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Role of carbon dioxide capture and storage in energy systems for net-zero emissions in Japan

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A R T I C L E I N F O

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A B S T R A C T

Japan's sixth Strategic Energy Plan mentions that carbon dioxide capture and storage (CCS) is one of the important options to achieve carbon neutrality by 2050; however, the technology faces significant uncertainties regarding its potential and costs. This study quantifies the impact of CCS uncertainties on Japan's net-zero energy mix using an energy system optimization model. The simulation results show that CO_2 storage availability largely affects the optimal energy choice in the entire energy sector, including the electricity and all end-use sectors. Future CCS implementation would determine the penetration of net-zero emission fuels, such as hydrogen and synthetic fuels. The results also imply that CCS is crucial in curbing Japan's emission reduction costs. Marginal CO_2 abatement cost in 2050 surges to 1717 USD/tCO_2 in a limited CCS case (injecting 10 MtCO_2/year in 2050), tripling from that of a higher CCS case (504 USD/tCO_2 when injecting 200 MtCO_2/year in 2050). An additional analysis of CCS costs confirms that CCS can be economically attractive even in a high CCS cost case. The results of this study can provide scientific insights into the design of country- and corporate-level energy strategies.

1. Introduction

Carbon dioxide capture and storage (CCS) is one of the important options for Japan to achieve carbon neutrality by 2050 (METI, 2021a, 2023). According to the sixth Strategic Energy Plan published in October 2021 (METI, 2021a), the Japanese government will pursue various low-carbon energy supply options, including thermal power generation with CCS, to reduce CO_2 emissions while maintaining diversified energy sources from an energy-security perspective. The aggregated share of fossil fuels with CO_2 capture and nuclear is expected to be 30–40 % by 2050 in the reference power generation mix discussed by the government (ANRE, 2021). The strategic energy plan also highlighted that CCS contributes to decarbonizing material industries such as iron, steel, and cement. Furthermore, recent modeling studies (Akimoto and Sano, 2021; Otsuki et al., 2022) have found that direct air capture with CO_2 storage (DACCS) can be a cost-effective option for offsetting residual CO_2 emissions in Japan's energy systems for net-zero emissions. The government published a CCS roadmap in March 2023 to promote the commercialization of CCS by 2030 and accelerate its deployment by 2050 (METI, 2023). The roadmap estimated Japan's annual CO_2 storage for 2050 at 120–240 MtCO_2/year by downscaling global energy scenarios published by the International Energy Agency (IEA, 2021). This range is approximately 12–23 % of Japan's energy-related CO_2 emissions in 2019 (1028 MtCO_2) (NIES, 2023).

However, there are some barriers to CCS commercialization in Japan. The first includes the legal and institutional barriers. Japan's permitting regime for CO_2 storage is primarily focused on sub-seabed storage under the Maritime Pollution Prevention Law (MOE, 2011). There are no provisions for onshore geo-sequestration, although some potential sites may include onshore storage (Global CCS Institute, 2016; Kishimoto, 2022). In addition, geological storage activities may conflict with existing rights such as land ownership and mining rights (Konno, 2022). From the financing viewpoint, liabilities can be a barrier. For example, the liability period for environmental pollution due to enhanced oil recovery, gas recovery, and coalbed methane recovery is five years after the extinguishment of mining rights under the Mining

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Law. In contrast, unlimited liabilities are required for other types of CO_2 storage under the Maritime Pollution Prevention Law (Konno, 2022), making investors hesitant to assess "pure" CCS projects. The government plans to establish a new framework for promoting the CCS business (i.e., new rights for CO_2 injection and storage) to overcome these legal and institutional barriers (METI, 2023).

The second barrier is the uncertainty regarding social acceptance. According to a survey conducted towards the end of 2015 (Saito et al., 2019), most Japanese public did not know much about CCS. About half of the respondents had no explicit opinions concerning a hypothetical offshore CCS plant near their home; however, the survey implied that the *not in my backyard* perception negatively influenced their views. These social factors may hamper the large-scale implementation of CCS.

The third barrier is the uncertainty of CO_2 storage costs and potential. Preliminary assessments (METI, 2023) indicated that Japan has a geological storage potential of approximately 240 $GtCO_2$, 230 times higher than the annual energy-related CO_2 emissions in 2019. CO_2-hydrate storage, a new concept for trapping CO_2 in a solid form rather than under a caprock, can expand Japan's storage potential (Ikegawa and Tobase, 2021). However, detailed economic evaluations and site-based potential assessments are underway (METI, 2023). The barriers discussed above, including liability and public acceptance, may raise the cost of large-scale CCS implementation (Flannery, 2011). Also, existing cost estimates of CCS are mainly based on engineering design considerations; these estimates do not account for issues that may arise in practice (Flannery, 2011). As for storage potential, Akimoto and Sano (2021) pointed out that the number of rigs and lead times of drilling operations can impede CO_2 storage site expansion. The commercially viable storage potential can be lower than the preliminary assessments, and the CCS costs can be higher than the current estimates.

Significant uncertainties exist regarding the degree of future CCS implementation in Japan, while some global and regional energy assessments reported that CCS is one of the most influential factors in climate change mitigation cost (Kriegler et al., 2014; Otsuki et al., 2019; Selosse et al., 2013). CCS may broadly impact Japan's cost-effective energy pathway, forcing energy industries to change their decarbonization strategies (e.g., limited CCS may change the future of existing fossil fuel-fired power plants, while accelerated CCS may displace other prospective decarbonization measures). The impacts of CCS availability should be assessed to analyze the risks and opportunities for Japan's energy sector. However, few studies have conducted in-depth assessments of CCS in Japan's net-zero energy system (see Section 2). Therefore, this study investigates the role of CCS and its impacts on deploying other technologies in net-zero energy systems through a sensitivity analysis of the potential and economics of CCS technologies. We employed an energy system optimization model that calculates a cost-effective energy technology choice under climate policies. We believe this paper provides a reference for energy policymakers and industries to quantitatively understand the potential impact of CCS in the future.

The remainder of this paper is organized as follows. Section 2 summarizes the existing research. An overview of the model is described in Section 3. Section 4 presents the simulation results. Finally, Section 5 summarizes the key findings and offers future research agendas.

2. Literature survey

This literature survey section consists of two parts. First, Section 2.1 provides an overview of existing global modeling frameworks. Then, Section 2.2 focuses on energy system analyses in Japan and identifies the research gap regarding CCS.

2.1. Overview of existing global modeling frameworks

Various global integrated assessment models and energy system models—such as AIM-Technology (Oshiro and Fujimori, 2022), DNE21+ (Akimoto et al., 2021), GCAM (Muratori et al., 2017), GRAPE (Ishimoto et al., 2017), IMAGE (Daioglou et al., 2019), LUT ESTM (Bogdanov et al., 2019), MESSAGE (Guo et al., 2022), NE_Global (OTSUKI et al., 2023), TIMES (Gracceva and Zeniewski, 2013), REMIND (Bauer et al., 2012), and WITCH (Carrara, 2020)—have been developed for analyzing long-term energy pathways for climate change mitigation. Several models have over 20–30 years of history, significantly contributing to the Intergovernmental Panel on Climate Change (IPCC, 2000, 2018, 2022). In addition to global assessments, some models have been downscaled to regional and national levels (e.g., GCAM (Binsted et al., 2020; Jeon et al., 2021), MESSAGE (Nogueira et al., 2014; Palatnik et al., 2023), TIMES (Selosse et al., 2013;Zhang and Chen, 2021; Pedinotti-Castelle et al., 2022)). These global, regional, and national assessments quantified the role of technologies in energy transition, including renewables (Bauer et al., 2012; Bogdanov et al., 2019; Daioglou et al., 2019; Guo et al., 2022; Otsuki et al., 2023), nuclear (Carrara, 2020), hydrogen (Akimoto et al., 2021; Ishimoto et al., 2017; Oshiro and Fujimori, 2022), and CCS (Kriegler et al., 2014; Muratori et al., Feb. 2017; Nogueira et al., 2014; Selosse et al., 2013). The CCS studies indicated that CCS is an important option (Muratori et al., 2017; Nogueira et al., 2014) or an influential factor for climate change mitigation costs (Kriegler et al., 2014; Selosse et al., 2013).

Structure and calculation logic vary by model. GCAM, REMIND, and WITCH are general equilibrium models encompassing the whole energy and economy systems, while IMAGE is a partial equilibrium simulation-type model. Other models (listed in the previous paragraph) are energy system optimization models based on linear programming techniques. Optimization models can explicitly describe technical and economic characteristics of energy technologies, such as cost, conversion efficiency, and controllability, which enables the models to conduct detailed technology assessments. These existing models have been continuously improved to reflect the real world better; one of the focuses in recent studies is incorporating the intermittency of VRE to capture the system integration costs (IRENA, 2017b; Ueckerdt et al., 2013). Several studies proposed new approaches, such as soft-linking energy system models and detailed power dispatch models (Deane et al., 2012; Dominković et al., 2020) and improving the time slices of energy system models (e.g., incorporating VRE's stochastic characteristics) (Collins et al., 2017). Other studies developed temporally detailed energy system models (Bogdanov et al., 2019). Our research group has also developed energy system models with an hourly temporal resolution for the world (OTSUKI et al., 2023) and Japan (Otsuki et al., 2023) (note that the Japan model is employed in this study). We believe such models are important for comparing cost competitiveness and synergies among VRE and other technologies (e.g., nuclear and CCS).

2.2. Energy system analysis for Japan

The potential contribution of low-carbon technologies has been assessed in Japan, mostly by technology-rich energy system optimization models. Akimoto et al. (2004) and Akimoto and Takagi (2008) developed an optimization model to investigate the cost-effectiveness of geological CO_2 storage, considering site dependency and economies of scale. These studies were conducted in the 2000s and assumed CO_2 emission reduction pathways are less stringent than the long-term goal of the Paris Agreement; however, CO_2 storage is estimated to be an important option for Japan even under such pathways. In the 2010s, national energy scenarios for realizing a 2°C world or 80 % emission reduction by 2050 were analyzed by Akimoto and Sano (2017), Oshiro et al. (2020), and Sugiyama et al. (2021). These studies employed technology-explicit models (see Table 1 for a list of models) and confirmed that Japan needs to deploy various mitigation strategies effectively, including energy efficiency improvement, end-use electrification, and electricity decarbonization (renewables, nuclear, and CCS). Another key finding was the cost of mitigation. Japan's marginal CO_2 abatement cost was projected to reach several thousand USD per tCO_2 by

Table 1
CCS assumptions in existing energy system analyses for Japan.

	Model	Climate policy	Sensitivity analysis of the CO_2 storage potential	Sensitivity analysis of the CCS cost
Akimoto et al. (2004)	National energy system model with 40 nodes (20 onshore and 20 offshore nodes)	0.5 %/year reduction of energy-related CO_2 from 2000 to 2050	No	No
Akimoto and Takagi (2008)	National energy system model with 102 nodes (47 onshore and 55 offshore nodes)	Per-GDP CO_2 emission in 2050: half and one-third relative to the amount in 2000	Yes. Model's default setting (cumulative CO_2 storage potential of 5.2GtCO_2) and no CCS case.	Yes. Default case setting (future cost reductions are included) and no cost reduction case.
Akimoto and Sano (2017)	DNE21+	80 % CO_2 emission reductions by 2050	Yes. Model's default setting (91 MtCO_2/year in 2050) and high case (182 MtCO_2/year)	No
Oshiro et al. (2020)	AIM/CGE, AIM/Enduse [Japan], COPPE-COFFEE, DNE21+, GEM-E3, IMAGE, POLES, REMIND-MAgPIE	Global 2 °C goal	No. Model's default settings.	No
Sugiyama et al. (2021)	AIM/Enduse-Japan V2.1, AIM/Hub-Japan 2.1, DNE21 Version 1.3, IEEJ Japan ver. 2017, TIMES-Japan 3.1	80 % emission reductions by 2050 in Japan	Yes. The default settings of participating models (median: 50 MtCO_2/year in 2050) and no CCS case.	No
Kato and Kurosawa (2021)	TIMES-Japan	Net-zero CO_2 emissions by 2070	No. Model's default setting (50 MtCO_2/year in 2050 and 200 MtCO_2/year in 2070)	No
Akimoto and Sano (2021)	DNE21+	Net-zero greenhouse gas emissions by 2050	Yes. The default setting (330 MtCO_2/year in 2050) and the high case (550 MtCO_2/year).	No
NIES (2021)	AIM/CGE, AIM/Enduse, Power dispatch model	Net-zero greenhouse gas emissions by 2050	No. Model's default setting (100 MtCO_2/year in 2050)	No
REI (2021)	LUT ESTM	Net-zero energy-related CO_2 by 2050	No. Model's default setting (0 MtCO_2/year)	No
Deloitte Tohmatsu Consulting (2021)	D-TIMES	Net-zero CO_2 emissions by 2050	No. Model's default setting (91 MtCO_2/year).	No
Matsuo et al. (2021)	IEEJ-NE_Japan	Net-zero energy-related CO_2 by 2050	Yes. The default setting (250 MtCO_2/year in 2050) and the high case (500 MtCO_2/year).	No
Otsuki et al. (2022)	NE_Japan	Net-zero energy-related CO_2 by 2050	Yes. The default setting (250 MtCO_2/year) and high case (500 MtCO_2/year)	No

2050 in 80 %-emission-reduction cases, implying economic challenges for realizing a low-carbon society.

Net-zero CO_2 emissions have been the focus of recent studies, especially since the government announced carbon neutrality by 2050. To formulate the latest (sixth) strategic energy plan, the government requested the following five institutes to provide scenarios for net-zero emissions: the Research Institute of Innovative Technology for the Earth (RITE), National Institute for Environmental Studies, Japan (NIES), Renewable Energy Institute (REI), Deloitte Tohmatsu Consulting (Deloitte), and the Institute of Energy Economics, Japan (IEEJ) (Akimoto and Sano, 2021; Deloitte Tohmatsu Consulting, 2021; Matsuo et al., 2021; NIES, 2021; REI, 2021). REI (2021) suggested that a 100 % renewable energy system is more cost-competitive than conventional energy systems. In contrast, various mitigation options (such as renewables, nuclear, and CCS) appeared in the cost-optimized pathways provided by the other four institutes (Akimoto and Sano, 2021; Deloitte Tohmatsu Consulting, 2021; Matsuo et al., 2021; NIES, 2021). As for the economics of a 100 % renewable-based power supply, RITE, Deloitte, and IEEJ reported that the marginal cost of electricity is more than double that of the cost-optimized scenario owing to grid flexibility costs and spatial limitations of variable renewables. The economic challenges of a 100 % renewable-based power supply were also confirmed by Otsuki et al. (2022) and Otsuki et al. (2023).

Another highlight of the five institutes' analyses was the role of negative emission technologies (NETs). RITE (Akimoto and Sano, 2021), NIES (NIES, 2021), and IEEJ (Matsuo et al., 2021) found that the large-scale deployment of DACCS and bioenergy with CCS offset residual emissions from the end-use sectors cost-effectively. This is consistent with the findings of Kato and Kurosawa (2021), which regarded NETs as essential for achieving the net-zero vision of Japan's long-term strategy.

These studies have revealed how energy strategies (such as cost-effective or renewable-focused strategies) impact Japan's long-term system. Yet, in-depth analyses of technological uncertainties, including CCS's potential and costs, are missing. Among the twelve existing studies listed in Table 1, six conducted sensitivity analyses of CCS potential (Akimoto and Sano, 2017, 2021; (Akimoto and Takagi, 2008); Matsuo et al., 2021; Otsuki et al., 2022; Sugiyama et al., 2021), but the granularity of their sensitivity cases was relatively simple, limited to "no" or "high" CCS cases. No studies have investigated Japan's cost-effective energy systems with different CO_2 storage levels in detail. Regarding the economics of CCS technologies, one study (Akimoto and Takagi, 2008) analyzed a "no future cost reduction" case, although net-zero CO_2 emission policies are not considered. The existing papers would be insufficient for understanding how the uncertainty of CCS affects Japan's energy system with net zero CO_2 emissions. Therefore, this study aims to fill these gaps and answer the following research questions.

- How sensitive are Japan's net-zero energy systems and mitigation costs to CCS potential?
- If the storage potential is relatively limited, which sector should use CCS, and what energy sources should other sectors use?
- What if the commercialization of CO_2 storage accelerated? Which decarbonization technology is displaced by CCS at which level of CCS implementation?
- Are CCS technologies economically viable even if their costs are higher than expected?

3. Method

This study employs the energy system model NE_Japan (NE: New Earth) developed by Otsuki et al. (2022). This linear programming model calculates a cost-effective energy system by minimizing the discounted total system cost from 2015 to 2080 (see supplementary material for key equations). NE_Japan calculates energy balances in seven representative years: 2015, 2020, 2030, 2040, 2050, 2065, and 2080. Japan is geographically divided into five regions (Hokkaido, Tohoku, Tokyo, West Japan, and Kyusyu) to reflect the regionality—such as local resource endowments and final demand—and to broadly consider the topology of power grids (Fig. 1). Various physical and technical constraints, including energy balances, controllability of power generation technologies, and spatial conditions for renewable energy, are incorporated. Electricity balances are modeled hourly, 8760 h/year, to reflect the intermittency of variable renewable energy (VRE) and system integration costs.

3.1. Modeled energy system and technologies

Fig. 2 illustrates the modeled energy system, comprising primary and secondary energies, energy service demand, energy-related CO_2, and about 400 technologies. This bottom-up model explicitly considers the techno-economic parameters of energy technologies, such as capital costs, capacity factors, and conversion efficiencies. The final demand is described by 37 types of energy services in the industry, transport, and building sectors (see the end-use sector category in Fig. 2). End-use technology choices, including electrification levels, are endogenous. Modeled CO_2 capture technologies include (1) pre-combustion capture at integrated coal gasification combined cycle (IGCC) power plants, coal gasification plants, and methane reforming plants; (2) post-combustion capture in coal-fired power plants, gas steam turbine power plants, gas combined cycle power plants, biomass-fired power plants, blast furnaces, cement kilns, and chemical plants; and (3) direct air capture (DAC) plants. Captured CO_2 can be geologically stored or utilized for synthetic fuels, such as synthetic methane and Fischer–Tropsch (FT) liquid fuels. Transboundary CCS is not considered in this analysis.

Other mitigation options in this model include energy efficiency, renewables, nuclear power, and imported net-zero emission fuels. VRE is modeled by six technology categories: ground-mounted, rooftop, and wall-mounted solar photovoltaics (PV); onshore wind turbines; fixed-bottom offshore wind turbines; and floating offshore wind turbines. Various integration measures—ramping operation of thermal power plants, curtailment, energy storage (pumped hydro systems, sodium–sulfur (NaS) batteries, Li-ion batteries, redox flow batteries, compressed hydrogen storage tanks), inter-regional power grid enhancement, and demand response (flexible operations of electric heat pumps in buildings and flexible charging and "vehicle to grid" of electric vehicles (EVs) and plug-in hybrid vehicles (PHEVs))—are considered for accommodating these VRE technologies. Net-zero emission fuels (hydrogen, ammonia, synthetic methane, and FT liquid fuels) can be imported if they are economically competitive. The capacity and operation of the modeled technologies, including CCS, were determined based on system optimization.

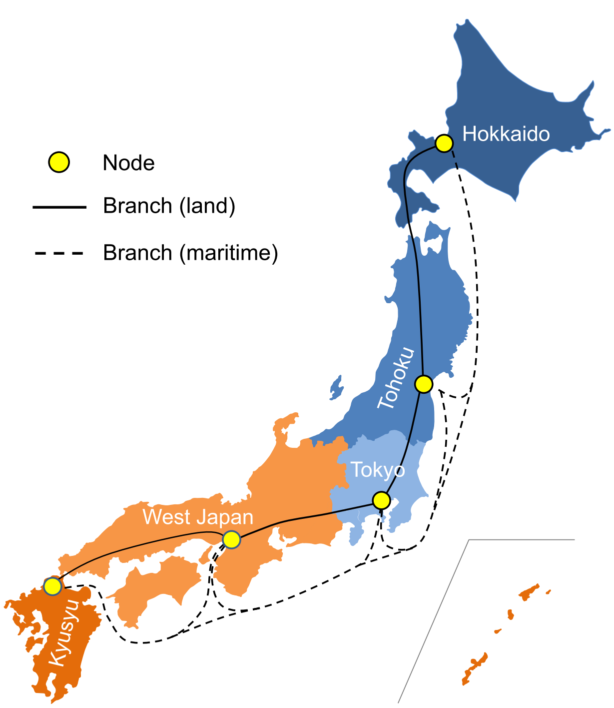

Fig. 1. Regional division of the model.

The computational costs may be of interest to energy modelers. The number of variables and constraints in the model are 68 million and 78 million, respectively. The calculations for one case require approximately 12 h using a dual-processor server with Intel Xeon Platinum 8362. The barrier method of solver Xpress is employed to solve the linear programming problem. The memory consumption during the calculation is approximately 110 GB.

3.2. Assumptions for CO_2 capture, utilization, and storage

The model requires many assumptions, including socioeconomic indicators, energy service demand, domestic primary energy resources, energy import prices, geological CO_2 storage potential, and techno-economic parameters (such as cost and efficiency) of energy conversion processes. Most assumptions were made for all nodes in each representative year. The data were obtained from various referenced sources (Cabinet Secretariat, 2021; Calculation Committee for Procurement Price, 2021;; Cole et al., 2021; Kawakami, 2021; ; IEA, 2022c; IRENA, 2017aKomiyama et al., 2015 MOE 2019; MOF, 2022; NEDO 2016; Obane et al., 2020, 2021; OCCTO, 2022; Power Generation Cost Verification Working Group, 2021), as explained in the supplementary material. Due to space constraints, this subsection describes the assumptions for CO_2 capture, utilization, and storage. All costs are in JPY (2019).

This model allows the endogenous installation of three CO_2 capture technologies: (1) pre-combustion capture at IGCC and hydrogen production plants (coal gasification and methane reforming), 2) post-combustion in blast furnaces, cement kilns, chemical plants, and other power plants (coal-fired, gas steam turbine, gas combined cycle, and biomass-fired), and (3) DAC. The techno-economic assumptions for these technologies for 2050 are summarized in Table 2. The assumed pre-combustion capture is physical absorption based on the Selexol process (Im et al., 2015), and the post-combustion capture is chemical absorption using aqueous amines. The cost and efficiency were obtained from a techno-economic analysis by the Japan Science and Technology Agency (JST, 2016). We also referred to Japan's technology roadmap (the target by 2030) (METI, 2021b) regarding the heat requirement for regenerating CO_2 in chemical absorption. CO_2 capture technologies in new power, industrial, and hydrogen production plants, and retrofitting them to existing plants, are modeled. Assumptions for the DAC were obtained primarily from long-term projections (Fasihi et al., 2019).

Assumptions regarding CO_2 utilization technologies, including methane and FT liquid fuel synthesis, are listed in Table 3. The cost and efficiency of fuel synthesis were obtained from long-term projections (IEA, 2019; NEDO, 2019). Hydrogen for fuel synthesis can be produced by water electrolysis (IEA, 2019) if it is economically competitive (see Table 3 for assumptions).

As for geological CO_2 storage, this model constrains cumulative and annual storage levels (see Eqs. S.8 and S.9 in the supplementary material). Cumulative CO_2 storage potential is described by five grades reflecting the quality of storage sites, such as geological conditions (e.g., shallow or deep), as shown in Table 4 (NEDO, 2003; Sharma et al., 2012). It should be noted that the assumed cumulative storage potential (total 9 $GtCO_2$) is much lower than the figure indicated in the Introduction (240 $GtCO_2$ based on preliminary assessments (METI, 2023)), as the references (NEDO, 2003; Sharma et al., 2012) assume that a part of

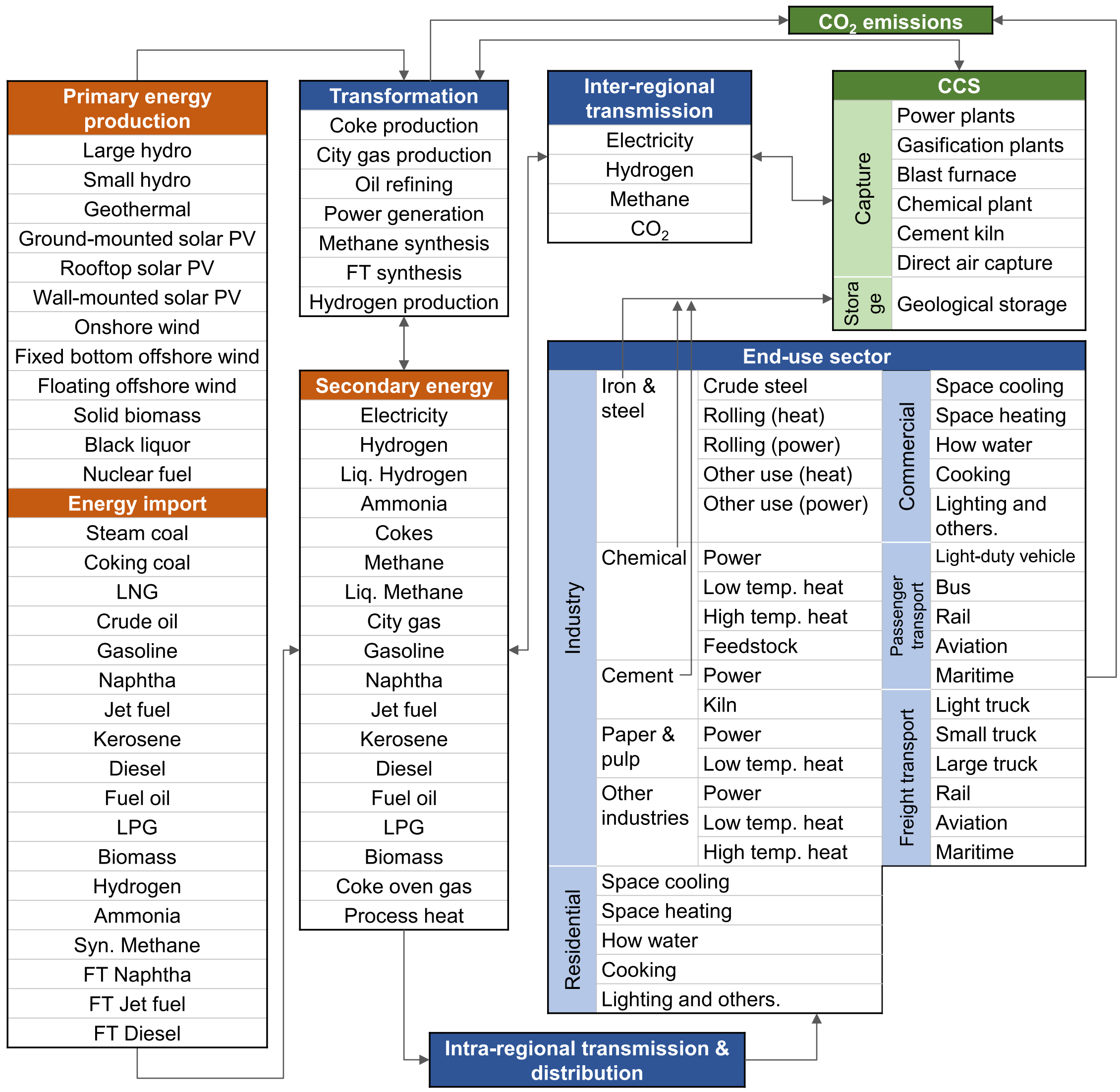

Fig. 2. Modeled energy system. FT: Fischer–Tropsch; PV: photovoltaic; LNG: liquefied natural gas; LPG: liquefied petroleum gas; liq.: liquid; syn.: synthetic; temp.: temperature.

Table 2
Techno-economic assumptions for CO_2 capture technologies for 2050 in Japan.

	Pre-combustion capture for IGCC and hydrogen production plants	Post-combustion capture for power plants (except IGCC), blast furnaces, chemical plants, and cement kilns	Direct air capture
Capital cost [JPY/(tCO_2/year)]	6862	6257	18500
Electricity consumption [kWh/tCO_2]	133	64	1316
Heat consumption [toe/tCO_2]	0.008 (about 0.3GJ/tCO_2)	0.035 (about 1.5GJ/tCO_2)	–
Aqueous amines cost [JPY/tCO_2]	–	400	–
Lifetime [year]	40	40	40
Annual O&M cost rate	3.0 %	3.0 %	3.7 %
CO_2 capture efficiency	90 %	90 %	–

storage reservoir can be practically utilized. Unit storage costs are assumed to increase with the cumulative amount of CO_2 storage. Storage costs consist of capital and fixed O&M costs for CO_2 compression, liquefaction, transportation to offshore storage sites, and injection. The electricity consumption in Table 4 is for compressing and liquefying CO_2. We referred to JST (2016) for CO_2 compression and liquefaction costs and Akimoto and Sano (2021) and NEDO (2003) for transportation and injection costs. The assumptions for the annual CO_2 storage potential ($CCSAP_y$ in the Eq. S.9) are presented in Section 3.3.

3.3. Case settings

To investigate the role of CO_2 storage and its impact on deploying other energy technologies, the authors simulated 10 cases based on the

Table 3
Techno-economic assumptions for fuel synthesis and water electrolysis for 2050 in Japan.

	Methane synthesis	FT liquid fuel synthesis	Water electrolyzer
Capital cost	56500 JPY/kW_{prod}	56500 JPY/kW_{prod}	45000 JPY/kW_e
Efficiency in lower heating value (LHV)	81 %	72 %	74 %
Lifetime [year]	40	40	15
Annual O&M cost rate	4 %	4 %	1.5 %

Table 4
Techno-economic assumptions for CO_2 storage in Japan.

	CO_2 storage				
	Grade1	Grade2	Grade3	Grade4	Grade5
Cumulative CO_2 storage potential (Japan total) [$MtCO_2$]	466	927	6489	927	466
CO_2 storage cost (excluding costs for compressor) [JPY/tCO_2]	774	2055	3337	4618	5899
Capital costs of CO_2 compressor [JPY/(tCO_2/year)]	1677	1677	1677	1677	1677
Electricity consumption for compression [kWh/tCO_2]	76	76	76	76	76

upper bounds for annual CO_2 storage: *10, 30, 50, 100, 150, 200, 250, 300, 400*, and *500 Mt* cases. For example, the *30 Mt* case assumes an upper bound of 30 $MtCO_2$ in 2050 ($CCSAP_4 = 30$ $MtCO_2$/year in Eq. S.9). In all cases, no CO_2 storage is assumed until 2030, and the upper bound for 2040 is one-third of the 2050 level (e.g., $CCSAP_3 = 10$ $MtCO_2$ /year in the *30 Mt* case). The upper bounds for 2065 and 2080 are the same as for 2050. The deployment of CCS is cost-optimized based on these annual and cumulative storage limits (Table 4). The other assumptions were the same in all cases. Energy-related CO_2 emissions are assumed to be net-zero by 2050. The capacity and operation of supply-side and end-use technologies are cost-optimized under the given constraints. As this study employs an optimization model, the results in Section 4 present a "best-case" outcome under each annual CO_2 storage potential.

4. Results and discussions

This section describes the salient characteristics of the simulation results, including the impacts of CO_2 storage on energy mix and costs. To test the robustness of the key findings, Section 4.5 performs an additional analysis of CCS cost. Note that this section focuses on the snapshot for 2050; results from 2030 to 2050 in selected cases are available in the supplementary material.

4.1. Recovered CO_2 balance: capture, utilization, and storage

Fig. 3 displays Japan's annual CO_2 balance for each simulation case. Captured CO_2 is expressed positively, whereas utilized or stored CO_2 is in negative values.

Our results suggest that CO_2 storage is a cost-effective option for a net-zero energy system in Japan. Annual CO_2 storage in the *10–400 Mt* cases reaches the upper bounds; for example, annual storage in 2050 is estimated to be 400 $MtCO_2$/year in the *400 Mt* case. Fig. 3 also indicates that the annual CO_2 storage saturates after the *400 Mt* case. This is because of the cumulative CO_2 storage constraints, as confirmed in section S.2 in the supplementary material. As for CO_2 capture, biomass for power generation appears to be a cost-effective CO_2 source in lower annual storage cases, such as the *10–50 Mt* cases, producing negative emissions. However, it saturated after the *100 Mt* case due to the upper bound for biomass supply (see section S.1); instead of biomass, CO_2 captured at gas combined cycle power plants and DAC plants grew from the *100 Mt* case, holding the majority share of CO_2 capture in higher annual storage cases. These CO_2 capture technologies would be necessary for Japan to reduce CO_2 emissions cost-effectively.

Contrary to CCS, CO_2 utilization (such as methane and FT liquid fuel synthesis) appeared marginal in all cases, implying economic challenges for domestic synthetic fuel production. This is because of hydrogen costs (or electricity costs for water electrolyzers) that predominantly affect the economics of synthetic fuels (Gorre et al., 2019; Otsuki and Shibata, 2020). In this study, Japan's average marginal power generation cost for 2050 ranges from 14 to 16 JPY/kWh (the lowest is the *150 Mt* case, and the highest is the *10 Mt* case). This would make water electrolysis less economically attractive; for example, the electricity costs amount to

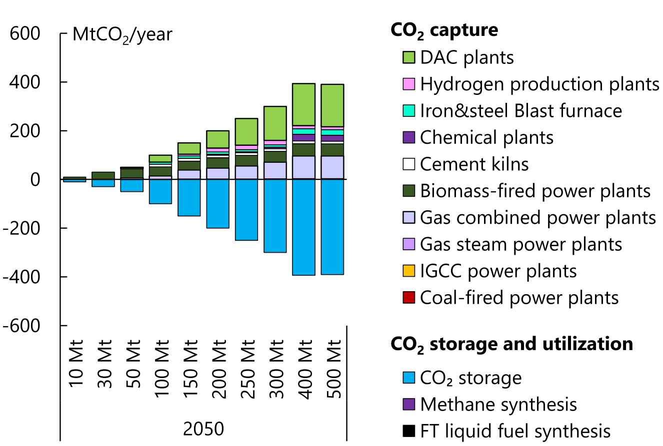

Fig. 3. Recovered CO_2 balances for 2050, Japan.
Note: DAC = Direct air capture, IGCC = Integrated coal gasification combined cycle, FT = Fischer Tropsch.

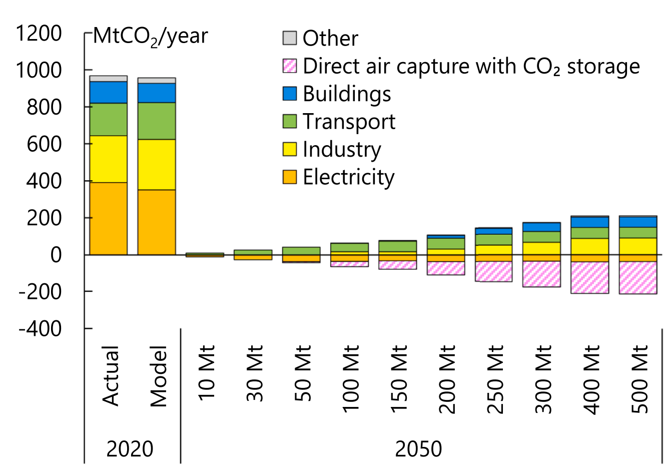

Fig. 4. Sectoral CO_2 emissions in Japan. *Other* includes the energy transformation sector, except for power generation.

58–64 JPY per Nm^3-H_2 (6.5–7.1 USD/tH_2) based on the efficiency in Table 3, insufficient to produce synthetic fuels at competitive prices (the assumed exchange rate is 100 JPY = 1 USD for discussion). Yet, it should be noted that imported synthetic fuels can be effective in some cases instead of domestic production, as discussed later in Section 4.3.2.

4.2. Sectoral CO_2 emission reductions

Fig. 4 illustrates the sectoral energy-related CO_2 emissions in 2020 and 2050. For model validation, the figure shows the actual values (NIES, 2023) and model results for the emissions in 2020; the model results for 2020 are broadly consistent with the actual values. This figure implies the following two points.

First, emissions from the electricity sector must be reduced significantly in all cases, reaching negative emissions by 2050. This is in line with global-level assessments (IPCC, 2022), which highlighted that the electricity sector needs to be decarbonized first and most. CO_2 storage potential has relatively modest impacts on electricity CO_2 emissions, although the penetration of CCS-equipped power plants and optimal power generation mix changed drastically (see Fig. 3 and Section 4.3.1).

Second, the CO_2 storage potential impacts the cost-effective mitigation strategy for end-use sectors, including industry, transport, and buildings. With limited CO_2 storage potential, end-use sectors are deeply decarbonized. For example, in the *10 Mt* case, the total CO_2 emissions from the three sectors are reduced by 98 % from 2020 to 2050 by combining efficiency, electrification, and net-zero emission fuels (such as imported synthetic methane and FT liquid fuels). In contrast, end-use CO_2 emissions need not be reduced to such levels in higher annual storage cases. In the *400–500 Mt* cases, even for 2050, the CO_2 emissions from the end-use sectors remain above 200 MtCO_2/year, about a 60 % reduction from that in 2020. The end-use sectors partly use conventional technologies and fossil fuels, such as internal combustion engines for road transport and natural gas-based city gas for heating in industrial processes and buildings. DACCS and BECCS offset these emissions. These results indicate that CO_2 storage is a versatile technology contributing to the entire energy system, including end-use sectors, by providing negative emission credits. Offsetting emissions can be more cost-effective for end-use sectors than replacing existing technologies and infrastructure with decarbonization technologies; the future of end-use decarbonization would be affected by CO_2 storage availability.

4.3. Energy technology choice

4.3.1. Power generation

Fig. 5 shows the power generation in Japan in 2020 (IEA, 2022b) and 2050 for each case. Power plants with CO_2 capture are estimated to be limited in lower annual storage cases (such as the *10–50 Mt* cases); other low-carbon technologies, including renewables and net-zero emission fuels (such as hydrogen, ammonia, and synthetic methane), become crucial for decarbonizing the power supply. For example, in the *10 Mt* case, renewables account for 73 %, and hydrogen-fired, ammonia-fired, and synthetic methane-based city gas cogeneration systems (CGS) together for 13 % of the power generation. It should be noted that these net-zero emission fuels are imported in all cases in this study. Renewables and imported net-zero emission fuels would play an important role in generating electricity in Japan if the annual CO_2 storage potential is limited by 2050.

In higher storage cases, the cost-optimal shares of biomass- and gas-fired (mostly gas combined cycle) with CO_2 capture increased, contributing to 15 % of power generation in the *200 Mt* case. Their aggregated share further increased to about 20 % in the *300 Mt* case. All the captured CO_2 is geologically stored (Fig. 3), implying that CCS is a cost-effective technology for Japan's electricity supply if a large CO_2 storage potential is available. CCS-equipped gas combined cycle partially displaced city gas CGS, hydrogen-fired, and some renewables (such as floating offshore wind). These technologies are economically competitive with CCS-equipped power plants; future CCS implementation would affect their installation. Here, the following two points should be highlighted to understand the results. First, the model is not able to consider energy security perspectives. Gas with CCS grew driven by cost; geopolitical considerations are not included in this assessment. Therefore, future work should test these results from a security perspective. The second point is about the total electricity generation, which increased from the *50* to *300 Mt* cases. In this model, the level of electricity consumption is endogenous based on the technology choice in the end-use and energy transformation sectors, and the increase in power generation is mainly due to the electricity inputs for the DAC plants.

Compared with the policy direction, the *250–500 Mt* cases broadly align with the reference power generation mix for 2050 published by the government (ANRE, 2021) (Table 5). Such CO_2 storage sites need to be developed to realize the government's reference mix, although this can be challenging. For example, injecting 250–500 MtCO_2/year is approximately 2500–5000 times larger than the Tomakomai CCS demonstration project, the first full-chain CCS demonstration in Japan (injecting about 0.1 MtCO_2/year). The number of storage sites would reach 500–1000 by 2050, assuming an injection capacity of 0.5 MtCO_2/year per site. As planned in the government's CCS roadmap (METI, 2023), policy support for the CCS business is critical for accelerating the deployment of CCS and realizing the power generation mix.

From the power system operation perspective, CCS-equipped power plants contribute to reducing CO_2 emissions and integrating variable

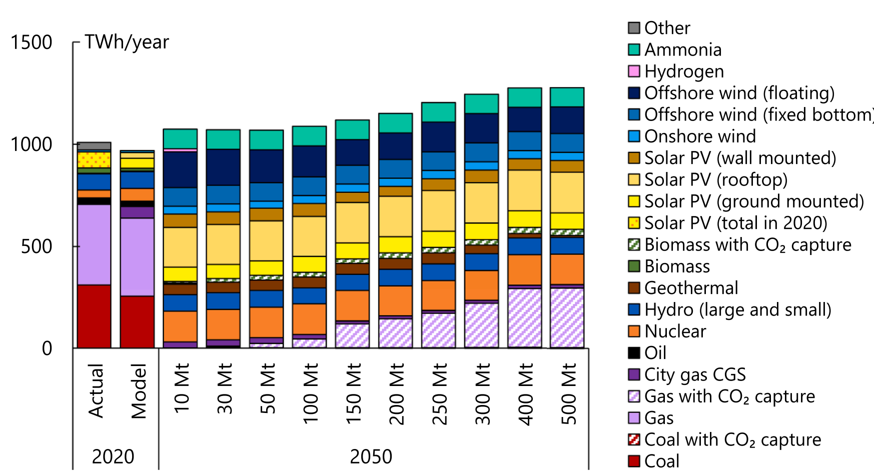

Fig. 5. Power generation in Japan. *CGS* indicates cogeneration systems. *Gas* in the actual values in 2020 includes city gas CGS.

Table 5
Comparing the Japanese government's reference power generation mix for 2050. CCUS represents CO_2 capture, utilization, and storage.

	Government's reference mix (ANRE, 2021)	*100 Mt* case	*150 Mt* case	*200 Mt* case	*250 Mt* case	*300 Mt* case	*400 Mt* case	*500 Mt* case
Renewables	About 50–60 %	71 %	66 %	65 %	64 %	62 %	57 %	56 %
Hydrogen and ammonia	About 10 %	11 %	10 %	9 %	8 %	8 %	7 %	7 %
Fossil fuels with CCUS and nuclear	About 30–40 %	18 %	24 %	26 %	27 %	31 %	36 %	36 %

Note: The total may not be 100 % in several cases due to rounding. Hydrogen and ammonia include hydrogen-fired, ammonia-fired, and synthetic methane-based city gas CGS.

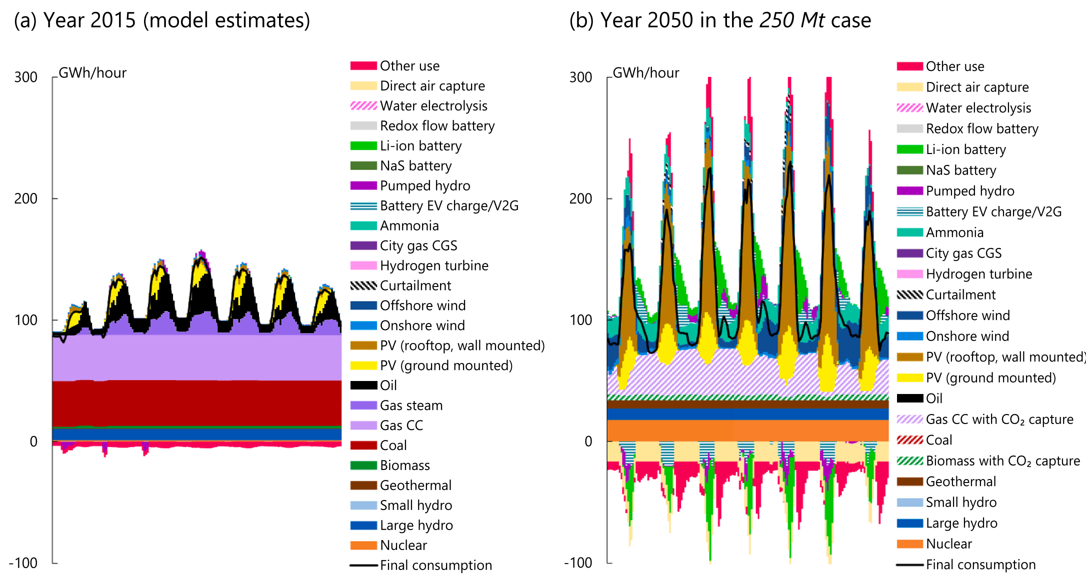

Fig. 6. Hourly power supply and demand balances in a week of May for Japan. Gas CC: gas combined cycle; CGS: Cogeneration system; V2G: vehicle-to-grid.

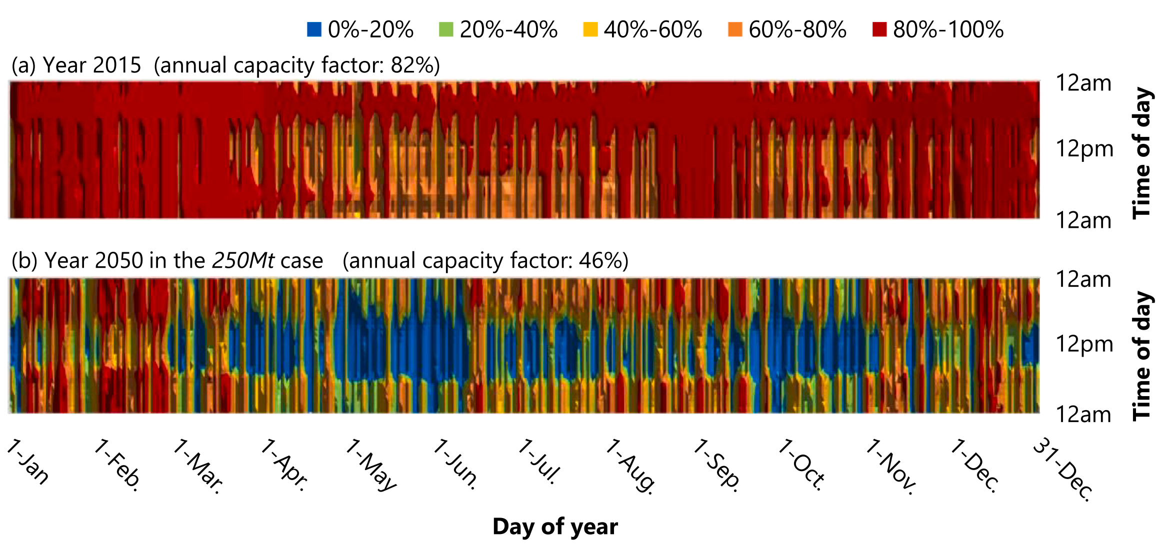

Fig. 7. Hourly capacity factor of gas combined cycle in Japan. All gas combined cycle power plants in Fig. 7a and Fig. 7b are without and with CCS, respectively.

renewables. Fig. 6 displays the hourly power generation in a week in May, and Fig. 7 shows the hourly capacity factor of gas combined cycle power plants in Japan. Due to space constraints, these figures focus on the results in 2015 and 2050 for the *250 Mt* case—which is close to the government's reference power generation mix. These figures indicate that the role of gas combined cycle changed from 2015 to 2050. It satisfies the base- and middle-load in 2015, with an annual capacity factor of 82 % (Figs. 6a and 7a). In contrast, a quick ramping operation of CCS-equipped gas combined cycle becomes necessary in 2050, from a system-wide perspective to integrate the solar PV. As illustrated in Fig. 6b, gas combined cycle with CCS manages the daily variability of solar PV by absorbing its output increase during the daytime and covering the output decrease during the nighttime. This technology also contributes to managing solar PV's longer-term variability, such as seasonality. Fig. 7b indicates that gas combined cycle with CCS reduced its output (less than 40 % of the capacity) for several weeks or almost the entire

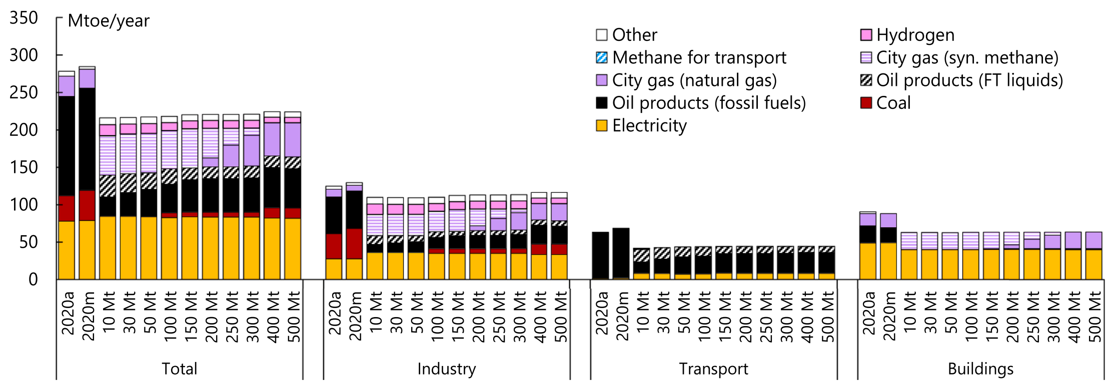

Fig. 8. Final energy consumption in 2020 and for 2050 in Japan. *2020a* and *2020m* indicate actual values and model results for 2020, respectively.

months of April, May, and late September, when solar PV output increases but electricity demand is moderate; while it maintains high capacity factors during winter (from December to February) to supplement low solar PV output. The estimated annual capacity factor of 46 % is much lower than in 2015. Several studies have highlighted the role of CCS-equipped power plants as flexible resources (Mac Dowell and Staffell, 2016; Mechleri et al., 2017; Rúa et al., 2020; Schnellmann et al., 2019); our case study for Japan supports these findings.

4.3.2. End-use sectors

Fig. 8 displays the sectoral final energy consumption in 2020 and 2050. Efficiency and electrification appeared cost-effective in realizing a net-zero energy system, regardless of CO_2 storage potential. The total final energy consumption declined by 20–22 % from 2020 (actual values) to 2050, owing to high-efficient electrified equipment in the transport and building sectors. Electricity becomes the largest final energy source in all cases, with its share growing from 28 % in 2020 to 37–39 % by 2050; this increment is driven by, for example, the newly installed electric arc furnaces for steelmaking, battery electric vehicles for road transport, and electric heat pump systems for water heating in buildings.

Fig. 8 also indicates that CO_2 storage potential affects the optimal penetration of alternative energy sources in each end-use sector. In industries and buildings, synthetic methane-based city gas becomes cost-effective to decarbonize heat in limited annual storage cases (like the *10 Mt* case). In contrast, natural gas-based city gas remains even in 2050 in higher storage cases because of the negative emissions created by BECCS and DACCS. Similarly, fossil fuel-based oil products appear more cost-effective than electricity and synthetic liquid fuels in the road transport sector; for example, battery electric passenger light-duty vehicles are important mitigation options in lower storage cases, whereas their optimal stocks decrease with accelerated CCS deployment (Fig. 9). Combining conventional fossil fuel technologies with NETs can be a cost-competitive option in some cases. In Japan, city gas and oil-related industries put efforts into synthetic fuels, and automobile industries into battery electric vehicles; our results suggest that NETs can be alternatives for these industries if CCS is commercialized.

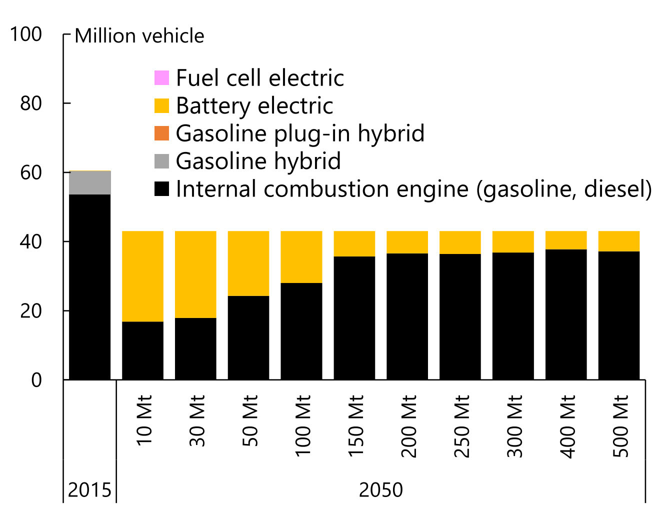

Fig. 9. Vehicle stock of passenger light-duty vehicles in Japan.

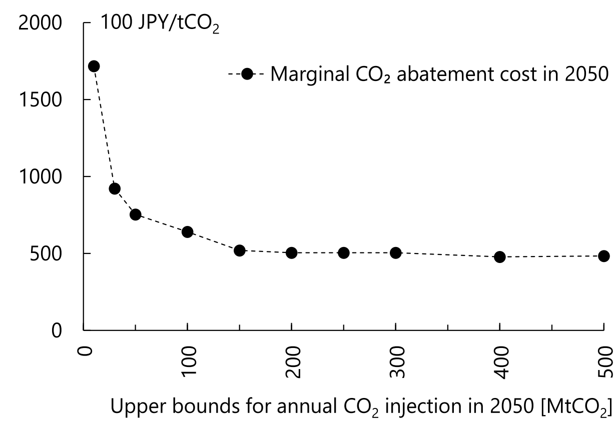

Fig. 10. Marginal CO_2 abatement cost in Japan for 2050.

4.4. Mitigation costs

Fig. 10 shows Japan's marginal CO_2 abatement cost (MAC) for 2050. MAC represents the mitigation cost at the margin, the cost of reducing one additional unit of CO_2 emissions, or the carbon price needed to achieve a net-zero energy system.

CCS is critical for curbing the MAC of Japan's net-zero energy system. For example, MAC reached 171700 JPY/tCO_2 (1717 USD/tCO_2) in the *10 Mt* case, sharply decreased to 75400 JPY/tCO_2 (754 USD/tCO_2) in the *50 Mt* case, and further declined to about 50400 JPY/tCO_2 (504 USD/tCO_2) in the *200 Mt* case. The lowered MAC in the latter cases would be driven by negative emission technologies, allowing end-use sectors to use conventional low-cost technologies, even in a carbon-neutral society. In addition, CCS-equipped power plants, including retrofitted plants, can save additional investment in other power plants, such as hydrogen-fired and offshore wind (Fig. 5). MAC is particularly sensitive around *10–50 Mt* cases; a CO_2 storage potential above these levels would be necessary to increase the economic viability of carbon neutrality in Japan.

MAC in this study is relatively low compared to existing assessments, focusing on 80 % emission reductions (several thousand USD/tCO_2)

Table 6
CCS cost assumptions in 2050 for sensitivity cases.

	CO_2 storage	Pre- and post-combustion CO_2 capture	DAC
Base	The same assumptions as Table 2 and Table 4 (Capital cost for DAC: 18500 JPY/(tCO_2/year), electricity consumption for DAC: 1316 kWh/tCO_2)		
Mid	Capital costs, electricity consumption, heat consumption, and aqueous amine costs: 1.5 times that in Table 2 and Table 4		Average of the Base and High cases
High	Capital costs, electricity consumption, heat consumption, and aqueous amine costs: doubled from the level in Table 2 and Table 4		Based on the level in 2020 (Fasihi et al., Jul. 2019) (capital cost: 67917 JPY/(tCO_2/year), electricity consumption: 1535 kWh/tCO_2)

(Akimoto and Sano, 2017; Sugiyama et al., 2021). This is due to the assumptions for technological developments and cost reductions of mitigation options; in particular, existing studies have not considered new and innovative technologies such as DACCS.

4.5. Additional analysis of CCS costs

As summarized in Section 1, the future CCS costs are significantly uncertain in Japan. Detailed site-by-site assessments of CO_2 storage are underway, and some capture technologies are in the demonstration or prototype stage (such as DAC (IEA, 2022a)). This subsection performs an additional analysis of CCS costs to test the robustness of the results in the previous subsections. The authors assumed three CCS costs (*Base, Mid*, and *High*) in the *10, 150*, and *300 Mt* cases (Table 6). The *Base* assumes the same cost as the previous subsections, while the *Mid* and *High* assume higher CCS costs.

Fig. 11 shows the key results for 2050 in the additional cases. Assumed CCS costs have partly impacted sectoral CO_2 emissions and energy mix. The incremental costs lowered the competitiveness of DACCS in the *150 Mt* and *300 Mt* cases (Fig. 11a). The modest negative emissions encouraged net-zero emission fuels, particularly synthetic methane-based city gas (Fig. 11b, c).

However, it should be noted that these results still suggest the importance of CCS in Japan's net-zero CO_2 energy systems. Even under the *High* condition, annual CO_2 storage reached the upper bound in the *150 Mt* cases or a very large amount (250 $MtCO_2$/year) in the *300 Mt* case (Fig. 11a). Instead of DACCS, the CO_2 storage potential is used for biomass-fired power generation, industrial sectors, and hydrogen production (methane reforming) for steel making. Fig. 11b indicates that offsetting end-use CO_2 emissions by NETs partly remains cost-competitive even under the *High* condition. Contrary to NETs and end-use sectors, the power generation mix is less sensitive to CCS costs (Fig. 11d). Gas combined cycle with CO_2 capture still largely contributed to a low-carbon electricity supply under the *Mid* and *High* conditions in the *150* and *300 Mt* cases (Fig. 11d). The total electricity generation declines from the *Base* to *Mid* and *High* conditions in the *300 Mt* case, as the modest deployment of DACCS reduced electricity demand. Finally, from the economic viewpoint, CCS is critical to reducing CO_2 emissions effectively, regardless of the CCS costs (Fig. 11e).

5. Conclusions

Japan's sixth Strategic Energy Plan mentions that CCS is one of the important options to achieve the carbon neutrality target by 2050. However, it faces significant uncertainties regarding storage potential and costs, and there have been no in-depth assessments of their impacts on Japan's long-term energy system. Therefore, this study performed a sensitivity analysis of CCS using an energy system optimization model for Japan (NE_Japan model). This model calculates a cost-effective energy mix under various physical, technical, and political constraints (such as the CO_2 emission reduction target). The NE_Japan encompasses the entire energy system, including end-use sectors, in a bottom-up fashion. To investigate the role of CCS and its impacts on deploying other technologies in net-zero CO_2 energy systems, we analyzed ten cases with varying CO_2 storage potential. The following two points are the highlights of this study.

First, CO_2 storage is a versatile technology that contributes to the entire energy system—not only to the sectors where CO_2 capture technologies can be deployed (such as the electricity and industry sector) but also to other sectors (such as the rest of end-use sectors) by providing negative emission credits. In the electricity sector, biomass and natural gas-fired power generation with CCS are prospective options. If a large CO_2 storage potential is available, direct air capture with CO_2 storage can also be cost-effective for Japan, offsetting CO_2 emissions in the end-use sectors. The government and several energy companies in Japan seek to import net-zero emission fuels, such as hydrogen, ammonia, and synthetic fuels, to decarbonize the electricity and end-use sectors. Our results imply that these fuels economically compete with CCS, including NETs; future CCS implementation would impact the cost-optimal share of net-zero emission fuels. The relevant organizations should recognize that accelerated CCS deployment can hinder the growth of net-zero emission fuel businesses. Incorporating CCS and NETs in their energy portfolio would contribute to managing the business risk.

Second, CCS is crucial to improve the economic viability of net-zero-energy systems. MAC in 2050 can be significantly curbed with CCS, e.g., from 171700 JPY/tCO_2 (1717 USD/tCO_2) in the *10 Mt* case to 50400 JPY/tCO_2 (504 USD/tCO_2) in the *200 Mt* case. MAC is estimated to be particularly sensitive around the *10–50 Mt* cases; an annual CO_2 storage capacity above 50 $MtCO_2$/year should be developed by 2050 to reduce social costs and increase the feasibility of net-zero CO_2 emissions. Our assessments implied that an annual CO_2 storage level of 250 $MtCO_2$/year or above would be necessary to realize the government's reference power generation mix for 2050 (see Table 5). However, developing storage sites with such capacities would be challenging. For example, the number of storage sites reaches above 500, assuming a storage capacity of 0.5 $MtCO_2$/year per site; on average, more than 25 sites (total capacity of 12.5 $MtCO_2$/year) need to be newly added annually by 2050 if CCS is commercialized in 2030. Accelerating CCS implementation is a prerequisite for realizing the figures. Policy support is critical for overcoming technical and institutional barriers, as planned in the government's CCS roadmap (METI, 2023).

An additional analysis of CCS costs tested the robustness of the key findings; CCS was confirmed as economically attractive even if CCS costs remain high. Uncertainties exist regarding CCS costs in Japan as detailed site-based economic assessments are underway, and some CO_2 capture technologies are still at the demonstration stage. However, this analysis implies that a moderate increase in CCS costs does not undermine the role of CO_2 storage in Japan's energy system. Here, it should be noted that other decarbonization technologies, including renewables, nuclear, and net-zero emission fuels, also face various uncertainties in Japan. For example, some VRE projects have raised environmental and social concerns, such as deforestation and adverse impacts on the local ecosystem and landscape. Nuclear power faces public acceptance issues and new strict safety regulations after the severe accident in Fukushima. Hydrogen-related technologies, such as hydrogen-fired and ammonia-fired power plants, are still in the research and development stage. International CO_2 accounting guidelines for imported synthetic methane and FT liquid fuels have not been developed. CCS may play a more critical role in the future if social, technological, and institutional factors hamper the deployment of these other technologies.

Existing global and European studies (Kriegler et al., 2014; Selosse et al., 2013) indicated the importance of negative emissions technologies—such as biomass-fired power generation with CCS. Our analysis also confirms this argument; CCS is utilized primarily for biomass-fired power plants and then for direct air capture. On the other hand, the role of fossil fuel power plants with CCS varies by study.

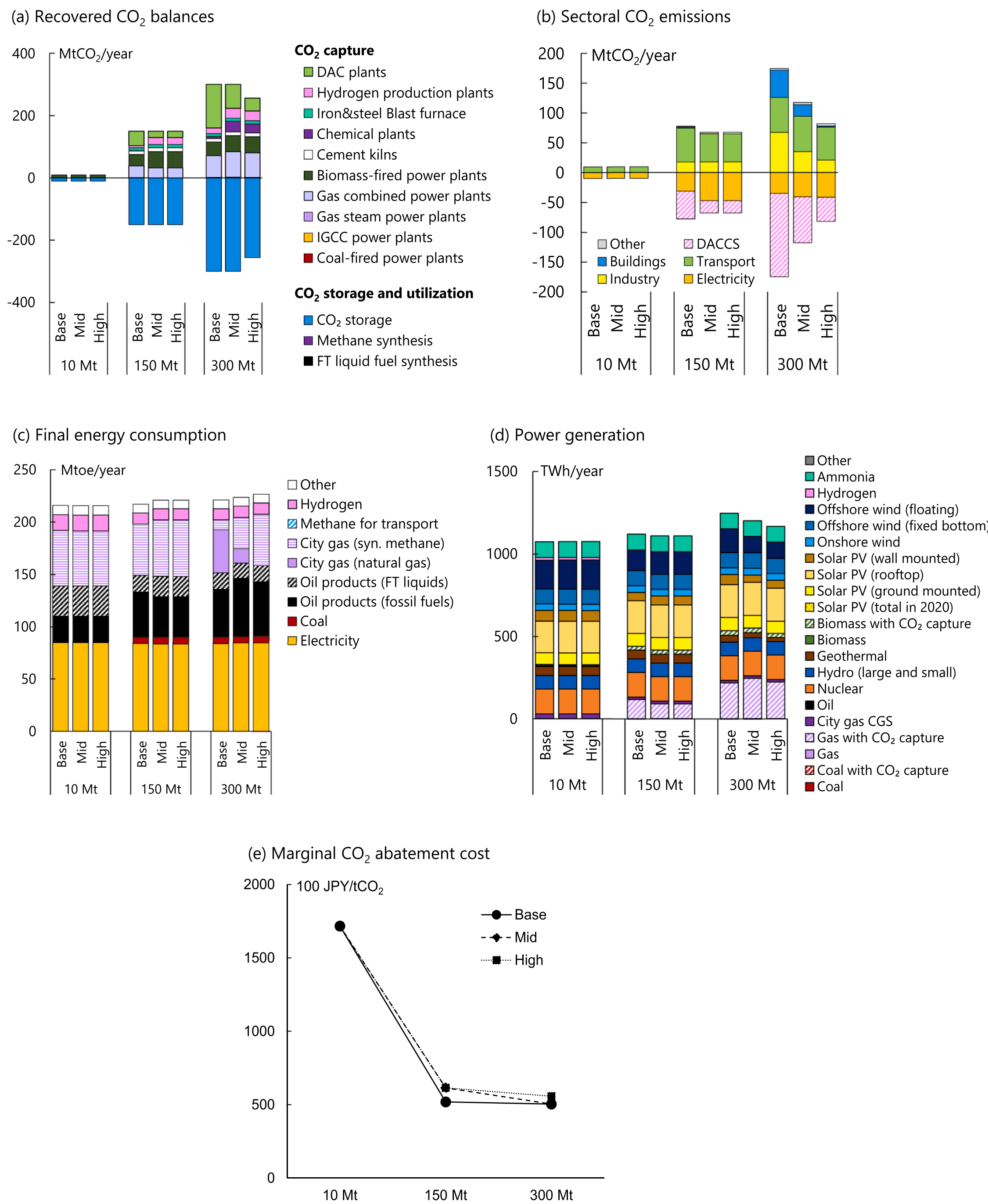

Fig. 11. Key results in 2050 in the additional cases.

A case study for Brazil (Nogueira et al., 2014) indicated that coal-fired power plants with CCS appeared cost-effective, while the European study (Selosse et al., 2013) challenged the concept. Our assessment showed that it depends on the CO_2 storage potential; combining gas-fired power generation and CCS can be cost-effective if a large CO_2 storage potential is available. Further case studies would be necessary to investigate the role of fossil fuel-fired power plants with CCS.

Turning to the priorities for future work, analyses of innovative CO_2 utilization and storage technologies, such as carbon mineralization and carbon-negative concrete, should be performed to investigate the role of CCU and CCS technologies comprehensively. In addition, our model has many simplifications, such as perfect foresight, low geographical resolution, and simplified modeling of industrial processes and lifestyle changes. Future studies should address these issues.

CRediT authorship contribution statement

Takashi Otsuki: Conceptualization, Funding acquisition, Investigation, Methodology, Writing – original draft. **Yoshiaki Shibata:** Project administration, Supervision. **Yuhji Matsuo:** Funding acquisition, Investigation. **Hideaki Obane:** Investigation. **Soichi Morimoto:** Investigation.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

Data availability

Model codes and assumptions are available upon reasonable request for the sole purpose of reading.

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Supplementary materials

Supplementary material associated with this article can be found, in the online version, at doi:10.1016/j.ijggc.2024.104065.

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