A Study on the Feasibility of 80% GHG Reduction in Japan Using a Bottom-up Energy System Model: The Effect of Changes in Meteorological Conditions

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Abstract

This paper presents the effect of changes in meteorological conditions in a study on the feasibility of reducing greenhouse gas (GHG) emissions by 80% in Japan toward 2050. The authors develop a bottom-up energy system model which incorporates a high-temporal-resolution power sector and analyze the feasibility under 18 patterns of variable renewable energy (VRE) power profiles. The simulation results show that changes in meteorological conditions, namely the duration of periods without sun and wind, would substantially impact the installed capacity of electricity storage systems. Since the capacity may differ by as much as 300 GWh in 2050, it is essential to consider several VRE power profiles when studying future massive decarbonization where VRE is expected to account for more than 50% in the power generation mix. Although the effect of changes in meteorological conditions on the degree of electrification and the technology choice in the final demand sectors is relatively small, even minor differences may lead to huge variations in GHG marginal abatement cost.

***Key words**:* GHG 80% Reduction, Battery Installation, Variable Renewables, Energy System Model, Linear Programming

1. Introduction

In recent years there has been growing awareness of the importance of tackling global warming. In Japan, the Cabinet approved the Plan for Global Warming Countermeasures[1] in May 2016, setting a goal of reducing greenhouse gas (GHG) emissions by 80% by 2050. Based on this plan, Japan's Long-term Strategy under the Paris Agreement as Growth Strategy[2] released in June 2019 aims to make Japan's energy system carbon-neutral by as early as possible in the second half of this century. Meanwhile, the government has yet to present any specific quantitative estimates regarding how to achieve these targets with combinations of energy technologies.

Regarding Japan's target to reduce GHGs or energy-related CO_2 by 80% by 2050, several studies using bottom-up energy system models have been conducted. Oshiro et al.[3] used the AIM/Enduse model, which divides Japan into 10 regions, to present the extent of reduction measures required to reduce GHGs by 80% as well as the effect of expanding the electricity interconnection capacity on alleviating the cost of reducing emissions. Akimoto et al.[4] conducted a study using the DNE21+ model to demonstrate that the carbon intensity of the power sector must become net negative and fossil fuel consumption must be minimized to achieve the 2050 target. As with MARKAL/TIMES and others, these bottom-up energy system models have a low temporal resolution for the power sector compared to models specializing in the power sector[5), 6)].

In previous analyses of the power sector using dedicated models, only several tens of time slices represent one year, employing the electricity demand curves of typical days[7]. However, such representations cannot explicitly express the fluctuating output of variable renewable energy (VRE), namely solar PV and wind turbines, and various constraints regarding demand-and-supply management of the power system. This methodology may over- or under-estimate the optimum amount of VRE to be introduced or the cost of reducing CO_2 in situations where large amounts of VRE may be introduced, such as for significant GHG reduction[8]. As such, it is becoming increasingly common to model the power sector with an hourly time resolution (with 8,760 time slices per year)[9), 10)]. However, this level of detailedness is still achieved only for studies specializing in the power sector; when modeling the entire energy system, it has been difficult to appropriately assess the impact of introducing large amounts of VRE with consideration of its hourly output variability, mainly due to computational restrictions[15), 16)].

To address this issue, Ueckerdt et al.[11], for example, presented a method that used residual load duration curves (RLDC) to incorporate the impact of large-scale use of VRE in an integrated assessment model (IAM), instead of directly handling 8,760-hour power supply-demand profiles. This approach has been, in fact, incorporated in IAMs targeting the global energy system, such as the REMIND and MESSAGE models, and used for analyses[12), 13)]. However, as the RLDC-based approach cannot appropriately

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represent the electricity supply and demand management mainly during windless periods, it has been suggested that this approach may not be able to fully assess the economic impacts when large amounts of VRE are installed[14]. Accordingly, we developed a bottom-up energy system model, for Japan to begin with, which fully models the power sector based on 8,760 hourly time slices[15), 16)]. This enabled us to appropriately assess the economic and technological impacts of large-scale VRE installation, while maintaining the advantages of the bottom-up energy system model, such as the ability to assess the competition among fuels (promotion of electrification) in the final consumption sectors (industry, residential and commercial, and transportation sectors), and use of excess electricity.

However, the estimated power profiles used in our previous reports were based on meteorological data for 2012. In reality, the results of the evaluation, such as the installed battery capacity and power generation cost, depend heavily on meteorological conditions (sunshine and wind conditions) and will not be reliable enough unless the study is based on multi-year data[14), 17)]. Thus, in this report, we employed an energy system model that incorporates a high-temporal-resolution power sector to estimate what kind of energy system is needed to reduce GHGs by 80%, while adopting multi-year meteorological data, to analyze the impact of meteorological factors on electricity demand (technology choice in the non-power sector), introduction of excess electricity management technologies, and the marginal GHG abatement cost.

Regarding considering the meteorological conditions for multiple years, some studies considered the meteorological conditions over several years[18)], with a number of studies assessing changes in meteorological conditions over longer periods (10 to more than 20 years)[19)]. However, there are perhaps just one study on Europe[20)] and one on Japan[14)] that actually estimate the electricity supply and demand in detail by incorporating multi-year data into a model. In addition, those studies were model analyses focusing on the power sector; to our knowledge, there had been no study on the entire energy system using multi-year data.

2. Analytical Framework

We conducted the analysis using the bottom-up energy system optimization model that we developed. This model is a techno-economic dynamic linear programming one and minimize the objective function, which is the discounted total energy system cost for the analyzing period, under multiple constraints. The key feature of this model is that it assesses the power sector on an hourly basis (8,760 hourly time-slices per year) even though it can model the entire energy system of Japan. The model also takes into account such excess electricity management technologies as EV charging and conversion into hydrogen as well as pumped hydro storage and batteries, and incorporates their hourly performance as well. The main exogenous variables of this model are energy service demand and the economic and technological characteristics of each technology comprising the energy system (such as conversion, distribution, and final consumption technologies); see previous reports[21), 22)] for details on the model. Unlike the power sector for which a hourly temporal resolution is adapted, for the non-power sectors, the supply-demand balance is satisfied on just annual basis. Improving the temporal resolution for the sectors is a challenge for the future. The main assumptions for the GHG reduction technologies used in this report are listed in **Table 1**.

Table 1 Key GHG reduction technologies

Power sector	Natural gas-fired with CCS, Coal-fired with CCS, Solar PV, Wind power (onshore, offshore), Geothermal, Biomass, Hydrogen-fired, Ammonia-fired, Pumped hydro, Batteries (NAS batteries, Li-ion batteries)
Other conversion sector	Hydrogen production from coal and natural gas, Hydrogen production by water electrolysis, Hydrogen storage, Methanation, CO_2 Direct Air Capturerom (DAC), EV charging
Industry sector	Innovative furnace technology, CO_2 recovery at furnace, Electric furnace, CO_2 recovery at cement production, High performance cement production, Black liquor recovery boiler, High efficiency industrial furnace, High efficiency boiler, High performance motor
Residential/Commercial sector	High efficiency air-conditioner, High efficiency gas air conditioner, Latent heat recovery water heater, High efficiency HP water heater, High efficiency lightings and power, Solar water heater
Transport sector	Hybrid electric vehicle (HEV), Plug-in hybrid vehicle (PHV), Electric vehicle (EV), Fuel cell vehicle (FCV), CNG vehicle (freight), LNG vehicle (freight), LNG fuel ship

This study was conducted for the period up to 2050 (at five-year intervals from 2015), dividing the entire Japan except Okinawa into five regions (Hokkaido, Tohoku, East Japan, West Japan, Kyushu), and taking into account power interchange between regions.

For solar PV, and onshore and offshore wind power, the impacts of changes in meteorological conditions on their output were taken into account. The hourly power profiles of these VRE technologies were estimated using AMeDAS data. The PV output per kW was estimated based on the amount of global solar radiation from the AMeDAS data. For wind power, the output was estimated by correcting the wind speed data from AMeDAS to the wind speed at the height of the hub (estimated to be 60 meters above ground), then assuming that the output per wind-receiving area corresponds to the cube of the wind speed. The cut-in wind speed for the wind power generator was estimated to be 3 m/s, the rated wind speed 11 m/s, and the cut-out wind speed 24 m/s. Since the electricity demand curve is likely to change with meteorological conditions as well, we used an artificial neural network (ANN) to estimate the demand profile for each region using past meteorological data. The actual electricity demand data of electric utilities (FY2012–2016) was fed into an ANN (three layers × 50 neurons) as past electricity demand data. For details on VRE power profiles and power demand settings, see Reference 17.

This report uses the data for 18 years from 2000 to 2017 calculated by the method above. The estimated annual average capacity factors for VRE power generation were more or less constant throughout these years (**Figure 1**), with 13.1% for PV (0.2% standard deviation), 23.9% for onshore wind power (0.1%), and 29.9% for offshore wind power (0.1%). However, there was greater variation among regions. For PV, for example, in 2003 and 2006 when the average capacity factor was low, low capacity factors were observed in East Japan and West Japan where demand is greater than in other regions. Specifically, the annual average capacity factor for East Japan was lower than the full-term regional average of 12.6% in 2003 with 11.7% and in 2006 with 11.6%. West Japan's annual average was lower than the full-term regional average of 13.2% in 2003 with 12.3% and in 2006 with 12.6%. Meanwhile, in 2010, the national average capacity factor was lower than in other years but the regional deviation was smaller, with a capacity factor of 12.5% for East Japan and 13.2% for West Japan.

Note that this report does not consider the growth in PV generation efficiency or the improvement in capacity factor associated with the growth in size of the wind turbines and thus the height of the hub over the target 18 years and in the future.

For GHG emissions other than energy-related CO_2, we excluded the Land Use, Land Use Change and Forestry (LULUCF) sector from the study, and assumed that GHG emissions from fossil fuel incineration and leakage are proportional to the endogenously-determined amount of fossil fuel consumption. For freon gas, we assumed, based on Reference

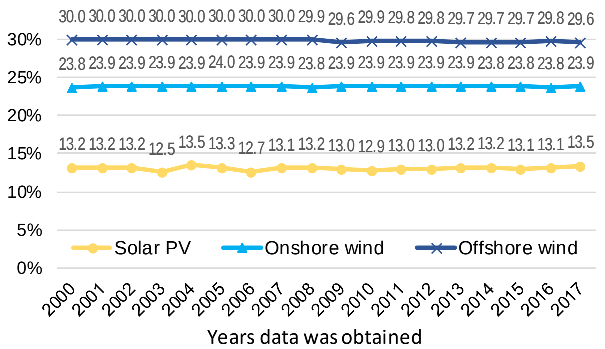

Figure 1 Annual average capacity factor of VRE power

23, that the emissions from refrigerators and air-conditioners, which account for most of the freon emissions, can be reduced at a cost of \$40/t-CO_2eq. The paths for other GHG emissions were set exogenously up to 2050 taking into account the rate of change in recent years. Here, the modeling was simplified and has much room for improvement.

In terms of size, the model contains approx. 14 million endogenous variables and about 24 million constraints. The optimum solution was obtained using the software Xpress.

3. Assumptions

3.1 Assumptions about the power sector

Our assumptions about the cost and operational features of each power generation and electricity storage technology are based on

Table 2 Exogenous variables of power plants

	Nuclear	Coal	LNG CC	LNG ST	Oil	Hydrogen
Construction cost [kJPY/kW]	370	272	164	120	200	164
Rate of fixed operation and maintenance cast	5.2%	4.0%	3.0%	3.0%	3.2%	3.0%
Efficiency (sending end, LHV)	-	39~41%	54~57%	42%	38~39%	57%
Annual average capacity factor Maximum	80%	80%	80%	80%	80%	80%
Peak capacity factor Maximum	90%	90%	95%	95%	95%	95%
Maximum load following [%/h]	0	26	44	44	44	44
Minimum load following [%/h]	0	31	31	31	31	31
Operational lifetime [year]	60	40	40	40	40	40
DSS operation rate	0	0	0.5	0.3	0.7	0.7
Minimum output rate	0.3	0.3	0.3	0.3	0.3	0.3
	Hydro	Biomass	Geo-thermal	Solar PV	Onshore wind	Offshore wind
Construction cost [kJPY/kW]	640	398	790	294~152	284~227	591~506
Rate of fixed operation and maintenance cast	1.4%	6.8%	4.2%	1.4%	2.1%	3.5%
Efficiency (sending end, LHV)	-	18%	-	-	-	-
Maximum capacity factor	55%	80%	70%	Refer to Fig. 1	Refer to Fig. 1	Refer to Fig. 1
Maximum load following [%/h]	5	30	5	-	-	-
Minimum load following [%/h]	5	30	5	-	-	-
Operational lifetime [year]	60	40	40	20	20	20

Table 3 Exogenous variables of storage technologies

	Pumped storage	NAS batteries	Li-ion batteries
Construction cost [kJPY/kW]	190	35	40
Construction cost [kJPY/kWh]	10	40~30	150~5
Rate of fixed operation and maintenance cast	1%	1%	1%
Maximum capacity factor	90%	90%	90%
Cycle efficiency	70%	85%	85%
Self discharge rate [1/h]	0.1%	0.5%	0.5%
Maximum kWh/kW ratio	6	∞	∞
C-rate	-	0.14C	2.0C
Cycle lifetime [cycle]	∞	4,500	6,000
Operating lifetime [year]	60	15	8

Table 4 Maximum capacity of VRE and geothermal power in 2050 (GW)

	Hokkaido	Tohoku	East Japan	West Japan	Kyushu	Total
Solar PV	18.0	42.2	89.6	129.2	49.9	328.9
Onshore wind	125.9	58.8	7.1	30.5	13.3	235.5
Offshore wind	86.7	5.5	10.9	8.5	0.3	111.8
Geo-thermal	0.6	3.4	0.5	0.2	1.5	6.2

References 22 and 24, and are listed in **Table 2** and **Table 3**. The costs and prices used in this study are in 2014 constant prices. The assumption about each item is common to all regions, and all ranges of numbers in the tables represent improved efficiency with time and technological progress. The decrease in construction cost of VRE power toward 2050 was obtained by extrapolating the decrease up to 2030 presented in Reference 24. The assumptions about ammonia-fired power generation are the same as those for hydrogen-fired power. Note that co-generation and autoproducer power plants are not considered in this study.

For the installed capacity of nuclear power, we assumed that the 33 power plants in operation as of October 2019 will continue to operate for a total of 60 years. The installed capacity will be 21.2 GW in 2050. The estimated maximum VRE and geothermal capacity that can be introduced in each region are as shown in **Table 4** based on References 25 and 26. The maximum capacity for hydraulic power and pumped hydro were set to their values in 2015. It was assumed that inter-regional transmission lines are not expanded unless they are already scheduled for expansion.

3.2 Other assumptions

For the CCS storage potential in 2050, many papers[4), 27)] estimate that large amounts of CO_2 of 91–150 Mt-CO_2/year can be stored, but this report adopted 30 Mt-CO_2/year, which is relatively small. We set the maximum amount of hydrogen import in 2050 to 150 billion Nm^3, the target level of the Basic Hydrogen Strategy of the Ministry of Economy, Trade and Industry, and assumed that the same amount of ammonia in calorific equivalent can also be imported. The assumptions for hydrogen production by water electrolysis, methanation, and hydrogen storage are based on References 28 and 29 (see Reference 30 for the value setting). Energy service demand was calculated using an econometric technique. Real GDP is estimated to grow by 1.7% per annum until 2030 and by 1.2% per annum thereafter till 2050, and accordingly, energy service demand will grow by around 0.5% per annum from 2015 through 2035 and remain mostly flat thereafter.

GHG emission constraints were set for emissions in and after 2030. Emissions were capped at 1,079 Mt-CO_2eq., the level indicated by METI's Long-term Energy Supply-Demand Outlook, for 2030, and at the level 80% lower than FY2014 for 2050. For all the years in between, linear interpolations between these two values were used as the caps.

3.3 Scenario

As mentioned earlier, this report uses the meteorological data for the 18 years from 2000 to 2017. Further, for examining the impact of CCS storage potential and the maximum amount of hydrogen import, we conducted a sensitivity analysis using the data for two years with representative meteorological conditions.

4. Results

4.1 The energy system for 80% GHG reduction

Taking the meteorological data for 2005 as an example, we outline the features of the energy system that can reduce GHGs by 80% in 2050. We selected 2005 as a typical year because the solution obtained using the year's data produced the median of the solutions for the 18 years in terms of installed battery capacity and marginal GHG abatement cost.

Figure 2 shows the power mix of Japan in 2035 and 2050 and of each region in 2050. In 2035, fossil fuel power sources, mainly LNG combined cycle (CC) power, account for 49% of power generation because GHG reduction constraints are still relatively relaxed. Coal-fired thermal and LNG CC both have a capacity factor of 45%. Meanwhile, in 2050, the power sector, which has a relatively large number of CO_2 reduction technologies, is required to achieve net-zero emissions. Based on the operating lifetime assumptions in **Table 2**, even though 14 GW of coal-fired thermal power and 98 GW of LNG CC capacities exist in 2050, their capacity factors will be zero. Instead, the share of VRE power will increase from 22% in 2035 to as much as 47% in 2050.

The measures for achieving net-zero emissions in the power sector vary by region. In the Hokkaido and Tohoku regions which have a large onshore wind power potential, the energy source will account for the majority of the output while other regions will have a high percentage of solar PV and hydrogen-fired and ammonia-fired power. Hokkaido has the highest potential for offshore wind power, but the technology will not be introduced due to large amounts of cheap onshore wind power and constraints in transmission capacity to Tohoku.

With the large-scale use of VRE, batteries will also be introduced in large amounts by 2050 (158 GW, including 9 GW of NAS batteries and 149 GW of Li-ion batteries, or 1,223 GWh, including 65 GWh of NAS and 1,158 GWh of Li-ion). GW capacity tends to increase more in regions with a large PV capacity, increasing the most in West Japan (54 GW) which will have the largest PV capacity (129 GW in 2050). Note, however, that the amount of batteries and other technologies to be introduced and the cost of GHG reduction will also be affected by the operating lifetime settings of the technologies. For example, if we assume that Li-ion batteries have the same operating lifetime as NAS batteries of 15 years, the relative economic efficiency of Li-ion

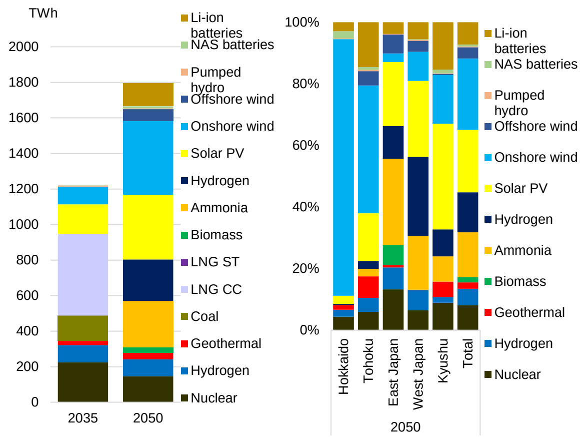

Figure 2 Power generation mix in 2035 and 2050, and the composition by region in 2050

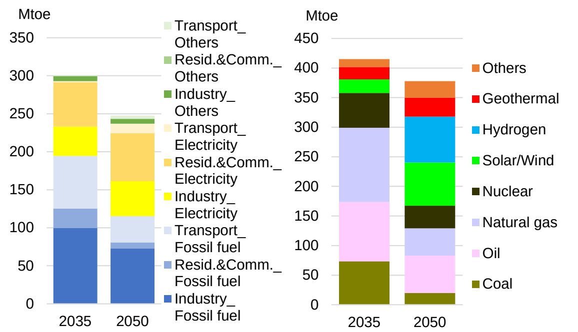

Figure 3 Final energy demand and primary energy supply

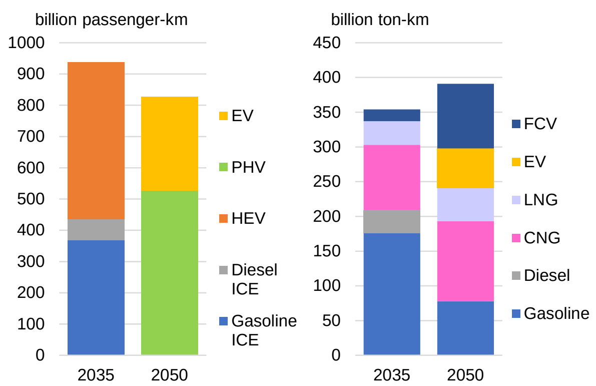

Figure 4 Share of transportation demand by vehicle (left: passenger sector, right: freight sector)

batteries will increase as they require fewer replacements, resulting in 177 GW / 1,561 GWh of Li-ion batteries and fewer NAS batteries being introduced in 2050. An increase in battery capacity will cause a change in the amount of new capacity and the output of each VRE power source, but the change will remain small as VREs will be installed up to their limit under the 80% GHG reduction target in any case.

In the final consumption sector, electrification will make progress as well as advances in energy conservation (**Figure 3**). The rate of electrification will increase from 33% in 2035 to as high as 49% in 2050, resulting in electricity demand reaching 1,416 TWh in 2050. The difference from the electricity output shown in **Figure 2** corresponds to the amount of electricity consumption in the conversion sector, that is, EV chargings, methanation, etc. The amount of methane produced by methanation will reach 4 Mtoe in 2050, equivalent to 9% of the final consumption of city gas of 48 Mtoe. Electrification will advance particularly in the residential/commercial and the transport sector, with all passenger vehicles becoming electrified by 2050 (**Figure 4**). For freight vehicles, various types of vehicles will be chosen, including LNG trucks and FCV trucks.

4.2 Comparison using multi-year meteorological data

(1) Introduction of electricity storage technologies

Figure 5 shows the estimated battery capacity in 2050 (NAS and Li-ion combined) based on the meteorological data of each year. The battery capacities depend on the VRE power profile used and have an average of 164 GW / 1,252 GWh, with a standard deviation of 9.5 GW / 106 GWh. Both values were greatest when the 2003 meteorological data was used (186 GW / 1,436 GWh).

To identify how the battery capacity is determined, we illustrated the electricity demand and supply management in total Japan for the day with the highest electricity storage level in the year, and for the 10 days before and after that day, using the meteorological data for 2003, which results in the 2050 installed Li-ion battery capacity (GWh) becoming the largest (1,371 GWh), and for 2004, which produces the smallest Li-ion battery capacity in 2050 (1,049 GWh), as shown in **Figure 6** and **Figure 7**. In the figures, “Day 0” indicates the day when the electricity storage level is the highest. With the 2003 data, the electricity storage level decreased as large amounts of electricity were discharged to maintain the supply-demand balance even though there was a shortage of sunshine for about one week from two days after Day 0 and the battery capacity was not being charged as fully as on other days. Meanwhile, with the 2004 data, the electricity storage level decreased two days after Day 0 due to low solar PV output

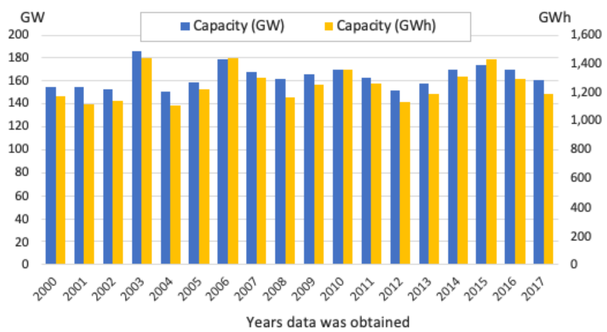

Figure 5 Battery installed capacity in 2050

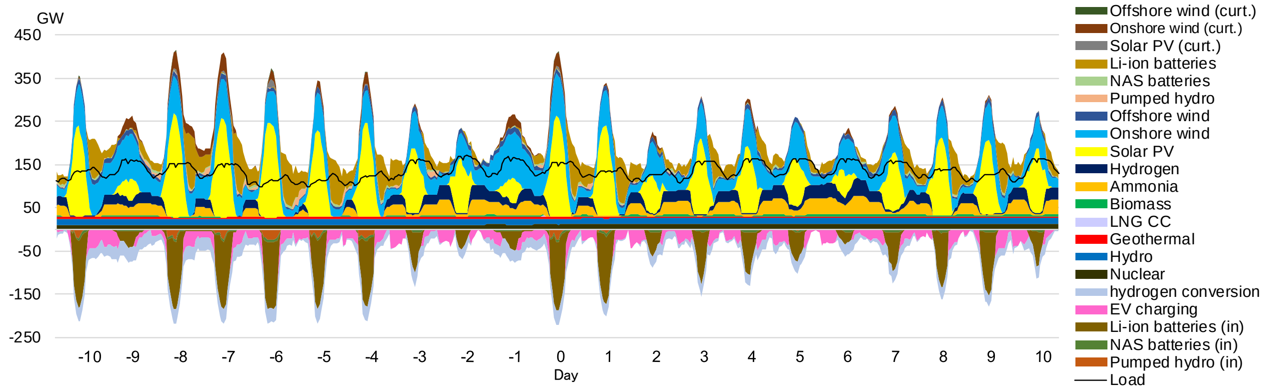

Figure 6 Power dispatch for the ten days before and after the day with the highest electricity storage level in 2050 based on 2003 data

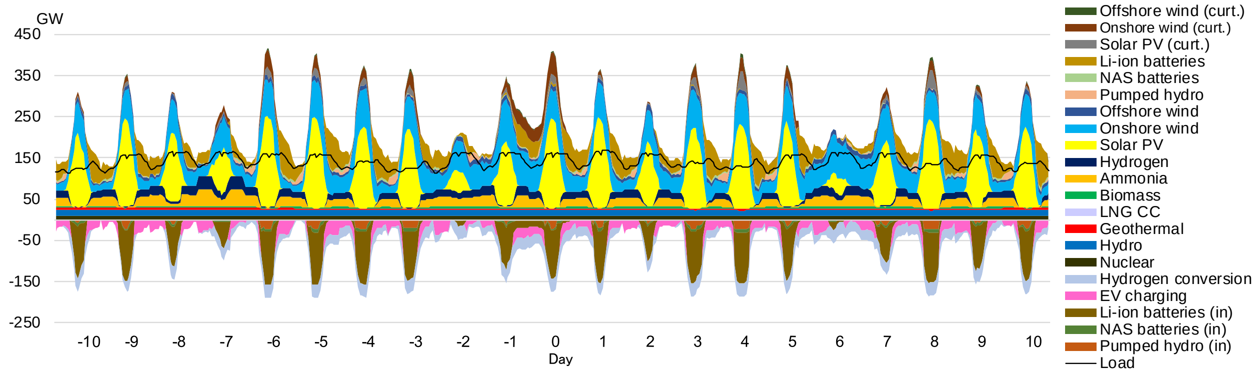

Figure 7 Power dispatch for the ten days before and after the day with the highest electricity storage level in 2050 based on 2004 data

but came back up from the third day as sufficient VRE output was obtained. This suggests that battery capacity (GWh) is determined based on the number of consecutive days without enough sunshine or with poor wind conditions (“windless period”). The difference in capacity between 2003 and 2004 would be equivalent to a difference in facility investment of 1.6 trillion yen in 2050.

Storage systems for hydrogen produced by water electrolysis will be introduced in the Hokkaido and Tohoku regions. Regarding their capacity, the GW capacity does not vary greatly by the year the data was obtained, as shown in **Figure 8**, but the GWh capacity is affected significantly by the VRE power profile of each year. The GWh capacity varies by year particularly for Tohoku. **Figure 9** shows the changes of the region’s hydrogen storage level for representative years. Well-suited for long-term storage, hydrogen is generally stocked up in early summer when the VRE power output is high and drawn down in autumn when the output is low. As any excess electricity is stored in batteries to supply as much zero-emission electricity as possible, hydrogen production by water electrolysis is conducted mainly when the VRE power output is large enough to trigger curtailments or when the electricity storage level is sufficiently high. The data for 2006

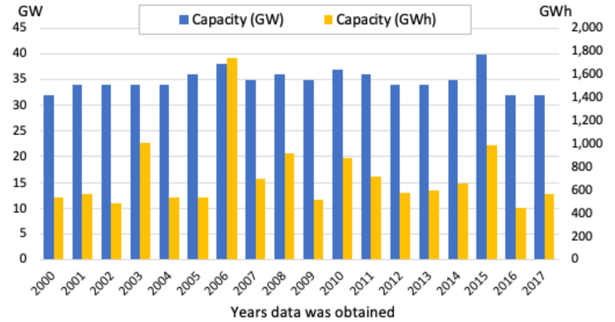

Figure 8 Hydrogen storage system capacity in 2050

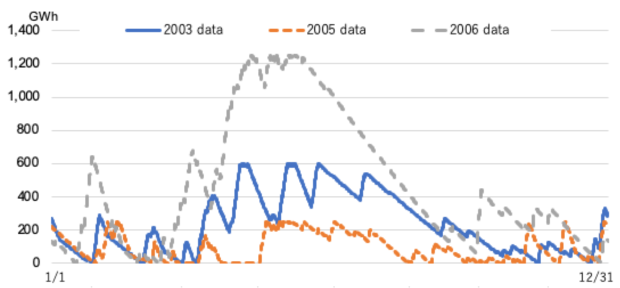

Figure 9 Changes in hydrogen storage in 2050 (Tohoku)

implies that because there are few chances to meet these conditions and stock up hydrogen during the summer, preparations must be made for drawdowns by increasing the GWh capacity and the storage level. However, it must be noted that this study sets the construction cost of the hydrogen storage system (the Wh part) to \$700/kg[31)], which is lower than that of Li-ion batteries in per unit energy stored cost. In **Figure 8** and **Figure 9**, the installed capacity in GW of the hydrogen storage systems is the highest calorific value of hydrogen produced per hour expressed in watts (GW), and the installed capacity in GWh and the amount of hydrogen stored are the calorific value of stored hydrogen expressed in watt-hours (GWh).

(2) Power generation mix and electricity demand

Figure 10 shows the power generation mix (excluding VRE output curtailments) and the electricity demand in the final consumption sector. Unlike battery capacity, both the total power generation and the electricity demand in the final consumption sector vary little due to the VRE power profile. In 2003 and 2006 only, the total power generation is smaller than in other years due to the slightly lower average capacity factor for solar PV, resulting in the electricity demand becoming around 10 TWh lower. **Figure 11** shows the installed capacity of VRE power, which also varies only slightly depending on which year's data is used. The average installed capacity of each power source was 319 GW for solar power, 200 GW for onshore wind power, and 25 GW for offshore wind power, with standard deviations of 5.6 GW, 2.9 GW, and 0.0 GW, respectively. For all years whose data was used, VRE power generation will be introduced up to the maximum capacity shown in **Table 4** in all regions except Hokkaido. In Hokkaido, due to low local demand, the installed capacity of all VRE power sources falls below the upper limit except for PV under the 2015 data. As mentioned in **Section 4.1**, zero-emission electricity and further electrification of the final consumption sector are critical for achieving an 80% GHG reduction. This report sets limits on the installed capacity of VRE power and zero-emission thermal power such as fossil-fuel fired with CCS and hydrogen fired; thus, there is a limit to the amount of zero-emission power supply in each region. Since the annual average capacity factor of VRE power varies only slightly year to year as shown in **Figure 1**, electricity demand, power generation mix, and installed VRE capacity will be almost the same regardless of the year of the data. On the other hand, the management of supply and demand of electricity will be affected significantly by the VRE profiles when large amounts of VRE are introduced, and will result in large differences in the installed battery capacity, as described in the previous section.

(3) Marginal abatement cost

Figure 12 shows the marginal abatement cost of GHG in 2050

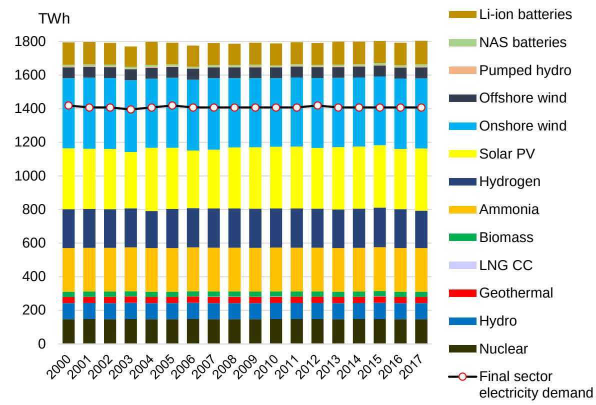

Figure 10 Power generation mix in 2050 (excluding curtailments of VRE output)

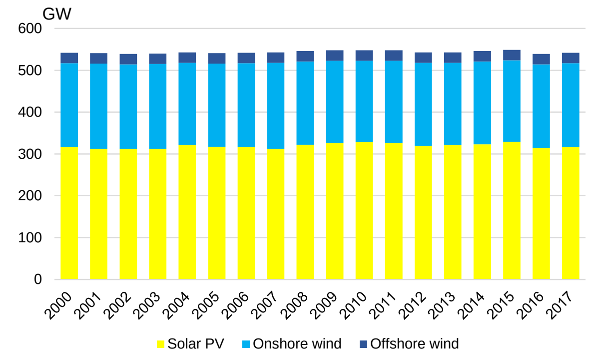

Figure 11 VRE Installed capacity in 2050

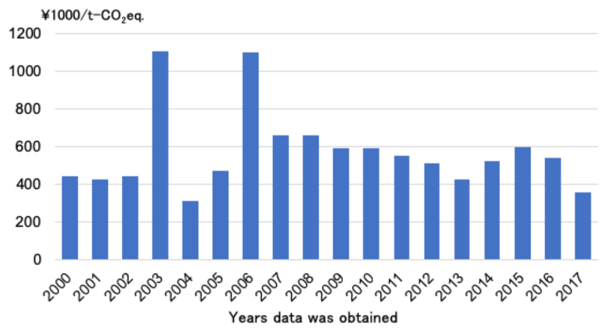

Figure 12 Marginal abatement cost of GHG in 2050

based on the meteorological data of each year. For the data of 2005, for which the selection of major technologies was explained in **Section 4.1**, the marginal abatement cost of 472,000/t-CO_2eq. was obtained. This value is in the upper portion of the estimated marginal cost for reducing the energy-related CO_2 emissions of Japan by 80% in 2050, which is roughly several hundred to several thousand dollars per t-CO_2[32)]. The marginal cost in this report is relatively high presumably because this report aims to reduce GHG by 80% and this requires reducing energy-related CO_2 by more than 80%, the maximum amount of CO_2 storage is set lower than in previous papers[4), 27)], and the energy service demand is set assuming a relatively high GDP growth rate.

The cost of 472,000/t-CO_2eq., for example, is equivalent to about 1,080 yen per liter of gasoline. This suggests that it is not easy to reduce GHG by 80% in light of the high economic burden on GDP and households.

While the marginal abatement cost lies between 400,000 and 600,000 yen/t-CO_2eq. for most years, it is significantly higher in 2003 and 2006 at about 1,100,000 yen/t-CO_2eq. and, in contrast, is around 350,000/t-CO_2eq. in 2004 and 2017. One of the reasons for the high cost for the 2003 and 2006 data is because the PV capacity factor is smaller than in other years in East and West Japan, which have a large electricity demand and limited ability to increase wind power, resulting in only a small amount of VRE power being connected to the grid in those regions (**Figure 13**). This limits the zero-emission power supply in those regions and results in the need for more expensive investments in energy conservation in the final consumption sector. The average capacity factor of PV is low also in 2010 according to **Figure 1**, but this is due to the relatively low utilization rate of VRE in Hokkaido and Tohoku which have a high VRE power generation potential and which do not act as a constraint on zero-emission electricity supply. When VRE power output is relatively low, the output curtailment rate for VRE is set low so as to maximize the zero-emission power supply, as shown in **Figure 13**. This is one of the reasons for the increases in battery capacity (particularly GW capacity) and GHG reduction cost.

4.3 Sensitivity analysis

We conducted a sensitivity analysis for the two factors, namely, the maximum amount of CCS storage and hydrogen import, which are likely to determine the degree of difficulty of achieving an 80% GHG reduction. We assume that the two factors will be higher than the baseline set in **Section 3.2**, using the 2003 and 2004 meteorological data which resulted in the battery capacity and the marginal cost of GHG reduction being the highest and the lowest in 2050 in the previous section. Here, the maximum CCS storage amount in 2050 was set to 50 Mt-CO_2 and the maximum hydrogen import to 300 billion Nm^3.

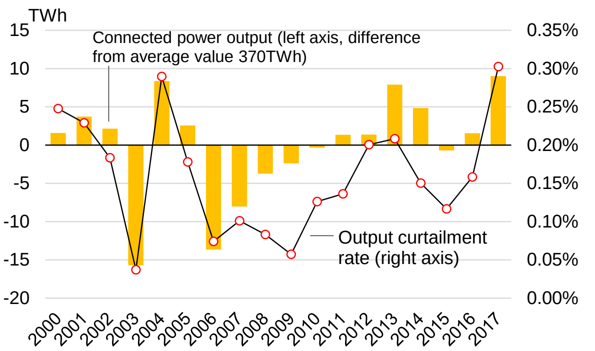

Figure 13 Amount of VRE power connected to the grid in East Japan and West Japan, and the output curtailment rate in 2050

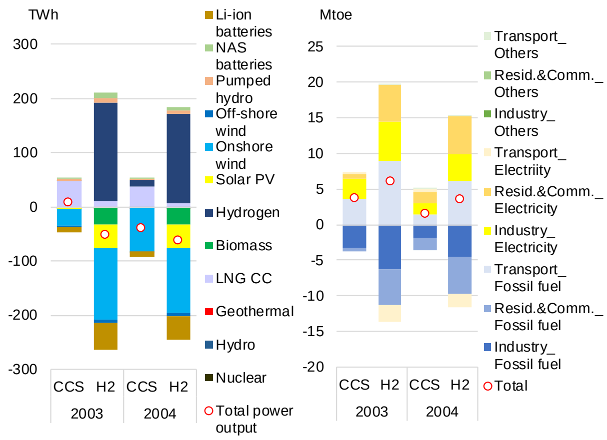

Figure 14 Changes in the power generation (excluding VRE output curtailment) and final energy consumption in 2050

Figure 14 shows the variation in the power generation mix and the final consumption composition between the cases with elevated maximum CCS storage capacity or hydrogen import and the baseline case. In the CCS case, the output of LNGCC with CCS increases and replaces onshore wind power due to an increase in CCS storage capacity. For the hydrogen case, the amount of hydrogen used in the power generation sector increases, replacing VRE power generation. As a large amount is replaced, the battery capacity and the amount of discharge also decrease sharply. For 2003, the battery capacity decreases to 65 GW / 450 GWh, down 121 GW / 985 GWh from the baseline case.

In both cases, extremely large reductions in the marginal abatement cost of GHG in 2050 were observed, with decreases down to 287,000 yen/t-CO_2eq. (2003) and 229,000 yen/t-CO_2eq. (2004) for the CCS case and to 105,000 yen/t-CO_2eq. (2003) and 106,000 yen/t-CO_2eq. (2004) for the hydrogen case. Any change in the operating lifetime of each technology mentioned in **Section 4.1** will affect not only the capacity of each technology to be introduced but also the electricity price through an increase or decrease in the total capital cost, and as a result, the marginal abatement cost may also change. For example, when the operating lifetime of Li-ion batteries was set to 15 years as with NAS batteries under the 2005 data, the marginal cost of reduction decreased by approx. 10% to 427,000/t-CO_2eq.

5. Conclusion

In this report, we analyzed the effect of meteorological conditions on the selection of energy technologies and the marginal GHG abatement cost when a significant GHG reduction is required, employing an energy system model that incorporates a high-temporal-resolution power sector. We analyzed the selection of technologies for reducing GHG by 80% in Japan using the meteorological data for the 18 years from 2000 to 2017.

The results suggested that variations in VRE power profiles, specifically, the maximum consecutive number of days with poor sunlight or wind conditions in a year, significantly affect the amount of battery capacity installed. The amount can change by around 300 GWh at most depending on the availability of CCS and imported hydrogen and how those profiles are set. Thus, in the cases studied here where large amounts of VRE power will be introduced, it is important to use the meteorological data of multiple years to, for example, correctly evaluate the cost of GHG reduction technologies. Meanwhile, the impact of meteorological conditions on the final consumption sector was relatively small. Nevertheless, a zero-emission power sector and further electrification of the final consumption sector are essential for achieving an 80% GHG reduction, and VRE power profiles do affect the available supply of zero-emission power. This will have an impact, albeit a small one, on the electricity demand in the final consumption sector, and as a result, may cause a significant change in the marginal abatement cost of GHG.

It must be noted that this study assumes a relatively high GDP growth rate, which is one of the reasons for the high GHG marginal abatement cost. The relationship between economic growth scenarios and the cost needed for 80% GHG reduction should be considered further in a future study.

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