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Model analysis for Japan's energy mix in 2040 and 2050

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1. Background

In pursuing the goal of achieving carbon neutrality by 2050, it is essential to transform the energy supply–demand structure by adopting renewable energy and other advanced, cost-effective energy technologies. Extensive analyses of long-term energy supply and demand have already been conducted using energy system models, and the results of scenario studies by various organizations have been presented at policy deliberation committees. For example, at the 44th meeting of the Strategic Policy Committee in June 2021, six organizations reported their findings on energy scenarios for 2050.

These scenario analyses indicate that large-scale adoption of solar and wind power will be indispensable for achieving carbon neutrality. However, in recent years, solar power facilities have increasingly been installed in forested areas, prompting local governments to introduce regulations that limit development in ecologically sensitive locations. Similarly, while offshore wind projects have primarily been planned in shallow waters, future expansion is expected to require development in deeper areas where economic feasibility is lower. Accordingly, long-term energy supply and demand scenarios must take into account the impact of site location constraints associated with large-scale solar and wind deployment.

This study employs a technology selection model to evaluate the installed capacity of energy technologies across the energy system, explicitly accounting for constraints and location changes related to the large-scale adoption of solar and wind power in Japan. Based on this analysis, this study presents long-term energy supply and demand scenarios for 2040 and 2050.

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This paper is based on "Model calculation for Japan's energy mix in 2040 and 2050", which Seiya Endo, Takashi Otsuki, Hideaki Obane, Yuhji Matsuo, Soichi Morimoto and Akira Yanagisawa presented at the 66th meeting of the Strategic Policy Committee of the Advisory Committee for Natural Resources and Energy on December 3, 2024.

2. Technology selection model

The technology selection model used in this study is based on a linear programming model (the NE Japan model) constructed by Otsuki et al.[1)-3)] This model assumes input values for the capital costs, fuel costs and other components of each energy technology in order to output installed amounts etc. for the energy technologies with the smallest costs in the energy system as a whole, based on linear programming. The technologies covered by the selection are approximately 300 technologies in the power generation, energy conversion, industry, transport, residential, and commercial sectors, and they are given a flowchart format that flows from primary energy supply through to energy conversion, secondary energy, interregional transmission and final consumption (**Fig. 1**).

In this model, the sum total of the costs relating to a technology k is considered to be the energy system costs, and the minimization of the cumulative costs is undertaken following discounting according to the objective function shown in Equation (1). The energy system costs include the capital costs and operating and maintenance costs for the demand side and supply side facilities, respectively, as shown in Equation (2), and the energy procurement costs (imports and domestic production of primary energy, and imports of secondary energy). The capital costs are converted into an annual cost across the number of years a facility is used, in line with Equations (3) and (4). The analysis period is 2022-2075, and supply and demand are estimated at six points in time, 2022, 2030, 2040, 2050, 2065 and 2075, as representative years YR_y.

$$min \sum_{y=0}^{5} \sum_{\tau=YR_y}^{YR2_y} \left\{ \frac{ac_y \cdot (YR_{y+1}-\tau) + ac_{y+1} \cdot (\tau - YR_y)}{YR_{y+1}-YR_y} \cdot \frac{1}{(1+DR)^{\tau - YR_0}} \right\} \quad (1)$$

$$ac_y = ivc_y + foc_y + voc_y + flc_y \quad (2)$$

$$ivc_y = \sum_{y' \in Y, y' \le y} \sum_r \sum_k AC_{k,y'} \cdot LM_{k,y',y} \cdot nnk_{k,r,y'} \quad (3)$$

$$AC_{k,y} = C_{k,y} / \sum_{j=1}^{LIFE_k} (1+HR)^{-j} \quad (4)$$

Here, DR is the time discount rate (5%), YR_{2y} is = YR_{y+1}-1, Y is the aggregate of the points in time, ivc_y is the capital cost of point in time y (unit: yen/year), foc_y is the fixed operating and maintenance cost (yen/year) at point in time y, voc_y is the variable operating and maintenance cost (yen/year) at point in time y, flc_y is the energy procurement cost (yen/year) at point in time y, $AC_{k,y}$ is the capital cost of technology k at point in time y converted into an annual cost (yen/kW/year), $C_{k,y}$ is the capital cost (yen/kW) of technology k at point in time y, $LM_{k,y}$ is a constant value showing the remaining equipment life of the technology k, (if equipment introduced at point in time y' is approaching the end of its service life at point in time y the figure is 0, and if the equipment has service life remaining the figure is 1), $LIFE_k$ is the service life (years) of technology k, and HR is the subjective discount rate of investment.

There was assumed to be a total of 39 energy service demands (hereinafter "service demand") covering industry (iron and steel, chemical, cement, paper and pulp, data centers, semiconductor factories, other industries); transport (passenger, freight); residential (lighting, cooling, heating, cooking) and commercial (lighting, cooling, heating, cooking). Within the model, service demand within each segment is further segmented, with transport (passenger) subdivided into the five categories of passenger vehicle, bus, marine vessel, rail and airplane, for example.

Electricity demand and thermal demand are determined endogenously according to the installed amount of the respective technology selected in order to meet each service demand. For example, in ordinary vehicle transport, in a case where electric vehicles are selected, electricity demand is assumed to increase within the model in response to that.

Notable features of the technology selection model used in this calculation are that it assumes a temporal resolution of 8,760 hours and divides regions in Japan into five areas (Hokkaido, Tohoku, Tokyo, West Japan, Kyushu/Okinawa), and both the temporal resolution and spatial resolution are subdivided. This makes it possible to take the time variability of solar power generation and wind power generation and the constraints of interregional connection lines into account in more detail, and it thus becomes possible to undertake a more refined assessment of the installed amount of storage batteries and variable renewable energy.

In addition, when it comes to solar power generation and wind power generation, for which changes in site location are predicted to accompany progress with introducing them, it is assumed they will be installed in locations where they are unlikely to suffer the effects of restrictions resulting from regional regulations, based on reviews of such regulations. Additionally, accompanying the expansion in the installed amount, they will be sited in locations where generation costs are high, and so installation locations were divided into grades according to site conditions such as quantity of solar radiation, wind conditions, and water depth.

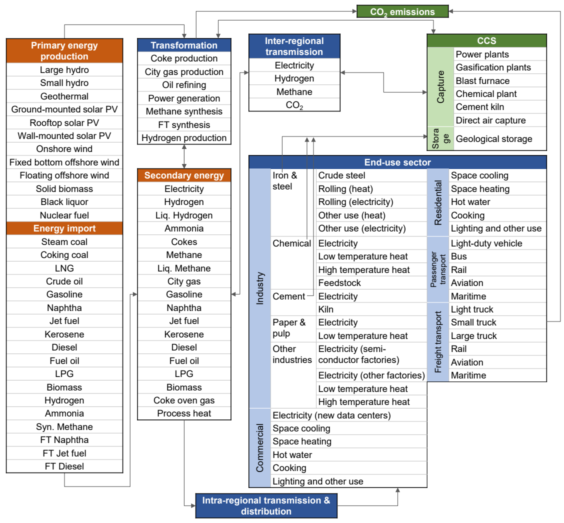


Fig. 1 The energy system in the technology selection model

3. Key assumptions

3.1 Scenario setting

Under the constraint that energy source CO_2 emissions will decline by 73% (333Mt–CO_2) by 2040 compared to 2013, and to a net 0 Mt–CO_2 by 2050, four types of scenarios were set in line with factors such as site conditions and degree of technological progress (**Table 1**).

(1) The renewable energy expansion case envisages a case in which maximum use is made of renewable energy, including making it possible to install agrivoltaic (dual use of land for solar energy and agriculture) power generation wherever possible on all agricultural land; (2) the hydrogen expansion case envisages a case in which import prices for hydrogen energy carriers decline as a result of declining costs for procuring green hydrogen from overseas and declining costs for carrier manufacturing facilities; (3) the CCS expansion case envisages a case in which it becomes possible to store CO_2 up to 240 million/t–CO_2, the upper limit of the target value for annual CO_2 storage volume presented in the CCS Long-Term Roadmap Study Group's final summary; while (4) the expanded innovative technologies case envisages that a renewable energy expansion, hydrogen expansion and CCS expansion are all realized.

3.2 Upper limits of installed amounts for solar and wind power generation

The upper limits of the installed amounts for solar and wind power generation are shown in **Table 2**. The upper limits of the installed amounts for ground-mounted solar power generation and onshore wind power generation are premised on the respective power sources being installed in locations that exclude zones restricted by regulations, based on Obane et al.[4] Incidentally, in the renewable energy expansion case, it was assumed that installation will be partly permitted in those zones where there is a low occurrence of cities, towns and villages where restrictions are in place as a result of them being landscape preservation areas, for example.

Where roof-mounted solar power generation is concerned, the upper limit of the installed amount was set by taking into account the installation coefficient that is the ratio of area where solar power generation is installed as a component of the entire roof area, based on Obane et al.[4] In the standard case an installation coefficient that is based on actual installation figures was used (7.9-38.8% depending on the type of building), while in the renewable energy expansion case the installation coefficient used (49.9%) is based on the concept of buildings' potential greenification areas. When it came to detached houses, they were divided into grades of solar radiation pattern according to roof angle.

With reference to Asano et al,[5] the upper limit of the installed amount of agrivoltaic power generation was assumed to be the installation capacity in a case where all agricultural management entities as of 2023 install 49.9 kW of solar power generation facilities, which falls within the range that does not require the appointment of a licensed electrician. Incidentally, in the renewable energy expansion case, installation was assumed to be possible on all agricultural land.

Where offshore wind power generation was concerned, based on Obane et al,[6] the assumed premise was that installation would take place in those marine areas that satisfy the specified prerequisites of "Promotion Zones" under the Act on Promoting the Utilization of Sea Areas for the Development of Marine Renewable Energy Power Generation Facilities. In the standard case, installation was assumed to be possible in marine areas 10-100 km away from the shore, taking into account the impact on the landscape and system connectivity constraints, while for the renewable energy expansion case, installation was assumed to be possible in marine areas 0-370.4 km away from the shore. In addition, because power generation costs differ considerably depending on the location of installation, a total of 60 grades were established, comprising four water depth patterns x three windspeed patterns x five power generation area patterns, with capital costs, capacity factors, and upper limits for installed amount set for each grade (**Fig. 2**).

Table 1 Set scenarios

Case	Upper limits of installed amounts for solar power and wind power generation	Hydrogen price	CO_2 storage volume
Renewable energy expansion (Case 1)	Renewable energy expansion	Standard	Low level (120 million t/year)
Hydrogen expansion (Case 2)	Standard	Advances in hydrogen technologies	Low level (120 million t/year)
CCS expansion (Case 3)	Standard	Standard	High level (240 million t/year)
Expanded innovative technologies (Case 4)	Renewable energy expansion	Advances in hydrogen technologies	High level (240 million t/year)

Table 2 Upper limits of installed amounts for solar power and wind power generation

		Approach taken	Upper limit of installed amount [GW]
Roof-mounted solar (detached houses)	Standard	Installed on roofs facing south, east and west	146.3
	Renewable energy expansion	Installed on roofs facing south, east and west, and north	194.4
Roof-mounted solar (other than detached houses)	Standard	Installed on 7.9%-38.8% of the entire roof area, depending on the type of building	137.2
	Renewable energy expansion	Solar power generation installed on 49.9% of the entire roof area	280.4
Ground-mounted solar	Standard	All types of zones restricted by regulations are excluded	52.3
	Renewable energy expansion	Some zones restricted by regulations are excluded	116.1
Onshore wind power	Standard	All types of zones restricted by regulations are excluded	25.2
	Renewable energy expansion	Some zones restricted by regulations are excluded	35.3
Agrivoltaic	Standard	Assumes that all agricultural management entities (84,000 management entities) install 50 kW of solar power generation facilities, which falls within the range that does not require the appointment of a licensed electrician	46.5
	Renewable energy expansion	Installation possible on all agricultural land	2,365

* Where ground-mounted solar power and onshore wind power are concerned, because they include facilities, etc. that are already installed in forests, they do not match the figures in Obane et al.[4)]

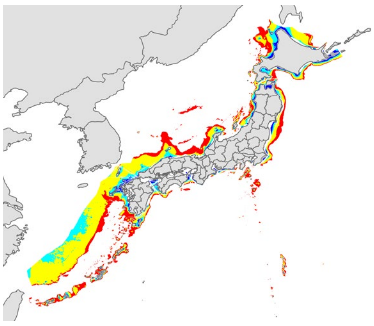
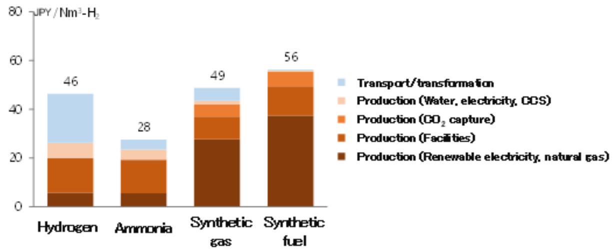


Fig. 2 Example of grading of offshore wind power generation
(Four water depth patterns)

3.3 Imported fuel costs

In this study, in terms of fossil fuels imports of crude oil, petroleum products (seven types), LNG, fuel coal and raw coal were taken into account. The assumed import prices were estimated by taking actual figures for FY2022 based on CIF prices in trade data as a base, and applying the growth rates for price forecasts contained in the IEA World Energy Outlook 2024's Net Zero Emissions by 2050 scenarios.

Where hydrogen energy carriers were concerned, liquid hydrogen, methylcyclohexane (MCH), ammonia, e-methane and synthetic liquid fuel were taken into consideration. The assumed prices were estimated by adding up the costs at each stage of the international supply chain, based on the approaches taken in reports such as the IEA's The Future of Hydrogen, and Otsuki and Shibata[7] (**Fig. 3**). Where hydrogen (liquid hydrogen and MCH) was concerned, the costs up to reconversion after unloading were assigned as a precondition, with the energy unit cost after unloading to be determined endogenously within the model. In addition, where liquid hydrogen, MCH and ammonia were concerned, manufacture from CCS-equipped natural gas upgrades was assumed, and for e-methane and synthetic liquid fuel manufacture from electrolytic hydrogen and atmospherically derived CO_2 was assumed.



* Of the import costs, the export port and reconversion are determined endogenously based on the energy unit prices within the model

Fig. 3 Import costs for hydrogen energy carriers (2050, standard case)

3.4 Capital costs of solar and wind power systems

The capital costs of solar power generation and wind power generation were set according to the FY2024 Power Generation Cost Verification Working Group. The capital cost of agrivoltaic power generation was assumed to be 20,000 yen/kW higher than the capital cost of ground-mounted solar power generation, based on questions put to operators. Furthermore, for offshore wind power generation the capital costs were premised on fixed bottom-type wind turbines being installed at water depths of 0-60 m and floating-type wind turbines being installed at water depths of 60 m or deeper, and with reference to NREL, the capital costs were assumed to be 416,000 yen/kW at a water depth of 0-30 m, 537,000 yen/kW at a water depth of 30-60 m, 806,000 yen/kW at a water depth of 60-100 m, 891,000 yen/kW at a water depth of 100-200 m and 1.02 million yen/kW at a water depth of 200m or deeper.

3.5 Energy service demand

Service demand up to 2050 was estimated recursively based on per capita GDP predictions and other information. Taking iron and steel production as one example, for instance, steel and iron production output into the future was predicted with industrial GDP as an explanatory variable. **Table 3** shows estimated results for representative service demand. Incidentally, the figures for GDP, population and number of households that appear within the table are explanatory variables for recursively predicting key service demand, and are shown for reference. It is assumed that the electricity demand of data centers and semiconductor factories will increase by a total of 100 TWh in 2040 and a total of 214 TWh in 2050, based on Mase et al.[8]

Table 3 Key service demand and assumed macro prerequisites

	Unit	2022	2040	2050
Steel and iron production volume	million ton	87.84	78.34	73.49
Ethylene production volume	million ton	5.48	5.45	5.34
Cement production volume	million ton	51.48	48.83	48.15
Paper production volume	million ton	30.83	28.21	27.75
Passenger vehicle traffic volume	billion people-km	767	695	667
Truck traffic volume	billion ton-km	228	217	205
Real GDP (2015 benchmark)	Trillion yen	554	737	857
Population	million people	124.35	116.27	110.70
Number of households	million households	60.27	60.55	58.20

4. Results

4.1 Generated electricity

The generated electricity under each scenario in 2040 and 2050 is shown in **Fig. 4**. The red figures displayed in the diagram show the ratio of electricity generated by renewable energy as a component of the total volume of electricity generated, and significantly differing results were shown for each scenario: 41% - 55% in 2040 and 48% - 63% in 2025.

In Case 1, the renewable energy expansion case, because this case is premised on it being possible to install agrivoltaics power generation on all agricultural land, the ratio of electricity generated by solar power generation is larger compared to the other cases. In Case 2, the hydrogen expansion case, because import prices for hydrogen carriers are set low, the volume of electricity generated by ammonia thermal power generation is increasing in place of offshore wind power generation. Additionally, in Case 3, the CCS expansion case, because CO_2 storage volume is being increased, the volume of electricity generated as a result of CCS-equipped LNG-fired power generation is increasing.

In all the scenarios, the volume of electricity generated is rising significantly from 2040 to 2050. In addition to growth in electricity demand from data centers and semiconductor factories, this is due to electrification in energy demand sectors and increases in the electricity consumed by direct air capture (DAC) of CO_2.

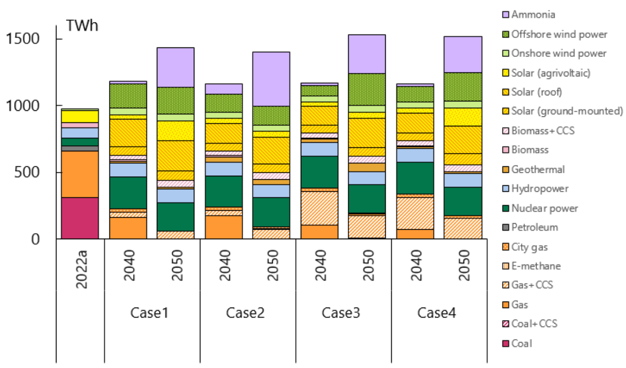


Fig. 4 Volume of electricity generated [TWh]

4.2 Primary energy supply

Primary energy supply in 2040 and 2050 is displayed for each scenario in **Fig. 5**. Those results suggested primary energy supply of 320 ~ 340 Mtoe in 2040, down by approximately 20% compared to 2022's primary energy supply of 392 Mtoe.

The ratio of fossil fuels as a component of the overall primary energy supply was 87% in 2022, but the calculation results indicated that the ratio falling to 57-64% in 2040 as a result of a decrease in the volume of electricity generated using coal-fired power generation. Incidentally, the results suggested that primary energy supply for natural gas for LNG-fired power generation, along with petroleum products for automobile and marine vessel use, will remain.

The results suggested that in 2050, the ratio of fossil fuels as a component of the overall primary energy supply will fall substantially, to around 20%, as a result of increases in the ratios of hydrogen energy carriers and renewable energy.

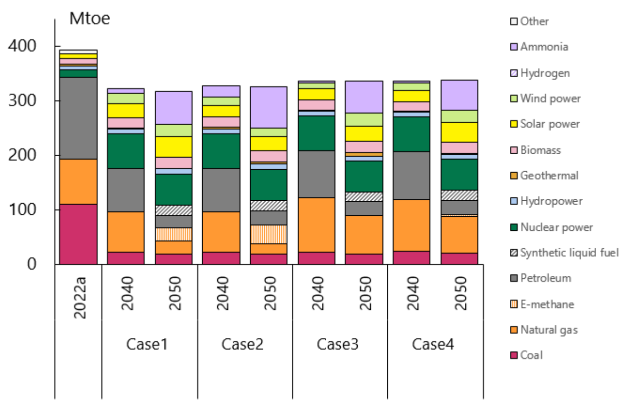


Fig. 5 Primary energy supply [Mtoe]

4.3 CO_2 emissions by sector

CO_2 emissions by sector in 2040 and 2050 for each scenario are shown in **Fig. 6**. The calculation results suggested that CO_2 will be emitted by sectors such as the industrial sector and transport sector in any of the scenarios in 2040. Additionally, in 2050, emissions such as CO_2 emissions from fossil fuel consumption in industrial sectors where electrification is difficult due to those sectors' reliance on intense heat sources will remain, with that remainder portion to be offset through BECCS (Bioenergy with carbon capture and storage), a technology combining biomass power generation with carbon capture and storage, and DAC (direct air capture), a technology for capturing and storing CO_2 directly from the atmosphere.

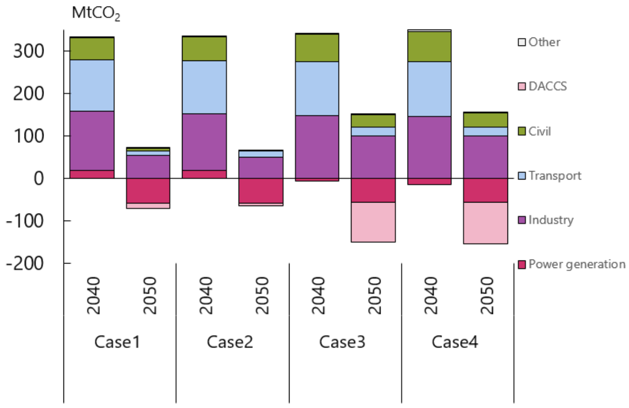


Fig. 6 CO_2 emissions by sector [Mt-CO_2]

5. Policy implications

This study employed a technology selection model to demonstrate long-term energy supply and demand scenarios, after taking into account siting restrictions for solar power generation and wind power generation, and the changes in site location that will accompany solar and wind power generation being adopted in large amounts. The results of that calculation suggest that with electricity demand anticipated to increase in the medium to long term, and given that the costs to the energy system as a whole will increase accompanying solar power generation and wind power generation being adopted in large amounts, it will be important to utilize not just renewable energy but a variety of energy sources, including nuclear power generation, CCS-equipped LNG-fired power generation and ammonia power generation. Incidentally, it needs to be kept in mind that the power supply mix in which the cost of the overall energy system is smallest will change significantly depending on factors such as CO_2 storage volume and the fuel import cost of hydrogen energy carriers. For example, the lower limit of CO_2 storage volume is assumed to be 120 million t-CO_2/year, but should a case arise in which actual CO_2 storage volume falls below 120 million t-CO_2/year, it will give rise to the need for alternative power sources, such as renewable energy, in place of CCS-equipped LNG-fired power generation.

Consequently, given the large degree of uncertainty surrounding factors such as how much progress is made with the different types of technologies and the cost of hydrogen energy carriers in the future, at the present point in time, it will be desirable to pursue the development of a variety of technologies and aim for a balanced energy mix.

Acknowledgement

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