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Series "Ushering in a New Era of Carbon Neutrality"

The Institute of Energy Economics, Japan

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Global Oil, Natural Gas and LNG Demand Outlook through 2022 - Uncertain Recovery from COVID-19 and Its Impacts -

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Introduction

As the COVID-19 outbreak originating from China developed into a global pandemic in 2020, the global economy plunged into the worst situation since the Great Depression. As major countries and cities imposed lockdowns and other severe travel restrictions to dramatically reduce international air transport demand, oil and other energy demand in the world recorded unprecedented declines. In such situation, we published five outlooks through 2021 concerning global energy demand including oil, natural gas and LNG under the pandemic on the website of the Institute of Energy Economics, Japan, from March 2020[1].

The pandemic is still spreading in the world instead of calming down. Since around last November when vaccination started in Europe, the United States and Israel, however, vaccination has been globally expanding. Although no optimism can be warranted because of problems regarding the beneficial and adverse effects of vaccination and the spread of mutant COVID-19 strains, hopes are emerging on an end to the COVID-19 pandemic. As each country has implemented powerful fiscal and monetary policies since the second quarter of 2020 to recover from the worst economic situation, the global economy has been moderately recovering since the second half of the year. The latest World Economic Outlook of the International Monetary Fund (published in January 2021) forecast that the global economy would grow 5.5% in 2021 in reaction to its unprecedented contraction of 3.5% in 2020. As noted above, however, how the global economy would recover from the pandemic remains uncertain along with an economic growth pace.

The COVID-19 disaster and global economic deterioration have greatly affected global energy demand. Particularly, oil demand received a devastating impact from lockdowns and a plunge in international air transport demand. Demand for natural gas and LNG, the second largest international traded energy commodity after oil, also turned down after continuing a sharp rise. In the future as well, demand for oil, natural gas and LNG as extremely important international energy trade goods will dramatically change depending on COVID-19 pandemic and global economic developments.

In the abovementioned context, we analyzed global oil, natural gas and LNG demand on the assumption of global economic growth through 2022 while referring to the latest IMF World Economic Outlook. As COVID-19 and global economic outlooks are accompanied by great uncertainties, we developed and analyzed not only the Reference Scenario but also the high-growth scenario and the low-growth scenario.

1. Global economic outlook through 2022 (Reference Scenario)

The Reference Scenario for this analysis is as follows, based on the IMF's World Economic Outlook Update released in January 2021 and the IEEJ's analysis and assessment (Fig. 1 and 2):

- In 2020, the global economy is estimated to have posted a 3.5% contraction, the largest shrinkage since the Great Depression and surpassing the drop during the global financial crisis.
- However, the global economy has been rebounding from the bottom in the second quarter of 2020 thanks to each country's successful economic measures (including sharp fiscal expansion and monetary easing).
- While COVID-19 vaccination is making progress mainly in Advanced Economies, the pandemic has not ended. Global economic recovery in 2021 will be moderate. In the second quarter of 2021, global GDP will restore the fourth

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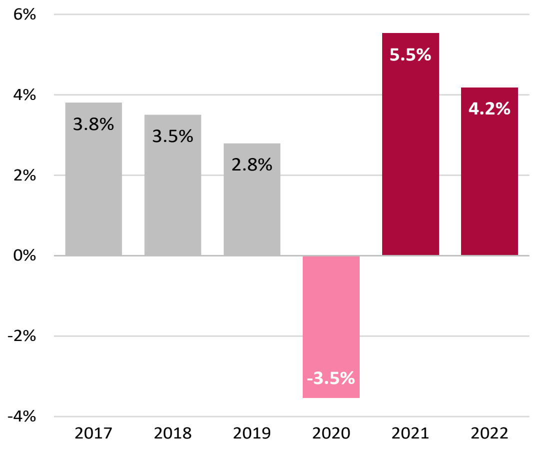
[1] For instance, see Ken Koyama & Shigeru Suehiro "Analysis of the Impacts of COVID-19 on the Global Demand for Oil, Natural Gas and LNG" (03/27/2020), Shigeru Suehiro & Ken Koyama "An Estimate on the Impact of a 'City Lockdown' on the Global Energy Demand" (04/14/2020), Ken Koyama & Shigeru Suehiro "Covid-19 and the Outlook for Oil, Natural Gas, and LNG Demand in 2021" (05/08/2020), etc.

quarter 2019 level before the COVID-19 pandemic.

- Global GDP in 2021 will grow by 5.5% in reaction to the sharp contraction in 2020.
- In 2022, COVID-19 vaccines will become available in many countries, with infections limited to a low level. As economic recovery gains momentum, global GDP will grow by 4.2%.



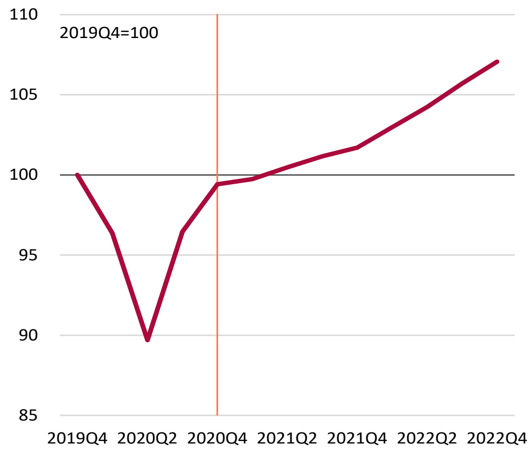
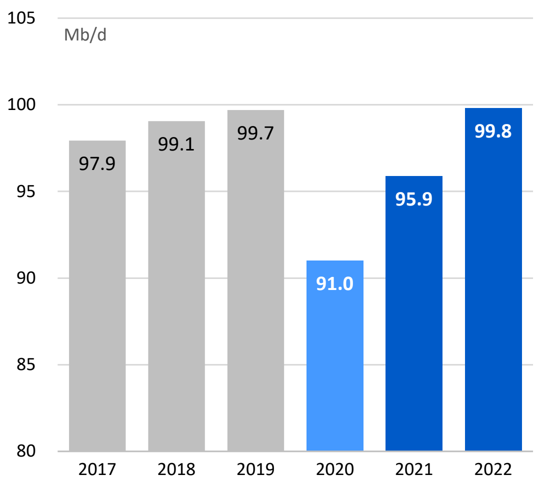


Fig. 1 Global economic growth outlook **Fig. 2 Global GDP trend (quarterly)**

Sources: IMF "World Economic Outlook Update, January 2021," IEEJ estimates

2. Global oil demand outlook through 2022 (Reference Scenario)

We developed the Reference Scenario for global oil demand based on the abovementioned economic growth outlook, while referring to past data in the Monthly Oil Market Report by the International Energy Agency. Fig. 3 to 6 show an annual oil demand outlook, a quarterly oil demand outlook, year-on-year changes in regional oil demand and year-on-year changes in petroleum product demand. Key points of the oil demand outlook are as follows:



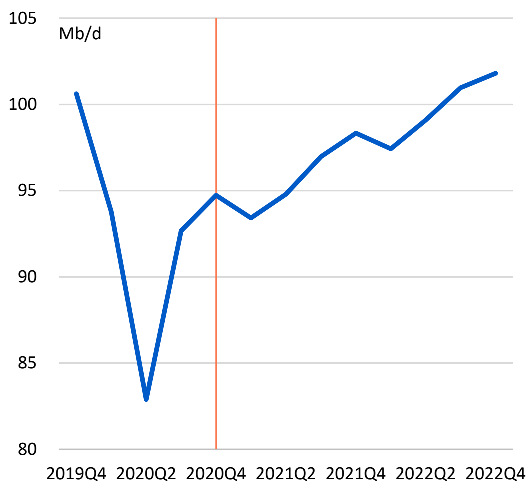


Fig. 3 Global oil demand outlook **Fig. 4 Global oil demand trend (quarterly)**

Sources: IEA "Oil Market Report," IEEJ estimates

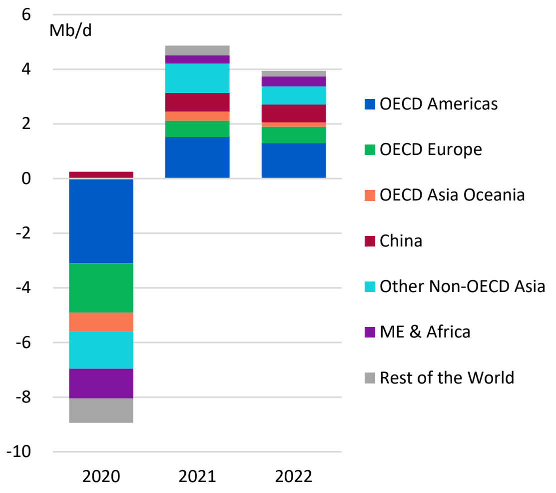


Fig. 5 Year-on-year changes in oil demand (by region)

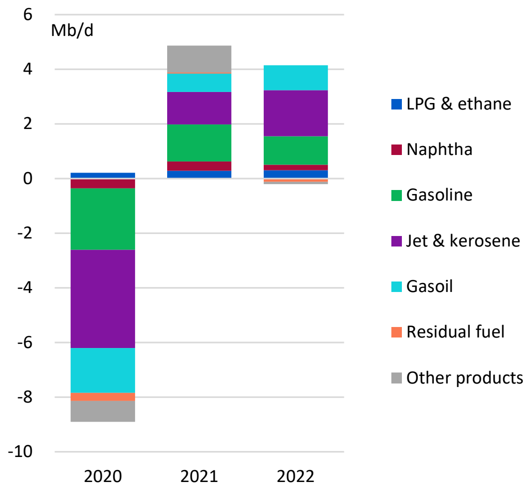


Fig. 6 Year-on-year changes in oil demand (by product)

Sources: IEA "Oil Market Report," IEEJ estimates

- Global oil demand in 2020 is estimated to have decreased by 8.7 million barrels per day from the previous year to 91.0 Mb/d (Fig. 3). Global oil demand plunged to 82.9 Mb/d in the second quarter of 2020 before rebounding (Fig. 4)[2].
- Advanced Economies accounted for some two-thirds of the global oil demand plunge (Fig. 5). China slightly increased its oil demand in 2020 from the previous year by containing COVID-19 infections and achieving an early economic recovery.
- Transportation fuels including gasoline, gasoil and jet fuel accounted for more than 80% of the sharp oil demand decline due to a plunge in vehicle and air transportation demand amid lockdowns and other travel restrictions (Fig. 6).
- Global oil demand in 2021 will fail to restore the pre-pandemic level, with recovery being moderate. It will increase by 4.9 Mb/d from the previous year to 95.9 Mb/d (Fig. 3)[3].
- Although vaccination is making progress, voluntary travel restrictions are slowing down a pickup in demand for transportation fuels. Particularly, jet fuel demand will remain slack due to international travel restrictions.
- Global oil demand will restore the pre-pandemic level in 2022, averaging 99.8 Mb/d. In the second half of 2022, global oil demand will top 100 Mb/d. Demand for all petroleum products will increase in all regions, though with growth paces varying.

3. Impacts on oil market

The substantial oil demand decline in the worst time in 2020 was a dramatic event described as "demand evaporation," triggering a crude oil price crash. The price crash prompted the Organization of the Petroleum Exporting Countries and non-OPEC oil-producing countries to launch and continue record production cuts. In this sense, a future oil demand recovery will become one of the major factors to exert great influence on the supply-demand balance and prices in the international oil market.

In the Reference Scenario for this analysis, global oil demand will steadily recover in 2021 and 2022 in line with the global economic growth and restore the 2019 level in 2022. The OPEC Plus group will have to maintain production cuts at least in 2021 while considering (1) non-OPEC oil production trends including a U.S. shale oil production increase, (2) the U.S. Biden administration's negotiations with Iran and the country's potential comeback to the international oil market and (3) potential geopolitical risks and oil supply disruptions in major oil-producing countries.

[2] Our analysis in April 2020 had forecast the bottom in the second quarter of 2020 at 83.3 Mb/d and demand in the whole of 2020 at 90.7 Mb/d.
[3] The March 2021 IEA Oil Market Report forecast global oil demand in 2021 at 96.5 Mb/d.

As the global oil demand rebound is expected to lead to a moderate rise in the call on OPEC Plus (global oil demand minus production by non-OPEC oil-producing countries that do not take part in the OPEC Plus production cuts), the OPEC Plus group will moderately reduce the production cuts in 2021 while watching the crude oil price trend. Major factors to determine the degree of the reduction will include the global oil demand recovery, crude oil prices and global oil stock trends. Crude oil prices have entered an uptrend since last November, but their future trend is still uncertain. The OPEC Plus group will have to continue the micro-management of oil production cuts based on the supply-demand balance in the international oil market at least until global oil demand rises back to the pre-pandemic level.

4. Global natural gas and LNG demand outlook through 2022 (Reference Scenario)

As was the case with oil demand, we developed the Reference Scenario for global natural gas and LNG demand based on the abovementioned economic growth outlook, while referring to past data made available. We also considered seasonal fluctuations in forecasting quarterly demand. Key points of the Reference Scenario for natural gas and LNG demand are as follows:

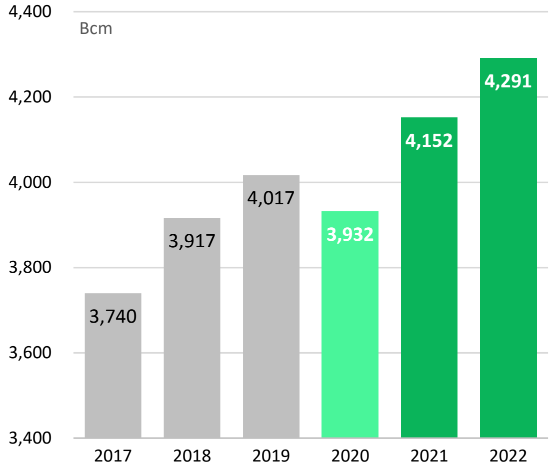


Fig. 7 Global natural gas demand outlook

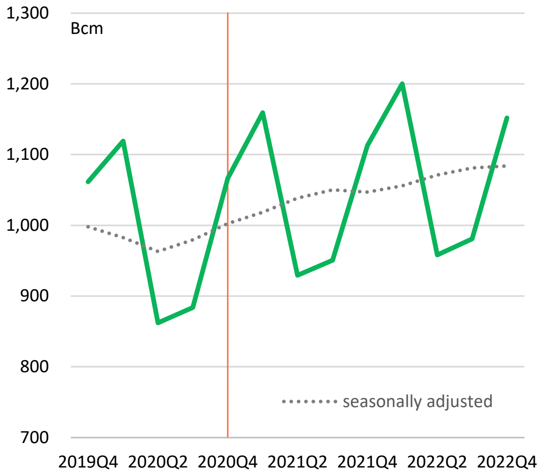


Fig. 8 Global natural gas demand trend (quarterly)

Source: IEEJ estimates

- Global natural gas demand in 2020 is estimated to have decreased by 2.1% from the previous year to 3.9 trillion cubic meters (Fig. 7)[4]. It has been rising back from the bottom hit in the summer of 2020. Its annual decline was smaller than that of oil demand[5].
- Natural gas demand plunged in North America and Europe including Russia while increasing in China and the Middle East (Fig, 11). Particularly, China is estimated to have expanded natural gas demand in 2020 by 8.0% by achieving an early economic recovery.
- Global natural gas demand will post a sharp recovery in 2021, restoring a pre-pandemic uptrend. Supported by a substantial increase in Advanced Economies, global natural gas demand in 2021 will rise by 5.6% from the previous year to 4.2 Tcm. Natural gas demand for heating and other industrial consumption will steeply expand in reaction to the decline in the previous year.

[4] The IEA Gas Market Report released in January 2021 estimated that global natural demand in 2020 might have decreased by 2.5% from the previous year.

[5] Our analysis in April 2020 had forecast that global natural gas demand in 2020 would post a substantial fall of 7.2% from the previous year. Demand for gas for power generation might have been stronger than expected, resulting in a slower-than-forecast fall in global gas demand.

- Global natural gas demand will continue a steady uptrend in 2022, increasing by 3.3% from the previous year to 4.3 Tcm. Despite the plunge in 2020 under the pandemic, natural gas demand will clearly come back to a traditional growth path in 2021.

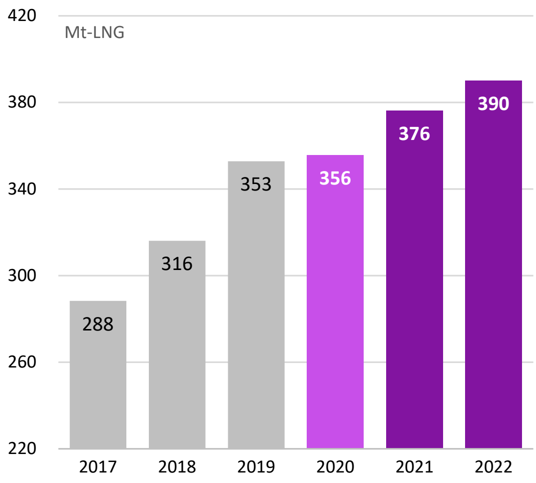


Fig. 9 Global LNG demand outlook

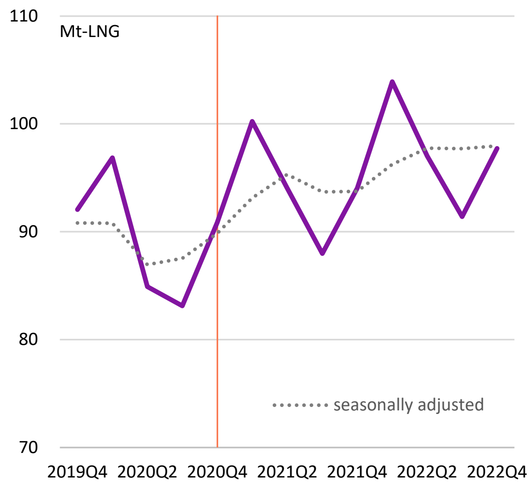


Fig. 10 Global LNG demand trend (quarterly)

Sources: Cediga, IEEJ estimates

- Global LNG demand in 2020 is estimated to have posted a slight increase of 0.8% from the previous year to 356 million tons (Fig. 9)[6].
- LNG demand declined in Advanced Economies and expanded in Developing Economies, indicating the same gap as for natural gas demand (Fig. 12). Asian Developing Economies including China recorded a remarkably robust increase.
- Global LNG demand in 2021 will sharply pick up, restoring a pre-pandemic uptrend. It will increase in all regions. While Advanced Economies boost LNG demand after a plunge in the previous year, Asian Developing Economies will drive global LNG demand growth. Global LNG demand will rise by 5.8% to 376 Mt.
- Global LNG demand will retain an uptrend in 2022. LNG demand will expand in all regions. Asian countries including China will continue to drive global LNG demand growth in the year. Global LNG demand in 2022 will increase by 3.7% to 390 Mt. After stagnating in 2020, global LNG demand will return to a pre-pandemic growth path from 2021 and on.

[6] Our analysis in April 2020 had forecast that global LNG demand in 2020 would decrease by 8% from the previous year to 325 Mt. See the analysis in page 12 on a gap between this forecast and our latest estimate at 356 Mt.

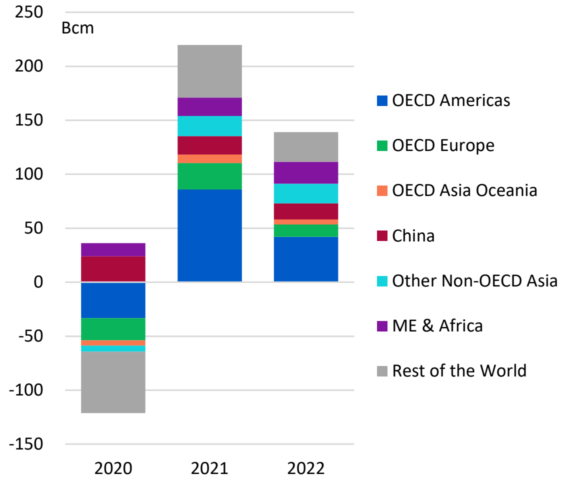


Fig. 11 Annual natural gas demand changes

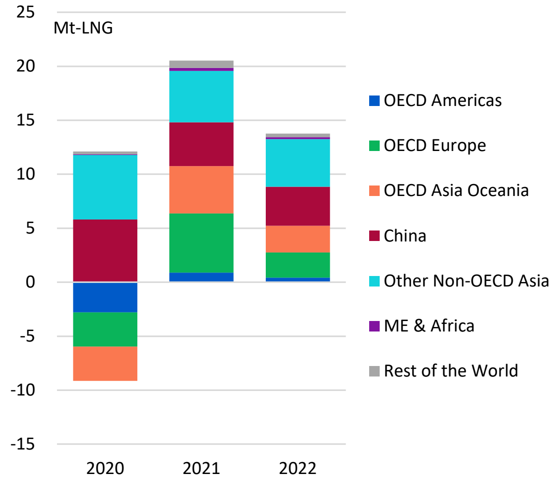


Fig. 12 Annual LNG demand changes

Sources: Cedigaz, IEEJ estimates

5. Impacts on global natural gas and LNG markets

<Wild fluctuations of spot LNG prices>

The COVID-19 pandemic exerted strong downside pressure on global natural gas and LNG demand as well as oil demand, having great impacts on the supply-demand balance and prices in international markets in 2020. In the most typical development, spot LNG prices slackened. Asian spot LNG prices plunged to record lows around $2 per million British thermal units around the middle of 2020. As the price plunge stimulated demand, Asian spot LNG prices turned up in the second half of 2020. They rose further toward the turn of the year due to disruptions to some LNG supply projects, constraints on LNG tankers for the expanding Asian market and restrictions on LNG tanker traffic through the Panama Canal. In early 2021, a sharp rise in LNG demand amid cold waves in Japan and Northeast Asia unusually pushed spot LNG prices up to more than $30/MMBtu (more than $200 per barrel of oil equivalent). As the cold waves ended, spot LNG prices calmed down. The wild spot price fluctuations from 2020 indicated the characteristics and problems of a developing LNG market that lacks thickness and depth and is vulnerable to wild price fluctuations on supply and demand changes.

Meanwhile, Asian LNG prices are mostly indexed to crude oil prices under long-term contracts accounting for most of Asian LNG supply, failing to fluctuate on changes in the LNG supply-demand balance. As LNG prices under long-term supply contracts are indexed to Japanese crude oil import prices three to four months ago, crude oil price hikes since around last November began to be reflected in LNG prices around March. Asian LNG prices will thus fluctuate depending on crude oil price changes. In this sense, we must closely watch crude oil prices regarding the Asian LNG price trend.

<Demand trend gap between natural gas and LNG>

As noted above, the COVID-19 pandemic exerted downside pressure on global natural gas and LNG demand in 2020, putting an end to the robust growth that had continued until 2019. However, there was a gap between natural gas and LNG demand trends. Natural gas demand in 2020 posted a 2.1% decline from the previous year, while LNG demand scored a slight increase of 0.8%.

A factor behind the global LNG demand rise even amid the economic slump under the COVID-19 pandemic might have been the characteristics of LNG as a good. Any LNG project requires far greater initial investment than a natural gas project, leading to continuous supply after a production launch. Although LNG supply can be adjusted to some extent in response to price drops affecting profitability or needs for flexibility regarding operation and contracts, the LNG market is basically driven by continuous supply. How to absorb (take delivery of) LNG supply in the market is important for the supply-demand balance.

In a key development seen in 2020, LNG supply became available on the market due to production launches under some projects, even amid a decline in potential LNG demand under the COVID-19 pandemic, and went to Europe as a last resort market for supply absorption. In Europe that absorbed LNG imports even amid a natural gas demand fall, pipeline natural gas imports from Russia decreased by some 20%. In other words, the LNG supply surplus was finally offset by a decline in European pipeline natural gas imports from Russia. Gazprom in charge of pipeline natural gas exports from Russia to Europe had no choice but to serve as a buffer.

While the OPEC Plus group including Russia played a key role in adjusting supply in the international oil market, Russia contributed to adjusting supply in the international natural gas and LNG market under the COVID-19 pandemic. In this sense, we will have to closely watch Russian trends in checking the supply-demand balance in global oil, natural gas and LNG markets.

6. High and low growth scenarios

In the Reference Scenario, the global economy is assumed to grow by 5.5% in 2021 and by 4.2% in 2022. As noted above, however, the future courses of the COVID-19 pandemic and the global economy are greatly uncertain. In the following, we provided the high-growth and low-growth scenarios to analyze oil, natural gas and LNG demand projections, while referring to the Upside Scenario and the Downside Scenario in the IMF outlook. The high-growth scenario corresponds to the IMF's Upside Scenario and the low-growth scenario to the Downside Scenario.

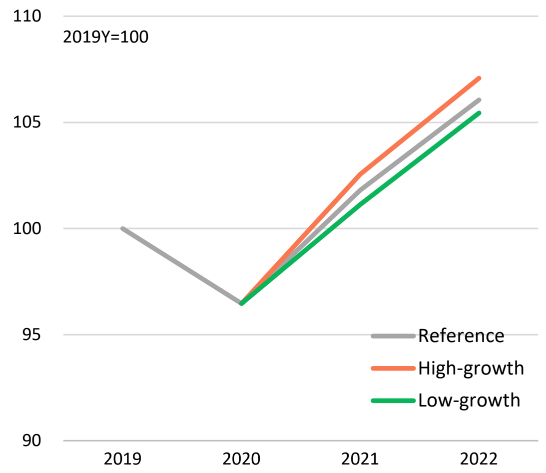


Fig. 13 Global GDP levels by scenario

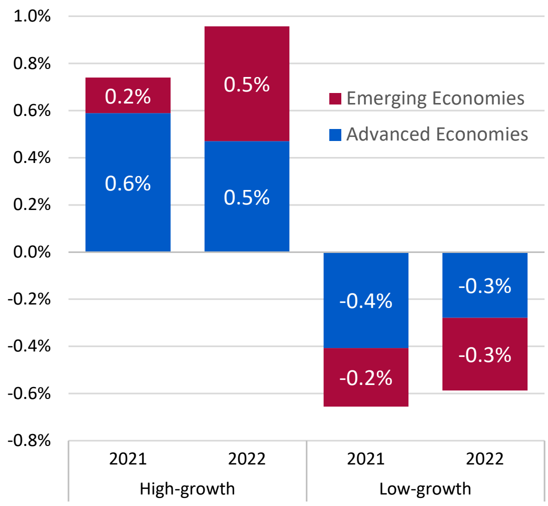
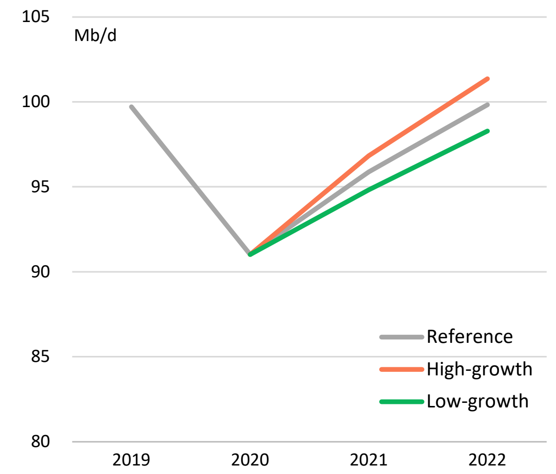


Fig. 14 Deviations from Reference Scenario

Sources: IMF "World Economic Outlook Update, January 2021," IEEJ estimates

- In the high-growth scenario, COVID-19 vaccination will make progress, with new infections declining, accelerating an end to the pandemic. Advanced Economies will see faster vaccine diffusion and economic growth than Developing Economies in 2021. In 2022, Developing Economies will attain vaccine diffusion and remarkable economic growth. Global GDP will be 0.7% more than in the Reference Scenario in 2021 and 1.0% more in 2022 (Fig. 13 and 14).
- In the low growth scenario, mutant COVID-19 strains will spread, with vaccine diffusion being slower, leading the pandemic to be prolonged. In 2021, vaccine diffusion will be delayed even in Advanced Economies, slowing down economic growth. In 2022, additional monetary easing will come in response to economic stagnation, easing downside risks slightly despite growth deceleration. Global GDP will be 0.7% less than in the Reference Scenario in 2021 and 0.6% less in 2022 (Fig. 13 and 14).



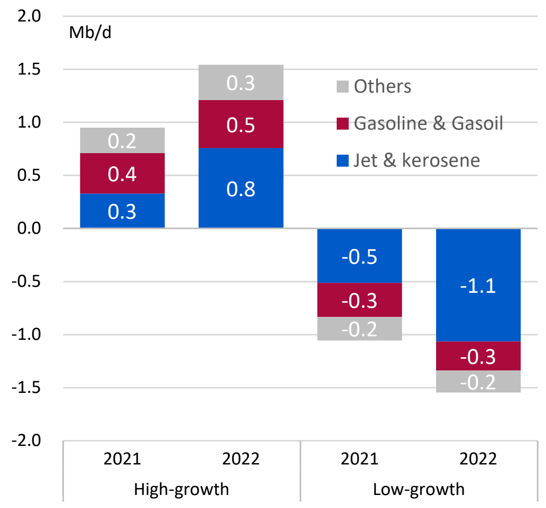
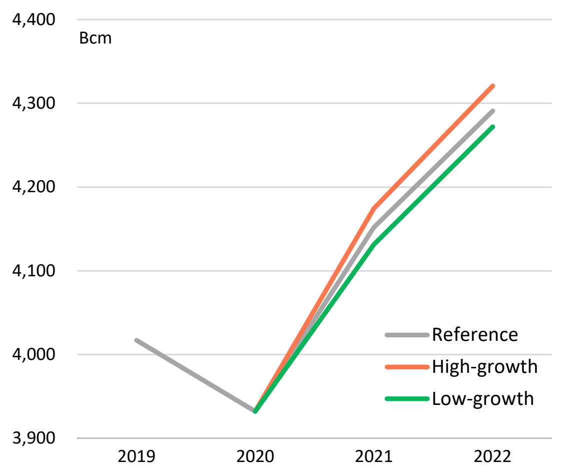


Fig. 15 Global oil demand by scenario **Fig.16 Deviations from Reference Scenario**

Source: IEA "Oil Market Report," IEEJ estimates

- Oil demand in the high-growth scenario will be 0.9 Mb/d more than in the Reference Scenario in 2021 and 1.5 Mb/d more in 2022. As transportation demand recovers on a faster end to the pandemic, a pickup in demand for transportation fuels will make great contributions to expanding oil demand.
- Oil demand in the low-growth scenario will be 1.1 Mb/d less than in the Reference Scenario in 2021 and 1.5 Mb/d less in 2022. As an end to the pandemic is delayed, demand will remain stagnant for transportation fuels including jet fuel.



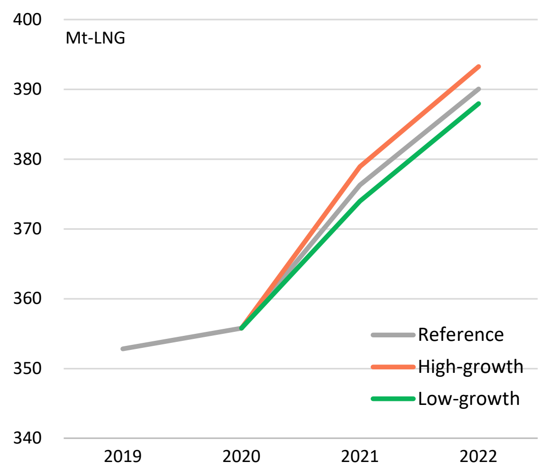


Fig. 17 Global natural gas demand by scenario **Fig. 18 Global LNG demand by scenario**

Sources: Cedigaz, IEEJ estimates

- Natural gas demand in the high-growth scenario will be 0.5% more than in the Reference Scenario in 2021 and 0.7% more in 2022. LNG demand will be 0.7% more in 2021 and 0.8% more in 2022. Gaps for natural gas and LNG will be smaller than for oil.
- Natural gas demand in the low-growth scenario will be 0.5% less than in the Reference Scenario in 2021 and 0.4% less in 2022. LNG demand will be 0.6% less in 2021 and 0.5% less in 2022.

Global oil, natural gas and LNG demand growth will accelerate or decelerate depending on the uncertain future courses of the COVID-19 pandemic and the global economy. If demand recovery or expansion accelerates in the high-growth scenario, the supply-demand balance in international oil, natural gas and LNG markets will be tighter than in the Reference Scenario. As far as other conditions remain unchanged, a faster demand recovery will exert upside pressure on oil, natural gas and LNG prices. In the low-growth scenario, however, demand stagnation will be prolonged along with the need for supply and demand adjustments. Downside pressure on oil, natural gas and LNG prices will work more easily than in the Reference Scenario. We will have to keep close watch on the fate of the COVID-19 pandemic and the global economy.

Conclusion

The COVID-19 pandemic has hardest hit oil demand and exerted relatively smaller impacts on natural gas and LNG (Fig. 19). It has been found that production launches under LNG projects work to expand market supply. While natural gas and LNG demand are expected to restore the pre-pandemic uptrend in 2021, oil demand is estimated to recover its pre-pandemic level in 2022. Depending on the greatly uncertain future courses of the pandemic and the global economy, global oil, natural gas and LNG demand growth will differ from the Reference Scenario, exerting different impacts on the international supply-demand balance. We will have to keep close watch on future global oil, natural gas and LNG demand trends.

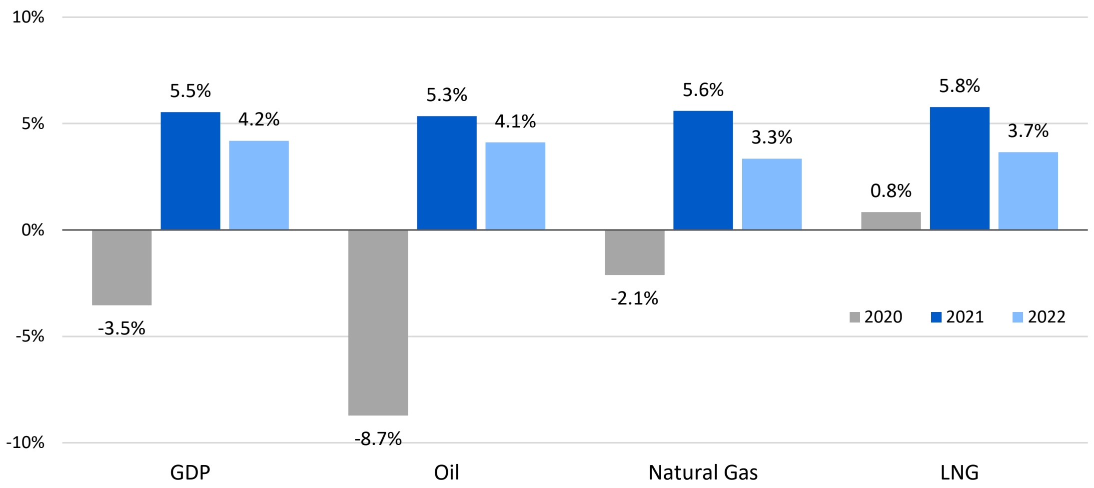


Fig. 19 Year-on-year changes in the global economy and energy demand

Sources: IMF, IEA, Cedigaz, IEEJ estimates

What Would Be the Most Suitable Battery for Utility-scale Energy Storage? - Redox Flow Battery Has Great Potential -

Masato Yoshida*

Introduction

In recent years, many economies including advanced ones have declared the target of achieving carbon neutrality by 2050, veering in the direction of a decarbonized society. In response, every corner of the world anticipates an age of massive renewable energy production, indicating that the importance of stationary batteries for large-scale energy storage would increase further. Especially, redox flow battery has been gathering much higher expectations among them. This paper analyzes the background to the growing importance of stationary batteries for utility-scale energy storage and outlines the structure, operating principles and technological characteristics of redox flow batteries. Furthermore, it checks the market size and cost for redox flow batteries, Japanese companies' position in the competition for the development of these batteries in the world and specific cases in which these batteries have been introduced, before spelling out challenges to be resolved toward the further diffusion of these batteries.

1. Growing importance of batteries for utility-scale energy storage

(1) Responses to power grid problems accompanying the expansion of solar and wind power generation

Renewable energy power generation including solar photovoltaics and wind power generation represents variable power sources where output varies depending on weather conditions. Therefore, the following problems unique to variable renewables must be addressed:

Surplus electricity

Surplus electricity comes when renewable power generation increases in seasons or time zones for smaller electricity demand. As renewable power generation capacity has expanded in recent years, surplus electricity and its fluctuations have gradually increased.

Duck curve problem

As renewable power generation, particularly solar photovoltaics, expands, the fluctuation velocity of apparent demand[1] in the morning and evening increases, surpassing the limit velocity for increasing or reducing output from generators, triggering the so-called "duck curve" problem[2].

Frequency regulation capacity shortage

As renewable output fluctuations can disturb the grid frequency, power utilities must keep the frequency at an adequate level. In the past, fossil thermal, hydro or pumped storage power generation had been used to regulate the frequency. Under the current priority power supply rule, however, output from fossil thermal power plants that have frequency regulation capacity is preferentially curtailed when renewable electricity production increases. Therefore, how to secure the frequency regulation capacity becomes a much more challenging issue.

There are various technological measures to these problems. Among them, the charge and discharge of energy storage systems (stationary batteries) can cover power generation, transmission/distribution and consumption sectors and feature high cost-effectiveness, as shown in Table 1 below. A forecast indicates that installed stationary storage battery capacity

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[1] Apparent demand is total electricity demand minus renewable electricity production. Power grid operators adjust supply and demand in the entire electricity system to balance the apparent demand with electricity production.

[2] The problem is called such because the curve of fluctuations in net electricity demand that represents daily electricity demand minus solar PV production looks like a duck.

would rapidly penetrate from the mid-2020s and reach 4,500 GWh in 2050. Utility-scale batteries are expected to account for more than three quarters of the total capacity (Fig. 1).

Table 1 Measures to electricity demand issues emerging from renewable power expansion

Technological measures	Power generation		Power transmission and distribution	Power consumption
	Large-scale, centralized	Distributed		
Improving balancing capacity for centralized power sources	✔			
Improving renewable output forecast accuracy	✔	✔		
Demand response				✔
Charge and discharge of energy storage systems	✔	✔	✔	✔
Controlling (curtailing) renewable power generation	✔	✔		
Wide-area supply and demand control			✔	

Source: New Energy and Industrial Technology Development Organization (NEDO) TSC Foresight vol.20 as modified by the author

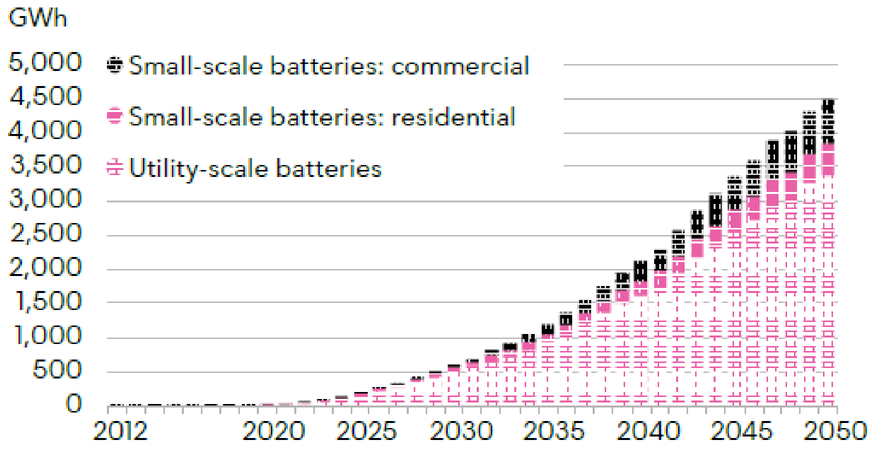

Fig. 1 Global cumulative energy storage installations (commercial, residential & utility sectors)

Source: Bloomberg New Energy Finance, "2019 Long-Term Energy Storage Outlook"[3]

Offshore wind power generation, planned to sharply expand, is expected to aggravate these problems unique to renewable power generation. In 2020, numerous economies declared net-zero emission targets for 2050 or 2060, including three (China accounting for 39% of global CO_2 emissions, Japan for 3% and Korea for 2%)[4] among the 10 largest CO_2 emitters. The realization of a decarbonized society will require not only the power sector but also the industry, transportation and manufacturing sectors to be electrified as much as possible and electricity must be required to be free from carbon. European and other countries that already feature renewables' high energy mix shares are planning to expand offshore wind power generation to further penetrate renewables. Offshore wind power generation capacity targets for 2050 in the European Union, the United Kingdom, the United States, China and Taiwan total more than 500 GW, equivalent to the capacity of 500 nuclear power plants (Table 2, Fig. 2). Massive wind power generation is a reasonably realistic measure to help realize a decarbonized society. However, wind power generation depends heavily on natural conditions. When wind is too strong, massive electricity generated may be abandoned. Therefore, utility-scale stationary batteries suitable for charging and

[3] BloombergNEF (July 2019), https://about.bnef.com/blog/energy-storage-investments-boom-battery-costs-halve-next-decade/
[4] Shell LNG Outlook 2021

discharging electricity generated by large offshore wind farms in long-time cycles will have to diffuse.

Table 2 2050 offshore wind capacity targets

Region	2050 offshore wind capacity targets
EU	2030: 60 GW, 2050: 300 GW
U.K.	2030: 40 GW, 2050: 100 GW
Germany	2040: 40 GW
United States	2030: 30 GW (*)
China	2020: 5 GW
Taiwan	2025: 5.5 GW, 2035: 15.5 GW
Japan	2030: 10 GW, 2040: 30-45 GW

* Reported on March 29, 2021

Source: Prepared by the author from "Offshore Wind Industry Vision" (Agency for Natural Resources and Energy)

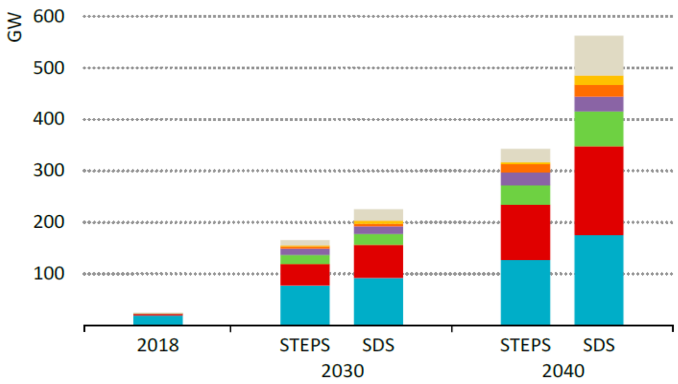

Fig. 2 Installed capacity of offshore wind by region and scenario

Source: Offshore Wind Outlook 2019 (IEA, November 2019)

Economic incentives are working for installing stationary batteries. Western countries have terminated feed-in tariffs for the initial-phase promotion of renewable energy. Instead, they have developed a mechanism in which renewable power generators are preferentially allowed to be connected to the grid and sell electricity in a timely manner in electricity exchange markets. The United Kingdom has introduced the Contract for Difference (CfD) in which the government covers the difference between a strike price fixed through auctions and a market reference price. Germany has set up the Feed-in Premium (FIP) to provide premium (subsidies) on renewable power generators' sales at market prices. California obliges electricity utilities to procure energy storage technologies (under State Law AB2514) while allowing utility-scale stationary batteries to take part in the electricity exchange market. This arrangement has prompted renewable power generators to positively generate revenue by charging batteries in time zones for lower electricity prices and discharging them (selling electricity) in the evening and nighttime when electricity prices rise with the supply-demand balance tightening (Fig. 3). In California, battery systems have increasingly participated in the electricity market, with their total capacity in the market standing around 400 MW at the end of the third quarter 2020[5].

[5] CAISO (February 4, 2021), "Q3 2020 Report on Market Issues and Performance," http://www.caiso.com/Documents/2020ThirdQuarterReportonMarketIssuesandPerformance-Feb4-2021.pdf, pp.125-126

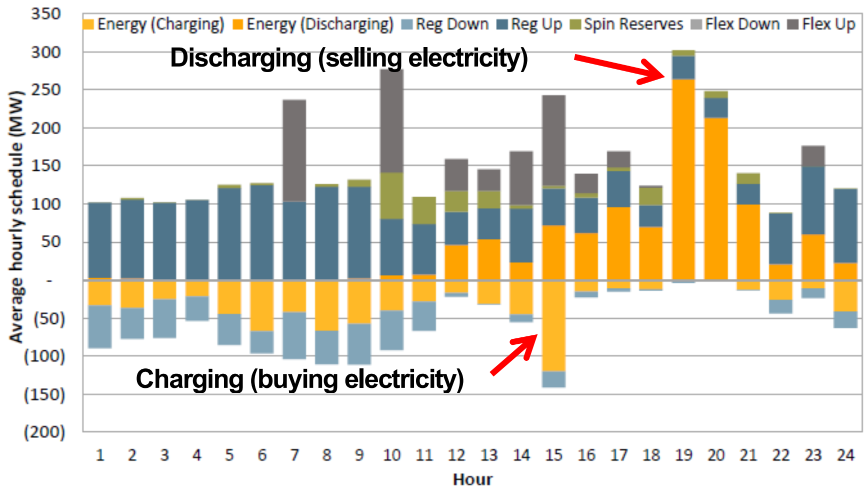

Fig. 3 Average real-time battery schedules in California (September 5 and 6, 2020)

Source: CAISO, Q3 2020 Report on Market Issues and Performance

(2) Fading fossil thermal power plants

Providers of balancing capacity are changing. While decarbonization speeds and approaches differ from region to region in the world, arguments are growing for curtailing output from and capacity of fossil thermal power plants that have undertaken regulation and for fading out fossil thermal power plants from the viewpoint of environmental friendliness, as noted earlier. The European Commission in June 2019 published the EU taxonomy that dropped natural gas-fired power plants without carbon capture and storage (CCS) and coal-fired power plants with CCS as well as nuclear power plants from a list of technologies for sustainable finance. The EU taxonomy, though having no binding power, represents a great trend towards decarbonization. Fossil thermal power plants are destined to be faded out and replaced by utility-scale stationary batteries as balancing capacity.

As noted above, demand is expected to further grow for utility-scale stationary batteries suitable for energy storage. Among such batteries, I pay attention to redox flow batteries (RFBs) in which Japanese companies are well positioned in fierce competition. The following outlines the structure, operating principles and technological characteristics of RFBs and a global RFB development trend.

2. Redox flow batteries

(1) Structure and operating principles

Batteries are broadly classified into three categories: consumer batteries built into smartphones and personal computers, vehicle batteries mounted on automobiles and stationary batteries for stabilizing power grids and storing electricity. RFBs are exclusively used as stationary batteries. An RFB is an electrolyte-circulation (flow) battery. It uses pumps to circulate electrolyte stored in external tanks to positive and negative electrodes separated with an ion-exchange membrane to generate ion oxidation and reduction reaction to control charging and discharging. Positive and negative electrodes are made of thin cellular carbon material and use the same electrolyte (Fig. 4). As the electromotive force per cell is limited to 1.4 V, cells are connected in series and laminated into a stack to get a practical voltage (Fig. 5). In addition to the conventional plant type, a container type has been developed and commercialized to reduce the transportation and construction cost and save space (Fig. 6).

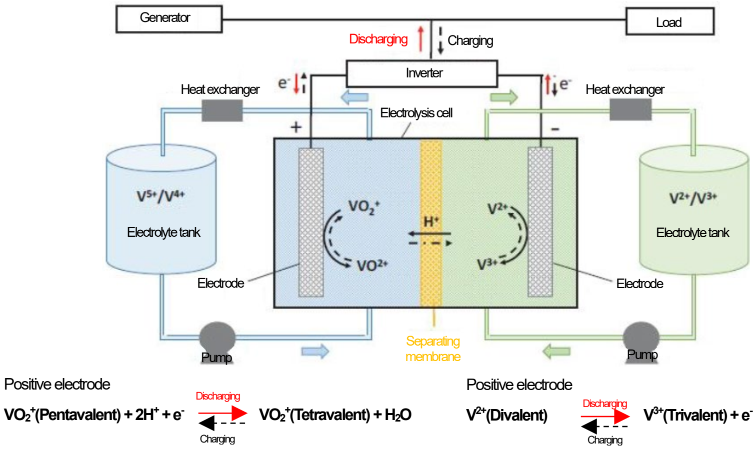

Fig. 4 Operating principle of RFB[6]

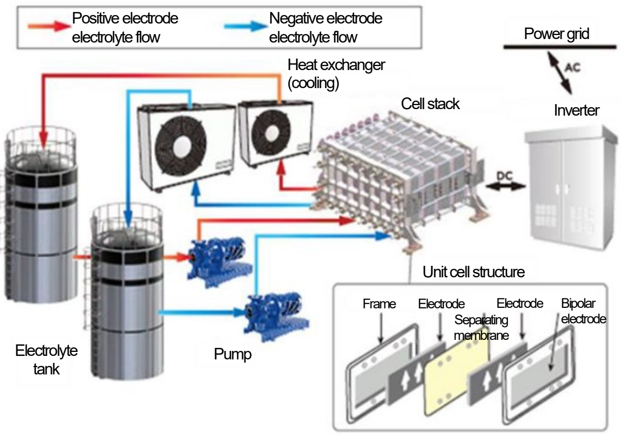

Fig. 5 Cell stack configuration details[7]

Fig. 6 Exterior appearance of RFB systems (Plant and Container Types)[8]

[6] (Center for Low Carbon Society Strategy (March 2017) "Proposal for Making Innovation Policy Based on Quantitative Scenario of Technology, Economy and Society towards Realizing Low-carbon Society," Technology Development, Storage Battery System (Vol. 4) - Redox Flow Battery System Configuration Analysis and Cost Assessment -

[7] Sumitomo Electric Industries, Ltd., Redox Flow Battery Catalogue, https://sei.co.jp/products/redox/pdf/Redox_Flow_Battery.pdf

[8] Sumitomo Electric Industries, Ltd., Products Information, https://sei.co.jp/products/redox/

(2) Technological characteristics of RFBs (Table 3, Fig. 7 and 8)

Table 3 below compares the technological characteristics of RFBs and other batteries. RFBs have the following excellent characteristics.

Table 3 Comparing technological characteristics of utility-scale batteries for energy storage

Battery Type	**Redox flow (Vanadium electrolyte solution)**	**Lithium ion**	**Sodium-sulfur (NaS) battery**	**Lead battery**
Active material (Positive/negative electrodes)	V ion / V ion	Metal composite oxide containing lithium ion / Carbon	Sulfur / Sodium	Lead oxide / lead
Theoretical energy density (Wh/kg)	100	392-585	786	167
Durability	◎ (Over 20 years) Highly durable to irregular charging and discharging	○ (about 10 years) (7,000 charging and discharging cycles)	○ (about 10 years) (4,500 charging and discharging cycles)	◎ (15-17 years) (3,000 charging and discharging cycles)
Safety	◎ (No fear of ignition, flame-resistant electrolyte)	× (Flammable)	× (Operating at high temperatures (300°C))	× (Dilute sulfuric acid and lead are harmful)
Expandability	◎ (Most expandable) (Output and capacity can be designed independently)	○ (Expandable) (Output and capacity increase linearly)	○ (Expandable) (Output and capacity increase linearly)	× (not expandable)
Charge and discharge time	◎ Available for long time (Available for 24-hour storage and discharging)	△ Available for high-speed, high-output charging/discharging	○ Positioned between RFBs and lithium ion batteries	× Short time
Output	◎Some 10 times as much as rated output can be discharged in a short time	◎ (High output)	◎ (Long time / high output)	◎(Short time / high output)
Charge/discharge efficiency	△ Battery alone: 75% System: 70%	◎ 95%	◎ Battery alone: 85% System: 75%	◎ 80-90%
Major accessory	Circulation pump	Nothing particular	Heater	Nothing particular
Resource constraints	△ (Vanadium)	× (Lithium)	◎(Not Applicable)	◎ (Not Applicable)
Features (Advantage ○ /disadvantage ×)	○ Residual power is easy to measure ○ Electrolyte solution can be reused almost permanently ○ Highly safe, installable in urban areas × Electric current can be lost	○ Used frequently for consumer products ○ High energy density ○ High charge/discharge efficiency ○ Self-discharge is limited × Safety (flammable) × Unsuitable for enlargement × Vulnerable to over-charging/discharging	○ Frequently used for storing electricity ○ Capacity can be increased with space saved ○ No self-discharge ○ Low cost (needing no rare earths) × Ignition risk (must be kept at 300°C) × Power consumption for warming	○ Used frequently for vehicles × Large and heavy ×Harmful to humans × Self-discharge is possible

Source: Prepared by the author from Shigematsu[9], NEDO TSE Foresight vol.20[10], etc.

[9] https://sei.co.jp/technology/tr/bn179/pdf/sei10674.pdf
(T. Shigematsu, Redox Flow Batteries for Electricity Storage, July 2011, SEI Technical Review, Vol. 179)
[10] https://www.nedo.go.jp/content/100866310.pdf (New Energy and Industrial Technology Development Organization, TSC Foresight vol. 20 (July 2017), Towards Formulating Technology Strategy for Electricity Storage)

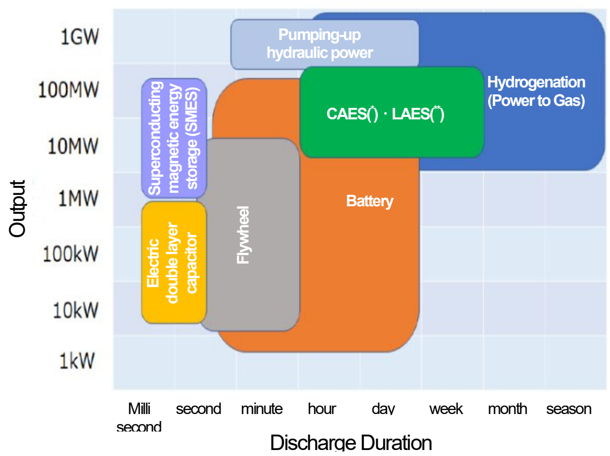

Fig. 7 Output and discharge durations for energy storage technologies

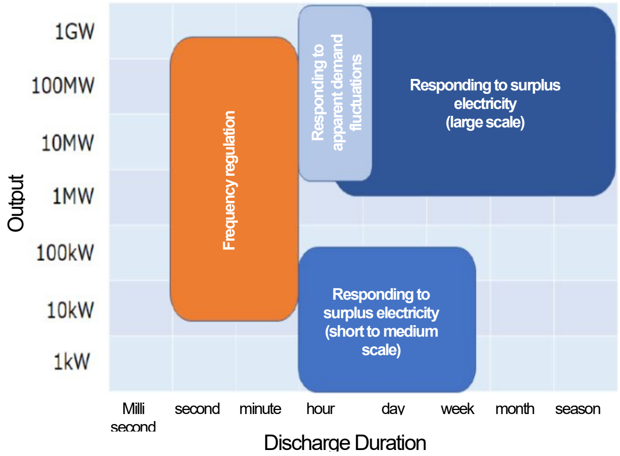

Fig. 8 Output and discharge duration required for each application

Source: Prepared by the author from NEDO TSC Foresight vol.20 (July 2017)

Excellent durability

First of all, RFBs feature excellent durability. Vanadium electrolyte redox flow batteries (VRFBs)[11], the most popular among RFBs, **only change the valence of vanadium ions in an electrolyte solution when charging and discharging electricity, remaining free from the dissolution or precipitation of electrodes. Their degradation is limited, allowing them to remain in service for a long time, with the charging and discharging frequency being unlimited.** Thanks to the excellent durability, RFBs are more competitive in the lifecycle cost than other stationary batteries including lithium-ion batteries. **RFBs are also durable in terms of irregular charging and discharging, having a high affinity for power generation technologies plagued with wild and unpredictable output fluctuations, including offshore wind farms that are expected to diffuse massively in Japan. Moreover, the vanadium electrolyte solution would not degrade through charging or discharging but remain in service almost permanently. It can even be recycled**, meaning that users can reduce the initial RFB installation cost by leasing electrolyte solutions (classifying rents as operating expenses).

Extremely high safety

Lithium-ion and NAS batteries use flammable materials, having a high risk of ignition. In contrast, **RFBs have no such risk because their electrodes and electrolyte solution are inflammable or flame-resistant. They also operate at ordinary temperatures, featuring extremely high safety.** RFBs can charge and discharge electricity for a long time ranging from several hours to several days, being suitable for stabilizing grids connected to large-capacity renewable power plants. Thanks to the high safety, RFBs can be even securely installed in urban areas. In this way, RFBs have great potential to play key roles in a decarbonized society using massive renewable energy (see Chapter 6).

High expandability (Fig. 9)

The electrolyte solution tank capacity (kWh) and the cell stack output (kW) can be designed independently, meaning that the RFB capacity and output can be designed flexibly. While output increases linearly as capacity increases for other batteries, an RFB's capacity can be raised through the addition of electrolyte solution tanks with output kept unchanged. As its capacity is expanded to enable charging and discharging over a longer time above 8 hours, the RFB can increase its cost competitiveness against other stationary batteries including lithium-ion batteries. (If the lithium-ion

[11] VRFBs account for about 58% of all RFBs in use, according to IDTechEx (June 2020), https://www.idtechex.com/en/research-report/redox-flow-batteries-2020-2030-forecasts-challenges-opportunities/723

battery that uses the rare metal lithium for electrodes expands its capacity, however, the material cost may increase substantially to the disadvantage of its cost competitiveness.)

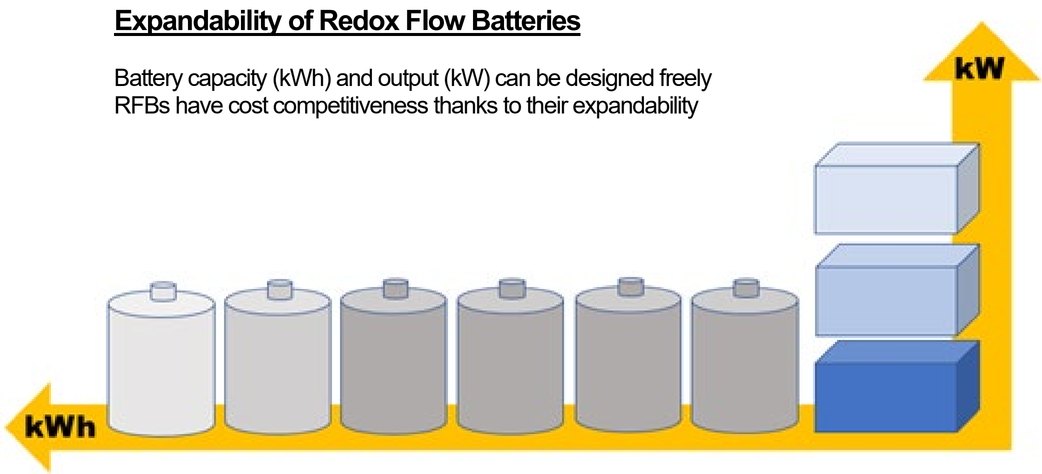

Fig. 9 Conceptual diagram of RFBs' expandability

Long charge/discharge cycle and high output in milliseconds

Generally, lithium-ion batteries have strength in charging and discharging electricity in a short time of milliseconds. However, **an RFB can discharge 10 times as much as the rated output in milliseconds and has a long charge/discharge cycle such as 24 hours for charging before 24 hours for discharging,** being suitable for large-scale offshore wind and other renewable power generation for which long charge/discharge cycles are required. RFBs can also be used as backup power sources that are required to continuously charge and discharge electricity for a long time of 24 to 48 hours during an outage caused by natural disasters, which have recently tended to bring about huge damage. (In contrast, lithium-ion and NAS batteries are suitable for charge/discharge cycles of several hours due to their technological characteristics.) In addition to their safety, RFBs have particularly excellent technological characteristics for providing grid stabilization functions to be required when massive renewable power generation capacity is installed towards the 2050 carbon neutrality target.

Disadvantages for RFBs include a low energy density attributable to separated electrolyte solution tanks, a charge/discharge efficiency of some 70% lower than for other stationary batteries and the insecure supply of the rare metal vanadium. The low charge/discharge efficiency is attributable to losses from the circulation of electrolyte solution with pumps and can be raised to around 80% through better loss control. As for the vanadium resource constraint, initiatives are being implemented to develop a more efficient electrolyte solution including no vanadium and to secure a stable supply of vanadium at cheap prices irrespective of international commodity price fluctuations (see details in Chapter 5).

3. Market size, cost, Japanese companies' position in global development competition

(1) Market size

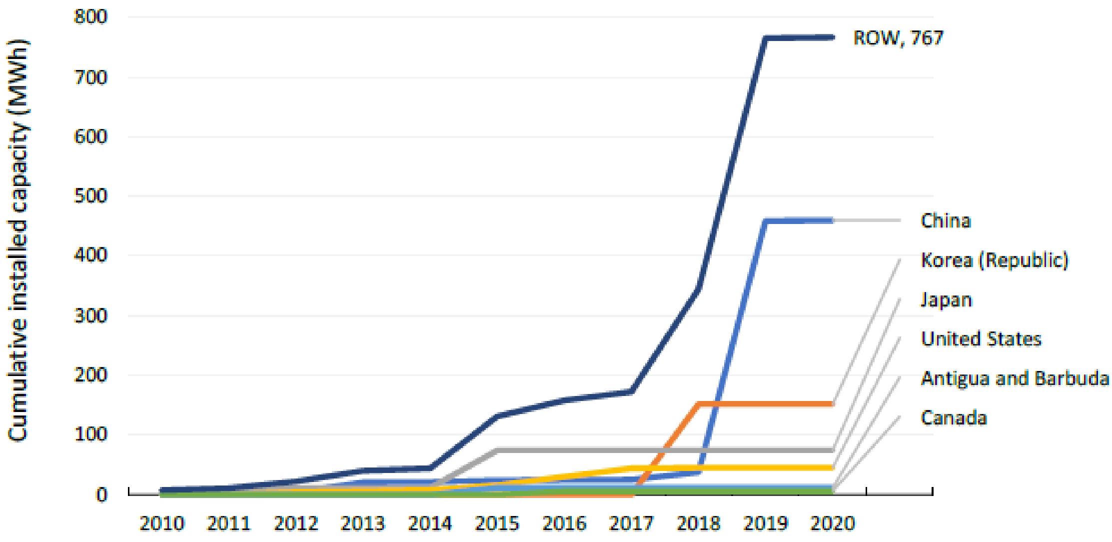

Fig. 10 Cumulative installed RFB capacity (by country, 2010-2020)

Source: Bloomberg New Energy Finance (2020), "Storage Data Hub – Storage Assets"

Note: ROW: Rest of the World

First, I would like to check the penetration of RFBs. Fig. 10 above shows cumulative installed RFB capacity in the world. RFBs rapidly penetrated from 2018 to 2019, driven by China and Korea.

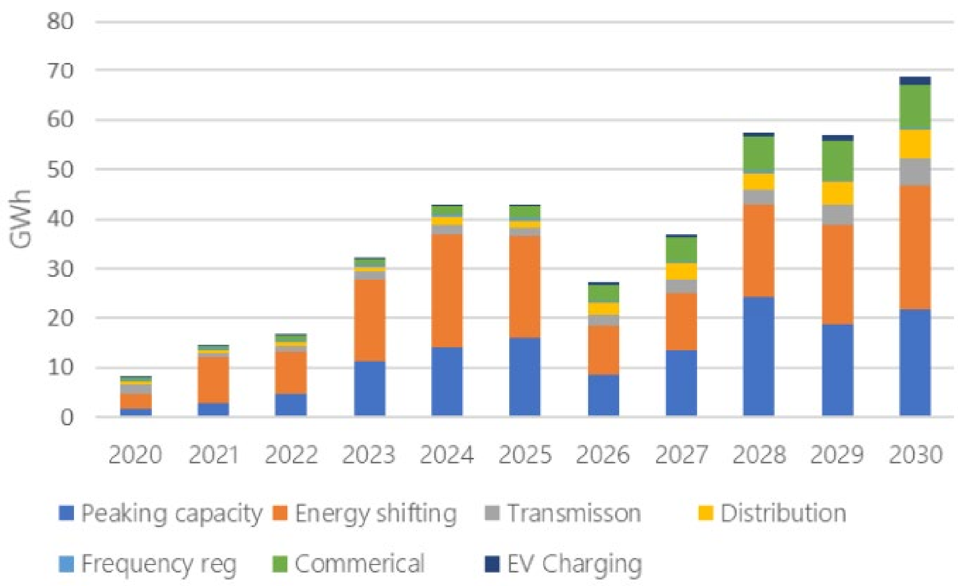

Fig. 11 RFB market outlook (2020-2030)

Source: J. Frith, "Emerging Energy Storage Technologies," Bloomberg New Energy Finance (2020)

Fig. 11 above shows a long-term RFB market outlook. The RFB market is expected to continue growing, with a total capacity reaching around 70 GWh in 2030. Major RFB applications are predicted to include energy shifting and peaking capacity.

(2) Cost

The most critical factor behind RFBs' failure to penetrate is the high initial installation cost, but the cost has been lowered down to 1.2-1.3 times the levels for other utility-scale stationary batteries. The unit installation cost for a utility-scale RFB system for a long charge/discharge cycle above 8 hours and a long lifecycle can be 60,000 yen/kWh[12] including electrolyte solution. If electrolyte solution is leased in and excluded from initial investment, the cost may slip below 40,000 yen /kWh. A useful reference for a cost outlook towards 2030 is an analysis by the U.S. Pacific Northwest National Laboratory under support from the U.S. Department of Energy. It indicates that RFBs are fairly competitive in terms of the annualized cost ($/kWh, $/kW) and the levelized cost of electricity (LCOE, $/MWh) in comparison with other stationary batteries under the assumption of the system having an output at 100 MW and a charge/discharge cycle at 10 hours (Fig. 12)[13].

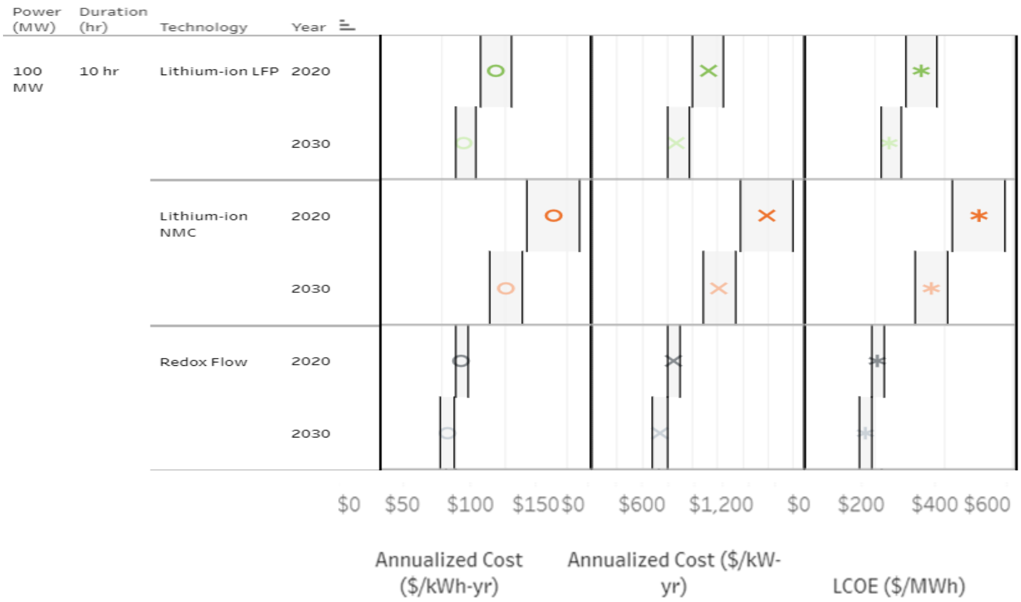

Fig. 12 Utility-scale stationary battery cost outlook (2020 and 2030)

Note: The LCOE ($/MWh) was computed by dividing annualized cost by annualized output (kWh).

(3) Japanese companies' positions in global RFB development competition

Demand has been growing year by year for RFBs with excellent technological characteristics suitable for utility-scale stationary batteries. A number of RFB manufacturers reaches as many as 50 to 70 in the world. While their elimination and consolidation have actively made progress in recent years, Sumitomo Electric Industries (Japan), Invinity Energy Systems (U.K.), Schmid Group (Germany) and VRB Energy (China) have ranked ahead of others in terms of system quality and sales. As stationary batteries become larger for large scale renewable power generation such as offshore wind, technology verification at installation sites is required more and more. Although hopes have recently been placed on the early commercialization of all-solid, all-polymer and other next-generation batteries, RFBs are fairly viewed as having a lead of three to five years over these next-generation batteries in that technology verification at installation sites has already made great progress. Particularly, Sumitomo Electric Industries features a long history of RFB development from the 1980s, RFB demonstrations at various sites in the world and massive deliveries of practical RFBs, boasting an advantageous position

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[12] According to a survey report on the impact of solar singularity, if the battery price slips below 60,000 yen/kWh, a storage parity in which the introduction of batteries becomes economically advantageous may be achievable.

[13] Pacific Northwest National Laboratory, "Energy Storage Cost and Performance Database," https://www.pnnl.gov/ESGC-cost-performance

over competitors. On the other hand, many Chinese companies such as VRB Energy and Pongke Power have joined the market for RFBs as well as lithium-ion batteries in a manner to intensify competition (Table 4).

Table 4 Major RFB manufacturers and their products lineups

Manufacturer	Output	Capacity	Note
Sumitomo Electric Industries (Japan)	250 kW	750kWh (3hr)-1.5MWh (6hr)	Single module specification
Invinity Energy Systems (U.K.)	78 kW-10 MW	220 kWh - 40 MWh	Operational over more than 25 years
Schmid Group (Germany)	5-60 kW	30-200 kWh	Single module specification
Volterion (Germany)	2.5-15 kW	13 kWh	Operational over more than 20 years
VRB Energy (China)	250-500 kW	4-80 MWh	Developing GW-class RFBs (maximum output at 250MW, 10hr)

4. RFB installation cases

Large stational RFBs have diffused in China, the United States, Australia and Europe. Apparent factors behind the diffusion include growing needs for longer charge/discharge cycles (charge/discharge cycles have lengthened from 2-3 hours to 8-48 hours due to greater offshore wind farm capacity, RE100 (Renewable Energy 100% initiative) participants have increased globally and demand has grown for utility-scale stationary batteries for longer charge/discharge cycles through progress in BCP (business continuity planning) responses).

As an overseas case for the installation of an RFB, a deal for installing an 8 MWh VRFB made by Invinity Energy Systems at a 6 MW solar PV array in South Australia was announced in December 2020. Under 5.7 million Australian dollars in funding by the Australian Renewable Energy Agency (ARENA), the VRFB will be delivered in the second half of 2021[14] (Fig. 13). Anticipating the future expansion of demand for VRFBs, Schmid Group announced in June 2020 that it would form a joint venture with Nusaned Investment (an investment subsidiary of Saudi Basic Industries Corporation) to establish a VRFB plant and a research and development center in Saudi Arabia. The plant will have an annual production capacity of 3 GWh, being among the biggest RFB production facilities[15].

[14] ARENA (November 11, 2020, Press Release), "First grid scale flow battery to be built in South Australia," https://arena.gov.au/news/first-grid-scale-flow-battery-to-be-built-in-south-australia/

[15] Schmid Group (May 6, 2020, Press Release), "Everflow JV to manufacture Vanadium Redox Flow Batteries (VRFB) in KSA," https://schmid-group.com/en/schmid-group/news-events/press-releases/everflow-jv-to-manufacture-vanadium-redox-flow-batteries-vrfb-in-ksa/

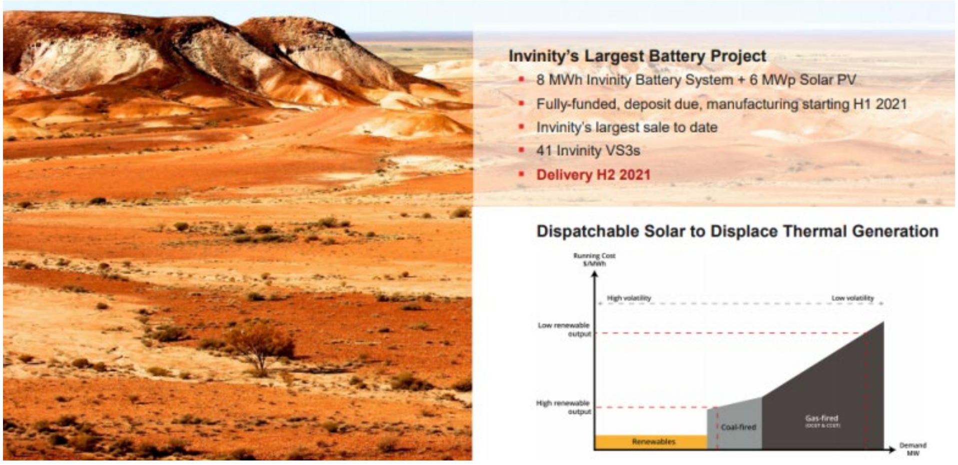

Fig. 13 Utility-scale VRFB in South Australia (Yadlamalka Solar + Storage Project)

Source: Invinity Energy Systems[16]

In Japan, Hokkaido Electric Power Co., Inc. (HEPCO) and Sumitomo Electric Industries jointly installed a utility-scale RFB (with rated output at 15 MW and storage capacity at 60 MWh) at the Minami Hayakita electric power substation as part of the main grid system to demonstrate the performance of the RFB over three years between February 2016 and January 2019 as new regulation and balancing capacity responding to renewable energy output fluctuations and establish optimum control technology[17]. HEPCO used the demonstration data to consider introducing a utility-scale stationary battery to raise the capacity for accepting electricity from wind farms. In March 2017, it invited bids for a project for a 600 MW wind power generation facility on the premises of a 360 MWh battery to be installed under a joint funding scheme[18]. Following the demonstration, HEPCO ordered a VRFB system (with installed capacity at 510 MWh (170 MW x 3 hours) from Sumitomo Electric Industries in July 2020. It is planned to be completed by March 2022[19] (Fig. 14).

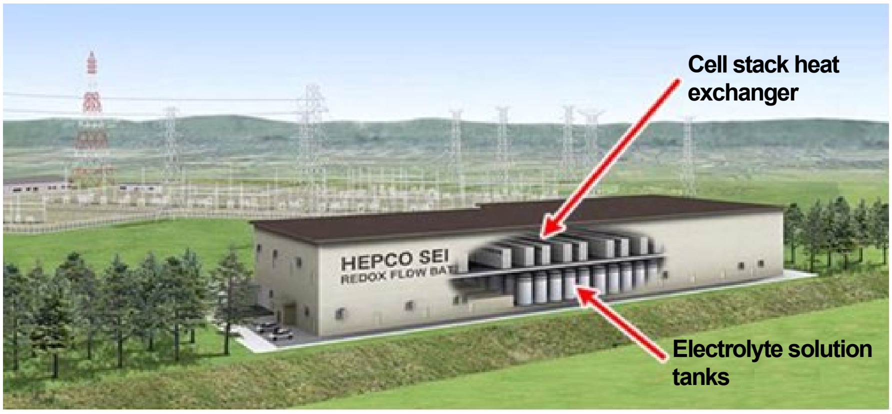

Fig. 14 Conceptual drawing of a large VRFB system to be introduced by HEPCO

Source: Nikkei BP "Next-generation Batteries 2018"

[16] Invinity Energy Systems (December 2020), "Production Flow Batteries," https://invinity.com/wp-content/uploads/2020/12/Invinity-Corporate-Presentation-Nov20_WEB.pdf

[17] (New Energy Promotion Council (February 2018) "Large Battery System Demonstration at Minami Hayakita Electric Power Substation") https://www.nepc.or.jp/topics/pdf/180320/180320_9.pdf

[18] (Nikkei Cross Tech (August 9, 2917) "Achievements of Large Redox Flow Battery Launched in Northern Japan") https://xtech.nikkei.com/dm/atcl/feature/15/415282/080700019/

[19] Sumitomo Electric Industries press release (August 7, 2020) "Sumitomo Electric awarded for Redox Flow Battery Systems from Hokkaido Electric Power Network" https://sumitomoelectric.com/sites/default/files/2020-12/download_documents/20200807Sumitomo%20Electric%20awarded%20for%20Redox%20Flow%20Battery%20Systems%20from%20Hokkaido%20Electric%20Power%20Network.pdf

5. Challenges

Cost reduction is the key to the further penetration of RFBs. Cost reduction measures include the improvement of battery efficiency (see 2. (2)) and the stable procurement of cheap vanadium. Fig. 15 below shows a breakdown of the VRFB cost and the electrolyte solution cost. Electrolyte solution accounts for about 40% of the total VRFB cost (electrolyte solution's cost share increases as a charge/discharge cycle lengthens). Vanadium, a main raw material for electrolyte solution, captures about 45% of the electrolyte solution cost. Producers of the rare metal vanadium are limited to China, Russia, the United States, etc. Japan must depend on imports from these countries for vanadium supply. Vanadium prices can rise easily in response to an increase in demand from the steelmaking industry that uses massive vanadium for specialty steel[20]. This is a reason why lithium-ion batteries that have diffused widely for vehicles and consumer products have been used for storing electricity from renewables.

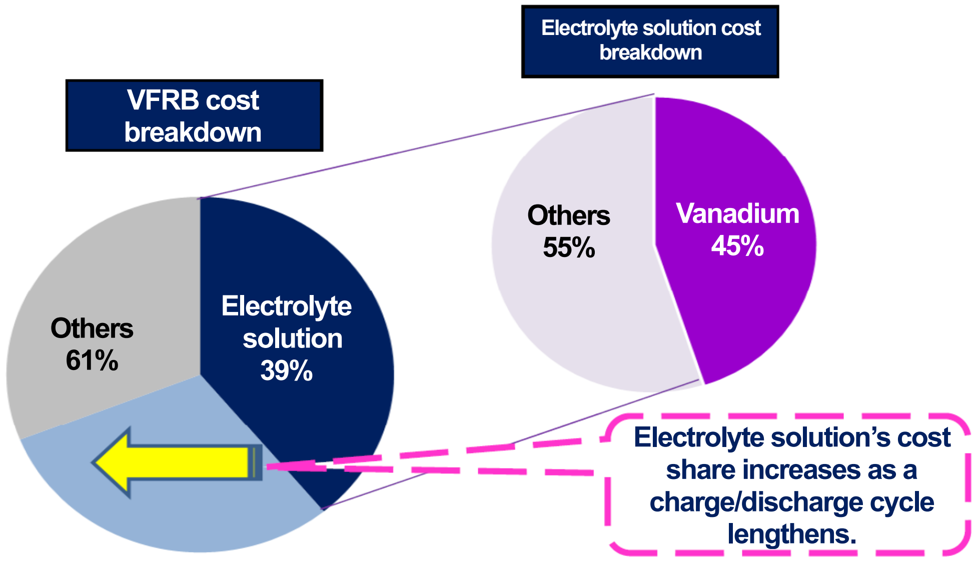

Fig. 15 VRFB cost breakdown and electrolyte solution cost breakdown

To reduce the electrolyte solution cost, Sumitomo Electric Industries is developing RFBs using titanium or manganese instead of vanadium. If RFBs are expected to spread in a full-fledged manner, however, priority should be given to the stable procurement of vanadium for the established RFB technology. LE SYSTEM, a vanadium electrolyte solution production venture based in Kurume, Fukuoka Prefecture, has developed a technology to collect vanadium from oil coke, combustion soot from thermal power plants, iron-ore mining residue, waste catalysts, slug and other vanadium-containing wastes and unused resources and use collected vanadium for producing electrolyte solution efficiently. By partnering with other companies in Japan to collect vanadium free from international commodity price fluctuations, LE SYSTEM could halve vanadium electrolyte solution prices at 500,000-800,000 yen/kL[21] and stably provide vanadium electrolyte solution (Fig. 16). LE SYSTEM has conducted domestic demonstration tests for the technology under funding by NEDO and is currently pursuing its commercialization. The company plans to complete a vanadium collection plant and an electrolyte production facility under construction in Namie, Fukushima Prefecture, by August 2021. The facilities will annually ship 5 million liters of electrolyte solution to domestic customers. In anticipation of renewable energy diffusion in Japan and other countries, LE SYSTEM plans to build plants in Yamaguchi and other prefectures to boost its electrolyte production capacity to 20 million liters per year by 2025. It is also preparing for a project to integrate vanadium collection and electrolyte solution

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20 In the past, market prices shot up to levels that were seven to eight times as high as normal levels.

21 (Nikkei Shimbun (April 16, 2021) "LE SYSTEM to commercially produce electrolyte solution for long-life, safe batteries in Fukushima) https://www.nikkei.com/article/DGXZQOJC089I60Y1A400C2000000/

production at overseas sites rich with untapped resources including mining residue. The LE SYSTEM technology could lower the RFB cost to 20,000-30,000 yen/kWh[22] paving the way for VRFBs to be used for solar PV. On the other hand, vanadium procurement from abroad has become difficult. International vanadium prices have begun to spike against the backdrop of growing global VRFBs demand. Particularly, competition to purchase mining residue with high vanadium contents has intensified, making it difficult for private companies to procure mining residue from abroad.

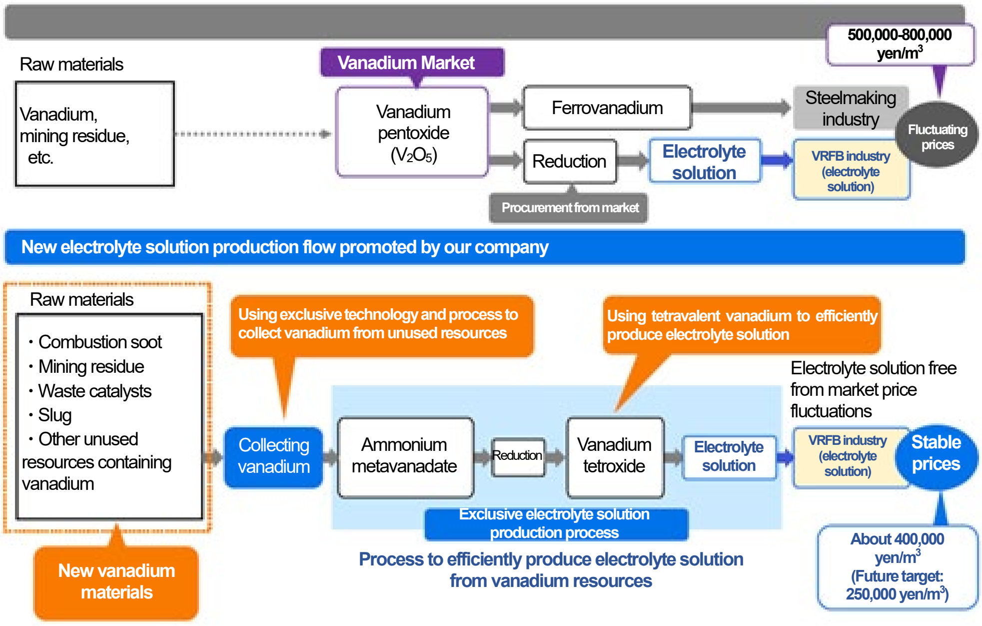

Fig. 16 Innovative vanadium electrolyte solution production flow

Source: Presentation material for NEDO venture business matching meeting (LE SYSTEM)

6. Realizing an RE100 decentralized model with a higher renewable energy share

Chapter 2 said that RFBs have great potential to play key roles in a decarbonized society using massive renewable energy. The 2050 carbon neutral target pursued by the Japanese government is difficult to achieve. Fig. 17 below indicates an image of a transition to carbon neutrality in 2050. A proposed decarbonized power mix for 2050 comprises renewable energy accounting for 50-60% of total power generation, nuclear energy and fossil fuels (with CCU/CCUS/carbon recycling) for 30-40% and hydrogen/ammonia for 10%. Given that the renewable energy share would have to be expanded if nuclear power plant replacement/restarting is difficult, the current centralized urban model focusing on fossil-fired power generation may have to be transformed into a decentralized model dominated by renewable energy through a bold change in the way of thinking.

[22] *Ibid.*

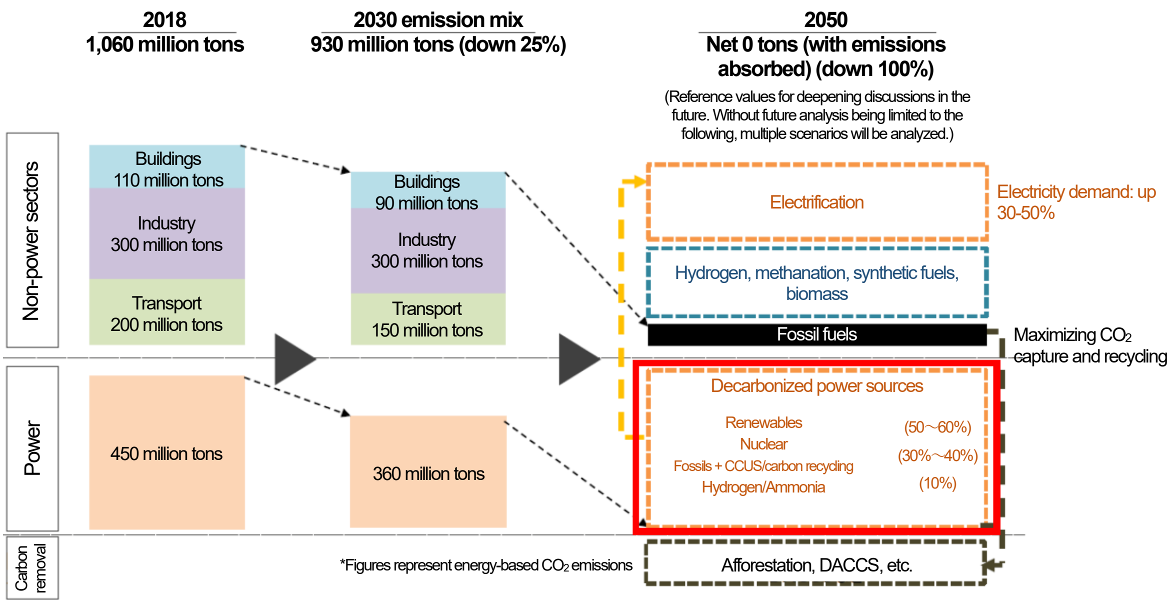

Fig. 17 Image of transition to 2050 carbon neutrality

Source: Ministry of Economy, Trade and Industry, "Green Growth Strategy to Support Japan's 2050 Carbon Neutral Goal" (December 2020)

In line with the 2050 Carbon Neutral Declaration, local governments are expected to formulate and publish their respective carbon zero plans. There may be numerous challenges to overcome. A potential option arising from a bold change in the way of thinking would be an RE100 renewable energy self-sufficiency model to be powered 100% by solar PV combined with utility-scale stationary batteries. Batteries being installed in urban areas would have to be extremely safe or free from the risk of ignition. From the viewpoint of emergency power sources for business continuity planning as well as renewable energy promotion, stationary batteries would have to have charge/discharge cycles as long as two to three days to maintain public services amid power outages caused by natural disasters. Given the abovementioned technological characteristics, VRFBs are highly adaptable to such emergency situations.

On the Japan Electric Power Exchange, electricity prices frequently fall to as low as 0.1 yen/kWh in spring, autumn and on weekends when electricity demand is lower. Batteries may be used for charging when electricity prices are low and discharging when such prices are high. In this respect, hopes may grow on VRFBs that can demonstrate a price advantage by storing electricity for a long duration.

From the viewpoint of sustainability, it is desirable for batteries to contribute to realizing a recycling-oriented society by recycling resources. RFBs' technological characteristics meet the desirability. Therefore, RFBs are fairly expected to play growing roles in realizing a decarbonized society.

Conclusion

Many economies in the world are veering in the direction of realizing net zero emissions by 2050. This trend will accelerate in the future, being irreversible. Although great hopes are placed on hydrogen as a new carbon-free energy source, relevant costs are still high. Without a further breakthrough, it may take much time to realize a low-cost, stable supply network for hydrogen. In such a situation, many economies have chosen a realistic solution to adopt renewables as a mainstay power source. The massive penetration of stationary batteries that are safe and highly durable, suitable for long charge/discharge cycles and able to be easily enlarged for power grids is seen as indispensable for the coming age of massive renewable energy introduction.

The Japanese government declared a 2050 carbon neutral target in October 2020. A pillar for its sixth Strategic Energy Plan now under formulation is the adoption of renewables including offshore wind as a mainstay power source. As the massive penetration of batteries is indispensable for the further diffusion of renewables, policy support will grow even more important for enhancing Japanese battery manufacturers' international competitiveness, as well as for nurturing and expanding the battery industry including electrolyte solution producers. Regarding RFBs and other batteries, Japan faces the problem of how to secure rare metals that are endowed in a limited range of countries and vulnerable to international price fluctuations. For the purpose of reducing and stabilizing RFB prices, Japan's public and private sectors are required to cooperate in procuring vanadium as a resource that has not necessarily been highlighted.

Essays on the Carbon Sources of Carbon-Recycle Fuels (1)

- Addressing Misconceptions of Methanation such as CO_2 Re-emission, and Long-term Perspectives -

Yoshiaki Shibata* Takashi Otsuki**

Carbon-recycle fuels (synthetic fuels)[1] are hydrocarbon fuels synthesized from hydrogen and carbon dioxide, and there are high expectations of the role they can play toward the realization of a decarbonized society. However, as they straddle the two technological fields of hydrogen and CCU (and carbon recycling), this often gives rise to misconception and confusion about their decarbonization effect and significance. In light of that, this series of articles examines the principles and long-term approach for carbon-recycle fuels, and the attribution of CO_2 emission reduction effect, with the aim of contributing to the development of materials for future discussions on energy policy. The first paper looks at the case of carbon-neutral methane (CN methane) and explains its principles, while suggesting the possible challenges toward the achievement of a decarbonized society in 2050. The second paper discusses the selection of CO_2 sources in the decarbonized society of 2050 as well as the transitionary period leading up to 2050. The third paper develops a wide range of approaches with regard to the attribution of CO_2 emission reduction effect when using recycled carbon fuels.

1. Key points of this paper

- While there are high expectations of the role that hydrogen and carbon-neutral methane (CN methane) can play in the decarbonization of city gas, there are still misconceptions about CN methane. There is first a need to reaffirm the principles, functions, and roles of methanation (production of CN methane). Based on the correct understanding of these points, there is then a need to set out an outlook for the approach for CN methane in the decarbonized society of 2050 as well as the transitionary period leading up to 2050.
- CN methane is synthesized from CO_2 that is separated and captured from certain facilities, and hydrogen that is sufficiently decarbonized. As the CO_2 that is emitted through the use (combustion) of CN methane is offset (cancelled out) with the separated and captured CO_2, the substitution of natural gas through the use of CN methane produces a CO_2 reduction effect. In short, as CO_2 is only separated and captured, utilized, and re-emitted, the use of CN methane is essentially the same as use of hydrogen. Accordingly, based on the principles, CO_2 emissions from CN methane are not problematic.
- There are forms of CCU and carbon recycling that contribute to reducing CO_2, and those that do not. Although CO_2 is used and recycled in the CCU-related processes of synthetic fuel production and utilization, including methanation, the objective is to make hydrogen easier to be used and not to generate CO_2 emission reduction effect. CO_2 emission reduction effect is ultimately generated through the hydrogen.
- Misconceptions about CO_2 re-emissions from CN methane and the CO_2 emission reduction effect are probably the result of focusing solely on CO_2 behavior by classifying methanation in the field of CCU. As the effects of CN methane are dependent on hydrogen, it would be appropriate to categorize methanation under the field of hydrogen rather than CCU, in order to avoid such misconception.

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[1] As there are no fixed names or terms, what is referred to as “recycled carbon fuels” in this series may—depending on the situation—also be known as synthetic fuels, or as carbon-neutral methane for methane produced through methanation.

2. Body text

Introduction

There are high expectations of the role that hydrogen and synthetic methane (carbon-neutral methane, or CN methane) can play in decarbonizing city gas, and we face the important question of how to produce, transport, and utilize these gases in an economically efficient way. However, the significance of CN methane is still often misunderstood. In particular, it is claimed that CN methane re-emits CO_2 during combustion, and therefore makes it necessary to capture that CO_2 once again, or to offset it. While this can be considered as an interpretation that is conscious of the recent goal of realizing a decarbonized economy by 2050, it is also believed to be the result of misconceptions of the very principles of methanation.

In any case, many of the misconceptions are probably the result of focusing solely on the behavior of CO_2 by classifying methanation in the field of CCU. There is first a need to reaffirm the principles, functions, and roles of methanation. If the challenges toward the achievement of a decarbonized economy by 2050 are not clarified based on an accurate understanding of these aspects, the positioning of methanation in the important transitionary period toward the realization of a decarbonized society in 2050 may become ambiguous. Accordingly, this paper reaffirms the principles of methanation, then organizes the long-term issues and sets out an outlook for the approach for hydrogen and CN methane.

CN methane ≒ Hydrogen, methanation ∉ CCU

Firstly, we shall reaffirm the principles of CN methane separately from the goal of achieving a decarbonized economy in 2050. The mechanism behind CN methane is as follows: it is produced (methanation) through the synthesis of CO_2 with sufficiently decarbonized hydrogen, CO_2 is emitted in combustion during utilization, and conventional natural gas is substituted in that process. In short, CO_2 that is separated and captured from certain facilities is offset (cancelled out) by CO_2 that is emitted through the combustion of CN methane, while CO_2 is reduced through the substitution of natural gas that would have been used if CN methane were not utilized (however, the effect is diminished for CO_2 emitted from CO_2 separation and capture and the CN methane production process). In other words, the utilization of CN methane is the same as the direct utilization of sufficiently decarbonized hydrogen, and the utilization of CN methane is essentially equivalent to "the utilization of hydrogen" and "the substitution of natural gas by hydrogen" (a comparison of the cases in the left and center of Fig.1 shows that CO_2 emissions volume for the overall system is the same). On the other hand, if we were to focus on "the utilization of hydrogen," CO_2 separation and capture is neither related to, nor exists in, that process. Accordingly, it would be appropriate to classify methanation (production of CN methane) in the field of hydrogen, and not in the field of CCU. An argument that we have heard of from long before is, as CN methane re-emits CO_2 during combustion, it is necessary to capture that CO_2 once again, or to offset it. This is a misconception that has arisen from focusing solely on the re-emission of CO_2 by classifying methanation in the field of CCU (and carbon recycling). Incidentally, IEA uses the term "hydrogen-based fuel" for synthetic fuel. Hypothetically, even if methanation were classified under CCU, CO_2 is only separated and captured, utilized, and re-emitted; no CO_2 emission reduction effect is generated through its function as CCU. The CO_2 emission reduction effect generated through CN methane is dependent only on hydrogen.

The following question arises: why do we go to the trouble of producing CN methane by synthesizing hydrogen with CO_2, instead of just utilizing hydrogen as it is? This is because hydrogen, in the form of CN methane, is easier to use in existing city gas infrastructure. Blending hydrogen as it is into the city gas infrastructure (although this is also dependent on the volume of hydrogen) creates challenges such as the need to change the regulations, adjust or change the equipment, and change the measuring method, but the blend of CN methane, which is the main feedstock of city gas, is said to make it possible to avoid many of these challenges. The new fuel derived from hydrogen, which can be used as it is in existing infrastructure, is also called "drop-in" fuel. In short, methanation is ultimately one of the ways of utilizing hydrogen in city gas that takes into consideration economic rationality based on the effective use of existing city gas infrastructure, as well as the second best measure. In other words, we can say that if there are cases where it is possible, from the perspective of economic rationality, to directly utilize hydrogen through hydrogen blends or new hydrogen infrastructure, it would be better to apply such methods; methanation itself must not be the objective. It is important to carry out verification continuously to assess if hydrogen or CN methane is the more economical decarbonization option, while taking into consideration factors such as the city gas demand structure for each region and the period for the renewal of city gas infrastructure.

Sources of CO_2 for methanation

Based on the above clarification of the principles, CO_2 reduction effect through natural gas substitution (in the case where the difference caused by the efficiency of the process is disregarded) is the same regardless of whether the CO_2 that is used in methanation is derived from fossil fuels, biomass, or DAC (a comparison of the cases in the right and center of Fig.1 shows that CO_2 emissions volume for the overall system is the same). Of course, emissions are not negative when it is derived from biomass and DAC.

Fig. 2 compares the cases where CO_2 from fossil fuels and CO_2 from DAC is used in methanation. CO_2 from thermal power plants is diffused in the atmosphere, in any case. The separation and capture of CO_2 before it is diffused, is the same as utilizing direct air capture (DAC) to separate and capture CO_2 from the atmosphere. In short, CO_2 that is used in methanation is the same regardless of whether it is derived from fossil fuels or DAC. In other words, if there exist thermal power plants, it would not be problematic to use the CO_2 from these plants, but it would not do to construct or maintain thermal power plants deliberately for the sole purpose of methanation.

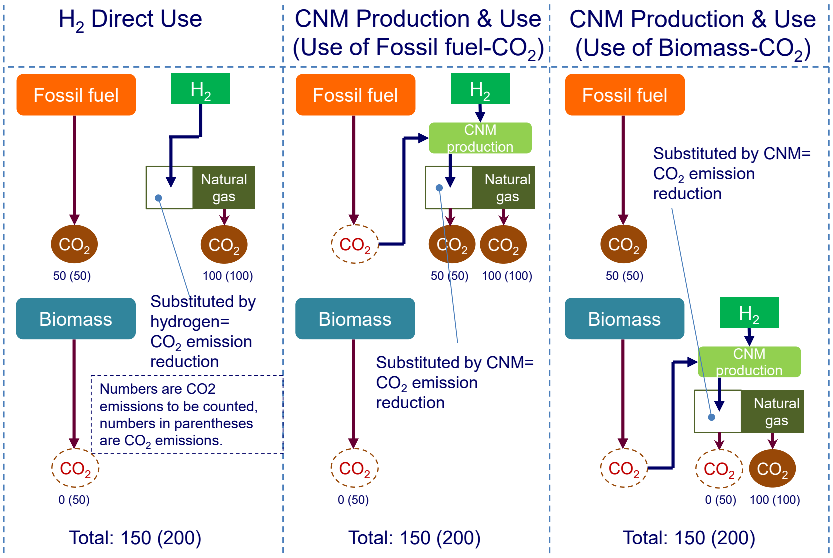

Fig.1 CO_2 emission reduction effect is the same in the utilization of hydrogen and the utilization of CN methane

Note: "CNM" refers to CN methane.

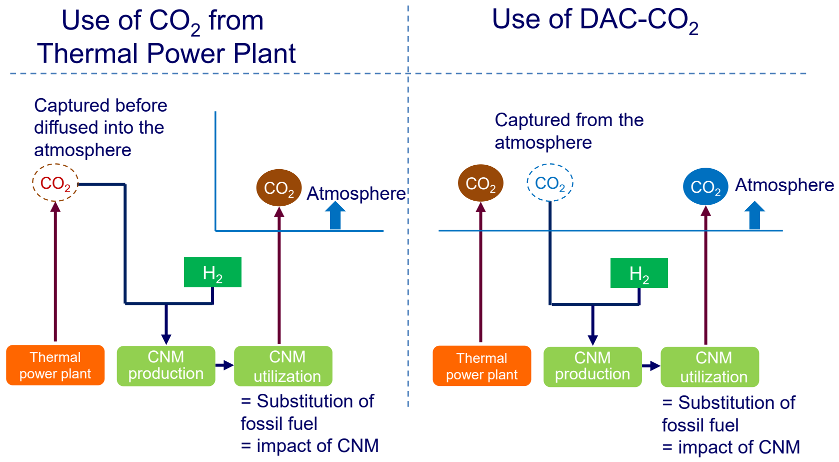

Fig. 2 CO_2 in CN methane production and utilization is the same regardless of whether the CO_2 is derived from fossil fuels or DAC

Note: "CNM" refers to CN methane.

In Europe, it is argued that the CO_2 used for methanation has to be derived either from biomass or DAC. However, this would be wrong based on a scientific interpretation of the principles of methanation. We can infer that political factor lies behind this, such as the intent to avoid extending the use of fossil fuels. As Europe has a history of restricting the use of fossil fuels, this argument is as a result no more than an indication of the argument that synthetic fuel manufacturing processes, including methanation that uses CO_2 derived from fossil fuels, are not allowed; it does not capture the essence of synthetic fuels.

Hence, based on the principles, if the hydrogen has been sufficiently decarbonized, CO_2 re-emission from CN methane is not problematic, and it does not matter what the source of the CO_2 is. However, as Japan aims to become a decarbonized economy by 2050, we may be approaching a turning point with regard to the interpretation of CO_2 sources. In 2050, when CO_2 emissions from fossil fuels are likely to be extremely limited, and in the transitionary period until then, how the synthetic fuels should be, including CN methane? This shall be discussed in the second paper.

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Essays on the Carbon Sources of Carbon-Recycle Fuels (2)

- Points to Note Toward the Realization of a Decarbonized Economy in 2050 -

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1. Key points of this paper

- There are high expectations of the role that carbon- recycle fuels (CR fuels: synthetic methane and synthetic liquid fuels, algae cultivation biofuels, etc.) can play toward the realization of a decarbonized economy. Candidate carbon sources for carbon-recycle fuels include fossil fuels, biomass, and CO_2 in the atmosphere, but CO_2 reduction effect is the same regardless of which carbon source is chosen.
- On the other hand, the viewpoint of the total volume of CO_2 that is emitted from the carbon recycling system is also important in a decarbonized economy. When biomass or CO_2 in the atmosphere is utilized, the carbon recycling system as a whole can be regarded as generating net zero CO_2 emissions.[1] Conversely, when fossil fuel-derived CO_2 is reused, positive CO_2 emissions are generated in principle from the viewpoint of the whole system, including the power plants and industrial plants that burn fossil fuels.
- There are now ongoing discussions about carbon pricing and the decarbonized economy of 2050 in Japan, and these could have an impact on the approach to carbon sources. For example, if carbon taxes were strengthened, taxes may be imposed on systems that reuse fossil fuel-derived CO_2. Furthermore, in the realization of net zero emissions in 2050, if fossil fuel-derived CO_2 were reused, there would be a need to offset the positive emissions. As shown in the estimates drawn up in this paper, the "costs" of carbon-recycle fuels using fossil fuel-derived CO_2 include not only the costs of CO_2 procurement, hydrogen production, and fuel production, but also the costs to the CO_2 itself (carbon taxes and offsetting costs, etc.). It is also important to take these costs into consideration.
- At a point where carbon constraints are relatively lax (such as 2030 or 2040), fossil fuel-derived CO_2 could possibly hold the key to the expansion of carbon-recycle fuels. On the other hand, we cannot deny the possibility that constraints to the reuse of fossil fuel-derived CO_2 may arise by 2050 due to the abovementioned factors, making it necessary to shift to other carbon sources depending on the situation. It is important to have a CO_2 procurement strategy that takes the time horizon into consideration.

2. Body text

CO_2 reduction effect from carbon-recycle fuels: Same across all carbon sources

In response to the "net zero" declaration for 2050 presented by Prime Minister Suga in October 2020, efforts have accelerated toward the realization of that goal. In December the same year, the government unveiled the "Green Growth Strategy Through Achieving Carbon Neutrality in 2050," and the bill to revise the Act on Promotion of Global Warming Countermeasures, which was approved by the Cabinet in March 2021, clearly set out the realization of a decarbonized economy by 2050.

Carbon recycling is a technology that is anticipated to contribute to the realization of decarbonization. Carbon recycling regards CO_2 as a resource and involves the reuse of CO_2 captured from power plants, industrial plants, and the atmosphere as fuel or raw material. In the reuse of CO_2 as fuel, the Green Growth Strategy points clearly to biomass fuel production

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1 To simplify the discussion, this paper disregards a number of points. It focuses on CO_2 emissions that arise from the combustion of biomass fuels and fossil fuels, but does not take into consideration CO_2 emissions in the processes of collecting/mining, transportation, etc. of these fuels. It also does not take into consideration CO_2 emissions that arise from the collection and transportation of biomass and the production and transportation of fossil fuels, as well as from the construction of direct air capture (DAC) facilities. It assumes that the energy needed for DAC and the production of carbon-recycle fuels is covered by zero-emission energy.

through algae cultivation. Furthermore, the government's Roadmap for Carbon Recycling Technologies, as well as councils, etc. contain descriptions of methane synthesis and liquid fuel synthesis (methanol, ethanol, diesel, etc.).

If these carbon-recycle fuels are used as substitutions for fossil fuels, it will be possible to avoid generating the volume of CO_2 emissions from the fossil fuels that were replaced. Examples of the carbon sources of carbon-recycle fuels include fossil fuels, biomass, and CO_2 in the atmosphere, and CO_2 reduction effect (CO_2 emission avoidance effect) is the same for all the carbon sources. Shibata (2020) has provided a detailed explanation, but we shall consider a few simple examples here.

> **[Example 1] Reusing CO_2 derived from fossil fuels**: Consider two companies, Company A and Company B, which are consuming natural gas. If Company A directly emits a tons of CO_2 per year, while Company B directly emits b tons of CO_2 per year, the total volume of emissions from the two companies would be a+b tons. Here, if Company A captures r tons of CO_2 ($r \leqq a$ and $r \leqq b$) and produces synthetic methane, after which Company B's natural gas consumption is partially substituted, then the volume of emissions from the two companies would be a+b-r tons.[2] Comparing the emissions before and after the implementation of carbon recycling, CO_2 reduction effect would be $(a+b)-(a+b-r)=r$ tons.

> **[Example 2] Reusing CO_2 derived from biomass**: Assume that Company A is burning biomass (carbon content is equivalent to a tons of CO_2), and Company B is burning natural gas (carbon content equivalent to b tons of CO_2). In the case where carbon recycling is not carried out, the total direct emissions from the two companies would be $0+b=b$ tons. Here, if r tons of CO_2 derived from biomass ($r \leqq a$ and $r \leqq b$) is captured from Company A for the production of synthetic methane, while the natural gas consumption of Company B is partially substituted, the total volume of emissions from the two companies would be $0+b-r=b-r$ tons. The CO_2 reduction effect from carbon-recycle fuels would be $b-(b-r)=r$ tons.

> **[Example 3] Using CO_2 derived from the atmosphere**: Here, consider only the case of Company B. Assume that natural gas containing b tons of carbon is consumed prior to the implementation of carbon recycling. If r tons of carbon are captured from the atmosphere in-house, and substituted for natural gas in the form of synthetic methane, then carbon emission volume would be $b-r$. In this case, CO_2 reduction effect would be $b-(b-r)=r$.

While these are simple estimates, a comparison of emission volumes with and without carbon recycling shows that CO_2 reduction effect is not dependent on the carbon source (CO_2 reduction effect is r tons in all the examples).

Carbon sources have an impact on the total volume of CO_2 emissions for the overall carbon recycling system

On the other hand, the total volume of CO_2 emissions for the overall carbon recycling system varies depending on the choice of carbon source. Here, the "overall carbon recycling system" refers to the total volume of direct emissions for both carbon providers (power plants, industrial plants, etc.) and users of carbon-recycle fuels. Looking at the three examples above, carbon emissions in the case where carbon recycling is carried out in Example 1 is a+b-r, and in Example 2 and 3 is b-r. Example 1 has the highest total volume of CO_2 emissions. While CO_2 reduction effect is the same for all the carbon sources, we can see that the total volume of emissions is different.

The impact that the choice of carbon source has on total volume of CO_2 emissions is also considered to form the viewpoint of the carbon flow. Fig. 1 shows the carbon flow for the carbon recycling system. The carbon source is biomass in Fig. 1a, CO_2 from the atmosphere in Fig. 1b, and fossil fuel in Fig. 1c. In the cases where biomass or CO_2 from the atmosphere are used, as carbon that had originally been present in the air circulates, the combustion of carbon-recycle fuels is not regarded as a contributing factor to the increase in CO_2 in the atmosphere (Fig. 1a-b). In contrast, when the carbon source is fossil fuel, CO_2 is ultimately discharged into the atmosphere even if it is reused. Hence, CO_2 emissions are positive for the whole of the carbon recycling system (Fig. 1c).

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[2] For simplification purposes, the elements of CO_2 capture efficiency are disregarded. The same applies to Example 2 and Fig. 1 mentioned later.

There are now ongoing discussions about carbon pricing and the decarbonized economy of 2050 in Japan. If the total volume of CO_2 emissions for the overall carbon recycling system were taken into consideration, the choice of carbon source may be considerably significant. For example, if carbon taxes, which is one of the methods of carbon pricing, were introduced, a recycling system that uses fossil fuel-derived CO_2 would be subjected to taxes for positive emissions. Furthermore, in the realization of net zero emissions in 2050, if fossil fuel-derived CO_2 were reused, there would be a need to offset the positive emissions. Specific offsetting measures including afforestation, DACCS, BECCS, etc.,[3] and it would mean that the respective costs for these measures would be incurred (in the case of offsetting, it may be possible to be exempted from penalties such as carbon taxes, but offsetting costs are incurred instead). In the case where fossil fuel-derived CO_2 is reused, there is a need to consider not only the costs of hydrogen production, CO_2 separation and capture, and fuel synthesis in the boundary of the costs for the production of carbon-recycle fuels, but also the costs to the CO_2 itself that is derived from fossil fuels (that is, carbon taxes, offsetting costs, etc.). While taking these costs into account, it is important to take a perspective that considers which of these carbon source options—fossil fuel derivative, biomass derivative, or present in the atmosphere—is the most economically efficient.

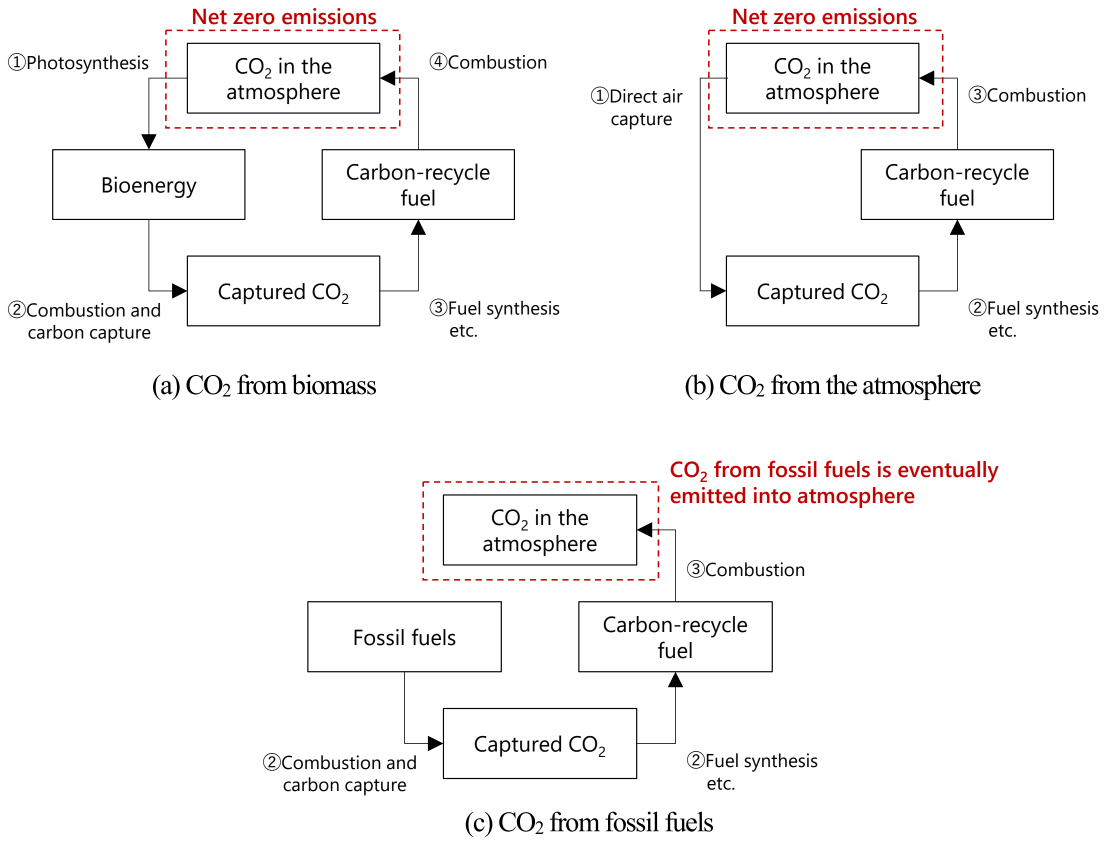


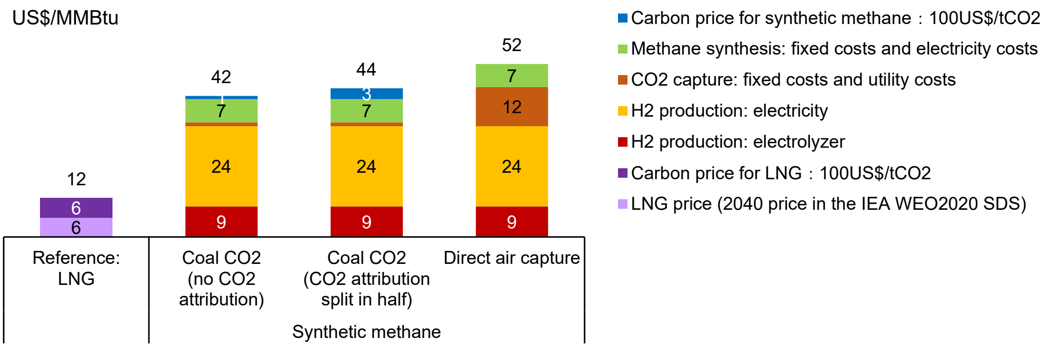
Fig. 1 Carbon flow for carbon recycling fuel systems

While the question of who shoulders these carbon tax payments and offsetting costs (the carbon providers, the carbon users, or both parties?) is a contentious point,[4] this is actually a problem of the attribution of CO_2, which will be discussed in the third essay. Here, based on assumptions about attribution, we drew up estimates on the extent of impact that the costs to CO_2 itself could potentially have, using synthetic methane as the subject (Fig. 2). The subject of the estimates is assumed

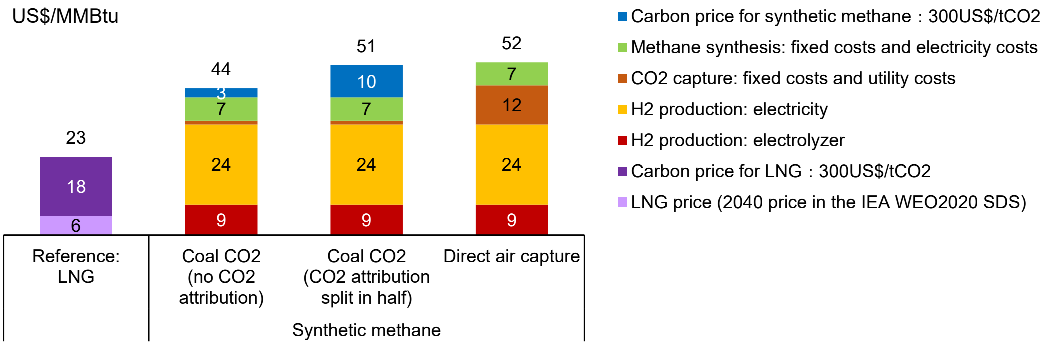
[3] DACCS = Direct Air Capture with CCS; BECCS = Bioenergy with CCS.

[4] With regard to the implementing entities of offsetting measures, there are various possibilities, including the implementation of offsetting measures independently by carbon providers or users of carbon-recycle fuels, or the implementation of negative emission projects by third parties in addition to the procurement of carbon offsetting credits for a part of the project. There is also a need to deepen future discussions on this point.

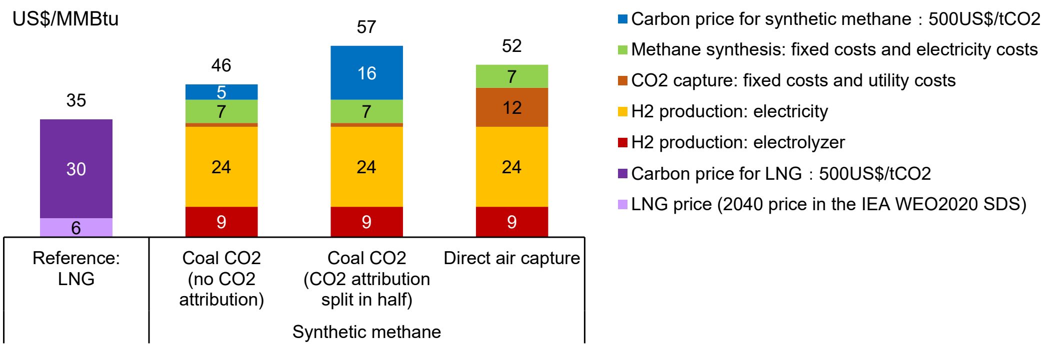
to be systems in Japan that carry out water electrolysis and CO_2 capture, and methane synthesis (assumption of Sabatier reaction). The case in which CO_2 is captured from emissions gases after coal combustion, and the case of DAC, are taken into consideration. As for the case where coal-derived CO_2 is utilized, further estimates were drawn up for the case where CO_2 is not attributed to the synthetic methane side ("no CO_2 attribution" in the figure) and the case where CO_2 attribution is split in half ("CO_2 attribution split in half" in the figure). Estimates were based on three situations, with carbon tax (or offsetting costs) at US\$100/tCO_2, US\$300/tCO_2, and US\$500/tCO_2. For the detailed assumptions used for the estimates, refer to the appendix at the end of this paper. Carbon tax is also imposed in the case of "no CO_2 attribution" for synthetic methane in the figure. Refer to the appendix for the considerations on this point.



(a) When carbon tax is US\$100/tCO_2



(b) When carbon tax is US\$300/tCO_2



(c) When carbon tax is US\$500/tCO_2

Fig. 2 Production cost for synthetic methane, taking carbon tax into consideration

The following two main points are implied by Fig. 2.

- In the case where carbon tax is US$100/t$CO_2$, it does not have a significant impact on the production costs of synthetic methane. Even in the case where CO_2 attribution is split equally in half, using coal-derived CO_2 is cheaper than using DAC. However, if the carbon tax is about US$100/ t$CO_2$, adding the carbon tax rate to LNG price is sufficiently cheap, and there is a need to pay attention to whether it is sensible to carry out CO_2 capture + hydrogen production + synthetic methane production domestically to begin with.
- In the case where environmental policies are tightened (US$300/t$CO_2$ and US$500/t$CO_2$), greater penalties are imposed for the use of coal (cost competitiveness falls for synthetic methane that uses coal-derived CO_2). The cost comes close to that of using DAC even when there is no CO_2 attribution, and cost significantly exceeds that of using DAC when CO_2 attribution is split in half. The reuse of coal-derived CO_2 may not be economically rational.

According to data compiled by the IPCC in its Special Report on Global Warming of 1.5ºC, the global coal price that is necessary for achieving the 1.5ºC goal may rise to about US$700/t$CO_2$.[5] To realize Japan's goal of a decarbonized economy by 2050, policies may be tightened to that level or above that level. Hypothetically, if that extent of climate change countermeasures is necessary, it would become difficult to reuse fossil fuel-derived CO_2 from the viewpoint of cost. Synthetic methane is used here as an example, but the cost is likely to be similar to that for using fossil fuel-derived CO_2 even for other carbon-recycle fuels such as synthetic petroleum and biomass fuels from algae cultivation. It will be important for business operators that are interested in carbon-recycle fuels to choose their carbon source based on this point.

As in the case of "no CO_2 attribution," when carbon-recycle fuel users are exempted from penalties, the penalties will be shouldered by the carbon providers. There is also a need for the carbon providers (thermal power plants, etc.) to consider whether or not to continue using fossil fuels as their fuel source even up to the point of taking on those penalties (shouldering a heavy carbon tax) (in short, whether to continue existing as a carbon source until 2050). In the case where they are unable to continue surviving as a carbon source (without fossil fuel consumption and the accompanying CO_2 emissions), the reuse of fossil fuel-derived CO_2 itself would become impossible. When environmental policies are tightened, splitting CO_2 attribution in half would make it less appealing, in terms of cost, to the users of carbon-recycle fuels (Fig. 2). On the other hand, attributing CO_2 emissions to the carbon provider makes it less appealing to the providers. This creates a dilemma.

The need to select carbon sources taking into consideration the time horizon

This paper pointed out that carbon sources have an impact on the total volume of CO_2 emissions of the carbon recycling system. Here, those who have been reading in sequence from the first essay may have been confused by the difference from Fig. 1 in the first essay. While an estimate was drawn up for the volume of emissions for the overall system in the first essay, it was pointed out that the volume of emissions remains the same regardless of the carbon source. This is because of the differences in the system boundaries and preconditions. In the first essay, the estimate is based on the assumption of a situation in which a fossil fuel user is present in the system, and it is shown that in such a case, emission volume remains unchanged for the system regardless of the carbon source used (in the case where fossil fuel-derived CO_2 is not reused, it is directly discharged into the atmosphere;[6] even if it were reused as carbon-recycle fuel, the same volume of CO_2 is ultimately released into the atmosphere). In contrast, this paper focuses only on the emissions from the parties involved in the production of carbon-recycle fuels (carbon providers and carbon-recycle fuel users).

The key is not to debate whether the approach in the first essay or this paper is correct. Rather, a choice should be made corresponding to the actual situation and time horizon. In the period of 2030–2040, many business operators will have no choice but to use fossil fuels in activities such as iron and steel manufacturing and cement production. In such situations, as

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[5] Figure 2.26 in the Special Report on Global Warming of 1.5ºC shows the estimated carbon prices for multiple models and scenarios. Here, we referred to the median values of the analysis results for 1.5°C Low Overshooting. However, as shown in the same Figure, there is a significant range of carbon price estimates depending on the model. Hence, it is necessary to note that there is a high level of uncertainty.

[6] For example, if biomass-derived CO_2 is reused, fossil fuel-derived CO_2 will become the emission of a third party (no longer be emitted by the carbon provider or carbon-recycle fuel user). However, in the first essay, that CO_2 is also included in the system in the discussion.

discussed in the first essay, regardless of whether fossil fuel-derived CO_2 were reused or CO_2 derived from biomass or the atmosphere were reused, the volume of emissions in the overall system (such as in the economy as a whole) remains unchanged. Hence, it probably does not matter which carbon source is used.

In contrast, the preconditions change in the case where business operators using fossil fuels can take countermeasures other than carbon recycling in the move toward 2050. In short, in addition to the following options: (i) carry out carbon recycling; (ii) release directly into the atmosphere if they do not carry out carbon recycling, they also have the option of (iii) decarbonize through methods such as shift to electricity and hydrogen in final demand, and CCS. In the preconditions for the first essay, when CO_2 derived from biomass or the atmosphere is used, fossil fuel-derived CO_2 is discharged into the atmosphere. If (iii) can be implemented in such situations, then it would be possible to realize decarbonization for the overall system by combining carbon recycling through CO_2 derived from biomass/the atmosphere with (iii). On the other hand, if option (i) is selected even though option (iii) is available, net emissions would be positive. Therefore, the emission volume for the overall system changes depending on the carbon source.

Based on the above, during the transitionary period such as 2030 or 2040, we can say that promoting decarbonization through the active use of CO_2, including industrial CO_2, emitted from business operators who have no choice but to use fossil fuels, is an important option (it is assumed that carbon pricing, etc. is relatively lax in the short and medium term, and cost penalties are low even if fossil fuel-derived CO_2 is used). Against this, there is a need to choose the carbon source based on perspectives such as environmental policy, CO_2 offsetting cost and quantitative potential, and shift to electricity and hydrogen/CCS, in order to realize the goal of decarbonization by 2050. It may be necessary for both the carbon providers and the users to adopt a strategy that takes the time horizon into consideration, such as changing the carbon source in line with how stringent the environmental policy is. For example, for carbon users, it would be beneficial to make pre-assumptions on the alternative carbon source and CO_2 procurement method (CO_2 pipelines and liquefied CO_2 tankers), and based on that, choose the location for the carbon-recycle fuel manufacturing plant and develop the infrastructure. For the providers of fossil fuel-derived CO_2, it may be necessary to refine the response policy in advance in situations where environmental policy is tightened, or where an alternative CO_2 source emerges.

Issues in recapturing CO_2 from carbon-recycle fuels

Even if fossil fuel-derived CO_2 were used, if CO_2 from carbon-recycle fuels were recaptured, it would be possible to prevent discharge into the atmosphere. The last aspect that this paper shall examine is this recapturing of CO_2. While it is possible to prevent the discharge of CO_2 into the atmosphere through recapturing, there is a need to address the following two points.

The first issue comes from the viewpoint of CO_2 capture efficiency. Although this has been disregarded in the discussion up till this point, CO_2 capture efficiency from combustion gas and other sources is currently at a level of about 90%. For this reason, a portion of the fossil fuel-derived CO_2 becomes discharged into the atmosphere when capturing CO_2 from fossil fuels or recapturing CO_2 from carbon-recycle fuels (shown by the red dotted line in Fig. 3). Even if carbon were recaptured and circulated, a portion of it continues to be discharged, making it necessary to offset that portion.

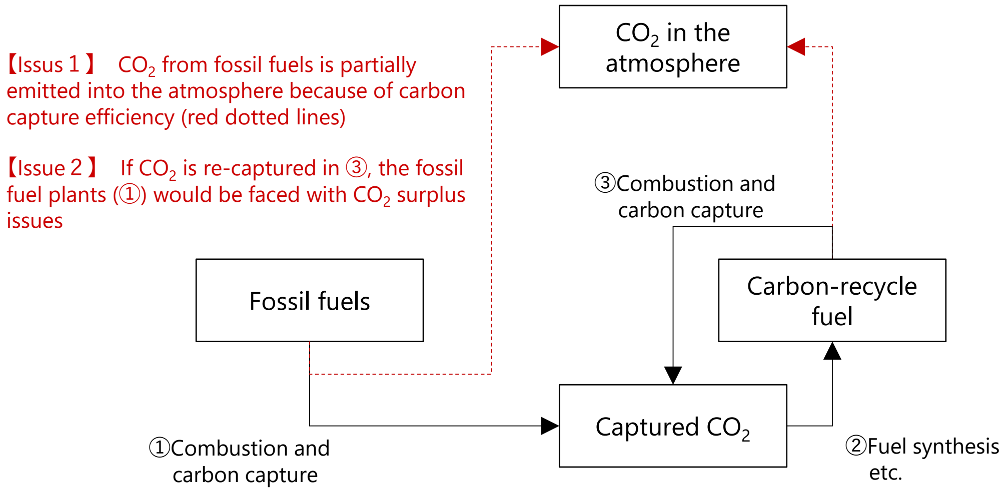

Fig. 3 Carbon flow and systemic issues in the case of recapturing CO_2 from carbon-recycle fuels derived from fossil fuels

A more important issue is the decrease in the number of the accommodating parties for fossil fuel-derived CO_2 (flow (1) in Fig. 3). For example, consider a system in which carbon-recycle fuel is manufactured from CO_2 captured at fossil fuel-based thermal power plants, and after combustion at an industrial plant or other facility, CO_2 is captured at the industrial plant and carbon-recycle fuel is produced for the same plant. Since CO_2 capture efficiency is not 100%, it will be necessary to replenish the carbon when fuel production is carried out the second time. However, it is sufficient to supply a smaller volume of CO_2 than that supplied from the power plant the first time. As a result, there will be surplus CO_2 at the power plant, making it necessary to put in place new measures (such as looking for other off-takers or carrying out CO_2 storage or fuel conversion). In cases where effective measures cannot be found, it may become difficult for the power plant to continue operating due to environmental constraints. From the perspective of the operator that owns the power plant, it may be impossible to say that this system is sustainable. Hence, we can see such challenges to the original carbon source in the case of recapture, as explained above.

Conclusion

This paper examined the potential of carbon-recycle fuels from the perspective of carbon sources. The key points are summarized in the following three items.

- Regardless of the carbon source that is chosen, CO_2 reduction effect (emission avoidance effect) is the same.
- On the other hand, total volume of CO_2 emissions for the carbon recycling system as a whole is impacted by the carbon source.
- The recapturing of CO_2 from carbon-recycle fuels gives rise to sustainability issues.

In aiming to achieve net zero emissions by 2050 for economy as a whole, the second point holds great importance. There are high expectations toward the reuse of fossil fuel-derived CO_2 in Japan, but such reuse may give rise to economic penalties (such as carbon taxes and offsetting costs). It is important to establish carbon procurement strategies based on a consideration of such penalties. If there are no means of offsetting the emissions, it would be difficult to introduce carbon-recycle fuels derived from fossil fuels in the move toward net zero emissions, and it may become necessary to use CO_2 from biomass or the atmosphere in the years leading up to 2050.

Of course, during the transitionary period, such as in 2030 or 2040, there are likely to be many operators (such as in the industrial sector) that have no other option but to use fossil fuels. The key to expanding the use of carbon-recycle fuels lies in the effective use of the carbon sources. As there is a need to physically procure CO_2 in carbon recycling, it is important to anticipate the situation from the transitionary period to 2050, select the carbon source and the location for carbon-recycle fuel production activities, and develop CO_2 procurement infrastructure.

Appendix: Assumptions for the estimates in Fig. 2

The estimates in Fig. 2 were drawn up based on the following assumptions, and established based on dissertations and reports from international and academic organizations.

- LNG prices in Fig. 2 take reference from 2040 yearly value (US$5.7/MMBtu) for the Sustainable Development Scenario in the International Energy Agency's (IEA) World Energy Outlook 2020.
- Discount rate: 5%.
- Carbon content in fossil fuels (low calorific value standard) – Natural gas: 0.0560tCO_2/GJ, Coal: 0.0946tCO_2/GJ.
- Water electrolysis – Cost of equipment: US$450/kW, Conversion efficiency: 74% (low calorific value standard), Facility utilization factor: 30%, Facility lifespan: 15 years, Annual operational and maintenance costs: 1.5% of equipment cost, Cost of power supply: US$50/MWh (Approx. 5 yen/kWh), Cost of industrial water: US$0.6/$m^3$. Power supply is assumed to be zero emission electricity, including direct air capture and methane synthesis described below.
- CO_2 capture from gas after coal combustion (chemical absorption) – Cost of equipment: US$292/(t$CO_2$/year), Facility lifespan: 40 years, Annual operational and maintenance costs: 5% of equipment cost, Capture efficiency: 90%, Heat consumption: 1.5GJ/tCO_2, Heat supply price: US$61/t (refer to the value for steaming coal from the aforementioned IEA outlook), Coal calorific value (low calorific value standard): 26GJ/t.
- Direct air capture (High-temperature, aqueous solution system) – Cost of equipment: 815Euro/(tCO_2/year), Facility lifespan: 30 years, Annual operational and maintenance costs: 5% of equipment cost, Power consumption: 1.535MWh/tCO_2, Price of power supply: US$50/MWh. Exchange rate is assumed to be 1 Euro = US$1.19.
- Methane synthesis (Sabatier) – Cost of equipment: US$5,000/($Nm^3$-$CH_4$/hour), Facility utilization factor: 30%, Facility lifespan: 30 years, Annual operational and maintenance costs: 5% of equipment cost, Auxiliary power: 0.32kWh/Nm^3-CH_4.

In Fig. 2, the amount equivalent to the carbon tax levied on synthetic methane was estimated for the case where CO_2 derived from coal is reused. The estimates were drawn up based on the following approach. When α tons of CO_2 is captured for use in methane synthesis, assuming that CO_2 capture efficiency is η, α/η of CO_2 is generated in the carbon source (Fig. 4). Based on this breakdown, we can classify the CO_2 as (a) CO_2 accompanying heat consumption in a CO_2 capture facility, and (b) CO_2 derived from businesses such as power plants and industrial plants. When CO_2 is not attributed to the synthetic methane side, (a) that is not derived from businesses such as power plants and industrial plants was considered to be CO_2 emissions from the synthetic methane side. In the case where CO_2 attribution is split in half between the synthetic methane side and the carbon supplier, half of the sum of (a) and (b) ($\alpha/2\eta$) was considered to be the CO_2 emissions of synthetic methane.

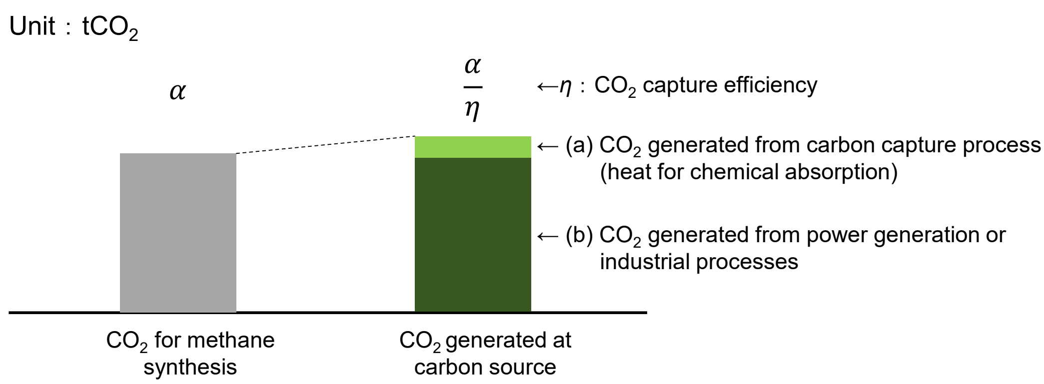

Fig. 4 Illustration of the breakdown of CO_2 generated in carbon sources

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Yoshiaki Shibata, "Perspectives Other Than the Decarbonization Required for CCU/Carbon Recycling—Misconceptions Caused by the Classification of CCUS," 2020, https://eneken.ieej.or.jp/data/8821.pdf (Accessed on March 8, 2021)

Essays on the Carbon Sources of Carbon-Recycle Fuels (3)

- Attribution of CO_2 Emission Reduction Effect -

Yoshiaki Shibata* Takashi Otsuki**

1. Key points of this paper

- There are two main schools of thought on the attribution of CO_2 emission reduction effect for carbon-recycle fuels that use CO_2 derived from fossil fuels.
- The first school of thought is that it is only attributable to the producers and users of carbon-recycle fuels. This stance is based on the following two lines of reasoning. (1) As CO_2 is only separated, captured, and re-emitted in the production and utilization of carbon-recycle fuels, and the CO_2 emission reduction effect is dependent solely on hydrogen, the utilization of carbon-recycle fuels is the same as the direct use of hydrogen. (2) Hypothetically, in order to attribute a part of the CO_2 emission reduction effect to CO_2 separation and capture facilities, it is necessary for "CO_2 reduction effect from the utilization of carbon-recycle fuels > CO_2 reduction effect from the direct use of hydrogen." However, due to the efficiency of the conversion process, CO_2 emission reduction effect is absolutely "Direct use of hydrogen > Utilization of carbon-recycle fuels." Consequently, it is considered that CO_2 emission reduction effects are not attributable to CO_2 separation and capture facilities.
- The second school of thought is that it should be allocated between the providers of CO_2 derived from fossil fuels (such as power plants and industrial plants), and the producers and users of carbon-recycle fuels. CO_2 providers and users have an interdependent relationship in carbon recycling. In short, for the CO_2 providers, CO_2 reduction cannot be achieved without any users; on the other hand, for the users, the provision of CO_2 is vital. From this perspective, it is important to have a structure that allows both sides to cooperate easily, and there is a need to allocate the CO_2 reduction effect to both parties. Hypothetically, if CO_2 reduction effect were not allocated to the carbon provider, power plants and industrial plants would have little motivation to participate in carbon recycling. In addition, as this would mean that power plants and industrial plants do not implement any CO_2 reduction measures, it would inevitably lead to the early closure of plants in the process of decarbonization. This signifies a reduction in carbon sources, which in turn, can also prove to be disadvantageous to CO_2 users.

2. Body text

In the first and second papers, we discussed the principles of carbon-recycle fuels and the carbon sources that are necessary in a decarbonized economy. In this paper, we offer two differing schools of thought on the attribution of CO_2 emission reduction effect of carbon-recycle fuels. With the aim of helping readers consider and discuss this subject, we have ventured to include a diverse range of opinions.

Attributing CO_2 emission reduction effect only to the users of carbon-recycle fuels

As explained in the first paper, hydrogen plays a leading role in carbon-recycle fuels, while CO_2 plays the supporting role (it is only offset in the processes of separation and capture, utilization, and re-emission). Hence, the decarbonization effect of carbon-recycle fuels is attributed to its main ingredient, hydrogen. In short, we can regard the utilization of carbon-recycle fuels as being equal to the utilization of hydrogen. If we were to consider the direct use of hydrogen, based on the assumption that hydrogen replaces fossil fuels, such as the case where there is a thermal power plant nearby, the power plant only emits and discharges CO_2 into the atmosphere, and does not generate any CO_2 emission reduction effect in itself. In other words,

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while CO_2 is temporarily separated and captured from thermal power plants in the case of carbon-recycle fuels, it is only emitted in a dispersed manner at different times and locations, and is therefore no different from the direct utilization of hydrogen.

If a portion of the CO_2 emission reduction effect in the production and use of carbon-recycle fuels is attributed to CO_2 separation and capture at thermal power plants, there is a need to identify the effect that can be generated through that action (CO_2 separation and capture at thermal power plants). In this case, the following must be true: "CO_2 reduction effect through the utilization of carbon-recycle fuels > CO_2 reduction effect through the direct utilization of hydrogen." However, due to losses in the conversion process, CO_2 emission reduction effect must absolutely be "Direct utilization of hydrogen > Utilization of carbon-recycle fuels." Consequently, CO_2 separation and capture from thermal power plants do not contribute to reducing CO_2 emissions. In short, it is considered to be impossible to attribute any CO_2 emission reduction effects to CO_2 separation and capture from thermal power plants. The same can be said for biomass power plants.

If the CO_2 that is separated and captured from thermal power plants is not stored but is utilized in the production of carbon-recycle fuels, in spite of the intention of the thermal power plant to carry out CCS (interception of CO_2 for CCS use), then it would be possible to attribute the CO_2 emission reduction effect that should originally have been generated through the implementation of CCS, to the thermal power plants. However, if CO_2 that has no way but to be discharged into the atmosphere is used, it would be reasonable to attribute the CO_2 emission reduction effect to the manufacturers and users of carbon-recycle fuels, or in other words, to the hydrogen users.

Accordingly, of course, the costs related to CO_2 separation and capture are shouldered by the producers and users of carbon-recycle fuels.

In order to avoid the problem of allocating CO_2 emission reduction effect to the sources of CO_2 emissions (CO_2 providers), introduced in the next section, as well as the issue of CO_2 re-emission in the realization of a decarbonized economy by 2050 covered in the second paper, one possibility could be for the producers and users of carbon-recycle fuels to have their own biomass power plants or direct air capture (DAC) facilities and utilize the CO_2 from these facilities.

Allocating CO_2 emissions effect to both the carbon providers and the users of carbon-recycle fuels

On the other hand, another school of thought posits that emission reduction effect should also be allocated to the carbon provider (such as power plants and industrial plants) in cases where fossil fuel-derived CO_2 is reused. If CO_2 reduction effect were not allocated to the carbon providers, power plants and industrial plants would have little motivation to participate in carbon recycling, making it possibly difficult to reuse fossil fuel-derived CO_2 in the medium- to long-term.

Hypothetically, if the CO_2 reduction effect were not allocated to the carbon providers, they would not in effect be implementing any emission reduction measures, nor would they be contributing to CO_2 reductions in economy. If environmental measures such as carbon taxes and emissions trading were to be tightened in the future, the carbon providers would then be subjected to penalties (such as payment of carbon taxes or incurring expenses to purchase carbon offsetting credits) for the combustion of fossil fuels.[1] This may be acceptable in a short-term situation where environmental regulations are lax. In contrast, if we were to consider the carbon neutral environment of 2050, it may be more rational for carbon providers to close their plants down at an early stage or put in place alternative measures such as fuel conversion and CCS, instead of maintaining fossil fuel power plants or industrial plants while being subjected to penalties. In short, in a situation where there are no advantages to the carbon provider from generating CO_2 reduction effects, they may become unable to sustain the "provision of fossil fuel-derived CO_2" in the medium- to long-term. This could place constraints on the quantitative expansion of carbon-recycle fuels, and could also be disadvantageous to CO_2 users.

In carbon recycling, the carbon providers and users of carbon-recycle fuels are considered to have an interdependent relationship. For the carbon providers, an absence of carbon-recycle fuel users would make it impossible to realize CO_2

[1] Even in the case where CO_2 reduction effect is not allocated to power stations and industrial plants, if CO_2 were passed on to users at a charge, it could be possible to ease the impact of the penalties imposed on fossil fuel combustion. However, this would be a situation in which a part of the penalties is shouldered by the CO_2 users. From an economic point of view, we can say that the CO_2 reduction effect is, in effect, redistributed.

emission reduction. At the same time, CO_2 is a vital resource for carbon-recycle fuel users, and the stable procurement of this resource holds the key to commercialization (without CO_2 supplies, it would become necessary to utilize hydrogen directly, making it impossible to enjoy the benefit of "compatibility with existing infrastructure" offered by carbon-recycle fuels). It is important to have a system that facilitates the cooperation and sustainability of both parties. From this perspective, there is a need to allocate the CO_2 reduction effect to both parties. In the CO_2 reduction effect is allocated, carbon-recycle fuels are also regarded as a source of CO_2 emissions.

Incidentally, in cases where reduction effect is not allocated to the carbon provider, as described above, issues may arise in relation to the sustainability of the carbon provider. As we have also discussed at the end of the second paper, it may be important for carbon-recycle fuel users to refine their carbon procurement strategy based on this point (for example, make plans in advance for alternative carbon sources and CO_2 procurement infrastructure).

Other issues

The discussion in this paper was based on the premise of the domestic production and utilization of carbon-recycle fuels. In the case where carbon-recycle fuels are produced overseas and imported in a cross-border scenario, there would be issues with the attribution of CO_2 emission reduction effect. In the case where Country A produces carbon-recycle fuels from hydrogen and CO_2, exports these fuels to Country B where the fuels are then utilized (combustion/CO_2 re-emission), CO_2 is captured in Country A and emitted in Country B, but only at a different time. Hence, from a global perspective, the volume of CO_2 emissions remains unchanged. However, as this is accompanied by cross-border activities, there is a need to establish international rules on the attribution of CO_2 emission reduction effect.

Essays on the Carbon Sources of Carbon-Recycle Fuels (4)

- Concluding the Series of Essays -

Yoshiaki Shibata* Takashi Otsuki**

Concluding the series of essays

In this series of "Essays on the Carbon Sources of Carbon-Recycle Fuels" (1)–(3), the first paper introduced the principles of carbon-recycle fuels, the second paper looked at the points to note in building a decarbonized economy by 2050, and the third paper examined various schools of thought on the attribution of CO_2 emission reduction effect. The following is the clarification of the key points in this series of essays. We hope that this series contributes to the formulation of policies and design of systems related to carbon-recycle fuels, with a view to the realization of a decarbonized economy by 2050.

- Carbon-recycle fuels are synthesized from sufficiently decarbonized hydrogen and CO_2. In addition to the need for hydrogen, it is accompanied by CO_2 separation and capture in the fuel production process and CO_2 emissions in the fuel utilization process (combustion). As such, the evaluation of CO_2 emission reduction effect and schools of thought on the attribution of the effect are extremely complex.
- Based on the principles, since the effect of carbon-recycle fuels is derived from hydrogen, under the condition of sufficient decarbonization of hydrogen, the selection of CO_2 sources and CO_2 re-emission would not be problematic. However, a different perspective is required if the objective were to establish a decarbonized economy. In the transitionary period until the realization of a decarbonized economy in 2050, the utilization of CO_2 derived from fossil fuels from the thermal power generation and industrial sectors is conceivable. On the other hand, in the case where the establishment of a decarbonized economy in 2050 is the condition, the re-emission of CO_2 must be avoided. In other words, at a point where carbon constraints are relatively lax (such as 2030 or 2040), fossil fuel-derived CO_2 could possibly hold the key to the expansion of carbon-recycle fuels. On the other hand, we cannot deny the possibility that constraints to the reuse of fossil fuel-derived CO_2 may arise by 2050, making it necessary to shift to carbon sources such as CO_2 derived from biomass or direct air capture (DAC). It is important to have a CO_2 procurement strategy that takes the time axis into consideration.
- There are now ongoing discussions about carbon pricing and the decarbonized economy of 2050 in Japan, and these could have an impact on the approach to carbon sources. For example, if carbon taxes were strengthened, taxes may be imposed on systems that reuse fossil fuel-derived CO_2. Furthermore, in the realization of net zero emissions in 2050, if fossil fuel-derived CO_2 were reused, there would be a need to offset the positive emissions. Who would shoulder the carbon taxes and the offsetting costs, the carbon providers, or the users? This would become an issue. It is also closely related to the problem of the attribution of CO_2 emission reduction effect elaborated below. As shown in the estimates drawn up in the second paper, it is important to consider the costs when discussing the feasibility of using fossil fuel-derived CO_2.
- The interpretation of the attribution of CO_2 emission reduction effect in the production and utilization of carbon-recycle fuels is an extremely complicated matter. Based on the principles, CO_2 in the production and utilization of carbon-recycle fuels is merely separated, captured, and re-emitted, unlike in the case of CCS where CO_2 is sequestrated and stored semi-permanently. In the process of the former, no CO_2 emission reduction effect is generated, and the CO_2 emission reduction effect depends solely on hydrogen. As such, all of the CO_2 emission reduction effects are considered

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to be attributed to the users of carbon-recycle fuels (in other words, the users of hydrogen). On the other hand, as carbon-recycle fuels cannot be produced without the provision of CO_2, CO_2 providers and the producers and users of carbon-recycle fuels share an interdependent relationship. For this reason, there is also a school of thought that posits that CO_2 emission reduction effect should be allocated to both parties. In other words, for example, while fossil fuel users are also sources of CO_2 emissions, they are also the providers of CO_2 that are necessary for the production of carbon-recycle fuels. In this sense, there is a need for fossil fuel users and the producers and users of carbon-recycle fuels to cooperate and work together.

- Carbon-recycle fuels are a means for facilitating the use of hydrogen in an economically efficient manner, through the utilization of mature, existing technologies and infrastructure that are now the foundation for fossil fuels. There is a need to pay attention to the fact that reducing CO_2 emissions through CCU and carbon recycling is not the primary objective. However, as they straddle the technological fields of hydrogen and CCU/carbon recycling, this complicates the interpretation of their functions and roles. In order to position carbon-recycle fuels as one of the options for the realization of an economically rational decarbonized economy, there is a need to further deepen discussions on the concrete system design, with a view to early social implementation.
- Unlike the easy-to-understand CCS technology of avoiding the discharge of CO_2 into the atmosphere semi-permanently through sequestration and storage, CCU and carbon recycling encompass a wide range of technologies. These include carbon-recycle fuels addressed in this paper, which require hydrogen and for which hydrogen plays a key role in reducing CO_2, technologies similar to CCS in which carbon sequestration has mostly been achieved, such as calcium carbonate and concrete curing, and technologies that already make use of CO_2 derived from fossil fuels, such as urea, methanol and dry ice. While the concept of CO_2 recycling is an important one, there is a need to classify the functions and effects of each type of technology in detail, such as whether CO_2 is sequestrated and discharge into the atmosphere can be prevented, or whether it brings about CO_2 emission reduction by substituting one thing for another. Without this thought and classification process, the misconception that all CCU and carbon recycling technologies contribute to decarbonization may be planted. At the same time, there is also a possibility that all technologies may be positioned as meaningless efforts toward decarbonization.

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Metrics Measuring the Economic Efficiency of Power Sources upon Large-scale Introduction of VREs: LCOE and the System LCOE◆

Yuji Matsuo*

1. Introduction

Growing concerns over climate change and the falling cost of variable renewable energies (VREs, which refer mainly to wind and solar PV) are transforming the electricity sector in many countries. From the perspective of the power system, VRE differs from conventional power sources in three main ways: VRE output changes with natural conditions and therefore cannot be adjusted in line with electricity demand; VRE plants are limited to locations with good wind conditions and solar radiation, and cannot be selected solely on convenience particularly for wind power generation; VRE generally has a very low marginal cost and a VRE plant, once established, can supply electricity at extremely low cost when wind and solar radiation conditions are favorable. With large VRE capacities already introduced in Europe and many other countries and expected to increase further, establishing appropriate expansion plans for generation facilities in the future has become a vital issue for the governments, regulators, and power companies of all countries.

Needless to say, an expansion plan for power sources should be based on a careful evaluation of economic efficiency. So far, the economic efficiency of each power source has been evaluated using a metric known as the levelized cost of electricity (LCOE). LCOE is the cost necessary to generate 1 kWh of electricity using a certain power source based on given assumptions (i.e., the unit cost). It is calculated by factoring in the characteristics of each power source, and it varies greatly even for the same power source depending on the capacity factor. As described later in this report, for example, coal-fired thermal and natural gas-fired thermal power have different fluctuation patterns, so their optimal shares (that would minimize the total cost) would be determined based on the electricity demand curve.

However, the characteristics of VRE described above often cannot be expressed fully using LCOE. For instance, since VRE does not offer flexible operation unlike thermal power, if thermal power and solar PV have the same LCOE, the former would generally have a higher value in the power system. In other words, the latter would be relatively more costly. Simply put, the issue is, what is the economic (in)efficiency of VRE that is not being adequately expressed by LCOE? This economic (in)efficiency can also be called "the additional cost of VRE associated with natural variation." However, to be accurate, the economic efficiency calculated for thermal power or VRE capacity is valid only within the power system it belongs to, and even thermal power is not completely flexible and has a similar economic inefficiency to some extent. This issue clearly is not simple and calls for any additional costs to be allocated to both VRE and conventional power sources through an accurate simulation of how each power source would behave in a power system with large amounts of VRE installed.

Based on these perspectives, this report outlines the key matters in considering the economic efficiency of the power sector when large amounts of VRE are introduced. There are ongoing international studies on this topic, including the report by the Nuclear Energy Agency of the Organisation for Economic Cooperation and Development (OECD/NEA) and the International Energy Agency (IEA)[1].

◆ This work was first published as the article "Economic Assessment of the Power Sector" in the January and March issues of the academic journal Energy and Resources of the Japan Society of Energy and Resources, and was published in this report, with some revisions, with permission from the Society.

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[1] Organization for Economic Cooperation and Development/Nuclear Energy Agency (NEA), International Energy Agency (IEA), (2020). Projected Costs of Generating Electricity 2020 Edition, OECD Publishing.

In the following sections, Chapter 2 presents an overview of LCOE centering on the results of the assessment by OECD/NEA and IEA. Then, Chapter 3 outlines methodologies for assessing economic efficiency that "go beyond LCOE" based on the latest research trends.

2. Levelized Cost of Electricity (LCOE)

2-1. Concept of LCOE

As described earlier, LCOE is the "cost of electricity" or the cost of generating 1 kWh of electricity with a certain technology. To be precise, it is defined as the constant p that satisfies the following equation:

$$\sum_t \frac{C_t}{(1+r)^t} = \sum_t \frac{pE_t}{(1+r)^t} = p\sum_t \frac{E_t}{(1+r)^t} \tag{1}$$

In this equation, t is a variable representing the number of years elapsed since year 0 when the plant started operation. It changes starting from the year before the start of operation when costs were first incurred (i.e., $t < 0$) to the year in which operation ends and costs arise for the final time. C_t is the cost incurred in year ts and includes all costs incurred during a plant's life cycle spanning from construction, operation and maintenance, to the costs for plant decommissioning and final disposal of spent fuel. E_t represents the electricity produced in year t. The left side of Equation (1) is the total cost translated into the present value as of the year plant operation started by dividing it by the discount rate r described later; the right side of the equation is the total estimated income assuming that electricity generated in that plant is sold at p yen per kWh. As described, LCOE is the unit cost at which the "cost" strikes a balance with "value."

Based on Equation (1), LCOE can be defined as:

$$p = \sum_t \frac{C_t}{(1+r)^t} \Big/ \sum_t \frac{E_t}{(1+r)^t} \tag{2}$$

For convenience, the denominator is called the "discounted output." However, it is not the output itself that is being discounted but the value p at a certain time in the future presented in Equation (1).

LCOE can be understood as a linear approximation of the change in the total cost arising from replacing the output of one power source with another in a power system at a certain year in the future, in a greenfield construction project in which a power supply facility was constructed from scratch. In other words, when the LCOEs of power sources A and B are defined as L_A and L_B, and one kWh of supply from power source A is replaced with that from source B, the cost for the system as a whole would increase by $L_B - L_A$. Put differently, LCOE must be considered insufficient for assessing the economic efficiency of the power system if this linear approximation does not hold; this highlights the importance of a metric "beyond LCOE" as described later. Furthermore, since the cost C_t (the initial investment and fixed O&M cost thereof) relies heavily on the plant's installed capacity, the capacity factor, i.e., how much electricity E_t can be produced by a given capacity, will significantly impact LCOE.

Note that C_t should only include actual cash spending and not accounting-term expenses. For instance, power plant construction costs should typically be reported before the start of plant operation, and not be depreciated over time. This is because the latter would cause the discounted present value to vary depending on when the expenses were incurred, and generally result in a somewhat smaller LCOE. In the 2011 LCOE assessment of power sources by the Japanese government, the capital cost was depreciated over time. However, this was later found to be inappropriate, and so the cost is reported as incurred at the start of operation in the 2015 government estimate.[2]

2-2. Points to note regarding the calculation of LCOE

2-2-1. Notion of the discount rate

The variation in timing at which expenses are incurred is important not only for the assessment of LCOEs but also for various economic indicators. This is typically represented by the discount rate *r*.

The discount rate is a rate used for converting a future monetary value into its present value. For example, assuming interest income of 3% per annum is guaranteed, an amount of 1 thousand yen now is equivalent in value to 1.34 thousand yen 10 years later. In other words, an amount of 1 thousand yen 10 years in the future can be discounted to 740 yen in present value. The rate of 3% used in this type of calculation is called the discount rate. As shown by this example, on a time scale of a few years to several decades, the discount rate can be considered as almost equivalent to the interest rate.

In many cases, the cost C_t that appears in Equations (1) and (2) is expressed as a real value with the impact of inflation or deflation removed. In these cases, the real discount rate is used for *r*. For example, when the nominal interest rate is 5% and the inflation rate is 2%, the real interest rate is approximately 3% and the relationship between the nominal discount rate and the real discount rate is the same. Note that equivalence is being discussed in two different contexts here, i.e., inflation/deflation and conversion into present value. First, because of inflation, 1 thousand yen in the current year is equal in value to 1.02 thousand yen in nominal terms next year, and the value for next year is indicated as (real) 1 thousand yen. When converted into present value, the equivalent of 1 thousand yen this year would be real 1.03 thousand yen and nominal 1.05 thousand yen next year.

2-2-2. Change in LCOE associated with the discount rate

As shown by Equation (2), the value of LCOE will vary greatly depending on the value used for discount rate *r*. Specifically, a higher *r* would significantly increase LCOE for nuclear power and renewables whose initial costs are high, but the impact of *r* would not be so large for sources such as thermal power, which incurs high costs when generating power (fuel costs) but not at the time of construction. This can be understood more easily by imagining borrowing money to build a nuclear power plant and repaying the loan with the income from power generation. The fact that a higher *r* would significantly increase LCOE for nuclear means that the higher the interest rate on the loan, the more income the plant must earn, otherwise repayment will become impossible. For this reason, the discount rate is considered one of the factors with the greatest impact on the economic efficiency of nuclear power. In Japan, costs have typically been calculated assuming a discount rate of 3%. However, the results may change greatly depending on the assumed discount rate.

2-2-3. The issue of backend costs

As described above, when calculating LCOE, all costs are converted to the present value as of the start of plant operation. This generally results in a smaller contribution of backend costs to LCOE. For example, in the 2015 estimate by the Japanese government[2], decommissioning only accounts for 0.1 yen/kWh, fuel reprocessing for only 0.5 yen/kWh, and high-level radioactive waste disposal for only 0.04 yen/kWh of the LCOE of nuclear power of 8.8 yen/kWh. This is because the costs for decommissioning and reprocessing are not incurred until at least 40 years after the plant starts operation, meaning that if the discount rate is set to 3%, the costs would decrease to a third ($1/1.03^{40}$) or less. The implications are clear in light of the discount rate concept described above. If a certain percentage of the proceeds from plant operation is set aside for

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[2] 発電コスト検証ワーキンググループ, (2015). 長期エネルギー需給見通し小委員会に対する発電コスト等の検証に関する報告. https://www.enecho.meti.go.jp/committee/council/basic_policy_subcommittee/ mitoshi/cost_wg/pdf/cost_wg_01.pdf

decommissioning the plant after its closure, even a small percentage will be enough to cover the decommissioning and reprocessing costs because it will usually yield investment returns. Thus, the decommissioning cost will not have a substantial impact on the economic efficiency of nuclear power if a small amount is put aside in a well-planned manner during the plant's lifetime for decommissioning.

The problem is somewhat more complex for high-level radioactive waste (HLW) disposal. The cost for geological disposal of HLW produced in Japan to date is estimated at 3 trillion yen. After disposal, the wastes must be monitored for a certain period, but thereafter, they would basically not be managed by humans. It is assumed that the location and design of the repository will be considered sufficiently conservatively to ensure no burden is placed on future generations, and to ensure that safety would not be undermined even without human involvement. These costs only arise several decades after the start of operation and have a small impact on LCOE. Rather than economic costs, this issue raises the question of how to ensure safety for hundreds of thousands of years.

It is worth considering what would happen if it became necessary to manage the repository for several hundred thousand years after waste disposal. If the possibility of radioactivity leaking into the human living space after disposal is not absolutely zero, then potential damage with a certain monetary value could occur and continue for a long time. Assuming that a latent or manifest cost of X yen is incurred from now into eternity at a discount rate of r, the cumulative costs into the future are expressed as the sum of the geometric series $X + X/(1 + r) + X/(1 + r)^2 + \ldots = X/r$. For example, when X is 1 billion yen/year and r is 3%, the cumulative costs would be 33.3 billion yen, which would have hardly any impact on the cost of nuclear power generation even when added onto the waste disposal cost of 3 trillion yen. Specifically, it is possible to cover the necessary costs permanently by saving a finite amount of funds (for example, 33.3 billion yen) by the time of disposal and investing those funds.

However, this does not solve all the problems. When it is necessary to handle such a long timeline, the discount rate should be assumed to decrease into the future[3] and it becomes difficult to conduct quantitative analyses based on such assumptions. But here again, the key question is how to reduce the risk of leakage in the future when designing the repository, and not economic efficiency.

2-2-4. Initial costs and accident risk costs

As discussed so far, the contribution of backend costs to the LCOE of nuclear power typically decreases considerably by discounting. Conversely, costs that are not discounted may have a significant impact on the economic efficiency of power sources. From this perspective, the cost for additional safety measures warrants particular caution for Japanese nuclear power. As this cost is added onto the initial cost, i.e. the plant construction cost, how to curb this cost to reasonable levels will strongly affect the economic efficiency of nuclear power going forward.

In addition, the cost related to nuclear accidents should also be excluded from the discount calculation, because a nuclear accident could occur potentially while generating power. Accident risks should normally be estimated as the monetary value of damages caused by an accident multiplied by the frequency at which accidents occur, but it is not easy to estimate the frequency. In any case, the accident-related cost per kWh estimated by some means should not be discounted, but be added to LCOE as is.

2-3. LCOE and the optimal power mix

LCOE helps determine the optimal share of conventional power sources. Fig. 1 illustrates the electricity demand for 8,760 hours in a year in order of the scale of demand (called the load duration curve). Assume that the electricity demand is covered using only coal- and LNG-fired thermal power. Since coal-fired thermal

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[3] C. Gollier, (2013). Pricing the planet's future: The economics of discounting in an uncertain world, Princeton University Press.

power usually has a higher construction cost and lower fuel cost than LNG-fired thermal power, coal would have a lower LCOE than LNG when its capacity factor is high, and the opposite would be true when its capacity factor is low.

Assume that *f* is the capacity factor at which the LCOE of coal and LNG are the same. In this case, the ratio of coal- and LNG-fired thermal power at which the total cost of the power system is minimized is shown by the horizontal dotted line in Fig. 1. In the area below this line, the capacity factor of coal is higher than *f*, so it would be economically rational to cover this area with coal-fired thermal power. Meanwhile, it would be more rational to use LNG-fired thermal power for the area above the dotted line. The theoretical optimal supply of electricity can be described simply, by using LCOE.

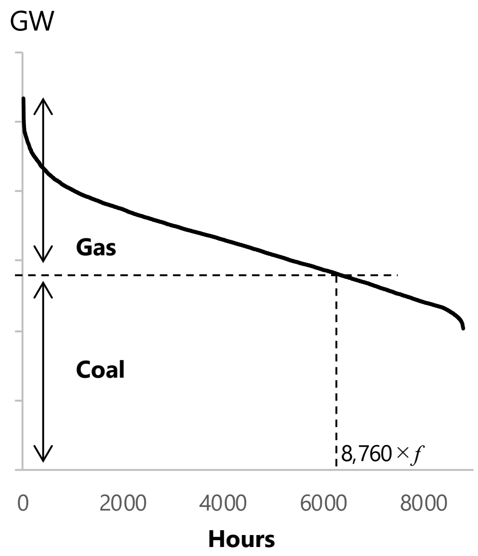

Fig. 1 Selection of power sources based on the load duration curve and LCOE

In this example, the LCOE of each power source, with its capacity factor factored in, can be considered to indicate the "marginal cost" of each source. This is because additional capacity installed in step with the increase in coal-fired thermal output will have a lower capacity factor, hence a higher LCOE (the cost for additional kWh). The point at which the LCOE for coal-fired thermal power, with capacity factor factored in, becomes equal to the LCOE of LNG-fired thermal power is the point at which the power mix becomes optimal. The marginal cost for each power source, described later, can be understood as a general application of this well-known relationship.

2-4. Examples of LCOE: Assessment by the OECD

The OECD/NEA and the IEA have been conducting comprehensive estimations of LCOE by technology and country since 1983, and the 9th report was published in December 2020. This report presents, in a unified format, the LCOEs of energy sources calculated based on the power generation data submitted by the representatives of various countries, mainly OECD member states. This report, the 9th, contains data from 24 countries. In recent years, the report has included data from non-OECD countries, including China, India, and Brazil, as well as Russia and Romania which are NEA member states. Japan's data is based on the values mentioned earlier presented by the Power Generation Cost Verification Working Group, which are the latest estimates for the country. However, for VRE, the 2030 estimates are used as the estimated costs for plants starting operation in 2025, in light of the current and possible future reductions in VRE costs.

The 9th report is notable in the following ways. First, it discusses not only LCOEs but also the value-adjusted LCOE, or VALCOE, proposed by the IEA as a metric "beyond" the LCOE, for the first time. This topic is outlined later in Chapter 3. Second, it presents estimates for technologies that were not covered previously, namely CCUS (carbon capture, utilization and storage), long-term operation (LTO) of nuclear power plants, and batteries. In particular, for batteries, for which estimates cannot be obtained using the LCOE methodology as it is, a new metric called levelized cost of storage (LCOS) was introduced. LCOE assumes that plant starts operation in 2025 and imposes a carbon price of \$30/tCO_2 on thermal power.

Fig. 2 shows the estimated LCOE for each technology. Note that the results for discount rates of 3%, 7%, and 10% are presented in the NEA/IEA report, but only those for 7% are presented here.

The cost for thermal power will rise due to CCUS, even with a carbon price of \$30/tCO_2 factored in. However, CCUS would be cost-competitive for coal-fired thermal power for carbon prices higher than \$50–60/tCO_2 and for natural gas-fired thermal power for prices over \$100/tCO_2. Given that the IEA World Energy Outlook 2020[4] predicts a carbon price of \$63/tCO_2 in 2025 and \$140/tCO_2 in 2040 in its Sustainable Development Scenario, CCUS would be a rational option, at least in an ambitious GHG emissions reduction scenario of this level.

The LCOE for nuclear power for Russia, which appeared in the report for the first time, was significantly lower than that of other countries at 4.2 cents/kWh for a 7% discount rate, less than two-thirds of the country's land-based wind power (6.7–7.2 cents/kWh for a 7% discount rate). The LCOE for LTO was estimated for the US, France, Sweden, and Switzerland, and was found to be 4.0–4.9 cents/kWh for a 20-year LTO. The technology is regarded as a highly competitive option compared to constructing new plants for other technologies.

There has been a steady reduction in costs since the previous report (2015) for renewable energies, particularly solar PV and wind power. In Europe, a significant reduction in LCOE was observed for offshore wind power, with the lowest LCOE being 4.5 cents/kWh for a 7% discount rate in Denmark. However, the LCOEs of renewable power sources vary greatly by country or even by region within the same country, and how to reduce them in high-cost countries and regions, including Japan, will be a major challenge going forward.

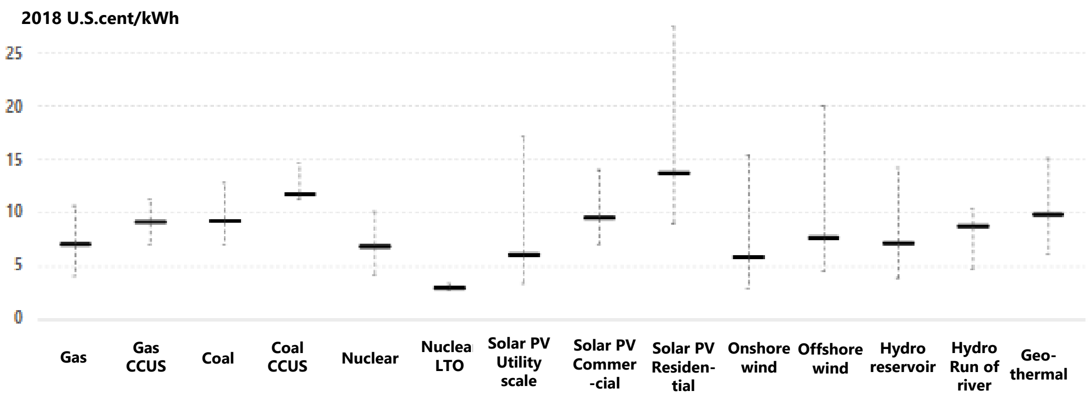

Fig. 2 Examples of LCOE Estimates by OECD/NEA and IEA (2020)

Note: The figure shows the median, the maximum, and minimum values of all data. The values for natural gas represent generation with the combined cycle generation technology (CCGT).

The values are for capacities of 1 MW or higher for land-based wind power and 5 MW or lower for hydropower.

3. Metrics "Beyond LCOE"

3-1. The need for new metrics

The LCOE approach has been used widely to compare the generation costs of different power sources. As mentioned earlier, if power source A is replaced with power source B in a certain power mix, the change in the

[4] International Energy Agency (IEA), (2020). World Energy Outlook 2020, IEA Publications.

cost for the system as a whole will be equal to the replaced output multiplied by a constant (the difference between the LCOEs of the power sources). However, in many cases, this linear approximation would not hold in a power system with high shares of VREs. For instance, solar PV output has a positive correlation with electricity demand when the capacity is small and thus helps to stabilize the electricity supply. However, as the capacity increases, it will be necessary to install electricity storage systems such as batteries, which pushes up the total cost of the power system accordingly. In such a case, the correlation between the solar PV capacity and the need for storage systems is clearly non-linear, and therefore, LCOE is not able to express the cost of solar PV by itself.

This problem has rapidly captured attention as an important issue in the last decade and was partly discussed in the 2015 NEA/IEA report. The latest report, published in 2020, describes the value-added LCOE (VALCOE) in more detail in Chapter 4. VALCOE is an evaluation indicator first presented in the IEA periodical publication, World Energy Outlook (WEO). As described later, the VALCOE of an energy source is obtained by complementing its LCOE with its value in the energy system and was newly developed to address precisely the issue discussed earlier. However, other similar metrics have also been developed for the same purpose. This paper hereafter describes various metrics including VALCOE based on the literature[5,6] and introduces the current status of discussions on this problem.

3-2. Integration cost

3-2-1. Concept of integration cost

The problem we are currently considering is essentially the following: what would be the extra cost in addition to the conventional LCOE? From this perspective, the total cost of a power system, which we assume can be calculated in some way, minus the portion corresponding to LCOEs, is called the integration cost in this report (Fig. 3). In a simple system consisting only of conventional power sources (CPSs) and VREs, when the output from CPSs multiplied by their LCOEs (L_{conv}) is the cost C_{conv} and the output from VREs multiplied by their LCOEs (L_{VRE}) is the cost C_{VRE}, then the total cost C is expressed as the sum of these costs and the integration cost C_{INT}.

Here, the VRE capacity x at which C becomes the minimum is the value that satisfies the following equation:

$$L_{\boldsymbol{conv}} = L_{VRE} + \frac{dC_{INT}}{dx} \equiv L_{VRE} + L_{INT} \tag{3}$$

The value on the left side of the equation is sometimes called the System LCOE for the VRE. However, as described later, the term System LCOE is more generally used for a somewhat different concept.

It goes without saying that it is crucial to calculate C_{INT} appropriately in order to evaluate the economic efficiency of power systems with large amounts of VRE, and many studies have quantitatively estimated this value in the last decade. It is important to note that C_{INT} includes many different kinds of costs and is often determined using a mathematical model-based simulation. In general, the following classification is often applied[7].

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[5] Y. Matsuo and R. Komiyama, (2021). System LCOE of variable renewable energies: A case study of Japan's decarbonized power sector in 2050, *Sustainability Science*, (in press).

[6] 松尾雄司，村上朋子，荻本和彦, (2019). 発電部門の経済性評価手法及び指標に係るレビュー，『第 38 回エネルギー・資源学会研究発表会講演要旨集』，20-4.

[7] F. Ueckerdt, L. Hirth, G. Ludere, and O. Edenohfer, (2013). System LCOE: What are the costs of variable renewables?, *Energy*, 63, pp. 61-75.

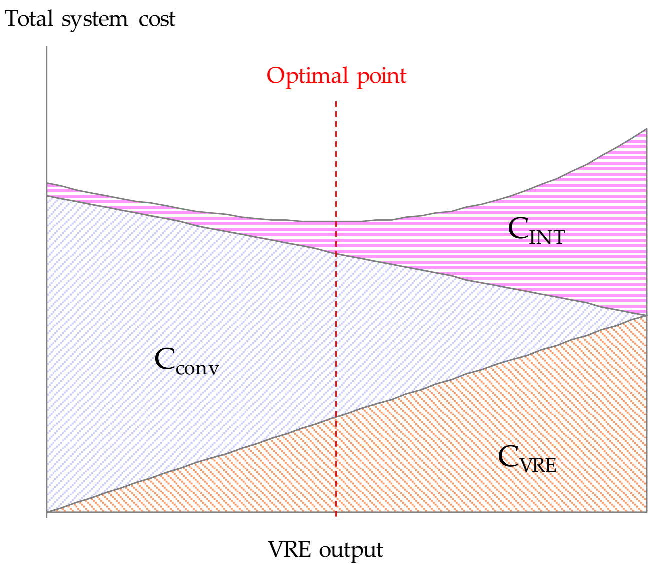

Fig. 3 Illustration of integration costs and system LCOE (horizontal axis: share of VRE; vertical axis: total system costs)

(1) Balancing costs

The cost of imbalance is associated with short-term prediction errors. The rise in this cost is recognized as a major challenge in the initial stage of introducing VRE.

(2) Grid costs

The cost associated with strengthening or expanding the power grid. However, in more general terms, it is defined as the cost arising from the spatial separation between VRE generation and electricity demand.

(3) Profile costs

The additional cost arising from temporal discrepancies between VRE generation and electricity demand; also called the utilization cost. This includes all the costs associated with VRE output control and introduction of batteries, low utilization factor of CPS, thermal power operation at part load, and increase in the number of start-ups and shutdowns. Unlike the balance cost, the profile costs would still be necessary even if fluctuations in VRE output and demand were completely predictable. The impact of profile costs is thought to grow when the share of VRE rises above a certain level.

Although Fig. 3 is simplified and shows only two types of technologies, the concept of integration cost in the diagram seems to be clear. Nevertheless, in fact the concept has some unclear points. First, a rise in the share of VRE usually results in a lower load factor of CPS and causes its LCOE to rise. Therefore, the problem arises that C_{conv} may not change linearly with the share of VRE, unlike in Fig. 3. Second, even among thermal power sources that are deemed as CPS, natural gas and coal differ in flexibility. Accordingly, as with VRE, some integration costs may be incurred, at least for relatively inflexible sources.

For the integration cost, or the total cost including it, one value is determined for an energy mix, and in that sense, it is different from LCOE whose purpose is to calculate the cost of each power source. As such, as described later, metrics that can show the cost of each power source were devised separately from integration cost. However, for practical purposes, the integration cost is sufficiently useful for formulating policies if the change in the integration cost or the total cost C for different shares of VRE can be determined accurately.

3-2-2. Estimating the integration cost

Starting in the 2010s, many studies that aimed to quantify the integration cost have been published. Many of the studies up to around 2015 to 2016 estimated the cost of VRE for shares of up to around 50%, but since 2017, more and more studies are estimating the cost for higher VRE shares. Recently, many studies are estimating the grid costs and profile costs above using a time resolution of at least 1 hour and finer regional divisions in modeling the uneven time and regional distribution of VRE output.

Some of the most common issues when assessing the results of estimating the integration cost are: (1) how much would the total cost rise if an extremely high share of renewables is to be achieved, if at all, and (2) whether the total cost would rise when, in addition to renewables, low-carbon power sources such as nuclear and zero-emission thermal power are used. A typical calculation using a mathematical model would show that, for achieving a zero-emission power sector, it would be less costly if renewables are combined with thermal and nuclear, rather than using renewables only. However, these results depend heavily on the modeling method and underlying assumptions as well as target regions, and some studies concluded that the total cost would be lower, under some conditions, if the share of renewables reaches 100% than if only CPS is used. The methodology for estimating the total cost has been generally consistent to date, yet the results still differ significantly among studies; it is hoped that yet more studies will be conducted in the next few years.

3-3. System value and the Levelized Avoided Cost of Energy (LACE)

3-3-1. Estimation of the system value

In the context of the large-scale introduction of VRE, there are increasing discussions on "values" in addition to the concept of integration "costs" described above. For example, the IEA has defined the "system value" of a power source as the net benefit, meaning all benefits less all costs, arising from adding that power source[8]. Possible benefits that have been mentioned include reductions in thermal power fuel costs and emission of CO_2 and other pollutants, and costs for other power sources resulting from the introduction of VRE; possible costs include, aside from the cost for introducing and operating facilities, negative effects on the existing power system, the need for additional investment in the transmission networks and other facilities, and the need to adjust the output of VRE itself.

If, hypothetically, the total cost of a power system can be estimated completely, the "value" of the power source in this sense would mean the difference in the total system cost before and after the power source was introduced. This means that if "costs" can be estimated completely, the value can also be estimated. For example, the "value" of pumped-storage hydroelectric power can be estimated explicitly by calculating the difference in total costs with and without the power source in the power system[9]. However, it is not so simple to estimate the "value" of technologies such as coal-fired thermal and solar PV, because adding these power sources to a given power system usually means that output from other sources must be removed, and the total costs change in different ways depending on which power source is removed, making it impossible to develop a unique definition of "value." This makes it necessary to consider "market value" as described in the next section.

3-3-2. Market value and cannibalization effect

The "market value" discussed here is the amount of revenue that can be derived from a certain power source in the various markets associated with the power sector. Measuring the market value has been attempted in relation to the wholesale electricity market. The market value of a one-kilowatt solar PV plant is obtained by

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[8] International Energy Agency (IEA), (2016). Next generation wind and solar power, IEA Publications.
[9] 荻本和彦，片岡和人，占部千由，斉藤哲夫, (2017). 日本における揚水発電所の System Value (II), 『平成 29 年電気学会 B 部門大会講演論文集』, 149.

weight-averaging the wholesale electricity price, which changes with time in a given supply-demand structure, by the plant's output. In mathematical modeling, this can be expressed as the weighted average of the shadow prices in supply-demand constraints. Note that when the output from a power source is in equilibrium with those of other power sources, in other words, the power system is at the optimal point or the point at which the total cost is minimized, the market value, i.e., the weight-averaged shadow price, is equal to the average cost of the power source, at least in an optimization calculation in a mathematical model. The market value would be higher than the average cost if the output is kept below the equilibrium by some constraint and would be lower than the average cost if it is introduced in larger amounts than the equilibrium.

This is particularly prominent for VRE whose output fluctuates greatly and is uncontrollable. When solar PV plants are introduced massively, the electricity price would be low, or even zero, in the day-time on a sunny day, making the value of introducing additional plants extremely small. A similar phenomenon occurs for wind power at a comparatively moderate, but remarkable level. This phenomenon, in which the value of VRE drops sharply when introduced in large amounts, is called the "cannibalism effect."

3-3-3. Levelized Avoided Cost of Energy (LACE)

The Levelized Avoided Cost of Energy (LACE)[10], which the US Department of Energy has been using in recent years, is essentially the same metric as market value. The market value of a power source is equal to the decrease in the total costs for other power sources in the power system when a very small amount of that power source is added into an energy mix. Therefore, as described earlier, it would be cost-competitive to introduce additional amounts of that particular power source when its LACE is greater than its LCOE, and its LACE would be equal to its LCOE at the optimal point.

3-4. Value-adjusted LCOE (VALCOE), System LCOE, and Enhanced Levelized Cost

As previously stated, the competitiveness of a power source in the power system can be evaluated more accurately by estimating the "value" of a power source as well as its "cost," and comparing them for different sources. Accordingly, considerations are underway to expand the concept of LCOE using a metric that combines cost and value. Such efforts can be seen as attempts to calculate the "marginal cost of each power source." The three important examples are described below.

3-4-1. Value-adjusted LCOE (VALCOE)

The concept of VALCOE was first presented by the IEA in the World Energy Outlook 2018 (WEO2018) and is used in the joint report by the NEA and IEA as mentioned earlier. The aim of this metric is to complement the conventional LCOE by evaluating "value", as illustrated in Fig. 4.

[10] U. S. Energy Information Administration (EIA), (2019). Levelized cost and levelized avoided cost of new generation resources in the Annual Energy Outlook 2019. https://www.eia.gov/outlooks/aeo/pdf/ electricity_generation.pdf

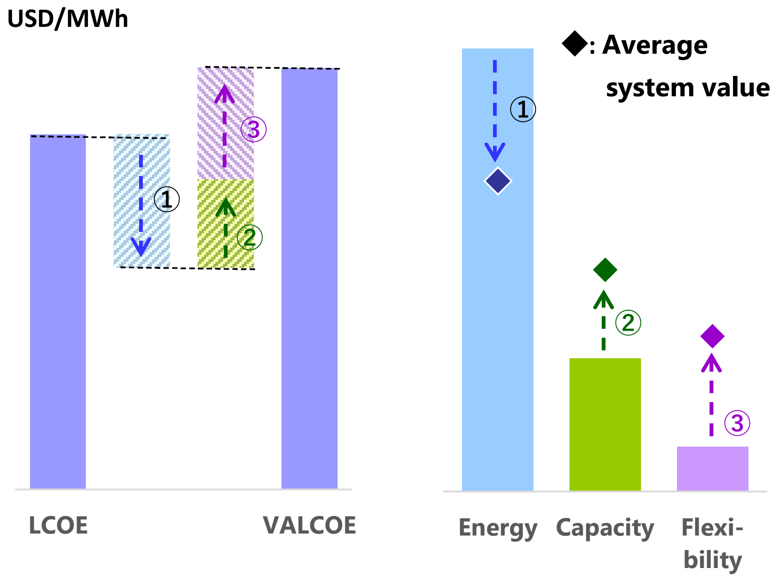

Fig. 4 Concept of the value-adjusted LCOE (VALCOE)

First, as shown on the right side of the diagram, the market value of a power source is measured in terms of its energy, capacity, and flexibility values. These values are then compared with the respective average market values (shown by ◆ in the diagram) in a given power system. Here, having a "high value" is synonymous with "low cost." That is, as shown in the left half of the diagram, for these three types of values, if the value of the power source is higher than the market average (as with the output value in this example), the difference is deducted from its LCOE; if it is lower than the market average, the difference is added on to its LCOE. Note that the LCOE used here is calculated based on the capacity factor of the power source in a particular power system. For example, when large amounts of VRE are installed in a system, the capacity factors for conventional power sources usually decrease and the resulting increase in costs is recognized as part of the profile costs. Meanwhile, note that the "LCOE before value-adjustment" referred to in the context of VALCOE already factors in this decrease in capacity factor and thus has a somewhat higher value.

3-4-2. System LCOE_HUE by Hirth et al. (2016)

System LCOE defined by L. Hirth, F. Ueckerdt and O. Edenhofer (2016)[11] (hereafter System LCOE_HUE) is a metric similar to VALCOE. It is defined as follows:

$$L_{HUE\ i} = c_i - v_i + v_L \tag{4}$$

Here, c_i stands for the LCOE of the power source i. As with the case of VALCOE, it is calculated based on its load factor in a given power system. v_i is the "unit value," which is obtained by the annual income that the power source derives from the markets related to the power system divided by the annual output of the power source. v_L is the "unit value of demand" calculated by dividing the value of demand, i.e., the total annual costs for obtaining electricity from the market to meet the demand, by the total annual output of the power source.

The definition of the "average market value in the system" used to calculate VALCOE cannot be determined accurately from published documents[12]. If it means the same as the "unit price of demand," if only the wholesale

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[11] L. Hirth, F. Ueckerdt and O. Edenhofer, (2016). Why wind is not coal: On the economics of electricity, *Energy Journal*, 37(3), pp. 1-27.

[12] International Energy Agency (IEA), (2020). World energy model documentation 2020 version. https://www.iea.org/reports/world-energy-model/documentation

market, capacity market, and flexibility market exist in the power system, VALCOE and system LCOE_HUE would be the same. Furthermore, if the average market value in a system of VALCOE means the weighted average of all power sources, VALCOE and system LCOE_HUE would be nearly equal when the impacts of battery systems and power grids are small. In any case, the two concepts are similar. The difference may be that, whereas VALCOE actually uses a model used by the IEA for calculation, and thus, the target markets and the data used (such as capacity market prices) are predetermined, system LCOE_HUE is defined as a more general concept.

Problems with the concepts of VALCOE and system LCOE_HUE are described in the following section. It should also be noted that these indicators do not have "separability," which refers to the ability to divide the target power system. For example, when calculating the system LCOE_HUE of wind power plants in a city in Hokkaido Prefecture, the value v_L in Equation (4) will vary depending on whether the electricity demand curve used in the calculation is for the city, Hokkaido Prefecture, or Japan as a whole, and so the system LCOE_HUE value cannot be determined uniquely. It seems appropriate to use the electricity demand for Hokkaido Prefecture if Hokkaido has a fixed wholesale electricity market price, but this does not seem to provide a general solution.

3-4-3. Enhanced levelized costs by UK BEIS

A metric similar to the above has been proposed by the Department for Business, Energy and Industrial Strategy (BEIS) of the United Kingdom in "Electricity Generation Costs 2020"[13]. For this metric, the impact on the (1) wholesale electricity market, (2) capacity market, (3) ancillary services market, and (4) power network when a certain power source is added to a given energy mix is quantified using BEIS Dynamic Dispatch Model as wider system impacts[14]. Then, this value is added onto the LCOE to obtain a value called enhanced levelized costs. However, as with the relative marginal system LCOE described later, this methodology also requires a baseline power source to be determined; the report evaluates the wider system impacts of each power source relative to nuclear power.

According to this assessment, from the present up to 2035, the LCOE of VRE is estimated to be significantly lower than that of thermal power (CCGT + CCUS), while the enhanced levelized costs would be higher than the LCOE for VRE but lower than the LCOE for CCGT + CCUS. However, the degree of increase or decrease depends on what kind of energy mix those power sources are part of. The study calculates the enhanced levelized costs for six types of energy mix with various compositions and electricity demand levels, and suggests that the costs for CCGT + CCUS both may or may not be lower than solar PV, depending on the case.

Unlike VALCOE and system LCOE_HUE above, BEIS' enhanced levelized costs do not use market value in their equations. However, all these indicators can be considered as attempts to evaluate the marginal cost of a power source in a given energy mix, as described in the next section.

3-5. Marginal costs and average costs of a power source: Calculation for Japan

3-5-1. LCOE_HUE and the relative marginal System LCOE

As described earlier, the concepts of VALCOE and system LCOE_HUE are similar. In this section, System LCOE_HUE is taken as an example to see how it is related to the total power system cost C.

Assume that the output x_i of power source (or technology) i is increased by a small amount Δx_i in a power system. When this is done, the part of cost C corresponding to the output of power sources other than i decreases by $v_i\Delta x_i$ as x_i increases (recall that the unit value v_i of technology i is the same as its avoided unit cost), while

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[13] Department for Business, Energy, and Industrial Strategy (BEIS), (2020). Electricity generation costs 2020. https://www.gov.uk/government/publications/beis-electricity-generation-costs-2020

[14] Frontier Economics, (2016). Whole power system impacts of electricity generation technologies. https://www.gov.uk/government/publications/whole-power-system-impacts-of-electricity-generation-technologies

the cost related to technology *i* increases in proportion to the amount corresponding to its LCOE, i.e. $c_i \Delta x_i$.

In an actual power system, the increase in x_i must be offset by reducing the output of other power sources. Here, we set up a *reference technology* 0 with an output of x_0, which decreases as x_i increases, and assume that the output of other sources does not change. As described above, C increases by $-(v_0 - c_0)\Delta x_0$ as a result. The ratio between the decrease in output of technology *i* and the increase in the reference technology is 1:1. This means that, if $\Delta x_i = -\Delta x_0$,

$$\frac{dC}{dx_i} = (c_i - v_i) - (c_0 - v_0) = L_{HUE\ i} - L_{HUE\ 0} \tag{5}$$

This shows that the difference in system LCOE_HUE would represent the marginal cost when the output of the reference technology is replaced with that of technology *i*.

The problem is that $\Delta x_i = -\Delta x_0$ does not always hold. Assume that technology *i* is solar PV and the reference technology 0 is thermal power, and that $R_i \Delta x_i = -\Delta x_0$ holds true. R_i is mostly equal to 1 when the share of solar PV output is small, but as it increases, the solar PV output corresponding to one unit of thermal power grows due to battery and transmission losses and curtailment, resulting in $R_i < 1$. As such, Equation (5) generally does not hold true in real life.

Based on the above, as an alternative metric to system LCOE_HUE, the relative marginal system LCOE L_i of technology *i*, is defined as follows:

$$L_i = \frac{1}{R_i}\frac{\partial C}{\partial x_i} - \frac{\partial C}{\partial x_0} + L_0 \tag{6}$$

In this equation, when a small output of technology *i* displaces the reference technology 0, $dC = -(L_i - L_0)\, dx_0$. $(L_i - L_0)$ represents the increase in total cost C when one unit of the reference technology is replaced with technology *i*. Since it is only the difference in marginal cost between the power sources that matters here, as implied by the name "relative" marginal system LCOE, any number can be adopted as the relative marginal System LCOE L_0 of the reference technology. In many cases, a fixed number, that is, 0, or the LCOE of the reference technology at a certain capacity factor, may be used for simplicity.

3-5-2. Average System LCOE

Whereas the section above described the "marginal" cost of each technology, it is also possible to calculate the "average" cost of it. That is, if the integration cost C_{INT} indicated in Fig. 3, and hence total cost C, can somehow be allocated to different power sources based on their contribution, it would be possible to calculate the average system LCOE L_{Ai} of each technology by dividing the allocated cost by the output. However, as conventional technologies are also inflexible in their respective ways, it is necessary to allocate I not only to VREs but to all technologies. In doing so, more flexible technologies should be allocated a smaller C_{INT}, and the C_{INT} allocated to two power sources with exactly the same characteristics must be proportional to the output of each power source.

The main problem here is that the incurred integration cost changes depending on the order in which technologies are introduced. When solar PV is introduced into a grid consisting of conventional power sources, followed by wind power, the rise in C_{INT} attributed to the introduction of wind power would be greater than for solar PV; in contrast, the rise in C_{INT} would be greater for solar PV when the order is reversed. This applies not only to VREs but also to conventional technologies. As a solution, one possible way to allocate C_{INT} in proportion to each power source is to assume a "costless technology" of infinite flexibility and zero cost, and then, starting with a hypothetical state in which power is supplied entirely by this costless technology, increase the outputs of all technologies at the same rate until a realistic state is reached, calculating the integrals in the process[5].

As is true for many economic problems, it is important to understand the difference between marginal cost and average cost. If a power source has a low average system LCOE, it would mean that the technology is supplying large amounts of power and helping to curb the total cost. Meanwhile, if it has a high marginal system LCOE, it means that it is difficult to install additional capacities of this power source, and from the perspective of total cost reduction, it may be necessary to accelerate the shift to other power sources.

3-5-3. Calculation for Japan

Fig. 5 shows the result of a calculation for the average system LCOE and relative marginal System LCOE for Japan[5]. They were calculated for solar PV, wind power, nuclear power, and zero-emission thermal power by dividing Japan into three regions, namely Hokkaido, Tohoku, and the rest, and assuming that all electricity is supplied by renewable energies, nuclear power, and zero-emission thermal power (imported hydrogen thermal power, etc.). The total electricity demand was set to just over 1,000 TWh, nuclear power capacity was capped at 25.5 GW, and solar PV and wind power were assumed to be available for mass introduction in line with the potential estimated by the Ministry of the Environment. Furthermore, the LCOEs for solar PV and land-based wind power were set to 7 yen/kWh and 8–9 yen/kWh, respectively. Zero-emission thermal power was selected as the baseline power source for relative marginal system LCOE, and its estimated LCOE of 12 yen/kWh at a capacity factor of 80% was used as L_0 in Equation (6). To be precise, the system LCOE may differ between the three regions even for the same type of power source, and so the values in Fig. 5 are the weighted averages of the three regions.

Because it is assumed here that VRE is cheaper than thermal power based on LCOE, the average system LCOE of VRE would be lower than thermal power in many cases. However, the average costs of other power sources rise gradually as thermal power restriction is reduced, and when it reaches 50 TWh or lower, the system LCOE of onshore wind power surpasses that of thermal power. Meanwhile, for relative marginal system LCOE, the values of other technologies rise sharply as thermal power output decreases. Note that all technologies that have reached an “equilibrium,” by definition, take the same value. In Fig. 5, the value for nuclear power is low because it has an output cap and has not reached equilibrium. Further, offshore wind power is not included in the solution described here because of the high estimated LCOE. Other energies, i.e., solar PV and onshore wind power, have the same relative marginal system LCOE in this calculation, even though their estimated LCOEs are different, because they are at an “equilibrium.” However, when the thermal output becomes 20 TWh, the value for solar PV falls below that of onshore wind power because solar PV reaches the maximum capacity. As this shows, relative marginal system LCOE can be regarded as a metric that shows how far the installed capacity of a power source is from equilibrium.

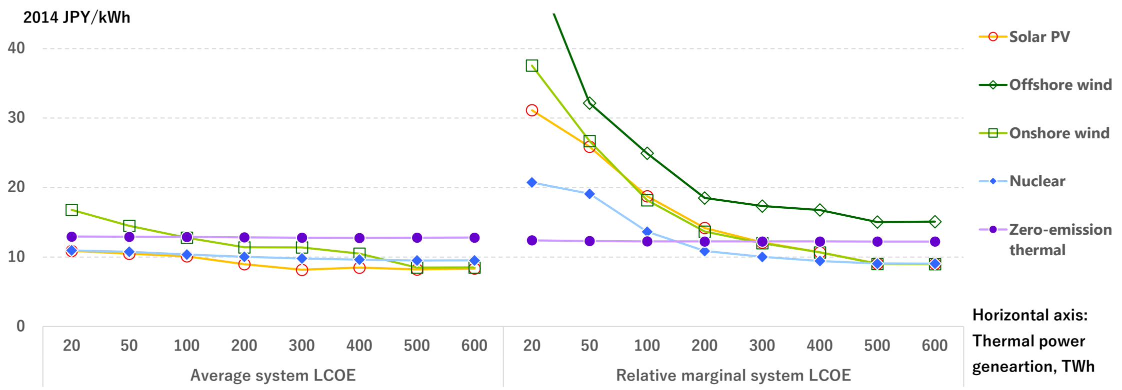

Fig. 5 Calculation of average and marginal System LCOEs

Conclusion

This report outlined various metrics "beyond LCOE" that are currently being proposed, while also referring to the relationships between the metrics. As explained, the metrics can generally be described as those for the "total cost (including integration cost)," "market value," "marginal cost by technology," and "average cost by technology," though there are slight conceptual differences and similarities between them. The most important idea among these is the integration cost, or the total cost, calculated for a given energy mix; if this can be estimated accurately with mathematical models or any other measures, it alone can provide very useful information for future energy and environmental policies. Other metrics solely express changes in the total cost.

The "market value" calculated for each technology is essentially the same as the "unit avoided cost." The market value of a technology is lower than its cost (LCOE) when installed beyond the optimal amount but is higher than the cost when below the optimal point. The marginal cost by power source uses this property to combine cost and value, and VALCOE and system LCOE_HUE fall in this category. Moreover, it would be more appropriate to use the relative marginal system LCOE as a metric representing the marginal costs of power sources.

In any case, these analyses show that, regardless of the type of power source, its marginal cost will rise rapidly once it is deployed beyond the optimal point, or the point of equilibrium. While this report considered the only cost, which can be converted into monetary value, the findings may be true for risk, which may not easily be converted into monetary value. This suggests that even in the future when more power sources become carbon-free and large amounts of VRE are introduced, a best mix of energy will exist, albeit somewhat different from the current one, and pursuing this best mix will be a key point for energy policy. Meanwhile, when VRE costs decrease considerably in the future, their average costs could become extremely low. The results indicate that even hard-to-handle power sources like VRE could help reduce the average cost of electricity, and raise hopes that, depending on the policy, it may be possible to replace all power sources with zero-emission ones without imposing a major burden on the public.

The economic assessment of power systems with a large VRE capacity will be a vital part of discussions on decarbonizing the use of energy. However, discrepancies remain among studies regarding the evaluation of integration cost itself. As the research progresses and researchers approach a consensus, it would be possible to present valuable information that can contribute to decent energy and environmental policies.

Series "Ushering in a New Era of Carbon Neutrality" (1)

Decarbonization Trends and Innovative Technologies◆

Hiroko Nakamura* Akiko Sasakawa*

"Carbon Neutrality" trends

Last October, Japanese Prime Minister Yoshihide Suga in his policy address expressed his intentions to focus on realizing a green society and pledged to achieve carbon neutrality by 2050.

His pledge was made against the backdrop of a global decarbonization trend. The Paris Agreement, adopted in 2015 at the 21st Conference of the Parties to the United Nations Framework Convention on Climate Change (COP21), set out two long-term goals. One goal is to limit global warming to well below 2 degrees Celsius, preferably to 1.5°C, compared to pre-industrial levels. The other is to reach global peaking of greenhouse gas emissions as soon as possible to achieve a balance between anthropogenic emissions by sources and removals by sinks of greenhouse gases (GHGs) in the second half of the 21st century. Carbon neutrality means achieving this balance between emissions and removals. The Special Report on Global Warming of 1.5°C, released by the Intergovernmental Panel on Climate Change (IPCC) in 2018, concluded that global net-zero emissions would be required between 2050 and 2070 to limit global warming to well below 2°C and that carbon neutrality would be required around 2050 to limit warming to 1.5°C (see Table 1).

So far, 120 economies have pledged to reach carbon neutrality by 2050. China, the world's largest GHG emitter, has vowed to achieve carbon neutrality in 2060. These economies view climate actions as opportunities for growth.

The business sector has also launched carbon neutrality campaigns. In addition to oil majors and technology giants in Western countries, leading Japanese companies have pledged to realize carbon neutrality in their business operations by 2050 or earlier. As one of the measures to do so, a rising number of companies have announced their commitment to procure all electricity used in their business operations from renewable energy. The number of Japanese companies participating in the global RE100 initiative stood at 53 in March 2021.

The European Union and the United States are considering the introduction of a carbon border adjustment mechanism (CBAM) in the near future. A CBAM would impose a carbon-related charge on imports to a country taking climate action from countries failing to implement sufficient climate change countermeasures (and may also provide export rebates corresponding to the carbon prices). Hence, more companies are accelerating their green energy procurement efforts to explore production processes free from carbon dioxide emissions.

These initiatives have also become important for attracting investment. ESG (environment, society and governance) investment has rapidly expanded across the world in recent years. According to the Global Sustainable Investment Alliance, global ESG investment has increased from $22.9 trillion in 2016 to $30.7 trillion. The Japanese ESG market has expanded about four-fold from $0.5 trillion to $2.1 trillion.

Renewables are increasingly important for decarbonization

How would carbon neutrality be realized?

Most importantly, GHG emissions will need to be substantially reduced. Carbon dioxide emissions that are hard to abate would be removed by sinks through afforestation and forest protection, or through the decarbonization of fossil fuels (carbon recycling) and by using carbon capture and storage (CCS) technologies that promise to contribute to negative emissions (removal of CO_2 from the atmosphere). Hence, the goal is to balancing emissions with removals.

Reaching Zero with Renewables, a report released by the International Renewable Energy Agency (IRENA) in September 2020, introduced the Deeper Decarbonization Perspective for reducing energy and process-related CO_2

◆ Created based on the published research in the April 13, 2021 issue of Financial Affairs (Kinzai Weekly)

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emissions to zero in 2050-2060 against a baseline scenario based on policies around 2015 when the Paris Agreement was adopted. Under the perspective, energy efficiency improvements and renewables (renewable electricity, renewable heat, biomass and renewable synthetic fuels) will contribute to “reducing” CO_2 emissions by 94%, with the remaining 6% being “removed”. As indicated by the perspective, the deployment of renewables and other carbon-free energy sources as well as energy efficiency improvements will be the key to achieving carbon neutrality.

The abovementioned IPCC Special Report on Global Warming of 1.5°C projects that to limit global warming during this century to below 1.5°C, renewables would have to account for 70-80% of global power generation in 2050. The renewables share for 2030 would need to be 48-60%. The International Energy Agency (IEA)’s Sustainable Development Scenario (that holds the temperature rise to below 1.8°C) sets a path towards meeting the objectives of the Paris Agreement goal and projects the renewables share of the global power mix in 2030 to be 49%. In the IRENA Transforming Energy Scenario for limiting global warming to well below 2°C, the renewables share is projected to be 57% for 2030 and 86% for 2050.

Japan gets serious about decarbonization

Last year on December 25, the Japanese government formulated the Green Growth Strategy, announcing ambitious decarbonization targets and action plans for 14 key areas where growth is expected. These key areas include offshore wind power generation, hydrogen, automobiles and storage batteries. The strategy calls for the decarbonization of the power sector and seeks to electrify other sectors while using hydrogen and CO_2 capture for heat demand. With a view to a 30-50% increase in electricity demand in 2050, the strategy provides a reference power generation mix, in which renewables would account for about 50-60%, hydrogen and ammonia for about 10% and nuclear energy and fossil fuels with CO_2 capture for 30-40%.

Under the third supplementary budget for FY2020, the government set up a 2-trillion-yen Green Innovation Fund at the New Energy and Industrial Technology Development Organization (NEDO) to support technology development and commercialization projects over 10 years in the three priority areas for reaching carbon neutrality by 2050: electrification and green power; realizing a hydrogen economy, and CO_2 fixation and reuse.

Given these recent developments, this series will introduce innovative technology trends in Japan and overseas that contribute to decarbonization.

Table 1 International organizations’ decarbonization scenarios

International organization reports	Projected renewables shares (global)
IRENA (2020) *Deeper Decarbonization Perspectives* (DDP)	Limiting global warming to 1.5°C 66% of 2050-2060 final energy consumption
IPCC (2018) *Special Report on Global Warming of 1.5℃*	Limiting global warming to 1.5°C 48-60% of power generation in 2030 70-80% of power generation in 2050
IRENA (2020) Transforming Energy Scenario (TES)	Limiting global warming to well below 2°C 57% of power generation in 2030 86% of power generation in 2050
IEA (2020) Sustainable Development Scenario	Limiting global warming to 1.8°C 49% of power generation in 2030

Note: IRENA: International Renewable Energy Agency
IPCC: Intergovernmental Panel on Climate Change
IEA: International Energy Agency
Source: Compiled by the authors

Series "Ushering in a New Era of Carbon Neutrality" (2)

Cutting-edge Solar PV Technologies and Business Models◆

Hiroko Nakamura*

New solar PV business model

On March 31, Seven & i Holdings Co. and Nippon Telegraph and Telephone Corp. (NTT) announced that they would partner to launch a new solar photovoltaics (PV) business scheme in April. Electricity from a solar photovoltaic (PV) plant built by NTT Anode Energy Corp. will be supplied via its electricity retail subsidiary to some stores of the Seven & i group.

This has been described to be the first offsite corporate power purchase agreement (PPA) in Japan. An offsite corporate PPA is a long-term contract where a power generator delivers electricity from a remote renewable energy power plant to the offtaker through the grid. This model does not use the feed-in tariff (FIT) scheme that requires power utilities to purchase electricity from renewable energy at a price fixed by the government over a pre-set period of time.

To date, corporate PPAs have mainly been realized onsite, where the power generator directly supplies the consumer with electricity generated by a facility built on the roof or idle land located on the property of the consumer. Offsite corporate PPAs are currently permitted only within corporate groups. At a meeting of the Subcommittee on Mass Introduction of Renewable Energy and Next-Generation Electricity Networks on March 22, the Ministry of Economy, Trade and Industry implied the possibility of interpreting the Electricity Business Act in a way that would allow offsite corporate PPAs between companies of different corporate groups. Offsite corporate PPAs would facilitate the procurement of 100% renewable electricity.

Another emerging trend is "solar sharing," or agrivoltaic systems, which allow the dual use of land for agriculture and solar power generation. This scheme contributes to the deployment of renewable energy and local consumption of locally produced energy. According to the Ministry of Agriculture, Forestry and Fisheries, in Japan, 1,992 cases (covering 560 hectares) of cropland conversion have been permitted for the purpose of installing solar sharing facilities as of FY2018 in Japan. Various crops, including vegetables, houseplants, fruits, rice and wheat, are produced below elevated solar PV panels.

In France, Germany, Italy and other countries, utility-scale solar sharing facilities are being installed in greenhouses, vineyards, olive orchards and the like. There is ongoing research on optimal solar array tilt angles and spacing with regard to insolation levels. Movable solar panel systems are also being explored. In an auction for innovative solar PV technologies implemented by the French Energy Regulatory Commission in January this year, agrivoltaic projects accounted for 31 (with total capacity of 80MW) of 47 successful bids (146.2MW). In February, Enel Green Power, a subsidiary of Italian energy giant Enel, launched a series of agrivoltaic pilot projects to retrofit nine existing solar PV arrays in Spain, Italy and Greece for integration with agriculture.

Solar PV technologies embrace the potential for use in a diversity of contexts, not limited to agriculture. In December 2020, the New Energy and Industrial Technology Development Organization (NEDO) released "NEDO PV Challenges 2020" as a technology development guideline, identifying six areas for further solar PV technology development: (1) building facades; (2) roofs with load limits; (3) vehicles (vehicle-integrated photovoltaics); (4) stand-alone houses; (5) water surfaces (floating solar PV); and (6) agricultural lands.

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Technological advancements in next-generation solar cells and future challenges

Next-generation solar cell technologies hold promise for emerging solar PV applications (see Table 1). Solar cells can be categorized into three types: silicon, compound and organic semiconductor solar cells. At present, crystalline silicon cells account for around 90% of the solar cell market.

Compound semiconductor solar cell technologies include existing technologies such as CIS (copper/indium/selenium) and CdTe (cadmium telluride) photovoltaics. Promising next-generation PV technologies using gallium arsenide (GaAs) have potential for innovative applications. For instance, Sharp Corporation has realized the world's highest PV conversion efficiency of 30-32% for GaAs cells, which were originally developed mainly for use in satellites. Having developed a 0.03-millimeter GaAs solar battery cell for electric vehicles, Sharp launched public road trials for vehicles equipped with these solar batteries in partnership with automakers in 2019.

Dye-sensitized solar cells (DSSCs) belong to a group of PV technologies that uses organic materials. They can stably generate electricity even at low light levels, and thus have been adopted as independent power sources for telecommunication devices and sensors. Its applications are expected to increase with the spread of Internet of Things technologies. Conventional liquid electrolytes based DSSCs embraced safety and durability issues associated with the leakage of electrolytes and corrosion. However, last year, Ricoh Company launched the world's first solid-state dye-sensitized solar cell modules, which have been applied for commercial use in wireless mouses.

Organic thin-film PV (OPV) cells are promising next-generation solutions that feature low-cost manufacturing and Earth-abundance. These cells can be fabricated by printing raw materials onto thin films. Colorful and semitransparent OPVs are becoming increasing used for building-integrated photovoltaics (BIPV) applications overseas. Lightweight and flexible, their low PV conversion efficiency of less than 20% remains a bottleneck.

Perovskite solar cells (PSC), a type of organic-inorganic hybrid solar cell technology, are gaining increased attention as a breakthrough alternative to silicon solar cells. PSCs were invented in Japan in 2009. PSCs can be fabricated by coating the substrate with a perovskite solution, thus resulting in low production costs. Film substrates can be used to fabricate lightweight and flexible PSCs. Printed PSCs promise to be used in various applications, such as glass and building facades.

According to the U.S. National Renewable Energy Laboratory (NREL), the PV conversion efficiency for PSCs have reached around 25%, which is comparable to that of mono-crystalline silicon solar cells. The use of lead, which is toxic, in PSCs remains an issue to be overcome; and therefore, other potential materials are being explored. On March 25, the U.S. Biden administration announced an ambitious goal of cutting solar energy technology costs by 60% by 2030 to accelerate the deployment of PV technologies, earmarking a quarter of the $128 million in total funding for PSC research and development.

As progress is made in large-scale PV deployment, a massive amount of waste PV modules will be decommissioned. NEDO estimates that in Japan, waste PV modules would peak at 17 to 27 tons per year from around 2035 through 2037. Given the multi-layered structure of PV modules, which are made of cells, sealants and glass for higher durability in long-term outdoor use, we are also faced with the challenge of developing recycling technologies to cost-efficiently separate the components.

Table 1 Cutting-edge next-generation solar cell technologies

Technology	Characteristics	PV conversion efficiency (%)
Gallium arsenide (GaAs) solar cells	High. PV conversion efficiency. High expectations for the application of GaAs cells on vehicles	30-32
Dye-sensitized solar cells	Stable power generation at low light levels indoors. Used in stand-alone power sources for telecommunication devices and sensors.	13
Organic thin-film solar cells	Printable, low-cost, lightweight and flexible. Can be fabricated in various colors. Low PV conversion efficiency needs improvement. Often used as building-integrated photovoltaic cells (BIPV).	18
Perovskite solar cells	Printable, low-cost, lightweight and flexible. Can be fabricated in various colors Use of lead remains an unresolved issue. Promising application in glass and buildings.	25

Source: Prepared by the author from NREL studies, Sharp website, etc.

Series "Ushering in a new era of carbon neutrality" (3)
Challenges for Promoting Offshore Wind Power Generation◆

Akiko Sasakawa*

Expectations for technological innovations

Expectations for offshore wind power generation are rising due to the decarbonization trends. Under the policy of reaching carbon neutrality by 2050, the Japanese government's Green Growth Strategy has set out a goal of increasing offshore wind power generation capacity to 10 GW by 2030 and 30-45 GW by 2040. Offshore wind capacity expansion is the key to developing renewable energy into a major electricity source.

Wind power generation, in which windmill turbines convert wind energy into electricity, features a relatively high efficiency among renewable energy power generation means. Unlike solar photovoltaic plants, wind power plants can generate electricity day and night so long as the wind blows. Wind power capacity expansion can hold down unit power generation costs. Thus, the wind power is viewed as an economically efficient power source.

Japan has expanded mainly onshore wind capacity since the 2000s. However, due to the limited availability of suitable onshore sites for wind power generation and time-consuming procedures for assessing wind power generation projects' impact on the environment, wind capacity's share of total power generation in Japan was limited to 0.7% in FY2019.

Under this circumstance, offshore wind power generation is attracting attention. Offshore wind farms are less vulnerable to location constraints than onshore facilities and can get greater wind pressure more stably.

Japan as an island nation is viewed to have high potential for offshore wind power generation. According to the Japan Wind Power Association, the potential capacity for bottom-mounted offshore wind farms (with platforms supported by columns fixed to the seabed) in Japan is estimated at 128 GW. Potential capacity for floating wind farms (with floating platforms anchored to the seabed with cables) for deep waters with depths between 100 and 300 meters is estimated at 424 GW, more than triple the potential capacity for bottom-mounted farms (see Table 1).

The United Kingdom as an island nation forerunning Japan

Europe has driven global offshore wind power generation growth since Denmark built the world's first commercial offshore wind power plant in 2002. According to the Global Wind Energy Council, Europe accounted for more than 60% of global offshore wind capacity totaling 35.3 GW in 2020. Of 6.1 GW in new offshore wind capacity installed in 2020, China accounted for about a half, increasing its presence in the global market. However, Europe still captured 49% of the new capacity.

Among European countries, the United Kingdom attracts attention with the world's largest offshore wind capacity covering about 30% of the global total. The island nation similar to Japan has promoted offshore wind power generation since the second half of the 1990s. In 2000, it launched the allocation of offshore wind contracts within U.K. sea areas. In a bid to promote renewable energy power generation, the U.K. government introduced the Renewable Obligation System in 2002, requiring electricity retailers to procure a certain percentage of electricity from renewable energy including offshore wind. In addition, the government provided subsidies covering 10% of offshore wind projects. Since 2009, it has implemented an incentive measure for offshore wind projects under the Renewable Obligation System.

Backed by such policy support, U.K. offshore power generation has remarkably grown while achieving cost cuts and technological advancement. From only 4 MW in 2002 when the Renewable Obligation System was introduced, U.K. offshore wind capacity increased substantially to 1.3 GW in 2010 and 10.2 GW in 2020. As the leading offshore wind power generator, the U.K. government has set a goal of boosting offshore wind capacity to 40 GW accounting for about 40% of

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its total electricity supply by 2030.

Challenges and prospects for Japan

Both the United Kingdom and Japan are island nations having long coastlines and great potential capacity for offshore wind power generation. However, Japan lacks experience with offshore wind power generation and must develop a business environment to promote offshore wind capacity expansion.

In this respect, Japan introduced a fixed price for purchasing electricity from offshore wind capacity under the Feed-in-Tariff system in 2014 and effectuated the revised Ports and Harbors Act in 2016 to promote offshore wind power generation at port and harbor areas. In 2019, the Act on Promoting the Utilization of Sea Areas for the Development of Marine Renewable Energy Power Generation Facilities was put into force. The act calls for designating "offshore power generation promotion sites" where wind farms would be adequately connected to grid networks without affecting fishing and shipping operations among areas with great potential for offshore wind power generation. Wind power generation project operators would be allowed to occupy such designated sites for up to 30 years. The act is thus designed to reduce business risks for promoting offshore wind power generation.

Japan has fewer shoaling coasts than the United Kingdom. Offshore wind farm in deep sea areas would cost more for installation, operational management, and maintenance. To cut such costs, larger-size windmills would have to be adopted to increase power generation capacity. Large work ships and port and harbor facilities for shipping windmill supporters would be indispensable for constructing such large offshore wind power generation facilities.

In addition to the cost and infrastructure challenges, how to develop competitive supply chains is also a key challenge. Given that Japan has no windmill production facilities and must depend on imports from abroad, the Green Growth Strategy has set out a goal of increasing the local content of the entire life cycle for offshore wind power facilities to 60% by 2040.

The offshore wind power generation industry is a broad-based sector rivaling the automobile industry as one wind turbine consists of 10,000 to 20,000 parts. The promotion of the offshore wind power generation industry is expected to have great spillover effects for related industries, contributing to creating new jobs. An increase in the local content of offshore wind facilities is projected to help cut costs for imports from Europe and China and for transportation of large components.

Taiwan, South Korea, and other Asian economies are expected to make progress in expanding offshore wind capacity. Japan needs to develop its internationally competitive offshore wind power generation industry by raising the local content of relevant facilities, serving as an Asian hub to promote relevant component exports, and leading the formulation of regional supply chains.

Table 1 Comparison of bottom-mounted and floating offshore wind farms

	Bottom-mounted	Floating
Characteristics	A wind power generator is fixed on a platform supported with columns fixed to the seabed in waters with depths of up to 50 meters.	A floating platform is anchored to the seabed with cables in waters with depths of more than 50 meters.
Representative platform types	Platforms have been developed to meet seabed, depth and other natural conditions. Representative types include (1) the monopile type, (2) the jacket type and (3) the gravity type.	Floating platforms have been developed to meet marine and wave conditions. Representative types include (1) the pontoon type, (2) the semi-submersible type and (3) the spar type.
Potential capacity in Japan	128 GW	424 GW

Note: Potential capacity in Japan has been estimated by the Japan Wind Power Association. ("Seeking to develop offshore wind into a major power source" July 17, 2020)

Sources: Compiled by the author from "A Guidebook for Bottom-Mounted Offshore Wind Farms" and "A Guidebook for Floating Offshore Wind Farm Technology" by the New Energy and Industrial Technology Development Organization (NEDO)

Series "Ushering in a New Era of Carbon Neutrality" (4)

Ocean Energy Technology Development - Will Japan catch up with Europe? -◆

Tomoko Matsumoto*

Overview of ocean energy and its challenging issues

Ocean energy plays an important part in the "blue economy" which aims to help economic growth and improve social quality as well as to ensure the conservation of marine resources. While ocean energy technology is currently in the phases of research, development and demonstration, it is expected to contribute to decarbonization in the long-term. There are different ocean energy technologies in power generation to utilize the following resources: (i) tidal stream (the tidal currents caused by the ebb and flow of the ocean's tides); (ii) tidal barrage (the tidal range which is the actual height difference between high and low tide); (iii) ocean currents (large circulations of the ocean currents initiated by an interplay of wind, temperature and salinity); (iv) wave energy; (v) ocean thermal gradient (the temperature difference between the warm ocean surface and the cold deep-sea water).

Tidal stream shows a periodic movement caused by the interaction of gravitational forces of the sun and the moon, which indicates that it will be a predictable and stable energy source. Tidal stream technology uses the tidal currents to generate power mainly through an underwater turbine and is close to commercialization.

Similar to hydropower, tidal barrage that makes use of the tidal range is a technology that stores water in an enclosed tidal basin with high tide and releases it in low tide to generate power through a turbine. This technology has been in operation for years. Tidal barrage makes up 98% of the global installed capacity of 535MW across ocean energy technologies. However, new developments have been limited due to the difficulty to find suitable locations where it is possible to construct a dam and the tidal range is more than five meters.

Ocean currents can be a stable and large-scale energy source as the currents are less fluctuated in velocity and direction. Similar technologies that are deployed for tidal streams could be applied to ocean currents. Still, it is challenging to develop ocean current power generation systems because high volumes of ocean currents are generally found several kilometers away from shore in much deeper waters.

Harnessing energy contained in ocean waves, wave energy has more resource potential than tidal streams with short-term predictability. While wave energy technology is yet to be commercialized, various technologies have been pursued.

Ocean thermal energy conversion (OTEC) requires a temperature difference of about 20 degrees. OTEC is advantageous in providing stable power around the clock, and is hence expected to work as a baseload power source. In addition, OTEC can be coupled with other technologies such as seawater reverse osmosis (SWRO) and seawater air conditioning (SWAC).

Although research and development on ocean energy have been conducted for a long time, several barriers have hindered large-scale deployment of ocean energy technologies. First of all, further technology development is necessary to improve power generation efficiency and take other critical aspects into account, e.g., improving durability against the harsh offshore environment and reducing impacts on marine ecology. Infrastructure development and operation and maintenance also necessitate complicated work under the sea. Moreover, it is difficult for ocean energy projects to receive financing due to the risks inherent in immature technologies. Investors may find uncertainty in ocean energy technologies because most of them are at the early stage of development and convergence in technology has not been observed. Last but not least, inadequate regulatory framework and lack of support from governments are raised as concerns.

On the other hand, ocean energy is expected to bring about substantial benefits. For example, as ocean energy is a predictable and stable power source, it can be combined with variable renewable energy such as solar and wind energy to

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develop an efficient hybrid power generation system. Decarbonization could also be accelerated if ocean energy were to supply electricity for the blue economy like aquaculture. In addition, it is possible that ocean energy would replace with petroleum products on remote islands such as the Small Island Developing States (SIDS) which are dependent on diesel currently if it became cost-competitive.

Ocean energy technology development in the major countries

Europe has been at the forefront of technology development in ocean energy.

Among others, Scotland has provided its policy support for ocean energy since the 2000s, and promoted technology development mainly in the European Marine Energy Centre which is a demonstration and test site in the Orkney Islands. The MeyGen project is an operating tidal power generation facility connected to the power grid and is planned to expand the capacity from 6MW at present.

The European Union (EU) puts a priority on clean energy including ocean energy as a technology that contributes to economic growth. In the EU Strategy on Offshore Renewable Energy published in November 2020, the target of ocean energy development is set at least 1GW by 2030 and 40GW by 2050 although offshore wind energy is the majority of offshore renewables. Ocean energy will be supported under Horizon Europe, the key funding program for research and innovation in the timeframe 2021-2027.

Ocean energy technology has received attention in North America as well.

The United States has actively pursued technology development generally through grant programs for research and development and several national marine renewable energy centers. In February 2021, the National Renewable Energy Laboratory reported that the total marine energy technical resource in 50 states would be 2,300TWh per year, which is equivalent to about 57% of the electricity generated in the United States in 2019.

Canada focuses on tidal energy development. The province of Nova Scotia has implemented a feed-in tariff (FIT) scheme for tidal energy even in the testing phase. In November 2020, the Canadian government announced funding of CAD 28.5 million to support the installation of the 9MW floating tidal energy system.

In the Asian region, China shows rapid progress in ocean energy development. China's filed patents related to ocean energy have increased steadily since 2005 and outnumbered other countries in recent years. In 2020, China added 500kW power generation capacity for tidal and wave energy, respectively.

Demonstration projects in Japan – policy support expected for commercialization

Japan's 5th Strategic Energy Plan published in July 2018 addressed the promotion of research and development to assist in reducing cost and improving efficiency for ocean energy along with other renewable energies. Then, demonstration sites were selected in eight sea areas of six prefectures as one of the measures to encourage ocean energy technology development with a view to achieving commercialization Table 1.

In July 2019, IHI, a comprehensive heavy-industry manufacturer, and the New Energy and Industrial Technology Development Organization announced to conduct a demonstration test of the 100kW class subsea floating type ocean current power generation system off the coast of Kuchinoshima Island (Toshima Village, Kagoshima Prefecture) for more than a year. As a recent demonstration project, in January 2021, Kyuden Mirai Energy installed the 500kW tidal power generation system at about 40 meters depth off the Naruseto Strait of Goto City (Nagasaki Prefecture).

However, ocean energy is not included among the new energy sources eligible for policy support under the Act on the Promotion of New Energy Usage. There are many challenges in promoting the deployment of ocean energy. Japan needs to deal with not only technological and economic obstacles but also issues related to fishery rights and regulatory constraints.

Surrounded by the sea, Japan has no reason not to harness ocean energy. It is about time to strengthen the policy measures to support ocean energy development.

Table 1 Offshore renewable energy demonstration sites in Japan

	Sea areas	Energy type
Iwate Prefecture	Off the coast of Kamaishi City	Wave energy, floating offshore wind power
Niigata Prefecture	Off the coast of Awashimaura Village	Ocean currents (tidal stream), wave energy, floating offshore wind power
Saga Prefecture	Off the coast of Kabeshima Island, Karatsu City	Tidal stream, floating offshore wind power
Nagasaki Prefecture	Off the coast of Hisakajima Island, Goto City	Tidal stream
	Off the coast of Kabashima Island, Goto City	Floating offshore wind power
	Off the coasts of Enoshima and Hirashima Islands, Saikai City	Tidal stream
Kagoshima Prefecture	Around Kuchinoshima and Nakanoshima Islands, Toshima Village	Ocean currents
Okinawa Prefecture	Kumejima Town	Ocean thermal energy conversion

Source: Cabinet Office, "The Selection of Offshore Renewable Energy Demonstration Sites," June 29, 2017.

Series “Ushering in a New Era of Carbon Neutrality” (5)

Utilization of Biomass, and Expectations Toward the Realization of a Carbon Cycle◆

Yu Nagatomi*

The need for the effective utilization of carbon resources

Reducing greenhouse gas emissions is an important measure in our goal to achieve carbon neutrality by 2050. However, there are sectors and applications for which it is not easy to reduce greenhouse gas emissions to zero.

Firstly, in the materials industry, resources whose constituent elements include carbon (carbon resources), such as petroleum and coal, are used in the production processes, and there are cases where it is difficult to reduce the volume of greenhouse gas generated. The iron and steel industry generates greenhouse gases during the reduction process, which uses coke as a reducing agent. While technological development is ongoing for an alternative reduction technology that uses hydrogen instead of coke, it is difficult to achieve drastic reductions of greenhouse gases in the current situation. Materials that are made from petroleum, such as plastic, are composed of the elements—carbon, hydrogen, and oxygen—and are not easy to decarbonize. In the transportation sector, initiatives that combine the decarbonization of power supply with the promotion of electrification through electric vehicles are highly anticipated. However, it will probably take time to achieve the electrification of means of transportation that require high output and can travel long distances, such as large freight vehicles, ships, and planes.

In these sectors, carbon resources such as fossil fuels and biofuels continue to play a key role. The carbon neutrality that Japan aims to achieve is to strike a balance between the volume of emissions and absorption. In short, in cases that require high-density and high-output energy, and where it is difficult to replace the energy source with other sources such as electricity or hydrogen, there is a need for initiatives that can maintain carbon neutrality by utilizing carbon resources appropriately, while at the same time capturing their greenhouse gas emissions appropriately.

Ongoing development of biofuels in Japan and abroad

Biofuels are expected to fulfill the role of a sustainable carbon resource for achieving this goal. Biomass, which is the raw material for biofuels, refers to animal and plant resources as well as waste matter originating from such resources. It covers a wide range of matter, including agricultural products, timber and seaweed, as well as industrial waste, general urban waste, and sewage sludge.

The characteristic of biomass is that the use of biomass energy in itself makes it possible to achieve carbon neutrality. For example, while burning wood releases carbon dioxide, that same wood absorbs carbon dioxide through photosynthesis during the process of its growth. For this reason, production and consumption are balanced, and it can be regarded as a state of carbon neutrality. However, as there are also cases in which general urban waste contains fossil fuel-derived waste matter, carbon flow needs to be managed appropriately through the disposal of the gases that are emitted during the combustion of such waste. In other words, in utilizing biomass, it is important to develop a mechanism that enables the circulation of carbon based on striking a balance between production and consumption.

Much of the biofuels that are currently being produced use sugar cane, corn, and palm oil as the raw materials, raising concerns of issues related to competition with food supplies and environmental destruction through deforestation for the development of agricultural land. Technological development is ongoing for new biofuels that can overcome such issues.

A representative example of technological development in Japan is the production of biomass plastic, biodiesel, and bio-jet fuel by Euglena Co., Ltd. using oil extracted from Euglena, which is a micro-algae. J-POWER is engaged in the

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production of bio-jet fuels using species of micro-algae cultivated in sea water. The Green Earth Institute, in cooperation with Japan Airlines, announced that it has completed the development of a bio-jet fuel with used clothing as the raw material. In February 2021, commercial flights were flown using this fuel. Furthermore, the Ministry of the Environment is reviewing the use of biomass in addition to biofuels. For example, it has unveiled a concept car that gives consideration to resource recycling, and which is more lightweight through the use of biomass-derived materials on the car body.

Overseas, Total S.A., a major player in the energy sector in France, is manufacturing bio-jet fuels by using waste cooking oil as the raw material. The U.S. company LanzaTech, which Mitsui & Co. has invested in, is producing fuels and chemical products, such as ethanol and butadiene, from gases emitted from iron and steel manufacturing plants. All Nippon Airways has announced that LanzaTech will be providing it with bio-jet fuel from 2021. On top of these, efforts are also ongoing to develop technology that contributes to carbon circulation through the production of biofuels with the waste matter as the raw material (Table 1).

Importance of utilizing biomass and establishing a carbon cycle

The consumers of fuels and chemical products are also looking forward to the emergence of carbon neutral resources, including biofuels. The International Civil Aviation Organization (ICAO) adopted “CNG2020” at its Assembly in 2010, which aims to prevent the increase of greenhouse gas (carbon dioxide) emissions from 2020. As one of the means for achieving this goal, it prescribes the utilization of sustainable aviation fuels (SAF) produced from sustainable supply sources, such as biomass. Furthermore, at a press conference held on April 22, Akio Toyoda, President of the Japan Automobile Manufacturers Association, pointed out that efforts will be made to reduce carbon dioxide emissions from all motor vehicles, including used vehicles, by combining the complex technology of high-efficiency engines and motors, with carbon neutral fuels such as biofuels.

In the realization of a decarbonized society, it is important to steadily reduce greenhouse gas emissions, and at the same time, combine that with the appropriate use and capture carbon resources in areas where it is difficult to switch to decarbonized energy sources, as well as technologies that enhance the effectiveness of resources. The utilization of biomass and establishment of a carbon cycle are climate change countermeasures, and at the same time, can be described as initiatives that support a sustainable society through the shift away from fossil fuels.

Table 1 Biofuel production technologies announced in recent years

Raw material	Product	Corporation	Overview
Algae	Jet fuels	Euglena Co., Ltd. (Japan)	Production of bio-jet fuel from the micro-algae, Euglena
	Diesel		Production of next-generation biodiesel from the micro-algae, Euglena
	Bioplastic		Promotion of technological development for biomass plastic
Algae	Jet fuels	J-POWER (Japan)	Production of bio-jet fuel from oceanic micro-algae
Clothing	Jet fuels	Green Earth Institute (Japan)	Production of bio-jet fuel from used clothes collected domestically
Waste cooking oil	Jet fuels	Total S.A. (France)	Production of sustainable aviation fuel (SAF) from waste cooking oil
Alcohol	Jet fuels	LanzaJet, Inc. (U.S.)	Production of jet fuel from alcohol
Waste matter	Ethanol	LanzaTech, Inc. (U.S.)	Production of ethanol from gases emitted in the fermentation process by microorganisms
Waste matter	Diesel, etc.	bio-bean Limited (UK)	Production of biodiesel, using waste coffee grounds as advanced biofuel and biomass pellets
Waste matter	Jet fuels	SkyNRG (Netherlands)	Production of jet fuel from waste oil
Waste matter	Methanol, ethanol	Enerkem (Canada)	Production of renewable methanol and ethanol from urban solid waste

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