A Study on the Feasibility of Complete Decarbonization of Japan's Power Sector in 2050: The Effect of Changes in Meteorological Conditions

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In this paper, we used an optimal power generation mix (OPGM) model, as well as meteorological data from 2000 to 2017, to assess the cost of achieving 100% renewable electricity mix in 2050 in Japan. Although the potentials of variable renewable energies, such as wind and solar PV, have been estimated to be large in Japan, grid-related system costs become significant in the cases with very high shares of variable renewables. Particularly, two factors affect the overall costs: the cumulative installed capacity of offshore wind power, and the required capacity of electricity storage systems. The former is dependent on the curtailment ratio of onshore wind and solar PV, whereas the latter is determined by the short-time "windless and sunless" factor, i.e. the maximum number of successive days with very small wind and solar power output. The analyses presented in this study highlight the necessity of using long-term meteorological data when estimating the economics of high penetration of variable renewables, as well as the importance of considering the risk of power supply disruption.

Keywords: Power generation mix, Decarbonization, Variable renewable energy, Hydrogen, Residual load curve

1. Introduction

1.1 Efforts to assess the complete decarbonization of Japan's power sector

There is growing awareness of the seriousness of global environmental issues and discussions on the need for drastic policies have begun. A special report by the Intergovernmental Panel on Climate Change (IPCC) published in October 2018 titled "Global Warming of 1.5 ºC"[1] states that all countries, both developed and developing, need to reduce their anthropogenic carbon emissions to net zero by 2050 in order to keep global warming within 1.5℃ from pre-industrial levels. Although the feasibility of this target is not clear, it is a fact that emissions must be reduced significantly by 2050, which is not far away.

Among the various sectors associated with the use of energy, the power sector is both expected and required, in particular, to significantly reduce its carbon emissions. To achieve the Japanese government target of an "80% reduction in GHG by 2050," for instance, it is necessary to reduce emissions from the power sector to effectively zero (actually reducing emissions to completely zero is not possible as nuclear and renewable power give off small amounts of emissions in processes other than power generation)[2] while electrifying the energy demand sectors. Accordingly, the possibility of achieving a carbon-free power sector is a crucial area of research today.

In previous studies[3,4], the authors have analyzed the possibility of complete decarbonization of the power sector of Japan by 2050. In those studies, we assumed that electricity will be covered by renewable power (variable and dispatchable), nuclear power, and zero-emission thermal power (the use of imported hydrogen power generation is expected but thermal power with carbon capture and sequestration (CCS) is also acceptable if domestic CCS technology becomes available), and set multiple cases with different costs for renewable energy, electricity storage systems, and imported hydrogen, and used them as a base to analyze the impact of generation constraints of each power source on the total cost of the power sector. The results showed that the economic efficiency of a carbon-free power sector will vary greatly depending on the availability of "zero-emission" thermal power, as shown in Figure 1. If zero-emission thermal power is hardly available, costs would rise significantly as it would be necessary to curtail large amounts of excess variable renewable energy (VRE; solar PV and wind power in this paper), which produces most of the electricity supply, or to store them in electricity storage systems, and further, to reinforce the grid to be able to use regionally-dispersed wind power resources. If nuclear and zero-emission thermal power are completely unavailable, the unit electricity cost would rise to as high as 24.9 yen/kWh (in 2014 real price; the same applies hereafter) for the medium cost case, as shown by the vertical axis intercept in Figure 1. For this particular case, the installed capacity of solar PV, and land-based and offshore wind power would be enormous at 239 GW, 271 GW, and 139 GW, respectively. In particular, a wind power capacity far exceeding the regional electricity demand would be installed in Hokkaido, the northernmost island of Japan, and significant reinforcement of the inter-regional lines between Hokkaido and Tohoku and between Tohoku and Tokyo would be required to send most of the power to Tokyo. The results also show that power output would be heavily curtailed in May when electricity demand is relatively low. The rise in cost would be smaller than in Figure 1 if nuclear power is available, but the unit cost would still be 20.0 yen/kWh if thermal power is not used at all.

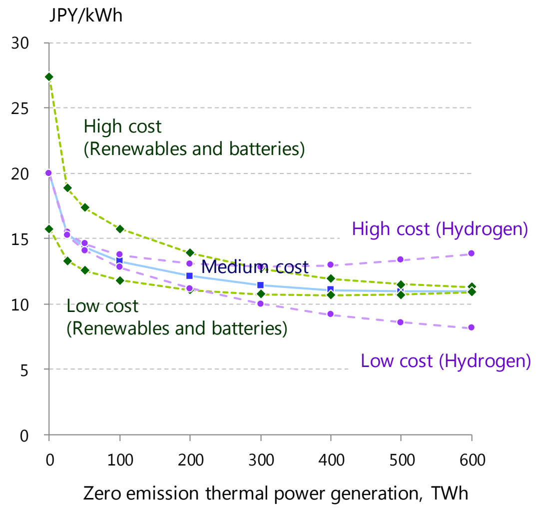


Figure 1 Unit electricity cost of a carbon-free power sector (Zero nuclear case: Matsuo et al., 2018[4])

1.2 Comparison of results from existing literature

Many studies have been conducted globally regarding the additional costs caused by introducing large amounts of VRE. Refs. 5), 6), and 7) study the existing literature and analyze the rise in costs when the VRE share in power generation mix increases to 30%, or to around 50%. More recently, assessments for shares of nearly 100% VRE are being conducted in Europe, the US, and elsewhere[8-12].

To the best of authors' knowledge, quantitative analyses of the economic efficiency of 100% renewable power generation in Japan include the peer-reviewed papers of Esteban et al. (2012)[13], Breyer et al. (2015)[14], Jacobson et al. (2017)[15], and Esteban et al. (2018)[16], in addition to our work[4], and a conference paper by Ogimoto et al. (2018)[17]. Among them, Jacobson et al. (2017) studied a scenario in which the energy consumption of 139 countries is electrified entirely by 2050 and covered exclusively by hydropower, wind power, and solar power. In this scenario, the supply-demand balance is kept by heat storage rather than electricity storage. For example, most of the demand fluctuation of households for hot water supply and air conditioning is met by heat storage systems, rather than by electricity. Breyer et al. (2015) presented a scenario in which a super-grid connecting the whole of Northeast Asia is built and is completely decarbonized by using PV resources located in western China and Mongolia. Other non peer-reviewed studies include WWF Japan (2017)[18] and Energy Watch Group (EWG) (2017)[19] The assumptions and results of these publications are summarized in Table 1. We did not include Jacobson et al. (2017) in the table, as heat storage systems in the commercial sector are unlikely to spread throughout Japan by 2050. It also excludes Breyer et al. (2015) considering the political difficulty of building a super-grid covering China, North Korea, South Korea, and Japan by 2050.

Table 1 Estimates for carbon-free power sector

Ref.	Target year	Number of divisions	Elec. demand TWh	Storage capacity TWh	Unit cost JPY/kWh
A	2050	9	1,044	6.1	24.9
B	2050	1	949	12.0	134
C	2050	10	627	0.4	8.4
D	2050	2	1,150	>20	8.3
E	2030	1	594–1,400	1.5–13.7	–
F	2100	1	1,400	41.0	–
Actual	FY2015	–	1,035[20]	–	11.3*

A: Matsuo et al. (2018)[4], B: Ogimoto et al. (2018)[17], C: WWF Japan (2017)[18], D: EWG (2017)[19], E: Esteban et al. (2018)[16], F: Esteban et al. (2012)[13]

*: Estimate based on ref. 21)

The difference in electricity storage capacity shown in Table 1 deserves particular attention. One of the reasons for the extremely high unit cost of 134 yen in the 100% VRE (not RE) case in Ogimoto et al. (2018), presumably, is its large required battery capacity of 12.0 TWh. In contrast, WWF Japan (2017) has a low unit electricity cost estimate (8.4 yen/kWh) which is probably due to its required battery capacity of 0.4 TWh, which is significantly smaller compared to those of other studies. Meanwhile, the unit electricity cost of EWG is as low as that of WWF Japan even though it has a large battery capacity of over 20 TWh. This may be because in the EWG case, electricity is not stored in batteries but is converted into methane which is then stored.

1.3 Purpose of this study

The above comparison reveals that, first, studies on the decarbonization of Japan's power sector are still insufficient and progress in discussions is needed as more knowledge is accumulated. Second, the cost is expected to be affected significantly by the electricity storage capacity necessary to achieve a 100% renewable power generation mix.

The electricity storage capacity required when large amounts of VRE are introduced is expected to vary depending on how VRE fluctuates. In existing studies, however, even if wind and solar PV output is accurately modeled with hourly or higher time resolution, the data are obtained only for one year. For instance, Matsuo et al. (2018), Ogimoto et al. (2018), and Esteban et al. (2018) use data for 2012, FY2013, and 2015 respectively. As the results are likely to vary by year depending on meteorological conditions, these studies do not provide a sufficiently general assessment of the required electricity storage capacity and economic efficiency for a 100% renewable generation mix; it is necessary to compare data for multiple years to assess the impact of meteorological changes.

Accordingly, in this study we used data[22)] for the 18 years from 2000 through 2017 and analyzed the impact of changes in meteorological conditions on the required electricity storage capacity and the unit electricity cost, following the methodology by Matsuo et al. (2018). Further, we examined the factors that determine the required electricity storage capacity to provide information to assist future discussions.

2. Methodology

2.1 Structure of the model

This study used the optimal power generation mix (OPGM) model developed by the authors in conducting the analysis[4,23)]. The model is a typical optimal power generation mix model based on linear programming, and simulates the electricity supply with the lowest cost based on multiple constraints. Whereas ref. 4) conducted a detailed, 10-min resolution assessment, dividing a leap year into 366 × 24 × 6 = 52,704 time slices, this report used data in 1-hour intervals (365 × 24 = 8,760 time slices). Geographically, Japan excluding the Okinawa region was divided into nine regions based on the service areas of former general electric utilities.

This study covered only the 100% renewable energy case (the case with no zero-emission thermal power shown in Figure 1) in which the impact of meteorological conditions is particularly high. Accordingly, the cap for nuclear and thermal power supply is set to zero. As the installed capacity and year-round output pattern of hydropower, geothermal, and biomass are constant, the impact on only solar PV and onshore and offshore wind power was evaluated. In reality, the operation of hydropower and other sources of power is not completely rigid and when this is considered, the electricity storage capacity required when large amounts of VRE are introduced would be somewhat smaller. However, the impact is considered to be small based on the assessment conducted in this paper. More details on the formulation of the model can be found in ref. 4).

2.2 Changes in meteorological conditions

(1) Solar PV power profile

The solar PV output per kW P (kWh/h・kW) was estimated as follows using the global solar radiation I (kWh/h・m^2) from AMeDAS data.

$$P = e \times I \times A \tag{1}$$

where e represents the generation efficiency and A the area per kW (m^2/kW). This paper assumes that e = 12% and A = 7 m^2/kW in accordance with ref. 24).

(2) Wind power profile

The wind power profile was created also using AMeDAS data by referring to the method used in ref. 25). First, as the elevation of the anemometers which measured the AMeDAS data differs by observation point, the wind velocity was corrected using the following equation:

$$V = V_0 \left(\frac{h}{h_0}\right)^{\frac{1}{n}} \tag{2}$$

where, V is the wind velocity after correction, V_0 the observed wind velocity before correction, h the hub height assumed at 60 m, and h_0 the height of the anemometer. n is determined based on experience and varies between 2 and 10 depending on whether the location is a prairie, coastal area, countryside, urban district, etc. This value was set individually by confirming the terrain near each observation point on Google Map.

Then, the output was calculated as follows based on the wind velocity V obtained by equation (2). Wind turbines typically do not generate power at all wind velocities and have characteristic values called cut-in velocity V_I, rated velocity V_R, and cut-out velocity V_O. The output is zero when V is less than V_I, and increases with V based on the following equation when $V_I \leq V < V_R$:

$$P_e = \frac{\eta}{2}\rho V^3 \quad (3)$$

where, P_e represents the output per wind receiving area (W/m^2), η the generation efficiency (estimated at 40%), and ρ the air density (1.225 kg/m^3). P_e stops increasing and becomes constant once V exceeds V_R and generation stops and output becomes zero discontinuously once V exceeds V_O. Here, V_I = 3 m/s, V_R = 11 m/s, and V_O = 24 m/s were adopted in accordance with ref. 25).

In ref. 4), the generation profile for solar PV and wind power are estimated assuming that the installed capacity for those power sources in each municipality will grow in proportion to their current capacities. Meanwhile, it is also possible to estimate the profiles using the installation potential data compiled by the Ministry of the Environment, which is available for each municipality. With this approach, the output smoothing would proceed as VRE generation plants are assumed to be introduced in proportion to the introduction potential of each municipality, and thus be introduced in more regions including the municipalities which have not yet introduced large amounts of VRE, resulting in a relatively moderate rise in unit electricity cost at the time of large-scale VRE introduction. As discussed in Section 2.4 (Case setting), this paper evaluated the difference between these two approaches.

(3) Electricity demand

Electricity demand changes with meteorological conditions. For example, solar PV output will increase on a hot and clear summer day while electricity demand will also increase as the temperature rises. Consequently, it is presumed that there is a correlation between the change in demand and VRE electricity output.

To address this issue, this paper used an artificial neural network (ANN), which is a type of artificial intelligence, to estimate the change in power demand in each region based on past meteorological data. ANN has become widely used in recent years for forecasting electricity demand from meteorological data, etc., and its effectiveness is well recognized[26)]. In this paper, a 3-layer, 50-neuron ANN learned past electricity demand data using the Softplus function of $f = \ln(1 + e^x)$ as the activation function. The output data were a 24-dimensional vector indicating the hourly electricity demand of each region, and the actual values for FY2012 through FY2016 were obtained from the website of each general electric utility and used for the learning process. The input data consisted of the year, month, day, day of the week (0: Sunday, 1: Monday, …, 6: Saturday), whether the day is a holiday (1 for a national holiday or from Dec. 28 to Jan. 3 or from Aug. 13 to 15, and 0 if not), the hourly temperature value, and four variables indicating the weather (clear, rain, overcast, snow: 1 if the words appear in the weather description, and 0 if not). The meteorological data were recorded at the location of the headquarters of each utility.

In this paper, power demand data were created as follows using the ANN. First, ANN uses the recorded meteorological data for year x as input instead of 2017, and estimates the power demand for the 8,760 hours (= 365 × 24) of 2017 assuming that "the weather for 2017 was the same as that of year x." Then, this value was multiplied by the ratio between the power demand estimate[4,27)] for 2050 of 1,043 TWh and the total annual power demand of the nine general utilities for 2017 of 890 TWh to obtain the 2050 power demand estimated for the meteorological conditions for year x. However, it must be noted that the power demand curve estimated by this method is based only on the data for FY2012 to FY2016 that ANN has learned, and thus, any changes in the shape of electricity demand anticipated by 2050, such as the shift to IT and the spread of EVs, are not considered.

2.3 Other assumptions

For other assumptions, those specified in ref. 4) were used. Among them, the main ones are described in Appendix 2. Based on the potential assessment by the Ministry of the Environment[28)], this study assumes that it will be possible to introduce large amounts of solar PV and wind power plants by 2050, making it possible to produce enough renewable energy to meet 100% of the power supply or more, at least in terms of quantity. The generation cost of each power source is based on an assessment by the Japanese government[29)] but we also assume that the generation cost for wind power and solar PV will decrease from 2030 to 2050 following a similar trend.

Ref. 4) (Figure 1) sets high, medium, and low cost assumptions for "renewable energy and electricity storage systems" and "zero-emission thermal power," respectively, and analyzes nine cost cases (3 cost levels × 3 factors). While it may be desirable to allow a certain latitude in the assessment scope to account for future uncertainty, the analysis in this paper focuses on the medium cost case as the direction of change associated with variable factors such as meteorological conditions should generally be the same for all the cost cases.

2.4 Case setting

The economic efficiency of a carbon-free power sector will depend on both the required electricity storage capacity and the installed capacity of solar PV and wind power. To analyze their effects in detail, this paper sets the following cases and studies each case in light of the meteorological conditions between 2000 through 2017.

Case 0: The same conditions as ref. 4) are used. (The maximum installed capacity for solar PV and onshore and offshore wind power are as described in Table A-1.)

Case 1: The same conditions as ref. 4), but with data from more distributed locations, are used to set the VRE generation profile.

Case 2: The installed capacity of VRE is fixed to the estimates in ref. 4) (239 GW for solar PV, 271 GW for onshore wind and 139 GW for offshore wind power). Also, data from more distributed locations were used to set the VRE generation profile.

The installed capacity for VRE used in Case 2, which was obtained from ref. 4), matches the potential assessment values for solar PV and onshore wind power but is only around 50% of the potential assessment value for offshore wind power. This suggests that solar PV and onshore wind, which cost relatively less, are introduced up to their full potential, after which offshore wind is introduced. Accordingly, it might seem that the only difference between Case 1 and Case 2 is the amount of wind power generation, which would depend on wind output profiles and other conditions. However, the results showed that this is not the case, as described later.

3. Calculation results

3.1 Unit electricity cost and total generation cost

Figure 2 shows the projected 2050 unit electricity cost (obtained by dividing the total generation cost by the total power demand) factoring in the meteorological conditions (meteorological data from 2000 through 2017). The average values for Case 0, Case 1, and Case 2 were 25.2 yen/kWh, 21.9 yen/kWh, and 22.4 yen/kWh, respectively, with standard deviations of 1.7 yen/kWh, 1.0 yen/kWh, and 1.4 yen/kWh.

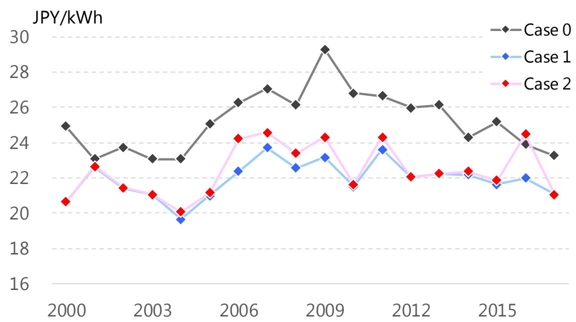
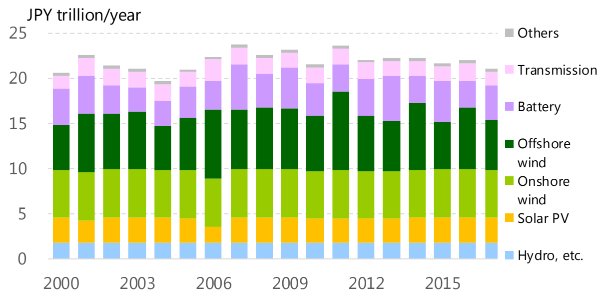
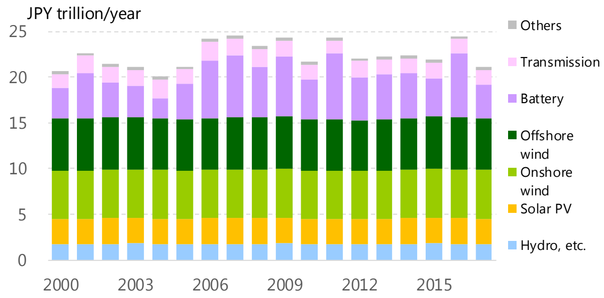


Figure 2 Unit electricity cost



Case 1



Case 2

Figure 3 Total generation cost

As can be seen from a comparison of Case 0 with Case 1, installing plants in more distributed locations reduces the variation in output and eases the rise in unit electricity cost. In comparison, the cost increase resulting from using fixed installed generation capacities was relatively small. In this paper, we selected Case 1 and Case 2, in which VRE plants are installed in more distributed places, as the major targets of comparison, aiming to simulate power generation mix in 2050.

Figure 3 shows the total annual cost for Case 1 and Case 2. The power generation cost is constant for Case 2, whose installed capacity is fixed, and any difference in cost results from the electricity storage and interregional grid connection. Meanwhile, for Case 1, the total annual cost is affected greatly by the generation cost for offshore wind power alongside battery costs.

3.2 Required electricity storage capacity

Figure 4 shows the required electricity storage capacity for each case factoring in meteorological conditions. The averages for Cases 0, 1, and 2 are 4,334 GWh, 3,334 GWh, and 4,327 GWh, with the maximum values being 5,805 GWh (2009 data), 4,505 GWh (2013 data), and 6,439 GWh (2011 data), respectively. Having plants in more distributed locations reduces the required storage capacity. However, in Case 2 in which the installed generation capacity is fixed, more than 6,000 GWh of electricity storage systems might be necessary as they would be the only means to deal with changes in meteorological conditions.

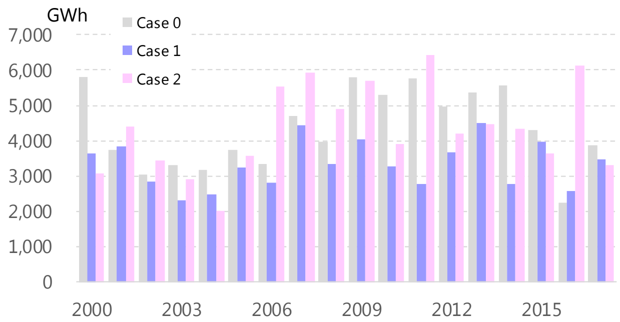
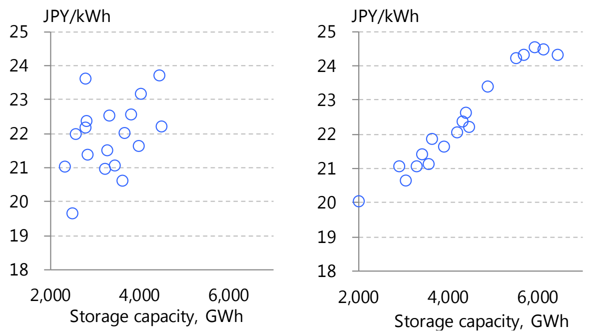


Figure 4 Required electricity storage capacity



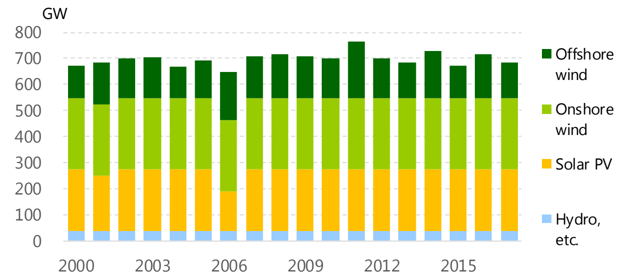
Case 1 Case 2

Figure 5 Correlation between the electricity storage capacity and unit electricity system cost

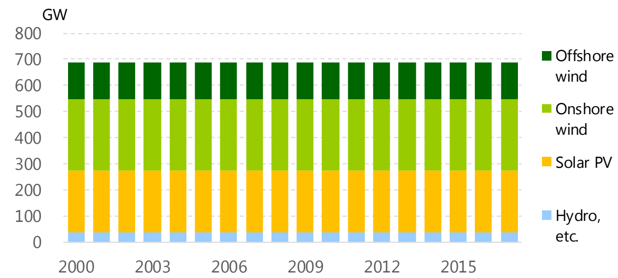
Figure 5 shows the correlation between the required storage capacity and unit electricity cost. In Case 2, unit electricity cost is correlated almost with storage capacity, suggesting the importance of evaluating the storage capacity correctly. Meanwhile, the figure shows little correlation for Case 1, in which costs are affected by the installed offshore wind capacity as well.

3.3 Power plant capacity and generation mix

Figure 6 shows the installed capacity of VREs. The result is uniform regardless of meteorological conditions for Case 2, in which the capacities are fixed. In contrast, the installed capacities change in Case 1 depending on meteorological conditions. Particularly notable is the fact that the installed solar PV capacity is lower than the upper limit in the 2001 and 2006 data whereas the installed onshore wind power capacity is at the maximum amount of 271 GW under all meteorological conditions. This shows that VRE plants are not necessarily installed simply in order of low to high projected unit electricity cost, and that depending on meteorological conditions, offshore wind power, which costs more than solar PV, can be introduced with higher priority. The causes for this phenomenon will be discussed in Section 4.2.



Case 1

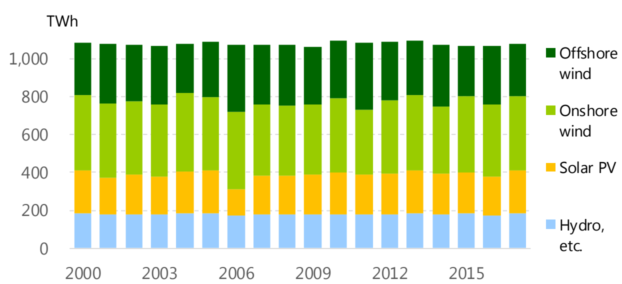


Case 2

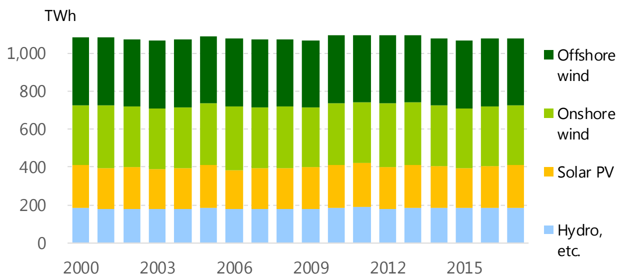
Figure 6 Installed capacity

Figure 7 shows the power generation mix after curtailment. For Case 2, the mix is similar for all the meteorological conditions, given that the installed capacities are fixed constant. However, the total electricity output fluctuates slightly from year to year due to the variation in electricity storage capacity owing to meteorological conditions, which translates to variations in the amount of storage losses.

For Case 1, solar PV output decreases in 2001 and 2006 reflecting the change in the capacity. For onshore wind, output varies as shown in Figure 7 even though the installed capacity is the same under all meteorological conditions, due to variations in the amount of curtailment.



Case 1



Case 2

Figure 7 Power generation mix

Figure 8 shows the output curtailment rates for Case 1, which are 30% on average for VREs overall and 22%, 37%, and 25% for solar PV, onshore wind power, and offshore wind power, respectively. The curtailment rate would be higher for onshore wind power than for solar PV as it has a greater installed capacity and is more regionally concentrated. Offshore wind power is also concentrated but since it has a relatively small installed capacity, its curtailment rate is only somewhat higher than that of solar PV.

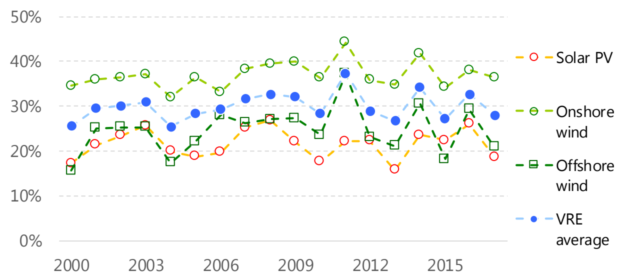


Figure 8 Curtailment rate (Case 1)

The curtailment rates for onshore wind and solar PV are correlated with the installed capacity for offshore wind power, as shown in Figure 9. This means that the higher the curtailment rate of onshore wind and solar PV becomes, the more offshore wind power must be introduced to meet the demand for electricity. For Case 1, this results in a fluctuation in offshore wind power capacity as shown in Figure 6 and, alongside the required electricity storage system capacity, has a great impact on the total cost.

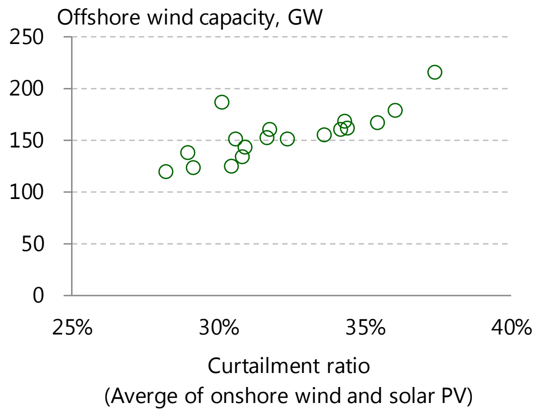


Figure 9 Correlation between output curtailment rate and installed capacity of offshore wind power (Case 1)

4. Discussion

4.1 Determinant of the required electricity storage system capacity

Figure 10 shows the daily average electricity storage for Case 2 based on 2007 data (required electricity storage system capacity of 5,938 GWh) to show the annual trend. As shown in the figure, the electricity storage surpassed 5,000 GWh on January 15 and December 10, and these two days, or more precisely, the single day with the highest demand for stored power, determined the required electricity storage system capacity for this case.

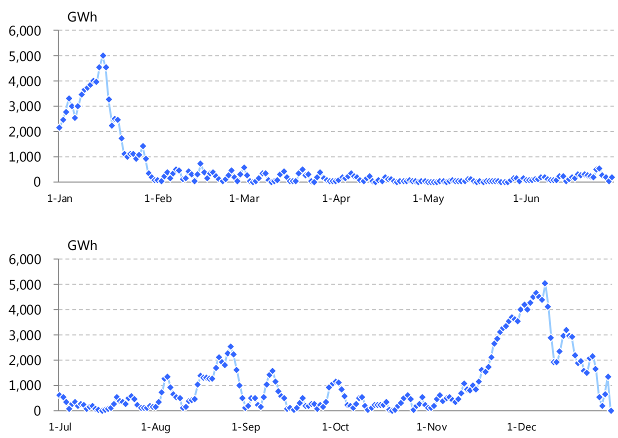


Figure 10 Amount of stored electricity (2011 data: Case 2)

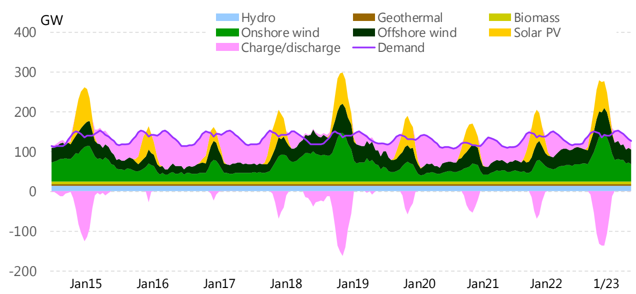
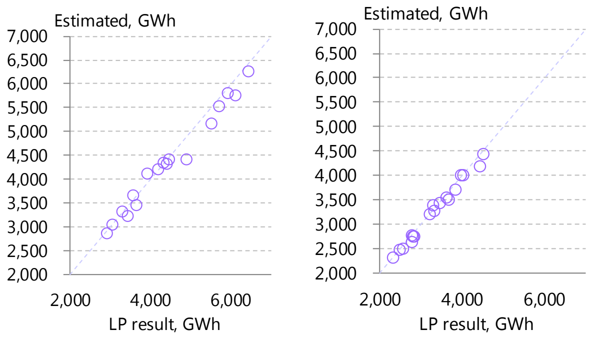


Figure 11 Electricity supply and demand for January 15–23 (Total of the nine regions: 2011 data, Case 2)

To see what was happening at this time when demand for stored power was high, the electricity demand for January 15–23 (total of the nine regions) is shown in Figure 11. One notable characteristic for the period January 16–17 and 20–22 is the fall in the wind power output to extremely low levels, resulting in large power discharge from storage systems as shown in pink in the graph to meet the power demand. This means that electricity demand could not be met with the installed solar PV and wind power capacities during this period due to meteorological conditions, and the electricity stored so far was used to meet the demand.

In other words, the figure shows that the required electricity storage capacity is determined by the maximum number of consecutive days with little wind and solar irradiation nationwide. Hereafter, this factor which affects the required electricity storage capacity is called the "windless factor" ("windless" in this paper refers to the state in which both wind and sunshine are not sufficient nationwide).

Whether this windless factor determines the electricity storage capacity for all cases can be verified by simple calculation. The required electricity storage capacity for meeting windless periods like those in Figure 11 can be calculated roughly by using the wind and solar PV generation profiles and the electricity demand over time, as shown in Appendix 2. Figure 12 shows the required electricity storage capacity associated with the windless factor plotted against the required electricity storage system capacity estimated in Figure 4.



Case 1 Case 2

Figure 12 Required electricity storage capacity (comparison between the model results and the estimated capacity due to the windless factor)

As shown above, the model estimates are correlated very strongly with the estimated required capacity due to the windless factor for both Cases 1 and 2. This means that the electricity storage capacity is determined almost exclusively by the windless factor at least for this model.

4.2 Installed solar PV capacity

As discussed earlier, the installed solar PV capacity is less than the maximum limit in the 2001 and 2006 data for Case 1. This phenomenon is also related to the required electricity storage system determined by the windless factor.

Figure 13 shows the supply and demand for electricity for December 11–17, including the windless period which determined the required electricity storage capacity for the 2006 data. The notable feature for this year is that a period without much wind coincided with a period with little sunshine. In other words, whereas the solar PV capacity factor for a typical year for this period (mid-December) was around 6–7%, the capacity factor for this year was only 4% on December 12 and 13 and 3% on the 14th on a nationwide average. As such, additional solar PV capacities do not contribute significantly to reducing the required electricity storage capacity, resulting in the optimal solution with a solar PV capacity being lower than the upper limit.

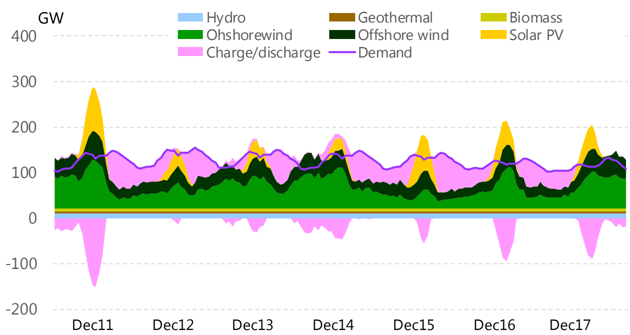


Figure 13 Supply and demand of electricity for December 11–17
(Total of the nine regions: 2006 data, Case 2)

In fact, suppose the solar PV capacity factor during this period was at 7% as is the case for a typical year (causing the annual average solar PV capacity factor to rise very slightly), then solar PV would be optimally introduced to the upper limit of 239 GW. This small change would also significantly lower the required electricity storage capacity from 2,817 GWh to 2,400 GWh, driving down the unit electricity cost from 22.4 yen/kWh to 21.9 yen/kWh.

5. Conclusions

As presented in this paper, the rise in unit electricity cost caused by the mass introduction of VRE can be alleviated to a certain extent by positioning plants at dispersed locations. However, the unit electricity cost would nevertheless increase considerably if the power supply is to be covered entirely by renewable energy without using thermal or nuclear power. As the unit electricity cost could fluctuate with a standard error of around 1 yen/kWh depending on meteorological conditions, it is necessary to use data of multiple years when evaluating such costs.

The total system cost depends mainly on the amount of offshore wind power and electricity storage capacity. The former is determined mainly by the curtailment rate of solar PV and offshore wind, which is determined by the year-round relationship between the VRE output and demand. Meanwhile, the latter is determined exclusively by the "windless factor," that reflects the supply-demand situation of a few days in a year with small wind velocities and solar radiation. In an optimization calculation like the one conducted in this study, the supply-demand situation of those few days has an extremely large impact on the overall economics of the power sector. For instance, the share of each energy source in the annual generation mix in Figure 7 would be affected greatly by these few days.

These results clearly show that a power supply disruption caused by a coincidental change in meteorological conditions could be a risk when large amounts of VRE are introduced. In an isolated grid such as that of Japan with no connection to the outside, it is necessary to install enough electricity storage systems to cover the maximum number of windless days that can be expected. The model used in this paper is based on complete foreseeability, and therefore the stored power increases heading toward windless periods. However, in reality, electricity storage systems have to be fully charged at all times to maintain energy security, as it is impossible to predict when it would be necessary to discharge power from storage systems. In reality, we should not depend only on electricity storage systems and should also consider backup supplies such as thermal power.

The limitation of optimization modelling is also shown by the fact that the optimal solution for a year-round generation mix can change greatly depending on the wind and sunshine conditions of just a few days. The correlation between the probability of occurrence of windless and sunless days are not yet clear, but from the risk management perspective, it would be necessary to assume that such days would coincide, and to estimate the maximum risk based on the meteorological data for longer periods than just 18 years.

The assessments in this study assume the use of pumped-storage hydroelectric power plants and batteries as electricity storage systems. In comparison, storing electricity in the form of hydrogen may provide a less costly means to address seasonal fluctuations, and needs to be studied in detail going forward. Further, it must be noted that simplifications which could be pointed out for ref. 4) could also apply to this paper. That is, the nine-region model used in this paper cannot fully express the cost of regional transmission lines, but in reality, this cost would be non-negligible once wind power increases to the level assumed in this study[23)]. Further, a model assuming complete foreseeability like the one in this study cannot consider additional costs associated with any incompleteness of predictions. Also, factors such as maintaining inertia, which may become an issue when introducing large amounts of renewable energy, have not been fully discussed in this paper. It is important to take these issues into consideration and to assess the feasibility of decarbonization of the power sector more realistically and accurately in future studies.

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Appendix 1 Major assumptions

As mentioned previously, major assumptions in this paper are based on ref. 4). The estimated upper limit for solar PV and wind power capacities, and the assumptions for the costs of each technology are shown in Tables A-1 to -3.

Table A-1 Maximum installed capacity assumptions for solar PV and wind

Unit: GW	Solar PV	Onshore wind	Offshore wind
Hokkaido	15	146	177
Tohoku	25	67	34
Tokyo	54	5	39
Hokuriku	9	4	0
Chubu	35	9	23
Kansai	26	11	0
Chugoku	24	9	0
Shikoku	13	5	2
Kyushu	37	16	2
Total	239	271	277

Table A-2 Generation cost assumptions (solar PV and wind)

Solar PV	Initial investment (JPY thousand/kW)	169
	Lifetime	30
	Annual expense ratio	0.008
Onshore wind	Initial investment (JPY thousand/kW)	212
	Lifetime	20
	Annual expense ratio	0.017
Offshore wind	Initial investment (JPY thousand/kW)	360
	Lifetime	20
	Annual expense ratio	0.040

Table A-3 Assumptions on electricity storage systems

	Pumped hydro	NaS Battery	Li-ion battery
Initial investment (JPY thousand/kW)	200	-	-
Annual expense ratio	0.01	-	-
Initial investment (JPY thousand/kW)	1	100	100
Annual expense ratio	0.01	0.01	0.01
Lifetime	60	15	15
Lifecycle (times)	-	4,500	3,500
Round-trip efficiency	0.70	0.85	0.85
Self discharge loss (1/h)	1E-4	5E-4	5E-4
C rate	-	0.14	2.0

Appendix 2 A simple method for calculating the required storage capacity due to the windless factor

The electricity demand (total of the nine regions) at time t ($t \in \{1, 2, \ldots, 8760\}$) is denoted as D_t, the VRE generation output as F_t, output from other sources (such as hydropower) as H_t. Residual demand R_t is defined by

$$R_t = D_t - F_t - H_t \qquad \text{(A-1)}$$

and the corrected remaining demand R'_t is calculated by

$$R'_t = \begin{cases} R_t & if\ R_t \geq 0 \\ ef\ R_t & if\ R_t < 0 \end{cases} \qquad \text{(A-2)}$$

where ef represents the cycle efficiency of the storage systems. The cumulative corrected residual demand C_t is given by

$$C_t = \sum_{T=1}^{t} R'_t \qquad \text{(A-3)}$$

In a situation where a large share of power supply is covered by VRE, as is assumed in this study, R'_t becomes negative for a large range of t, and C_t will continue to decline. However, if the VRE output continues to fall below the demand, that is, local increase in C_t continues, for a certain period of time, this increase would represent the requirement for power discharge (shown in pink in Figures 11 and 13).

Since

$$X_t = C_t - \min_{T \leq t} C_T \qquad \text{(A-4)}$$

is the cumulative required amount of discharge at time t, its maximum value would indicate the cumulative demand for discharged power, which is equivalent to the required electricity storage capacity. Therefore, the required electricity storage capacity in GWh due to the windless factor can be obtained by:

$$L = \max_{t} X_t \div r \div LF \qquad \text{(A-5)}$$

where r is the self-discharge factor which is estimated as $r = (1 - 0.004)^5 = 0.982$, assuming a self-discharge rate of 0.4%/day and five consecutive days without wind. LF represents the capacity factor of the electricity storage system, assumed at 90% in this paper.