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Contents

Analysis of Future Scenarios for ASEAN Mobility

Kei Shimogori *, Ichiro Kutani **

1. Introduction

Against the backdrop of accelerating climate change measures in recent years, there has been progress in the decarbonization of power sources and the electrification of powertrains. This trend is not limited to developed countries. In developing countries, governments and the automotive industry are making efforts to popularize battery electric vehicles (BEVs), including two-wheelers and three-wheelers. While decarbonization efforts have been underway in the transportation sector, Russia's invasion into Ukraine in February 2022 has heightened interest in economic security, including stable energy supply, in both developed and developing countries. In particular, what economic and industrial policies each country will adopt in light of the Russian invasion into Ukraine is attracting a great deal of attention as the current industrial structure, including the automotive industry, is supported by global supply chains.

In light of this situation, we have held a workshop[1] to examine the pictures of the future energy supply structure and automotive industry using a scenario planning approach[2]. The following overviews of the scenarios are compiled based on the workshop. Although the workshop developed global and regional scenarios, this paper outlines regional scenarios for the Association of Southeast Asian Nations (ASEAN). It should be noted that ASEAN in this report represents Indonesia and Thailand.

2. Approach to scenario formulation

- The scenarios cover the period from 2022 to 2050. As a result of discussions at the workshop, we selected two driving forces – whether climate change measures will be enhanced (in each country) by 2030 and whether each country will strengthen its policies that emphasize economic security by 2025 to 2030 – in depicting scenarios. Using these two driving forces, we developed a quadrant for depicting scenarios.

- The world population is assumed to increase in all scenarios. Based on the United Nations' World Population Prospects for 2022, Central and South Asia and Sub-Saharan Africa will account for most of the population growth through 2050. In developed countries, the population will age further.

- Against the backdrop of population and economic growth, the frequency and amount of movement of people and goods will increase. The two selected driving forces basically have negative effects on the movement of people and goods. However, the domestic cargo movement frequency alone will increase due to e-commerce growth amid smart city development. The frequency and amount of movement of people and goods (ton-kilometers and person-kilometers) are assumed to increase in Scenario 3, remain unchanged from the present level in Scenarios 2 and 4, and decrease in Scenario 1.

- As the world moving toward decarbonization is politically correct, Europe and the U.S. Democratic Party, which have traditionally led climate change measures, are expected to accelerate the allocation of resources to green investment and climate change measures while remaining interdependent under a plan to focus policy (government) and finance (investors) on decarbonization. Specifically, a scenario in which climate change measures are enhanced aims to achieve the 1.5°C target, while a scenario in which these measures stall will

* Senior Researcher, Global Energy Group 1, Energy Security Unit, IEEJ
** Senior Research Director, Manager, Global Energy Group 1, Director, Energy Security Unit, IEEJ

[1] The researchers participating in the workshop (posts at the time of the workshop) are as follows: Ken Koyama (Senior Managing Director and Chief Economist), Ichiro Kutani (Senior Research Director, Strategy Research Unit), Yoshikazu Kobayashi (Executive Analyst, Fossil Energy and International Cooperation Unit), Takahiko Tagami (Executive Analyst, Global Environment Unit), Yoshiaki Shibata (Executive Analyst, Electric Power Industry & New and Renewable Energy Unit), Shigeru Suehiro (Executive Economist, Energy Data and Modelling Center), and Kei Shimogori (Senior Researcher, Strategy Research Unit).

[2] Scenario planning is an approach for examining images of different futures that are highly uncertain. When considering the future picture of a specific problem area, various factors influence the future picture. The approach extracts the most important and highly uncertain factors among them and logically depicts completely different future world pictures according to different developments of the factors. In this sense, the approach does not represent a simple extension of the current situation or a future prediction based on trend analysis, but different future scenarios that are potentially and logically consistent, with the aim of contributing to strategic decision-making on responses and policies for different scenarios.

continue low-carbonization initiatives, though failing to achieve the 2℃ target. In addition, the electrification of energy demand will progress in all scenarios.

- The degree of emphasis placed on economic security in each country will influence progress in the division of the world into trading blocs and in the fragmentation of the global trading system. The key point here is the U.S. move (whether the United States will manage its relationship with China or intensify confrontation with China in a manner to accelerate its emphasis on economic security). The division of the world into trading blocs here refers to a situation where free trade will be maintained in each bloc, with production and supply completed within each bloc as much as possible. The high cost incurred as a result of the division of the world into blocs will be accepted as a cost for security. In a world in which geopolitical confrontation will be managed or eased, the global free trade system and the global division of labor will be promoted to develop optimum supply chains. In such a world, however, international competition will become more intense, widening gaps between industries and between companies.

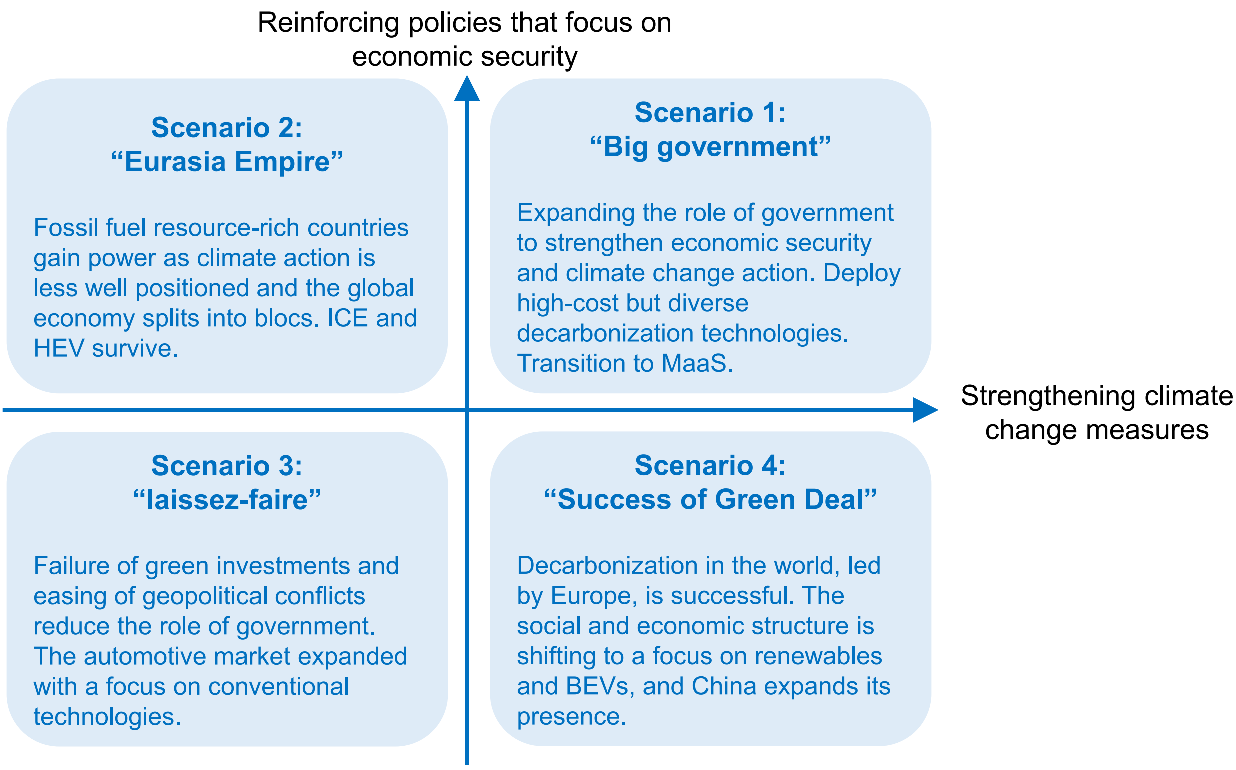

Figure 1: Scenario driving forces and scenario outline

Key Points of the Scenario Elements for the ASEAN Automotive Industry

- Affordability is highly important for considering the energy supply structure and the automotive industry of ASEAN. In each of the four scenarios outlined below, governments and citizens will require the most economical ways to ensure energy security and address climate change.
- The technologies at the heart of mobility in the ASEAN region differ by scenario. In Scenarios 1 and 4, in which climate change measures are enhanced, the diffusion of BEV cars makes common progress, though with differences seen in technological options for powertrains. In Scenario 1, in which various decarbonization technologies are used, biofuel consumption for large vehicles (buses and trucks) expands faster. Scenarios 2 and 3, in which climate change measures are weak, both see some progress in the BEV diffusion and the overwhelming presence of internal combustion engine (ICE) vehicles. Between the scenarios for the world's split into blocs and for the maintenance of the global free trading system, however, gaps are seen in the size of accessible automotive markets for ASEAN and in the ASEAN automotive industry size, despite the industry seeking to expand exports.

3. Scenario 1 overview: Growing economic security concerns and accelerating climate change measures

3.1. Society & economy

- As countries focus on economic security in line with the U.S.-China confrontation, the global economy will split into blocs. This framework will deviate from a world pursuing economic efficiency and minimized costs, leading growth markets to be locked up and thereby making strategically important goods costly. Industries and companies will belong to blocs, reducing their accessible market size. As a result, annual global economic growth will slow down to 1.5%. Since economic security and climate change measures cannot be achieved by market mechanisms alone, government market intervention will be the strongest among the four scenarios. Government intervention will exert great influence on income redistribution, contributing to narrowing income gaps.
- As the world's split into blocs makes progress, ASEAN will pursue neutral diplomacy giving priority to both the United States and China. U.S.-China competition to support ASEAN will encourage ASEAN's economic growth and transformation.
- From the perspective of climate action, each bloc will individually develop the prioritization of green investment. Under such circumstances, the world will achieve the 1.5°C target. Although there is a strong desire for climate change measures, the momentum to establish global standards will be lost due to the world's split into social and economic blocs.
- As blocs compete to win over emerging countries, financial aid to emerging and developing countries for decarbonization will be activated. In Scenario 1, all regions and countries will make efforts to reduce GHG emissions, even though the momentum to establish global standards will be lost. However, they will promote such efforts in various ways. Japan, the United States, and Europe will be more aggressive in reducing GHG emissions, while China and ASEAN cut GHG emissions as a result of their energy transition.

3.2. Mobility

- As for the assumed ASEAN urban structure, the government-led development of public transportation networks (railways, subways, and buses) will be promoted, with a focus on walking and bicycles, if the construction of new cities progresses with technical and financial support from developed countries and China. To meet demand for traffic between cities and within cities and their suburbs, urban air mobility (UAM) systems[3] will also spread in areas lacking public transportation networks, with support from Europe and China. Autonomous driving will be easily introduced for the main roads of new cities for the transportation of both goods and people, but the scopes of the introduction will vary depending on the economic powers of cities.
- As for automobiles, BEVs will be the main choice in combination with the supply of zero-emission electricity amid the enhancement of climate change measures, with technological options limited. In ASEAN as well as other regions, the transition to BEV cars will progress from the perspective of regional industrial development. On the other hand, large vehicles, such as trucks and buses, will mainly use biofuels. Competition between food and biofuels, a matter of concern regarding biofuels, will not arise in countries where plants for food are produced separately from those for biofuels.
- In Scenario 1, energy demand will remain flat due to sluggish economic growth and strong climate action. As a result of the lowest oil demand among the four scenarios, oil prices will be weak (at $64 per barrel in 2020 prices). As decarbonization efforts accelerate, electricity prices will increase by an average of 50%, but government intervention will keep them low for the industry sector. Under these circumstances, the status of BEVs will be established in the ASEAN region, benefitting from tax incentives. Gasoline will be subjected to high taxes from the perspective of climate change measures, despite sluggish crude oil prices. Biofuels will be used to the fullest, but supply (capacity) will be limited. So, natural gas vehicles may be reviewed (promoted) in ASEAN.
- As for the energy system, ASEAN will first pursue thorough energy conservation, accelerating natural gas use and energy efficiency

[3] Urban air mobility may be introduced in the United States, China, and ASEAN, where public transportation is not in place (Europe is focusing on standardization). Since UAM is premised on electrification, it will be introduced in Scenarios 1 and 4, where climate change measures will be strengthened. Scenario 1 is more likely to involve government intervention, so the deployment of UAM will also be more advanced. In addition, it is assumed that short-distance: automobile (autonomous driving), medium-distance (about 100 km): UAM, long-distance: railway / aircraft. UAM is expected to travel about 100 km due to current capability, but development is also underway for intercity travel of 300 km.

improvement. Gas and ammonia co-firing as transitional technology will progress. From the viewpoint of energy security, the distribution of hydrogen and ammonia in the region will be pursued. (Since energy affordability is highly important for the region, profit sharing through the production and distribution of blue and green hydrogen in the region will be sought.) ASEAN will seek to achieve gradual decarbonization by co-firing coal with ammonia and using carbon capture and storage (CCS) technology for gas. With support from Europe and the United States, renewable energy (mainly solar photovoltaics) will expand while depending on domestic or regional technologies.

4. Scenario 2 overview: Economic security will be enhanced while climate action stalls

4.1. Society & economy

- As countries focus on economic security, the global economy will split into blocs. This framework will deviate from a world pursuing economic efficiency and minimized costs, leading growth markets to be locked up and thereby making strategically important goods costly. As the global market size shrinks, markets that companies belonging to a certain bloc can access will be limited. As a result, annual global economic growth will slow down to 1.5%. In this scenario in which the world will be divided into blocs, ties between China and Russia will be strengthened in terms of security and energy (fossil fuel) supply over the long term (structurally).
- In ASEAN, structural economic and social transformation will fail to progress, leaving current challenges to remain (or worsen). ASEAN will tend to follow the countries that will supply cheap energy sources (as it is basically difficult for ASEAN to achieve self-sufficiency even if regional energy development is promoted). Instead of actively participating in one of the blocs, however, ASEAN will choose to deal with any bloc in a manner to benefit most from it.
- Regarding climate change, low-carbonization will progress slowly, with the world failing to achieve the 2°C target. As it becomes clear that climate action will not lead to economic growth, emerging economies will strongly oppose the enhancement of climate change measures led by developed countries, making the COP (Conference of Parties to the United Nations Framework Convention on Climate) framework unsustainable. Due to the collapse of the international framework, even funds for adaptation to climate change will fail to circulate sufficiently. Climate change measures in this scenario will be the most inferior among the four scenarios. As bloc leaders seek to win over developing countries, bilateral funding will increase for Southeast Asia, South Asia, and Africa. The position of climate change action as a social value that should be shared by the world will fade away, leaving each country or bloc to choose economically rational energy sources.

4.2. Mobility

- As the global economy's split into blocs limits economic development potential, the current urban structure of ASEAN will remain fixed. In order to improve the economic efficiency of large cities, the development of public transportation networks (railways, subways, and buses) will be pursued. ASEAN will consider the introduction of autonomous driving for the distribution of goods on main roads around new cities that have already been developed.
- The global economy's split into blocs will reduce the global auto market size. As climate change measures weaken, ICE vehicles and hybrid electric vehicles (HEVs) will continue to be used. Against this backdrop, the automotive industry in ASEAN will promote regional sales and exports focusing on ICE vehicles under government industrial policy.
- In Scenario 2, energy demand will remain flat due to stagnant economic growth. Oil demand will be maintained mainly in emerging and developing countries under weaker pressure from climate change measures. As the international market is divided, crude oil and other fossil fuels will have multiple prices ($100/bbl for 2050 in 2020 prices). Electricity prices will rise moderately despite cost hikes resulting from greater dependence on fossil fuels, as energy demand is suppressed. In ASEAN, gasoline prices will range from the current level to higher levels, with electricity prices being relatively high. Due to the weakening of climate change measures, the use of biofuels will not progress so much. Biofuel production will depend only on surplus crops. On the other hand, the use of natural gas vehicles will expand.

- ASEAN's energy system will give top priority to promoting energy efficiency. Coal-fired power plants will remain the main power source. Decarbonization measures for these plants will be limited to co-firing ammonia and biofuels with coal. Since energy affordability is emphasized in this region, deployment of renewable energy will be limited to the extent where energy affordability is maintained. The deployment of renewable and nuclear energy for the purpose of improving energy self-sufficiency will fail to progress. As the decarbonization of power sources makes little progress, the electrification of automobiles will fail to progress.

5. Scenario 3 overview: Economic security concerns will wane while climate measures stall

5.1. Society & economy

- The global free trade system will be firmly maintained, and economically optimal supply chains will be developed under the division of labor. Climate measures will be given low priority, with fossil fuels continuing to be used. The current situation in which resource-rich countries and emerging economies are driving economic growth will be maintained. Consumers will have many choices for technologies and goods, with vigorous consumption continuing. The global economy will slow down until around 2030 due to the aftereffects of current inflation and the economic failure of green investment. Later, however, the global economy will return to a solid growth path led by emerging economies due to the restoration of the free trade system and the reduction of constraints related to climate change measures. Economic growth will accelerate to 2.5%.

- ASEAN will establish its position as the world's factory comparable to China. As the political system differs from country to country, however, political control will remain weaker than in China. If a new economic and trade framework that includes ASEAN works, the region's economic power will increase.

- From the perspective of climate change, the world will fail to achieve the 2°C target, though with the temperature rise around 2100 limited to about 2.6°C (in line with the STEPS (Stated Policies Scenario) in the International Energy Agency's World Energy Outlook 2021). Emerging economies will strongly oppose the enhancement of climate change measures led by developed countries, which will fail to lead to economic growth. As climate change progresses, however, mainly emerging economies will become more oriented toward adaptation to climate change. The COP framework will be maintained as geopolitical conflicts are managed or mitigated, but COP discussions will focus on adaptation rather than mitigation.

- In ASEAN, climate change policy will fail to make progress. Increasing climate impacts will lead ASEAN to request more funding from developed countries.

5.2. Mobility

- As population concentration in large cities and depopulation in their neighbors continue globally, ASEAN will see population concentrating in large cities and functional problems (such as sanitation deterioration and rich-poor gaps) arising in the rising number of cities. Some new cities will be developed but fall short of being smart cities (distributed cities optimized by digital technology). Thus, the number of conventional cities will increase.
- Global demand will be high for vehicles, including those used in urban areas. Thanks to weak climate-related restrictions and the demonstration of innovation in a globalized market, the range of automotive technology options will be the widest among the four scenarios, including BEV and ICE vehicles. The wide range of automotive technology options will support the expansion of the automotive market in developing countries. As population concentration in cities continues in ASEAN, vehicle demand will change from two-wheelers to three/four-wheelers. As traffic congestion and air pollution become more serious, efforts will be made to develop and promote public transportation, with political priority given to public transportation rather than private transportation. However, public transportation capacity will remain insufficient. Public transportation in ASEAN will include not only high-volume transportation but also small-scale vehicle sharing. The diffusion of BEV vehicles will progress to combat air pollution and reduce oil imports (for example, in Indonesia). As transportation volume increases, freight and passenger transportation services will make progress and develop into businesses. Under these circumstances, ASEAN will promote the automotive industry's expansion of ICE and other vehicle exports to developing countries under its industrial policy, as China has done.

- In Scenario 3, oil prices will be relatively high (at $88/bbl for 2050 in 2020 prices) due to growing oil demand. Electricity prices will rise due to the remaining dependence on fossil fuels, of which prices will increase. In ASEAN, gasoline prices will stand at the current or higher levels. Electricity prices will also be relatively high. Due to the weakening of climate change measures, the use of biofuels will fail to progress. Biofuel production will depend only on surplus crops. On the other hand, the use of natural gas vehicles will expand.
- In ASEAN's energy system, existing coal-fired power plants will continue to be used. As the use of cheap gas is promoted, LNG demand will increase.

6. Scenario 4 overview: As economic security concerns wane, climate action will accelerate

6.1. Society & economy

- The global free trade system will be firmly maintained, and economically optimal supply chains will be built under the global division of labor. As green investment leads to economic growth, both developed and developing countries will take advantage of clean energy sources to expand their markets and achieve economic growth. Among the four scenarios, global economic growth will be the highest (at 3%).
- As for the balance of power in the world economy, the status of fossil fuel-rich countries will relatively decline, leading Europe, the United States, and China to benefit the most from green growth. Demand for energy will increase in line with global economic growth, but investment in fossil fuels will not progress.
- The world will achieve the 1.5°C target. In global rulemaking on climate change, global standards will be created under the leadership of Europe. Financial contributions and technology transfers will be made to developing countries within a global support framework. The COP framework will continue to function. On the financial front, climate change pressures are also strong, with green investment being prioritized more globally (prioritization will vary from country to country).
- Against this backdrop, ASEAN will aim to replace China as the world's factory. As the emphasis is placed on climate change measures, the selection of partners for technical assistance will grow important, leading ASEAN to increase its economic and policy dependence on foreign countries. In addition, the cost of living will rise due to the higher cost of climate action.

6.2. Mobility

- From the perspective of climate change measures (including decarbonization and efficient energy use), the development of smart cities (distributed cities optimized by digital technology) will make strong progress. Based on the belief that the centralization of cities has a high environmental load, smaller cities will be distributed under the smart city approach. In ASEAN, urban development will stagnate in existing large cities due to delays in environmental measures, while the development of new cities (distributed smart cities) around large cities will make progress. Until 2050, however, ASEAN will pursue large-sized cities.
- New cities in ASEAN will have well-developed roads, making progress in the diffusion of autonomous driving for not only the distribution of goods but also human transportation. Automobiles will be converted into BEVs, with vehicle-sharing services using autonomous driving becoming more widespread. UAM systems based on the standards of the United States, Europe, and China and supporting the construction of new cities will be introduced as an option for medium-distance transportation.
- The global automotive industry will expand BEVs' share of production in conjunction with an increase in zero-emission electricity to fight against climate change. Since the range of BEV technology options is limited, making it difficult to differentiate BEVs, automakers will differentiate themselves in regard to services and contents. Thanks to its production and market sizes, China will become the center of BEV production. Against this backdrop, the automotive industry in ASEAN will promote BEVs in passenger car production for industrial development purposes. In Indonesia and Thailand, biofuels will be used as one fuel option.
- In Scenario 4, a virtuous cycle will be created in which the widespread adoption of renewable energy will lower costs, leading renewable energy to become the center of energy supply. As an early exit of coal-fired power generation is realized in both developed and developing countries, short-term supply-demand imbalances and subsequent fluctuations in fossil fuel prices are likely to occur during

the transition period. As a result of Scenario 4, oil prices will stand at $24/bbl (in 2020 prices) in 2050. Amid decarbonization efforts, electricity prices will increase significantly, posting an average increase of 50%. The hydrogen supply price will be 30 yen per normal cubic meter or less in 2030 and 20 yen/Nm^3 or less in 2050, achieving the targets of the Japanese government. In ASEAN, the status of BEVs in short- and medium-haul travel will be established, leading them to be treated favorably in taxation. Electricity will be subject to higher prices and taxes. As fossil fuel prices fall, gasoline prices will decrease. However, higher taxes will be levied on gasoline from the perspective of climate change measures. Although the use of biofuels will be maximized in the region, absolute consumption will be limited due to supply constraints. As hydrogen supply prices decline significantly, the use of hydrogen in the transportation sector will be promoted.

- In the ASEAN energy system, coal-fired power generation will be forced to retire early and be replaced by renewable energy power generation. Decarbonization pressure will increase on gas-fired power generation, requiring gas and hydrogen co-firing and the installation of CCS systems at gas-fired plants. With support from Europe and the United States, the use of renewable energy, such as solar power, will expand. The use of hydrogen and ammonia with support from Japan will become marginal.

7. Summary

In this paper, we have drawn a picture of the energy supply structure and mobility in 2050, mainly for ASEAN. Even amid population and economic growth, ASEAN will be required to promote decarbonization efforts. Although decarbonization efforts differ by scenario, the electrification of passenger cars will progress in all scenarios. Particularly in a scenario in which the decarbonization of power sources progresses, the electrification of passenger cars may be actively pursued from the perspective of regional industrial promotion.

At the same time, the development of public transportation will play a major role in ASEAN. Although the urban structure differs from scenario to scenario, it is expected that public transportation systems, such as railways, subways, and buses, will be developed to contribute to decarbonization in new small cities and to efficient large-scale transportation and the mitigation of traffic congestion and air pollution in large cities.

As noted above, when the energy supply structure and the automobile industry in ASEAN are considered, affordability (reasonable prices) is important. While some countries in the region have set out carbon neutrality and other ambitious climate targets, the importance of a realistic energy transition is growing further. There are multiple paths to energy transition, indicating that a wide range of technologies will be required in the field of mobility. In particular, the use of biofuels and natural gas is conceivable for large vehicles, which are difficult to electrify. Various technologies will contribute to the decarbonization of the transportation sector in the region.

8. Conclusion

The trend of climate change measures, such as those to achieve carbon neutrality, has been coupled with Russia's invasion of Ukraine, making the global situation and direction regarding energy and mobility more uncertain and unclear. Therefore, we conducted a scenario analysis using two driving forces – whether climate change measures will be enhanced (in each country) by 2030 and whether each country will strengthen its policies that emphasize economic security by 2025 to 2030. The two driving forces allow us to draw different pictures of the future world and regions. As mentioned above, the scenarios indicate that the future of mobility and relevant energy in ASEAN could vary depending on the driving forces.

Given the world, with its high degree of uncertainty, we should pay close attention to which of the scenarios depicted in this paper will be realized and implement a strategy responding to the realized scenario flexibly and without delay.

Energy Mix for Japan's Carbon Neutrality by 2050
: Analysis of Marginal Cost of an Electricity Supply Based on 100% Renewable Energy◆

Takashi Otsuki*,** Hideaki Obane*** Yuji Matsuo**** Soichi Morimoto*****

Abstract

The authors' previous assessment indicated that the marginal electricity cost in 2050 in Japan would be more than doubled in an energy system based on a 100% renewable power supply compared to the cost-optimal system. However, some assumptions may be conservative given recent developments, including the cost of variable renewable energy (VRE) and energy storage technologies, and the availability of dispatchable renewable power generation (such as biomass-fired). Therefore, to test the robustness of the previous assessment, this study conducts a sensitivity analysis with a focus on these factors, using an energy system optimization model with a detailed temporal resolution. Simulation results imply that the high marginal electricity cost in the "100% renewable power system" is partially due to the costs of managing the seasonality of VRE. Low-cost energy storage and dispatchable renewable power plants can curb the marginal electricity cost. However, the results also suggest that the marginal cost in these sensitivity cases remains high compared to the cost-optimal system, still posing economic challenges to the system based on a 100% renewable power supply.

Keywords: Carbon neutrality, Energy system analysis, 100% renewable power, Marginal electricity cost

1. Introduction

Towards the achievement of carbon neutrality by 2050, the ideal form of Japan's energy system should have been actively considered. In May 2021, the Research Institute of Innovative Technology for the Earth (RITE) analyzed the energy mix and marginal electricity cost in 2050 under multiple scenarios using its DNE21+ model for assessing global warming countermeasures and provided the analysis to the 43rd meeting of the Strategic Policy Committee of the Advisory Committee for Natural Resources and Energy.[1] Subsequently, at the 44th meeting of the Strategic Policy Committee, four research organizations – the National Institute for Environmental Studies (NIES), the Renewable Energy Institute (REI), Deloitte Tohmatsu Consulting, and the Institute of Energy Economics, Japan (IEEJ) – reported their analyses using energy system models,[2),3),4),5)]

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* Associate Professor, Division of Intelligent Systems Engineering, Faculty of Engineering, Yokohama National University (YNU); Principal Research Fellow, Clean Energy Unit, IEEJ,

** Corresponding author

*** Senior Economist, Energy and Economic Analysis Group, Energy Data and Modelling Center, IEEJ

**** Associate Professor, College of Sustainability and Tourism, Ritsumeikan Asia Pacific University (APU); Principal Research Fellow, Energy Data and Modelling Cener, IEEJ

***** Senior Researcher, Climate Change Group, Climate Change and Energy Efficiency Unit, IEEJ

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discussing challenges and constraints regarding fundamental energy supply and demand structure transition. We participated in the IEEJ [5] analysis and published detailed reports.[6),7)]

One of the points that attracted attention in these analyses was the marginal electricity cost (or the potential electricity price) for the case of large-scale renewable energy power generation. The marginal electricity cost indicates the amount of change in the objective function when electricity demand is slightly increased or decreased from the equilibrium state, being interpreted as the supply and demand equilibrium price of electricity. At the 43rd and 44th meetings of the Strategic Policy Committee, three analyses[1),4),5)] presented marginal electricity cost estimates (long-term marginal cost including construction cost), indicating that the marginal electricity cost could rise significantly if renewable energy spreads widely **(Table 1)**. In the IEEJ [5] analysis, for instance, the average annual marginal electricity cost in the scenario of 100% renewable energy supply in 2050 will almost double from the standard carbon neutrality scenario. In addition, the one-hour marginal electricity cost tended to be polarized depending on the season.[5),6)] This means that in seasons with excellent solar radiation and wind conditions, there is a constant surplus of electricity, with the marginal electricity cost standing at around 0 yen/kWh frequently. On the other hand, it was suggested that the marginal electricity cost rises during periods of poor weather conditions, pushing up the average. Economic challenges for the 100% renewable energy supply case are implied.

On the other hand, cost reductions for solar photovoltaics and wind, or variable renewable energy (VRE) power generation have made significant progress. VRE electricity prices in 2050 may be far lower than assumed in our earlier analyses,[5),6),7)] which did not consider a sensitivity analysis regarding VRE power generation cost. While suggesting that hydrogen storage and biomass as a dispatchable renewable energy source may play an important role in responding to seasonal fluctuations in VRE power supply, the earlier analyses failed to consider uncertainties about a significant improvement in the economic efficiency of energy storage technologies and biomass resources in Japan. Against this background, this study conducted sensitivity analyses regarding VRE power generation, energy storage costs and domestic biomass resources to consider the robustness of the earlier analyses. [5),6),7)]

Table 1 Marginal electricity cost estimates in earlier analyses

		Marginal electricity cost	
		Standard scenario	100% renewable energy scenario
Strategic Policy Committee (43rd and 44th meetings)	RITE [1)]	25 yen/kWh	53 yen/kWh
	NIES [2)]	N.A.	N.A.
	REI [3)]	N.A.	N.A.
	Deloitte [4)]	23 yen/kWh	52 yen/kWh
	IEEJ [5)]	16 yen/kWh	28-33 yen/kWh
Otsuki, et al [6),7)]		16 yen/kWh	34 yen/kWh

2. Research methodology

2.1. Overview of a high time-resolution Japan energy system model

In this study, we use a high-time-resolution optimal power generation mix model that targets the whole energy system and expresses electricity supply and demand in hourly values.[6),7)] This model is formulated as a linear programming problem, depicting efficient energy supply and demand by minimizing the total cost for an analysis period under various constraints, such as energy supply-demand balance and CO_2 constraints. The analysis period is between 2015 and 2080, including 2015, 2020, 2030, 2040, 2050, 2065, and 2080 as representative years for the calculation of supply and demand (this paper focuses on estimates for 2050). We divided Japan into five regions (Hokkaido, Tohoku, Tokyo, West Japan,

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[6] Otsuki Takashi, Obane Hideaki, Kawakami Yasuaki, Shimogori Kei, Matsuo Yuji, Mizuno Yuji, Morimoto Soichi; Energy mix for net zero CO_2 emissions by 2050 in Japan, Journal of the Institute of Electrical Engineers of Japan, Vol.142, No.7, pp.334-346, (2022)

[7] Otsuki T., Obane H., Kawakami Y., Shimogori K., Mizuno Y., Morimoto S., Matsuo Y., Energy mix for net zero CO_2 emissions by 2050 in Japan, Electr Eng Jpn., e23396, (2022)

and Kyushu Okinawa) and considered the uneven distribution of VRE resources in each region and interregional power transmission costs.

The components of the model include primary and secondary energy supply, final demand, energy-related CO_2 emissions, and about 300 technologies and processes that link them. The biggest feature of this technology stack model is that it can explicitly handle each energy technology and express its economic and technological performances (construction cost, capacity factor, energy intensity, etc.) in detail. The economic and technological performances of energy technology groups and each technology, as well as final demand, are handled as given data. Final demand is modeled as energy service demand in the industrial, consumer, and transportation sectors (37 categories in total).

The model covers six VRE sources: ground-mounted solar photovoltaic panels, roof-mounted solar PV panels, wall-mounted solar PV panels, onshore wind farms, bottom-mounted offshore wind farms, and floating offshore wind farms. Taken into account as measures to cope with VRE volatility are thermal power generation adjustment, VRE output control, energy storage (pumped-up hydropower, sodium sulfur [NaS] batteries, lithium-ion batteries, redox flow batteries, water electrolysis, and compressed hydrogen storage), and demand response (charging for electric vehicles [EVs] and plug-in hybrid vehicles, discharging from EVs [V2G], control over consumer heat pump (HP) water heater operations). Modeled as renewable energy sources other than VRE are large-scale hydropower, small- and medium-scale hydropower, geothermal energy, and biomass-fired power plants (using woody biomass or black liquor as fuel). Thermal power generation using hydrogen from renewable energy is also considered.

The model covers 54 million variables and 58 million constraint equations. The calculation time (real time) for one case is about 6 hours for the Intel Xeon Gold 6326 CPU (2.90GHz). The Xpress solution algorithm (an interior point method) is used as the optimization solver. Approximately 55 GB of memory is required for calculation. See Otsuki et al.[6] for major variables and constraint equations.

2.2. Analysis cases

Based on the RE100 case in Otsuki et al.,[6] we conducted a sensitivity analysis regarding VRE construction costs, domestic biomass resources, and energy storage technology costs (a total of five cases were estimated as shown in **Table 2**).

Table 2 Analysis cases

<table>
<tr><th></th><th>RE100</th><th>VRE+</th><th>Biomass+</th><th>Storage+</th><th>Combo</th></tr>
<tr><td>CO_2 Constraints and power generation mix</td><td colspan="5">Net-zero energy-related CO_2 emissions by 2050
100% renewable energy</td></tr>
<tr><td>VRE construction costs (2050)</td><td>Table 3 VRE assumptions for 2050 (RE100, Biomass+, Storage+ cases) level</td><td>Down 90% from RE100 case</td><td colspan="2">Equivalent to RE100 case level
(Table 3 VRE assumptions for 2050 (RE100, Biomass+, Storage+ cases) level)</td><td>Down 90% from RE100 case</td></tr>
<tr><td>Domestic woody biomass resources (2050)[Note]</td><td colspan="2">Solid biomass production is assumed as equivalent to FY2020 level (7.4 Mtoe/year)</td><td>Estimated from forest accumulation (18 Mtoe/year)</td><td>Equivalent to RE100 level (7.4 Mtoe/year)</td><td>Estimated from forest accumulation (18 Mtoe/year)</td></tr>
<tr><td>Hydrogen storage and redox flow battery construction costs (2050)</td><td colspan="3">Hydrogen storage
(Water electrolysis: 45,000 yen/kW,
Compressors, etc.: 70,000 yen/kW,
Storage tank: 15,000 yen/kWh)
Redox flow batteries
(Input/output part: 28,000 yen/kW,
Electrolyte tank: 9,900 yen/kWh)</td><td colspan="2">Down 90% from RE100 case
RE100</td></tr>
</table>

Note: Of domestic woody biomass resources, 0.7 Mtoe/year is assumed to be externally used for black liquor in the pulp and paper sector. The remainder is assumed as available for woody biomass-fired power generation or steelmaking (supplementary heat supply in hydrogen reduction steelmaking).

Table 3 VRE assumptions for 2050 (RE100, Biomass+, Storage+ cases)

	Construction costs (10,000 yen/kW)	Capacity factor
Ground-mounted solar PV panels	10.5-17.7	16-18%
Roof-mounted solar PV panels	12.3~22.8	11%
Wall-mounted solar PV panels	17.5	8%
Onshore Wind farms	22.1	20-39%
Bottom-mounted offshore wind farms	45.0	33-40%
Floating offshore wind farms	58.5	33-40%

Note: Within the model, grades are assumed for each technology category, resulting in construction cost and capacity factor gaps. Capacity factors are estimated based on regional weather conditions.

In the RE100 case, renewable energy will cover all electricity generated in 2050, with net-zero energy-related CO_2 emissions being achieved. Nuclear power generation will be phased out by 2050, and thermal power generation will be fueled only by biomass and hydrogen from domestic renewable energy sources.

In the VRE+ case, VRE construction costs in 2050 are assumed as down 90% from the RE100 case **(Table 3)** (for instance, 11,000-18,000 yen/kW for ground-mounted solar PV panels).

In the Biomass+ case, the amount of woody biomass resources in Japan is assumed in line with the amount of forest accumulation.[8] (In the RE100 case, biomass production is assumed to remain unchanged until 2050.) According to the Forestry Agency,[8] the amount of forest accumulation in 2020 stood at about 5.41 billion m^3. If the resources are assumed to be used over a 40-year cycle (annual woody biomass production is assumed at 52.4÷40 = 135 million m^3/year), the amount of domestic resources is estimated about 18 Mtoe/year. This is equivalent to 4% of Japan's primary energy supply in 2019. Since most of the forest accumulation is in artificial forests, this paper estimates the calorific value for cedar and cypress, which are typical tree species for artificial forests. Specifically, the density is assumed at about 0.57 t/m^3 with the moisture content at 40%, and the calorific value at 10 GJ/t (low calorific value standard). The calorific value is computed as 135 million m^3/year × 0.57 t/m^3 × 10 GJ/t = 770 million GJ/year.

In the Storage+ case, construction costs are cut by 90% from the RE100 case for hydrogen storage (water electrolysis and compressed hydrogen storage)[9),10)] and redox flow batteries that are suitable for relatively long-term energy storage and considered contributing to responding to the seasonality of renewable energy. (As lithium-ion and NaS batteries are viewed as economically rational for short-term charging and discharging,[6),9),10)] we paid attention to only hydrogen storage and redox flow batteries.)

In the Combo case, optimistic assumptions are made about VRE, domestic woody biomass resources, and energy storage technologies.

Here, the following two points should be noted regarding domestic woody biomass resources in this analysis. The first point is about their usage. Domestic woody biomass resources in **Table 2** are assumed to be used as (1) woody biomass fuel and (2) black liquor. Woody biomass fuel is assumed to be used for power generation and auxiliary heat supply for hydrogen reduction steelmaking. Black liquor is considered

8 Forestry Agency; Forests and Forestry Statistics 2021, p.5, (2022)

9 Komiyama Ryoichi, Otsuki Takashi, Fujii Yasumasa, A Study on Optimal Power Mix Considering Hydrogen Storage for Surplus Renewable Energy Electricity, Journal of the Institute of Electrical Engineers of Japan, Vol.134, No.10, pp.885-895, (2014)

10 Komiyama R., Otsuki T., Fujii Y., Energy modeling and analysis for optimal grid integration of large-scale variable renewables using hydrogen storage in Japan, Energy, 81, pp.537-555, (2015)

for power generation and heat supply in the paper and pulp sector. The fuel use is determined endogenously. The second point concerns the upper limits on the supply of (1) woody biomass fuel and (2) black liquor. In this analysis, we have set upper limits on the annual supply of (1) woody biomass fuel and (2) black liquor. The combination of the upper limits is adjusted to match the amount of domestic woody biomass resources in **Table 2**. First of all, the upper limit on black liquor supply is estimated based on current black liquor consumption,[11] domestic production's share of pulpwood,[12] and projected energy service demand in the paper and pulp sector. It is set at 0.7 Mtoe/year for all cases. The upper limit on woody biomass fuel supply is assumed as the amount of domestic woody biomass resources (**Table 2**) minus the black liquor supply limit. In the RE100 case, for example, the upper limit on woody biomass fuel supply is assumed at 7.4 - 0.7 = 6.7 Mtoe/year. Meanwhile, the upper limit on black liquor supply for this analysis is revised down from Otsuki et al.[6),7)] In the RE100 case for this analysis, therefore, woody biomass fuel available for power generation is assumed at a higher level than in the same case for Otsuki et al.[6),7)] It should be noted that due to this, the marginal electricity cost in this analysis is slightly lower than reported in the references (as discussed later).

2.3. Assumptions

Assumptions other than those in **Table 2 and 3** are the same as those in Otsuki et al.[6)] We here explain the hourly power load value, VRE output, and renewable energy capacity limit assumptions. The hourly power load curve and VRE output waveform for FY2012 are given. Although these data change depending on annual weather conditions, a multi-year sensitivity analysis is omitted in this study and left for a future study.

Renewable energy capacity limits are assumed as follows: First of all, it is assumed that VRE capacity should not be installed at any locations where such capacity could seriously affect the natural environment or social activities. Specifically, it is assumed that solar PV or onshore wind farm facilities will not be allowed to be installed in forests. Offshore wind power generation facilities are assumed to be installed in waters where their conflicts with stakeholders are unlikely to occur (defined as outside fishing rights areas, 5 km or more from the coastline, and with a monthly ship traffic of 20 vessels or less[13)]). A specific capacity limit is assumed at 66 GW for ground-mounted solar PV panels, 203 GW for roof-mounted solar PV panels, 96 GW for wall-mounted solar PV panels, 23 GW for onshore wind farms, 31 GW for bottom-mounted offshore wind farms, and 142 GW for floating offshore wind farms. Large-scale hydroelectric power generation capacity is assumed to remain unchanged from 20.6 GW in 2015 in the whole of Japan. Capacity limits for small- and medium-scale hydropower and geothermal power generation are optimized in line with potential capacity limits in the Ministry of the Environment[14)] (54 TWh/year and 71 TWh/year in the whole of Japan). The capacity and operation of biomass-fired power generation facilities will be constrained by the amount of biomass resources as described above.

3. Simulation results and discussion

3.1. Marginal electricity cost

From this model, we can obtain the marginal electricity cost in 1-hour increments by region. **Figure 1** shows the weighted average value of Japan's marginal electricity cost in each case (hereinafter referred to as the "average value").

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[11] Agency for Natural Resources and Energy, Comprehensive energy statistics, (2022)

[12] Japan Paper Association, Pulpwood collection trends and import share, https://www.jpa.gr.jp/states/pulpwood/index.html, (accessed January 3, 2023)

[13] Obane H., Nagai Y., Asano K.; Assessing the potential areas for developing offshore wind energy in Japanese territorial waters considering national zoning and possible social conflicts, Marine Policy, Vol.129, 104514 (2021)

[14] Ministry of the Environment; FY2019 report on preparation and disclosure of basic zoning information on renewable energy, Chapter 3, (2020)

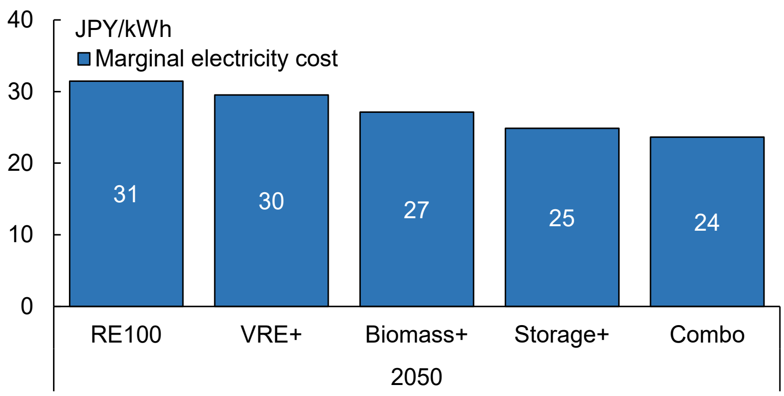


Figure 1 Average marginal electricity cost in Japan

Note: Within the model, grades are assumed for each technology category, resulting in construction cost and capacity factor gaps. Capacity factors are estimated based on regional weather conditions.

Equation (1) was used to calculate the average value.

$$wsp_{c,y} = \sum_r \sum_t (sp_{c,t,r,y} \cdot elc_{c,t,r,y}) / \sum_r \sum_t elc_{c,t,r,y} \quad \cdots\cdots \text{Equation (1)}$$

In the equation, c stands for Case, y for Year, r for Region, t for Time (t=0, 1, …, 8759), $wsp_{c,y}$ for Japan's average marginal electricity cost (yen/kWh) in Case c in Year y, $sp_{c,t,r,y}$ for marginal electricity cost (yen/kWh) for Case c in Year y in Region r at Time t, and $elc_{c,t,r,y}$ for net power generation (kWh/hour) for Case c in Year y at Time t in Region r.

The average marginal electricity cost is 31 yen/kWh in the RE100 case. No significant improvement from the RE100 case was seen in the VRE+ case (**Figure 1**). In the Biomass+ and Storage+ cases, however, the average value was estimated to decrease to 25-27 yen/kWh. In the Combo case, the average was limited to 24 yen/kWh. As discussed in Section 3.2, a seasonal increase in biomass-fired power generation in the Biomass+ case, energy storage over multiple months or seasons in the Storage+ case, and their combination in the Combo case respond to long-term VRE fluctuations, contributing to lowering the marginal electricity cost. The increase in the marginal electricity cost for the RE100 case may be partly attributable to the cost of responding to the seasonality of VRE (as confirmed in Section 3.3). In order to achieve an extremely high renewable energy share, it may be important to secure dispatchable renewable energy power sources and introduce technologies suitable for long-term energy storage to respond to the seasonality of VRE. The average marginal electricity cost for the RE100 case in this study fell from 34 yen/kWh in our earlier analysis[6] to 31 yen/kWh. This is because an assumed amount of woody biomass resources available for power generation was revised upward, as noted in Section 2.2.

The moderation of seasonal fluctuations is evident in the hourly marginal electricity cost trend (**Figure 2**).

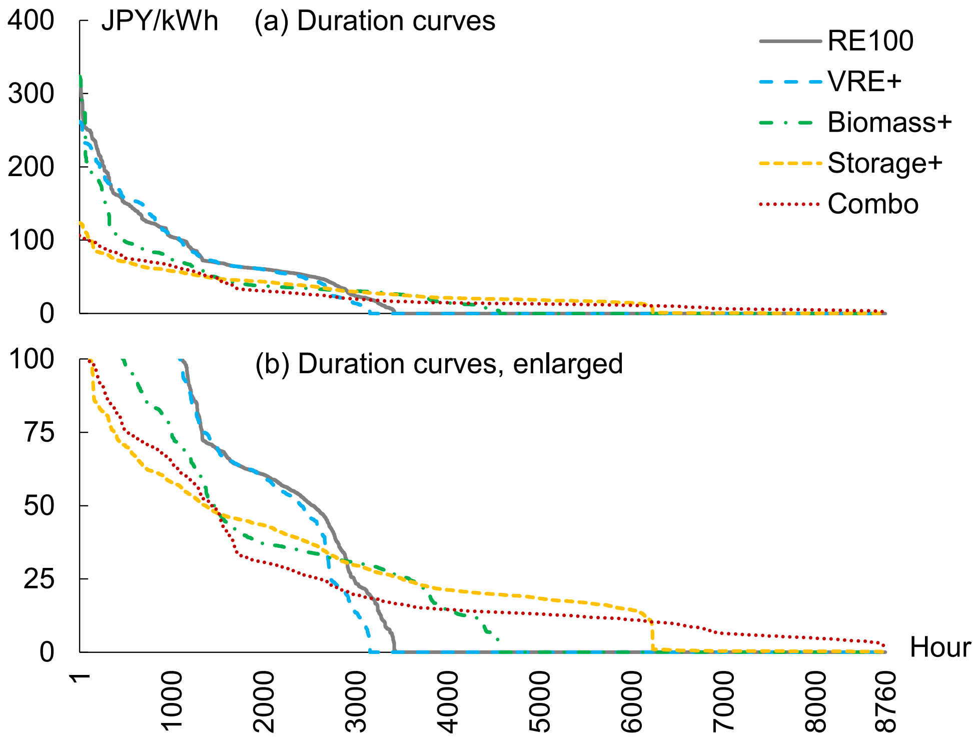


Figure 2 Hourly marginal electricity curves (weighted average for 2050 of 5 regions)

(Note) See **Appendix Figure 1** for regional results

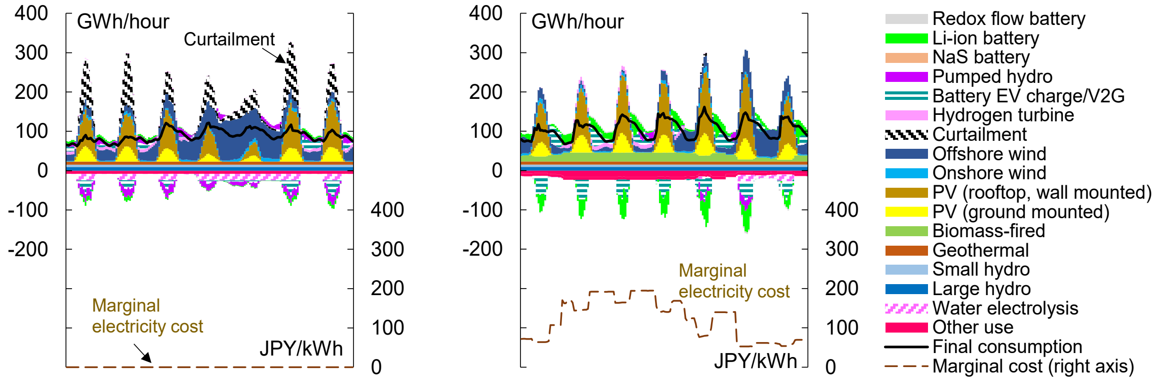
In the RE100 case, the marginal electricity cost is polarized over the course of a year. This means that the marginal electricity cost remained at 0.01 yen/kWh or less for about 5,300 hours and at 100 yen/kWh or more for about 1,100 hours. The hours for the cost of 0.01 yen/kWh or less generally correspond to those for output control, indicating that there is surplus electricity over a long time covering multiple months in the RE100 case. In the Biomass+ case, the annual high of the marginal electricity cost reached the same level as in the RE100 case. However, the polarization was relatively weaker. In the Storage+ and Combo cases, the polarization was far weaker. In the Combo case, the annual number of hours decreased to zero for the marginal electricity cost of 0.01 yen/kWh or less and to about 80 hours for 100 yen/kWh or more.

Here, it should be noted that even if technological development in the Combo case is assumed, the average marginal electricity cost will reach as high as 24 yen/kWh. In the standard case in which a wide range of technology options is assumed to include fossil-fired power generation with carbon capture systems, nuclear power generation, and hydrogen/ammonia power generation, the marginal electricity cost is estimated at 16 yen/kWh. Compared to strategies that utilize a wide range of options, even the Combo case entails a challenge regarding the marginal electricity cost.

3.2. Electricity supply and demand

Figure 3 to 6 indicate hourly electricity supply and demand in the RE100, Biomass+, Storage+, and Combo cases (for May when the marginal electricity cost declines and for a week between late August and early September when the cost rises).

The results in the VRE+ case are similar to those in the RE100 case and omitted here. In the RE100 case, abundant solar radiation and lower power demand are combined to cause frequent output control in May (**Figure 3 (a)).** Between late August and early September, however, the supply-demand balance tightens due to an increase in power demand, requiring power generation with stored hydrogen and biomass that pushes up the marginal electricity cost (**Figure 3 (b)**). In this way, hydrogen and biomass-fired power generation is required in a season when the supply-demand balance tightens, resulting in a rise in the marginal electricity cost (**Figure 7 (a)**).



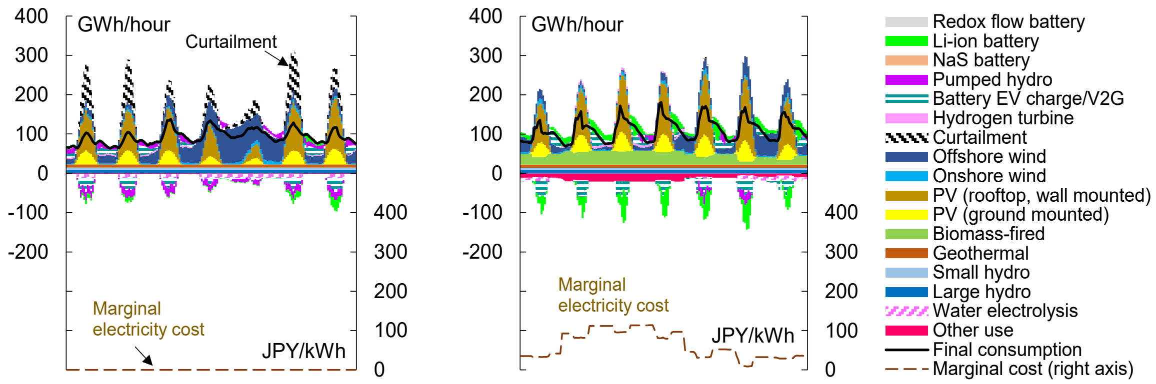
(a) May **(b) Late August to early September**

Figure 3 Hourly electricity supply and demand over a week in the RE100 case (total for Japan in 2050)

Note: "Other use" refers to electricity consumption other than final consumption (including consumption at fuel synthesis and direct air capture facilities). In this study, direct air capture facilities account for most of the "other use" in each case.

While May electricity supply and demand in the Biomass+ case were similar to those in the RE100 case, more biomass-fired power generation was seen between late August and early September (**Figure 4 (a)(b)**), contributing to loosening the supply-demand balance and to suppressing the marginal electricity cost. Over the course of a year, biomass-fired power generation increased in response to the tightening supply-demand balance, substantially suppressing the marginal electricity cost between late July and mid-September (**Figure 7 (a)(b)**). Annual biomass-fired power generation in the Biomass+ case more than doubled from the RE100 case (**Appendix Figures 3 and 8**).

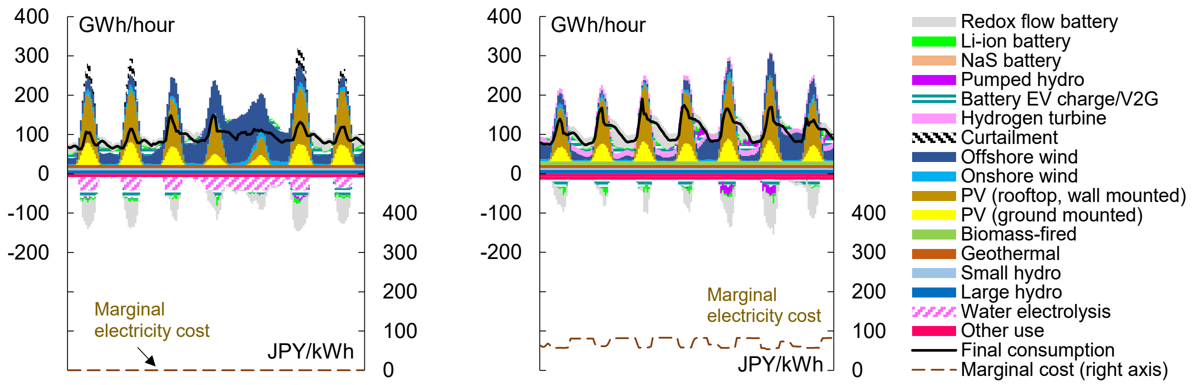
All biomass-fired power generation growth in the RE100 and Biomass+ cases is accompanied by CO_2 capture and storage (CCS) devices, creating negative emissions. (In this analysis, large-scale biomass-fired power plants with CO2 capture devices are assumed, with no consideration given to small, distributed biomass power plants.) Biomass-fired power generation might have contributed to suppressing the marginal electricity cost not only by serving as a dispatchable renewable energy power source but also by creating negative emissions. In the RE100 case for this analysis, direct air capture with CO_2 storage (DACCS) systems is used to offset residual CO_2 emissions in the final consumption sector to cut CO_2 emissions to net zero for the entire energy system, including the power generation sector (**Appendix Figure 2**). In contrast, negative emissions created by biomass-fired power plants with CCS devices in the Biomass+ case worked to reduce DACCS contributions. This means that biomass-fired power plants with CCS devices might have cut energy consumption for operating direct air capture devices, contributing to loosening the electricity supply-demand balance further.



(a) May **(b) Late August to early September**

Figure 4 Hourly electricity supply and demand over a week in the Biomass+ case (total for Japan in 2050)

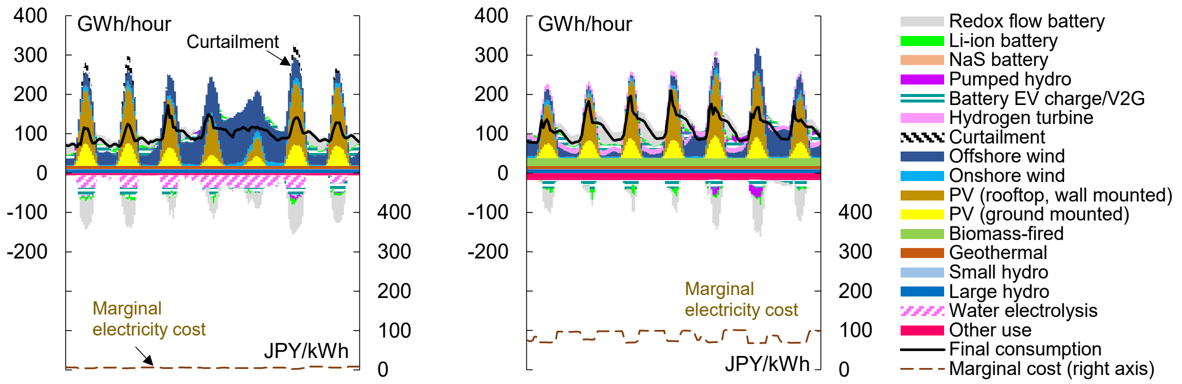
In the Storage+ case, we can see a significant increase in hydrogen storage systems and redox flow battery capacity. In May, hydrogen production and redox flow battery charging were chosen instead of output suppression (**Figure 5 (a)**). As construction costs for these technologies declined, it was considered that capital investment in these technologies was more economically rational than output suppression. When the electricity supply-demand balance tightened (**Figure 5 (b),** hydrogen power generation increased. Fuel hydrogen was produced from around April to June and stored for several months before being used for power generation (**Figure 8(b)).** Energy storage through hydrogen storage reached up to 22 TWh, equivalent to final electricity consumption over eight days in 2050 for the Storage+ case. While hydrogen storage was used for energy storage across weeks and months (**Figure 8 (a))** in the RE100 case as well, hydrogen or energy storage was implemented on a larger scale and over a longer period of time in the Storage+ case to adjust electricity supply and demand over multiple seasons, contributing to leveling the marginal electricity cost over multiple seasons.



(a) May **(b) Late August to early September**

Figure 5 Hourly electricity supply and demand over a week in the Storage+ case (total for Japan in 2050)

In the Combo case, it can be seen that hydrogen storage and biomass-fired power generation are combined to cope with VRE fluctuations. **Figure 7 (a)** indicates that hydrogen is produced from output from solar PV and wind power generation. **Figure 7 (b)** shows that power generation using stored hydrogen and biomass-fired power plants contributes to balancing supply and demand. The contribution of hydrogen storage technology to leveling VRE output reduced the spot rapid operation of biomass-fired power plants from the Biomass+ case (**Figure 7 (b)(c)**). Hours of operation increased for biomass-fired power plants to stabilize their output. The maximum energy storage reached 17 TWh, down from 22 TWh in the Storage+ case (**Figure 7 (b) (c)**).



(a) May **(b) Late August to early September**

Figure 6 Hourly electricity supply and demand over a week in the Combo case (total for Japan in 2050)

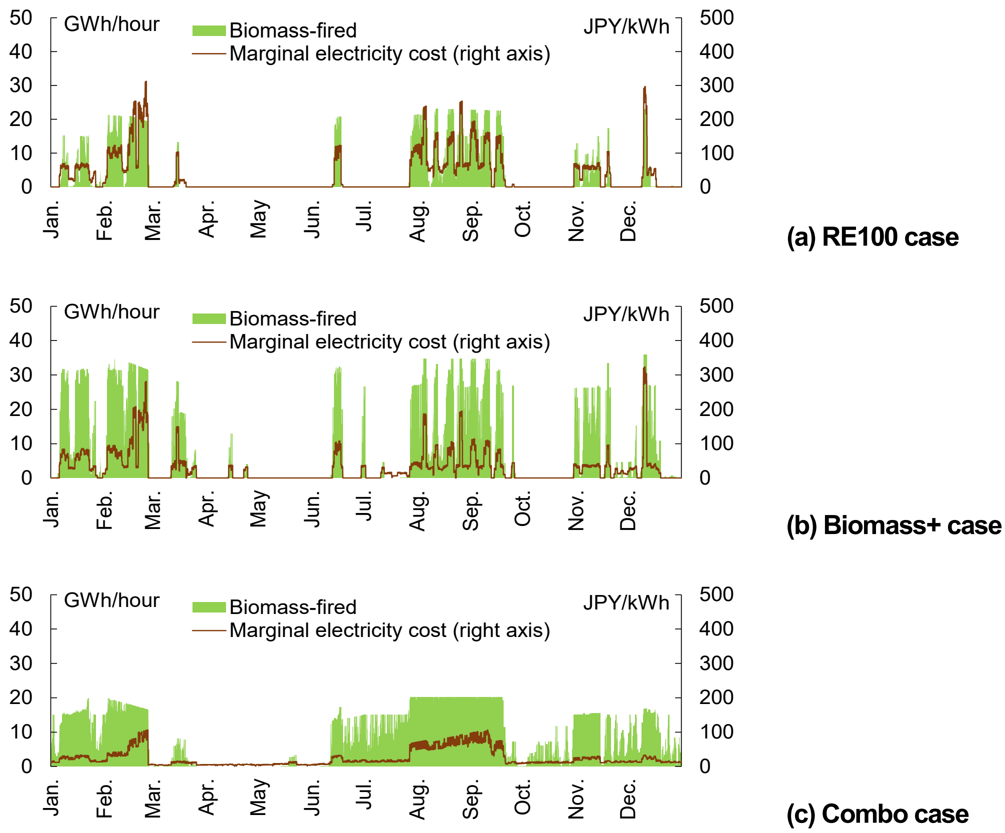


Figure 7 Hourly biomass-fired power generation and marginal electricity cost in 2050 (total for Japan)

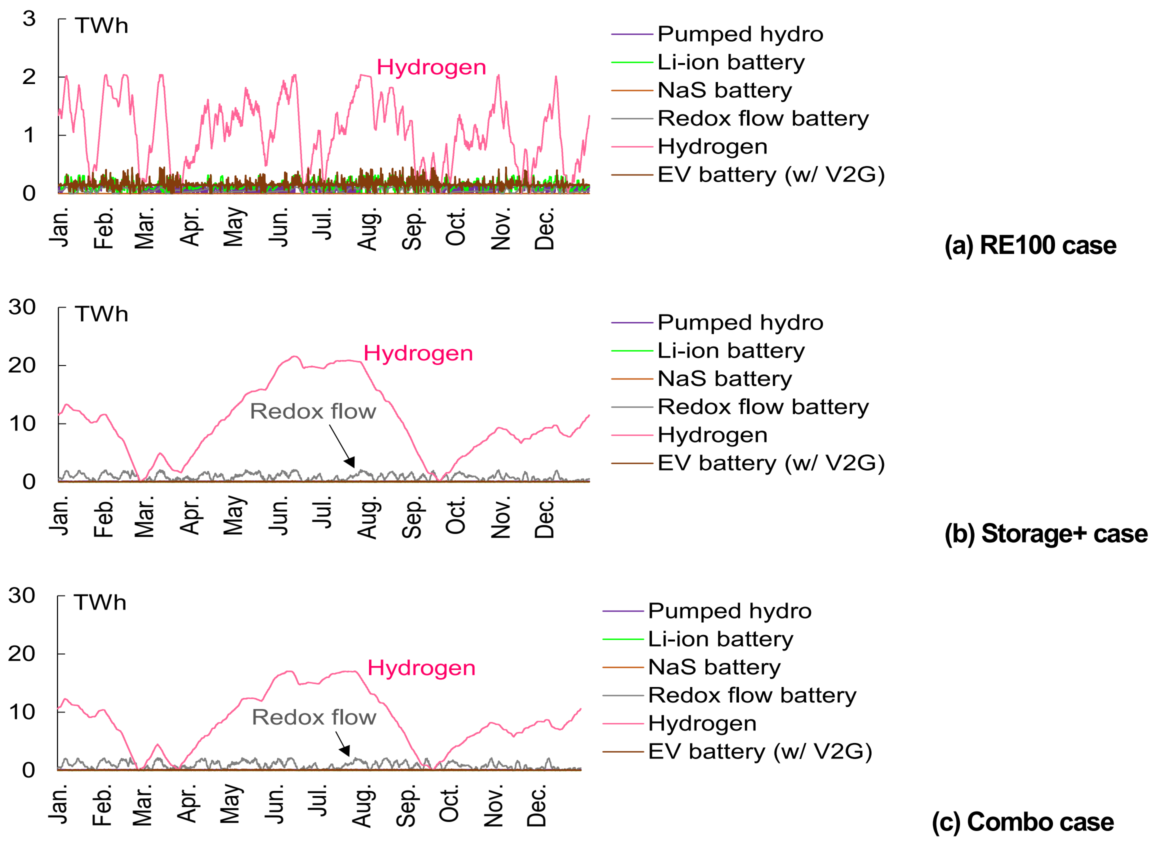


Figure 8 Hourly energy storage in 2050 (state of charge, total for Japan)

(Note) EV Battery (w/ V2G): Vehicle-mounted batteries available for vehicle-to-grid services (assumed to account for half of the number of EV cars in use)

3.3. Determinants of marginal electricity cost

Annual highs of the hourly marginal electricity cost in the RE100, VRE+, and Biomass+ cases (Figure 2) reached 260-320 yen/kWh. In this paper, we finally examine the determinants of the marginal electricity cost. In the examination, we extracted five regional peak-cost time periods in each case, changed electricity demand during those time periods by 1 GWh/h, and evaluated objective function differences. See **Appendix B** for specifics.

Figure 9 shows the determinants of the marginal electricity cost. The cost required to cover an additional electricity demand unit is displayed as a positive value (as an additionally introduced technology may replace other technologies as explained later, the cost of the replaced technologies is given as a negative value). The net cost increase (net increase in the figure) corresponds to the marginal electricity cost. For example, the net increase for the RE100, VRE+, and Biomass+ cases is 250-320 yen/kWh, close to annual highs in **Figure 2. Figure 9** indicates the following two points:

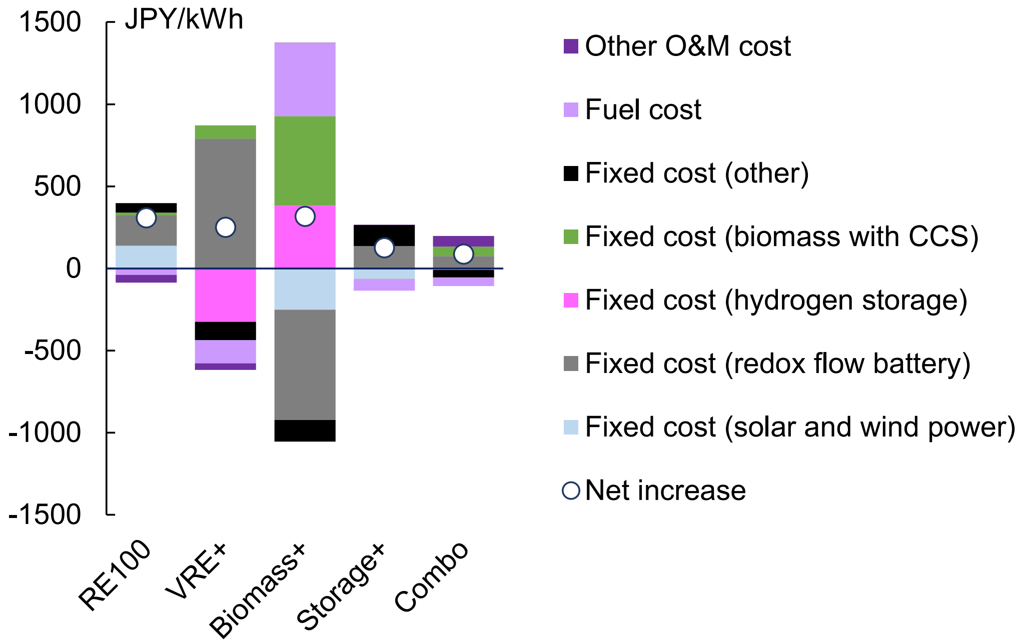


Figure 9 Factor analysis of the highest hourly marginal electricity cost

(Note) O&M: Operation & Maintenance CCS: Carbon capture and storage.

The first point is that the VRE integration cost contributes to the marginal electricity cost in each case. In the RE100 case, VRE and redox flow battery costs pushed up the marginal electricity cost, with the latter being the biggest contributor. In other cases, energy storage technologies and CCS-equipped biomass-fired power plants account for most of the additional costs. The marginal electricity cost rises under poor weather conditions.[5),6)] Under such conditions, dispatchable technologies (including energy storage) are required to meet one additional demand unit. Such technologies might have contributed to the marginal cost. Of course, additional VRE capacity can be introduced to meet one additional demand unit. In this case, however, the additional VRE capacity may generate more surplus electricity in other time periods (including seasons when surplus electricity is abundant under excellent weather conditions). Additional VRE capacity thus turns out inefficient for annual operations. Compared with additional VRE capacity, dispatchable technologies became more economically rational. However, even dispatchable technologies are required to operate at low capacity. Fixed costs for power generation and storage might have pushed the marginal cost up to more than 100 yen/kWh.

The second point is about the determinants of the marginal electricity cost. In each case, the VRE integration cost contributes to the marginal electricity cost, but the cost's breakdown and formation mechanism differ from case to case.

The RE100, Storage+, and Combo cases are considered relatively simple. In the RE100 case, a combination of wind farms and redox flow batteries is additionally installed to cover changes in electricity demand, as reflected in the breakdown of the marginal electricity cost. In the Storage+ case, redox flow batteries are the main factor. In this case, surplus electricity from the existing onshore and offshore wind farms (electricity output that would have been subjected to suppression if there were no additional electricity demand) is charged and discharged to cover the additional demand. The batteries are operated mainly during additional demand periods. Although their capacity factor is low in this case, their construction cost is assumed to decline by 90% (to cut their fixed cost), making even the inefficient operation economically rational. In the Combo case, CCS-equipped biomass-fired power plants and redox flow batteries are combined to cover additional demand. In this analysis, redox flow batteries have been selected in each case. This may be because these batteries have been viewed as advantageous through the comprehensive consideration of VRE diffusion conditions (including VRE varieties and surplus electricity generation patterns) and their technological and economic characteristics (such as the construction cost, the self-discharge loss, and the ratios of storage capacity to electricity generation capacity). In particular, these cases feature high power generation mix shares for offshore wind power generation (**Appendix Figure 3**), indicating the high affinity between offshore wind farms' output fluctuations and redox flow batteries (while solar PV generation fluctuates in a short cycle between night and day, wind power generation fluctuates in longer cycles randomly).

In contrast to the above three cases, the VRE+ and Biomass+ cases show larger negative values and multiple determinants of the marginal electricity cost. In the VRE+ case, the addition of redox flow batteries pushed up the marginal cost, while reducing hydrogen storage and fuel costs. Like the Storage+ case, this case results in the effective use of surplus electricity from the existing wind farms with redox flow batteries. In the VRE+ case, however, it is not assumed that the redox flow battery construction cost will be reduced. Additional batteries are designed not only to cover the change in demand, but also to be operated to increase their capacity factor. As a result, it is thought that the optimal energy storage capacity has changed to replace some hydrogen storage. The background for the fuel cost reduction is somewhat complicated. In this case, the technology mix on the final consumption side is changed in order to increase additional batteries' capacity factor. Specifically, additional redox flow batteries are combined with the building sector's electrification (including the diffusion of heat pump water heaters) to create additional electricity demand and secure their longer operations. With the progress in the electrification of the building sector, the use of decarbonized fuels (including imported synthetic methane) decreases, leading to a reduction in fuel costs. It should be noted that since this model is an energy system model, the marginal cost is calculated to include the ripple effect on the entire energy sector, including power generation.

In the Biomass+ case, CCS-equipped biomass-fired power plants, hydrogen storage, and fuel cost drive up the marginal electricity cost, while VRE capacity and redox flow batteries offset some of the cost increase. In this case, where mainly additional CCS-equipped biomass-fired power plants cover one additional power demand unit, these additional plants are operated longer than required for the coverage to raise their capacity factor, serving to replace some VRE capacity. The increase in the fuel cost is thought to have resulted from changes in the final consumption sector. The additional CCS-equipped biomass-fired power plants create negative emissions, allowing the final consumption sector to use more fossil fuels. In particular, conventional vehicles replace EVs, leading their fuel costs to push up the marginal electricity cost. Changes in hydrogen storage and redox flow battery capacity might have resulted from the flexible operation of the additional biomass-fired power plants. In other words, output from the additional biomass-fired power plants is adjusted to respond to shorter-cycle fluctuations in VRE output (fluctuations over several hours to several days that have been covered by redox flow batteries in the absence of additional biomass-fired power plants). Such flexibility may have contributed to the reduction in the redox flow battery capacity. On the other hand, redox flow batteries have also responded to longer-cycle VRE fluctuations, and hydrogen storage is believed to have been introduced to complement the response.

4. Conclusion

In this study, we conducted a sensitivity analysis regarding the marginal electricity cost in a 100% renewable energy, carbon-neutral energy system, using a high-temporal resolution energy system model. In the sensitivity analysis, we focused on the assumptions of VRE construction costs, biomass resources in Japan, and energy storage technology costs.

A characteristic analysis result indicates that the marginal electricity cost in the RE100 case is not so sensitive to VRE construction costs but is influenced by domestic biomass resources and energy storage technology costs. In particular, biomass-fired power generation as a dispatchable renewable energy source and large-scale, long-term energy storage contribute to the response to seasonal VRE fluctuations, tending to suppress the marginal electricity cost. It has been suggested that the VRE integration cost related to seasonal fluctuations is one of the factors contributing to increasing the marginal electricity cost in the RE100 case. This apparently indicates that the suppression of the VRE integration cost is an important factor in achieving renewable energy's high share of the power generation mix. This point was confirmed by an analysis of the determinants of the marginal electricity cost.

Even in the Combo case that includes optimistic assumptions of biomass resources and energy storage costs, however, the average marginal electricity cost reached as high as 24 yen/kWh. The level is far higher than the marginal electricity cost of 16 yen/kWh in the standard case that takes into account a wide range of technology options, including fossil fuel-fired power plants equipped with carbon capture, utilization, and storage systems, as well as nuclear and hydrogen/ammonia power plants, implying economic challenges. This analysis thus indicates the same economic challenges as pointed out in Otsuki et al.[6] Although it is necessary to verify the marginal electricity cost from various perspectives in the future, we infer that the robustness of Otsuki et al.[6] remains unshaken.

One of the challenges to be considered in the future is to refine the model and study the possibility of massive renewable energy power generation. In this regard, we would like to take up three points. The first is the expansion of demand responses. This model takes into account EV charging and discharging, and controls consumer heat-pump water heater operations. It also takes into account the time shift of electricity demand through five different energy storage technologies and controls on household fuel cells. However, other demand responses (such as turning on and off of consumer and industrial equipment other than heat pump water heaters, and measures to curb demand for energy services) are not taken into account. It is necessary to expand technology options and quantify their contributions to the massive renewable energy power generation and the marginal electricity cost. The second point is the refinement of regional resolution. The regional resolution of this model covers five regions, simplifying the topology of the power system, connection constraints, and system expansion costs. VRE output waveforms are aggregated into five regions. Since such a model may fail to adequately reflect grid constraints and meteorological data from various locations, it is necessary to enhance the regional resolution and perform a more realistic analysis. The third point is how to respond to uncertainties. This model assumes perfect foresight, failing to take into account electricity demand or VRE output prediction errors. It is important to analyze the costs associated with prediction errors. Although we used hourly power load shape and meteorological data for 2012 in this analysis, load curves and weather conditions vary from year to year. It is necessary to conduct analyses that take into account power load and weather conditions over multiple years and quantify sensitivity to them. This analysis examined the determinants of the marginal electricity cost, which may be sensitive to various assumptions and model structure changes. It is necessary to deepen the understanding of the determinants through further sensitivity analysis regarding assumptions and comparative studies using multiple models.

Acknowledgment

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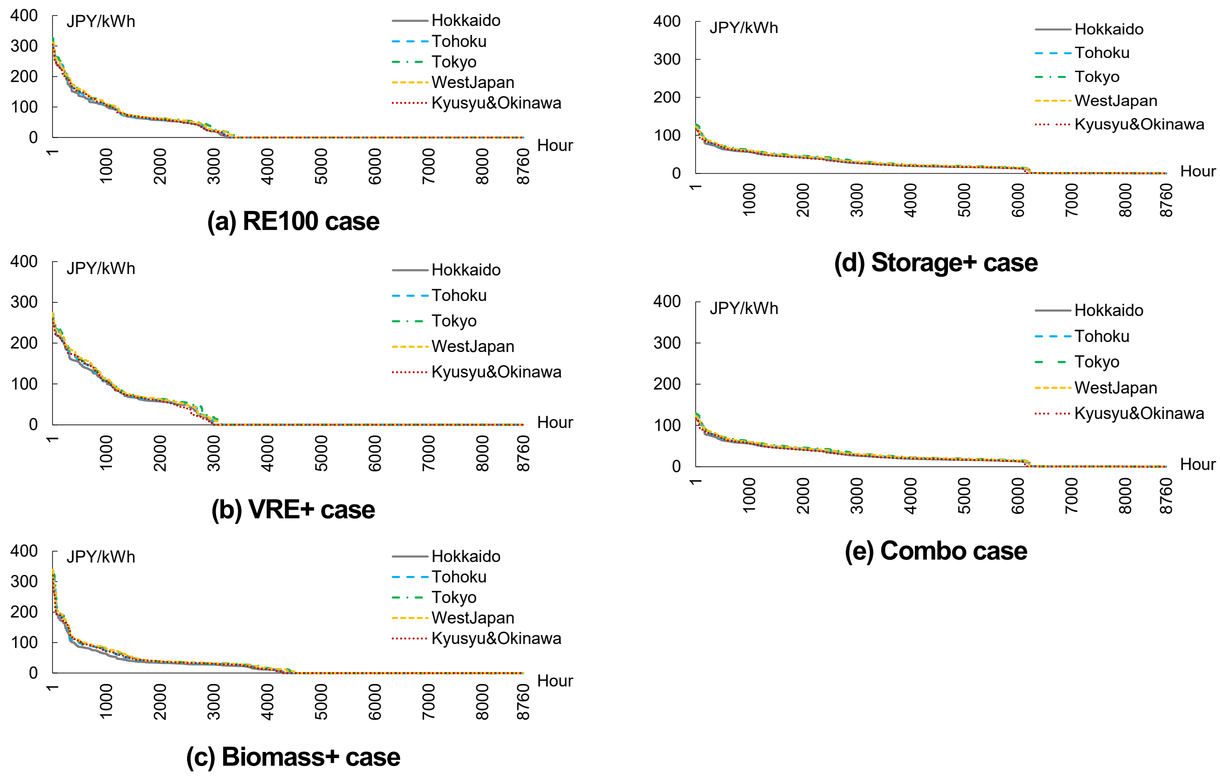
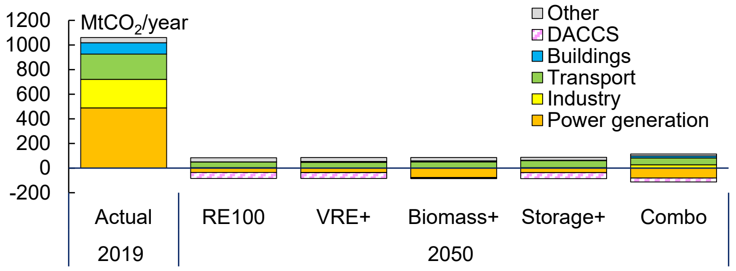
Appendix A. Supplementary results

Appendix Figure 1 shows the hourly marginal electricity cost (duration curve) for each case by region in 2050. In all cases, there are no significant regional differences in the marginal electricity cost. As indicated by **Appendix Figure 7** later, interregional interconnection lines have been greatly enhanced in each case. It is thought that the formation of large-scale power grids on a nationwide scale has led to the nationwide uniformity of the marginal electricity cost.

CO_2 emissions by sector are shown in **Appendix Figure 2,** electricity generated in the whole of Japan and each region in **Appendix Figure 3 and 4**, energy storage capacity in **Appendix Figure 5 and 6**, interregional interconnection capacity in **Appendix Figure 7**, and biomass supply and demand balance in **Appendix Figure 8.** In all cases, floating offshore wind farms account for the largest share of total power generation in Japan (**Appendix Figure 3**). They are located mainly in Tohoku, Western Japan, and Kyushu **(Appendix Figure 4 (a)-(c)**). Hydroelectric power generation (mainly by small- and medium-scale hydropower plants) in the Combo case is less than in the RE100 case. As VRE power generation and energy storage costs in the Combo case are lower than in the RE100 case, offshore wind farm capacity expansion and the integration of such wind farms into the power grid make progress in Tohoku and Western Japan, contributing to reducing power generation by small- and medium-scale hydropower plants. As electrification on the demand side is promoted against the backdrop of improvements in the economic efficiency of renewable energy power supply in the Combo case, total power generation in each region is more than in other cases. Energy storage capacity (**Appendix Figure 5**) is smaller in the Biomass+ case, in which biomass-fired power plants contribute to the power supply and demand adjustment, and far larger in the Storage+ and Combo cases. In the RE100 and VRE+ cases, hydrogen storage capacity is expanded in Western Japan and Tohoku to respond to fluctuations in offshore wind power generation (**Appendix Figure 6 (a)** shows the RE100 case as an example). In the Storage+ and Combo cases, hydrogen storage capacity is substantially expanded not only in Western Japan and Tohoku, but also in Tokyo and Kyushu (**Appendix Figure 6 (b)** shows the Combo case that indicates trends similar to those in the Storage+ case). Interregional interconnection capacity (**Appendix Figure 7**) is required to be substantially increased in each case to transmit electricity generated by onshore and offshore wind farms (e.g., interconnection capacity in 2050 will be 9-15 GW between Hokkaido and Tohoku and 42-50 GW between Tohoku and Tokyo). Among the cases, the VRE+ case with a larger VRE power generation capacity has the largest interregional interconnection capacity. Interregional interconnection capacity is small in the Storage+ case, where energy storage can be used to level VRE output and interregional power transmission to cut such capacity.

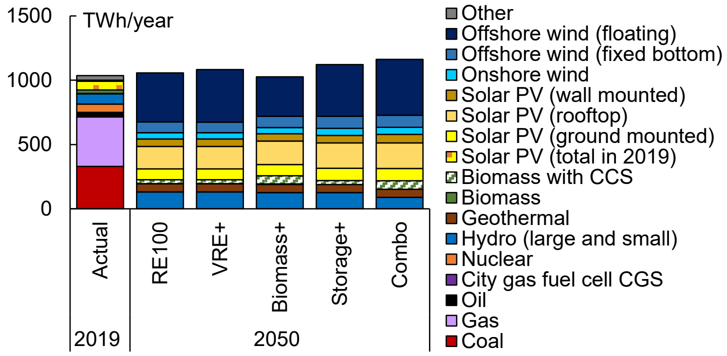


Appendix Figure 1 Hourly marginal electricity cost duration curves in each case (2050)



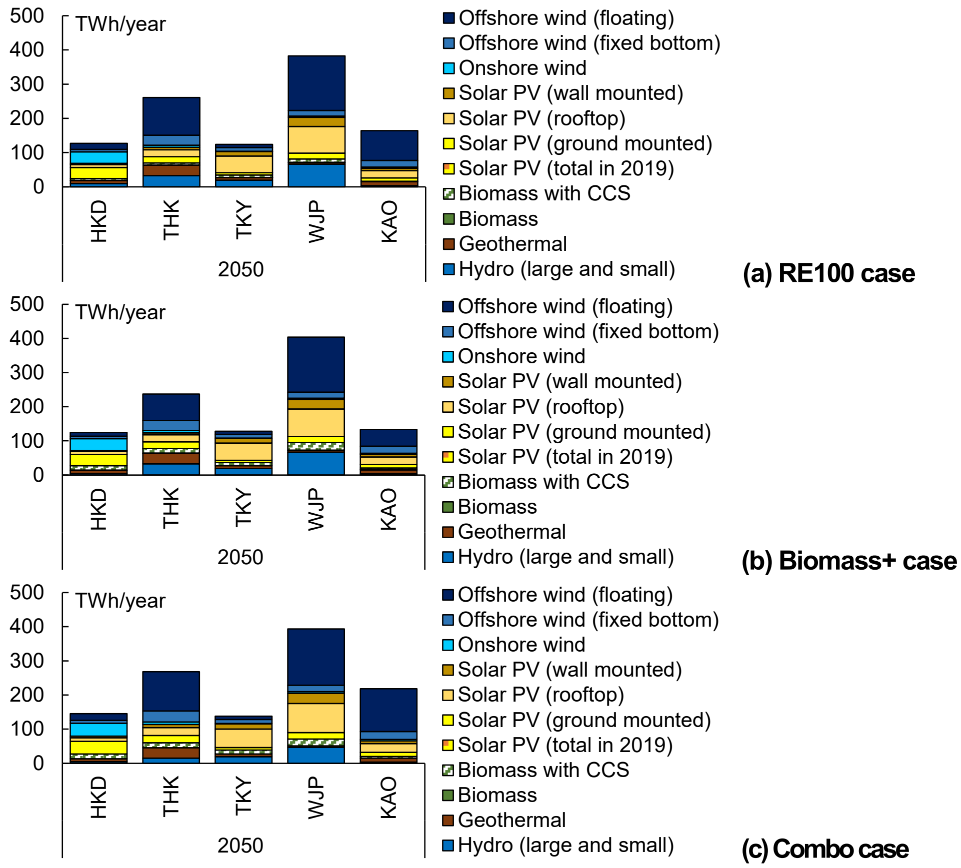
Appendix Figure 2 CO_2 emissions by sector (total for Japan)

(Note) DACCS: Direct air capture with CO_2 storage.



Appendix Figure 3 Electricity generation (total for Japan)

(Note) CGS: Cogeneration system.



Appendix Figure 4 Electricity generation by region

(Note) HKD stands for Hokkaido, THK for Tohoku, TKY for Tokyo, WJP for Western Japan, and KAO for Kyushu & Okinawa (the same in **Appendix Figure 6**)

Appendix B. Formulation in Section 3.3

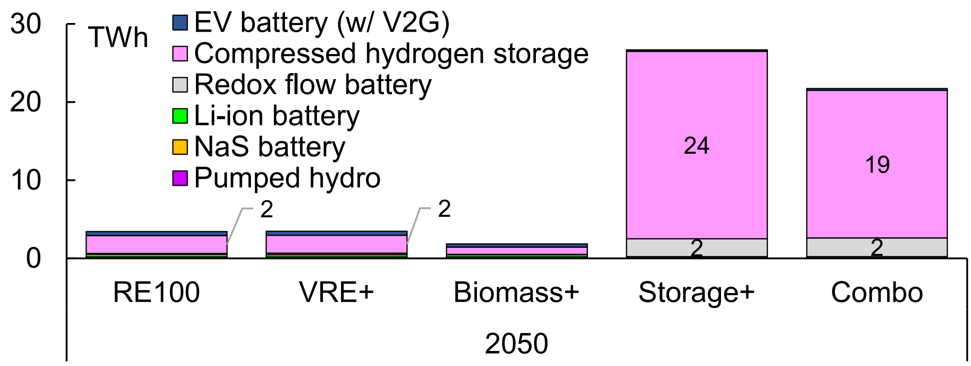
Electricity supply and demand in this model consist of a balance equation (Equation (2)) before electricity transmission and distribution within a region and another balance equation (Equation (3)) after transmission and distribution to final consumers (Equation (3)). In Section 3.3, $D_{t,r,y}$ (unit: GWh/h) was newly added to the right side of Equation (2). Then, the time period *Tr* for the highest hourly marginal electricity cost in each region in 2050 was extracted as $D_{t,r,y,2050} = -1$ and the rest as $D_{t,r,y} = 0$.

$$\sum_{k\in KP} x_{k,t,r,y} + \sum_{k\in KS}(dis_{k,t,r,y} - cha_{k,t,r,y}) + \sum_{r'\neq r}(TEF_{r,r'} \cdot xt_{t,r',r,y} - xt_{t,r,r',y}) = elg_{t,r,y} + \sum_{k\in KC} xc_{k,t,r,y} + D_{t,r,y}$$
……………………………………………………………… Equation (2)

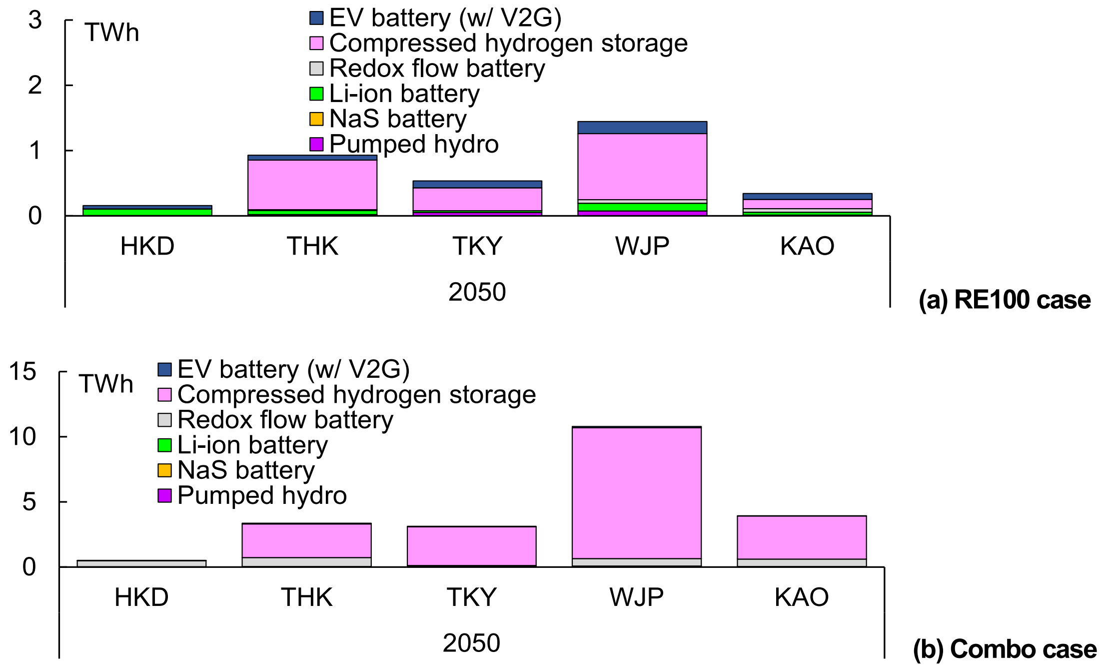
$$elg_{t,r,y} \cdot TDEF + \sum_{k\in KP2} x_{k,t,r,y} + v2g_{t,r,y} = ev_{t,r,y} + hp_{t,r,y} + LDC_{t,r} \cdot edem_{r,y}$$
…………… Equation (3)

Here, $KP1$ stands for a collection of power generation technologies (excluding those in *KP*2 below), *KP*2 for a collection of power generation technologies installed on the end consumer side (roof- and wall-mounted solar PV panels, city gas fuel cells), *KS* for a collection of power storage technologies (pumped-up hydropower, NaS batteries, lithium-ion batteries, redox flow batteries), *KC* for a collection of power consumption technologies for purposes other than final consumption (water electrolyzers, fuel synthesizers, direct air capture system, etc.).

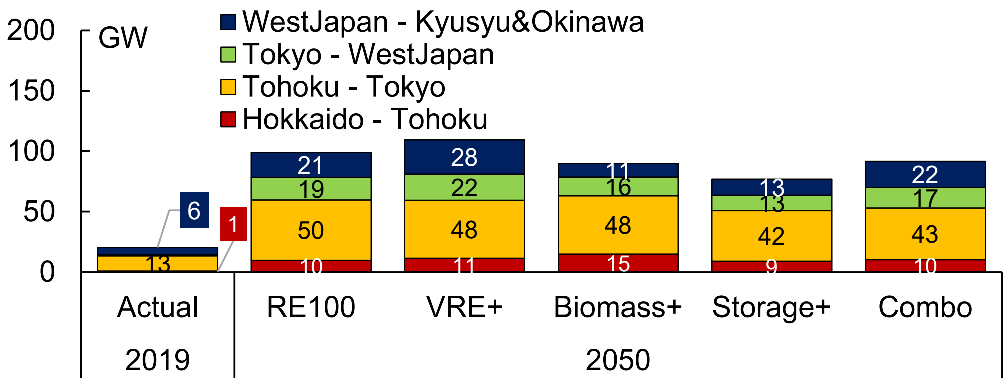
Among endogenous variables, $x_{k,t,r,y}$ stands for power generation output (GWh/h) at Time *t* in Year *y* in Region *r* with Technology *k*, $dis_{k,t,r,y}$ for the power discharge amount (GWh/h) at Time *t* in Year *y* in Region *r* with Power Storage Technology *k*, $cha_{k,t,r,y}$ for the power charge amount (GWh/h) at Time *t* in Year *y* in Region *r* with Power Storage Technology *k*, $xt_{t,r',r,y}$ for the amount of power (GWh/h) transmitted from Region *r'* to Region *r* at Time *t* in Year *y*, $elg_{t,r,y}$ for the amount of power (GWh/h) transmitted and distributed to the final consumption sector at Time t in Year *y*, $xc_{k,t,r,y}$ for the amount of power (GWh/h) consumed with Technology *k* at Time *t* in Year *y* in Region *r*, $v2g_{t,r,y}$ for the amount of power (GWh/h) discharged from EVs at Time *t* in Year *y* in Region *r*, $ev_{t,r,y}$ for the amount of power (GWh/h) charged to EVs at Time *t* in Year *y* in Region *r*, and $hp_{t,r,y}$ fostands for power consumption by consumer heat pump water heaters at Time *t* in Year *y* in Region *r*. Among exogenous variables, $TEF_{r,r'}$ r the efficiency of power transmission from Region *r* to Region *r'*, $TDEF$ for the regional power transmission and distribution efficiency, and $LDC_{t,r}$ for a coefficient for converting annual final power consumption ($edem_{r,y}$) in Region *r* into the hourly load. $\sum_t LDC_{t,r} = 1$ is satisfied. However, $edem_{r,y}$ does not include the amount of power charged to EVs and PHEVs or power consumption by consumer heat pump water heaters (their consumption is represented by $ev_{t,r,y}$ and $hp_{t,r,y}$).



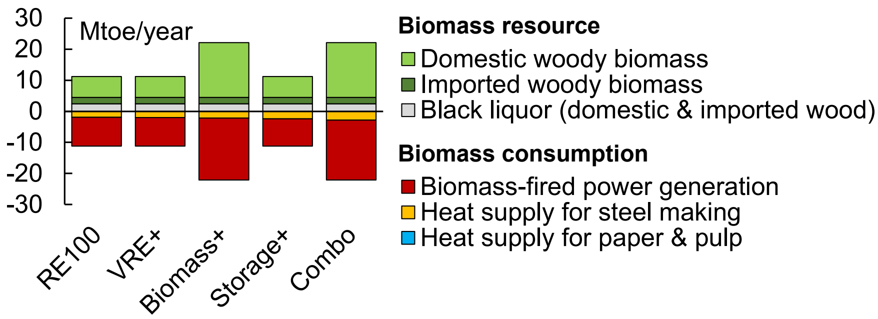
Appendix Figure 5 Energy storage capacity (total for Japan)



Appendix Figure 6 Energy storage capacity by region



Appendix Figure 7 Interregional power interconnection capacity



Appendix Figure 8 Biomass supply and demand balance (total for Japan)

Considering the Impact on Utility Companies of the Price Ceiling for the Fuel Cost Adjustment System

Taiju Morimoto *

1. Overview of the Fuel Cost Adjustment System and of the Recent Situation with Energy Prices

Seven of the former general electric utilities, including Tokyo Electric Power Company (TEPCO), applied for approval to raise their regulated rates, and the rate increases became effective from June 1. This paper provides estimates of and discussion on the fuel cost adjustment system and its upper price limit, which are the focus of these price revisions.

The fuel cost adjustment system was introduced with the aim of "clarifying the business efficiency improvements by externalizing the effects of fuel prices and exchange rates that are beyond the scope of utility companies' efficiency improvement efforts, and to reflect changes in economic conditions in rates as promptly as possible while at the same time working to stabilize the business environment for utility companies."[1] The price ceiling is defined as "a fixed upper limit (+50% of the base point) on the range of automatically adjusted rates in order to mitigate large impacts on consumers when fuel prices rise significantly." The fuel cost adjustment amount is calculated as a unit price per kWh per month for each utility company, and an example of the calculation is shown in **Figure 1**. The system is such that, if the average fuel price calculated here exceeds the price ceiling (1.5 times the base fuel price for each utility company), then the utility company cannot charge the difference to consumers.

Figure 1: Image of the calculation flow for the fuel cost adjustment system

(Source: TEPCO Energy Partner website)

Factors such as Russia's invasion of Ukraine and the continued depreciation of the yen have caused soaring fuel prices since January 2022 (**Figure 2**). Comparing the prices as of January 2022 and their respective highs, crude oil prices have risen by approx. 1.7 times, thermal coal has risen by approx. 2.8 times, and LNG prices have risen by approximately 2.0 times. The prices for thermal coal and LNG in particular have reached record highs. Although prices are showing signs of stabilizing as of March 2023, there is still a large discrepancy from what they were as of January 2022, and high fuel prices are becoming the norm. Under these circumstances, the average fuel prices for each company exceeded the price ceiling, and the companies were unable to pass the prices on to consumers. This forced the companies to bear the unrecoverable portion of fuel costs, resulting in ballooning deficits, which was one of the reasons behind the recent revision to the regulated rates.

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* Economist, Energy and Economic Analysis Group, Energy Data and Modeling Center (EDMC), IEEJ

1 "About the Fuel Cost Adjustment System" on the Agency for Natural Resources and Energy website https://www.enecho.meti.go.jp/category/electricity_and_gas/electric/fee/fuel_cost_adjustment_001/

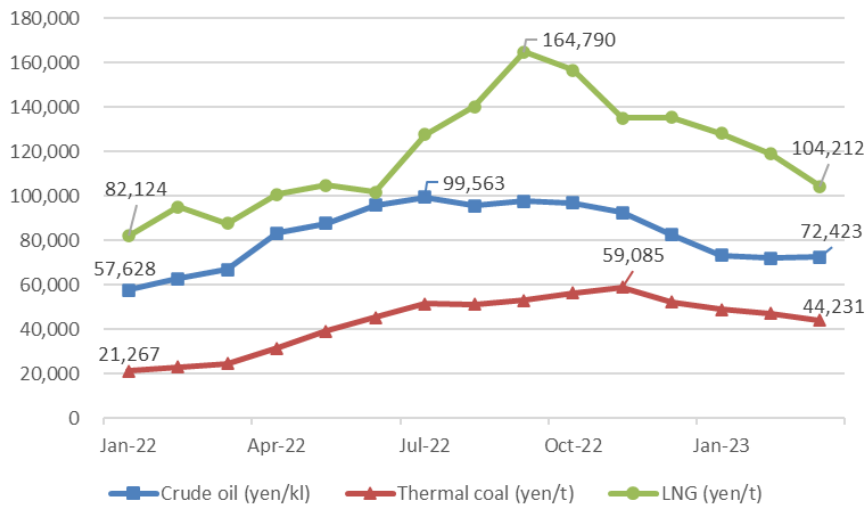

Figure 2: Trends in average import CIF prices for fuel

(Source: Created by the author based on trade statistics from the Ministry of Finance)

2. Estimating the of the Price Ceiling on Utility Companies

Based on the information provided in the first section, this paper will examine the impact that the sharp rise in fuel costs since last year has had on utility companies, using TEPCO as a case study. **Figure 3** shows the fuel adjustment unit price based on the price ceiling after April 2022, the actual fuel adjustment unit price in the absence of the ceiling price, and the difference between them, which is the unit price borne by utility companies. Since September 2022, when a burden of 1.37 yen/kWh was incurred, a burden on utility companies has continued to be incurred until May 2023. Although the amount borne by utility companies peaked at 7.91 yen/kWh in February 2023, as of May 2023 prices have not yet fallen below the upper limit of 5.13 yen/kWh that can be passed on to consumers. In response to soaring fuel costs, the Ministry of Economy, Trade and Industry implemented drastic alleviation measures,[2] which reduced the burden on consumers from January 2023 onwards. However, it should be noted that these measures were only aimed at consumers and that they did not contribute to reducing the burden on utility companies. As a result, since September 2022 TEPCO has been left with a structure in which it accumulates more losses the more electricity it sells under the regulated rate plan, and this situation has remained unresolved.

[2] "In order to Implement Measures to Alleviate Drastic Changes in Electricity and Gas Prices, Special Approval has been Granted to Discount Electricity and Gas Rates" on the Agency for Natural Resources and Energy website
Provided subsidies for electricity (7 yen/kWh for low voltage and 3.5 yen/kWh for high voltage) and city gas (30 yen/m3) to electricity and gas utility company consumers who received special approval, starting from January 2023 usage (February meter reading).
https://www.meti.go.jp/press/2022/12/20221216004/20221216004.html

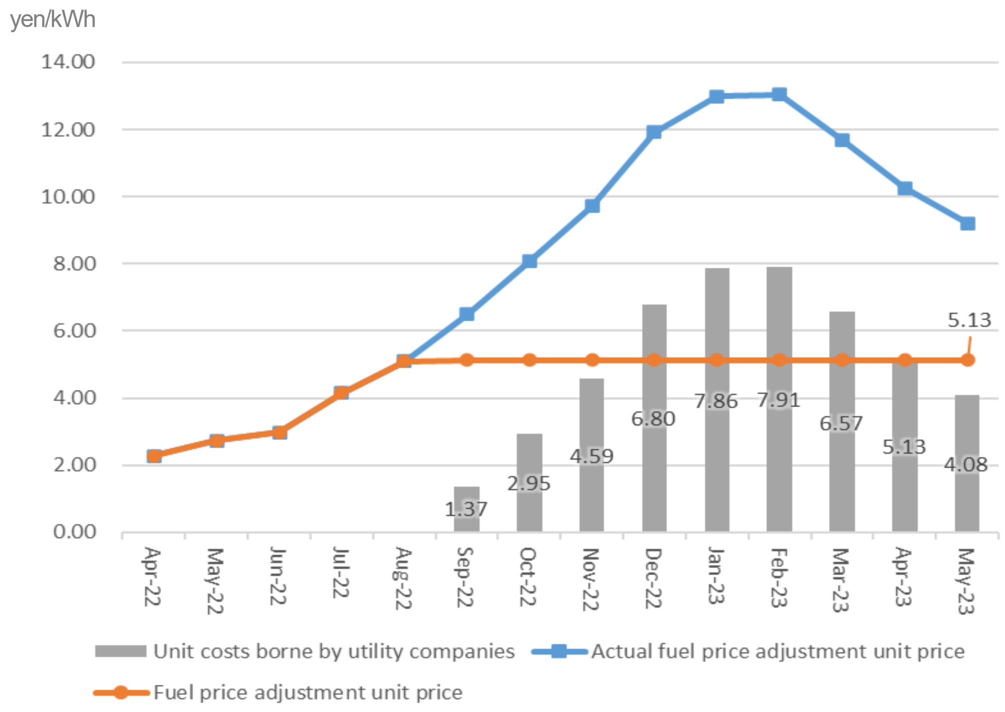

Figure 3: Trends in fuel price adjustment unit prices and unit costs borne by utility companies

(Source: Created by the author from the TEPCO website)

Figure 4 shows an estimate of these monthly costs that are being borne by utility companies, calculated by multiplying the sales volume of regulated rate plans in the TEPCO area. Although this is only a rough estimate based on publicly available statistics, the monthly burden on utility companies has been increasing since September 2022, resulting in a monthly burden of approx. 30 billion yen in January and February 2023, the peak period for heating use. The cumulative burden on utility companies from September 2022 to February 2023 was 101.6 billion yen. This amount accounts for 36% of the TEPCO Group's overall ordinary loss of 285.3 billion yen[3] for FY2022. Estimates were only able to be made up until February due to the publication of statistics, but if the figures for March are taken into account, then the burden could increase even further by 10s of billions of yen. Considering that the average ordinary income of the entire TEPCO Group is approx. 210 billion yen/year,[4] the accumulated burden up to February is just under 50% of TEPCO's ordinary income for a typical year. The results of these estimates have a strong impact on management, and it is easy to understand why utility companies so strongly wanted the rate revisions.

[3] "Financial Results for the Fiscal Year Ended March 2023" on the TEPCO website
https://www.tepco.co.jp/about/ir/library/results/pdf/2303q4gaiyou-j.pdf

[4] Estimated from "Consolidated Statement of Income" on the TEPCO website. Calculated the average for the nine-year period from FY2013 to FY2021, excluding FY2011 and FY2012, when TEPCO incurred losses due to the incident at the nuclear power plant.
https://www.tepco.co.jp/corporateinfo/illustrated/accounting/statement-income-consolidated-j.html

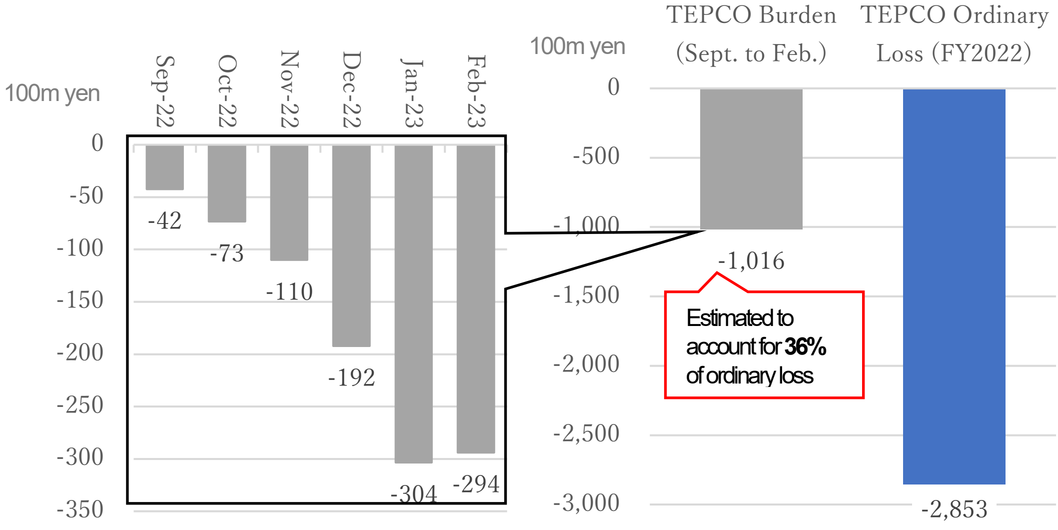

Figure 4: Estimate of the burden on TEPCO, derived from the price ceiling for regulated rates

(Source: Created by the author from TEPCO's website and the Electricity Trading Report)[5]

3. Impressions for the Future in Response to the Regulated Rate Review

Based on the results of the estimates in the second section, it is clear that the burden on utility companies, which is derived from the price ceiling for regulated rates, is a major contributor to expanding deficits at utility companies. The estimates in this paper looked at TEPCO, but it can be assumed that a similar situation is occurring at the other six utility companies that revised their prices this time. In light of this, one point that can be commended is that the rate revisions for all seven of the utility companies that applied for approval have been accepted and will be applied as of June 1, thereby reducing the excessive burden on the utility companies resulting from the price ceiling.

However, we recognize that several issues that should be considered in the future have become apparent in the recent regulatory rate revisions. The heated debate on raising regulated rates this time delayed the application of the new rate plans, which resulted in increased losses for the utility companies. Against the background of soaring fuel costs, there are also limits to utility companies' efforts to reduce costs. It seems necessary to design a system that will enable more flexible responses if a similar situation occurs in the future, at least regarding the fuel cost adjustment system and the price ceiling. Additionally, there were also reports[6] of a reversal phenomenon in which the regulated rates were cheaper than freely-set rates which do not impose a limit on passing on fuel costs to consumers. If the presence or absence of a legally mandated price ceiling becomes an incentive for consumers to choose regulated rates, then this could be a reversal of the market liberalization efforts that have been pursued to date. Taking this rate revision as an opportunity, it may be necessary to concretely reexamine the question of how long regulated rates should remain in the free market, along with measures to protect consumers that do not rely on regulated rates.

In any case, as indicated in **Figure 2**, fuel prices continue to remain high, and future trends are even more uncertain because they are influenced by developments in Russia and the global economy. Bearing in mind that similar situations may occur in the future, it may be necessary to sort out the direction of the electricity market as a whole, including the state of regulated rates. This seems like something that should be addressed as soon as possible, and the author will keep a close eye on future discussions on the system.

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[5] For estimation purposes, all regulated rate sales volumes in the Electricity Trading Report were calculated by assuming that all sales volumes were for metered contracts.
[6] "Reversal Phenomenon in Electricity Prices: Liberalized Rates More Expensive Due to Soaring Fuel Costs" in the Sankei Shimbun https://www.sankei.com/article/20220812-2Z4VED7PS5L4HLSTRFLAVOLRKM/

Voluntary Carbon Credit Trends (April-June 2023)

Corporate Trends in the Use of Voluntary Credits and Efforts to Ensure Credibility

Kiyoshi Komatsu* Soichi Morimoto** Mai Kojima*** Keita Katayama****

1. Introduction

Private demand for carbon credits has grown in recent years. For example, credits are used to offset greenhouse gas emissions generated in the LNG value chain to provide carbon neutral LNG (CNLNG). In fact, many Japanese companies provide CNLNG. On the other hand, a major challenge is how to ensure the credibility of credits, as media reports have been concerned about whether emissions reduction projects really reduce the amount of emissions.

The importance of carbon markets was emphasized in the Group of Seven Ministers' Meeting on Climate, Energy and Environment in Sapporo, Japan. Here, the Principles of High Integrity Carbon Markets were adopted, reaffirming the need to improve the quality of carbon markets, including voluntary credits. Initiatives to ensure the quality of credits are undertaken by both the supply and demand sides for voluntary credits. There are moves to formulate specific guidelines for this purpose.

This report shows the latest trends in voluntary carbon credits, summarizing the trends of private sector and credit issuers from April to June 2023.

2. Private sector trends

While some cast doubts on the credibility of voluntary carbon credits, some private sectors promote the development and trading of the credits. Among them, information technology giants Apple Inc. and Meta Platforms Inc. have announced their purchases of credits and their investment in nature-based solutions (NBSs), which are actions to reduce or remove CO_2 emissions through the protection of natural ecosystems In Japan, interest in voluntary carbon credits among companies is still high, as evidenced by a project to absorb CO_2 into seaweed and the opening of exchanges for trading in J-Credits. On the other hand, it has been reported that a well-known Western fashion brand used carbon credits to achieve its carbon neutrality goal, but later withdrew its claim on carbon neutrality due to concern about the credibility of the credits.[1] This reminds us that there are risks associated with voluntary carbon credits.

Here, we report in detail on the trend of demand for NBSs, regardless of headwinds or tailwinds, and on lawsuits over the use of credits for companies' voluntary carbon neutrality initiatives.

2.1. Persistent demand for NBSs

Currently, there are many projects called REDD+ (reducing emissions from deforestation and forest degradation) that reduce emissions through forest conservation and provide massive carbon credits. On January 18, 2023, however, the Guardian reported that REDD+ projects registered with VCS, which is a leading crediting program, might have provided excessive credits. Subsequently, a similar report was issued by Die Zeit, German newspaper), raising concerns about the credibility of REDD+ projects registered with VCS.[2]

There are various criticisms about credits derived from forest conservation, in particular REDD + project pointing to suspicions of overstating emissions reduction. However, demand is strong for credits derived from NBS initiatives to reduce or remove CO_2 from the atmosphere through the protection of natural ecosystems, including forest conservation.

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* Executive Analyst, Climate Change Group, Climate Change and Energy Efficiency Unit, IEEJ

** Senior Researcher, Climate Change Group, Climate Change and Energy Efficiency Unit, IEEJ

*** Senior Researcher, Climate Change Group, Climate Change and Energy Efficiency Unit, IEEJ

**** Researcher, Climate Change Group, Climate Change and Energy Efficiency Unit, IEEJ

[1] Greenfield, P., Ambrose, J., and Ormesher, E. (2023, May 15). Adverts claiming products are carbon neutral by using offsetting face UK ban. *The Guardian*. https://www.theguardian.com/environment/2023/may/15/uk-advertising-watchdog-to-crack-down-on-carbon-offsetting-claims-aoe

[2] Greenfield, P. (2023, January 18). Revealed: more than 90% of rainforest carbon offsets by biggest certifier are worthless, analysis shows. *The Guardian*. https://www.theguardian.com/environment/2023/jan/18/revealed-forest-carbon-offsets-biggest-provider-worthless-verra-aoe
REDD+ initiatives reduce CO_2 emissions or remove CO_2 from the atmosphere by preventing deforestation and expanding forest sinks. For more detailed information, see the following website: http://carbon-markets.env.go.jp/

In April, IT giant Apple announced that it would invest up to an additional $200 million in the Restore Fund launched in 2021 to tackle NBSs as part of the measures to achieve carbon neutrality in Scope 3 emissions by 2030.[3] Last year, Apple announced its goal of becoming carbon neutral throughout its global supply chain by 2030, achieving a 75% reduction in emissions and balancing residual emissions that are difficult to reduce with existing technologies through high-quality carbon removal. The investment aims to achieve this goal, with the company expected to remove up to one million tons of CO_2 per year.

The Restore Fund is planned to invest in two types of projects: (a) nature-forward agricultural projects that generate income from sustainably managed farming practices and (b) conserve and restore critical ecosystems that remove and store carbon from the atmosphere. Apple will use satellite imagery and other equipment to monitor and measure the impact of Restore Fund projects.

In June, Meta (formerly Facebook) signed a deal to purchase NBS-derived credits, according to an executive of Aspiration, the partner of the deal.[4] Meta has pre-ordered 6.75 million tons of carbon removal credits with an expected delivery from 2027 through 2035. These credits will be derived from reforestation, agroforestry, and sustainable agricultural practices in Aspiration's portfolio.

Although there has been no official announcement about the deal from Meta, the executive explains that Meta has set a goal to reach net-zero emissions across its entire value chain in 2030 and will work with Aspiration to achieve the goal. It is emphasized that the credits to be provided to Meta in the future will be those created by projects developed under high standards based on the company's experiences and achievements. Due to the fact that Aspiration has a track record of providing payment services and developing businesses related to voluntary credits and has already developed various projects to generate credits, Meta partnered with Aspiration.

Despite negative views about voluntary carbon credits, some companies have a strong demand for NBSs. Given that both Apple and Meta plan to use high-quality credits, it could be concluded that interest among companies in credible credits has not diminished.

It is also interesting that Apple plans to deploy its innovative remote sensing technologies for monitoring the status of Restore Fund projects to accurately grasp the status and measure carbon removal by using high-resolution satellite imagery to check forests and other natural ecosystems. This indicates that not only developers but also investors in NBS projects are required to engage to ensure the credibility of these projects.

2.2. Delta Air Lines hit with lawsuit over greenwashing allegations

The voluntary setting of carbon neutrality goals is coming under increasing scrutiny, leading to cases of suspected greenwashing. In Europe, government regulations on greenwashing have been implemented, with relevant lawsuits going on. In the United States as well, a lawsuit has been filed on suspected greenwashing regarding a corporate carbon neutrality initiative.

The lawsuit was filed against Delta Air Lines, a major U.S. air carrier. On May 30, it was sued in U.S. District Court in California for alleged greenwashing. One California resident filed the lawsuit as a so-called class action.[5]

According to the complaint, the plaintiff had purchased multiple tickets for Delta Air Lines in view of an ad on Delta's carbon neutrality initiative since 2020, paying premiums on recognition of the carrier’s contributions to environmental conservation. Delta claimed the use of voluntary carbon credits as grounds for its carbon neutrality initiative. Noting that voluntary carbon credits have been often criticized for failing to contribute to reducing emissions, however, the plaintiff has complained that Delta’s claims regarding carbon neutrality are misleading.

In response to the complaint, a Delta spokesperson countered that the company is not relying solely on voluntary credits to achieve carbon neutrality, commenting that the lawsuit is not subject to legal action. The spokesperson also noted that Delta focuses not only on voluntary carbon credits toward the decarbonization of its operations, but also on its efforts to invest in sustainable aviation fuel and renew its fleet with more fuel-efficient aircraft since 2022[6]

A legal expert pointed out that consumers’ lawsuit targets are shifting from companies’ products to their false advertisements of addressing social and environmental issues as a consequence of an increase in consumer interest in environmental issues, which has led companies to

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[3] Apple. (2023, April 11). *Apple expands innovative Restore Fund for carbon removal* [Press release]. https://www.apple.com/newsroom/2023/04/apple-expands-innovative-restore-fund-for-carbon-removal/?utm_source=pocket_reader

[4] Lee, R. (2023, June 7). Meta and Aspiration partner to scale nature-based carbon removal solutions. *Green Biz*. https://www.greenbiz.com/article/meta-and-aspiration-partner-scale-nature-based-carbon-removal-solutions?utm_source=pocket_reader

[5] A class action is a procedural device that permits one or more plaintiffs to file a lawsuit on behalf of a larger group, or “class.” See https://www.law.cornell.edu/wex/class_action

[6] Davey, E. (2023, May 31). Delta Air Lines hit with lawsuit over claims of carbon neutrality. *AP*. https://apnews.com/article/delta-airlines-lawsuit-carbon-credits-carbon-neutral-469f2671010ba7f40c934cc23d62149a

implement and advertise various initiatives to protect the environment.[7] This means that companies have no choice but to prepare for such risks when advertising their initiatives to address environmental issues. In this sense, companies that claim to be committed to protecting the environment need to ensure that they are making efforts to protect the environment and should prepare to respond decisively when greenwashing and other allegations are raised, according to the expert.

We here introduced the lawsuit filed against Delta Air Lines in the United States. Lawsuits have been filed over the use of credits by companies to achieve voluntary carbon neutrality in Europe as well, indicating litigation is a risk for companies that use voluntary carbon credits.

3. Trends among credit issuing institutions

Amid the scrutiny of corporate greenwashing, there is a growing need for standards and guidelines to enhance the credibility of voluntary carbon credits. These standards and guidelines have been considered by both the credit supply and demand sides. The consideration is difficult, involving coordination among a wide variety of stakeholders and navigation between ideals and reality. Here, we introduce credit quality standards published by the Integrity Council for the Voluntary Carbon Markets (ICVCM) in late March 2023 and a rulebook for companies using voluntary credits published by the Voluntary Carbon Markets Integrity Initiative (VCMI) in late June. While there is still some work to be done, both are expected to become operational within 2023.

3.1. ICVCM published standards to ensure the quality of voluntary credits[8]

On March 30, 2023, the ICVCM released the final version of the Core Carbon Principles (CCPs) and related documents. The ICVCM was established in October 2021 as an organization to consider global quality standards and evaluation frameworks for voluntary credits. It took over the consideration of the CCPs for voluntary credits and credit-issuing institutions to secure the quality of credits, as recommended by its predecessor, the Taskforce on Scaling Voluntary Carbon Markets (TSVCM).

The final version of CCPs came far behind schedule via public consultations on a draft published in July 2022. As described later, however, half the assessment framework required for the implementation of the CCPs has yet to be published, leaving relevant talks to continue.

The published CCPs consist of the following 10 principles that credible carbon credit programs must meet:

Table Overview of Core Carbon Principles (CCPs)

Governance	Emission Impact	Sustainable Development
・ Effective Governance ・ Tracking ・ Transparency ・ Robust independent third-party validation and verification	・ Additionality ・ Permanence ・ Robust quantification of emissions reductions and removals ・ No double counting	・ Sustainable development benefits and safeguards ・ Contributing to net zero transition

Source: Retrieved from "Fact Sheet: Integrity Council for the Voluntary Carbon Market" by ICVCM[9]

When the principles are implemented, criteria are naturally required to determine whether the above principles are satisfied. The criteria are described in a document called Assessment Framework. The Assessment Framework consists of criteria at the program level (at the level of programs for registering Verra, Gold Standard, and other projects and issuing credits) and at the category level (at the level of individual credit-issuing projects [such as forest projects] registered under the programs). Only the program-level criteria have been released along with the CCPs (category-level criteria are planned to be released in the middle of 2023).

[7] McLain, B. J., and Waldhauser, C. K. (2023, June 15). Carbon Neutrality Suit Against Delta Airlines Signals the Arrival Time of "Greenwashing" Litigation. *Foley & Lardner LLP*. https://www.foley.com/en/insights/publications/2023/06/carbon-neutrality-suit-delta-airlines-greenwashing

[8] The Integrity Council for the Voluntary Carbon Market. (2023, March 29). *Integrity Council launches global benchmark for high-integrity carbon credits* [Press release]. https://icvcm.org/integrity-council-launches-global-benchmark-for-high-integrity-carbon-credits/

[9] The Integrity Council for the Voluntary Carbon Market. *Fact Sheet: Integrity Council for the Voluntary Carbon Market.* https://icvcm.org/wp-content/uploads/2023/05/CCP-Fact-Sheet-6-4-23.docx

The program-level criteria comply with the requirements for programs to issue credits recognized as eligible under the Carbon Offsetting and Reduction Scheme for International Aviation (CORSIA) implemented by the International Civil Aviation Organization (ICAO) since 2021 for commercial airlines to counter global warming, while including some additional requirements.[10] As for CORSIA-eligible programs, there is no need to provide evidence for the criteria required by CORSIA, but evidence is required for additional requirements. For example, in addition to the governance requirements under CORSIA, establishing an independent council operated under robust rules is required.

Furthermore, the ICVCM has paid special attention to indigenous peoples and local communities in the development of CCPs regarding sustainable development. The ICVCM holds a public consultation process including a workshop to hear from indigenous peoples and local communities and they allocate three of their 22 board seats to members from indigenous peoples and local communities. The CCPs require free, prior and informed consent (FPIC) to be secured for indigenous peoples and local communities and REDD+[11] projects to comply with Cancun Safeguards[12] measures to prevent adverse social and environmental impacts.

Critical requirements, such as the specifics of category-level criteria for projects to be approved, the definition of additionality and permanence, and the quantification of reductions and removals (setting baselines) will be made available when the category-level criteria are published in mid-2023. According to the ICVCM, applications for specific programs will be opened in mid-2023. In the third quarter of 2023, the categories that should be promoted quickly or prioritized will be announced. In the second half of this year, CCP-Eligible programs and CCP-Approved categories will be published, with CCP-labeled credits debuting in the market.

A document on CCP Attributes has also been released. Three attributes are used to identify additional features: (1) Host country authorization pursuant to Article 6 of the Paris Agreement, (2) Share of Proceeds for Adaptation, and (3) Quantified positive SDG impacts.

As mentioned above, the announcement of the CCPs seems to have been generally welcomed by major carbon credit programs, such as Verra and Gold Standard, which issue voluntary credits, as well as market participants, although some details of the CCPs are still unclear. Verra had once criticized the draft published in July last year as a "one-size-fits-all approach" failing to take into account regional characteristics and the requirements for CCPs as too prescriptive and unworkable.[13] However, Verra announced that the release of CCPs was "an important moment for the voluntary carbon market", and "the work of the ICVCM will continue to increase confidence in the market".[14] The Environmental Defense Fund (EDF), an environmental NGO, and others have asserted that the allocation of proceeds to adaptation, which is currently optional, should be mandatory. However, this assertion came under opposition from project developers and market participants.[15]

3.2. VCMI published a rulebook for the use of voluntary credits[16]

On June 28, 2023, the VCMI published the VCMI Claims Cod, a rulebook for companies using voluntary credits. The VCMI, established in 2021 by Sir Alok Sharma, who was appointed as president for the 26th Conference of Parties to the United Nations Framework Convention on Climate Change (COP26), has formulated the above rulebook for credit users and the VCM Access Strategy Toolkit as guidance for credit suppliers to encourage host countries' market participation. The rulebook for credit users is an extension of the provisional version announced in June last year, reflecting the requirements of major initiatives, such as the Carbon Pricing Leadership Coalition (CPLC) and the Science Based Target initiative (SBTi). Its publication came after public consultations and field trials by about 70 companies. The Claims Code consists of four steps for the use of voluntary credits for corporate emissions reductions:

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[10] Under CORSIA, commercial airlines operating international flights are required to limit emissions to the standard level from 2021. Credits allowed to be used to comply with this requirement are limited to those issued in programs that meet the criteria set by ICAO and CORSIA-Eligible programs. For more information on the criteria for CORSIA-Eligible programs, see the following website (in Japanese): http://carbon-markets.env.go.jp/mkt-mech/climate/icao.html

[11] For an explanation of REDD+, see **footnote 1**.

[12] Safeguards to avoid adverse social and environmental impacts in the implementation of REDD+ were discussed at the UNFCCC and adopted as Cancun Safeguards at COP16. For more details, see (in Japanese): http://redd.ffpri.affrc.go.jp/technical/safeguard_ja.html

[13] Verra. (2022, September 21) *ICVCM Process Needs Course Correction* [Press release]. https://verra.org/icvcm-process-needs-course-correction/

[14] Verra. (2023, March 31). *March Newsletter* [Press release]. https://verra.org/march-newsletter-2/

[15] Lo, J. (2023, March 30). Carbon credit industry resists vulnerable nations' call to fund adaptation. *Climate Home News*. https://climatechangenews.com/2023/03/30/carbon- credit-industry-resists-vulnerable-nations-call-to-fund-adaptation/

[16] VCMI. (2023, June 28). *Global launch: New VCMI Claims Code to accelerate corporate use of voluntary carbon markets as part of net-zero pathways* [Press release]. https://vcmintegrity.org/launch-claims-code/

Steps for making a VCMI claim

(1) Comply with the Foundational Criteria. Specifically, a company is required to maintain and publicly disclose an annual GHG emissions inventory, to set and publicly disclose validated science-based near-term emissions reduction targets and publicly commit to reaching net zero emissions no later than 2050, and to demonstrate that the company is on track towards meeting a near-term emissions reduction target. The company is required to set an emission reduction target[17] based on its identification of emissions throughout its value chain (covering Scopes 1, 2, and 3) and disclose the target's percentage share of the emissions.

(2) Select a VCMI Claim to make from the three tiers – Platinum, Gold, and Silver. VCMI Silver is the lowest tier that a company is required to demonstrate progress towards its near-term targets. It requires the purchase and retirement of carbon credits in an amount of 20-60% of a company's remaining emissions. Gold requires 60-100% and Platinum, the highest tier, requires equal to or greater than 100% of remaining emissions.

(3) Select high-quality credits following the ICVCM CCPs beyond value chain mitigation.

(4) Obtain third-party assurance following the VCMI Monitoring, Reporting and Assurance (MRA) Framework

In November 2023, the abovementioned MRA Framework and other additional documents will be released, allowing companies to make VCMI claims by the end of the year.[18]

While initiatives to formulate codes for using voluntary credits have been undertaken not only by VCMI but also by various other entities,[19] voluntary credit market experts have questioned that VCMI requirements are so hard for companies, which will result in a decrease in demand for credits. According to Trove Research, more than 470 companies using carbon credits show that only 3.8% of these companies currently meet VCMI Silver claims since the foundational criteria are difficult to achieve. The survey shows that although 40% of companies have a net zero target, only 25% meet VCMI's requirements.[20]

In response, the VCMI plans to consider and publish some additional guidance within several months to make the rulebook more flexible to secure more companies' market participation while maintaining high ambitions for emissions reductions.[21] We should consistently observe whether this rulebook will be established as a guideline balancing between ideals and reality, which will diffuse among companies.

[17] Regarding Scope 3 near-term targets, the SBTi standards require that 67% of Scope 3 emissions must be covered under target(s) if Scope 3 emissions become 40% or more of total emissions. If a company sells fossil fuels, however, its target must cover all Scope 3 emissions.

[18] VCMI. (2023, June 28). *Global launch: New VCMI Claims Code to accelerate corporate use of voluntary carbon markets as part of net-zero pathways* [Press release]. https://vcmintegrity.org/launch-claims-code/

[19] For example, South Pole, a project developer and credit intermediary, published its own Funding Climate Action label on the day before the publication of the VCMI Claims Code of Practice.

[20] Trove Research (2023, June 29) *VCMI Claims Code of Practice – Important progress but the difficult stuff still lies ahead.* https://trove-research.com/report/vcmi-claims-code-of-practice-important-progress-but-the-difficult-stuff-still-lies-ahead

[21] Presentation by Mr. Mark Kenber, Executive Director of VCMI, at the VCMI Claims Code of Practice Global Launch Event. Available on the following website: https://vcmintegrity.org/vcmi-claims-code-launch-event/

Introduction to Emission Trading Systems in Various Countries

Tohru Shimizu[*,**]

Japan promulgated the Act on Promotion of a Smooth Transition to a Decarbonized Growth-Oriented Economic Structure (GX Promotion Act) that contains the establishment of an emission trading system (ETS) on May 19, 2023. The Basic Policy for the Realization of GX passed by the Cabinet in February ahead of the promulgation indicates the start of voluntary ETS (GX ETS) in FY2023, initiate to full implementation of GX ETS from FY2026, and implementation of a specified business charge (emission allowance auction) for power generation operators based on the GX Promotion Act from FY2033.

The GX ETS design reflects the interim report of the Study Group on Ideal Economic Approaches for Achieving Worldwide Carbon Neutrality prepared in August 2021 and subsequent dialogue with industry organizations and companies in the GX League. Companies that plan to participate need to set voluntary target levels by the end of September 2023.

And, before the full implementation of GX-ETS from FY2026, the GX Promotion Act stipulates the preparation of a detailed system design within two years of promulgation, and discussions that factor in voluntary GX ETS progress and results should steadily advance.

While discussions in Japan often cite the European Union Emission Trading System (EU ETS) as an example, the World Bank's annual report on carbon pricing (State and Trends of Carbon Pricing 2023) indicates that 36 countries and regions were implementing ETS as of April 2023, and each of these systems has its own characteristics. Cap, allocation, minimum and maximum price setting, and other aspects of these programs are not necessarily the same as the EU ETS.

Comparative analysis of these various countries and regions, ETS is likely to offer valuable suggestions for the detailed system design of GX ETS. However, this must be done from a comprehensive perspective. For example, the price level of ETS with different system designs incorporates impacts from many factors, such as allowance auction ratio, availability of carbon offset credits, minimum and maximum price setting, energy supply-demand conditions, socioeconomic structures, and related energy efficiency and renewable energy policies of individual countries and regions as background of the ETS. This is why it is necessary to conduct a comprehensive review that covers not only the pricing level but also the background of system design when comparing systems. Rooted in this awareness, the subject series hence reviews and analyzes the country and regional ETS of the EU, China, Korea, US (RGCI, California), NZ, India, Australia, and Canada comprehensively and using common measures as much as possible, and finally compares systems.

While the subject series utilizes results from reviews of the carbon pricing programs of various countries conducted in FY2022 by the IEEJ as a consignment project from METI, the suggestions for GX ETS using these results are the independent opinions of individual researchers and do not represent METI opinions.

* Senior Researcher, Climate Change Group, Climate Change and Energy Efficiency Unit, IEEJ

** Corresponding author

Korea Emissions Trading Scheme (K-ETS)

Kim Seonghee*

1. Climate change policy outline

The Republic of Korea set out its 2020 greenhouse gas emission reduction target (a 30% cut from the business-as-usual level) in 2009 and enacted the Basic Act on Low Carbon Green Growth (hereinafter referred to as the Basic Act) as a basic framework for reducing GHG emissions in January 2010. The Basic Act stipulated the formulation of a basic plan on climate change and energy, and the introduction of the GHG and Energy Target Management System,[1] a GHG emissions and energy consumption reporting system, and an emissions trading scheme (hereinafter referred to as ETS) as major policies. In 2012, the Act on the Allocation and Trading of Greenhouse Gas Emission Permits (hereinafter referred to as the Trading Act) was enacted, stipulating detailed rules for the ETS. Since January 2015, the ETS has been implemented.

In Korea under a presidential system, policy changes tend to accompany government changes. The Moon Jae-in administration between May 2017 and April 2022 focused on environmental policy, advocating the enhancement of air pollution countermeasures and a transition to renewable energy, as well as promoting nuclear and coal phase-out. Regarding the national GHG emission reduction target for 2030, its predecessor set out a 37% cut from the BAU level in 2015. In October 2021, however, the Moon administration revised the target into a 40% cut from 2018 and specified the target in law to make it difficult for any future administration to revise the target.[2] Nonetheless, the conservative Yoon Suk Yeol administration, which was launched in May 2022 after winning back the presidency in the March 2022 election, has announced policies such as the withdrawal of the nuclear phase-out, the appropriate, feasible spread of renewable energy, and priority given to incentives for companies rather than regulations. The First National Basic Plan for Carbon Neutral Green Growth Basic Plan,[3] formulated in April 2023, retained the national GHG emission reduction target for 2030, while lowering the reduction target for the industrial sector from 14.5% to 11.4% to ease the sector's burden.

2. ETS scheme design

2.1. Overview

Since 2015, the K-ETS has been implemented for 69 subsectors in six sectors: industry, energy conversion, buildings, transportation, public, and waste.[4] The ETS is positioned as a major measure to achieve Korea's medium-term GHG emission reduction target. Basically, a five-year plan is set for implementing the ETS. However, the first six years of 2020 were designed as a transitional system operation period that was divided into the first phase (between 2015 and 2017) and the second phase (between 2018 and 2020). The third phase started in January 2021 and will last for five years. In the future, each phase will be set for every five years. The Korean ETS covers both direct and indirect emissions from the use of electricity and heat.

Although free emission permits have been allocated to alleviate the industry sector's burden regarding the reduction of GHG emissions, the percentage share for free emission allowances has been gradually lowered. The share was 100% in the first phase, 97% in the second, and 90% in the third. Some emission permits are allocated to a liable entity through auctions held regularly by the government.

As a flexibility mechanism, surplus emission permits can be carried over to the next compliance year and if emission permits

* Executive Economist, Manager, Energy Efficiency Group, Climate Change and Energy Efficiency Unit, IEEJ

[1] The GHG and Energy Target Management System, a system in which the government sets and manages GHG and energy reduction targets for companies and business sites of a certain size or larger, has been in effect since 2010. The system initially covered companies with annual GHG emissions of 125,000 tons of CO_2 equivalent or more and gradually expanded the coverage later to eventually include companies with annual GHG emissions of 50,000 t-CO_2e or more. When the ETS was launched in 2015, companies with annual emissions of 125,000 t-CO_2e or more were covered by the ETS, leaving smaller companies to be subject to the system, which was renamed GHG Target Management System.

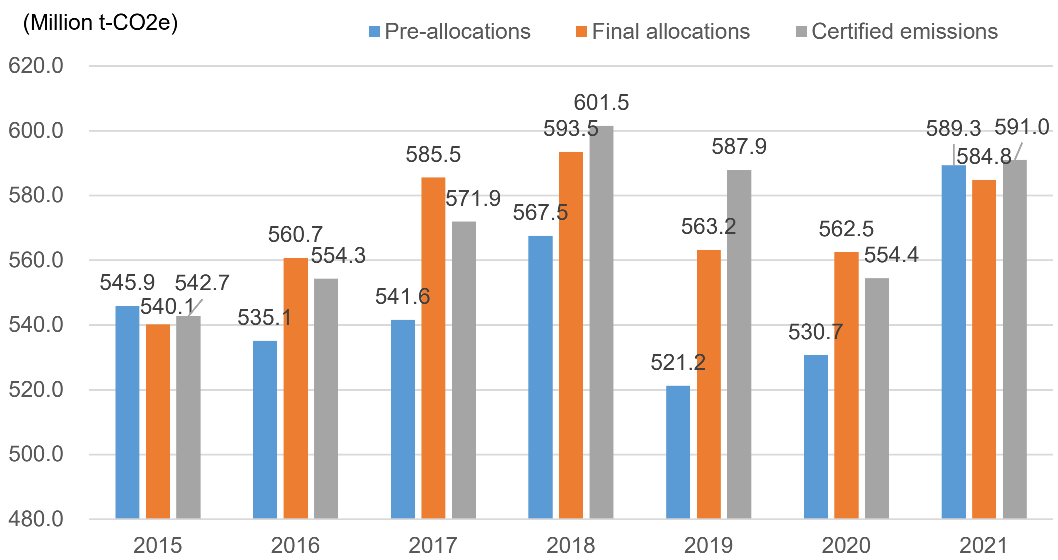
[2] In December 2019, the government replaced the target GHG emission cut from the BAU level with the cut from a base year and adopted a target of cutting GHG emissions in 2030 by 26.3% from 2018. In October 2021, however, the target was raised to a 40% cut. In order to prevent the downward revision of the target after a government change, the Framework Act on Carbon Neutrality and Green Growth for Coping with Climate Crisis (implemented in September 2021) provides that the government shall determine the GHG emission reduction target rate for 2030 within a range of 35% or more from 2018 by presidential decree (Article 8 (1)).

[3] Relevant government agencies (April 2023), "National Strategy for Carbon Neutrality and Green Growth and First National Basic Plan."

[4] In 2015, the K-ETS covered 23 subsectors in five sectors: industry, energy conversion, buildings, transportation, and waste.

are insufficient, a portion of allocated emission permits can be borrowed from the next compliance year within a single phase. In the first phase, there were no restrictions on banking volume, however, supply shortages of emission permits have led to the introduction of restrictions on banking volume to encourage companies to sell surplus emission permits to the market. For banking and borrowing restrictions, see the appendix table at the end of the text.

Figure 1 shows pre-allocations, final allocations, certified emissions, and the number of liable entities designated between 2015 and 2021. Liable entities need to apply to the government for allocations four months before the start of a phase. The final allocation amount will be adjusted reflecting a number of changes including new entrants, additional allocation, allocation revocation, and succession of rights and obligations that occur in that compliance year. The trend of annual certified emissions shows that emissions were increasing despite the K-ETS introduction, before decreasing in 2019 for the first time. In 2020, emissions decreased due to the impact of the economic recession caused by the COVID-19 outbreak. In 2021, however, emissions increased by 6.6% from 2020 due to an economic recovery and an increase in the number of liable entities in the third phase.



FY	2015	2016	2017	2018	2019	2020	2021
Number of liable entities designated	522	560	591	586	610	636	687

Figure 1 Changes in the number of liable entities designated, allocations and certified emissions (2015-2021)

Source: Prepared by the author from each year's edition of the Korean Emissions Trading System Report by the Greenhouse Gas Inventory and Research Center of the Korea Ministry of the Environment

2.2. Allocation methodology

Allocation methods consist of grandfathering, under which emissions permits to liable entities are based on historic emissions, and benchmarking, under which emissions permits are allocated based on the emissions efficiency of their facilities. From the viewpoint of equitability and incentives for investment in emission reductions, subsectors applying the benchmarking method have gradually increased. The number of subsectors for the benchmarking method rose from 3 in the first phase to 7 in the second and 12 in the third (Table1).

Table1 Subsectors for benchmarking-based allocation

Phase	Subsectors for benchmarking
First phase (2015-2017)	Oil refinery, Cement, Aviation
Second phase (2018-2020)	Oil refinery, Cement, Aviation, Integrated energy supply (residential), Integrated energy supply (industrial), Waste
Third phase (2021-2025)	Oil refinery, Cement, Aviation, Integrated energy supply (residential), Integrated energy supply (industrial) Waste, Steel, Petrochemical, Buildings, Paper and wood

Source: Korea Ministry of the Environment (September 2020) National Emission Allowance Allocation Plan for the Third Phase of the GHG Emissions Trading Scheme

When the grandfathering method is used for calculating allocations, actual reductions in the base period[5] are reflected, with some allocation coefficients[6] used, in order to improve the equitability of allocations.

When emission allowance allocations to companies are decided, allowances for auction (10% of total allowances in the third phase) are subtracted from the company's account and transferred to the government's accounts for auction in the allowance registry. Auctions are held by the government regularly. Unsold allowances are canceled at the end of each phase or carried over.

In consideration of international competition, all allowances are allocated free of charge to subsectors with a value of 0.002 (0.2%) or more for trade intensity[7] multiplied by the cost incurred. In the third phase, 28 sub-sectors were subjected to free allocations.

2.3. Offset Credits

In the K-ETS, emission reductions implemented by covered entities outside their organizational boundaries are referred to as "external reductions". Credits generated from external reductions can be used for compliance with the K-ETS. External reductions are divided into domestic and overseas reductions and subjected to government approval and registration through application according to the prescribed methodology.

- Domestic reductions: Reductions outside liable entities' organizational boundaries
- Overseas reductions: Reductions through overseas CDM (Clean Development Mechanism) projects implemented directly by domestic companies, etc.[8]

Korea Offset Credits (KOCs) are issued for approved domestic and overseas external reductions. KOCs are tradable, but they must be converted into Korea Credit Units (KCUs) to be used for K-ETS compliance. Only liable entities can apply for converting KOCs into KCUs. KCUs are limited to 5% of liable entities' annual budget in the third phase.[9]

Figure 2 shows the trading volume and annual average transaction prices of all emission permits (Korean Allowance Units (KAUs), KCUs, and KOCs) from the first phase to August 2022 of the third phase. Total trading volume came to 257.2 million tons, or about 6,225.8 billion won. Annual trading volume was limited to 5.7 million tons in 2015 before increasing to 12 million tons in 2016, 26.3 million tons in 2017, and 47.5 million tons in 2018. Thus, trading volume soared by more than 100% every year. Trading volume for KAUs totaled 216.8 million tons, accounting for about 84.3% of the total trading volume, followed by 36.3 million tons (14.1%) for KOCs and 4.1 million tons (1.6%) for KCUs.

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[5] The base period for each ETS phase is the three-year period beginning four years prior to the start of the phase. For example, the base period for Phase 3 is 2017-2019.

[6] Emissions from relevant emission activities, sectoral or sub-sectoral emission characteristics, or emission reduction potential, shares of emissions in relevant sub-sectors, etc. are comprehensively considered to decide whether to use any allocation coefficients.

[7] The calculation method for cost incurred and trade intensity is stipulated in the enforcement decree of the Trading Act (Article 19, Appendix 1).
Trade intensity: (average annual export value + average annual import value) / (average annual sales value + average annual import value)
Cost incurred: (average annual emissions × average market price of emission allowances) / (average annual value-added production)

[8] If an international emission reduction scheme is established to recognize Korean reductions in accordance with the Paris Agreement, however, reductions under the scheme will be certified as external reductions.

[9] Initially, offset credits were limited to 10% of liable entities' annual budget, with overseas credits limited to 50% of offset credits. In March 2021, however, the offset credit limit was lowered from 10% to 5%, with a limit on overseas credits lifted.

No trading was seen in KCUs between 2018 and 2021. The average annual trading price of KAUs accounting for more than 80% of the total trading volume increased significantly every year, from 12,044 won (1 yen is 9.08 won) in 2015 to 30,713 won in 2020, but it fell due to the COVID-19 outbreak before rising back slightly in 2022.[10] In the first and second phases, only liable entities were allowed to participate in transactions. From December 2021, however, securities companies were allowed to take part in transactions to vitalize the market.

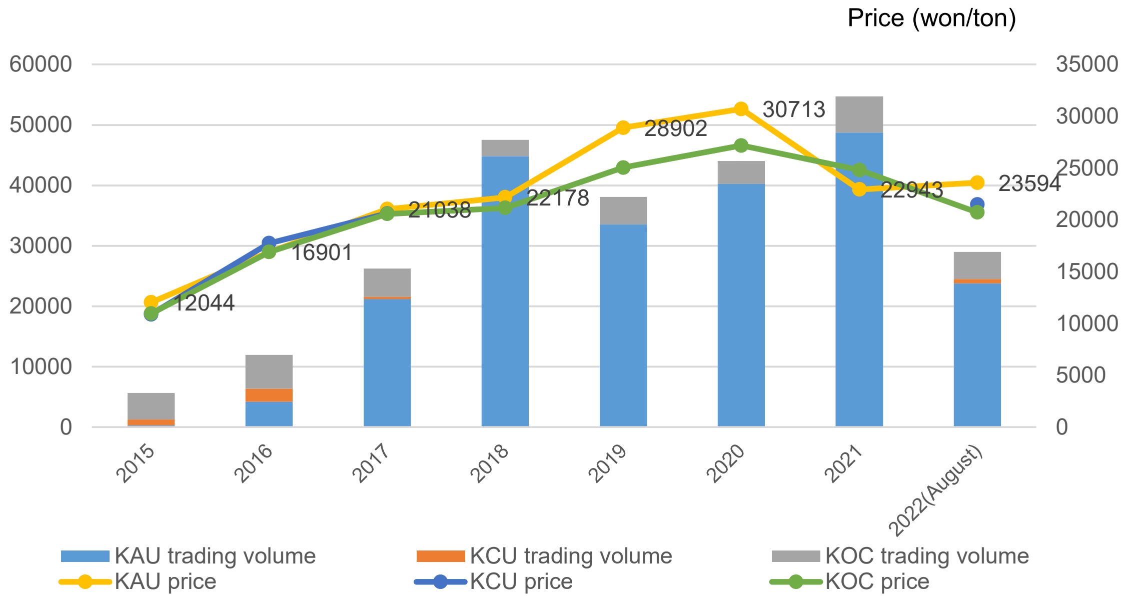

Figure 2 Trading Volume and transaction prices by emission allowance (2015-August 2022)

Source: Prepared by the author from "2022 Korean Emissions Trading System Report" by the Greenhouse Gas Inventory and Research Center of the Korea Ministry of the Environment

2.4. Monitoring, reporting, and verifying of emissions

The details of how to monitor, verify, and report emissions to the government are provided in the guidelines for reporting and certification of emissions for the allocated GHG emission allowance trading scheme (Ministry of the Environment Notification No. 2021-10, implemented on January 1, 2021). Liable entities calculate annual emissions by corporation, business site, equipment unit, and emission activity, prepare detailed emissions statements, have them verified by third-party verification organizations, and submit them to the Minister of the Environment electronically within three months after the end of the relevant fiscal year. The Ministry of the Environment confirms and certifies the submitted statements, but the Minister of the Environment can outsource certification to a contractor (Figure 3). The Ministry of the Environment also undertakes the disclosure of statements submitted by companies, publishing relevant company names, their emissions, verification organization names, energy consumption, etc. on the website of the National Greenhouse Gas Management System (https://ngms.gir.go.kr/main.do) every year.

[10] As of July 2023, the FY2022 KAU price declined further to 9.950 won/ton temporarily. In preparation for the KAU22 settlement (covered entities' submission of emission permits to offset their emissions) in August, massive surplus allowances might have flowed into the market. The decline may also be attributable to an economic slowdown and the supply of surplus emission allowances above the banking limit.

2020	
September	・Designation of liable entities
October	・Formulation of an allocation plan
October-November	・Submission of applications for allocations
December	・Notification of allocations

2021-2024	
March	・Submission of detailed emissions statements ・Application for additional allocations
May	・Certification of emissions ・Notification of additional allocations
July	・Designation of liable entities (including new entry)
August	・Submission of applications for allocations (including new entry) ・Application for banking and borrowing ・Submission of emission permits
October	Notification of allocations (including new entry)

2025	
March	・Submission of detailed emissions statements ・Application for additional allocations
May	・Certification of emissions ・Notification of additional allocations
August	・Application for banking and borrowing ・Submission of emission permits

Figure 3 Main schedule for the third phase

Source: Created by the author from the website of the Korea Environment Corporation[11]

2.5. Relationship with other policies

The K-ETS is not directly linked to other systems such as taxation. Korea's energy tax system seeks to secure adequate transportation fuel consumption and improve air pollution. It was introduced as a transportation tax in 1993 and completely revised in 2006 into a transportation, energy, and environment tax. The tax is designed not to combat global warming, but to raise financial resources for projects to expand transportation facilities, such as roads and railways, foster public transportation, develop energy resources, and improve air pollution and other environmental problems. On the other hand, a subsidy program is implemented to cover up to 50% of investment in emission reduction equipment to support ETS target company. The subsidy program covers purchasing, installment, test operation, consulting, and other costs for emission reduction equipment, such as renewable energy, waste heat recovery, and energy-efficient facilities.[12]

3. Implications for Japan's GX ETS

The characteristic of the K-ETS is that, although the framework is given by the Trading Act, details are provided by the enforcement decree, presidential decrees, guidelines, etc., and can be revised or changed in a timely manner according to the operation status of the scheme. The flexibility in system design and operation had the advantage of allowing K-ETS participants to easily undergo the trial-and-error process, especially in the early stages of the scheme. However, frequent rule changes have increased uncertainties about the scheme, making it difficult for companies to make bold investments in emission cuts. If sufficient information or data are not available for relevant sectors, how to fairly make initial emission allowance allocations is important. In Korea, there were many lawsuits over the appropriateness of pre-allocations. Other major challenges include how to encourage companies to reduce emissions and find appropriate price levels to avoid excessive burdens on them as allowance prices fluctuate wildly.

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[11] Korea Environment Corporation, "Greenhouse Gas Emissions Trading Scheme" website https://www.keco.or.kr/web/lay1/S1T164C1007/contents.do

[12] Article 35 of the Trading Act stipulates that auction revenues can be used for tax incentives, financial aid, subsidies, and other support measures for investment and technological development for cutting emissions.

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1) "Act on the Allocation and Trading of Greenhouse Gas Emission Permits (Enacted on September 4, 2021, and implemented on March 25, 2022)"
https://www.law.go.kr/LSW/lsInfoP.do?lsiSeq=235581#0000

2) "Enforcement Decree of the Act on the Allocation and Trading of Greenhouse Gas Emission Permits (Implemented on March 25, 2022)"
https://www.law.go.kr/LSW/lsInfoP.do?lsiSeq=241541#0000

3) Greenhouse Gas Inventory and Research Center (2020), "2018 Korean Emissions Trading System Report"
http://www.gir.go.kr/home/board/read.do?pagerOffset=40&maxPageItems=10&maxIndexPages=10&searchKey=&searchValue=&menuId=20&boardId=37&boardMasterId=9&boardCategoryId=

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Appendix: K-ETS Outline

Outline	Name	Korea Emissions Trading Scheme
	Legal ground (Names of laws)	Framework Act on Carbon Neutrality and Green Growth for Coping with Climate Crisis (2010) (formerly, the Basic Act on Low Carbon Green Growth (2010)) Act on the Allocation and Trading of Greenhouse Gas Emission Permits (2012)
	Outline	Domestic emissions trading scheme covering six sectors: industry, energy conversion, buildings, transportation, public, and waste
	Supervisory authorities	Ministry of the Environment, competent government agencies for each sector
	Commencement	January 2015
	Trading phases	1st phase (2015-2017), 2nd phase (2018-2020), 3rd phase (2021-2025), followed by five-year phases
Targets	Units	(1) companies (corporations) as organizations, but companies, business establishments, and facilities are required to report emissions and energy consumption to the government.
	Major requirements for targets	Business operators with average annual GHG emissions of 125,000 t-CO_2eq or more for the past three years, or business establishments with average annual GHG emissions of 25,000 t-CO_2eq or more. Voluntary participation by others is allowed.
	Target GHGs	6 gases (CO_2, CH_4, N_2O, HFCs, PFCs, SF_6) and indirect emissions are covered.
	Emissions (direct and indirect)	Direct and indirect emissions
	Coverage	3rd phase (2021-2025): 685 companies in 69 sub-sectors, covering 73.5% of emissions
How to set targets	Allocation method[13]	・Based on past GHG emissions, emission cuts, expected sub-sector growth, carbon intensity, trade intensity, etc. ・Free allocations for third and later phases account for 90% or less of total allocations.[14] ・Allocations are based on the emission standard (grandfathering) method and the emission efficiency standard (benchmarking) method. 【Subsectors for benchmarking】 ・1st phase: 3 subsectors (oil refinery, cement, aviation) → 2nd trading phase: 7 subsectors (1st phase targets + Integrated energy supply (residential), Integrated energy supply (industrial), Waste) → 3rd trading phase: 12 subsectors (2nd phase targets + Steel, Petrochemical, Buildings, Paper and wood) ・In response to liable entities' applications for allocations, allocations are made to business operators within caps for sectors/subsectors to which the companies belong.[15] ・Subsequent adjustments, such as allocation additions and cancellations are allowed. Additions are made mainly for new facilities[16].
Flexible measures	Banking/ borrowing	Banking[17] ・Allowances can be carried over to the next fiscal year in a phase or to the first fiscal year of the next phase (approval by competent government agencies is required). 【1st phase】 ・If banking covers more than 10% of the average annual allocations in the first phase plus 20,000 tons, the equivalent of the excess will be deducted from allocations for the second phase to help vitalize the market (applicable from August 2018). 【2nd phase】 ・Banking restrictions are imposed, with unsold emission allowances equivalent to three times the net sales volume in 2018 and double the net sales in 2019 being allowed for banking. However, there is no restriction for companies holding only small amounts of emission allowances. 【3rd phase】 ・Banking is allowed for the equivalent of net sales for annually allocated emission allowances (KAUs) and offset allowances (KCUs) for each of the 3rd and 4th phases.

13 National Emission Allowance Allocation Plan for the Third Trading Phase (September 2020)

14 Article 18, Paragraph 3 of the Enforcement Decree

15 Article 12 of the Trading Act, Article 17 of the Enforcement Decree

16 Articles 16 and 17 of the Trading Act, Article 29 of the Enforcement Decree

17 Articles 18 and 32 of the Trading Act, Article 46 of the Enforcement Decree, third allowance allocation plan

		<u>Borrowing</u>[18] Borrowing is allowed only within each phase. [1st phase]: Borrowing is allowed for up to 20% [2nd phase]: Borrowing is allowed for up to 15% [3rd phase]: Borrowing is allowed for up to 15% in the first year and up to the number of emission allowances to be submitted by the relevant company ×{emission allowance borrowing limit for the previous year - (percentage share of emission allowances borrowed out of emission allowances to be submitted in the previous performance year × 0.5)) for the second to fourth years. Borrowing is not allowed for the fifth (final) year.
	Offset credits[19]	・Emissions reduction credits generated outside covered entities can be converted into emission permits, which can be used for compliance. However, the offset credit limit is set at 5%.
	Price measures (setting upper and lower limit prices, market surveillance mechanism)	【Market stabilization measures[20]】 <u>Criteria for triggering market stabilization measures</u> ・Emission allowance prices are three times higher than the average price of the previous two years for six consecutive months. ・A rapid increase in trading volume in a short period due to a surge in demand (when the average trading volume of one month is more than twice as high as the average trading volume in the same month of the previous two years, or the average emission allowance price in the last month is more than twice as high as the average price of the previous two years), etc. ・The average emission allowance price in the last month is less than 60/100 of the average in the previous two years, etc. <u>Market stabilization measures</u> ・Additional allocation of up to 25% of reserves ・Set a limit on the ownership of emission allowances (minimum of 70% of the current year's emission allowances of the relevant allocation target company, maximum of 150% of the company's annual emission allowances) ・Setting temporary upper and lower price limits
	Carbon leakage countermeasures	All allocations are free for subsectors with a value of 0.002 (0.2%) or more for trade intensity multiplied by the cost incurred. Note) Trade intensity: (average annual export value + average annual import value) / (average annual sales value + average annual import value) Cost incurred: (average annual emissions × average market emission allowance price) / (average annual value-added production)
	Trading type	Competitive trading, negotiation trading
Market	Links with other systems (status of consideration)	—
	Registry / MRV Methods	・Submission of a detailed emissions statement (specifying company size, fuel and raw material consumption, production volume, emissions, equipment capacity, equipment quantity, and equipment operating rates). ・External organizations verify emissions statements. ・Emissions are certified by an emissions certification body.
	Background of K-ETS introduction (explaining discussions leading to introduction and differences between initial and final plans)	・Since pre-allocations (caps) in the first phase (2015-2017) were linked closely to the 2020 national emission reduction target of 30% from the 2020 business-as-usual level, the government and the industry were at odds over the calculation of the BAU level in 2020. ・The industry requested revisions to the scheme (the revision of pre-allocations, the postponement of the scheme's launch until 2020, etc.). ・The Ministry of the Environment, which had jurisdiction over the K-ETS then, proposed a compromise plan that included measures for easing emission reduction burden by subsector, conditions for implementing market stabilization measures (setting the price cap at 10,000 won), the active use of flexible measures, the re-estimation of the 2020 BAU level, and other burden reduction measures.

18 Article 28 of the Trading Act, Article 45 of the Enforcement Decree, third emission allocation plan

19 Guidelines for assessing the validity of external emission reductions and certifying emissions (implemented on May 21, 2021)

20 Article 23 of the Trading Act, Article 38 of the Enforcement Decree

How to report		Covered entities submit emissions statements and verification reports by the third party to competent authorities.
Penalties	Compliance costs	【Surcharge】 ・The penalty is 100,000 won or less, three times the average price of emission allowances.
Effects, recent developm ents, etc.	Use of auction revenues	・ Auction revenues are put into the energy and resources special account.
	Recent developments	・August 2022: Announcement of the strategy for promoting international GHG emission reduction projects ・December 2022: Announcement of a proposal to improve the K-ETS ・April 2023: Formulation of the first draft basic plan for national carbon-neutral green growth.

China's Carbon Emission Trading System (China ETS)

Zhongyuan Shen*

1. Overview of climate change policy

The Chinese government submitted its second "Nationally Determined Contributions" (NDC) aimed at the reduction of greenhouse gases by 2030 to the UNFCCC Secretariat in 2021. The latest version raised contributions from the first NDC submitted in 2015. The following six items cover the numerical goals of the second NDC.

1) Strive to realize peaking out of CO_2 emissions prior to 2030
2) Lower CO_2 emission per unit of GDP by at least 65% versus the 2005 level
3) Raise the non-fossil fuel percentage in primary energy consumption to about 25%
4) Increase forest stock volume by 6 billion m^3 versus the 2005 level
5) Increase wind power and solar power facility volume by at least 1.2 billion kW
6) Strive to effectively realize carbon neutrality by 2060

The first item (peaking out goal) and sixth item (carbon neutrality goal) have attracted the most attention among these goals and are referred to as the "dual carbon goals" or "30-60 goals" in China.

Detailed climate change policy promotes priority measures, mainly in priority areas and sectors, with top-down type directions from the central government using industrial structure enhancement, low-carbon energy usage, energy saving, carbon absorption, and other policy methods. Within this context, China is implementing an Emission Trading System[1] (ETS) as a priority measure.

2. ETS design

In the 12th (2011-15) Five-Year Plan for National Economic and Social Development from 2011, regarding greenhouse gas emissions, China officially presented a goal of reducing the carbon dioxide emission intensity per unit of GDP by 17% versus the 2005 level and stated its intent for the first time to "gradually build a carbon emission allowance trading market." It also subsequently mentioned promoting a "carbon emission allowance trading market" in various national policies issued by the National Development and Reform Commission, including "Work Plan for Greenhouse Gas Emission Control during the 12th Five-Year Plan Period" (2011) and "Opinions on Accelerating Construction of an Ecological Civilization by the Central Committee of the Communist Party of China and the State Council" (2015). Against this backdrop, the National Development and Reform Commission launched regional ETS programs as trial programs in two provinces and five cities during 2013-15 (Beijing, Shanghai, Shenzhen, Tianjin, Chongqing, Hubei, and Guangdong).

In 2014, China formulated the Provisional Administrative Rules on Carbon Emission Trading and presented the concept of a national EPS framework for the first time. In 2015, it officially declared its intent to implement a national ETS program. It subsequently advanced further with related preparations and then announced the Administrative Rules on Carbon Emission Trading (Draft) (hereinafter, ETS Administrative Rules) in December 2020 and "2019-2020 Implementation Plan for National Carbon Emission Trading, Total Allowances Setting and Allocation (Power Generation Industry)" (hereinafter, ETS Power Generation Plan). It launched a national ETS program, albeit limited to the power generation industry, on February 1, 2021. Actual trading started on July 16, 2021, 2021, taking 10 years for China to initiate the national ETS.

2.1. Overview

ETS Administrative Rules stipulate that the criteria to qualify as a subject company for the ETS program are (1) an operator in a sector covered by the national ETS system designated by the national government and (2) an operator with an annual emission volume of greenhouse gases of 26,000 tons or more of carbon dioxide equivalent. Preparations are currently proceeding for eight industries with high energy consumption

* Executive Researcher, Renewable Energy Group, Clean Energy Unit, IEEJ

[1] In China, the official program name is Carbon Emission Trading System. As similar programs, it also operates the Energy Usage Allowance Trading System, Water Usage Allowance Trading System, and Pollutants Emission Trading System.

(petrochemicals, chemicals, building materials, steel, non-ferrous metals, paper and pulp, power generation, and airlines) as national ETS program candidates. However, as of July 2023, China has only designated the power generation industry based on the ETS Power Generation Plan.

According to the ETS Power Generation Plan, the national ETS program in 2019-2020 covers the power generation industry (including self-generated power in other sectors) for companies or other economic entities with own use power facilities that have carbon dioxide emissions of 26,000t-CO_2 or more (about 10,000 tons of total energy consumption volume of standard coal equivalent) in any year from 2013 to 2019. Carbon dioxide emission volume includes direct emissions from fossil fuel consumption and indirect carbon dioxide emissions from purchased power. The corporate emission allowance is the total value calculated by the power generation unit based on the benchmark value for power generation (or heat supply). This covers power-only units and cogeneration units and does not apply to heat supply facilities without power generation. Specifically, it applies to four types of fossil-fuel power generation units - conventional coal thermal at 300MW or more, conventional coal thermal at less than 300MW, non-conventional coal using coal waste, slurry, or water slurry, and gas thermal. In the case of mixed-combustion power generation units, mixed combustion with less than 10% biomass (including wastes and sludge) comes under the power generation unit of the primary fuel type. Excluded formats are biomass power generation, special fuel power generation, exclusively self-produced fuel power generation, and other mixed-combustion and special power generation that meet certain criteria.

2.2. Allocation method (paid/free)

According to the ETS Administrative Rules, the carbon emission allowance is mainly allocated as free allocations, with paid allocations to be introduced depending on the circumstance. The calculation of emission allowance in the power generation industry multiplies activity volume obtained via the following equation with the benchmark value (under the ETS Power Generation Plan). The procedure introduced the corrective coefficient to reflect unique technology characteristics for the unit and other factors. It does not set a corrective coefficient that factors in regional disparity.

Power generation unit emission allowance = Actual power supply volume × Power supply benchmark value × Corrective coefficient[2] + Actual heat supply volume × Heat supply benchmark value

Table 1 Benchmark values in the power generation industry[3]

<table>
<tr><th rowspan="2">Type</th><th rowspan="2">Subject power facilities</th><th colspan="3">Power supply (t-CO2/MWh)</th><th colspan="3">Heat supply (t-CO2/GJ)</th></tr>
<tr><th>2019-2020</th><th>2021</th><th>2022</th><th>2019-2020</th><th>2021</th><th>2022</th></tr>
<tr><td>I</td><td>300MW or more, coal thermal (conventional)</td><td>0.877</td><td>0.8218</td><td>0.8177</td><td>0.126</td><td rowspan="4">0.1111</td><td rowspan="4">0.1105</td></tr>
<tr><td>II</td><td>Less than 300MW, coal thermal (conventional)</td><td>0.979</td><td>0.8773</td><td>0.8729</td><td>0.126</td></tr>
<tr><td>III</td><td>Non-conventional coal thermal (50% or more waste or slurry)</td><td>1.146</td><td>0.9235</td><td>0.9303</td><td>0.126</td></tr>
<tr><td>IV</td><td>Gas thermal (10% or less use of other fuel)</td><td>0.392</td><td>0.3920</td><td>0.3901</td><td>0.059</td></tr>
</table>

Source: Prepared by the author using Ministry of Ecology and Environment materials (2018)

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[2] Corrective coefficient = Cooling method corrective coefficient (R1) x co-heating ratio corrective coefficient (R2) x utilization rate corrective coefficient (R3). Water cooling: R = 1, Air cooling: R = 1.05. R2 = 1-0.22×co-heating ratio. R3 set in four tiers based on the utilization rate. Utilization rate F≥85% R3 = 1.0, 80%≤F<85% R3 = 1+0.0014×(85-100F), 75%≤F<80% R3 = 1.007+0.0016×(80-100F), F<75% R3 = $1.015^{(16-20F)}$.

[3] Benchmark values and corrective coefficients are reportedly based on a substantial amount of data, many contact discussions, and in advance ETS simulations. According to the International Energy Agency's (IEA) "IEA Emissions Factors 2022," average thermal power generation emission coefficients in 2019 for China were coal at 0.933.5 t-CO_2/MWh and gas at 0.334 t-CO_2/MWh and for Japan were coal at 0.898 t-CO_2/MWh and gas at 0.388 t-CO_2/MWh. Simple comparison is not possible because of differences in China's boundary using ETS data and the IEA's country boundaries.

Allocations began with an initial allocation based on 70% of the unit power supply (heat supply) in 2018 and were confirmed in 2019 and 2020 values for actual performance. For the purpose of avoiding excessive burden on companies, however, the program adopted the total value of 20% of actual emissions and emission allowance as the maximum value of the compliance obligation for cases in which actual emissions exceeded the allowance. Furthermore, with the aim of promoting the gas power generation unit, the program set the allocated emission allowance as the maximum value of the compliance obligation for the gas power generation unit and hence exempted compliance for the portion exceeding the allowance. In the second compliance phase (2021 and 2022), it added a measure for borrowing up to 10% from the 2023 emission allowance.

In cases of a merger, spin-off, closure, or move outside of the administrative zone that affects a subject company, it is necessary to submit a report to the Ministry's Central Supervision Office of Ecological and Environmental Protection within 30 days. The Central Supervision Office adjusts free allocations based on actual conditions, reports to the Ministry of Ecology and Environment, and provides general disclosure, including related information.

Companies that already received an emission allowance allocation under the regional ETC program at the time of the announcement of the ETS Power Generation Plan do not participate in the national ETS program. Other companies, meanwhile, participate in the national ETS program.

Regarding emission allowance trading, the ETS Administrative Rules limit the traded product to the subject allowance for the time being and stipulate the addition of derivative products depending on future circumstances. They also indicate that subject companies, institutions, and individuals can partake as transaction participants. Transactions occur via the national ETS transaction system. It is possible to utilize the discussion method between parties, single-direction sales auctions or purchase auctions, or other methods that satisfy requirements. Permitted price fluctuation limits are ±10% versus the previous day's closing price for transactions of less than 100,000 tons and ±30% for transactions of 100,000 tons or more.

As implementation guidelines for ETS operation, the Ministry of Ecology and Environment formulated and disclosed the Carbon Emission Allowance Registration Administrative Rules (Draft), Carbon Emission Allowance Transaction Administrative Rules (Draft), and Carbon Emission Allowance Settlement Administrative Rules (Draft) in May 2021. Regarding operation conditions, the Ministry of Ecology and Environment announced the "Report on the National ETS Market's First Compliance Phase (2019-2020)" in 2022. According to the report, transaction activity in the first compliance phase involved 2,162 companies initially (though actually 2,011 companies after mergers, etc.) and covered 4.5 billion tons of CO2 emissions. Other key data were 114 transaction days, 179 million tons of transaction volume, CNY7,661 million in transaction value, and CNY42.85/ton as the average transaction price (a single CNY is roughly 20 yen). Closing-price fluctuation had a range of CNY40-60 per ton, indicating stable movement in the transaction price (Figure 1). Furthermore, 847 companies had allocation shortages totaling 188 million tons. Allocation shortage and transaction volume were roughly equal. This suggests that transactions largely took place for compliance.

According to the report, the ETS program operation effect was improving power generation carbon emission intensity by 1.07% versus the 2018 level in 2020. The questionnaire found that 80% of subject companies established dedicated departments related to carbon asset management. It also confirmed that 90% of subject companies intend to place more emphasis on statistical data and 46% plan to invest transaction income in energy savings and other measures.

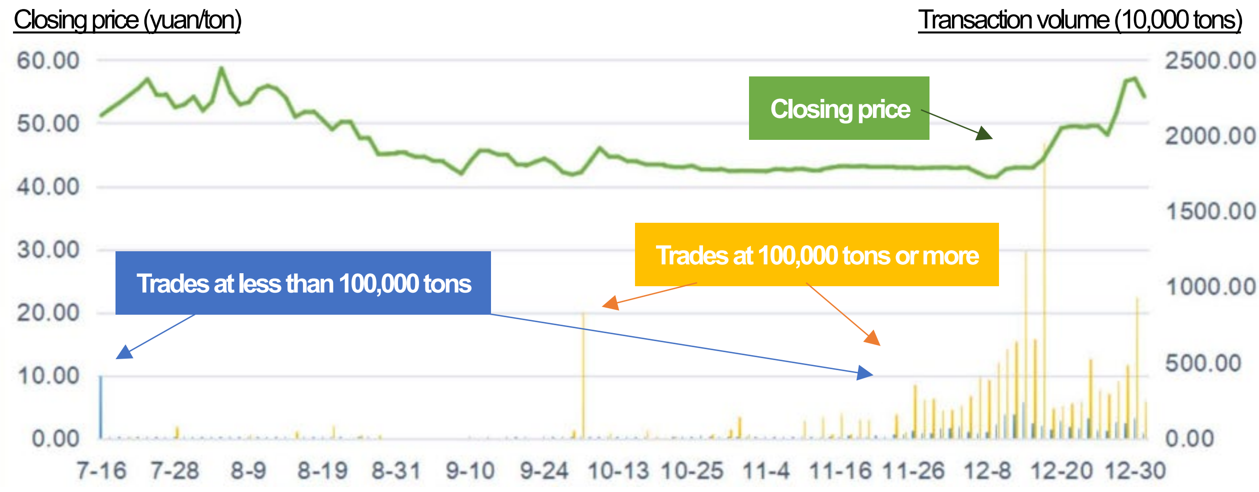

Figure 1 Transaction activity in the first compliance period

Source: Prepared by the author using Ministry of Ecology and Environment materials (Document 4)

2.3. Availability of offset credits

Subject companies apply these within the deadline set by the Ministry of Ecology and Environment. Offset based on the China Certified Emission Reduction (CCER)[4] program is possible for up to 5% of the emission allowance. The program recognizes three types of CCER – renewable energy, forest absorption, and methane usage.

CCER usage volume in the first compliance period (2019-2020) was 32.73 million tons. A total of 189 CCER projects, such as wind power generation, solar power generation, and forest absorption, generated CNY980 million in income.

2.4. Emission volume MRV

As shown in Figure 2, the program manages and supervises data calculation, reporting, verification, allocation, settlement, market trading, and other activities related to the carbon emission volume of subject companies with different roles handled by key parties - program design and jurisdiction under the Ministry of Ecology and Environment, management and supervision by regional governments (provincial, metropolitan, etc.), and cooperation with program operation by third-party entities and industry organizations. China built three information systems for program operation – a data reporting system, an emission allowance recording system, and an emission allowance trading system.

[4] Domestic credit program comparable to Japan's J credits

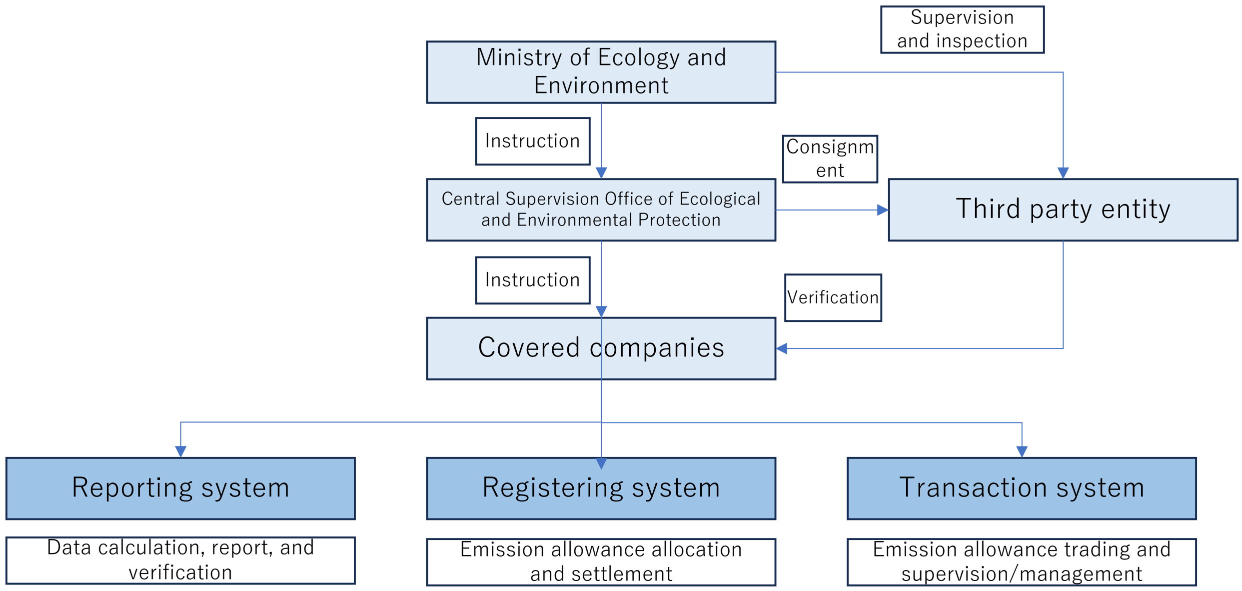

Figure 2: Overall image of China's national ETS program

Source: Prepared by the author using Ministry of Ecology and Environment materials (Document 2)

Subject companies have an obligation to report to the Ministry's Central Supervision Office of Ecological and Environmental Protection by March 31 of each year and retain data records and management ledgers for at least five years. Companies bear responsibility for the accuracy of reported data. Penalties are CNY10,000-30,000 for false reports and CNY20,000-30,000 for non-compliance within the required period as well as suitable reduction of the allocation in the next fiscal year. There is recourse to pursuing criminal responsibility in cases involving crimes.

The Central Supervision Office verifies reports and sends verification results to subject companies. It can consign verification to third-party verification entities. Its reviews utilize a "double random, one-open" method (random section of the verification target and verifying agent and disclosure of verification results). The verification entity bears responsibility for the accuracy of verification results. As standards, the verification process uses the Ministry of Ecology and Environment's "Guidelines on Calculating and Reporting Company Greenhouse Gas Emissions (power generation facilities)" and "Technology Guidelines on Verification of Company Greenhouse Gas Emissions (power generation facilities)." The Ministry of Ecology and Environment supervises and inspects verifications by third-party entities. During the first compliance period, it inspected 401 subject companies and 35 related third-party entities. Following inspections, it announced the discovery of serious fraud at four third-party entities and disclosed the company names.

The above-mentioned guidance provides detailed rules on power generation boundary and emission source decisions, the method of calculating emissions from fossil fuel combustion, the method of calculating emissions of purchased electricity, the method of calculating total emissions, the method of calculating production volume (power generation volume and heat production volume), the data quality management plan and requirements, the periodic report, and specifications related to information disclosure. For example, it defines the power generation boundary in the manner shown in Figure 3. The power generation boundary is power generation facilities (within the dotted line areas in the Figure), mainly the combustion system, steam and water system, electricity system, and control system and dust removal, desulfurization, and denitrification systems. It does not include other auxiliary production systems or auxiliary production systems in the plant area.

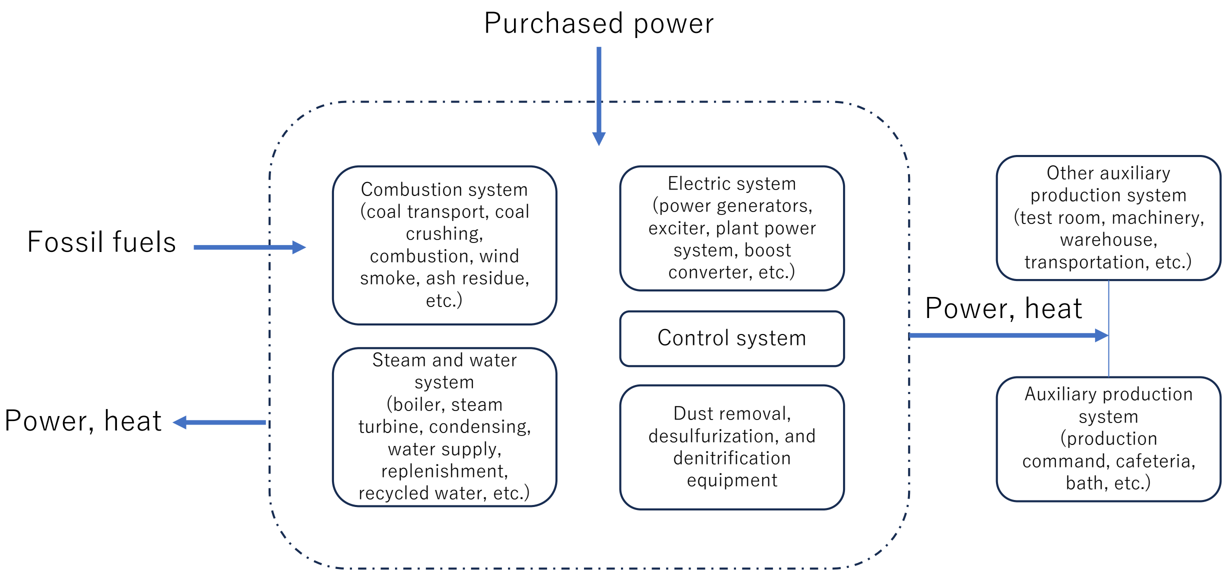

Figure 3 Power generation boundary

Source: Prepared by the author using Ministry of Ecology and Environment materials (2018)

3. Observations

China's national ETS program started trading activity as the world's largest carbon market, despite the COVID-19 pandemic, and its completion of the first compliance phase with a 99.5% compliance ratio has significant implications. In the second compliance phase, the program set the benchmark value for the power generation industry at a roughly 8% tougher level, and the trading price exceeded the average price from the first phase. This means that the price signal related to carbon has strengthened. Looking ahead, the main point is whether China is capable of bringing in other industries with high energy consumption at the appropriate time.

Meanwhile, China needed a preparatory period of 10 years for an ETS program restricted to the power generation industry. Even though it formulated detailed calculation guidelines for data related to the power generation industry and put efforts into verification by third party entities and training of subject companies during this period, data falsification and other serious fraudulent acts occurred. Compared to the power generation industry, other industries with high energy consumption present more complexity in data calculation and verification, setting benchmark values, and other tasks. It will not be easy to expand the ETS program, and there is a possibility of falling behind the plan. In any case, China needs more time than the roughly five years[5] of preparation in Europe and Korea to achieve a full-fledged rollout of the ETS program.

Furthermore, the Ministry of Ecology and Environment issued a report indicating that the ETS program effect was 1.07% improvement in power generation carbon emission intensity over two years (0.54% annually). However, the actual improvement in standard coal equivalent intensity in power generation for the thermal power unit of 6,000kW or more in the five years through 2020 prior to implementation of the ETS program was 0.63% annually. At this point, it is hence not possible to conclude that the rollout of the ETS program delivered an advance in energy savings. China is likely to incrementally bolster the benchmark values similar to Europe, and it is necessary to continue monitoring the program effect. It is also essential to assess the program effect from a variety of perspectives considering reports that the EU ETS program, a predecessor, weakened corporate interest in green investments.

[5] Europe took roughly five years from announcement of the program construction concept in the "Green Paper on greenhouse gas emissions trading within the European Union" (2000) until rollout of the pilot phase (2005), and Korea required about five years from issuance of a document on ETS program deployment in accordance with the "Framework Act on Low Carbon, Green Growth" (2010) until official program rollout (2015).

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Appendix: Overview of China's National ETS Program

Overview	Name	China's National Carbon Emission Trading System
	Program starting date	June 2021
	Program period	From 2021: Only applies to the power generation industry Plans to broaden scope during the period through 2025 (14th Five-Year Plan Period)
	Summary	1) (Coverage sector) Only power generation in the initial stage 2) (Coverage standard) Coal and gas thermal power generation operators (including self-generation) with carbon dioxide emissions of 26,000t-CO_2 or more in any year from 2013 to 2019 3) (Emission allowance allocation method) Benchmark method (allocation based on power generation efficiency) 4) (Credit usage) Use of the China Certified Emission Reduction (CCER) program possible for up to 5% of the emission allowance (limited to three types – renewable energy, forest absorption, and methane usage 5) (Subject operator responsibility) Bears responsibility for GHG management, reporting, compliance, information disclosure, and accepting supervision 6) (Emissions total allocation) Decided comprehensively in accordance with national goals by the Ministry of Ecology and Environment 7) (Trading participants) Subject business operations, institutional investors, individuals 8) (Trading products) Add products other than actual emission allowances at the appropriate time
	Penalties	1) Incur penalty fees of CNY10,000 to CNY30,000 for non-compliance, etc. 2) Face criminal responsibility in cases of committing crimes
Scope	Unit	Business operator
	Main operator criteria	Power generation industry (including self-generated power in other sectors) for companies or other economic entities that have carbon dioxide emissions of 26,000t-CO_2 or more in any year from 2013 to 2019 (planning to apply to industries with high energy consumption (petrochemicals, chemicals, non-metals, steel, non-ferrous metals, paper and pulp, and airlines)
	Covered gases	CO2, CH4, N2O, HFCs, PFCs, SF6, NF3
	Coverage	Covers 2,162 electricity firms, roughly 4.5 billion t-CO_2 in total emissions
Allocation method	Allocation method	1) Applies benchmark standards 2) Mainly no-charge allocation initially, introduce paid allocation as appropriate 3) Allocate respectively to 2019 and 2020 in the first compliance phase (allocate respectively to 2021 and 2022 in the second compliance phase)
	Burden mitigation and leakage measures	1) Compliance upper limit at 20% of the allocation (compliance exempted for surplus beyond 20% over the allocation) 2) Preference for the gas power generation unit (compliance upper limit at the allocation level)
Flexibility measures	Banking, borrowing	Not approved in the first compliance period (though accepts voluntary amortization of surplus allowance) (borrowing allowed up to 10% from 2023 in the second compliance period)
	Other credit usage	Permits use within 5% of CCER
	Price spike measures	The exchange operator has responsibility to effectively prevent excessive speculative trades.
	Volume measures	The Ministry of Ecology and Environment decides the total amount of carbon emission allocation and allocation method in accordance with national greenhouse gas emission regulation criteria and based on a comprehensive review of economic growth, industrial structure adjustments, energy structure optimization, air pollution emission adjustment and management, and other factors
Market	Price	1) Prices on the first trading day (July 16, 2021): Starting price at CNY48/ton, closing price at CNY51.23/ton 2) Prices during the first compliance period: Fluctuation range of period closing prices at CNY40-60/ton, period-average at CNY42.85/ton, and period final-day closing price at CNY54.22/ton 3) Closing price on June 20, 2023: CNY57.53/ton
	Transaction volume	1) 1.79 trillion tons of cumulative transaction volume in 2021, CNY7,661 million in cumulative transaction value
	Exchange	Shanghai Environment and Energy Exchange handles trading-related work

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Editor: Yoshihiko Omori

Publisher: The Institute of Energy Economics, Japan
Inui Bldg., Kachidoki, 13-1,
Kachidoki 1-chome, Chuo-ku, Tokyo
104-0054, Japan
e-mail: report@tky.ieej.or.jp

Please contact the editor for inquiry
e-mail: yoshihiko.omori@tky.ieej.or.jp

The Institute of Energy Economics, Japan