Integration Costs of Variable Renewable Energy Sources

Final Report of a GJETC Working Group

Authors

Yuhji Matsuo, Institute of Energy Economics, Japan

Stefan Thomas, Wuppertal Institute for Climate, Environment and Energy (Co-Author)

With contributions by Andreas Löschel, University of Münster and Margaret Jackson, Visiting Researcher, Institute of Energy Economics, Japan

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Publisher
Wuppertal Institute for Climate, Environment and Energy
Döppersberg 19
42103 Wuppertal
Germany
www.wupperinst.org

Institute of Energy Economics Japan
Inui Bldg. Kachidoki, 10th, 11th Floor
13-1, Kachidoki 1-chome, Chuo-ku,
Tokyo 104-0054
Japan
https://eneken.ieej.or.jp/en/

Contact
GJETC Secretariat
gjetc@wupperinst.org
Phone: +49 202 2492-184
Fax: +49 202 2492-108

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1. Introduction

Climate change is an increasingly important issue these days, with drastic changes in energy policies being required to mitigate greenhouse gas (GHG) emissions. According to a recent report published by the Intergovernmental Panel on Climate Change (IPCC) [1], to limit the global temperature rise from preindustrial levels to 1.5 °C, global anthropogenic carbon dioxide (CO_2) emissions need to reach net zero around 2050. At the same time, it must be noted that considerable costs would be involved in achieving very ambitious GHG reduction targets. For example, the marginal mitigation costs in achieving the abovementioned target have been estimated to rise to 245-14,300 USD/tCO2 (2010 price) by 2050[1]. Although it is not clear if we can really afford these costs or if they can be reduced as it has been observed for many technologies, it should be clear that we must make every effort to curb GHG emissions as soon as possible to zero in the long-term.

Of the many energy demand and transformation sectors, the reduction of CO_2 emissions from the power generation sector is particularly important for deep decarbonization of energy systems. To achieve Japan's official decarbonization target of 80% reduction from current levels by 2050, for example, it would be essential to decarbonize the power sector almost completely, as shown by a number of studies[2][3][4]. The reason for this lies simply in the fact that energy carriers other than electricity are much more difficult to decarbonize.

Low-carbon technologies include nuclear, renewable, and "low-carbon thermal" power generation. These technologies, however, have their own challenges. As for nuclear power, in the wake of the Fukushima Daiichi nuclear power plant accident in 2011, it would be difficult, at least, to expand nuclear power generation capacity as planned before the accident. Some European countries, including Germany, have declared to phase out nuclear power gradually along with the closure of existing reactors after their lifetimes. Thus, these countries cannot expect very high or will have zero nuclear shares in the mid- to long-term.

The costs of renewable power generation, especially those of solar PV, have been declining rapidly, and they are expected to decline further in the future. However, a major barrier to the use of both wind and solar PV is their recognized variability, or intermittency, with fluctuating power outputs depending on weather and climate conditions. Therefore, a massive introduction of these technologies would require additional costs for flexibility technologies to support their system integration, affecting the economics of the power sector.

Low-carbon thermal power generation includes not only conventional systems with the addition of CCS technology but also nearly CO_2-free hydrogen-fired power generation technology. Although the CCS technology has long been studied worldwide, and several studies suggest that the technology could be deployed with relatively low costs[5)6)], existing CCS power projects exhibit quite high costs around 13-14 USD thousand/kW[7)8)]. In this regard, CCS could play an important role as a low-carbon technology only if the costs can be reduced significantly in the future and we can make full use of the underground aquifers. Otherwise, we must rely on other technologies.

Another option is power generation by CO_2-free synthetic fuels. Synthetic fuels can be generated via electrolysis, using renewable electricity to split water into hydrogen and oxygen. The gaseous hydrogen can be further processed in additional synthesis steps to the gaseous energy carrier methane or to liquid fuels such as liquefied natural gas (LNG) and synthetic gasoline, diesel and kerosene. Other methods for producing hydrogen include steam reforming of fossil fuels, and thermochemical water splitting processes by high-temperature gas-cooled nuclear reactors. Although hydrogen does not emit CO_2 during use, it emits CO_2 during the production process, depending on the primary energy source. If the primary energy is from a non-fossil source, or from a fossil fuel source with CCS, the hydrogen is said to be produced (and used) by low-carbon processes.

This output paper investigates the economic feasibility of (almost) complete decarbonization of the power sector, comparing related studies for Japan and Germany. As shown in the following subsections, there are similarities and dissimilarities, probably depending on country-specific characteristics. Although we tried to draw general conclusions from the comparative discussions, future elaborate studies would be needed to make the points even clearer, given the essential importance of this issue on the feasibility of long-term GHG reduction targets.

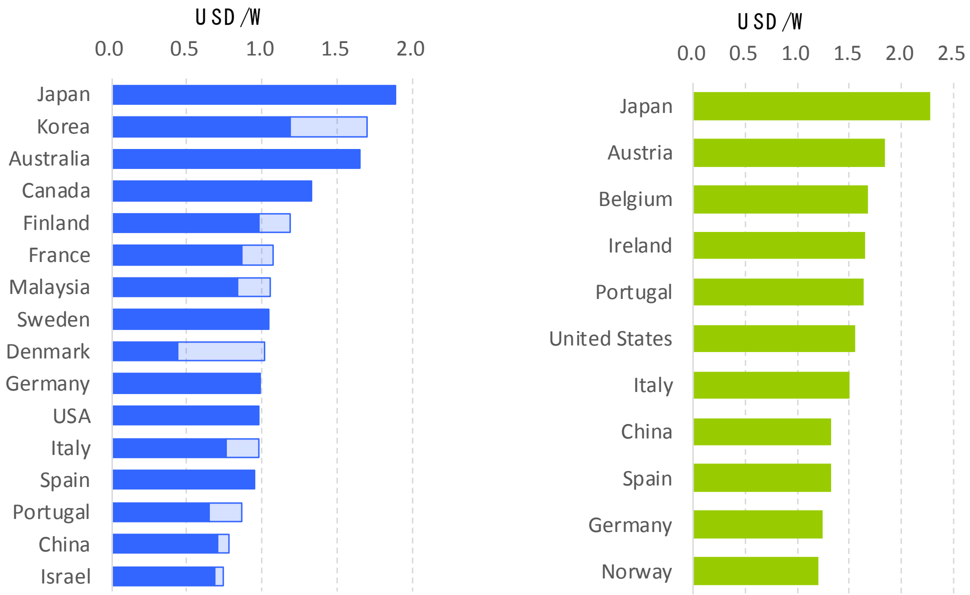
2. Case of Japan: IEEJ modelling

As is the case with European and North American countries, many modelling studies have been conducted to estimate quantitative system integration costs related to high penetration of variable renewable energies (VREs) in Japan in recent years[10-13)]. This section proposes a future projection of the Levelized Costs of Electricity (LCOEs) of solar PV and wind, which exhibit a different picture from those in other countries, followed by an estimation of the economics of the power sector under very high penetration of VREs, mainly referring to Refs. 14-15).

2.1 Future projection of the LCOEs of solar PV and wind in Japan

As of 2017, the unit initial cost of solar PV is under 1USD/W, and that of onshore wind is slightly higher than the same value in many countries in the world. In Japan, however, they are considerably higher than global average at around 2 USD/W (Figure 1).

Figure 1: Initial investment costs for solar PV and wind - an international comparison



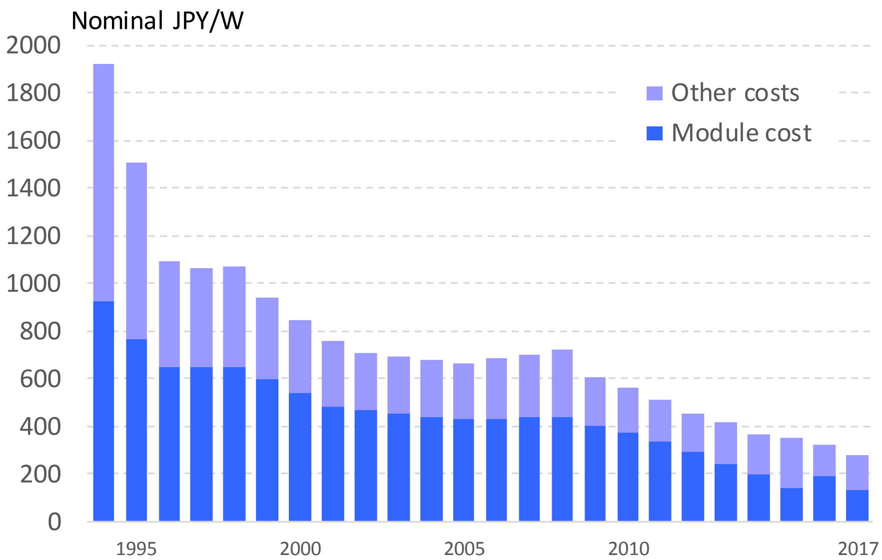
Solar PV (ground-mounted) Onshore wind

Note: Ranges in solar PV costs are indicated by light blue areas.

Sources: IEA-PVPS (2018)[16)], IEA-Wind (2017)[17)]

This does not mean that the costs have not been declined in the past. Rather, the initial cost of solar PV has rapidly been declining after 1990s as shown in Figure 2.

Figure 2: Historical trend in the initial cost: Residential solar PV



Source: IEA-PVPS (2018)[16)]

The "Learning rate" refers to the decline rate of the unit cost of a product, with a doubling of the cumulative production. In the case of solar PV systems, the rate can be obtained by linear regression of the relationship between the logarithm of the initial cost divided by the capacity, versus that of the cumulative installed capacity. In many cases, the initial cost of solar PV can be divided into two parts, i.e. the cost of the module and that of the remaining part, referred to as "balance of systems (BOS)". For the module part, we can use the cost data by IEA[16)] to estimate the learning rate of the global average module price, which is found to be around 20%, using the global cumulative installed solar PV capacity. For BOS, we can obtain the learning rates as shown in Table 1, using the cumulative installed capacity in the country. As shown in this table, the learning rate is smaller for residential than for large-scale ground mounted and is smaller in developed countries than in developing countries. They are roughly at same levels in Japan and in Germany.

Table 1: Observed learning rates (BOS)

	Residential	Large-scale ground mounted
United States	12.9%	17.6%
Germany	14.3%	20.9%
United Kingdom	12.6%	17.5%
Japan	14.3%	19.8%
China	19.8%	20.4%
Malaysia	16.3%	20.3%

Source: IEEJ estimate

As for wind power, long-term data are available for only a few countries. We use the learning rates observed for the U.S. data, which stand considerably smaller than solar PV at 8.2% for turbines and 6.7% for the remaining part.

Using these learning rates, as well as an assumption for future installed capacities shown in Table 2, we can calculate expected declines in the costs of onshore wind and solar PV (residential and large-scale ground mounted) as depicted in Figure 3, where

Case 1 assumes cost learning from the current levels in Japan, and Case 2 assumes that the costs of solar modules and wind turbines are reduced more rapidly so that they take global average values in 2050. As shown in these charts, past trends indicate that the LCOE of solar PV will decline to around 10 JPY/kWh (Case A), which is roughly the same level as the costs of conventional power generating technologies, and to around 7 JPY/kWh (Case B). They also imply that the LCOE of onshore wind will also decline to 10 JPY/kWh by 2050.

We should note here that the cost reduction targets set by the government stand at 7 JPY/kWh by 2025 for solar PV, and at 8 to 9 JPY/kWh by 2030 for onshore wind[19)], thus we could expect even more rapid cost declines than that shown in Figure 3.

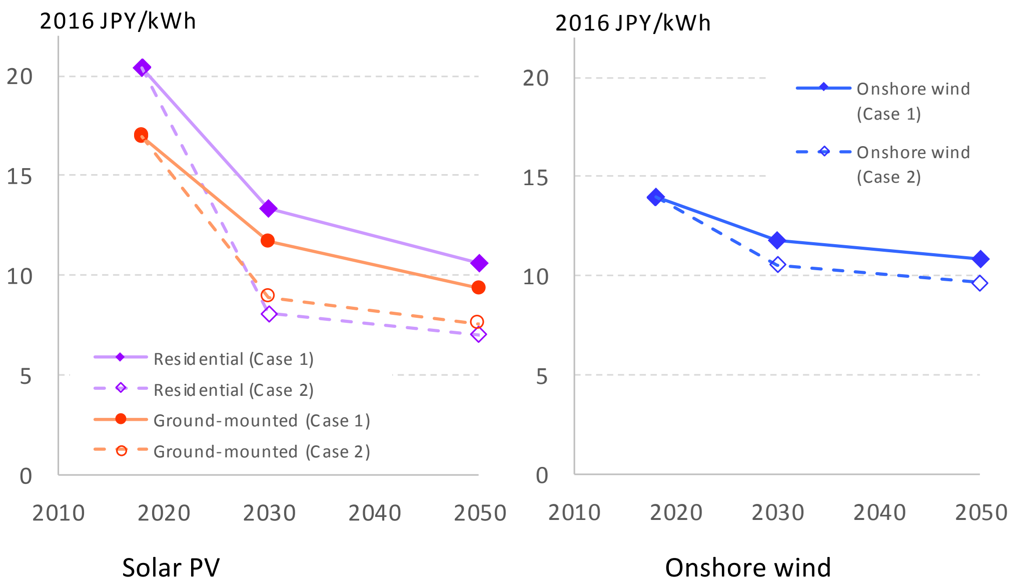
Table 2: VRE capacities assumed for projecting LCOEs in 2050

	2018	2030	2050
Solar PV	44.6	64.0	130.4
Onshore wind	3.8	9.2	35.0

Unit: GW

Source: IEEJ estimate

Figure 3: Exploration of historical trends in the initial cost of solar PV and onshore wind power in Japan



Source: IEEJ estimate

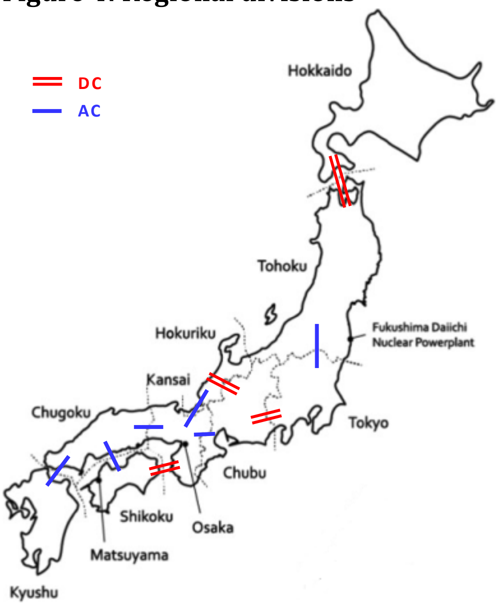
2.2 Estimation of the economics of complete decarbonization of the power sector – Methodology

(1) Optimal power generation mix (OPGM) model assuming complete decarbonization of the power sector

In this study, we used the detailed OPGM model, which is a revised version of the Optimal power generation mix (OPGM) model used for past studies. This model divides Japan, excluding Okinawa, into nine regions (Figure 4), interconnected to one another by Alternating Current (AC) or Direct Current (DC) cables.

The model exploits the LP method to simulate the cost-minimal electricity mix and dispatch under multiple constraints. For simplicity, we used 8,760 (=365×24) time slices for one year. More detailed description of the model can be found in Refs. 14-15).

Figure 4: Regional divisions



Source: IEEJ modelling

(2) Multi-annual data reflecting meteorological conditions

In the latter part of this study, we used the meteorological (AMeDAS) data for the years 1990–2017, as downloaded from the website of the Japan Meteorological Agency, to produce hourly VRE output profiles and electric loads for the nine regions.

For the VRE output, we followed Refs 20-21). We note that electric load also changes along with the changes in weather conditions, and that a certain level of correlation is supposed to exist between electric loads and VRE outputs. For example, on a sunny summer day in Japan, when the output from solar PV facilities is relatively large, electric load also becomes large due to air cooling demands. To address this issue, we used the artificial neural network (ANN) method[22)] to reproduce electric loads from meteorological data.

(3) Other assumptions

According to an estimation of VRE potentials in Japan by the Ministry of the Environment[23)], VRE (solar PV, onshore wind, and offshore wind) can meet all the electricity demands in Japan in 2050, at least in terms of electricity generated. “FIT” and “Potential” in Table 3 represents the economic and theoretical potentials, respectively. We used the “FIT” figures for this study.

For cost assumptions, we referred to an estimation by the Japanese government[24)], assuming that the VRE costs continue to decline until 2050, in line with the trends shown by the calculation in the last chapter.

Other cost assumptions were made, as in Table 4, based on the literature. We set the high-cost assumptions as those generally expected in the future, while the medium-cost assumptions reflect the most ambitious targets found in the literature. We referred to METI Yoshino et al. [25)] and Kamiya et al. [26)] for the high assumption and to METI[27)] for the medium assumption on the cost of imported hydrogen. We also referred to IRENA[28)] for batteries, to FCH JU[29)] for electrolysis, and FCH JU[30)] for hydrogen tanks. Note that the assumptions for the costs of solar PV and onshore wind roughly correspond with the extrapolation of observed historical trends, as shown in the previous subsection. Additionally, we set low-cost assumptions, just for reference, which stand at half of the medium-cost assumptions.

The pumped hydro storage capacity is assumed at the current level of 163 GWh, without any additional initial investments.

Table 3: Solar and wind potentials in Japan

Unit: GW	Solar PV		Onshore Wind		Offshore Wind	
	FIT	Potential	FIT	Potential	FIT	Potential
Hokkaido	15	20	146	152	177	399
Tohoku	25	46	67	69	34	215
Tokyo	52	81	4	4	39	82
Chubu	38	50	11	11	23	40
Hokuriku	9	17	5	5	0	43
Kansai	26	39	11	11	0	30
Shikoku	13	18	5	5	2	46
Chugoku	24	33	9	9	0	120
Kyushu	37	53	16	17	2	359
Total	239	356	271	281	277	1,339

Source: Ministry of the Environment (2019)[23)]

Table 4: Major cost assumptions

	Unit	Current costs	2050 assumptions		
			High	Medium	Low
Imported hydrogen	JPY/Nm^3	—	30	20	10
NAS battery	USD/kWh	435	200	100	50
Li-ion battery	USD/kWh	1,739	739	100	50
Electrolysis	USD/kW	2,181	793	462	231
Hydrogen tank	Euro/kg	3,000	600	500	250
Solar PV	JPY thousand/kW	294	188	169	143
Onshore wind	JPY thousand/kW	284	284	212	181
Offshore wind	JPY thousand/kW	515	446	360	308

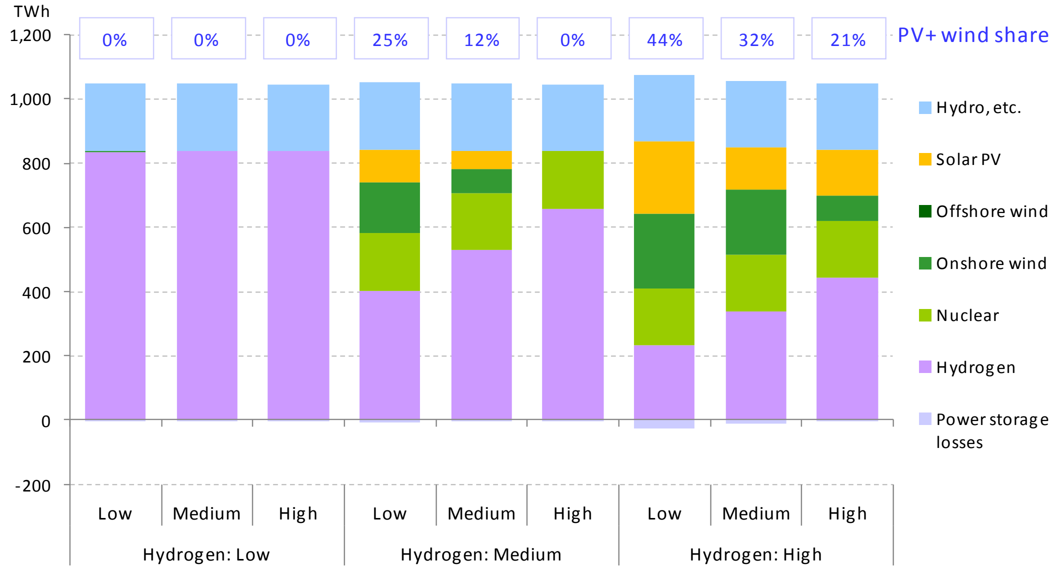
Sources: Yoshino et al. (2012)[25)], Kamiya et a. (2015)[26)], METI (2019)[27)], IRENA (2017)[28)], FCH JU (2014a)[29)], FCH JU (2014b)[30)]

In this study, we simulated the low-carbon power sector in Japan in 2050, assuming the use of dispatchable renewables, VREs, nuclear power, and thermal power generation by imported hydrogen. As we have fixed a relatively small upper limit for nuclear power generating capacity, low-carbon thermal power and renewable energies compete with each other in the power generation mix in 2050. From this perspective, we set nine cost cases, with three cases (high, medium, and low cases) for the cost of imported hydrogen, each with three cases for the renewables' and storage costs, as shown in Table 3. For each of the nine cases we assumed two subcases, with the upper bounds of nuclear power capacity at 0 GW and 25 GW, respectively.

2.3 Calculation results: integration costs under high penetration of VRE

Figure 5 shows the results of cost optimization for the nine cost cases, with the maximum nuclear power capacity at 25 GW. In the cases with the low hydrogen cost assumption, hydrogen-fired power generation accounts for almost all of the power supply, except for hydro, geothermal, and biomass, whose outputs are fixed in the model. In other cases, nuclear power is used to the upper limit, whereas wind and solar PV are used depending on the assumption for the costs of renewables and storage systems. In the M/M case (medium cost of imported hydrogen and medium costs of renewables and storage systems), the share of intermittent renewables, i.e. the sum of wind and solar PV, stands at 12%, while the largest penetration of intermittent renewables is achieved in the H/L case allowing the sale of hydrogen to other sectors, where the share rises to 44%.

Figure 5: Optimal generation mix resulting from modelling nine cost cases for renewables & batteries and hydrogen, allowing for 25GW of nuclear energy

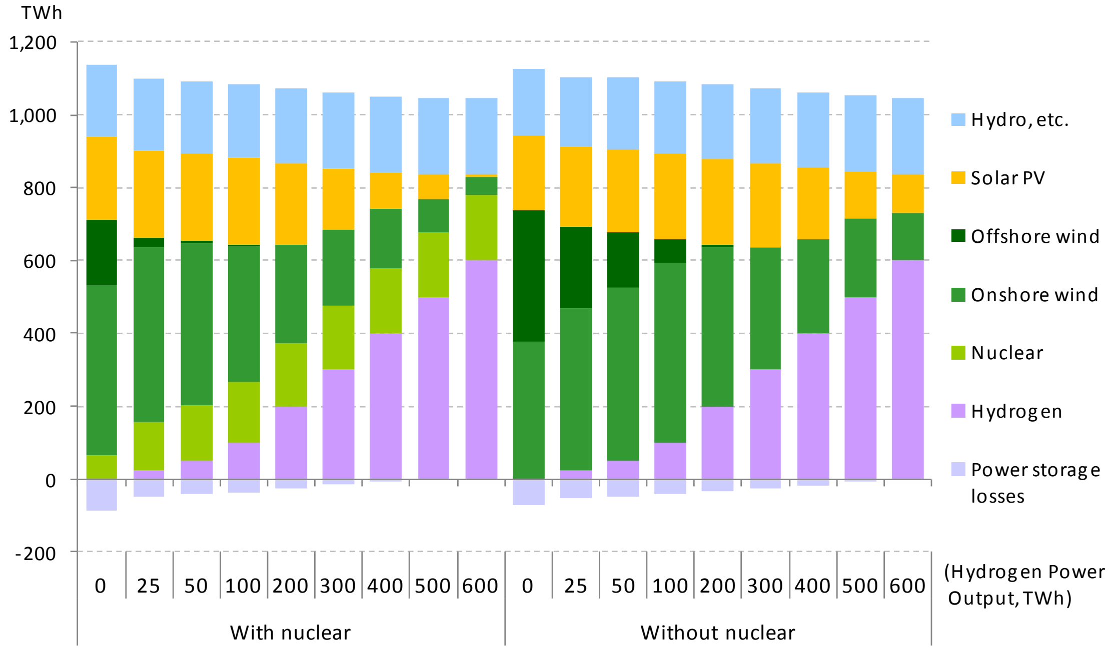


Low, medium, high: cost cases for renewable energies and batteries

Source: Matsuo et al. (2018)[14)]

Figures 6 and 7 show the results of the M/M case, without allowing the sale of hydrogen, with fixed hydrogen-fired power generation from 0 TWh to 600 TWh. Renewables penetration becomes larger for smaller hydrogen-fired power generation. Offshore wind is introduced massively, when hydrogen power generation is assumed to be below 25 TWh with nuclear and 100 TWh without nuclear. In the extreme case, with zero hydrogen-fired and zero nuclear power generation, offshore wind accounts for 34%, which is almost the same as the share of onshore wind. In the cases with very little hydrogen-fired power generation, total power output becomes larger than in other cases, due to the power losses caused by frequent power charges and discharges.

Figure 6: Power generation mix with different levels of hydrogen power output



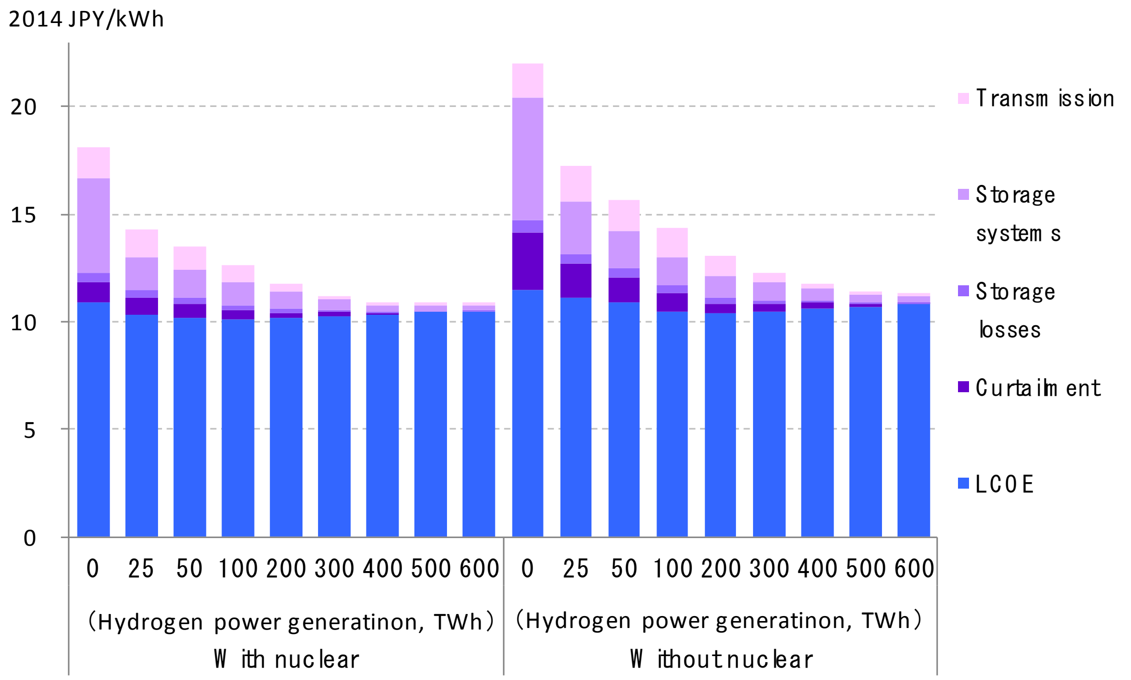
Source: Matsuo et al. (2018)[14)]

The unit cost of the system, defined as the total cost divided by the minimum power output, i.e., the output in the cases without power losses for storage, increases with decreasing hydrogen-fired power generation. In the cases with zero hydrogen-fired power, the unit cost stands at 18.1 JPY/kWh (2014 price; 15.1 eurocents/kWh if an exchange rate of 120 JPY/Euro is assumed) with nuclear and at 22.0 JPY/kWh (18.3 eurocents/kWh) without nuclear, compared with 11.0 JPY/kWh (9.2 eurocents/kWh) with a hydrogen-fired power generation of 600 TWh. As shown in Figure 7, the costs of batteries account for the largest part of the cost increase, standing at 4.4 JPY/kWh with nuclear and 5.7 JPY/kWh without nuclear. The costs of transmission, which is required with high penetration of wind power with large resources in the northern area of Japan, will also increase with the rising share of renewables.

The curtailment cost, which is related to the drop in the net capacity factor of wind and solar PV caused by the curtailment of excess electricity, will also increase, as shown in the figure.

Note that the modelling does not include several types of flexibility options, e.g., demand-side management, notably the storage of heat, cold, or manufactured products, battery electric vehicles with vehicle-to-grid technology, and a flexible use of biomass power generation facilities, because preliminary analyses had suggested that these options would exert only limited influence on the results of the calculations in the Japanese context[14)]. Nonetheless, explicit consideration of these options could be useful for future studies.. Note also that the “hydrogen power output” includes that of “green hydrogen”, that has been produced from excess electricity and has been stored in hydrogen tanks. Thus the “0 TWh” case in this chart actually prohibits the use of hydrogen storage systems.

Figure 7: Change in the unit system cost and its components (M/M case)



Source: Matsuo et al. (2018)[14)]

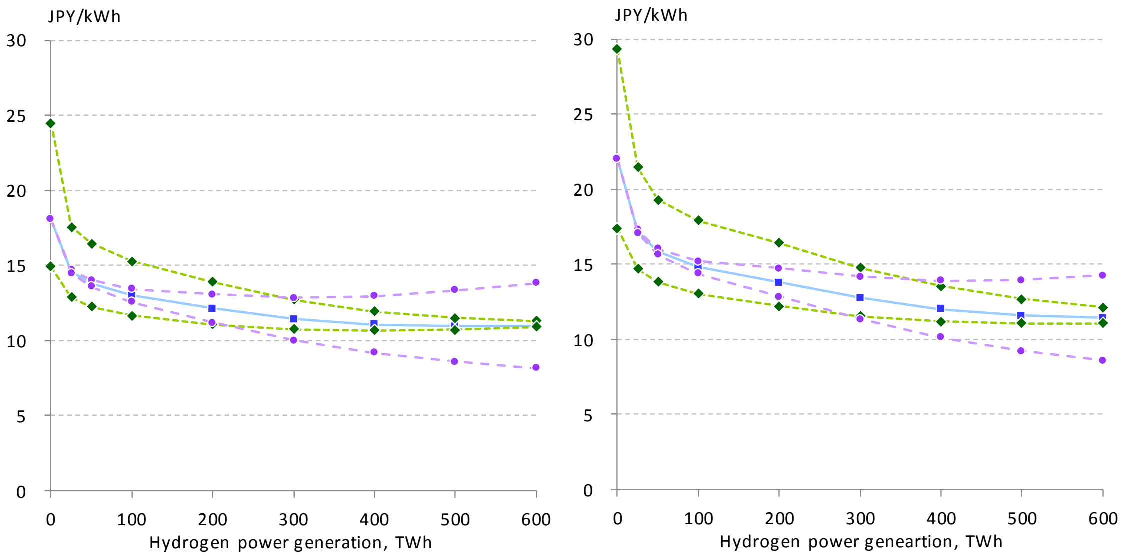
Figure 8 shows the unit system cost for the M/M case and the H/M, L/M, M/H, and M/L cases. In the case with nuclear, the unit cost with zero hydrogen is 14.9 JPY/kWh for M/L, 18.1 JPY/kWh for M/M, and 24.5 JPY/kWh for M/H, respectively. Without nuclear, the unit costs rise to 17.4 JPY/kWh, 22.0 JPY/kWh, and 29.3 JPY/kWh for M/L, M/M, and M/H, respectively, respectively.

In the cases with the high hydrogen costs (H/M), the unit system cost is the same as in the medium cost case (M/M) with zero hydrogen power generation; however, as the hydrogen-fired power generation increases the gap between H/M and M/M increases, showing a convex curve. The minimal point of this curve corresponds to the optimal solution shown in Figure 5. If hydrogen-fired power generation is set at 600 TWh, with nuclear at 25GW, the unit costs are 8.2 JPY/kWh, 11.0 JPY/kWh, and 13.8 JPY/kWh for the L/M, M/M, and H/M cases, respectively.

These results show that the total cost rises very sharply with hydrogen-fired power generation below 100 TWh. This suggests the extreme difficulty of supplying electricity only with non-flexible power sources, such as nuclear and renewables, even in 2050, when Japan aims to achieve zero emissions in the power sector. On the other hand, in the case with nuclear, for example, the results show moderate changes in the unit cost with hydrogen-fired power generation larger than 200 TWh, indicating that a considerably high share of intermittent renewables could be economically feasible under the condition that their costs will be reduced greatly, as assumed in this study.

Another observation is that, with zero hydrogen, the difference between the unit costs with and without nuclear amounts to 2.5 JPY/kWh, 3.9 JPY/kWh, and 4.8 JPY/kWh, for the M/L, M/M, and M/H cases, respectively. This implies that nuclear power is effective in suppressing the surge in the total system cost with very small flexible power generation.

Figure 8: Unit power generation cost for different cost cases



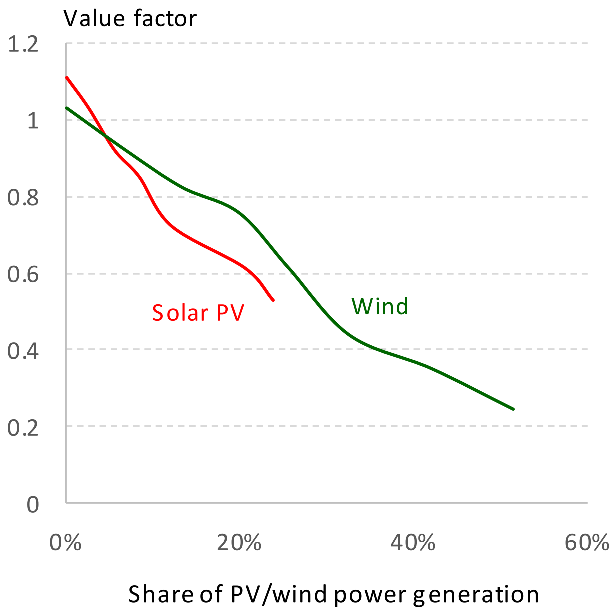
With nuclear Without nuclear

Source: Matsuo et al. (2018)[14)]

As wind and solar output are weather-dependent, they tend to produce electricity at the same time. The consequences of this strong auto-correlation of power output are referred to as the "cannibalization effect"[31-32]. The very low (or zero) prices when the output of wind and solar power is large lead to declining market value of VRE power generation with high penetrations. Ref. 31) argued that the subsidy to VRE may never end, as the value of the energy produced may decrease faster than the cost as renewable capacity increases.

Figure 9 shows the value factor, defined as the weighted average of the shadow price with regard to PV/wind output, normalized by the average shadow price, depending on VRE shares of total power generation. We can observe significant declines in the value factors, which could make additional deployment of VRE facilities more and more difficult with increasing shares of VREs.

Figure 9: "Cannibalization" effect



Sources: IEEJ modelling

2.4 Effects of changes in meteorological conditions

We used the 28 meteorological conditions corresponding to the 1990–2017 data and performed LP simulations for the M/M case (Figure 10).

Case A assumes use of batteries and pumped hydro power generation for power storage, while Case B assumes only hydrogen storage systems, in which hydrogen is produced by excess electricity, stored in tanks, and is used for power generation during periods with small VRE output. Note that, as the assumed fixed capacity of pumped hydro storage is rather small at 163 GWh, Case A actually represents the expanded use of batteries. Also note that Case B, which assumes no pumped hydro systems, should not be regarded as a realistic case, given that pumped hydro facilities and batteries have already been deployed to a certain extent in Japan.

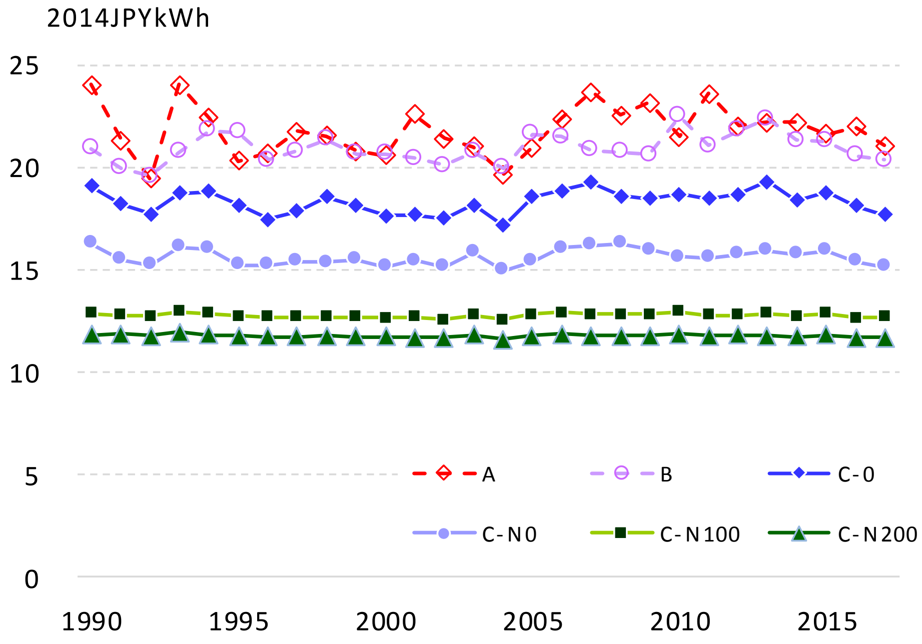
Cases C-0 and C-Nx (x= 0, 100, and 200) utilize batteries and pumped hydro facilities, in addition to hydrogen storage systems. Cases C-Nx set the upper limit of nuclear power generating capacity at 25 GW, which is equivalent to the sum of the capacities of the existing plants that started operation after 1990 and of the three plants currently under construction. These cases also assume the use of *imported* hydrogen power generation at x TWh (fixed). As the total annual electricity demand is assumed to be approximately 1,000 TWh, which varies slightly depending on the meteorological conditions, Case C-N200 assumes that thermal power generation accounts for approximately 20% of the power generation mix. Although the calculations in the previous subsection also assumed the use of hydrogen storage systems, the 0 TWh cases in Figures 7 and 8 correspond to Case A in Figure 10, because they actually prohibit the use of hydrogen storage by setting the *total* hydrogen power generation at 0 TWh, as described above.

As shown in Figure 10, the total cost with 100% renewables varies significantly depending on the meteorological conditions. The average unit cost stands at 21.8 JPY/kWh for Case A. Though it exhibits a slight decline to 20.9 JPY/kWh for Case B, with hydrogen storage rather than batteries, it declines significantly to 18.3 JPY/kWh for

Case C-0, which assumes both hydrogen and batteries. The standard deviation is 1.2 JPY/kWh, 0.7 JPY/kWh, and 0.6 JPY/kWh, for Cases A, B, and C-0, respectively.

The unit cost declines further when nuclear and/or imported hydrogen power generation are available, standing at 15.6 JPY/kWh, 12.8 JPY/kWh, and 11.8 JPY/kWh for Cases C-N0, C-N100, and C-N200, respectively. The standard deviation also declines to 0.38 JPY/kWh, 0.10 JPY/kWh, and 0.07 JPY/kWh on average, respectively. As expected, different meteorological conditions result in significant changes in the unit cost, particularly for the cases with 100% renewable penetration.

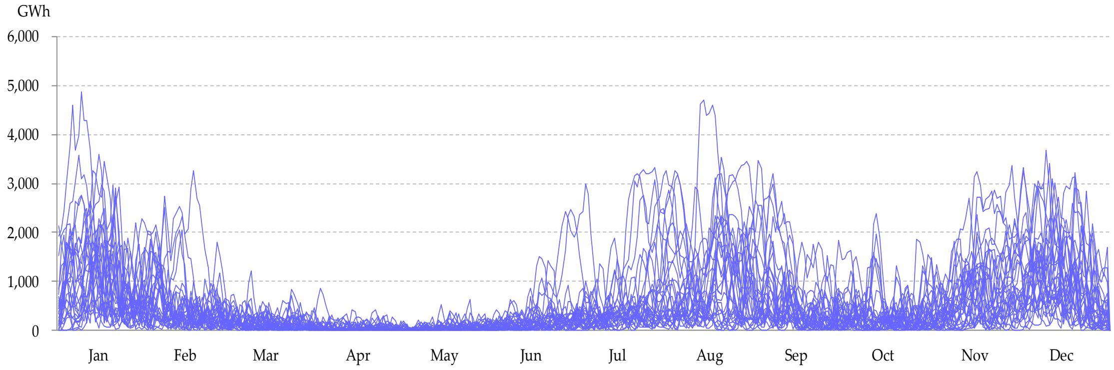
Figure 10: Unit system cost for different meteorological conditions



Source: Matsuo et al. (2020)[15)]

Figure 11 presents the stored energy in Case A for the 28 meteorological conditions. Although maximum storage takes place on different days depending on the meteorological conditions, we can say roughly that windless and sunless periods appear in summer (August to September) and winter (December to February). To meet the storage requirements during these periods, large amounts of energy are stored during July to August and November to January.

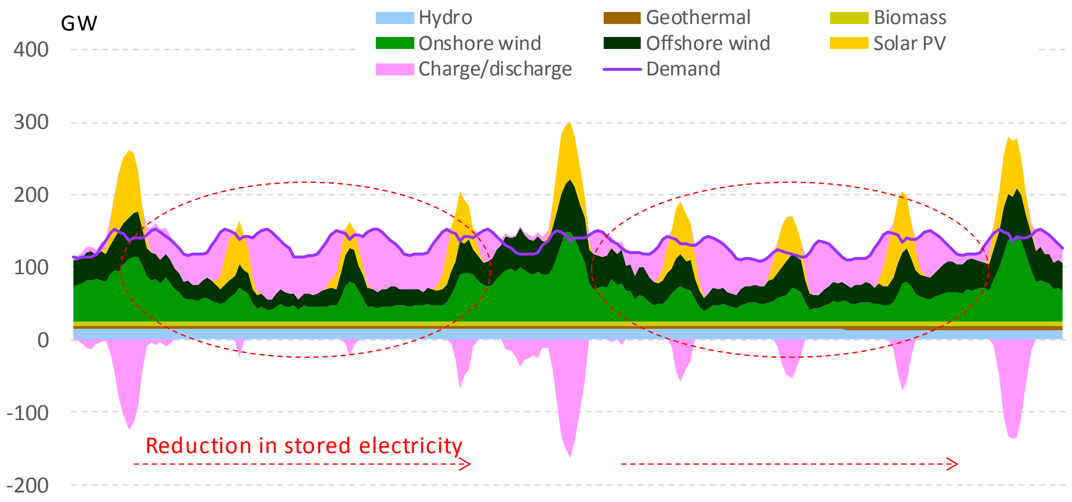
Figure 11: Total stored power for the 28 meteorological conditions (Case A)



Source: Matsuo et al. (2020)[15)]

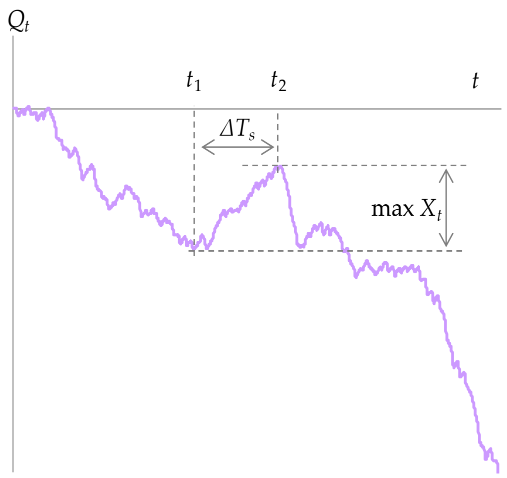
To illustrate what is happening on the days with large stored electricity, Figure 12 shows the power demand and supply from Sep. 1 to 15 (Case A, 2000 data, total of the nine regions). We can see that the wind power output is extremely small from Sep. 6 to 14 and that power discharge, shown in pink in the chart, accounts for a large part of power supply. These situations imply that the total amount of the residual load, i.e., the electricity demand minus the power output during windless and sunless periods in which VRE power output remains very small, determines the requirement of power storage systems. Although this is true both for batteries and for hydrogen storage systems, the latter require larger capacities and longer periods for building up stored energy, because of the lower cycle efficiency. As described later, we can verify that this "windless and sunless" factor actually determines the storage requirements for all the meteorological conditions. These "windless and sunless" periods are also referred to as "dark doldrums," which represent one of the largest risks of electricity supply disruption under very high penetration of VREs.

Figure 12: Electricity demand and supply during Sep. 1 to 15 (Case A, 2000 data, total of the nine regions)



Source: Matsuo et al. (2020)[15)]

Figure 13: An illustrative diagram of the cumulative residual load Q



Source: Matsuo et al. (2020)[15)]

If the "windless and sunless" factor really determines the storage requirement, as speculated above, we should be able to estimate that quantitatively by calculating the residual loads during the periods. The point here is that we can calculate the storage requirements uniquely, without any detailed model simulations, from exogenous data, such as hourly electric loads and VRE output profiles. Although the LP model used in this study divides Japan into nine regions to make detailed simulations, the CRL method described here uses only the total data of the nine regions and is able to simulate the changes in power demand and supply situation with high VRE penetrations under different meteorological conditions.

We denote electricity demand (total of nine regions) at time t ($t\in[1, 8760]$) as D_t, VRE output at t as F_t, and other power output from hydro and other sources as at t H_t. The residual load R_t is calculated by

$$R_t = D_t - F_t - H_t \tag{1}$$

and the situation-corrected residual load R'_t is defined as

$$R'_t = \begin{cases} \dfrac{R_t}{e_D} & if\ R_t \geq 0 \\ e_C\ R_t & if\ R_t < 0 \end{cases} \tag{2}$$

where e_C and e_D denote the efficiencies during the processes of power charge and discharge, respectively. In this study, we assume a cycle efficiency of 0.85 for e_C and 1 for e_D for batteries. For hydrogen storage systems, we assume the efficiency of electrolysis at 0.9 and that of hydrogen thermal power generation at 0.57 (gross calorific value) for e_C and e_D, respectively. These different efficiencies define the different roles of the power storage systems, as described in the previous subsection.

The cumulative corrected residual load Q_t is defined as

$$Q_t = \sum_{T=1}^{t} R'_t \tag{3}$$

Figure 13 illustrates the relationship between Q_t and t. As our calculations in this study feature very high VRE penetration, R'_t is usually negative and Q_t decreases over time. However, during the windless and sunless period, R'_t takes positive values, and Q_t

continues to increase temporarily. The total amount of this temporary increase corresponds to the storage requirement.

Let X_t be the local cumulative storage requirement, i.e.,

$$X_t = Q_t - \min_{T \leq t} Q_T \tag{4}$$

and the maximum value of X_t is the requirement of storage systems. Thus, we can calculate the required storage capacity L in the unit of GWh by

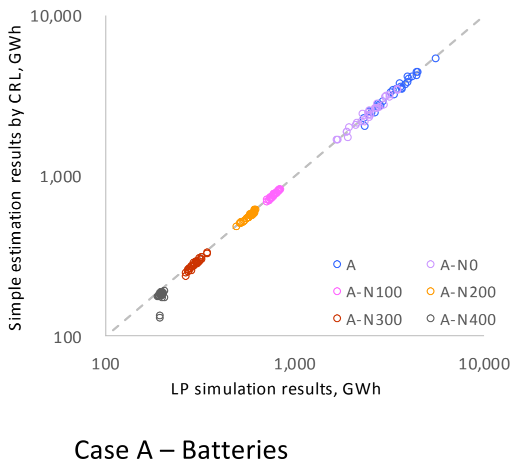
$$L = \max_t X_t \div r \div l_S \tag{5}$$

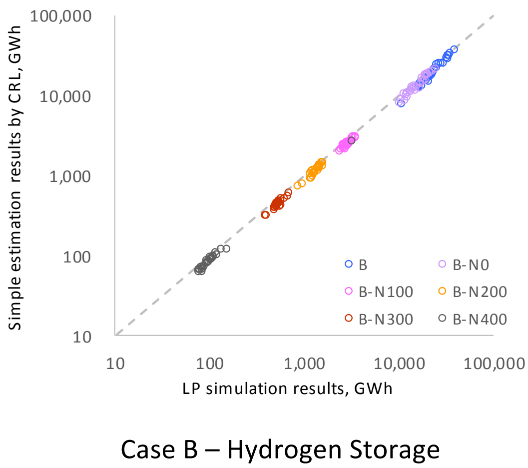
where l_S is the load factor of the storage systems, and r is the auto-discharge factor related to the time span from charge to discharge. We can estimate r approximately using ΔT_s in Figure 13, which is the distance between the time t_1, when Q_t takes a minimal value, and t_2, when X_t takes the maximum value:

$$r = exp(-r_h \Delta T_s), \quad \Delta T_s = t_2 - t_1 \tag{6}$$

where r_h denotes the self-discharge rate per hour.

Figure 14: Capacity of storage systems: Comparison of the CRL and the LP results





Source: Matsuo et al. (2020)[15)]

Figure 14 shows the capacity of the storage systems calculated by Eq. 5, plotted against the results of the LP model calculations for Cases A, B, A-Nx, and B-Nx, assuming also nuclear (25 GW) and thermal power generation (x TWh). Note that, in the LP simulations for Case A, the minimum capacity of storage systems is set at 163 GWh, corresponding to the existing pumped hydro facilities. The much larger storage capacities for Case B than for Case A reflect the large cost differences in the assumed types of storage facilities (i.e. hydrogen tanks and batteries). In terms of the costs for providing these facilities, the both cases are roughly comparable. In addition, due to the efficiencies for charging and discharging assumed, hydrogen storage will anyway need higher capacities for the same effect as batteries, by a factor of 1.65. These charts show clearly that the "windless and sunless" factor determines the storage requirements not only in 100% renewable cases but also in any case with nuclear and thermal power generation.

2.5 Discussion

In this subsection, we compare our results with past similar studies, i.e. Ogimoto et al. (2018)[9], WWFJ (2017)[10], Ram et al. (2017)[11], Esteban et al. (2018)[12], and Esteban et al. (2012)[13]. Table 5 summarizes the assumptions and the results of these studies.

Table 5: Comparison of related studies

	Target year	Number of regional divisions	Electricity demand, TWh	Storage capacity, TWh	Unit cost, 2014 JPY/kWh
This study (Case A)	2050	9	1,044	3.5	22.0
Ogimoto et al. (2018)	2050	1	949	12.0	134
WWF Japan (2017)	2050	10	627	0.4	8.4
Ram et al. (2017)	2050	2	1,150	>20	8.3
Esteban et al. (2018)	2050	1	594-1,400	1.5-13.7	-
Esteban et al. (2012)	2100	1	1,400	41.0	-
Actual	FY2015	-	1,035		11.3

Source: Matsuo et al. (2020)[15]

As shown in this table, the required storage capacity and the unit cost differ significantly across studies. As for the storage capacity, the result of Ogimoto et al. (2018) is much larger than this study, whereas that of WWFJ (2017) is much smaller. We should note here that Ogimoto et al. (2018) estimate the storage capacity and unit cost for a "100% VRE" case, rather than a 100% renewables case, which can be a reason for the large storage capacity. The small storage capacity by WWFJ (2017) seems to result from the fact that this study does not use hourly demand and supply data throughout a year, but exploits statistical methods for the simulation. For Ogimoto et al. (2018) and WWFJ (2017), the very large difference in the unit system cost apparently result from the difference in the required storage capacity.

Ram et al. (2017) assume methane storage, rather than batteries, which is comparable with Case C-0 that assumes hydrogen storage. We can see that the storage capacity by Ram et al. (2017) (20 TWh) lies within the range of Case C-0 (11.2-25.4 TWh). The reason of the small unit cost by Ram et al. (2017) (7.4 JPY/kWh) is unknown. One reason could be the number of regional divisions; as Ram et al. (2017) divide Japan into two regions with 50HZ and 60HZ AC power frequencies, Hokkaido island, the largest VRE producer, and Tokyo, the largest energy consumer, are assumed to exist in the same node. This may result in underestimation of the required capacity of transmission lines. It may also be due to lower cost assumptions for solar PV and wind. More detailed discussion of the reasons behind different unit costs is considered important future work.

Esteban et al. (2018), that assume batteries for power storage, conclude wider range of the storage capacity, because of a wider range of the total electricity demand. The grounds for the large storage capacity by Esteban et al. (2012) are unknown. The results shown in Table 5 suggest at the same time that the results of this work are roughly consistent with those found in the literature, and that further detailed studies are required as the unit costs vary significantly depending on various assumptions.

3. Case of Germany: Review of Three Scenario Modelling Studies

Germany's "Climate Action Plan for 2050" calls for the country to be extensively greenhouse-gas (GHG) neutral by 2050. This section will highlight three studies by German institutions that assessed the feasibility of achieving the target to reduce GHG emissions by 80% to 95% by 2050 from the 1990 baseline[33-35)]. The German Academies of Sciences' joint "Energy Systems of the Future" initiative, the Federation of German Industries and the German Energy Agency conclude that the scenarios they propose are technically feasible within the time constraint of year 2050 but require immediate policy action. To meet these ambitious targets, Germany will have to rapidly scale up VRE capacity and make significant changes to the existing power system. Such changes are challenging and require policy and structural reforms but will also present opportunities for employment, trade, and technological development. The studies estimate that the costs associated with the changes to the energy system will amount to approximately one to two percent of German GDP and have minimal impact on the economy; however, the longer the government waits to act, the higher the costs will be.

3.1 Comparison of Baseline Studies

(1) "Energy Systems of the Future" Initiative

The "Energy Systems of the Future" (ESYS) Working Group under the German Academy of Sciences developed a study to determine how to accelerate the energy transition in Germany and achieve a "climate-friendly" energy supply by the year 2050. The researchers used both quantitative and qualitative evaluation to identify the challenges of the current approach to the energy transition, including not only technological limitations, but also economic and social barriers. This study provided possible development paths, and the key technologies, projected costs, and political action necessary to achieve them.

The timeframe of the study spanned June 2015 through November 2017 and employed expert discussions, scenario comparisons, and model calculations using the simulation and optimization model REMod-D developed by the Fraunhofer Institute for Solar Energy Systems. They used a reference scenario and seven model calculations to examine what impact the respective GHG emissions reductions would have on the overall energy system. The first four model calculations set emissions reductions to 60%, 75%, 85%, and 90% respectively by 2050. The second round of model calculations analyzed the influence of hydrogen, synthetic combustibles and fuels, and increased energy saving measures each within an 85% emission reduction scenario. Unlike the two subsequent studies, ESYS rules out the import of synthetic energy carriers and instead proposes higher penetration of VRE and domestic production.

(2) Federation of German Industries

The Federation of German Industries' (BDI) study addressed what conditions are necessary to achieve German's climate target of 80% to 95% emissions reduction by the year 2050. The research identifies the existing shortfalls of current policies and provides cost-efficient paths for meeting the respective goals. The power sector is one of five areas where they focus attention, and where they identify the emerging technologies that have not yet reached maturity, but will play an important role in the future of climate protection, such as carbon-capture utilization and storage, hydrogen, and power-to-X. These new technologies, coupled with the expansion of solar and wind power, will provide Germany increased opportunities for trade and development. The BDI study lasted from January 2017 until January 2018 and conducted scenario and reference analysis based on a bottom-up process. Using the Prognos energy system and electricity market models, the researchers analyzed a reference scenario, 80% and 95% GHG emission reduction scenarios based on national initiatives, and 80% and 95% GHG emission reduction scenarios based on global climate protection initiatives. The comparison between paths under national initiatives and within a global context allowed the researchers to identify the challenges if Germany significantly increases ambition for climate protection and other nations do not follow suit.

(3) German Energy Agency

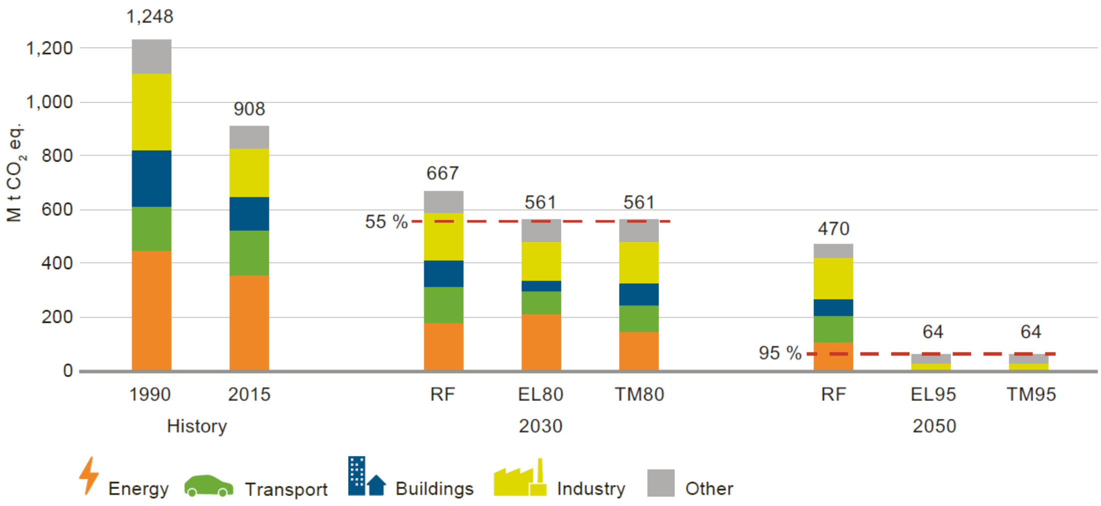
The study by the German Energy Agency (dena) developed a framework for realizing a sustainable energy system in Germany by the year 2050. The final report includes realistic solutions and investment recommendations for the German government to integrate the energy system in an efficient and cost-effective way to meet the challenging time restraints. This research provides pathways for the energy transition in the context of macroeconomic trends and determines what influence the development and adoption of new technologies will have on the German economy and the security of energy supply.

The dena study ran from January 2017 through June 2018, and therefore is the most recent of the three studies included in this section. The research used the ER&S DIMENSION+ energy market model to run five scenarios. In addition to a reference scenario based on current energy policies, the study included electrification scenarios with 80% and 95% GHG emission reduction targets, and two technology mix scenarios with 80% and 95% GHG emission reduction targets. The differentiation between a pathway with higher rates of electrification verses a broader mix of technologies allowed the researchers to make cost comparisons and determine the most economically efficient way forward.

3.2 Results: Recommendations to meet Germany's climate targets

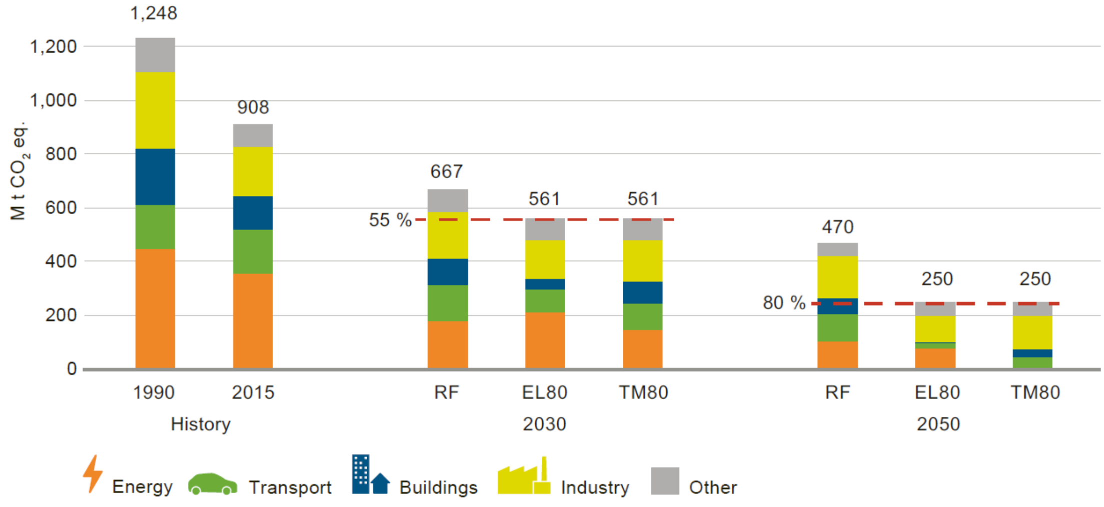
Although the studies discussed above use different modeling approaches to analyze potential paths for Germany's energy transition, they draw similar conclusions in many respects. The studies agree that in the reference scenario, Germany will fail to meet its climate targets by 2050, and as explained in the BDI study, will fall short by 19 to 34 percentage points. According to the dena study, GHG emissions must decrease by about 19 million tons GHG CO2 eq. or 24 million t CO2 eq. per year to meet the 80% and 95% climate targets respectively. The 95% climate target requires zero carbon emissions from the transportation, building, and power sectors by 2050. Therefore, the government must take substantial action in a timely manner to address this gap. Policy control is crucial to achieving these targets because it will provide a regulatory framework and increased certainty for investment cycles. The common proposed approaches in the three studies identify two very different paths; the 95% emissions reduction path is not merely an extension of the 80% emissions reduction path. Each path requires a dedicated effort to the investment and prioritization of specific technologies that will replace conventional fuels. The following sections discuss the recommendations and conclusions of these three studies to promote the energy transition away from fossil fuels and towards renewable energy in the power sector and the associated cost to achieve the climate targets.

Figure 15: GHG emissions by sector under 95% climate target (dena)



Source: dena (2018)[35)]

Figure 16: GHG emissions by sector under 80% climate target (dena)

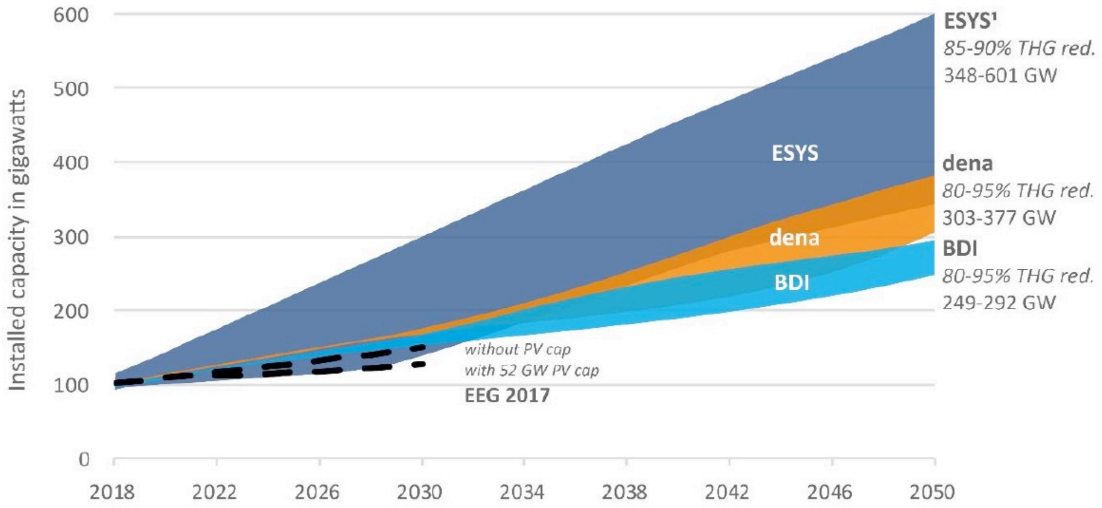


Source: dena (2018)[35)]

(1) Expanding renewable energy capacity and integration costs

The expansion of VRE technology is critical to reaching a nearly emissions-neutral power energy system by 2050. The current rate of expansion of wind and solar in Germany is insufficient to reach this target and must rapidly accelerate. At the end of 2018, Germany had 105 GW of wind and solar photovoltaic capacity, with plans to increase at a rate of about 4 GW per year per the Renewable Energy Sources Act of 2017. The three studies present development approaches that include expansion of wind and solar photovoltaic capacity ranging from 249 to 601 GW, depending on the scenario, which means the statutory expansion corridor must increase to at least 6 GW per year. The results of these studies vary due to the differing assumptions about the amount of electrification, use of renewable synthetic energy fuels, and projections for technology advancement. However, they all clearly demonstrate the necessity for VRE as a central pillar of the future energy system.

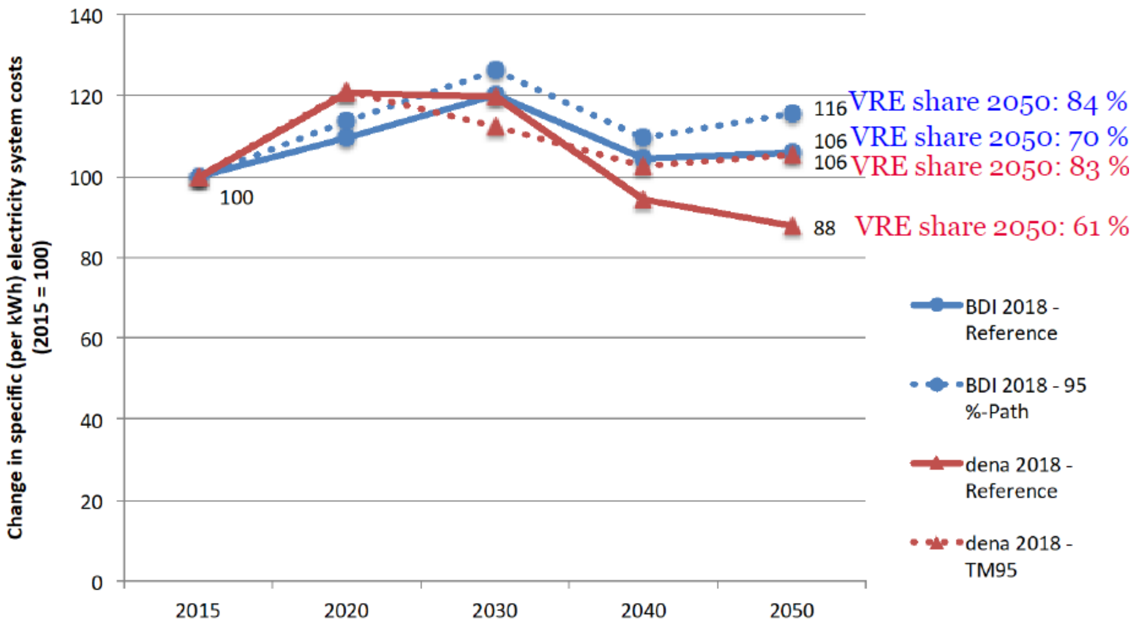
Figure 17: Expected wind and solar PV capacities



Source: Energy Systems of the Future et al. (2019)[33)]

The study by ESYS designates electricity as the most important energy carrier in the energy system of 2050 and therefore, requires a higher installed capacity of renewable energy. In comparison, the dena study concludes that a technology mix is a more economical way to decrease carbon emissions. These distinct paths and the technologies they designate for investment priorities have a notable impact on the cost calculation. According to the review by Löschel[36)] of these studies and others, scenarios with higher rates of variable renewable energy (over 85%) in the energy system in 2050 have costs around 10% to 20% higher than today's cost when compared with scenarios with 60% to 70% variable renewable energy in the energy mix, as shown in Figure 18. For example, the base year costs (100 index) in the BDI 2018 study cited in Figure 18 are 13.4 Euro-cents/kWh; the reference scenario for 2050 shows 14.2 Euro-cents/kWh, and the 95% scenario shows 15.5 Euro-cents/kWh (all 2015 Euros). So the increase in costs is 1.3 cents vs. the reference scenario and 2.1 cents vs. the base year. These additional costs come from the need to expand and improve a wider range of energy infrastructure to accommodate the new technologies and account for a higher reliance on electricity across multiple sectors. Specific adjustments and infrastructure development include expanding transmission and distribution lines, building new renewable power plants, retiring conventional power plants early, and providing for flexibility options such as storage, DSM, and flexible back-up plants.

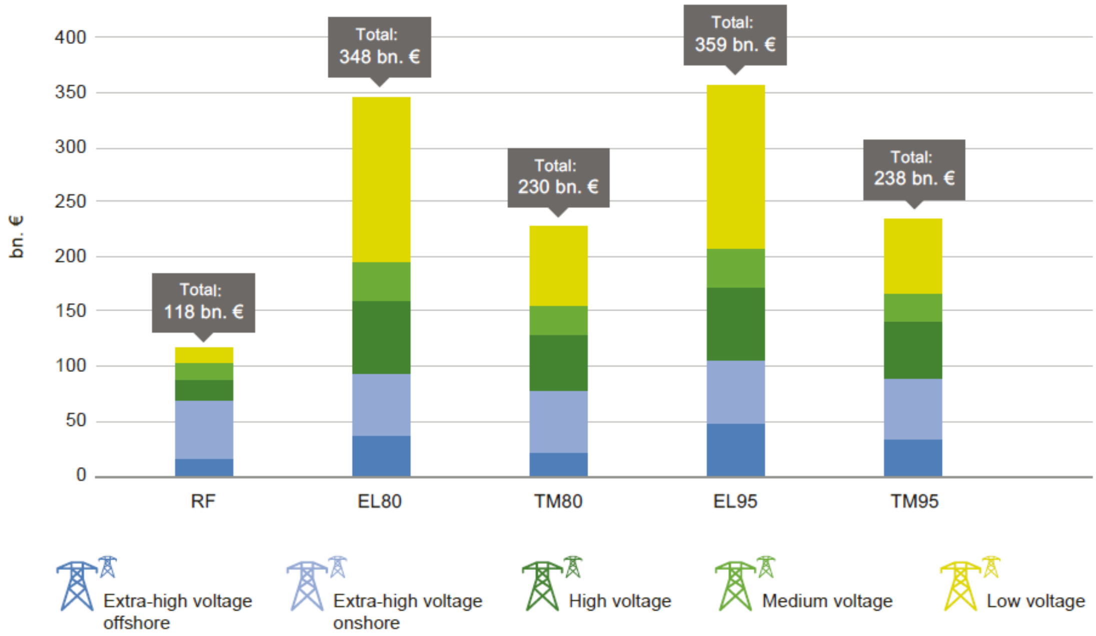
Figure 18: Average system costs for high VRE penetration scenarios



Source: Löschel (2019)[36)]

The dena study provides an example of the cost breakdown with a specific focus on the distribution and transmission grid costs associated with the respective scenarios. The necessary expansion of the distribution grid in the electrification scenario requires over 100 billion euros more than in the technology mix scenario to meet the 80% and 95% climate targets. In the reference scenario, the investment in the distribution grid is 48 billion Euro, compared to 252 billion Euro in the two electrification scenarios. The transmission grid requires less investment overall than the distribution grid and amounts to 79 to 91 billion Euro in the technology mix scenarios and 96 to 107 billion Euro in the electrification scenarios, compared to the reference scenario investment of 70 billion Euro. Figure 5 shows the cumulative investments based on the scenarios through the year 2050.

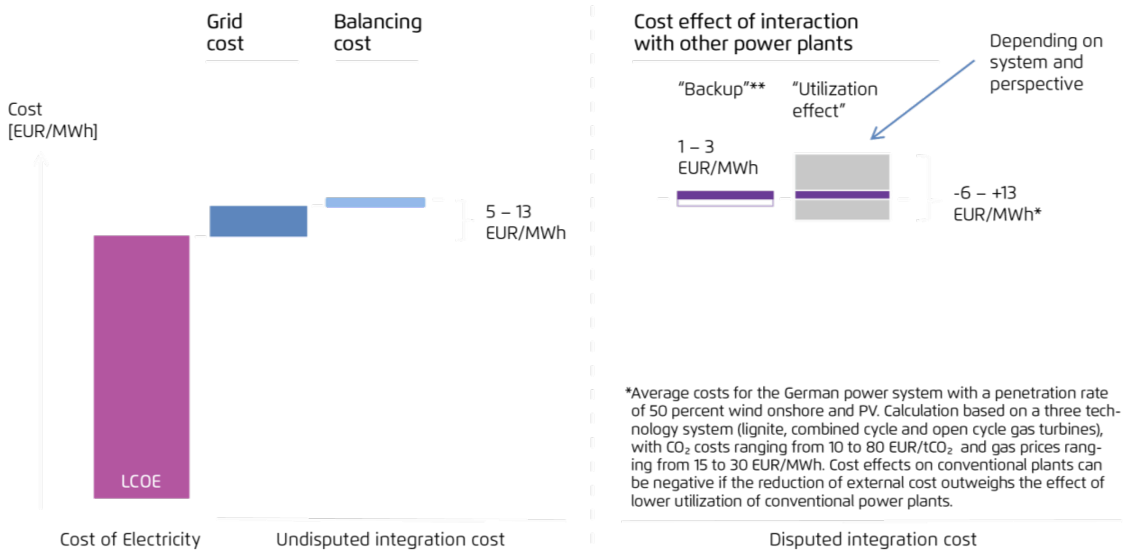
Figure 19: Cumulative investments for electricity grids until 2050



Source: dena (2018)[35)]

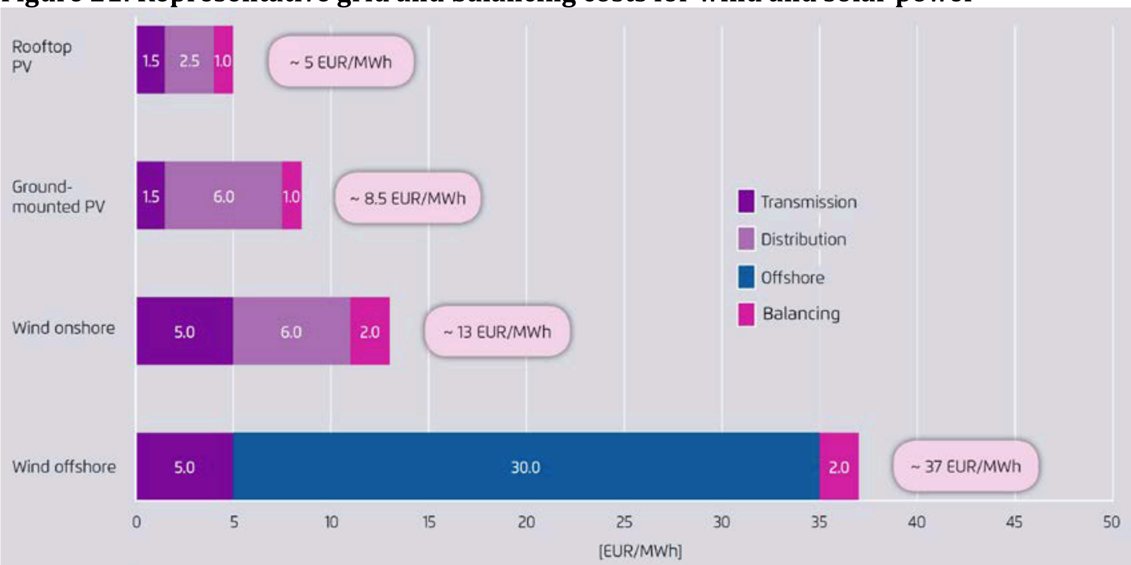
However, according to a study by Agora Energiewende for the GJETC[39)], the grid costs for integrating onshore wind and PV in Germany are relatively low despite these investments, between 0.4 and 1.1 Euro-Cents/kWh (Figure 6 and 7). Grid costs for offshore wind power are higher. Even lower than grid costs are balancing costs to compensate for the variable nature of the renewable energies compared to system load. This is due to an intelligent combination of flexible generation, sector integration, and specific flexibility options. The total of integration cost has been estimated to be 0.5 to 1.3 Euro-Cents/kWh, except for offshore wind power.

Figure 20: Overview of components discussed under "integration costs"



Source: Agora Energiewende (2017a)[39)]

Figure 21: Representative grid and balancing costs for wind and solar power



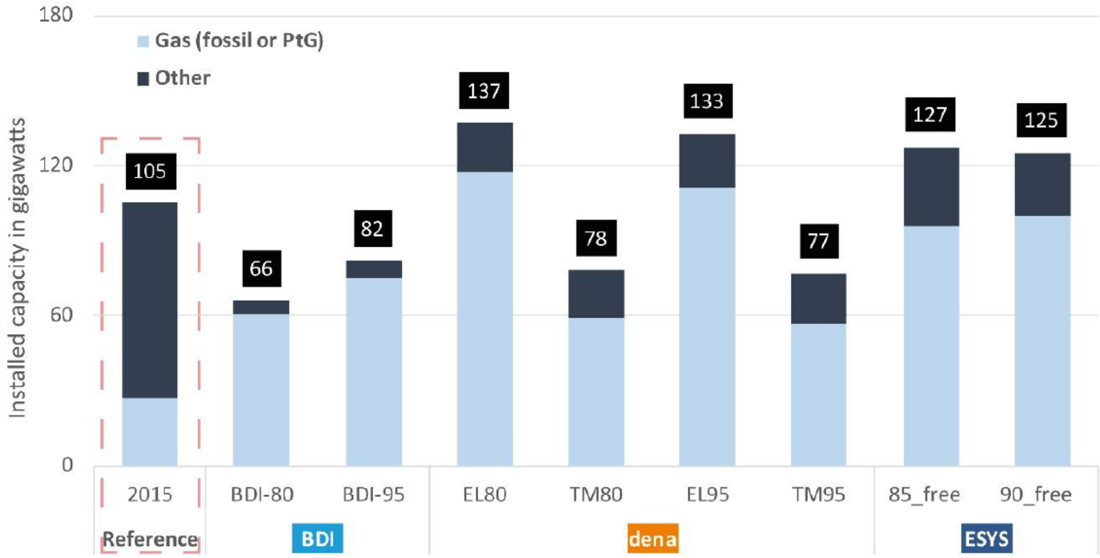
Source: Agora Energiewende (2017b)[40)]*, cited in Agora Energiewende (2017a)*

(2) Ensuring security of supply

Higher rates of electrification and growth of VRE will not only require changes to the electrical grid, but also require a broader array of energy storage technologies and dispatchable power plants. The variable nature of wind and solar PV technology means that the system must mitigate the risks associated with the "dark doldrums" through improved short-term flexibility. Therefore, Germany must invest in the research and development to improve and scale up storage and flexible technologies. Power plants, on the other hand, will serve as a backup power source and will have relatively low operating hours in the future. Policies must be set in place to ensure that the dispatchable power plants are able to remain profitable, which requires restructuring of the current tax and fee structure, and that processes such as power-to-x are economically viable to replace fossil fuels.

The amount of generating capacity Germany will need in 2050 will depend on the degree of electrification and the extent that Europe integrates the electrical grid, among other factors. The three studies estimate that Germany will require dispatchable power plants between 60 and 130 GW by 2050, compared to 100 GW in 2018 and 105 GW in 2015. The conventional electricity generation in these scenarios are primarily gas-fired power plants. Germany is already phasing out nuclear power and plans to end coal-fired power plant generation by 2038. Therefore, natural gas is replacing nuclear and coal power. However, the 95% climate target scenarios, which require zero-emissions in the power sector, will only be possible if these backup generation plants are fueled by power-to-gas (hydrogen or methane). As their operating hours are low, so will be their contribution to power generation overall. For example in the BDI study, it is less than 50 TWh/yr or around 8% of total power generation.

Figure 22: Dispatchable power generation in Germany 2050

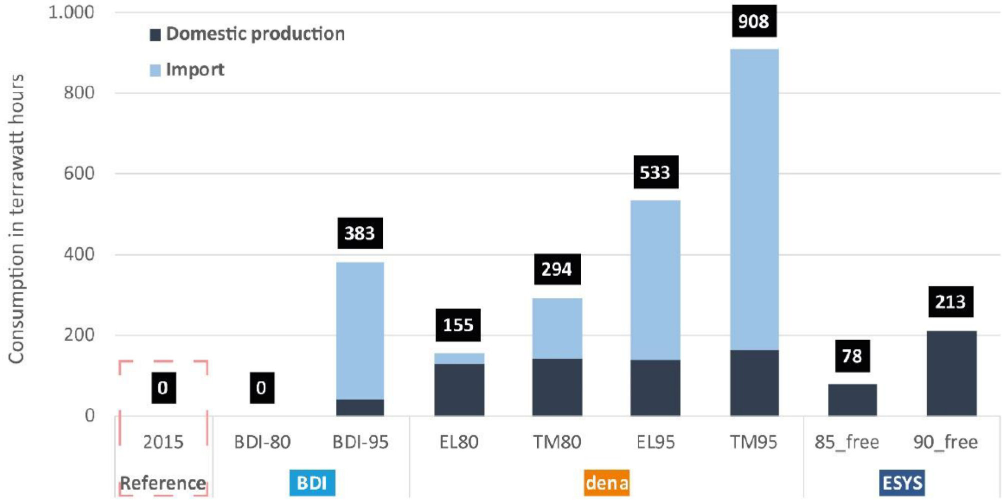


Source: Energy Systems of the Future et al. (2019)[33)]

(3) Developing new technologies: renewable synthetic energy carriers

All three studies emphasize the necessity to develop VRE in every scenario; however, they do not discount the role that synthetic energy carriers and power-to-x technologies will play, particularly in later phases of the energy transition. The 95% climate target is not possible without the employment of synthetic energy carriers that will provide a replacement for fossil fuels as a direct energy source and serve as a long-term storage mechanism for excess wind and solar capacity. These energy carriers will complement electrification and the development of VRE because they will require energy to complete electrolysis and the other chemicals processes needed for production. To achieve carbon-neutral emissions, these processes must rely on renewable energy rather than conventional fuels.

Figure 23: Use of synthetic carriers in Germany 2050



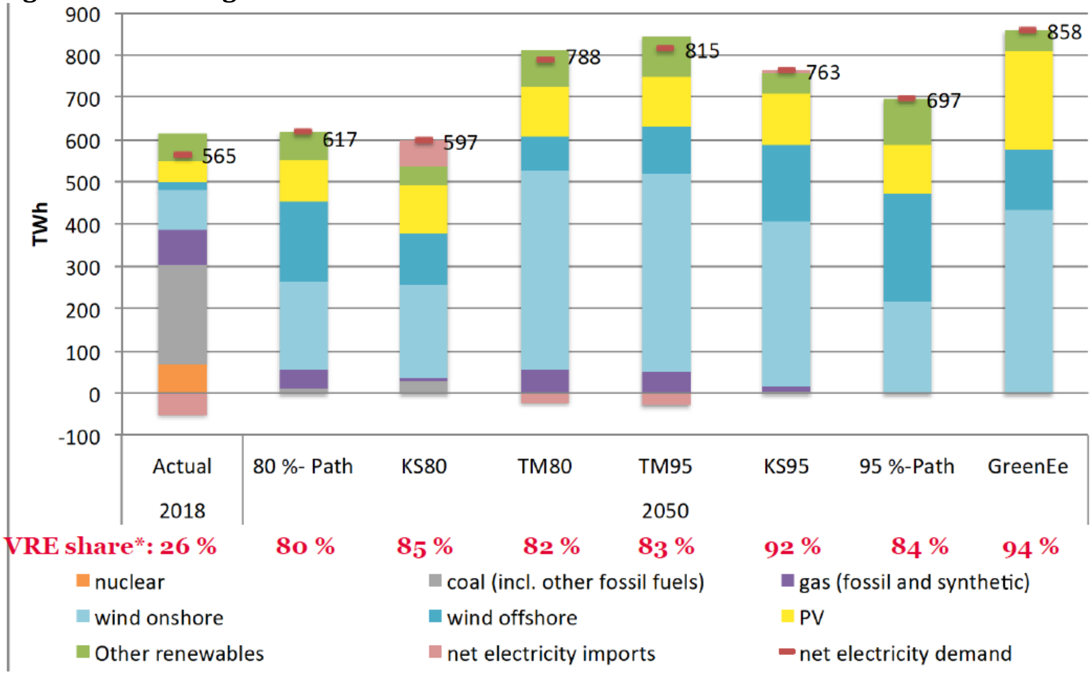
Source: Energy Systems of the Future et al. (2019)[33)]

The ESYS study rules out imports of renewable synthetic energy carriers due to political uncertainties in other countries that may not support the technological development and economic feasibility of this technology. However, the BDI and dena studies show that Germany will likely have to depend on imports from other nations who have relatively abundant wind and solar resources. The question of how other countries will address the energy transition and to what extent they will increase ambition in climate targets will shape Germany's energy future as it determines investment and policy priorities. If Europe integrates its electricity grid, for example, Germany would be able to import a higher amount of electricity and build fewer power plants to support VRE. In the same sense, if other countries within Europe utilize renewable resources to develop a market for synthetic energy carriers, Germany could then import those fuels. The above figure depicts the results of some of the scenarios from each study. The technology mix scenario by dena estimates that Germany will have to import more synthetic fuels compared to the other scenarios, but dena also concludes that the 95% target technology mix scenario is more cost-effective than the 95% target electrification scenario. It should be noted that these synthetic energy carriers are rather used in other sectors than power generation: they are a means of sector coupling to use the renewable electricity potential for other sectors. Therefore, their link to VRE system integration costs is rather indirect: on the one hand, they will increase the needed VRE generation capacity, depending on the share of imported vs. domestically produced synthetic energy carriers. On the other hand, the electrolysis needed for their domestic production is providing a means of storage for electricity in the form of hydrogen, thereby reducing the integration cost.

3.3 Discussion

The ESYS, BDI, and dena studies present potential paths for Germany to realize the transition to a carbon-neutral energy system by 2050. Each study takes a slightly different approach and the results are based on the differences in assumptions of factors such as the degree of cross-sectoral coupling, the global climate policy environment, and the likelihood of a synthetic energy carrier market. However, they all conclude that Germany will require a higher rate of electrification and much broader deployment of VRE. The findings by Löschel[36)] based on a review of the same and similar studies, as shown in Figure 24 below, depict the projected high penetration rates of VRE in comparison to other technologies. They determine that VRE penetration must be over 80% to reach the 80% and 95% climate targets, and that the remaining energy carriers will be other renewables and gas, and in some scenarios, supplements from electricity imports. As noted earlier, nuclear energy and coal will not be a part of Germany's future energy mix due to the plans for phase-out already in place.

Figure 24: Power generation mix for different scenarios



Sources: Löschel (2019)[36], based on Energy Systems of the Future et al. (2019)[33], Öko-Institut (2015)[37], German Environment Agency (2019)[38]

The overall cost of this energy transition, according to BDI, will require an additional investment of 1.5 trillion to 2.3 trillion Euro by 2050, which includes around 530 billion Euro for efforts under existing policies. The additional amount of investment equates to around 1.2% to 1.8% of GDP per year through 2050. The dena and ESYS studies also estimate additional investment will cost one and two percent of GDP respectively. The studies also assess that the economic impacts of the energy transition will be neutral to slightly positive, though the issue of carbon leakage could be a concern for industries who face overseas competition. And hence, for example the BDI study concludes that it will be very difficult to achieve the 95% climate target without a global effort to increase ambition to achieve carbon-neutrality. Finally, the cost of technologies and the amount of effort necessary to achieve these ambitious targets may be offset in the future by technology developments such as a steeper learning curve for photovoltaics and storage technologies, more efficient production of hydrogen and power-to-X processes, and cheaper CCUS applications.

4. Comparative discussion and conclusions

We can find many similarities and dissimilarities between the Japanese and German studies as described above. The largest dissimilarity would be the assumptions for nuclear power. The German studies do not take into account the use of nuclear power in the long-term, which is a natural assumption given the nuclear phase-out policy of the country, whereas the Japanese study concludes that nuclear power can mitigate the cost hikes related to very high penetration of VREs.

Another point of disaccord may be the role of low-carbon thermal power generation; the Japanese studies imply that imported hydrogen can play an important role to reduce the cost of the decarbonization of the power sector, whereas German studies assume relatively small shares of green hydrogen or synthetic fuels from renewable power as backup power only, with much higher shares of direct VRE power generation over 80%. This difference may arise due to different assumptions on the future generation and system integration costs of VRE vs. hydrogen power.

We should note various natural and socioeconomic differences between Germany and Japan. One major difference is related to meteorological conditions and VRE potentials; for example, some studies point out that the realistic potential of onshore wind in Japan, taking public acceptance and legislative aspects into account, should be much smaller than that estimated by the Ministry of the Environment[41)]. The Japanese studies shown in this paper concluded that the unit system cost rises significantly with very high VRE shares, even if the maximum deployment of onshore wind according to the estimates by the MOE is assumed. If we take more "realistic" potential estimation into account, the difference between the German and the Japanese studies will be even larger.

We should also note the differences in the LCOEs of VRE. As described in Section 1.1.1, the LCOEs of wind and solar PV are at much higher levels in Japan than in Europe. As the difference lie not only in the costs of PV modules and wind turbines, but also in other parts intrinsic to the country, the gap cannot be dissolved at least in the near future. However, if we assume that the LCOEs of VREs in Japan will become as low as those in Europe in the long-term, the discrepancy between the results of the studies may also be smaller.

There is also a possibility that other major assumptions are different; for example, heat storage is regarded as one of the most promising technologies that can provide flexibility of energy supply in Europe, while it has not been assumed in Japanese studies, as large-scale deployment of heat storage in Japan is not regarded as realistic, although there may exist some potential for example in industry. This may be a part of the difference in climatic conditions. In addition, demand side management and vehicles-to-grid (V2G) technologies have not been taken into account in the Japanese studies. Although explicit consideration of these technologies is not supposed to change the picture significantly, as explained in Ref. 14), it may reduce the cost of intermittency at least to some extent. At the same time, taking into account other aspects, such as rotational inertia[42)], may boost the cost hikes.

We can observe multiple similarities. For example, the dena study concluded that cumulative investment of 230-348 billion Euro will be required on power grids for VRE 80% scenarios, as compared with 118 billion Euro for the reference scenario, whereas the Japanese study estimates the cumulative additional investment for the 100% renewables case at 40 trillion yen (330 billion Euro). The large required investments result from the fact that large wind potentials exist in remote areas from large energy consumers in both countries.

The "cannibalization" effect, as point out in Refs. 31-32), can also be a major challenge in the mid- to long-term, both in Japan and in Europe. German studies conclude that the total economic impacts by achieving decarbonized energy systems are practically negligible, if any. At the same time, we should be aware that economic equilibrium is always determined by marginal costs, rather than by average costs, and that the "cannibalization effect" refers to anticipated rise in the marginal costs of renewable sources. This would highlight the necessity of continuous policy supports in the long-term, even if the LCOEs of VREs decline dramatically along with the rapid global deployment.

Another common conclusion is related to the necessity of the use of synthetic gas or hydrogen. Hydrogen, or any other form of "low-carbon gases", should be regarded as a promising option to achieve a carbon neutral energy system in the future, although some people still doubt the feasibility of the technology, due mainly to the required large investments on the infrastructure, which have not been realized so far.

The importance of the effects of "dark doldrums", or "windless and sunless" periods, on energy security under high penetration of VRE has also been emphasized in both studies. In the Japanese studies, the costs of power storage systems to avoid electricity disruption during these periods account for a large part of the additional costs related to the decarbonization of the power sector. In Germany, the dena report points out that this issue has led to very controversial discussions, and concludes that "a further study should investigate what contribution is required to secure capacity for a long, cold dark doldrums period and whether electricity imports can achieve this."

In Japan, where electricity import from overseas is politically very difficult, this exerts much larger effects on the economics of the power sector than in Europe. However, as pointed out in the dena report, "dark doldrums" can take place simultaneously in whole Europe. Thus this constitutes a major challenge for very high penetration of VRE, not only in Japan, but also in Europe and probably in any other countries and regions. It is highly likely that there will remain the need for some backup power plants using hydrogen or other low-carbon synthetic gas; for energy efficiency reasons, using CHP plants, e.g. in industry or in Germany also in district heating, would be the optimal solution. This is shown in most German scenario studies, particularly those with lower additional costs such as the BDI study or dena's technology mix (Figure 24 in the chapter on Germany above). It can also be derived from the steep increase in the IEEJ's modelling when decreasing the share of hydrogen power from 200 or 100 TWh/yr to zero (Figure 7 and 8 in the part on Japan).

A difference is that the IEEJ has directly modelled the system costs of the Japanese electricity system under a larger number of different cost assumptions, while the German studies allow to compare the overall power system costs of selected very low-carbon scenarios with reference scenarios, as done in Figure 18 above. Under German conditions and the Paris Agreement, even reference scenarios have a high share of VRE in 2050 (60 to 70%). Still, as Figure 18 shows, the difference between minus 95% GHG scenarios and the reference scenarios is only 10 to 20 % of total electricity system costs, which can be interpreted as the integration costs of very high shares of VRE. For example, the increase in costs for the 95 % scenario in the BDI 2018 study is 1.3 cents vs. the reference scenario and 2.1 cents vs. the base year 2015, and almost zero vs. 2020.

In the same direction, there has been a thought experiment by Öko-Institut for Agora Energiewende[43)], which modelled the system costs for a hypothetical fossil fuel electricity system for 2050 (i.e., replacing existing power plants with new coal or gas plants) and a RES-based system in 2050. In half of the cost cases each, one or the other system was more expensive than the other, so the costs are more or less on par: meaning no net increase in system costs.

A likely reason for the low increase in system costs for very high shares of VRE is that all of these studies on Germany use a full combination of available flexibility and grid integration options for VRE. These range from demand-side management, batteries including BEV, heat storage and heat pumps, to smart grids and grid restructuring, to other storage and the existing pumped storage hydro (which is much less than in Japan), and to electrolysis and gas-fired back-up power with ‚green' hydrogen or methane. These can either be produced from surplus VRE power in Germany or Europe or imported as hydrogen or synthetic fuels. In minus 95% scenarios with lower additional costs, synthetic gas from PtG provides some 5 to 10% of the power generation in 2050. This is the main long-term (weeks/months) storage option. Of course there may be other factors explaining differences, like the integration of Germany into the grid of its neighbours that may reduce costs.

In contrast to these German studies, IEEJ's Case C-0 in Figure 10 sees an average cost of 18 JPY/kWh, considerably higher than the optimal level of 11 JPY/kWh. This case assumes flexible pumped hydro power and hydrogen storage as well, with 50 to 90 TWh/yr of power generated from this hydrogen, but no imported hydrogen. As described above, these differences between German and Japanese studies for similar cases may result, at least partly, from differences in cost assumptions particularly for wind and solar power, as well as weather conditions. We should note, however, that with the use of a reasonable amount of nuclear power and/or imported hydrogen (around 100 to 200 TWh/yr of electricity production), the cost hike can be reduced to less than 3 JPY/kWh (2.5 Euro-cents/kWh) even in the case of Japan, as is obvious from Figure 8.

We may conclude that 1) the potential of achieving a high share of variable renewable energies in power generation will highly depend on the future development of their generation costs in relation to hydrogen and nuclear power plants, and 2) it will be necessary to optimise the grid integration, flexibility, and sector integration technologies and their mix, as well as energy efficiency, in order to minimise specific and overall power system costs with growing shares of VRE. The studies reviewed here indicate that it will be possible to limit additional power system costs to reasonable levels even with high shares of VRE, if we can address several anticipated challenges properly, and optimise our efforts in achieving ambitious GHG reduction targets.

The GJETC therefore recommends (1) further analysis and simulation to better understand the opportunities of different technologies and their combination, as well as the differences in costs found between Germany and Japan (cf. chapter 4.6), taking experiences in other countries on board, such as US federal states or Denmark; (2) to implement joint German-Japanese demonstration and pilot projects to test advanced technologies and business models for flexibility, similar e.g. to the SINTEG program in Germany; and (3) to develop a priority list for market readiness and implementation of different flexibility options, with the timing of implementation related to the share of VRE in the system. Obviously, such a priority list would also be adapted to the situation in each of both countries, Germany and Japan.

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