was likely unprofitable in 2018 and 72% could be so by 2040 – independent of additional climate or air pollution policy;
- 35% of coal capacity cost more to run than building new renewables in 2018, increasing to 96% by 2030; and
- Coal owners could avoid US$267bn in stranded asset risk by phasing-out coal capacity.[12]

In this report Carbon Tracker use a series of reasonable assumptions to analyse the financial risks and economic competitiveness associated with new and existing coal power.

2.2 Power market overview

Japan is the fourth largest consumer of power in the world behind China, the US and India. Security of supply has historically been of upmost importance to Japan, as the nation imports for almost all of its fossil fuel supply. Japan's recent energy policy has been dominated by efforts to overcome the impact from the 2011 Fukushima Daiichi nuclear disaster. According to the International Energy Agency (IEA), the Fukushima disaster and the subsequent shutdown of Japan's nuclear units increased its import dependence from 80% to nearly 95% in 2010 and resulted in power generation emissions rising by around one-quarter as it used more foreign coal, oil and gas.[13]

Japanese energy policy is mainly defined and implemented based on the SEP, which the Basic Act on Energy Policy (2002) obliges the government to formulate. SEP is revised at least every three years and is usually to be accompanied by supply and demand forecasts. The SEP was approved by the cabinet in August 2018 and decided to maintain the previous power mix decided in 2015, calling for nuclear energy to account for 20%-22% of power generation by 2030, with 22%-24% coming from renewable energy sources, while coal's share will decline to 26%, gas to 27% and oil's to just 3%. This electricity mix is a basis of Japan's 2030 greenhouse gas emissions target, which aims to reduce greenhouse gas emissions by 26% by 2030, compared with 2013 levels.[14]

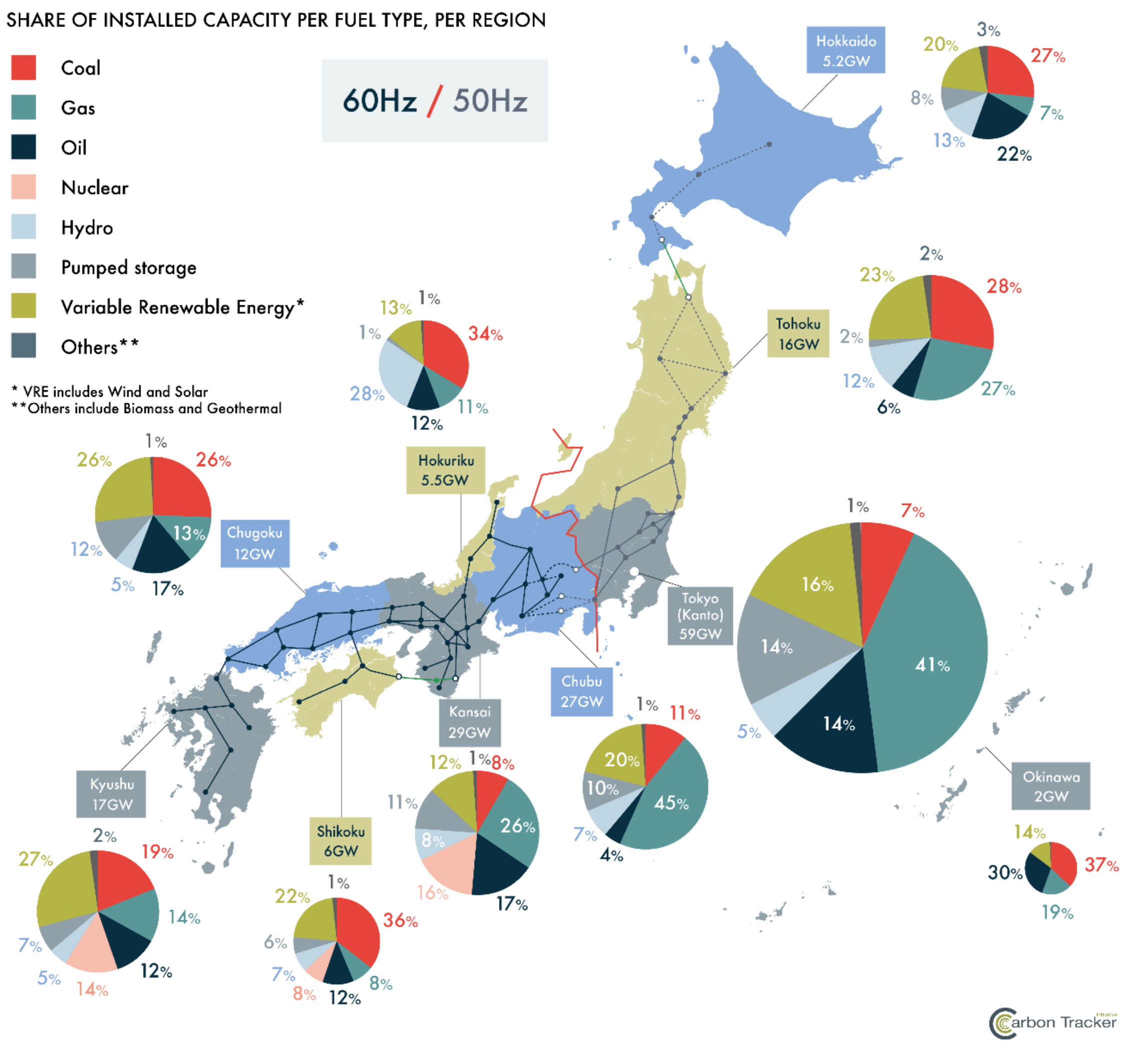
Japan's grid network is divided into ten areas, with each area historically having one vertically integrated utility that operates as a monopoly franchise, controlling generation, distribution and retail.[15] Hokkaido, Tohoku and TEPCO are the eastern grids, while the western grids are Chugoku, Kansai, Hokuriku, Chubu, Kyushu, Shikoku and Okinawa. The eastern grids have a 50Hz frequency while the western grids have a 60Hz frequency. Apart from Okinawa, nine areas are interconnected. The inter-area connection capacity is limited. As part of electricity market

[12] *Carbon Tracker (2018). Powering Down Coal. Available:* https://www.carbontracker.org/reports/coal-portal/
[13] *IEA (2016). Energy Policies of IEA Countries: 2016 Review. Available:* https://www.iea.org/publications/freepublications/publication/EnergyPoliciesofIEACountriesJapan2016.pdf
[14] *METI (2018). Cabinet Decision on the New Strategic Energy Plan. Available:* https://www.meti.go.jp/english/press/2018/0703_002.html
[15] *The country was initially divided into nine regions for integrated utilities. In 1972, when Okinawa was returned to Japan, the number of vertically integrated utilities was increased to ten. The ten vertically integrated utilities include: Hokkaido Electric Power, Tohoku Electric Power, Tokyo Electric Power, Chubu Electric Power, Hokuriku Electric Power, Kansai Electric Power, Chugoku Electric Power, Shikoku Electric Power, Kyushu Electric Power, and Okinawa Electric Power. Available:* https://www.emsc.meti.go.jp/english/info/public/pdf/180122.pdf

reform, the Organisation for Cross-Regional Coordination of Transmission Operators (OCCTO) was established in 2015 to coordinate the transmission of power between regional grids.

Japan has high reserve margins across its ten grids and thus variable renewable energy does not pose serious threats to its ten grids. Nonetheless, the spatial distribution of renewable energy varies significantly in Japan. The overall power system in Japan only accommodates around 6% of wind and solar, but Kyushu, a large island located in the southwest, has a higher share of variable renewable energy and has already faced curtailment problems. On Kyushu, the instantaneous solar PV penetration in certain periods is about 80% of electricity demand.[16] This has resulted in the development operational approaches to optimise the existing resources, including: thermal plants, reservoir hydro and pumped storage hydropower plants.

FIGURE 4. OVERVIEW OF JAPAN'S POWER GRIDS AND THEIR INTERCONNECTORS



Source: Carbon Tracker analysis adapted from OCCTO (2019)

[16] Nikkei Asian Review (2018). https://asia.nikkei.com/Spotlight/Environment/Japan-to-slash-fixed-prices-for-solar-power-feed-ins

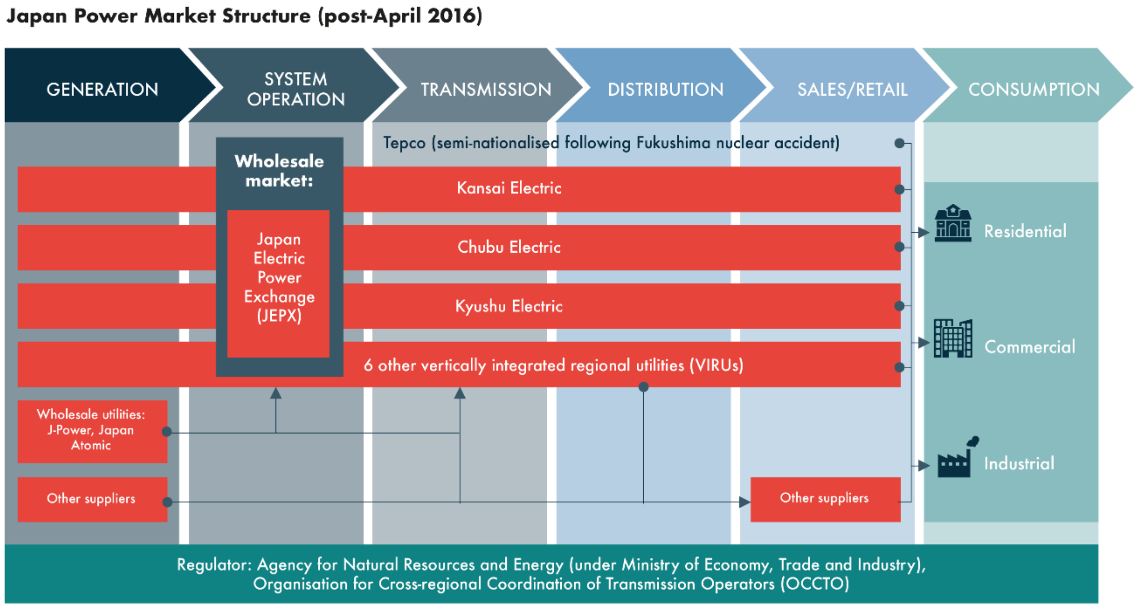
Prior to 2000, Japan's retail market has been held by vertically integrated utilities who offered regulated tariffs on a cost-plus basis, which stifled innovation in energy efficiency and demand response. Since 2000, Japan policymakers have been deregulating its retail market to allow new entrants. These reforms were fully implemented in April 2016. According to the Agency for Natural Resources, as of 9 of September 2019, there are 611 registered retailers.[17] Retailers can secure power by purchasing in the wholesale market, owning generation assets, signing PPAs and buying continuous backup.[18]

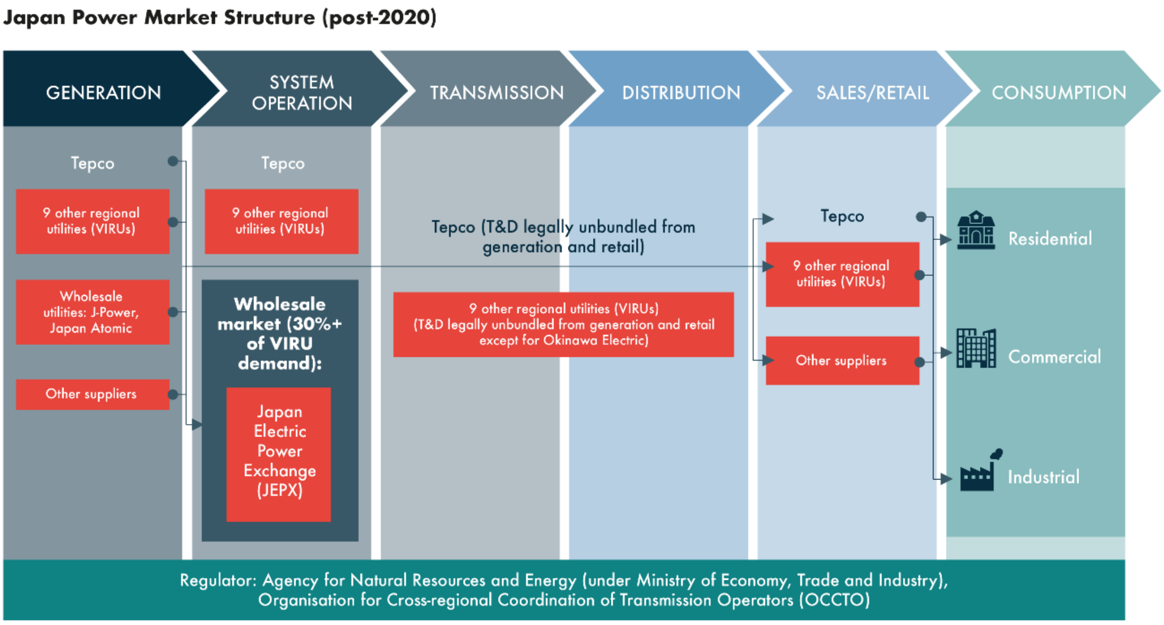
From 2020 onwards, policymakers are requiring legal unbundling: vertically integrated utilities are required to breakup their business in two parts – via a holding or affiliate company structure – into generation & retailing and transmission & distribution. The separate businesses will unlikely prove to be independent like liberalised markets in Europe, as they will remain part of the same holding company that is listed on capital markets. To facilitate the power system reform, the government has decided to create new markets between now and 2020. These new markets include baseload, capacity, non-fossil fuel certificates, balancing services, interconnector capacity and gross bidding. Figure 5 illustrates Japan's power value chain before and after 2020.

[17] *Agency of Natural Resources (2019). Available:* https://www.enecho.meti.go.jp/category/electricity_and_gas/electric/summary/retailers_list/

[18] *Tariffs for users below 50kW remain regulated until 2020 unless consumers opt out. See footnote 4 for more information. METI (2018). Available:* https://www.emsc.meti.go.jp/english/info/public/pdf/180122.pdf

FIGURE 5. JAPAN'S POWER MARKET BEFORE AND AFTER 2020





Source: Adapted from Bloomberg NEF (2017)

2.3 The role of coal and climate action beyond central government

According to Climate Analytics, between 1990 and 2016, around 90% of the rise in energy-related emissions is explained by the increase in emissions from coal power.[19] Therefore, in terms of climate policy measures, addressing emissions from coal should be a primary focus for Japan. Despite ongoing efforts towards a cleaner power mix, coal is the dominant source of electricity in

[19] *Based on data from MOEJ and METI. Climate Analytics (2017). Science-based coal phase-out timeline for Japan. Implications for policymakers. Available: https://climateanalytics.org/media/coalphaseout-2018-en-report_1.pdf*

Japan, producing 29%[20] of total gross generation in 2017. As detailed above, according to the SEP, by 2030 coal is still expected to generate around a quarter of power in Japan. Japan has 11 GW of coal planned and under construction. The country's SEP, which aims to stimulate the economy with lowest cost energy and improve energy independence, risks being derailed by a continued focus on coal power.

Japanese investors, corporations and local government are becoming increasingly supportive of more ambitious climate policy. After the adoption of the Paris Agreement in 2015, financial institutions are actively requesting company disclosure of climate-related risk. The Task force on Climate related Financial Disclosure (TCFD) established under G20 published recommendations for disclosure in 2017. The Government now strongly supports this initiative. As of 20 September 2019, 44 of Japanese financial institutions and 128 companies from non-financial sector expressed its support for the recommendations of the TCFD.[21]

In May 2019, Tokyo Keizai reported[22] that 90% of companies listed on the Tokyo Stock Exchange:

- Have implemented or are considering a science-based target consistent with the temperature goal in the Paris Agreement.
- Are requesting energy providers to supply low-carbon emission power and more than half are requesting the Government to change the policy direction toward decarbonization including drastic reduction or phase-out of coal.

In June 2019, 20 companies, including Apple and Sony, have requested the government increase Japan's renewable energy target from 22-24% in 2030 to 30%.[23] 19 large local governments have also made similar declarations.[24]

[20] *Ministry of Environment (2017). Available:* http://www.env.go.jp/earth/ondanka/ghg-mrv/emissions/results/JNGI2019_2-7.pdf
[21] *METI, (2017). TCFD. Available:* https://www.meti.go.jp/policy/energy_environment/global_warming/disclosure.html
[22] *Toyo Keizai Weekly No. 18 May 2019. Available:* https://toyokeizai.net/sp/visual/tkp/decarbonization-survey/
[23] *The Climate Group (2019). Available:* https://www.theclimategroup.org/news/major-companies-call-ambitious-2030-renewable-electricity-targets-japan
[24] *City Renewable Energy Council (2019) Available:* https://enekyo-city.jp/wp-content/uploads/20190730.pdf

3 Data sources, key assumptions and modelling methodologies

3.1 Data sources and key assumptions

The asset-level model outputs in this analysis are based on a number of assumptions about commodity prices (fuel, power and carbon), variable and fixed operations and maintenance costs (O&M) and policy outcomes (out-of-market revenues and control technologies costs, for example). These data sources and assumptions are detailed in Table 2. For the technical definitions used in this report see Box 1.

TABLE 2. DATASETS AND KEY ASSUMPTIONS USED IN THIS ANALYSIS

PARAMETER	DETAIL	SOURCE
Inventory data on unit-level characteristics	Unit name, plant name, plant location, unit installed capacity; unit status, year of unit operation, parent organization, sponsor organization, combustion technology type, coal type, heat rate, and emissions factor.	Kiko Network (2019), Global Energy Monitor (2019)
Capital cost	In the absence of publicly available information we assume for the following boiler technologies: US$/kW 2,100 for subcritical, US$/kW 2,400 for supercritical, US$/kW 2,600 for ultra-super and US$/kW 2,900 for IGCC.	IEA (2014)
Cooling type and pollution control technologies by plant	Installed environmental control technologies for nitrogen dioxide, sulphur dioxide and particulate matter, as well as the type of cooling technology.	Platts (2019)
Fixed O&M	Fixed O&M assumptions depend on the combustion technology of the boiler US$9/kW for subcritical technologies; US$12/kW for supercritical technologies; US$13/kW for ultra-supercritical technologies; and US$21/kW for integrated gasification combined cycle technologies (IGCC).	Carbon Tracker estimate based on IEA (2014)
Variable O&M	Variable O&M assumptions depend on the combustion technology of the boiler: US$5.98/MWh for subcritical technologies; US$4.79/MWh for supercritical technologies; US$4.49/MWh for ultra-supercritical technologies; and US$7.73/MWh for integrated gasification combined cycle technologies. We also index the cost depending on the unit's size: 133% for units 0 to 100 MW; 107% for units 100 to 300 MW and 100% for units 300 MW or more.	North America Electric Reliability Corporation (2010)
Capacity factor	Realised annual capacity factors at the asset level for existing capacity.	Kiko Network based on METI (2019)
Fuel type, cost and transport	Fuel costs include the expenses incurred in buying, transporting, and preparing the coal. For the cost of coal for producers we use benchmarks from Bloomberg LP. Estimates for 2019 are based on daily price averages, while from 2019 onwards we take an annual average from 2015 to 2019. Fuel costs also include a model which calculates the transport of coal. This is a cost-optimised supply route algorithm, which computes the distance between a unit's location and the nearest suitable coal mine, considering coal type, mode of transport and related costs and other charges, and available port, mine and import capacities. We assume bituminous coal is imported from Australia, Indonesia and Russia via seaborne and then land routes to plant Japan.	Bloomberg (2019), Ports.com (2018), UN Comtrade (2018), Carbon Tracker analysis
Carbon price	US$2.68 t/CO2 based on 289 yen/tCO2 from implemented government policy.	Environment and Economy Division Ministry of the Environment January (2017)
Combustion efficiency	Gross, low heating value (LHV) adjusted for unit age.	IEA (2015) and Carbon Tracker analysis
Efficiency adjustments from cooling and pollution controls	Adjustments made to the overall combustion efficiency of the plant depending on the technology installed.	EPA (2018)
Environmental control technology capital and operational costs	These costs include fixed operations and maintenance ($/kW per year) and variable operations and maintenance ($/MWh). Adjusted for pollutant and nameplate capacity of plant.	US EPA (2018)
Unabated coal-fired power generation pathway for below 2°C scenario	We assume OECD decline rates in the IEA's Beyond 2°C scenario (B2DS) for Japan generation.	IEA (2017), Carbon Tracker analysis

Pollution limit regulations and associated capital and operational costs	No changes to existing air pollution regulations assumed over the modelling period.	Carbon Tracker analysis
Plant revenues	Japan is in the process of liberalizing its power market. The real sales price per kWh is decided by over-the-counter trading and not disclosed to the third parties. As a proxy for revenues we use a five-year of average day-ahead spot prices from Japan Electric Power Exchange.	Bloomberg LP (2019)
LCOE estimates of onshore wind, offshore wind and solar PV	Top-down cost analysis based on high, medium and low scenarios. See the Appendix for more information.	Carbon Tracker estimate
Discount rate for the net present value (NPV)	5% for the below 2°C stranded asset model.	Carbon Tracker estimate
Working cost of capital (WACC)	2.8%, 3.5% and 4.2% for the high, medium and low scenarios of the LCOE estimates, respectively. 2.5% for project economics model.	Carbon Tracker estimate

Sources: see above and references.

BOX 1 METRIC DEFINITIONS

Short-run marginal cost. The short-run marginal cost (SRMC) of a coal unit includes fuel, carbon (where applicable) and variable O&M (VOM) cost. Fuel costs include the cost of buying, transporting, and preparing the coal. There are different types of coal which vary in cost depending on the energy content. The transportation costs depend on whether the coal is imported from the seaborne market or purchased domestically from a nearby mine. VOM costs vary with the use of the unit. These costs include, but are not limited to, purchasing water, power and chemicals, lubricants, and other supplies, as well as disposing of waste. The short-run operating cost tends to impact dispatch decisions in liberalised markets where units enter competitive markets for the right to sell power to consumers. Liberalised markets operate in the following way:

1. The grid operator forecasts power demand ahead of time.
2. The grid operator asks for bids to supply quantity of power required to meet the forecast. Power generators typically bid at SRMC of producing the next unit of power.
3. The grid operator starts purchasing the power offered by the lowest bid operators until they add up to the required power in the forecast. This is called the uniform clearing price.
4. The grid operator pays all suppliers the same uniform clearing price regardless of what they bid. In regulated markets the way coal plants are dispatched varies depending on market structures.

LRMC. LRMC includes SRMC plus fixed O&M (FOM) and any capital additions from meeting environmental regulations. FOM include the expenses incurred at a power plant that do not vary significantly with generation and include staffing, equipment, administrative expenses, maintenance and operating fees, as well as installing and operating control technologies to meet regulations. While the SRMC governs dispatch decisions, the LRMC impacts the bottom-line.

Relative competitiveness. The year when the LCOE of either onshore wind or solar PV is lower than the LRMC of coal capacity.

Gross profitability. Revenues from in-market (i.e. wholesale power markets) and out-of-market (i.e. ancillary and balancing services and capacity markets) sources minus the LRMC.

Below 2°C scenario retirement year. The year when the unit should be retired to be consistent with the temperature goal in the Paris Agreement. The retirement schedule is determined based on the long run marginal cost or gross profitability. See Section 3.2.3 Below 2°C scenario model for more information.

Below 2°C scenario stranded asset risk. The potential revenues lost from shutting the unit prematurely in accordance with the retirement year mentioned above. See Section 3.2.3 Below 2°C scenario model for more information.

Stranded asset. A fossil fuel energy and generation resources which, at some time prior to the end of their economic life (as assumed at the investment decision point), are no longer able to earn an economic return (i.e. meet the company's internal rate of return), as a result of changes in the market and regulatory environment associated with the transition to a low-carbon economy.

3.2 Modelling methodology overview

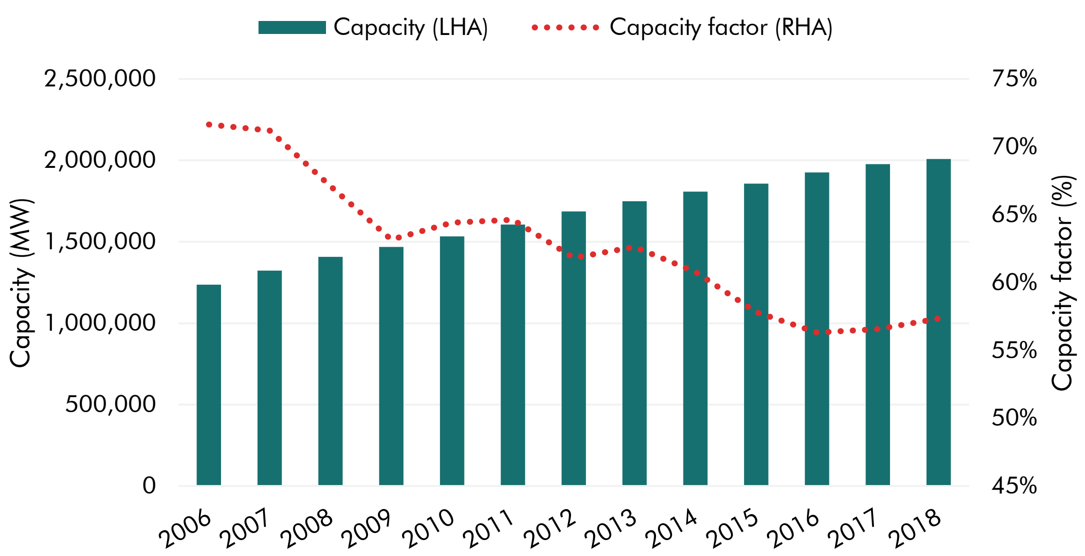
3.2.1 Project economics model

Carbon Tracker's project economic model analyses the financial viability of planned coal capacity and coal capacity under-construction. The purpose of this analysis to illustrate how, under different scenarios, a coal project could become unviable over its lifetime. The main assumptions underpinning model outputs are detailed in Table 2 and 4.

Project finance modelling assesses the risk-reward of lending to, or investing in, a coal power project and includes a forecast of revenues, construction, operating and maintenance costs, tax, the IRR and NPV. The NPV is the difference between the present value of cash inflows and the present value of cash outflows. The IRR is the discount rate that makes the NPV of all cash flows from a particular project equal to zero.

As detailed in Figure 6, there is a coal capacity underutilisation trend occurring across the globe, whereby coal capacity additions are outpacing coal generation.

FIGURE 6. GLOBAL COAL CAPACITY VERSUS AVERAGE GLOBAL CAPACITY FACTOR FROM 2006 TO 2018



Source: Global Energy Monitor, BP and Carbon Tracker analysis

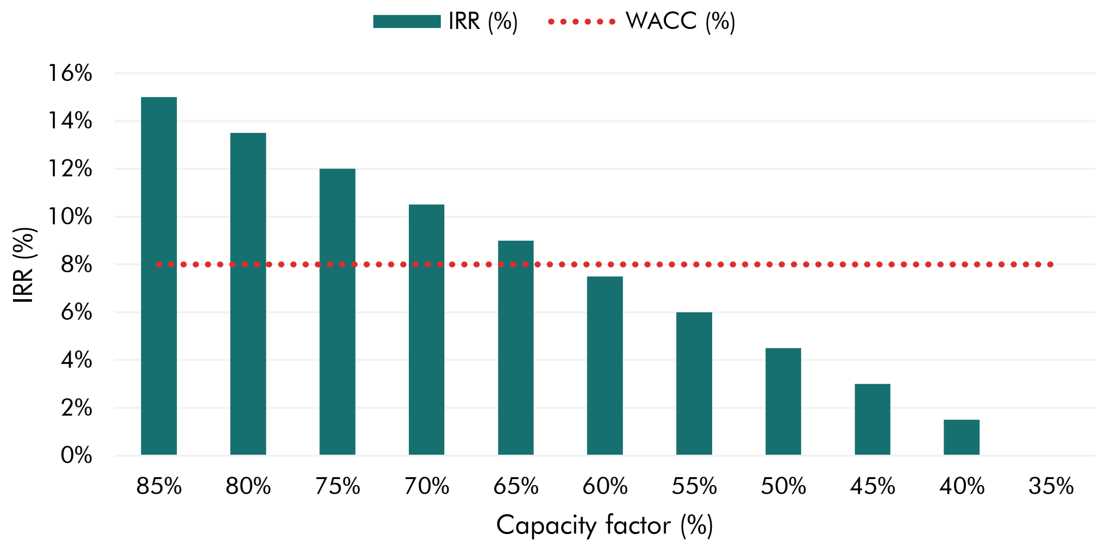
Notes: Based on gross generation from BP.

A declining capacity factor is one example of how a project could become unviable over its lifetime. The process of pouring capital into increasingly underutilised assets cannot continue indefinitely; at some point the IRR becomes so low that debt obligations cannot be met.[25] At that stage one of two events occur: capital from projects will become stranded because debt obligations will not be met, or the projects will start to deliver little to no IRR. Diminishing returns is a very serious concern and should prompt governments and investors to act with conviction to stop economically irrational coal power investments.

[25] *Unless there is a policy to compensate generators from declining capacity factors, which does occur in several jurisdictions.*

To illustrate how coal power investments will lose their viability with lower levels of utilisation, Figure 7 compares the IRR of a hypothetical coal project with different capacity factors. Since a proportion of a coal plant's running cost is fixed, a lower capacity factor means that fixed O&M costs are spread over a smaller number of operating hours. This, in turn, progressively reduces the IRR of the project. In theory, once the IRR is less than the cost of capital it becomes an unviable project.

FIGURE 7. ILLUSTRATIVE EXAMPLE OF HOW A DECLINING CAPACITY FACTOR IMPACTS THE PROJECT IRR



Source: Carbon Tracker analysis

Notes: for illustrative purposes only.

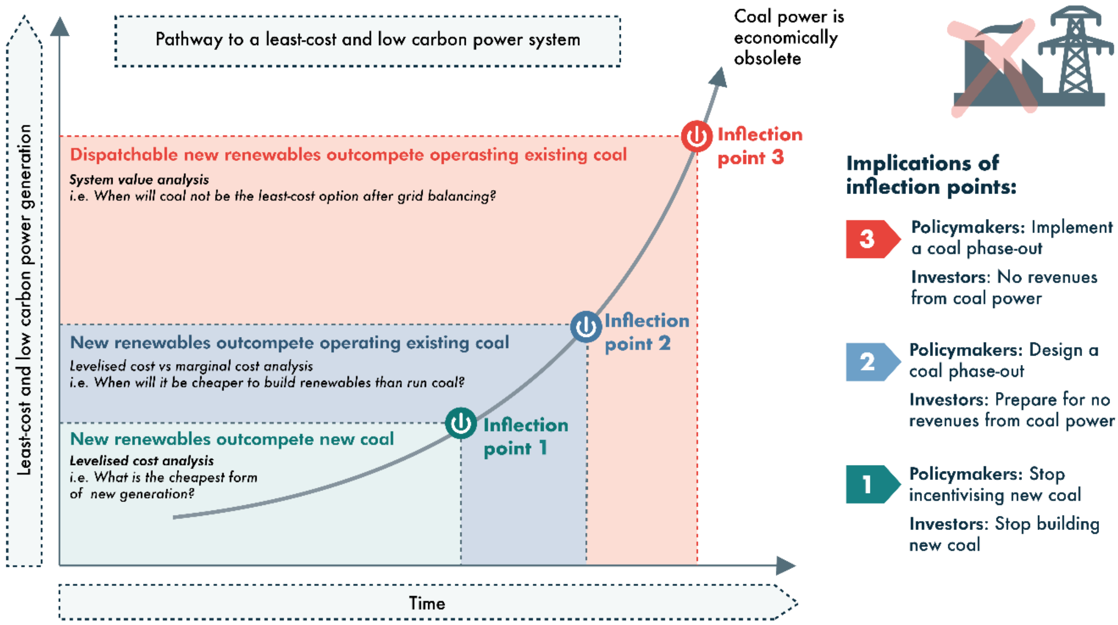
3.2.2 Relative economics model

Carbon Tracker's transition risk model compares both the LCOE of new coal investments and the LRMC of existing coal assets with the LCOE of onshore wind, offshore wind and utility-scale solar PV.[26] The assumptions for the LRMC and LCOE estimates are detailed in Table 2 and the Appendix.

There are three economic inflection points that policymakers and investors need to track to provide the least-cost power and avoid stranded assets: when new renewables and gas outcompete new coal; when new renewables and gas outcompete operating existing coal; and when new firm (or dispatchable) renewables and gas outcompete operating existing coal. These inflection points are illustrated in Figure 8.

[26] *We acknowledge that LCOE analysis is a limited metric as it does not consider revenues from generation and the system value of wind and solar. According to the IEA, the best way to integrate variable renewable energy (VRE) is to transform the overall power system through system-friendly deployment, improved operating strategies and investment in additional flexible resources. Flexible resources include better located generation, grid infrastructure, storage and demand side integration. See: IEA (2016), Next-generation wind and solar power: From cost to value. Available:* *https://www.iea.org/publications/freepublications/publication/NextGenerationWindandSolarPower.pdf*

FIGURE 8. THE INTERSECTION BETWEEN THE ECONOMIC INFLECTION POINTS AND THE POLICYMAKING PROCESS FOR A LEAST-COST POWER SYSTEM



Source: Carbon Tracker analysis (2018)

LCOE is a standard analytical tool used to compare power generation technologies and is widely used in power market analysis and modelling.[27] While the limitations of using generic LCOE analysis for understanding the economics of power generation have been well documented, it does provide a simple proxy for when new investments in coal power no longer make economic sense and when investors and policymakers should plan and implement a coal power phase-out.[28] The LCOE is simply the sum of all costs divided by the amount of generation. The costs include capital costs, the capital recovery factor, fixed O&M, variable O&M, fuel and carbon taxes.

3.2.3 Below 2°C stranded asset model

The stranded asset risk in Carbon Tracker's 2°C scenario is defined as the difference between the NPV of revenues in a BAU scenario and a scenario consistent with the temperature goal in the Paris Agreement. The retirement schedules are developed based on the LRMC. Underlying this analysis is the logic that in the context of efforts to reduce carbon emissions and demand for coal power, the least economically efficient will be retired first. The modelling approach involves three steps.

Firstly, we identify the amount of capacity that is required to fill the generation requirement in the IEA's beyond 2°C scenario (B2DS). Under the B2DS, coal generation without carbon capture and storage (CCS) is phased-out globally by 2040. This analysis assumes CCS will not be available to

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[27] *While we recognise that other renewable options for power generation may be appropriate in some regions, onshore wind, offshore wind and utility-scale solar-PV have been chosen for comparability and simplicity.*
[28] *LCOE analysis is a limited metric as it does not consider revenues from generation and the system value of wind and solar. For more information, see: IEA (2016). Next-generation wind and solar power: From cost to value. Available:* *https://www.iea.org/publications/freepublications/publication/NextGenerationWindandSolarPower.pdf*

extend the lifetimes of coal capacity, as the costs will likely be prohibitively expensive.[29] Regions have different phase-out dates. For Japan, we assume a phase-out date of 2030 which is broadly consistent with other OECD countries.[30]

Secondly, we rank the coal-fired generation units to develop a retirement schedule, based on the authority, region or grid responsible for maintaining security of supply. The units are ranked based on the LRMC. The coal units with the highest LRMC are phased-out until the aggregated asset level generation reaches the limits set out in the B2DS.

Thirdly, we calculate the cash flow of every operating and under-construction unit in both the B2DS and BAU outcomes to understand stranded asset risk. Stranded asset risk under the B2DS is defined as the difference between the NPV of cash flows in the B2DS (which phases-out all coal power by 2030) and the NPV of cash flows in the BAU scenario (which includes announced retirements in company reports or otherwise assumes a minimum lifetime of 40 years). Figure 9 provides a schematic illustration of the below 2°C stranded asset modelling methodology.

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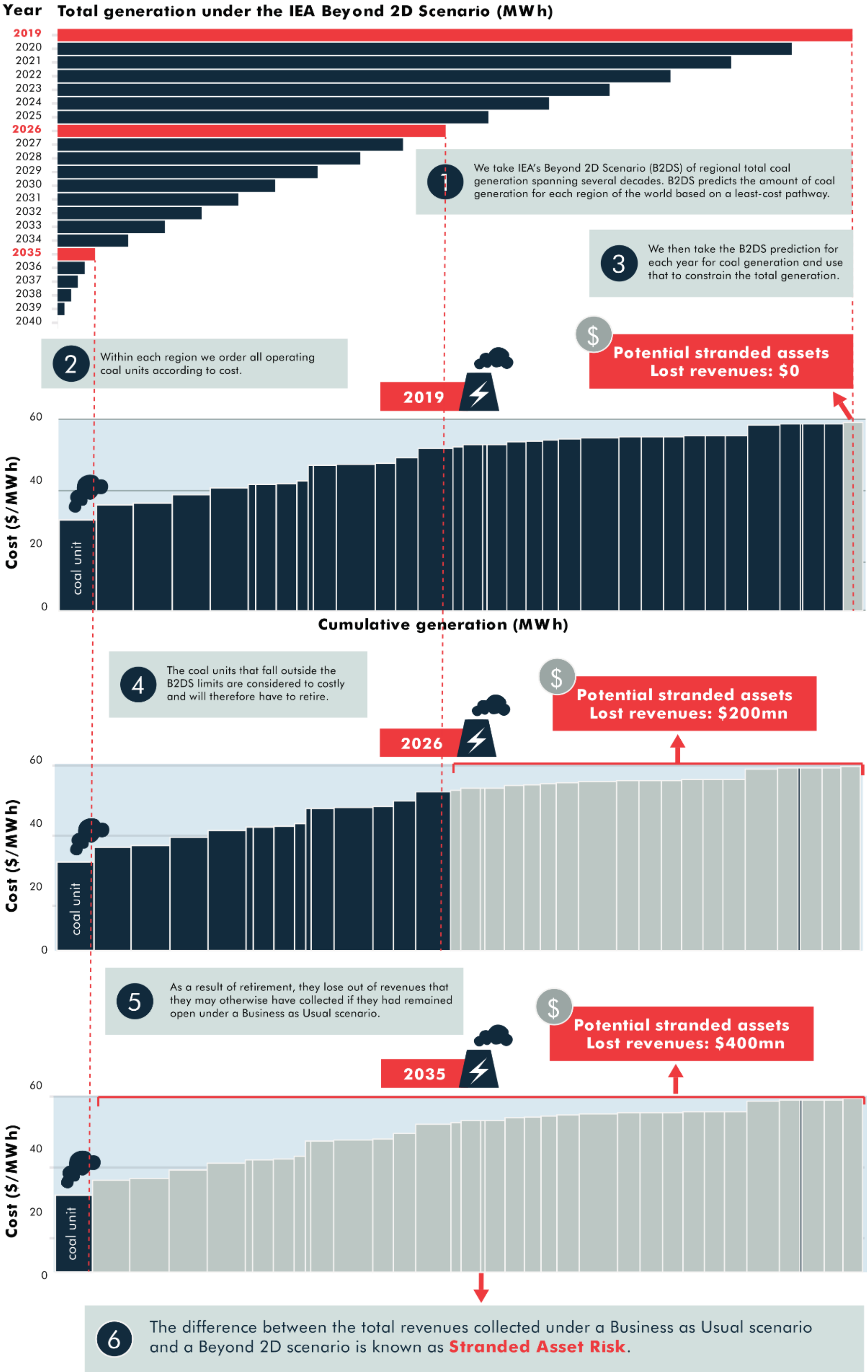
[29] *There is currently two CCS-equipped coal-fired power plant operating in the world today (Boundary Dam in Canada and Petra Nova in the US). Due to limited progress to date and the new build and retrofit costs compared to other decarbonisation options, this report assumes that CCS will only be viable in niche applications over the lifetimes of the fossil fuel plants analysed, and thus is not included in this study which focuses on global averages without subsidies. For more information see: Carbon Tracker (2016). End of the load for coal and gas? Available: https://* www.carbontracker.org/reports/the-end-of-the-load-for-coal-and-gas/

[30] *For more information see: IEA (2017). Energy Technology Perspectives (ETP) 2017. Available:* https://www.iea.org/etp/

FIGURE 9. SCHEMATIC ILLUSTRATION OF THE MODELLING METHODOLOGY



4 Findings

4.1.1 Project economics of planned and under-construction coal

Japan currently has over 11 GW of under-construction, permitted or pre-permitted coal capacity. Without a policy intervention, this capacity is likely to be operational by the early to mid-2020s and has an estimated overnight capital cost of US$29 billion.

TABLE 3. UNDER-CONSTRUCTION AND PLANNED COAL CAPACITY IN JAPAN

Project	Status	Capacity (MW)	Boiler technology	Estimated start date	Estimated capital cost (million US$)
Akita Unit 1	Permitted	650	Ultra-super	2024	1,690
Akita Unit 2	Permitted	650	Ultra-super	2024	1,690
Hirono IGCC	Construction	540	IGCC	2021	1,134
Hitachinaka Kyodo Unit 1	Construction	650	Ultra-super	2020	1,690
Kaita	Construction	112	Subcritical	2021	291
Kobe Unit 3	Construction	650	Ultra-super	2021	1,690
Kobe Unit 4	Construction	650	Ultra-super	2022	1,690
Kushiro	Construction	112	Ultra-super	2020	235
Misumi Unit 2	Construction	1000	Ultra-super	2022	2,600
Nakoso IGCC	Construction	540	IGCC	2020	1,134
Saijo Unit 1	Construction	500	Ultra-super	2023	1,300
Kashima Unit 2	Construction	645	Ultra-super	2020	1,677
Takehara New Unit 1	Construction	600	Ultra-super	2020	1,560
Taketoyo Unit 5	Construction	1070	Ultra-super	2022	2,782
Tokuyama East Power No. 3	Construction	300	Subcritical	2022	780
Ube Unit 1	Pre-permit	600	Ultra-super	2026	1,560
Ube Unit 2	Pre-permit	600	Ultra-super	2026	1,560
Yokkaichi	Pre-permit	112	Subcritical	2019	235

Yokosuka Unit 1	Construction	650	Ultra-super	2023	1,690
Yokosuka Unit 2	Construction	650	Ultra-super	2024	1,690
Total	**n/a**	**11,281**	**n/a**	**2021**	**28,679**

Source: Global Energy Monitor (2019), Kiko Network (2019), IEA (2014) and Carbon Tracker analysis

The main assumptions we use are presented in Table 4 below.

Table 4. Main assumptions used for the project economics model

Parameter	Detail	Source
Capital cost	In the absence of publicly available information we assume for the following boiler technologies: US$/kW 2,100 for subcritical, US$/kW 2,400 for supercritical, US$/kW 2,600 for ultra-super and US$/kW 2,900 for IGCC.	IEA (2014)
Fuel price	2014 to 2019 weighted average of Australian, Indonesia and Russian coal. See Table 2 for transport algorithm.	Bloomberg (2019), Ports.com (2018), UN Comtrade (2018), Carbon Tracker analysis
Capacity factor	Average capacity factor based on realised annual capacity factors at the asset level for existing capacity.	Kiko Network based on METI (2019)
Revenues	As a proxy for revenues we use a one year of average day-ahead spot prices from Japan Electric Power Exchange.	Bloomberg (2019)
WACC	2.5%	Carbon Tracker estimate
Discount rate	2.5%	Carbon Tracker estimate
Tax rate	27%	OECD (2019)
Debt to equity ratio	Due to a lack of publicly available information we use a 80:20 debt to equity ratio.	Carbon Tracker estimate
Capital allowances	Straight-line depreciation of equipment and building over 15 years and 38 years, respectively. Assume that power equipment represents 50% of capital costs and the building represents 11%.	Japan Ministry of Finance (2019), US Dept. of Energy (2008)

Source: See table.

Notes: for other assumptions see Table 2.

The results of the project economics model are presented in Table 5. The results include a scenario analysis of the three most important variables: capacity factor, fuel price, tariff price and carbon price. If the capacity factor goes below 48%, the fuel price goes higher than US$104/t, the tariff is lower than US$72/MWh, or the carbon price goes higher than US$26/t$CO_2$, then these projects could become unviable. If these projects become unviable it could leave consumers, taxpayers and/or investors at risk.

Table 5. Results of the project economics model

Project	Parent owner	Forecasted NPV (million US$)	Lowest capacity factor to achieve an IRR greater than WACC = 2.5% (%)	Highest fuel price to achieve an IRR greater than WACC = 2.5% (US$/t)	Lowest tariff to achieve an IRR greater than WACC = 2.5% (US$/MWh)	Highest carbon price in 2040 to achieve an IRR greater than WACC = 2.5% (US$/tCO2)
Akita Unit 1	KEPCO, Marubeni	$1,110	49%	$109	$70	$28
Akita Unit 2	KEPCO, Marubeni	$1,110	49%	$109	$70	$28
Hirono IGCC	Mitsubishi (90%), TEPCO (10%)	$539	62%	$95	$75	$21
Hitachinaka Kyodo Unit 1	JERA	$766	50%	$100	$73	$24
Kaita	Chugoku Electric Power (50%), Hiroshima Gas (50%)	$65	59%	$85	$78	$10
KobeUnit 3	Kobelco Power Kobe 2	$1,050	45%	$111	$69	$32
KobeUnit 4	Kobelco Power Kobe 2	$1,028	44%	$111	$69	$31
Kushiro	IDI Infrastructures F-Power	$201	40%	$106	$68	$23
Misumi Unit 2	Chugoku Electric Power	$1,970	42%	$121	$66	$38
Nakoso IGCC	Mitsubishi (90%), TEPCO (5%), Joban Joint Power (5%)	$575	62%	$95	$75	$21
Saijo Unit 1	Shikoku Electric Power	$1,239	42%	$125	$64	$40
Kashima Unit 2	Nippon Steel, J-power	$1,011	47%	$111	$70	$33
Takehara New Unit 1	J-POWER	$1,029	44%	$112	$68	$34
Taketoyo Unit 5	JERA	$1,954	43%	$118	$67	$36
Tokuyama East Power No. 3	Tokuyama, Marubeni, Tokyo Century	$176	57%	$87	$77	$11
Ube Unit 1	J-POWER, Ube Industries	$1,122	43%	$117	$67	$34
Ube Unit 2	J-POWER, Ube Industries	$1,113	42%	$119	$67	$34
Yokkaichi	Mitsubishi	$74	54%	$87	$77	$11
Yokosuka Unit 1	JERA	$5	48%	$76	$82	$4
Yokosuka Unit 2	JERA	$5	47%	$76	$82	$4
Average	**n/a**	**n/a**	**48%**	**$104**	**$72**	**$25**

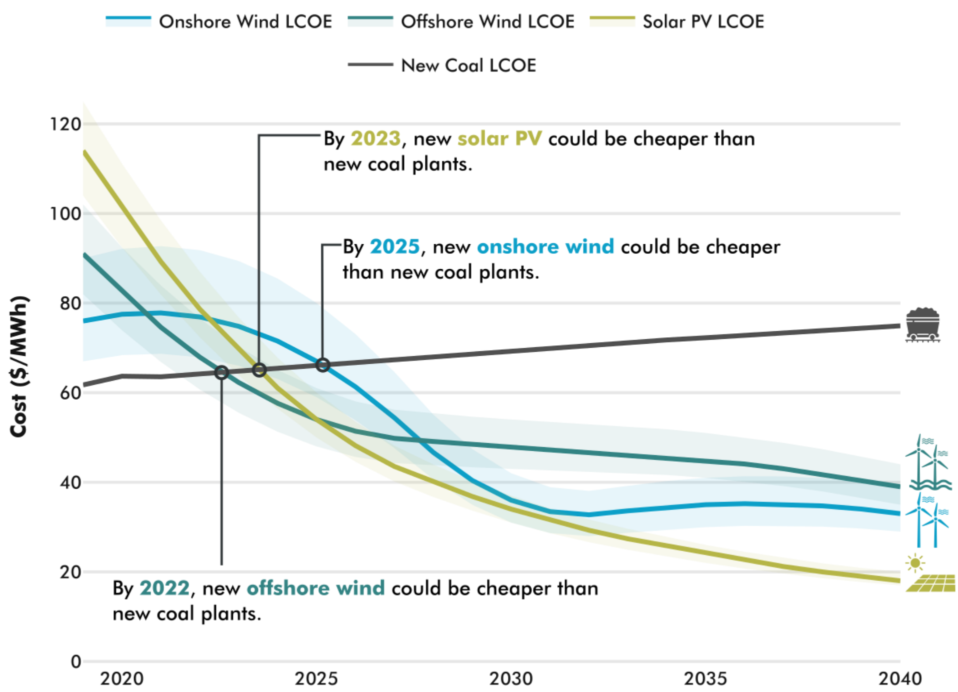
Source: Carbon Tracker analysis

Notes: Scenarios assume a five-year average for the other variables. For example, the capacity factor scenarios assume a five-year average fuel and tariff prices.

4.1.2 Relative economics: new renewables cheaper than new coal by 2022

While Japan currently has some of highest renewable energy costs in the world, it should be noted that the cost of solar PV has declined by 74% from 2010 to 2018.[31] As detailed in Figure 10, we expect new offshore wind to be cheaper than new coal by 2022 and new solar PV by 2023. The government has fixed mid-term cost targets of 7 yen/kWh (~US$65/MWh) in 2025 for utility-scale solar PV and 8-9 yen/kWh (~US$74-84/MWh) by 2030 for onshore wind.[32] These official targets are largely consistent with predicted cost trends in Figure 10. These changing cost dynamics post a significant stranded asset risk if investors and policymakers decide to move forward with the 11 GW of coal capacity under-construction, permitted or pre-permit. The capital recovery period for new investments in coal capacity is typically 15-20 years and therefore we consider these investments high risk, as burning coal to generate power will unlikely be a least-cost option from a systems value perspective before debt is fully amortised.

FIGURE 10. LCOE OF COAL VERSUS ONSHORE WIND, OFFSHORE WIND AND SOLAR PV IN JAPAN



Source: Carbon Tracker analysis

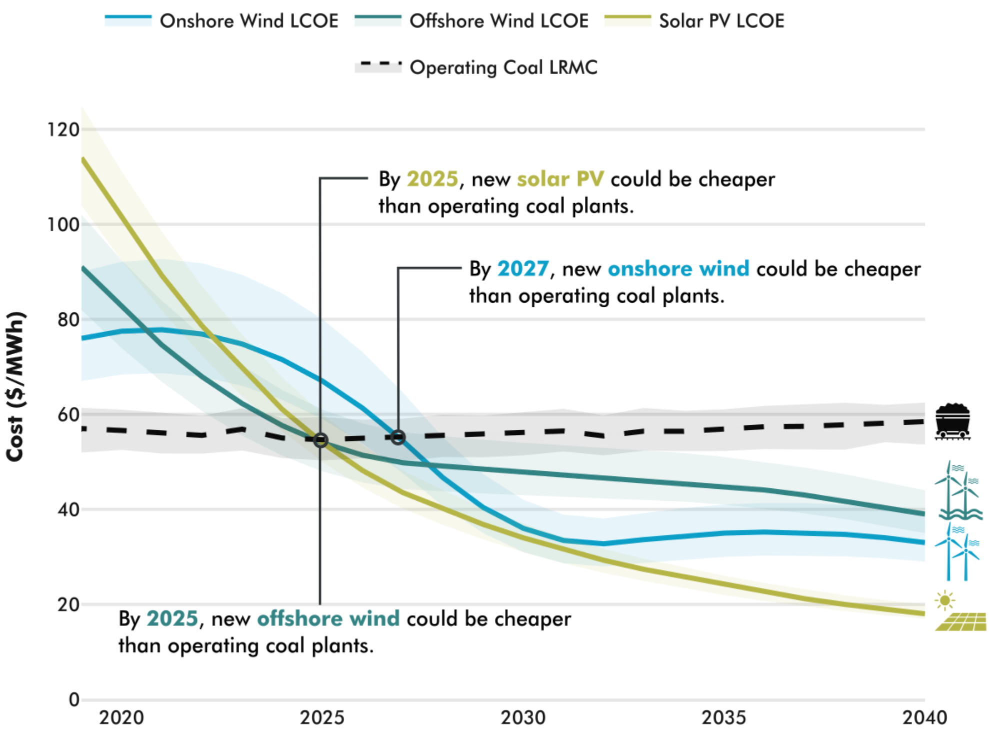
Notes: Notes: the key assumptions for onshore wind include: CAPEX of US$2231/KW, O&M of 1.7% of CAPEX, capacity factor of 26%, capacity projection of 30 GW by 2040, real WACC of 3.5%, debt equity split of 80:20, a learning rate of 25%. The key assumptions for solar PV include: CAPEX of US$1932/KW, O&M of 1.3% of CAPEX, capacity factor of 14%, capacity projection of 282 GW in 2040, real WACC of 3.5%, debt equity split 80/20 and learning rate 60%. The key assumptions for offshore wind include: CAPEX of 4135 US$/kW, annual O&M costs 2.5% of CAPEX, capacity factor of 49%, real WACC of 4.2%, debt equity split of 75:25, capacity projection of 20 GW in 2040 and learning rate of 12%. See Table 2 and the appendix for more information.

[31] *IRENA (2019), Renewable Power Generation Costs in 2018, International Renewable Energy Agency (2019).*
[32] *Opinion on the Tariffs of FY2019 Onward by the Tariff setting committee (in Japanese). Available: https://www.meti.go.jp/shingikai/santeii/pdf/20190109001_01.pdf*

4.1.3 New renewables cheaper than existing coal by 2025

Due to the deflationary trend of renewable energy we expect that, in the not too distant future, new investments in renewable energy will likely cost less than running coal. As illustrated in Figure 11 and Table 6, the relative competitiveness of coal-fired power depends on prevailing fuel prices. In the lower bound fuel prices, it could be cheaper to build new offshore wind and solar PV than operate existing coal plants by 2026. In the mid-range fuel prices, it could be cheaper to build new offshore wind and solar PV by 2025. Finally, in the upper-bound fuel prices it could be cheaper to build new offshore wind by 2024 and new solar PV by 2025. These results are based on a median LCOE forecast for solar PV and onshore wind. However, it is plausible that LCOE prices will drop further. See Table 6 for more scenarios summarising these possibilities. Moreover, making coal highly dispatchable to accommodate increased amounts of low-cost variable renewable energy increases O&M costs, exacerbating its economic disadvantage.[33]

FIGURE 11. LRMC OF JAPAN'S OPERATING COAL CAPACITY VS THE LCOE OF NEW ONSHORE WIND, OFFSHORE WIND AND SOLAR PV



Source: Carbon Tracker analysis

Notes: Upper and lower bounds for the cost of operating coal units are calculated using several scenarios. Notes: Operating coal cost is capacity-weighted and based on LRMC, which includes fuel, variable O&M and fixed O&M (SRMC plus fixed operating and maintenance costs). Imported coal is assumed from Australia, Russia and Indonesia. The upper and lower bounds represent the 25% and 75% confidence intervals in the LRMC given the variance in historical coal prices from the last 10 years. The historical mean coal price is $75/ton.

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[33] *The IEA Clean Coal Centre estimated these costs. Hot, warm and cold starting a 500 MW coal unit could cost $94,000, $116,000 and $174,000, respectively. Load cycling a 500 MW coal unit down to 180 MW could cost $13,000. IEA Clean Coal Centre (2016). Levelling the intermittency of renewables with coal. Available:* https://www.usea.org/sites/default/files/Leveling%20the%20intermittency%20of%20renewables%20with%20coal%20-%20ccc268-1.pdf

Table 6: The year when new renewables will be cheaper to build than operating existing coal, according to a range of scenarios

		Solar PV LCOE			Onshore wind LCOE			Offshore wind LCOE		
		Low	Mid	High	Low	Mid	High	Low	Mid	High
Coal LRMC	Low	2025	2026	2027	2027	2028	2029	2024	2026	2033
	Mid	2024	2025	2026	2026	2027	2028	2023	2025	2028
	High	2024	2025	2026	2025	2027	2028	2023	2024	2026

Source: Carbon Tracker analysis

Notes: See notes from Figure 11 for more information.

4.1.4 Dispatchable renewables and systems balancing

The point when new dispatchable (or firm) renewables outcompetes operating coal is outside the scope of this analysis. The challenge for policymakers today is no longer whether or not renewable energy will be the least-cost option, but rather how to integrate wind and solar to maximise system value or lower the cost to the overall system. The IEA notes that it is possible to get to 15% solar and wind by simply upgrading some operational practices, such as grid codes, forecasting, scheduling and so on, which are not capital intensive.[34]

For example, in 2003, when wind made up 2% of annual generation in Ireland, the head of the National Grid stated that:

"This amount of wind generation does, however, pose an increased risk to the security and stability of the power system which the transmission system operator feels exceeds the level normally likely to be accepted by a prudent system operator."

Wind now makes up over 20% of annual generation in Ireland and during this time security of supply has increased.

A report by Agora and the Renewable Energy Institute found that the Japanese power system could accommodate a larger proportion of wind and solar energy than is currently planned by 2030. The report modelled two scenarios: (i) the currently planned amount of variable renewable energy of 22-24% or 64 GW solar and 10 GW wind; and (ii) a more ambitious scenario of 100 GW solar and 36 GW wind. The report concluded:

- Several technical measures already exist to improve grid stability in situations where a high proportion of variable renewables could place a strain on grid operations.
- Integrated grid and resource planning can help mitigate the impact of wind and solar PV deployment on intraregional and interregional load flows.
- Non-discriminatory market regulations, enhanced transparency and state-of-the-art operational and planning practices to facilitate the integration of a higher proportion of variable renewables.

[34] *IEA (2017). Insights Series 2017 - Getting Wind and Solar onto the Grid. Available:* https://webstore.iea.org/insights-series-2017-getting-wind-and-solar-onto-the-grid

4.1.5 Stranded coal assets and higher energy costs

Japan's planned and operating coal capacity are currently safeguarded indirectly by the government due to a combination of legacy PPAs[35] and regulations that give coal generation an advantage in the marketplace. These regulations include, but are not limited to, the baseload power market and inefficient dispatch.

4.1.5.1 Baseload power market

In July 2019, Japan introduced its baseload market. The purpose of the baseload market is to give new entrant retailers access to baseload power. Baseload power includes generation from coal, hydro, nuclear and geothermal assets which are predominantly owned by incumbent utilities.[36] The price includes the FOM and VOM of these assets. The power is traded via the Japan Electric Power Exchange, but price is decided via auctions. The baseload market emulates France's market (termed ARENH), which was introduced in 2010. Importantly, mothballed nuclear capacity is included in the baseload power market. This inflates the clearing cost of the baseload market as the fixed cost of these non-operating facilities is blended into the price.[37] This acts as a subsidy for mothballed nuclear facilities and effectively forces new entrant retailers – and their customers – to pay for these unused facilities. The latest results of bids for its first baseload market show the impact of this policy decision. According to Genscape, prices in France's ARENH were 23% lower than the average wholesale power price in 2018 average.[38] Moreover, assuming the baseload market price clears below the price on the wholesale market, it could shelter coal generators from any increase in generation costs from carbon pricing.

4.1.5.2 Cost-inefficient dispatch

As detailed in Table 7 Japan's power market regulation currently mandates economically inefficient dispatch, prioritising nuclear, hydro and geothermal before wind and solar. In the context of Japan's power market regulation, inefficient merit order results in generation technologies with a higher SRMC being dispatched ahead of, and thus being curtailed before those technologies with a lower SRMC. In practice, this dispatch order negatively impacts wind and solar, which have a near-zero SRMC.

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[35] While PPA between retailers and developers, the government provides guidance for thermal bidding.

[36] Of the 109 GW of capacity from coal, hydro, nuclear and geothermal assets around 85% is owned by incumbent utilities. Bloomberg NEF (2017): Power Market Design Series: Japan. Unavailable without subscription.

[37] Incumbent utilities are losing money due to offline nuclear capacity. Tokyo Electric, for example, paid US$5.7bn in 2016. Genscape (2019). Available: https://www.genscape.com/blog/who-benefits-japan-baseload-market

[38] Genscape (2019). Available: https://www.genscape.com/blog/who-benefits-japan-baseload-market

TABLE 7. JAPAN'S INEFFICIENT POWER DISPATCH ORDER

Dispatch priority	Technology
1.	Nuclear
2.	Solar and wind
3.	Local biomass
4.	Large-scale biomass
5	Coal, gas, oil and co-firing biomass

Source: Bloomberg NEF adapted from OCCTO[39]

Without policy reform the Japanese consumer could pay for US$71bn of stranded coal assets through high power prices

These regulations may be sheltering high-cost coal from low-cost renewables and therefore mean that the Japanese consumer may not be receiving the lowest-cost power possible. In Carbon Tracker's below 2°C scenario, where planned, under-construction and operating coal capacity is forced to shut down in a manner consistent with the temperature goal in the Paris Agreement, stranded asset risk from capital investments and reduced operating cashflows could amount to $71bn. This scenario is not totally unrealistic in the context of Japan. For instance, Japan's LTSD which was approved by the cabinet and submitted to the UNFCCC this June, states: "The Government will work to reduce CO2 emissions from thermal power generation to realize a decarbonized society and consistent with the long-term goals set out in the Paris Agreement."[40] Without policy reform, this liability will cascade through the economy as detailed in Figure 12.

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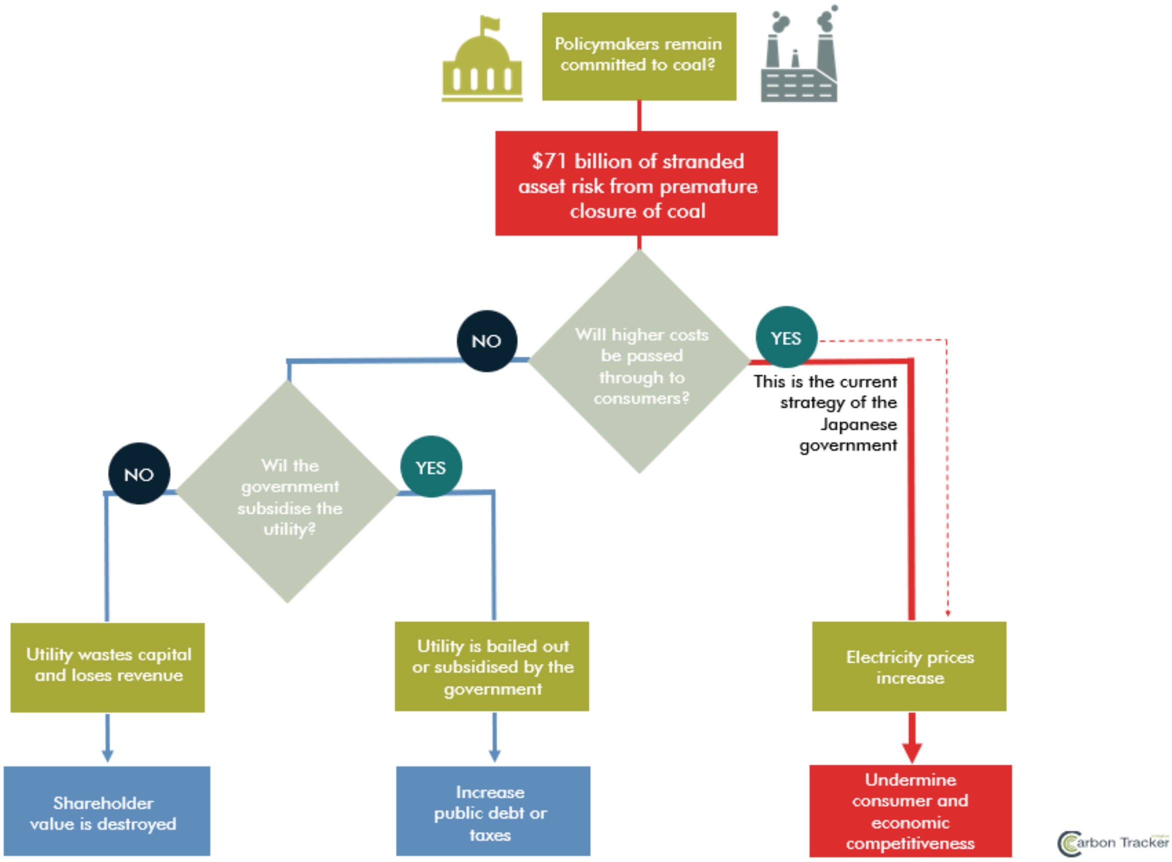
[39] *Bloomberg NEF (2017): Power Market Design Series: Japan. Unavailable without subscription*

[40] *The Government of Japan (2019). The Long-term Strategy under the Paris Agreement. Cabinet decision, June 11, 2019. Available: https://unfccc.int/sites/default/files/resource/The%20Long-term%20Strategy%20under%20the%20Paris%20Agreement.pdf*

FIGURE 12. HOW STRANDED ASSET RISK WILL MATERIALISE IN THE JAPANESE ECONOMY



Source: Carbon Tracker analysis

5 Policy recommendation

We offer two recommendations. Please note that these policy recommendations are high level by design. Detailed policy recommendations are outside the scope of this report and will form future analysis with our local partners.

5.1 Immediately reconsider planned and under construction capacity and develop a retirement schedule for the existing fleet that is consistent with the decarbonisation goal in the Paris Agreement

New investments in coal capacity will unlikely be a least-cost solution over the capital recovery period. This period is typically 15-20 years for new coal capacity and 5-10 years for retrofits relating to performance enhancements or control technology installations. This analysis highlights how coal power is losing its economic footing, independent of additional climate change and air pollution policies. As such, Japan should stop investing in and building new coal immediately. Japanese policymakers should develop a retirement schedule based on the LRMC of individual coal units. This analysis will allow policymakers to close the higher cost units first and lower cost units last, which should help ensure that the end consumer receives the lowest cost electricity possible, maximising economic growth. Once policymakers have developed a cost-optimised retirement schedule at the asset level, they should then undertake systems planning analysis to take into consideration the system value of individual assets. Understanding system value is outside the scope of this analysis. Carbon Tracker intends to conduct this analysis with local partners and make this research publicly available.

5.2 Accelerate renewable energy through non-discriminatory regulations

Without further reform the Japanese government risks missing the economic opportunity associated with renewable energy and locking-in high cost power. In doing so, the government will likely further compromise energy security, public debt and economic competitiveness. Along with many other countries, Japan faces several technical and political challenges to decarbonise its power system. Lowering renewable cost, making regulations and markets more renewable friendly, capturing surging demand from business are the challenges that Japan should address immediately.

Renewable energy and other supporting technologies – such as battery storage, demand response and high-voltage transmission – are part of a mega trend with no precedent in the 21st century. The benefits from this mega trend will go to those governments who develop a strategy to capture value from the rapid growth of these technologies. Japan has a long track record of technological and engineering prowess that means the nation is well placed to capture value from these technologies as markets mature and product quality commands a price premium.

Incentivising renewables begins with seeing these technologies as an opportunity to reinvigorate the nation's industry and economy as well promote energy security. To execute this vision, wholesale changes need to be made to ensure renewable capacity gets built at scale and in manner that maximises its value to the grid. At the heart of these changes is a step change in transparency to avoid discriminatory regulations and potential market abuse, as well as incentivise investments in appropriately located renewables and the associated infrastructure required to maximise its value to the power system.

6 Modelling risks and revisions

This analysis cannot capture unforeseen changes to commodity prices, environmental policies, market structures and technology costs as well as company risk management and company reporting practices. Below are the main modelling risks associated with this analysis.[41]

- **Debt to equity ratios.** Owing to a lack of publicly available data, Carbon Tracker's project finance model does not make assumptions around debt to equity ratios, and therefore (i) the WACC estimate may not reflect the ratio between a company's total debt financing and its total equity financing; and (ii) we cannot estimate the IRR for financers.
- **Market structures.** Market structures are rarely homogenous and vary from region to region depending on numerous technical, political and economic factors. These differences are essential for interpreting the results of this analysis as the asset stranding risk from high-cost and unprofitable coal capacity materialises differently depending on market structures.
- **Risk management practices.** Utilities often hedge their revenue and cost exposure through the future and forward markets. The level and extent of hedging varies depending on whether the utility operates in a liberalised or regulated market, as well as on the evolution of power market price formation. For instance, European utilities who operate in liberalised power markets have historically hedged their revenues up to four years in advance. When European utilities sell their power on the future and forward markets, they also cover their fuel and carbon costs. For example, European carbon prices are currently ~€30/t now but numerous generators are not necessarily exposed to this cost as they hedged their carbon exposure when prices were ~€10/t. Moreover, due to increasing levels of variable renewable energy, revenue optimisation – and thus risk management activities – are concentrated at the front of the curve.
- **Fixed operating costs.** Estimated fixed operating and maintenance costs (FOM) is particularly challenging. The amount an operator spends on FOM depends on a variety of factors. Unit owners who are expecting to close within 3 to 5 years can take a "sellotape" strategy to operations by only making minimal investments to keep the unit running. However, over the long-term, unit owners need to invest in operations and maintenance to sustain unit performance and availability, as well as in control technologies to meet air pollution regulations. These are not immaterial and could influence operating cash flows significantly.

In addition, we have made a number of modelling revisions to several markets since publishing Powering Down Coal in November 2018. These revisions are detailed in Table 8 below.

TABLE 8. MODELLING REVISIONS SINCE POWERING DOWN COAL 2018

	Fuel cost (US$/MWh)		Variable O&M cost (US$/MWh)		Fixed O&M cost (US$/MWh)		Control Tech Cost (US$/MWh)		Carbon cost (US$/MWh)	
	2018	Latest	2018	Latest	2018	Latest	2018	Latest	2018	Latest
Australia	29.32	29.32	1.29	1.30	8.66	8.66	5.06	5.06	0.00	0.00
China	41.61	42.73	3.56	3.57	2.13	2.10	0.13	0.14	0.00	0.00
EU	31.53	31.10	2.15	2.09	6.42	6.34	3.46	3.57	16.80	16.41
India	29.79	30.66	5.59	5.72	3.96	4.10	2.33	2.81	0.00	0.00
Indonesia	27.00	28.13	5.64	5.94	2.53	2.41	2.71	2.32	0.00	0.00

[41] *For a full breakdown of our commodity, policy regulatory and technology assumptions, please refer to the methodology document.*

Japan	47.11	41.49	6.15	6.04	1.72	1.83	5.75	6.07	0.00	2.58
Philippines	39.79	41.00	5.32	5.48	2.09	2.02	2.67	2.63	0.00	0.00
Russia	31.51	31.52	3.96	3.96	2.63	2.63	1.75	1.75	0.00	0.00
South Africa	21.75	21.35	5.36	5.28	7.61	7.31	4.28	4.92	0.00	0.00
South Korea	40.75	41.46	4.84	4.89	3.10	3.13	4.70	4.47	0.35	0.35
Turkey	36.70	36.70	4.57	4.57	2.62	2.62	3.97	3.97	0.00	0.00
Ukraine	54.90	54.90	7.03	7.03	6.93	6.93	1.34	1.34	0.00	0.00
United States	26.93	26.94	4.86	4.87	3.74	3.70	2.41	2.39	0.06	0.06
Vietnam	37.67	31.53	5.25	5.39	2.87	3.30	5.35	5.64	0.00	0.00

	Revenues (US$/MWh)		Stranded Asset Risk (million US$)	
	2018	Latest	2018	Latest
Australia	65.57	65.57	15,160	15,160
China	46.61	46.56	-388,775	-388,775
EU	42.64	42.48	-122,947	-122,947
India	57.66	57.59	76,174	76,174
Indonesia	68.73	68.85	34,735	34,735
Japan	60.75	82.85	20,370	71,495
Philippines	64.96	65.05	13,111	13,111
Russia	17.80	17.79	-19,930	-19,930
South Africa	72.73	72.73	51,276	51,276
South Korea	77.85	78.12	106,212	106,212
Turkey	22.27	22.27	-153	-153
Ukraine	63.54	63.54	-6,593	-6,593
United States	33.87	33.86	-16,996	-16,996
Vietnam	54.78	56.47	11,683	6,462

Source: Carbon Tracker analysis

Notes: 2018 column represents when Powering Down Coal was published in November 2018. The main change is that these capacity-weighted averages now take into consideration whether a unit was operating during the averaging period or not. Previously, this was ignored. The model results for Japan now include the capital costs associated with capacity under construction, permitted and per-permit. Previously, this was ignored.

7 Conclusions

In this report, we presented the findings of Carbon Tracker's coal power economics analysis for Japan to understand the potential for asset stranding and relative competitiveness of renewable energy. Coal has long been considered the least-cost option for power in Japan. However, that is quickly changing as a confluence of factors are disrupting coal's pre-eminence. Most notably, low-cost renewable energy, which will soon be cheaper to build than to run coal plants. Japanese policymakers need to stop new investments in coal power immediately and start a longer conversation about the future of the fuel. Failure to do so will result in stranded assets which will likely be realised through high energy prices.

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9 Appendix – LCOE modelling

9.1.1 General considerations

The LCOE calculations are based on a discounted cash flow model in which costs (CAPEX and O&M) of developing and running renewable energy assets are discounted using a real weighted average cost of capital (rWACC). These costs are then divided by the discounted (also using rWACC) lifetime production (kWh) of the asset to obtain a unique value, the LCOE.

The variables of the model are the following ones:

- Investment Costs (CAPEX) - USD/kW
- O&M Costs – annual % of CAPEX
- Capacity factor – percentage points of 8760 (number of hours in a year)
- Lifetime of the asset – years
- Real weighted average cost of capital (rWACC) – percentage points

The real weighted average cost of capital is calculated using a division between debt and equity to finance a project, usually 80% debt and 20% equity for OECD countries. The weight of the debt (e.g. 80%) is then multiplied by the cost of debt (interest charged for loans) minus the inflation rate. The weight of the equity (e.g. 20%) is multiplied by the return on equity minus the inflation rate. The sum of the two results is the rWACC. All assets are assumed to have a 25 years lifetime.

9.1.2 Assumptions for onshore wind

CAPEX for onshore wind in Japan in 2019 was estimated using data[42] from 2016 from a research paper produced by the *Renewable Energy Institute*. The cost breakdown structure came from the same sources. CAPEX values were reduced by 8% annually going to 2019 to account for cost declines during the period. A lower bound CAPEX was calculated using 15% assumption and a higher bound using a 20% assumption.

O&M costs were collected from the same paper, declined by 5% per year going to 2019. A lower bound O&M was calculated using 15% assumption and a higher bound using a 20% assumption.

Capacity factor data was collected from the same paper, mid value. The lower bound capacity factor was declined by 3 percentage points while the higher bound capacity factor was added 3 percentage points.

Data on return on equity[43] was taken from a dataset maintained *here* by Aswath Damodaran, a finance professor at NYU Stern. The mid value 14.67% return on equity was reduced by 15% to obtain the lower bound and increased by 15% to obtain the higher bound. Upper variation of RoE is assumed to be less significant as the upper variation of other variables.

Data on cost of debt[44] was sourced from *World Bank*. The rate, 0.99%, found was for loans on short and medium term to which another 1 percentage point is added to account for the riskier long term loan. Finally, inflation data[45] was sourced from *International Monetary Fund*. The debt

[42] *Renewable Energy Institute (2018). Available:* https://www.renewable-ei.org/en/activities/reports/img/pdf/20180125/JapanWindPowerCostReport_EN_20180124.pdf
[43] *NYU Stern, A. Damodaran (2019). Available:* http://people.stern.nyu.edu/adamodar/New_Home_Page/datacurrent.html
[44] *World Bank (2019). Available:* https://data.worldbank.org/indicator/FR.INR.LEND?locations=JP
[45] *IMF (2019). Available:* https://www.imf.org/external/datamapper/PCPIPCH@WEO/OEMDC/JPN

equity split was assumed to be 80% debt and 20% equity, a common assumption for OECD member countries.

Data for capacity (MW) projections was sourced from the REMAP[46] team at IRENA while data for 2019 was projected using historical deployment data[47] from IRENA. The underlying file is not be shared or quoted, as per the request of the REMAP team who created the projections using very aggressive carbon prices.

A learning curve of 25%, upped from 21%, was used to project LCOE declines going forward based on global results[48] published in *2018*.

Finally, the low, mid and high LCOE and the REMAP highest capacity projections were used to compute the LCOE of onshore wind going to 2040.

9.1.3 Assumptions for solar PV

CAPEX for solar PV[49] in Japan in 2019 was estimated using data from an IRENA publication, specifically for Japan, for 2018 that was declined by 8% for 2019. The cost breakdown structure came from the same sources. A lower bound CAPEX was calculated using 15% assumption and a higher bound using a 20% assumption. The cost breakdown of solar PV is from the same paper.

O&M costs[50] data was sourced from data on USA solar PV plants which was scaled upwards by the difference between CAPEX in Japan versus CAPEX in USA to account for generally a more expensive market in Japan. A lower bound O&M was calculated using 15% assumption and a higher bound using a 20% assumption.

Capacity factor was calculated using fleet generation[51] data for 2018 and adding an 8% premium to account for the utility average production being dragged down by less productive rooftop installations. The lower bound capacity factor was assumed to 15% lower while the higher bound capacity factor was assumed to be 20% higher.

The same data for return on equity, debt and inflation and equity – debt split was used as in the case of onshore wind. Capacity projections[52] were collated using REMAP data and assumptions from BNEF NEO 2018 as the REMAP data was less aggressive for 2040.

A learning rate of 60% was used for solar PV LCOE for two reasons: Japan has the highest CAPEX and LCOE of utility solar PV which allows for significant declines going to 2040. Secondly, the LCOE decline for Japan from 2010 to 2018 was 75%[53] according to IRENA data.

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[46] *IRENA.* https://www.irena.org/remap/REmap-Publications
[47] *IRENA.* https://www.irena.org/Statistics/View-Data-by-Topic/Capacity-and-Generation/Statistics-Time-Series
[48] *IRENA (2018). Available:* https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2018/Jan/IRENA_2017_Power_Costs_2018.pdf
[49] *See footnote 33*
[50] *New Energy Update (2019).* https://analysis.newenergyupdate.com/pv-insider/us-solar-maintenance-costs-plummet-tech-gains-multiply
[51] *Renewable Energy Institute (2019).* https://www.renewable-ei.org/en/statistics/electricity/?cat=quarterly
[52] *IRENA (2019). Available:* https://www.irena.org/publications/2019/Apr/Global-energy-transformation-A-roadmap-to-2050-2019Edition
[53] *See footnote 33*

Learning rates were calculated using the most aggressive deployment scenario and the mid, low, and high 2019 LCOE for solar PV.

9.1.4 Assumptions for offshore wind

High quality data for offshore wind is harder to come by for Japan given the thin deployment of the technology in the country, 65 MW[54] cumulative capacity at end of 2018 according to *IRENA* stats. However, going further it seems that the government provides increasing support (*here*) to the nascent industry.

CAPEX data for offshore wind was sourced from *IRENA*, from global weighted average CAPEX for offshore wind and from the insight that projects outside of Europe tend to be less expensive than the ones in Europe, mostly due to cheaper wind turbine use. Thus, I assumed a 95% of the global weighted average offshore wind CAPEX in 2019 in Japan. *IEA* is providing 2% lower value for 2017 modelled project. A lower bound CAPEX was calculated using 15% assumption and a higher bound using a 20% assumption. Cost break down of CAPEX was sourced from *NREL*[55] and *IEA*[56].

O&M costs were sourced from *IRENA*[57] and *IEA* and were assumed to 2.5% of CAPEX for Japan in 2019, the mid-point between approximately 2% of CAPEX for IRENA and 3% from IEA. A lower bound O&M was calculated using 15% assumption and a higher bound using a 20% assumption.

Capacity factor values were sourced as well from IRENA and IEA as the mid-point between the global weighted average in IRENA publication and the value provided in the IEA offshore wind report. A lower bound capacity factor was calculated using a 15% decline rate and a higher bound using a 20% increase rate.

The same data was used for debt, equity and inflation except that given the small offshore market in Japan and the fact that offshore is riskier, more so in new market the equity debt split was assumed to 70/30. IEA uses the same split in their report.

The low, mid and high LCOE calculated was used to compute the cost decline going further to 2040. REMAP most aggressive deployment scenario was used and a learning rate of 12%, 2% lower than in *IRENA*[58] 2018 publication at global level, lower due to Japan having more uncertainties over how much offshore will develop.

[54] *See footnote 32*
[55] *NREL (2016). Available:* https://www.nrel.gov/docs/fy18osti/70363.pdf
[56] *IEA (2018) - Wind TCP Task 26- Offshore Wind Energy International Comparative Analysis*
[57] *See footnote 33*
[58] *See footnote 33*

10 Disclaimer

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