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

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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

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[1] Keigo Akimoto, Fuminori Sano; Scenario Analysis on Carbon Neutrality by 2050 (interim report), Document 2 for the Strategic Policy Committee (43rd meeting) of the Advisory Committee for Natural Resources and Energy https://www.enecho.meti.go.jp/committee/council/basic_policy_subcommittee/2021/043/043_005.pdf (accessed March 14, 2023)

(IEEJ) -- reported their analyses using energy system models,[2), 3), 4), 5)] 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

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[2] National Institute for Environmental Studies; An Analysis on Scenarios for the Realization of a Decarbonized Society by 2050, Document 2 for the Strategic Policy Committee (44th meeting) of the Advisory Committee for Natural Resources and Energy https://www.enecho.meti.go.jp/committee/council/basic_policy_subcommittee/2021/044/044_005.pdf (accessed March 14, 2023)

[3] Renewable Energy Institute: Energy Mix to Support a Decarbonized Japan in 2050 -- Towards the Formulation of the Next Strategic Energy Plan, Document 3 for the Strategic Policy Committee (44th meeting) of the Advisory Committee for Natural Resources and Energy https://www.enecho.meti.go.jp/committee/council/basic_policy_subcommittee/2021/044/044_006.pdf (accessed March 14, 2023)

[4] Deloitte Tohmatsu Consulting: Scenario Analysis for a Carbon-Neutral Society, Document 5 for the Strategic Policy Committee (44th meeting) of the Advisory Committee for Natural Resources and Energy, https://www.enecho.meti.go.jp/committee/council/basic_policy_subcommittee/2021/044/044_008.pdf (accessed March 14, 2023)

[5] Matsuo Yuji, Otsuki Takashi, Obane Hideaki, Kawakami Yasuaki, Shimogori Kei, Yuji Mizuno Aritomo, Morimoto Soichi; Model Estimation for Carbon Neutrality by 2050, Material 6 for the Strategic Policy Committee (44th meeting) of the Advisory Committee for Natural Resources and Energy https://www.enecho.meti.go.jp/committee/council/basic_policy_subcommittee/2021/044/044_009.pdf (accessed March 14, 2023)

[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)

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, 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 1 Analysis cases

	RE100	VRE+	Biomass+	Storage+	Combo
CO_2 Constraints and power generation mix	Net-zero energy-related CO_2 emissions by 2050 100% renewable energy				
VRE construction costs (2050)	Table 3 level	Down 90% from RE100 case	Equivalent to RE100 case level (Table 3 level)		Down 90% from RE100 case
Domestic woody biomass resources (2050)[Note]	Solid biomass production is assumed as equivalent to FY2020 level (7.4 Mtoe/year)		Estimated from forest accumulation (18 Mtoe/year)	Equivalent to RE100 level (7.4 Mtoe/year)	Estimated from forest accumulation (18 Mtoe/year)
Hydrogen storage and redox flow battery construction costs (2050)	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)			Down 90% from RE100 case RE100	

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**

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)

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 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 **Tables 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

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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)

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").

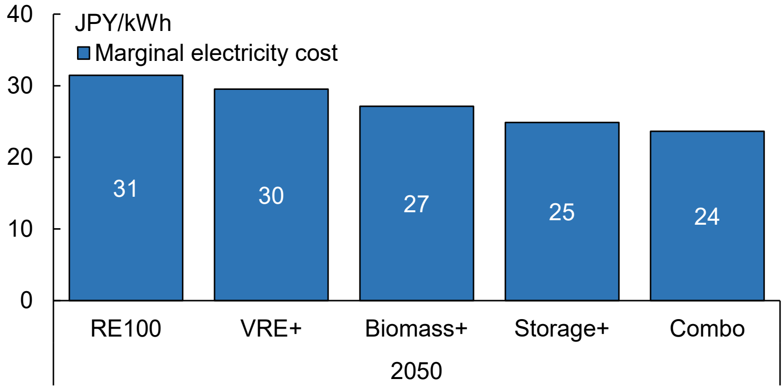


Figure 1 Average marginal electricity cost in Japan

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.

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

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**).

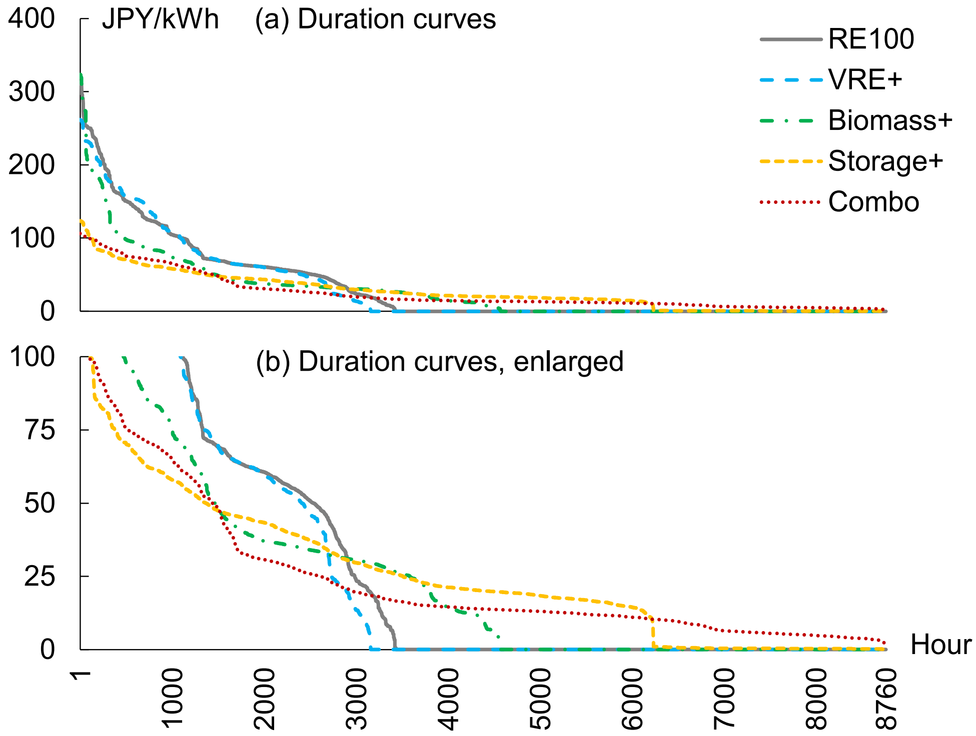


Figure 2 Hourly marginal electricity curves (weighted average for 2050 of 5 regions)

(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.

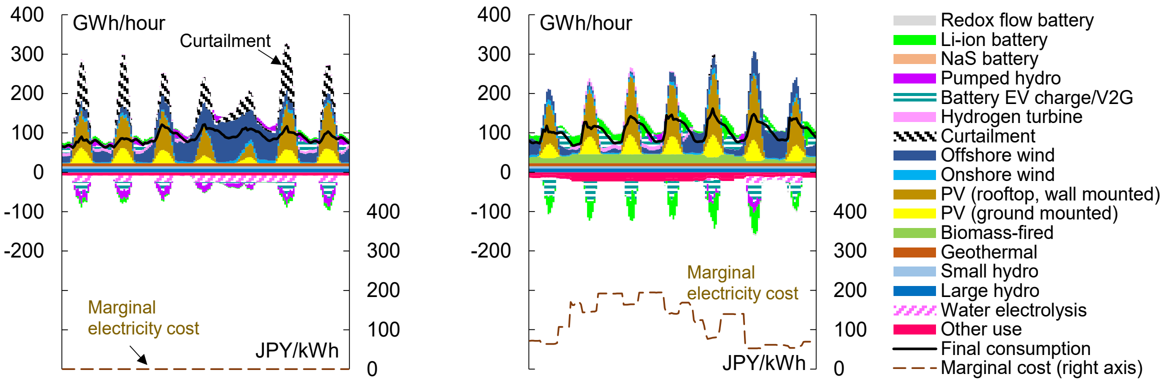
Here, it should be noted that even if technological development in the Combo case is assumed, the average marginal electricity cost will reach as high as 24 yen/kWh. In the standard case in which a wide range of technology options is assumed to include fossil-fired power generation with carbon capture 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

Figures 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)**).



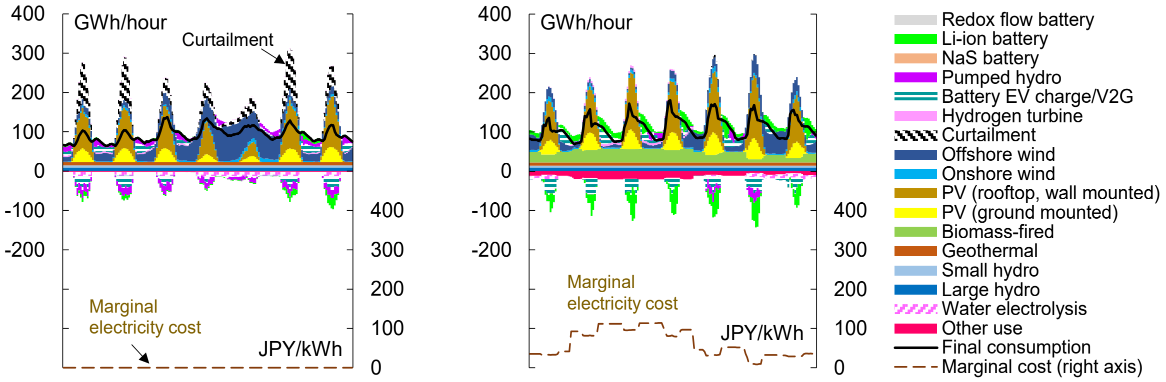
(a) May **(b) Late August to early September**

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**).

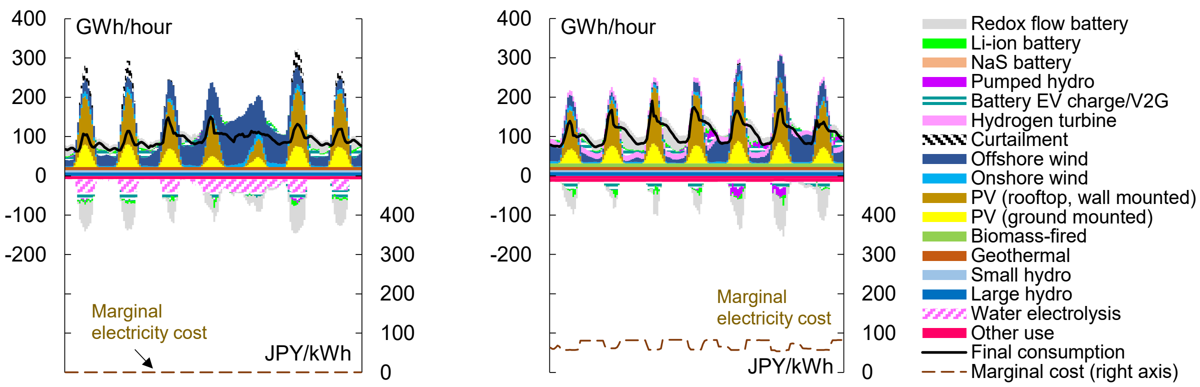
All biomass-fired power generation growth in the RE100 and Biomass+ cases is accompanied by CO_2 capture and storage (CCS) devices, creating negative emissions. (In this analysis, large-scale biomass-fired power plants with CO2 capture devices are assumed, with no consideration given to small, distributed 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.

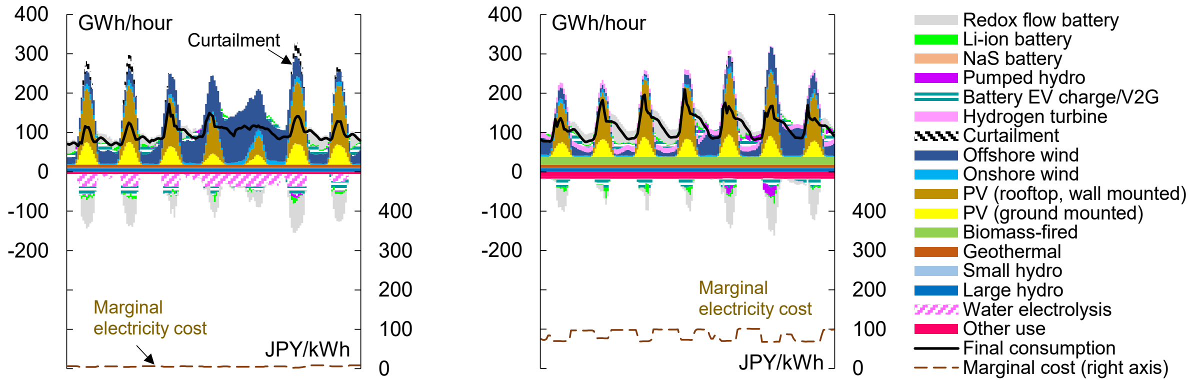


(a) May **(b) Late August to early September**

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

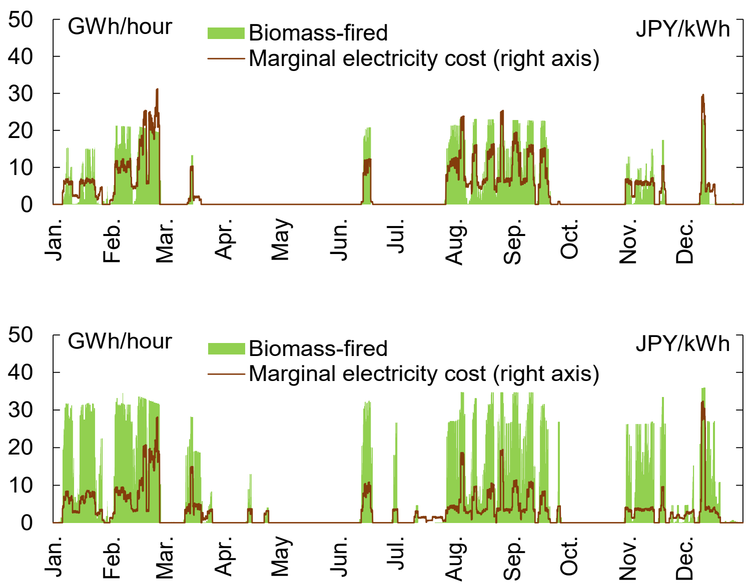
for Japan in 2050)

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)**).



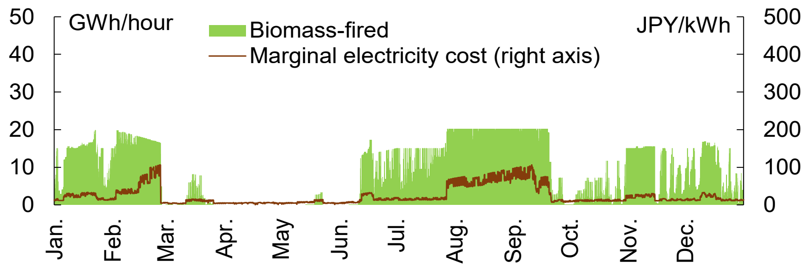
(a) May **(b) Late August to early September**

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



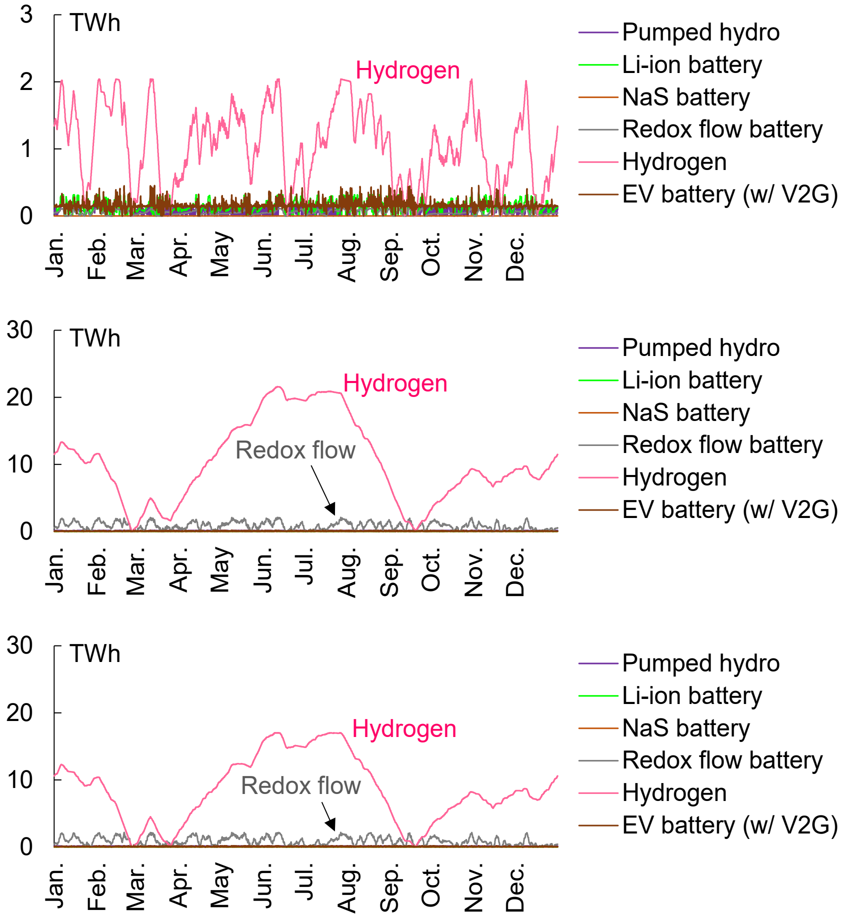
(a) RE100 case

(b) Biomass+ case



(c) Combo case

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



(a) RE100 case

(b) Storage+ case

(c) Combo case

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:

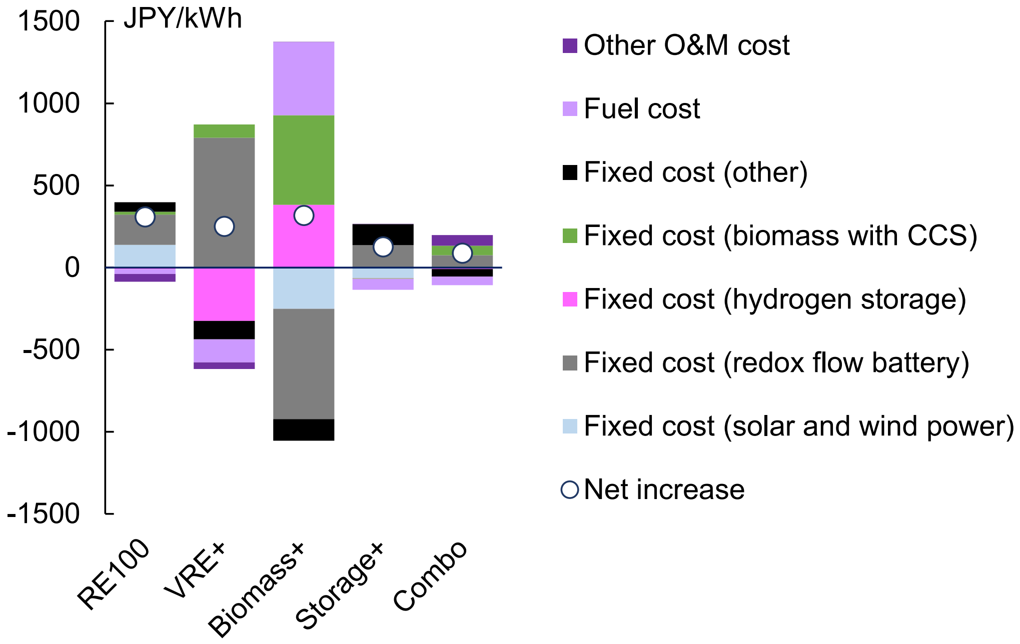


Figure 1 Factor analysis of the highest hourly marginal electricity cost

(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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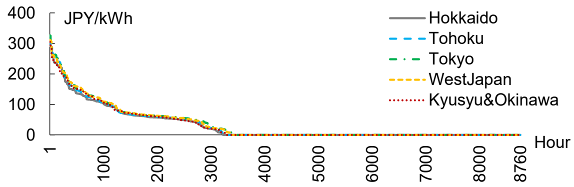
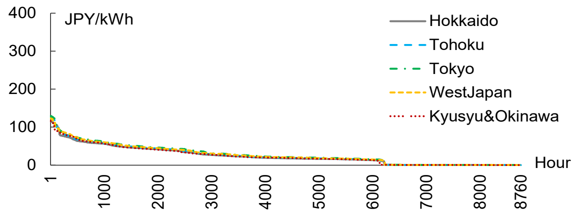
Appendix A. Supplementary results

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.

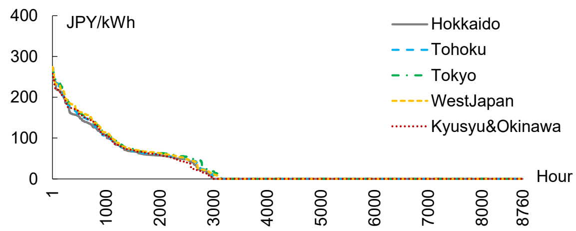
CO_2 emissions by sector are shown in **Appendix Figure 2**, electricity generated in the whole of Japan and each region in **Appendix Figures 3 and 4,** energy storage capacity in **Appendix Figures 5 and 6,** interregional interconnection capacity in **Appendix Figure 7,** and biomass supply and demand 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 Figures 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.



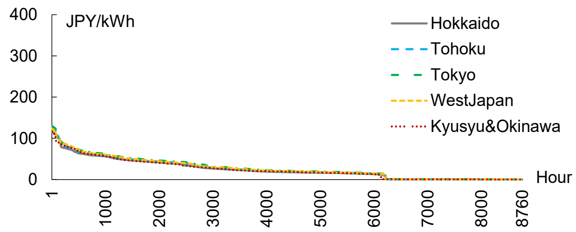
(a) RE100 case



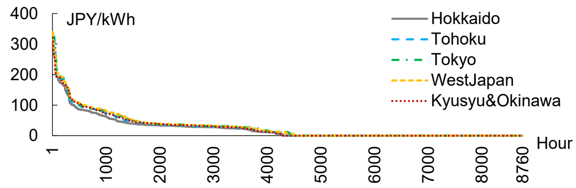
(d) Storage+ case



(b) VRE+ case

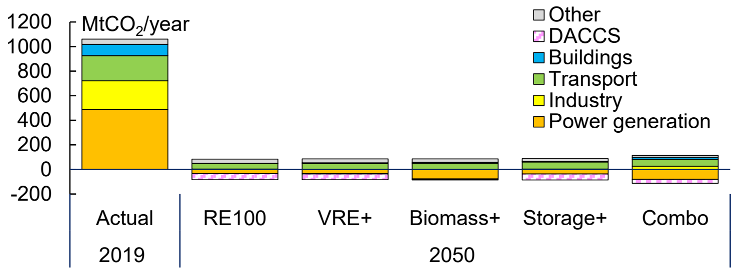


(e) Combo case



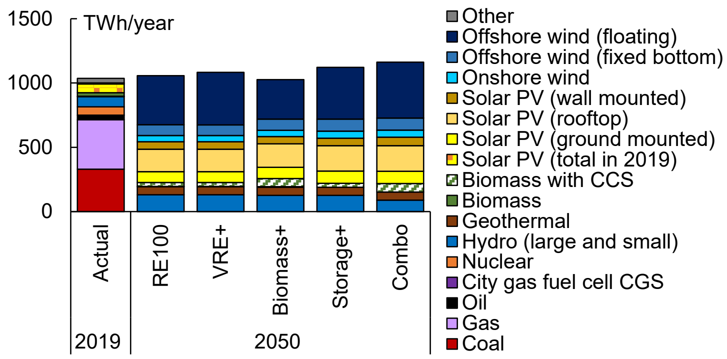
(c) Biomass+ case

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



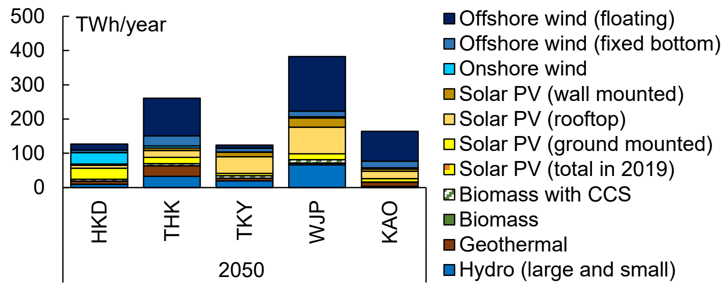
Appendix Figure 2 CO_2 emissions by sector (total for Japan)

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

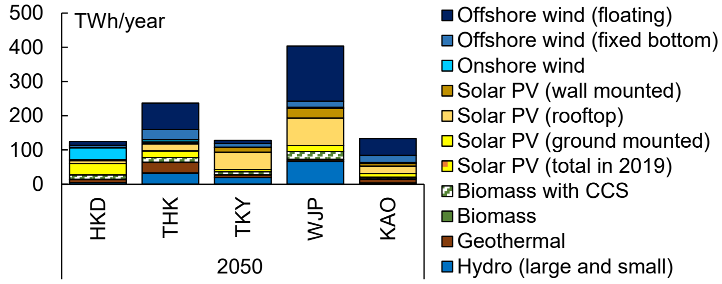


Appendix Figure 3 Electricity generation (total for Japan)

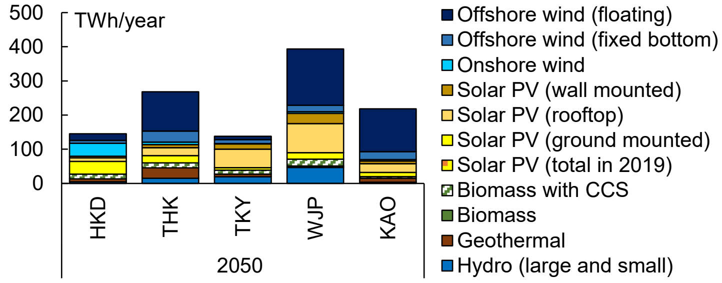
(Note) CGS: Cogeneration system.



(a) RE100 case



(b) Biomass+ case



(c) Combo case

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 $D_{t,r,y} = 0$.

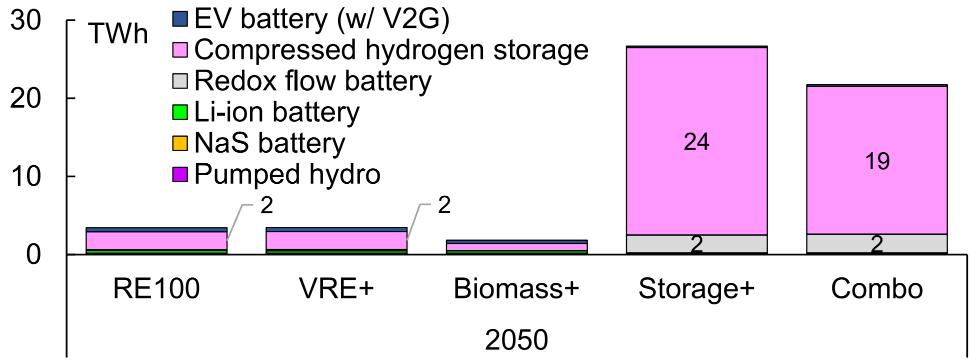
$$\sum_{k\in KP} x_{k,t,r,y} + \sum_{k\in KS}\left(dis_{k,t,r,y} - cha_{k,t,r,y}\right) + \sum_{r'\neq r}\left(TEF_{r,r'}\cdot xt_{t,r',r,y} - xt_{t,r,r',y}\right) = elg_{t,r,y} + \sum_{k\in KC} xc_{k,t,r,y} + D_{t,r,y}$$
.... Equation (2)

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

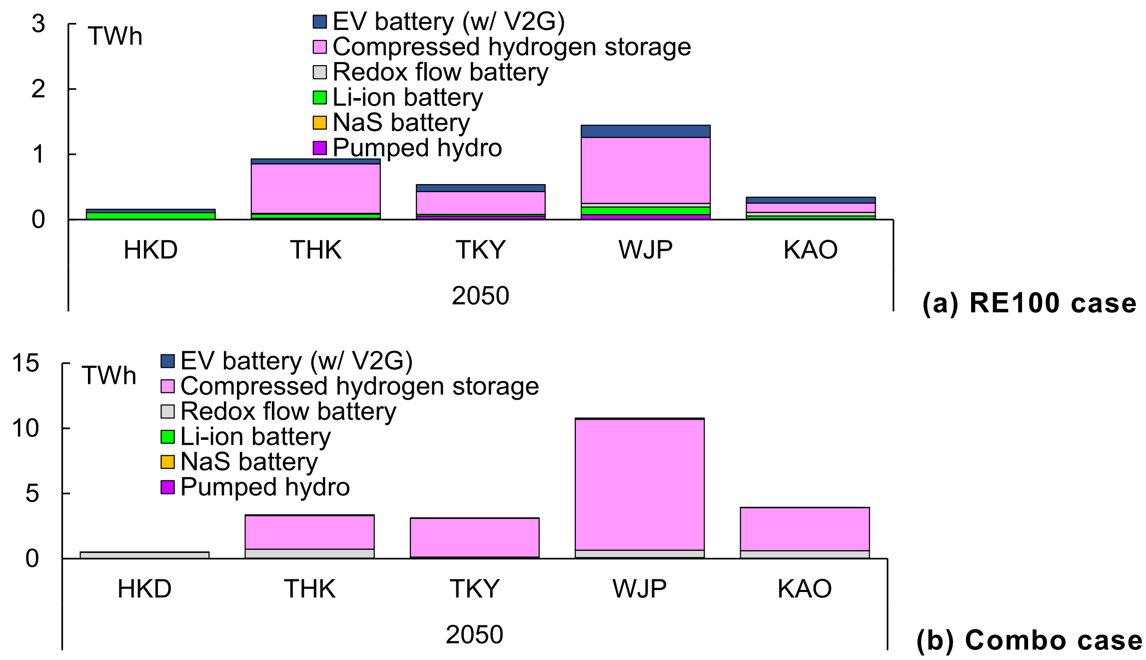
Here, $KP1$ stands for a collection of power generation technologies (excluding those in $KP2$ below), $KP2$ for a collection of power generation technologies installed on the end consumer side (roof- and wall-mounted solar PV panels, city gas fuel cells), KS for a collection of power storage technologies (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

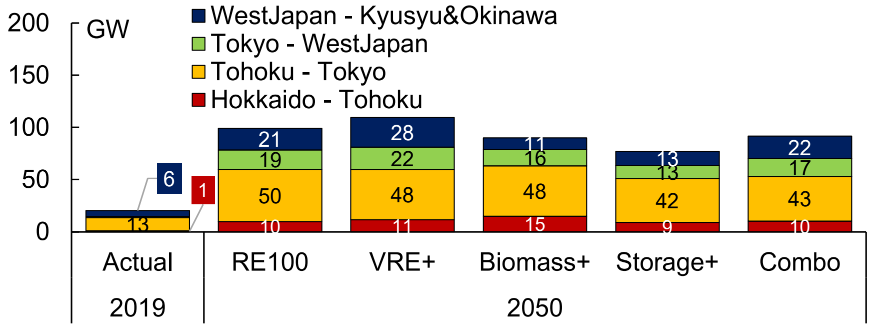
r, $v2g_{t,r,y}$ for the amount of power (GWh/h) discharged from EVs at Time t in Year y in Region r, $ev_{t,r,y}$ for the amount of power (GWh/h) charged to EVs at Time t in Year y in Region r, and $hp_{t,r,y}$ for power consumption by consumer heat pump water heaters at Time t in Year y in Region r. Among exogenous variables, $TEF_{r,r'}$ stands for 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 $hp_{t,r,y}$).



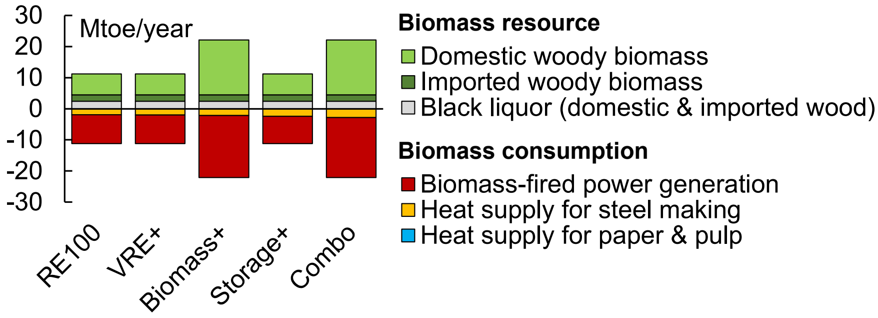
Appendix Figure 5 Energy storage capacity (total for Japan)



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)

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