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Myanmar's Power Mix and International Interconnection: Cost Minimization Model◆

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Abstract

In Myanmar, it is unclear how long the political turmoil caused by the military coup will last. However, one of the keys to sustainable economic development of the country and living standard improvement of the people continues to be tackling the increasing demand for electricity. This requires Myanmar's government to construct an electricity supply system based on long-term planning and to consider the installation of international interconnection lines under the situation where many countries are starting to go forward to decarbonization. Therefore, this paper illustrates the preferable energy mix for Myanmar in 2050 from the perspective of the 3Es (economic efficiency, environmental sustainability and energy security) in multiple scenarios, setting different carbon prices and hydropower potentials for Myanmar. In conclusion, Myanmar should strongly promote hydropower development, including large-scale power plants, which will contribute to ensuring the 3Es, and also promote the development of international interconnection lines with neighboring Thailand, which will improve the fiscal revenue from the electricity export.

Key words: Myanmar, Power mix, International interconnection, Cost minimization

1. Introduction

In Myanmar, the National League for Democracy (NLD) led by Aung San Suu Kyi remained in power from 2016 to February 2021 when the national military forces staged a coup and took power amid the COVID-19 pandemic. However, many people have participated in an anti-government movement in pursuit of democratization, continuing armed conflicts with the military government. While how long the turmoil's adverse political and economic impacts would last is uncertain, one of the keys to the sustainable development of the Myanmar economy and the improvement of living standards for citizens is to respond to growing electricity demand. The Ministry of Electricity and Energy (MOEE) achieved power grid access for 50% of all households in December 2019 and has enhanced electricity supply. Efforts to achieve the electrification rate of 100% are continuing. The development and enhancement of power plants and power transmission/distribution networks may take a long lead time and installed facilities may remain in service for at least 25 to 40 years. Therefore, it is important to develop an overall electricity supply system based on long-term planning. Electricity exports to neighboring countries may also benefit the Myanmar economy. Given the global decarbonization trend, Myanmar may be required to reduce electricity generated from fossil fuels. This study considers the optimum power generation mix and international interconnection lines for Myanmar in 2050 and argues that the Myanmar government should focus on hydropower development and consider electricity exports through international interconnection lines to neighboring Thailand.

2. Literature review

2-1. Electricity demand outlook

Power generation in Myanmar quintupled from only 5 TWh in 2000 to 25 TWh in 2018 (IEA, 2021a[1)]). According to Myint (2021)[2)], power generation in 2050 is expected to nearly quadruple to 99 TWh (Fig.1). IEEJ (2021)[3)] predicts Myanmar's power generation to nearly sextuple from 2019 to 137 TWh in 2050. Both predictions are based on an econometric approach, indicating a relatively wide gap between 99 TWh and 137 TWh.

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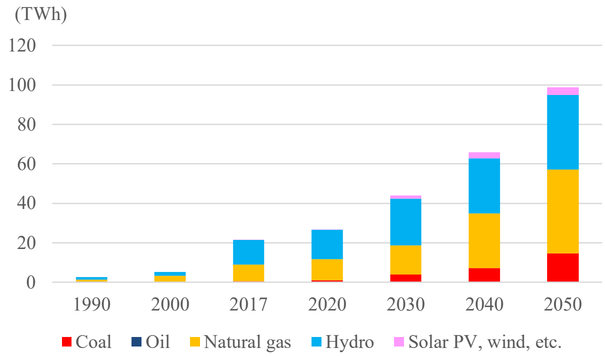

Fig. 1 Power generation results and outlook in Myanmar

Source: Myint, 2021[2)]

Power generation mix shares estimated for 2050 by Myint (2021)[2)] are 43% for natural gas, 38% for hydro, 15% for coal and 4% for variable renewable energy (VRE). The IEEJ (2021)[3)] projects the respective shares for 2050 at 60%, 15%, 21% and 4%. Their power generation mix projections also differ from each other.

2-2. Power generation outlook by source

(1) Gas-fired power generation

Gas has replaced hydro as Myanmar's largest power source. According to the IEA (2021a)[1)], gas-fired power generation totaled only 1.8 TWh against 6.2 TWh in hydropower generation in 2010 and surpassed 10.5 TWh in hydropower generation to 11.3 TWh in 2019. The literature[1)] indicates that gas' share of total power generation rose from 20.4% in 2010 to 46.7% in 2019.

Myanmar has so far used domestically produced natural gas for power generation. As domestic gas fields are being depleted, however, the country is required to expand liquefied natural gas (LNG) imports in the future. In 2014, Myanmar consumed 20% of its domestic gas production, totaling about 1,900 million standard cubic feet per day (mmscfd), and exported the remaining 80% to Thailand and China (Nippon Koei Co., etc., 2016[4)]). In 2040, however, domestic production will decline to about 810 mmscfd, while domestic demand increases to 1,142 mmscfd. In this way, Myanmar will fail to cover its gas demand with domestic production even if it discontinues all exports (Kobayashi & Phoumin, 2018[5)]). The NLD explored new gas fields but failed to find any large ones (Kobayashi & Phoumin, 2018[5)]), indicating that Myanmar will transition from a natural gas exporter to an LNG importer. It launched LNG imports in May 2020 (Yep, 2020a[6)]). The MOEE minister has indicated that a project has started to increase LNG power generation capacity by 4,000 MW (Yep, 2020b[7)]).

Given that gas for power generation is expected to account for about 80% of gas demand in 2040 (Kobayashi & Phoumin, 2018[5)]), Myanmar will have to further promote domestic gas field exploration and development and predict the gas consumption required for power generation.

(2) Coal-fired power generation

The government has considered developing coal-fired power plants as a new power source to meet growing electricity demand. Due to opposition from local residents and the absence of coal distribution networks, however, the development has been stalled.

The 120 MW Tigyit coal-fired power plant is Myanmar's only existing coal power generation facility (Emmerton et al., 2015[8)]), accounting for 9.3% of its total power generation as of 2019 (IEA, 2021a[1)]). The government has considered developing coal-fired power plants at some locations. However, the development has stagnated in the face of opposition from local residents who are concerned about such plants' environmental and social impacts (Myanmar Times, 2018[9)]). Myanmar's Nationally Determined Contribution (NDC) updated in July 2021 sets coal-fired power plants' share of total power generation capacity in 2030 at 20% for an unconditional target with its own efforts and 11% for a conditional target with international cooperation, indicating that the country plans to suppress coal-fired power generation through international cooperation (Myanmar, 2021[10]).

Major coal deposits have been confirmed in northwestern and central eastern regions that are far away from Yangon as the demand center (Emmerton et al., 2015[8]). Railway transportation capacity is insufficient. Rivers are sufficiently deep in the rainy season but shallow in the dry season, failing to be suitable for barge transportation (ERIA, 2020[11]). Deposits are not so large in any coalmine. Coalmines that can stably supply coal for large coal-fired power plants are extremely limited (ERIA, 2020[11]). At present, constraints exist on domestic coal supply, meaning that Myanmar may have to depend on imported coal.

If Myanmar were to use coal-fired power generation to help meet growing electricity demand, its government would have to get local residents' understanding and develop supply chains for domestic and imported coal while considering environmental and social impacts.

(3) Hydropower

Myanmar, though rich with water resources, has stagnated their development in consideration of environmental and social impacts and water shortages in the dry season. Its technologically feasible hydropower potential is estimated by IFC (2020)[12] and Tang et al. (2019)[13] at 40-50 GW. The MOEE's Aye (2017)[14] claims that the potential reaches 100 GW. Due to insufficient considerations given to local residents regarding past dam development and concern about negative impacts on the ecosystem, however, there is particular opposition to large-scale hydropower development (Dapice, 2015[15]). While sufficient water must be stored in reservoirs during the rainy season to secure full hydropower operation even during the dry season (Saw & Li, 2019[16]), output declines or stands at zero at some hydropower plants during the dry season (Dapice, 2015[15]). Given such conditions, Schmitt et al. (2021)[17] asserts that the hydropower potential should be regarded as 6.7-10.3 GW. In its updated NDC given in July 2021, however, the Myanmar government projects the hydropower potential in 2030 at 22.8 GW including large-scale hydropower plants (Myanmar, 2021[10]). As a long lead time around 20 years is required for large-scale hydropower plant development (Dapice, 2015[15]), long-term development plans must be formulated.

Regarding the stagnant hydropower development in Myanmar, IFC (2020)[12] supports the formulation of economic and social impact assessment standards to identify suitable locations for hydropower development. The IEA (2021b)[18] concludes that the value of hydropower must be reaffirmed globally, proposing to combine hydropower and solar photovoltaics facilities during water shortages in the dry season. In the context of Myanmar, ERIA (2020)[11] indicates that Myanmar could take advantage of its long sunshine hours to combine solar PV and hydropower during the dry season to help stabilize electricity supply. The IEA (2021b)[18] notes that the long lead time for hydropower plant construction may be shortened through the rationalization of the approval process and that large-scale hydropower plants feature long-term revenue predictability that is useful for lowering fundraising costs and improving the feasibility of development projects.

(4) Renewable energy (excluding hydropower)

Myanmar has embarked on renewable energy development, launching its first commercial solar PV power generation in 2019. However, its government has yet to specify goals or roadmaps for each renewable energy source.

The government has traditionally promoted the electrification of rural areas through solar PV power generation, introducing solar home systems and solar mini-grids under support from various international organizations (SolarPower Europe, 2019[19]). Myanmar's solar PV potential is relatively high in the Association of Southeast Asian Nations (ASEAN), estimated at about 40 TWh per year (ADB, 2016[20]). Regarding renewable energy development, its NDC updated in July 2021 specifies solar PV capacity in operation at 40 MW, such capacity under construction at 8.25 MW, such capacity in auction processes at 1,060 MW and wind power generation capacity under feasibility study at 30 MW, indicating that Myanmar gives development priority to solar PV among renewables. The updated NDC projects a power generation capacity mix share for renewables (excluding hydro) at 11% for an unconditional target with Myanmar's own efforts and 17% for a conditional target with international cooperation, indicating that the country plans to promote renewables under international support.

To further develop solar PV capacity, the Myanmar government should clarify its policy and strategy on renewable energy development and establish adequate law and regulation frameworks, as indicated by Aung et al. (2018)[21)].

2-3. ASEAN Power Grid (Myanmar-Thailand international interconnection lines)

ASEAN is promoting the ASEAN Power Grid (APG) initiative to develop interconnected grid systems to efficiently use and share regional resources and improve energy security (ACE, 2015[22)]). Total AGP capacity stood at 5,502 MW as of January 2019. Myanmar, though having its power distribution lines with Thailand and Laos to link local areas (IEA, 2019a[23)]), has no international interconnection lines. For the future, Myanmar is considering developing international interconnection lines with capacity totaling 26,680 to 30,150 MW. In particular, potential capacity for international interconnection lines between Myanmar and Thailand is estimated at as much as 11,709 to 14,859 MW (IEA, 2019 b[24)]). As noted by IEA (2019a)[23)], international interconnection lines may improve the flexibility of electricity supply and demand in the ASEAN region and contribute to reducing the intermittency of VRE expected to spread in the future.

2-4. Comparison with similar studies

This study is similar to ERIA (2020)[11)] and ERIA (2021)[25)] that analyzes Myanmar's optimum power generation mix.

ERIA (2020)[11)] assumes Myanmar's total power generation in 2040 at a level in the Alternative Policy Scenario of ERIA Outlook 2018 and sets hydropower and VRE power generation in reference to Emmerton et al. (2015)[8)], without using any optimization or econometric model. Then, it sets a fossil-fired power generation mix, giving priority to economic efficiency, environmental sustainability and energy security. Electricity exports are assumed to remain at the level for 2016.

ERIA (2020)[11)] projects a power generation mix for 2040, while this study illustrates one for 2050. Given the lead time for power plant construction, this study gives the Myanmar government more time to formulate and implement a power development plan. While ERIA (2020)[11)] uses no optimization or econometric model, this study uses an optimization model to project a power generation mix and electricity exports.

Meanwhile, ERIA (2021)[25)] uses an optimization model to indicate cost changes accompanying the presence or absence of international interconnection lines and changes in the solar PV share for eight ASEAN countries, including Myanmar, and the ASEAN region in 2040. As a reference, it indicates a cost optimum power mix, including minimum shares for fossil fuels, and electricity exports for the case of a carbon price at US$50/t-$CO_2$.

In line with the ERIA (2021)[25)] approach, this study uses an optimization model to minimize costs. Unlike ERIA (2021)[25)], however, this study focuses on Myanmar and Thailand, uses the latest power generation cost data and projects a power generation mix for 2050 without setting minimum shares for fossil fuels. While ERIA (2021)[25)] focuses on solar PV share changes as an issue for the entire ASEAN region, this study pays attention to and deepens discussions on hydropower potential as an issue peculiar to Myanmar. Furthermore, this study quantitatively assesses each scenario.

3. Methodology

3-1. Total power demand settings

As the prolongation of the current turmoil in Myanmar is expected to exert downward pressure on energy demand, we adopt a conservative projection of total power demand for 2050 in Myint (2021)[2)][1]. On an assumption that power supply will meet the projected demand, we seek a power generation mix to minimize costs, without considering standby power. Although the impact of COVID-19 is not reflected in Myint (2021)[2)], we adopt the projection on an assumption that the COVID-19 pandemic's long-term impact on total power demand will be small (IEEJ, 2020a[27)]; Kimura et al., 2021[28)]).

3-2. Optimization model

To determine an optimum power generation mix in Myanmar, we use a cost-minimization model for Myanmar and

[1] For Thailand, we adopt an outlook in Kamalad (2021)[26)] that is in the same book as Myint (2021)[2)].

neighboring Thailand. The model assumes one year as 8,760 hours and determines a power generation mix to minimize total power generation costs for the electricity system in the two countries. The cost minimization logic is that the power generation mix is determined when power generation marginal costs for all energy sources become equal[2]. The power generation costs include annual construction, operation and maintenance & management costs for each power generation technology, each power storage system and international interconnection lines. When total power generation exceeds total power demand due to an increase in VRE power generation, the utilization of power storage systems or the suppression of output from VRE power facilities will be chosen. Given high power storage costs, the output suppression will be chosen more frequently.

3-3. Assumptions

(1) Power generation costs

As projected power generation costs (construction, operation and maintenance & management costs) in 2050 for gas-fired, coal-fired, hydrogen-fired, hydro, geothermal, biomass, solar PV, onshore wind and offshore wind power plants in Myanmar and Thailand were difficult to collect, we adopt such projected costs in 2050 in Indonesia as another ASEAN member (DEN, 2021[29)]). As for power generation costs for gas-fired power plants with carbon capture and storage (CCS) and nuclear power plants on which data in DEN (2021)[29)] are insufficient, we estimate the costs based on projections in IEA (2020)[30)]. We set fuel costs in line with international energy price assumptions (for Reference Scenario) in IEEJ (2020b)[34)], based on Indonesian coal prices (PLN, 2019[31)]) and average gas prices for Indonesia, Malaysia and Thailand (PLN, 2019[31)]; EGAT, 2019[32)]; Energy Commission, 2021[33)]). As a result, the levelized cost of electricity (LCOE) for each energy source in 2019 dollars is set for the carbon price of zero, as shown in Table 1.

Table 1 LCOE in Myanmar and Thailand

Unit: US cents/kWh in 2019 dollars

Coal	Gas	Gas+CCS	Hydrogen	Nuclear	Hydro
4.2	4.8	7.3	11.5	5.7	5.0

Geothermal	Biomass	Solar PV	Onshore wind	Offshore wind
3.8	8.2	3.7/4.4	12.5/9.4	12.8/21.1

Note: Left values for solar PV and onshore/offshore wind are for Myanmar and right values for Thailand.

(2) Renewable energy potential

We estimate solar PV and wind potential out of renewable energy power generation potential by using geographic information system data to consider land-use classification and land gradients. We also use data in Renewalbes.ninja (Staffell & Pfenninge, 2016[35)]; Pfenninge & Staffell, 2016[36)]) to find solar PV and wind output patterns.

Table 2 Renewable energy potential in Myanmar and Thailand

Unit: GW

	Solar PV	Wind	Hydro	Geothermal	Biomass
Myanmar	524	1	49	1	12
Thailand	1,120	73	6	0	7

[2] When maximum and minimum constraints are imposed, marginal costs for energy sources subject to the constraints may become higher or lower than for other sources. For details, see ERIA (2021)[25)]

We set hydropower potential at 49 GW for Myanmar in line with IFC (2020)[12] and at 6 GW for Thailand in line with Huber et al. (2015)[37]. Geothermal potential is set at 1 GW for Myanmar according to Huber et al. (2015)[37]. Biomass potential is set at 12 GW for Myanmar and at 7 GW for Thailand according to Tun et al. (2019)[38].

(3) International interconnection line costs

Although there is no international interconnection line between Myanmar and Thailand as noted in Section 2.3, we assume their future interconnection potential at 14.9 GW (IEA, 2019b[24]).

We set construction costs and a power transmission loss rate for international interconnection lines according to Kutani & Li (2014)[39]. As for power transmission costs, we first set a unit cost per kilometer for transmission lines and computed costs according to the transmission distance. Then, we add electric power substation (switching station) construction costs according to the number of substations required for the interconnection lines. Specifically, we set a unit price for power transmission lines at US$0.9 million/km/2 circuits, based on past construction cost data for neighboring countries. As for electric power substation (switching station) construction costs, we set a fixed cost at US$20 million per substation and an additional cost at US$10 million per circuit. Furthermore, we assume operation and maintenance & management costs at around 0.3% per year of total construction costs. We assume the power transmission loss rate at 1% per 100 km. Based on these assumptions, we estimate costs for international interconnection lines between Myanmar and Thailand at US$24 million/GVA/year and the power transmission loss rate at 5.4%.

3-4. Scenarios

(1) Scenarios regarding international interconnection lines

We assume the scenarios with and without international interconnection lines between Myanmar and Thailand in 2050.

(2) Base scenario

In the base scenario, we assume the carbon price at zero in Myanmar and Thailand and Myanmar's hydropower generation potential at 49 GW.

(3) Scenario for the carbon price at US$50/ t-$CO_2$

In this scenario, we assume that the carbon price will rise to US$50/t-$CO_2$ in 2050. The carbon price may not necessarily be realized as a carbon tax. It may be regarded as a carbon avoidance cost.

(4) Scenario for hydropower potential at 23 GW

In this scenario, we assume that Myanmar's hydropower potential in 2050 will be lower than 49 GW and limited to 23 GW as given in the updated NDC for 2030.

(5) Scenario for the carbon price at US$25/t-$CO_2$ for Myanmar (US$50/t-$CO_2$ for Thailand) plus hydropower potential at 23 GW

In this scenario, we assume Myanmar's hydropower potential at 23 GW and the carbon price at US$50/t-$CO_2$ for Thailand and at US$25/t-$CO_2$ for Myanmar in consideration of economic gaps between the two countries.

3-5. Assessment standards

(1) Assessment of scenarios

To consider which scenario is favorable for Myanmar, we set specific assessment standards for this study from the perspective of the 3Es (economic efficiency, environmental sustainability and energy security) and assess each scenario.

(2) Economic efficiency

As a standard to assess the economic efficiency of each scenario, we use costs per MWh that we determine by dividing total costs in US dollars by total power generation (MWh) in Myanmar and Thailand.

(3) Environmental sustainability

As a standard to assess the environmental sustainability of each scenario, we use CO_2 emissions per MWh that we determine by dividing total CO_2 emissions (t-CO_2) by total power generation (MWh) in Myanmar and Thailand.

(4) Energy security

As it is conceivable that Myanmar will deplete domestic fossil fuels and import natural gas and coal in the future, we use fossil fuel input per MWh that we determine by dividing total fossil fuel input (toe) by total power generation (MWh) in Myanmar and Thailand to assess the energy security of each scenario.

4. Scenario results

4-1. Optimum power generation mix for each scenario

(1) Overview

Of the scenario estimation results based on the assumptions, the Myint BAU scenario at the left edge of Fig. 2 indicates a business as usual scenario in Myint (2021)[2)]. Indicated next are three scenarios without international interconnection lines: ①Base (hydropower potential at 49 GW) as the base scenario, ②Hydropower 49 GW + CP50 for the carbon price at US\$50/t-CO_2 and ③ Hydropower 23 GW + CP50 for the carbon price at US\$50/t-CO_2 and hydropower potential at 23 GW. In addition to the three scenarios (④-⑥) with international interconnection lines for the respective assumptions, the figure indicates the ⑦ Hydropower 23 GW + CP25 (Thailand 50) scenario that assumes different carbon prices reflecting an economic gap between Myanmar and Thailand – the carbon price at US\$25/t-CO_2 for Myanmar (the carbon price at US\$50/t-CO_2 for Thailand) and hydropower potential at 23 GW.

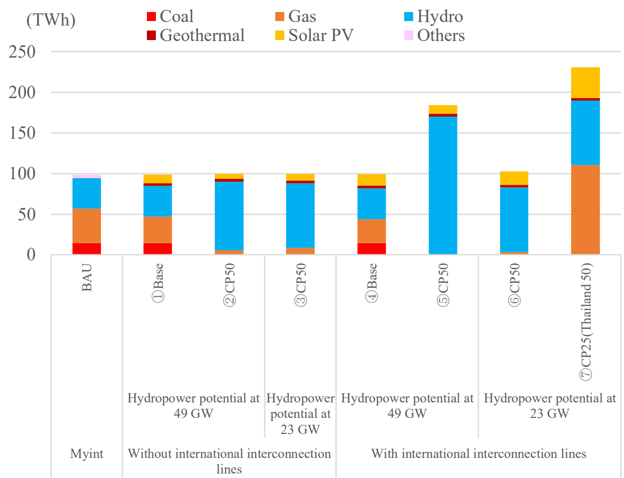

Fig. 2 Myanmar's optimum power generation mix in 2050 for each scenario

Note: "Others" for Myint BAU means solar PV, wind, etc.

(2) Scenarios without international interconnection lines

In the scenarios without international interconnection lines, there will be no electricity trade between Myanmar and Thailand. In the ① Base (hydropower 49 GW) scenario close to the Myint BAU scenario, the minimum-cost power generation mix for total power generation of 99 TWh will consist of hydropower (38%), gas-fired power (33%), coal-fired power (15%), solar PV (11%) and geothermal power (4%)[3].

In the ② Hydropower 49 GW + CP50 scenario, the carbon price will raise fuel costs for coal and gas, while low-cost hydropower increases. Hydropower will account for 85% of the cost optimum power generation mix to generate 99 TWh in electricity. Gas-fired power and solar PV each will capture 6% and geothermal power 3%[4].

In the ③ Hydropower 23 GW + CP50 scenario, the carbon price will have a similar impact, with hydropower generation falling slightly in line with the hydropower potential drop. The optimum mix for power generation totaling 99 TWh will consist of hydropower (80%), gas-fired power (9%), solar PV (8%) and geothermal power (3%)[5].

(3) Scenarios with international interconnection lines

In the scenarios with international interconnection lines, electricity trade between Myanmar and Thailand will help lower power generation costs. Exports from Myanmar to Thailand will dominate bilateral trade because Myanmar's electricity costs, even if including those for international interconnection lines, will be cheap for Thailand. However, optimum electricity imports and exports will differ by scenario.

In the ④ Base (hydropower potential at 49 GW) scenario, coal- and gas-fired power generation will cost less than renewable energy power generation including hydropower because of the carbon price at zero. The optimum power mix in this scenario will be almost the same as in the base scenario without international interconnection lines. Myanmar's optimum power generation will be the same as 99 TWh in the base scenario without interconnection lines. The optimum power mix will consist of hydropower (38%), gas-fired power (30%), coal-fired power (15%), solar PV (14%) and geothermal power (3%). Myanmar's power generation costs will be minimized when Myanmar exports a small volume of electricity generated from solar PV and imports the same volume generated from Thai gas-fired power plants[6].

In the ⑤ hydropower 49 GW + CP50 scenario with international interconnection lines, massive hydropower electricity consumption in the two countries will optimize Myanmar's power generation costs from the perspective of hydropower costs and potential. The best solution for the two countries is for Myanmar to export surplus electricity after satisfying domestic demand. Myanmar's power generation will increase to 185 TWh. Myanmar's cost optimum power generation mix will consist of hydropower (92%), solar PV (6%) and geothermal power (2%), with exports to Thailand totaling 83 TWh[7].

In the ⑥ hydropower 23 GW + CP50 scenario with international interconnection lines, power generation costs will be optimized, with Myanmar's exports to Thailand being limited to only 5 TWh, as Myanmar's smaller hydropower potential is used primarily to satisfy domestic demand. The optimum power generation mix will consist of hydropower (78%), solar PV (16%), geothermal power (3%) and gas-fired power (3%), with power generation totaling 103 TWh[8].

In the ⑦ hydropower 23 GW + CP25 (50 for Thailand) scenario, Myanmar's hydropower potential will be used to satisfy domestic demand while 128 TWh in electricity generated from solar PV and gas-fired power plants that cost less than in Thailand is exported. The optimum power generation mix for Myanmar's power generation totaling 231 TWh will include gas-fired power (48%), hydropower (34%), solar PV (16%), geothermal power (1%) and coal-fired power (a little)[9].

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[3] In the ① scenario, Thailand's power generation will total 402 TWh, of which gas-fired power will account for 74%, coal-fired power for 22%, hydropower for 3% and solar PV for 2%.

[4] In the ② scenario, Thailand's power generation will total 402 TWh, of which gas-fired power will account for 71%, coal-fired power for 23%, hydropower for 6% and solar PV for 1%.

[5] In the ③ scenario, Thailand's power generation and its mix will be the same as in the ② scenario.

[6] In the ④ scenario, Thailand's power generation will total 401 TWh, of which gas-fired power will account for 75%, coal-fired power for 22% and hydropower for 3%.

[7] In the ⑤ scenario, Thailand's power generation will total 321 TWh, of which gas-fired power will account for 70%, solar PV for 22%, hydropower for 7% and coal-fired power for 1%.

[8] In the ⑥ scenario, Thailand's power generation will total 399 TWh, of which gas-fired power will account for 71%, solar PV for 22%, hydropower for 6% and coal-fired power for 1%.

[9] In the ⑦ scenario, Thailand's power generation will total 277 TWh, of which gas-fired power will account for 67%, solar PV for 24%, hydropower for 8% and coal-fired power for 1%.

(4) Summary

In scenarios with and without international interconnection lines, solar PV that features the lowest LCOE is adopted first at optimum points. As the solar PV share's rise is accompanied by a rapid increase in the marginal integration cost, however, massive solar PV diffusion is not cost optimal. Geothermal power is adopted next, but its potential is small. As far as the carbon price is zero, therefore, the optimum solution is the massive diffusion of coal- and gas-fired power generation that features the third lowest LCOE after solar PV and geothermal power.

As the carbon price rises in the absence of international interconnection lines, however, raising the hydropower share after adopting solar PV and geothermal energy contributes to minimizing costs. Hydropower costs less than coal- and gas-fired power generation on which the carbon price is imposed. Even in the case where hydropower potential is limited to 23 GW, therefore, hydropower should be expanded to the maximum extent to minimize costs.

In the ⑤ hydropower 49 GW + CP50 and ⑥ hydropower 23 GW + CP50 scenarios with interconnection lines, exporting electricity to Thailand will be cost optimal. However, the export volume will differ between the two scenarios. The export volume in the ⑤ scenario will stand at 83 TWh against only 5 TWh in the ⑥ scenario. In the ⑤ scenario, the large hydropower potential of 49 GW will allow cheap hydropower electricity to be consumed in Myanmar and Thailand to minimize power generation costs in the two countries. In the ⑥ scenario where hydropower potential will be limited to 23 GW, however, all cheap hydropower electricity will be consumed in Myanmar alone. This means that whether massive electricity will be exported from Myanmar to Thailand depends on hydropower development in Myanmar.

In the ⑦ hydropower 23 GW + CP25 (50 for Thailand) scenario with interconnection lines in which the carbon price in Myanmar will be lower than in Thailand due to an income level gap, massive electricity exports from gas-fired power plants in Myanmar to Thailand will be the optimum solution, even if hydropower potential is limited to 23 GW. This is because importing electricity from Myanmar will cost less than domestic gas-fired power generation for Thailand due to the carbon price gap.

4-2. Scenario assessment

(1) Assessment overview

Table 3 indicates assessment results for each scenario based on the assessment standards set in Section 3-5.

Table 3 Scenario assessment

International inter-connection lines	Scenario	Economic efficiency USD/MWh	Environmental sustainability t-CO_2/MWh	Energy security toe/MWh
Absent	① Base (hydropower 49 GW)	48.21	0.203	0.139
	② Hydropower 49 GW + CP50	61.32	0.118	0.086
	③ Hydropower 23 GW + CP50	61.36	0.120	0.086
Present	④ Base (Hydropower 49 GW)	48.08	0.204	0.140
	⑤ Hydropower 49 GW + CP50	59.34	0.091	0.066
	⑥ Hydropower 23 GW + CP50	61.18	0.118	0.085
	⑦ Hydropower 23 GW + CP25 (Thailand 50)	59.62	0.119	0.086

(2) Economic efficiency

The unit cost per MWh in Myanmar and Thailand will generally increase in line with a carbon price rise, irrespective of whether international interconnection lines will exist.

The unit cost in the ④ Base (hydropower 49 GW) scenario with interconnection lines will be US$0.13/MWh lower than in the ① Base (hydropower 49 GW) scenario. The unit cost in the ⑥ Hydropower 23 GW + CP50 scenario with international interconnection lines will be US$0.18/MWh lower than in the ③ Hydropower 23 GW + CP50 scenario. These suggest that economic efficiency has only slight differences among the scenarios with or without international interconnection lines.

However, the unit cost in the ⑤ Hydropower 49 GW + CP50 scenario with interconnection lines will be US$1.98/MWh lower than in the ② Hydropower 49 GW + CP50 scenario, indicating a large economic efficiency gap between the two scenarios.

The unit cost in the ⑦ Hydropower 23 GW + CP25 (50 for Thailand) scenario with interconnection lines will be US$1.56/MWh lower than in the ⑥ Hydropower 23 GW + CP50 scenario with interconnection lines, showing a clear economic efficiency difference.

Therefore, economic efficiency, though deteriorating under the carbon price imposition, will improve substantially if hydropower generation capacity increases to 49 GW to realize massive electricity exports. If the carbon price is US$50/t-$CO_2$ in Myanmar and Thailand, with Myanmar's hydropower capacity limited to 23 GW, economic efficiency may not improve even with international interconnection lines. If the carbon price in Myanmar is lower than in Thailand, however, economic efficiency may slightly improve through electricity trade.

(3) Environmental sustainability

CO_2 emissions per MWh in Myanmar and Thailand will decrease in line with a carbon price increase, irrespective of whether international interconnection lines will exist.

The unit CO_2 emissions in the ④ Base (hydropower 49 GW) scenario with interconnection lines will be only 0.001 t-CO_2/MWh more than in the ① Base (hydropower 49 GW) scenario. The unit CO_2 emissions in the ⑥ Hydropower 23 GW + CP50 scenario with international interconnection lines will be only 0.002 t-CO_2/MWh less than in the ③ Hydropower 23 GW + CP50 scenario as electricity exports are limited. These suggest that environmental sustainability has little difference among the scenarios with or without international interconnection lines.

However, the unit CO_2 emissions in the ⑤ Hydropower 49 GW + CP50 scenario with interconnection lines will be 0.027 t-CO_2/MWh less than in the ② Hydropower 49 GW + CP50 scenario, indicating a large environmental sustainability gap between the two scenarios.

The unit CO_2 emissions in the ⑦ Hydropower 23 GW + CP25 (50 for Thailand) scenario with interconnection lines will be only 0.001 t-CO_2/MWh more than in the ⑥ Hydropower 23 GW + CP50 scenario with interconnection lines, indicating a small environmental sustainability gap in contrast to the clear economic efficiency gap.

If the carbon price is imposed, with massive electricity from hydropower being exported from Myanmar to Thailand, environmental sustainability will improve remarkably. Between other scenarios, however, the environmental sustainability gap will be small. Even if the carbon price in Myanmar is lower than in Thailand, with massive electricity from gas-fired power plants being exported from Myanmar to Thailand, environmental sustainability will change little from a scenario for Myanmar's hydropower potential limited to 23 GW and the two countries' carbon price at US$50/t-$CO_2$ as gas-fired power generation declines in Thailand. This is because gas consumption will increase in Myanmar while decreasing in Thailand.

(4) Energy security

Fossil fuel input per MWh in Myanmar and Thailand will generally decline in line with a carbon price hike, irrespective of whether international interconnection lines will exist.

The unit fossil fuel input in the ④ Base (hydropower 49 GW) scenario with interconnection lines will be only 0.001 toe/MWh more than in the ① Base (hydropower 49 GW) scenario. The unit fossil fuel input in the ⑥ Hydropower 23 GW + CP50 scenario with international interconnection lines will be only 0.001 toe/MWh less than in the ③ Hydropower 23 GW + CP50 scenario as electricity exports are limited. These suggest that energy security has only slight differences among scenarios with or without international interconnection lines.

However, the unit fossil fuel input in the ⑤ Hydropower 49 GW + CP50 scenario with interconnection lines will be 0.020 toe/MWh less than in the ② Hydropower 49 GW + CP50 scenario, indicating a major improvement in energy security.

The unit fossil fuel input in the ⑦ Hydropower 23 GW + CP25 (50 for Thailand) scenario with interconnection lines will be only 0.001 toe/MWh more than in the ⑥ Hydropower 23 GW + CP50 scenario with interconnection lines, indicating a small energy security gap. This is because gas consumption will increase in Myanmar while decreasing in Thailand.

If the carbon price is imposed, with massive electricity from hydropower being exported from Myanmar to Thailand, energy security as well as environmental sustainability will improve remarkably. Between other scenarios, however, the energy security gap will be small. Even if the carbon price in Myanmar is lower than in Thailand, with massive electricity from gas-fired power plants being exported from Myanmar to Thailand, energy security will change little from a scenario for Myanmar's hydropower potential limited to 23 GW as gas-fired power generation declines in Thailand.

(5) Scenario assessment

If priority is given only to economic efficiency, base scenarios with the lowest unit cost, including the ④ Base (hydropower 49 GW) scenario with interconnection lines, will be optimal.

If the carbon price is assumed to be introduced in some form, however, the ⑤ Hydropower 49 GW + CP50 scenario with interconnection lines is the most preferable for economic efficiency, environmental sustainability and energy security. This scenario features greater economic efficiency even than the ⑦ Hydropower 23 GW + CP25 (50 for Thailand) scenario with interconnection lines that includes a lower carbon price for Myanmar and more electricity exports.

5. Discussion: Benefits from investment in international interconnection lines

In the previous chapter, we have found that investment in international interconnection lines has an economic advantage from the perspective of the unit cost per MWh. In this chapter, we compute total costs for investment in international interconnection lines for each scenario and determine benefits from the investment as a cost decrease through investment in interconnection lines.

Table 4 shows electricity exports from Myanmar to Thailand through international interconnection lines and changes in total costs through investment in interconnection lines in 2050 for three scenarios: ⑤ Hydropower 49 GW + CP50 scenario with interconnection lines, ⑥ Hydropower 23 GW + CP50 scenario with interconnection lines and ⑦ Hydropower 23 GW + CP25 (50 for Thailand) scenario with interconnection lines. The total costs cover costs for the construction of international interconnection lines in Myanmar and Thailand and almost all power generation costs (including fuel costs) in the two countries. However, the total costs do not include costs for investment in domestic power transmission and distribution networks, which are required irrespective of international interconnection lines and offset when the benefits are measured. The total costs do not include environmental or social costs.

Table 4 Changes in total costs through investment in international interconnection lines (US$ million per year)

Scenario	Impact of investment in international interconnection lines	
	Export volume (TWh)	Change in total costs
⑤ Hydropower 49 GW + CP50	83	-740
⑥ Hydropower 23 GW + CP50	5	-60
⑦ Hydropower 23 GW + CP25 (Thailand 50)	128	-390

The table indicates that the total costs will decrease thanks to investment in international interconnection lines in all three scenarios.

In the ⑤ Hydropower 49 GW + CP50 scenario with interconnection lines, massive electricity from hydropower plants in Myanmar will be exported to Thailand, contributing to increasing hydropower generation and interconnection line costs in Myanmar and to decreasing fossil-fired power generation costs (including fuel costs) in Thailand. As a result, the total costs will decline by US$740 million. In the ⑥ Hydropower 23 GW + CP50 scenario with interconnection lines, a decline in the total costs will be far smaller as electricity exports are limited. In the ⑦ Hydropower 23 GW + CP25 (50 for Thailand) scenario with interconnection lines, the carbon price gap between the two countries will lead massive electricity from gas-fired power plants in Myanmar to be exported to Thailand, contributing to increasing interconnection line costs and to decreasing fossil-fired power generation costs (including fuel costs) in Thailand. As a result, the total costs will decline by US$390 million.

We here estimate economic benefits in Myanmar. If the total costs are simply divided by 2, the benefits are US$30-370 million. If the total costs are allocated in proportion to the ratio of power generation in Myanmar to that in Thailand, the benefits are US$10-270 million. Government final consumption expenditure's share of gross domestic product (GDP) at 18%[40)] in 2018 is applied to real GDP assumed by Myint (2021)[2)] at US$511 billion for 2050, and government spending for 2050 is estimated at US$92 billion. The benefits in the ⑤ Hydropower 49 GW + CP50 scenario with interconnection lines will cover around 0.3% of government spending in 2050. If environmental sustainability such as CO_2 emission cuts and energy security like electricity imports from Thailand during a severe drought are incorporated into economic efficiency, the benefits may increase further. However, accurate economic or financial benefits may be determined through negotiations between Myanmar and Thai governments on matters such as how to share costs for constructing international interconnection lines between the two countries and their electricity sales contracts.

Myanmar's benefits from investment in international interconnection lines in the highest benefit case (⑤ Hydropower 49 GW + CP50 scenario with interconnection lines) will come to US$270-370 million. The value may not be so much compared with GDP or government spending in 2050. However, the benefits may represent stable annual income from a foreign country. As pointed out in Section 2.2, gas resources in Myanmar are expected to be depleted, leading to a decline in foreign currency income from natural gas exports. Then, foreign currency income from electricity exports to Thailand will undoubtedly support government finance in Myanmar over the long term.

6. Conclusion

Amid the global decarbonization trend, Myanmar's promotion of hydropower development including large-scale power plant construction and of the installation of international interconnection lines with neighboring Thailand will contribute to ensuring the power sector's economic efficiency, environmental sustainability and energy security. If hydropower generation capacity reaches 49 GW in Myanmar in 2050, with the carbon price of US$50/t-$CO_2$ being imposed in Myanmar and Thailand, Myanmar's power generation mix will become cost optimal when hydropower accounts for 92% of total power generation at 185 TWh, solar PV for 6% and geothermal power for 2%, with electricity exports to Thailand standing at 83 TWh. Benefits from investment in international interconnection lines are estimated at about US$270-470 million per year. Electricity exports will become a precious foreign currency income source for Myanmar expected to see a decline in future natural gas exports.

However, Myanmar has many challenges regarding hydropower development. The Myanmar government should take leadership in continuing and deepening discussions on whether to give top priority to environmental sustainability (IFC, 2020[12]) or tolerate some economic rationality (IEA, 2021b[18]).

While Myanmar is now plagued with a domestic armed conflict, it is hoped that the Myanmar government will discuss hydropower potential and carbon prices and accelerate the formulation and implementation of energy policy to realize a power generation mix giving consideration to economic efficiency, environmental sustainability and energy security, to implement electricity exports and to promote the country's economic development and the improvement of citizens' living standards.

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A Quantitative Analysis of Japan's Optimal Power Generation Mix towards 2050 - Considering macroeconomic effects of nuclear power generation and hydrogen price -◆

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Abstract

In this study, assuming the power supply portfolio in Japan in 2050, we conducted a model analysis to achieve carbon neutrality while supplying the required amount of power. The energy model developed in this paper is an integrated model which combines an optimal power generation mix model and an econometric model.

As a result, we show the superiority of nuclear power generation, and at the same time, if the sole purpose is to minimize the costs of power generation and transmission, depending on the preconditions, economic growth is restrained by the ripple effect of the decrease in capital investment related to power plants and the increase in fuel import value, etc. We hope that this study will be a beneficial starting point for both policy makers and electric utilities.

Key words: Hydrogen price, Nuclear power generation, Macro economy, Power generation mix

1. Preface

The sense of impending crisis with regard to climate change is rapidly increasing worldwide. The Sixth Assessment Report[1] released by the Intergovernmental Panel on Climate Change (IPCC) in August 2021 stated for the first time that human impacts on atmospheric, oceanic and terrestrial warming are "unequivocal," removing all uncertainty. In addition, the fact that Shukuro Manabe and others, who developed a climate model to predict global warming and revealed the relationship between carbon dioxide (CO_2) concentration and temperature in the atmosphere for the first time in the world, received the first Nobel Prize in Physics (2021)[2] in climate research in October 2021 symbolizes the growing interest in climate change. Starting with the United Kingdom's passage of a law[3] in June 2019 calling for net zero greenhouse gas (GHG) emissions by 2050, a number of other countries have stated their commitment toward "carbon neutrality" by 2050, and as of October 26, 2021, this number totaled 136 countries and one region (European Union)[4].

In an October 2020 policy speech prior to the special Diet session former Prime Minister Yoshihide Suga declared that "Japan will aim to achieve zero greenhouse gas emissions as a whole, that is, to realize carbon neutrality, and a decarbonized society by 2050."[5] Thereafter, following discussions at the Basic Policy Subcommittee, the "Sixth Strategic Energy Plan"[6] was approved by the Cabinet in October 2021 and included the "Green Growth Strategy"[7] formulated by the Ministry of Economy, Trade and Industry. This strategy is an industrial policy to link the challenge of carbon neutrality in 2050 to a positive cycle involving the economy and environment.

In addition, analysis of the impacts on the economy and the public burden caused by a country's energy selection for carbon neutrality is being actively carried out both domestically and internationally, and there are several works which carried out the same evaluation for Japan. For example, Ram et al. (2017)[8] and WWF Japan (2017)[9] say that even if all Japanese power is supplied with variable renewable energy (VRE) in 2050, the total cost of the power system including the integrated cost will decrease compared to the current situation. On the other hand, if thermal power generation is not available, Matsuo et al. (2018)[10] and Matsuo et al. (2020)[11] state that the power system cost will rise significantly, and if not only VRE but also nuclear power can be used to suppress the cost increase, while Ogimoto et al. (2018)[12] indicates that if power is supplied only by VRE, the unit price of the electric power system will be much higher than the present state.

Since Japan's carbon neutrality declaration, as a similar analysis including new technologies such as hydrogen, at the

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43rd meeting (2021)[13] of METI's Basic Policy Subcommittee, the Research Institute of Innovative Technology for the Earth (RITE) and at the 44th meeting (2021)[14], the National Institute for Environmental Studies, the Renewable Energy Foundation, RITE, Deloitte Tohmatsu Consulting, and the Japan Institute of Energy Economics used their own models to evaluate economic rationality mainly on electric power systems, with each recommending a different power generation mix.

However, a common denominator of works 8) to 14) is that they each find that "the lower the total cost of energy system development and upkeep, the more economical." For this reason, the authors are not aware of any research that has quantitatively or simultaneously examined ripple effects on the macro economy caused by changes in the cost of new technologies such as hydrogen and capital investment from the selection of energy systems. Furthermore, the above-mentioned "Green Growth Strategy"[7] is arranged as an action plan for establishing a positive cycle and growth of the economy based on a plan aiming to maximize the curtailing of total costs of the energy system, and thus, it can be said that the strategy does not examine these simultaneously.

In this study, the authors assume that carbon neutrality will be achieved by new technologies such as hydrogen thermal power and gas-fired thermal power with carbon dioxide capture and storage (CCS), nuclear power, renewable energy, and storage batteries in the power generation sector in Japan in 2050, which currently accounts for about 46%[15] of Japan's domestic supply of primary energy and is important for achieving carbon neutrality. On top of that, this study will use the Integrated Energy-Economy Model created by the authors by combining optimal power generation mix model and the econometric model using the linear planning method to simultaneously analyze how "macroeconomics such as total cost of power generation and transmission" and "gross domestic product (GDP)" change when the social tolerance of nuclear power and the hydrogen price changes.

Below, this paper consists of the following. Chapter 2 outlines of the model used and the main preconditions are described. Chapter 3 describes the results of the model analysis. After considering the relationship between power generation mix and economic growth, Chapter 4 describes the conclusions and policy implications from this study.

2. Evaluation Method

2-1. Integrated Economy-Energy Model

In order to simultaneously evaluate the effect of changes in the preconditions related to nuclear power generation and hydrogen price on the high and low costs of power generation and transmission and high and low economic growth (scale) in the case of restrictions for the power production sector to achieve carbon neutrality, this study adopts an "Integrated Energy-Economy Model" that combines a cost minimization optimal power generation mix model and an econometric model.

The cost-minimization optimal power generation mix model models Japan's power generation mix by a linear planning method. This model was based on Fuji and Komiyama (2017)[16] and improved by Matsuo et al. (2019)[17], Matsuo et al. (2020)[11] Okabayashi et al. (2021)[18] . It determines the introduction scale of equipment and technology that is the minimum cost according to the supply and demand of power. The objective function is the total cost of the system after discounting over a calculation period, and as a constraint formula, resource quantity constraints and power supply and demand balance constraints are considered. The regional division is nine regions that integrate Kyushu and Okinawa in the supply area of the former general electric utility, and the integrated region is connected by DC or AC interconnected power lines. The annual supply and demand of power is calculated by the granularity of 1 hour (365×24 = 8,760 divisions).

The econometric model was developed by Murota et al. (2005)[19] and improved by Yangagisawa (2008)[20], Komiyama et al. (2012)[21], Okabayashi et al. (2021)[18]. Based on the preconditions of overseas factors such as global trade, economic policies such as public investment, demographics, and energy prices such as fossil fuel prices, the model estimates various economic indicators, and sensitivity analysis of the national economy is also possible, focusing on GDP, investments constituting it, and imports and exports. It consists mainly of real expenditure module, wage price module, income distribution module, labor module, and can estimate the effect of changes in various exogenic variables on the economy as a whole. For details of the model, see Komiyama et al. (2012)[21], Okabayashi et al. (2021)[18].

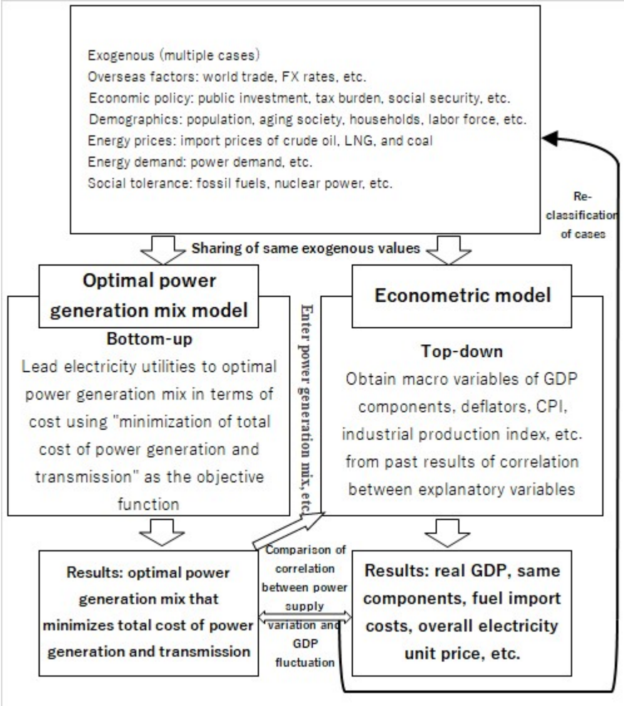

Fig. 1 Integrated Energy-Economy Model

2-2. Trial Calculation Case

This study does not cover conventional thermal power generation such as coal-, gas-, and oil-fired power generation based on the assumption of atmospheric emission of combustion CO_2 from fossil fuels; instead it covers carbon neutrality-compatible gas-fired power with CCS. As the assumption for 2050, Table 1 indicates a total of 12 cases, consisting of 4 cases each of (a) decommissioning case, (b) existing facility tolerance cases, and (c) new facility tolerance case as divided into groups according to the level of tolerance in the society of nuclear power plants, and hydrogen thermal fuel costs are 12 yen to 40 yen / Nm^3 using real prices in 2018. The following prices are all real 2018 prices.

Additionally, these 12 cases exemplified the characteristic case division that ultimately led to the significant conclusion presented, and in actual estimation, more than 150 cases were examined, with most of these introduced into the Integrated Energy-Economy Model, confirming the results.

Table 1 Comparison of Each Trial Calculation by Case Number

Group	Case no.	Nuclear power		Hydrogen price (yen/Nm^3)
		Existing	New	
(a) Nuclear power decommissioning case	①	×	×	12
	②	×	×	20
	③	×	×	30
	④	×	×	40
(b) Nuclear power existing facility tolerance case	⑤	○	×	12
	⑥	○	×	20
	⑦	○	×	30
	⑧	○	×	40
(c) Nuclear power new facility tolerance case	⑨	○	○	12
	⑩	○	○	20
	⑪	○	○	30
	⑫	○	○	40

2-3. Conditions

In all cases, in accordance with Matsuo et others (2019)[17], the preconditions were set assuming the energy mix of a carbon neutral state in Japan in 2050. However, some conditions were set independently according to the purpose of this study as follows.

(1) Amount of power generated

The amount of power generated was assumed to be about the technical progress scenario (1,003 TWh/year in 2050) in IEEJ Outlook 2021 (2020)[22], but since the amount of power generated including that not supplied to the electric power market increases or decreases due to the occurrence of output suppression of renewable energy, it is shown in the results (Table 8) described later.

(2) Nuclear power generation

As shown in Table 2, the power generation cost and performance of existing large reactors as at the current level were assumed. In 2050, the maximum installable amount of nuclear power generation capacity in 2050 was assumed to be 42.5 GW combining the total capacity of new reactors under construction and existing reactors, which had not been decommissioned as of October 2021. Assuming 60-year operation, by 2050, 17 GW of existing reactors will be decommissioned, but when the profitability of a new reactor is obtained and new expansion is socially acceptable, replacement is performed up to the interconnected capacity of the abolished power plant, and if it is not accepted, it is assumed that it will be decommissioned. Furthermore, the construction cost of reactors under construction or already in operation (collectively referred to as “existing reactors”) that do not reach 60 years by 2050 after the start of operation in 2050 is assumed to be a sunk cost of the electric utility and deducted from the capital cost at the time of calculation.

Table 2 Power Generation Cost/Performance Assumption (Nuclear Power)

Construction cost (1,000 yen/kW)	420
Service life (existing) (years)	60
Service life (new) (years)	40
Annual expense ratio (%)	4.5
In-house consumption rate (%)	4
Fuel cost (yen/kWh)	1.8
Upper limit of output increase (%)	2
Lower limit of output increase (%)	2
Upper limit of annual utilization rate (%)	80
Minimal output level (%)	80

(3) Renewable energy power generation

Referencing the cost reduction target for renewable energy by the Government's procurement price calculation committee (2021)[23] and the cost assumption for 2030 of the power generation cost verification working group report (2021)[24], this study assumed that the lower limit of the expected unit price range will be reached in the 2050 cross-section, and further assumed that solar power is 7.0 yen/kWh, onshore wind power is 8.5 yen/kWh, and offshore wind power is 10.0 yen/kWh, while construction cost and service life were assumed to be as shown in Table 3.

Table 3 Power Generation Cost Assumption （PV and Wind Power Generation）

		Standard
PV	Construction cost (1,000 yen/kW)	102
	Service life (years)	30
	Annual expense ratio (%)	1.4
Onshore wind	Construction cost (1,000 yen/kW)	190
	Service life (years)	30
	Annual expense ratio (%)	2.1
Offshore wind	Construction cost (1,000 yen/kW)	286
	Service life (years)	30
	Annual expense ratio (%)	4.4

The maximum installable amount of PV and wind power was set as shown in Table 4. Although the latest version (2021)[25] of the potential evaluation values by the Ministry of the Environment is used for both PV and wind power, the figures of Obane et al. (2019)[26] are used only for onshore wind power from the viewpoint of realistic land use constraints.

Table 4 Maximum Installable PV and Wind Power Precondition

Unit: GW	PV	Onshore wind	Offshore wind
Hokkaido	14.6	16.4	207.2
Tohoku	32.0	2.8	88.3
Tokyo	60.1	0.6	45.4
Hokuriku	7.8	0.2	3.5
Chubu	33.2	0.5	35.5
Kansai	28.8	0.6	7.4
Chugoku	17.2	0.8	4.2
Shikoku	10.7	0.5	14.7
Kyushu/Okinawa	31.0	2.2	54.0
Total	235.1	24.6	460.3

(4) Storage batteries

The storage battery cost was set at US$150/kWh in the middle case of Cole and Frazier (2019)[27] for lithium-ion batteries (Table 5). Furthermore, according to the above-mentioned past study[17], it is assumed that pumped-storage power generation (163 GWh) equivalent to existing facilities is used separately.

Table 5 Storage Battery Cost Assumption

Storage batteries (USD/kWh)*	150

*Each model was configured using 1 US dollar equals 110 Japanese yen.

(5) Thermal Power Generation in Response to Carbon Neutrality

This study assumed that all coal-, gas- and oil-fired power plants based on the assumption of atmospheric dissipation of combustion CO_2 will be decommissioned in a manner corresponding to carbon neutrality, and thermal power generation, which will continue to be an important adjustment power source, was examined on the assumption that only hydrogen power generation and gas thermal power with CCS can be used. The study also assumes that the entire amount of hydrogen and gas for thermal power will be imported, and the CCS method includes not only deep subterranean injection in Japan but also the case of transferring the collected CO_2 liquid overseas, including looping back with LNG, and injecting it underground, and both hydrogen-fired and gas-fired with CCS do not have an upper limit on the installation capacity of the power plant. In addition, gas thermal power with CCS incorporates the efficiency deterioration from the conventional gas thermal power plant based on IEA (2020)[28]. The assumptions of the power generation facilities are as shown in Table 6.

Table 6 Power Generation Cost Assumption
(Hydrogen Thermal and Gas Thermal with CCS)

	Hydrogen thermal	Gas thermal with CCS
Construction cost (1,000 yen/kW)	128	159.5
Service life (years)	40	40
Annual expense ratio (%)	2.4	2.4
Heat efficiency (%)	57	47*
In-house consumption rate (%)	2	2
Fuel cost	(Table 7)	(Table 7)
Upper limit of output increase (%)	26	44
Lower limit of output increase (%)	31	31
Upper limit of seasonal utilization rate (%)	95	95
Upper limit of annual utilization rate (%)	80	80
DSS operating ratio (%)	50	50
Minimal output level (%)	30	30

*After deducting energy consumption for CCS.

Fuel costs were set based on the fuel cost assumptions of RITE in the Hydrogen and Fuel Cell Strategy Roadmap (2019)[29] and the 43rd meeting of the Basic Policy Subcommittee 43rd (2021)[14], as shown in Table 1 and Table 7 below. In particular, the concept of case classification of hydrogen price (unit price) is as described at the beginning of 2.2 Trial Calculation Case.

Table 7 Fuel Cost Assumption and Hydrogen Price Case Classification

Gas price (yen/kWh)	16
CCS price (1,000 yen/t-CO_2)	10
Hydrogen price (yen/Nm^3)	12, 20, 30, 40

(6) Other Preconditions

As for the domestic rate of capital investment in power generation and transmission, the domestic rate of total investment in facilities and construction was assumed to be 95% for nuclear power, 80% for hydrogen thermal and gas thermal with CCS, 40% for storage batteries, 27% for PV, 23% for onshore wind power, and 22% for offshore wind power, referencing NEDO (2014)[30], Ishii (2014)[31], TEPCO (2020)[32], Mitsubishi Research Institute (2020)[33], Procurement Price Calculation Committee (2021)[23], and the 43rd meeting of the Basic Policy Subcommittee 43rd Meeting (2021) (RITE)[14]. In addition, carbon tax is not considered because it does not affect the power supply selection under carbon neutrality. Changes in the international competitiveness of imports and exports due to differences in environmental policies with other countries are not taken into account.

3. Evaluation Results

3-1. Evaluation Results using the Integrated Energy-Economy Model

The impact of the power generation mix on macroeconomic indicators is arranged and compared in Table 8 below, after using the Integrated Energy-Economy Model to derive the power generation mix in which the total cost of power generation and transmission is minimized.

Table 8 Power Generation Mix for Minimizing Total Cost of Power Generation and Transmission and Macro Economy

Group	(a)Nuclear power decommissioning case			
Case Number Hydrogen (yen/Nm^3)	① 12	② 20	③ 30	④ 40
Existing nuclear power (GW)	―	―	―	―
New nuclear power(GW)	―	―	―	―
Nuclear total (GW)	―	―	―	―
Hydrogen thermal (GW)	162	161	121	―
Gas thermal with CCS (GW)	―	―	―	99
Thermal total (GW)	162	161	121	99
PV (GW)	79	194	165	182
Onshore wind (GW)	12	17	25	25
Offshore wind (GW)	―	―	156	186
Geothermal/biomass (GW)	16	16	16	16
Hydroelectric (GW)	20	20	20	20
Renewables total (GW)	127	246	382	428
Installed capacity (GW)	289	407	503	528
Storage batteries (GWh)	0.2	0.5	58	93
Power generation amount (TWh)	1,009	1,013	1,026	1,031
Total cost of power generation and transmission (Tn yen)	**10.65**	**12.39**	**14.34**	**15.00**
Same as above (yen/kWh)	**10.55**	**12.22**	**13.98**	**14.55**
Same as above rank () is overall rank	**1 (4)**	**2 (8)**	**3 (11)**	**4 (12)**
Real GDP (Tn yen)	**628.0**	**628.8**	**629.2**	**628.4**
Same as above rank () is overall rank	**4 (12)**	**2 (10)**	**1 (8)**	**3 (11)**
Private consumption expenditure (Tn yen)	318.9	319.2	319.3	319.1
Government consumption expenditure (Tn yen)	76.7	76.7	76.7	76.7
Private sector capital investment (Tn yen)	84.7	86.1	89.1	88.9
Fuel imports (Tn yen)	28.9	27.2	24.0	23.2
Overall rates for electricity and lighting (yen/kWh)	23.64	25.67	30.21	30.75

Group	(b) Nuclear power existing facility tolerance case			
Case Number Hydrogen (yen/Nm^3)	⑤ 12	⑥ 20	⑦ 30	⑧ 40
Existing nuclear power (GW)	26	26	26	26
New nuclear power (GW)	—	—	—	—
Nuclear total (GW)	26	26	26	26
Hydrogen thermal (GW)	137	137	101	—
Gas thermal with CCS (GW)	—	—	—	83
Thermal total (GW)	137	137	101	83
PV (GW)	67	168	145	161
Onshore wind (GW)	10	12	25	25
Offshore wind (GW)	—	—	120	135
Geothermal/biomass (GW)	16	16	16	16
Hydroelectric (GW)	20	20	20	20
Renewables total (GW)	112	216	326	357
Installed capacity (GW)	275	379	452	466
Storage batteries (GWh)	0.2	0.3	56	84
Power generation amount (TWh)	1,009	1,014	1,026	1,029
Total cost of power generation and transmission (Tn yen)	**9.84**	**11.15**	**12.55**	**12.99**
Same as above (yen/kWh)	**9.75**	**11.00**	**12.23**	**12.62**
Same as above rank () is overall rank	**1 (2)**	**2 (5)**	**3 (9)**	**4 (10)**
Real GDP (Tn yen)	**629.1**	**630.0**	**630.2**	**629.6**
Same as above rank () is overall rank	**4 (9)**	**2 (6)**	**1 (4)**	**3 (7)**
Private consumption expenditure (Tn yen)	319.8	320.2	320.3	320.1
Government consumption expenditure (Tn yen)	76.7	76.7	76.7	76.7
Private sector capital investment (Tn yen)	84.9	86.2	88.5	88.0
Fuel imports (Tn yen)	27.5	25.8	23.3	22.8
Overall rates for electricity and lighting (yen/kWh)	23.60	25.06	28.47	28.49

Group	(c)Nuclear power new facility tolerance case			
Case Number Hydrogen (yen/Nm^3)	⑨ 12	⑩ 20	⑪ 30	⑫ 40
Existing nuclear power (GW)	26	26	26	26
New nuclear power(GW)	16	17	17	17
Nuclear total (GW)	42	43	43	43
Hydrogen thermal (GW)	120	120	88	—
Gas thermal with CCS (GW)	—	—	—	69
Thermal total (GW)	120	120	88	69
PV (GW)	53	147	168	194
Onshore wind (GW)	9	12	25	25
Offshore wind (GW)	—	—	66	76
Geothermal/biomass (GW)	16	16	16	16
Hydroelectric (GW)	20	20	20	20
Renewables total (GW)	99	194	290	330
Installed capacity (GW)	261	357	421	441
Storage batteries (GWh)	0.1	0.2	51	84
Power generation amount (TWh)	1,009	1,014	1,025	1,030
Total cost of power generation and transmission (Tn yen)	**9.60**	**10.63**	**11.79**	**12.23**
Same as above (yen/kWh)	**9.51**	**10.48**	**11.51**	**11.88**
Same as above rank () is overall rank	**1 (1)**	**2 (3)**	**3 (6)**	**4 (7)**
Real GDP (Tn yen)	**630.0**	**631.2**	**631.0**	**630.3**
Same as above rank () is overall rank	**4 (5)**	**1 (1)**	**2 (2)**	**3 (3)**
Private consumption expenditure (Tn yen)	320.4	321.0	320.9	320.7
Government consumption expenditure (Tn yen)	76.7	76.7	76.7	76.7
Private sector capital investment (Tn yen)	85.0	86.2	87.7	87.3
Fuel imports (Tn yen)	26.7	25.0	23.1	22.6
Overall rates for electricity and lighting (yen/kWh)	22.91	24.15	26.64	26.80

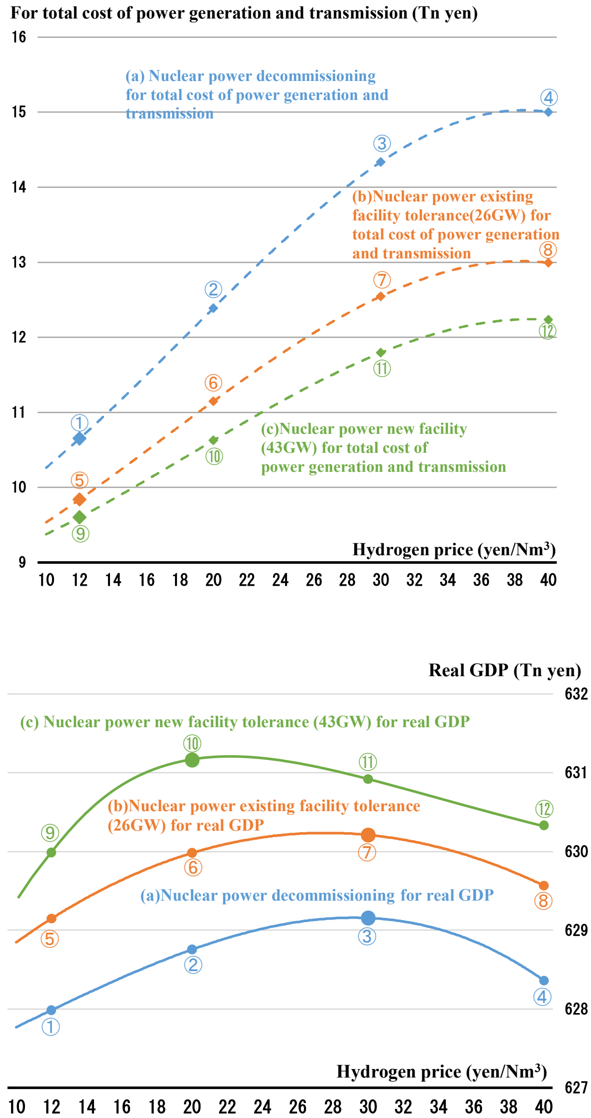

Fig. 2 Correlation between Hydrogen Price and Total Cost of Power Generation and Transmission / Real GDP

(1) Nuclear power helps reduce total cost of power generation and transmission and increase real GDP

As shown in Fig. 2, in the upper graph of the total cost of power generation and transmission, (c) < (b) < (a), and the larger the installed capacity of nuclear power, the lower the cost, resulting in a higher reading (ranking). On the other hand, in the lower graph of real GDP, (a) < (b) < (c), and the larger the installed capacity of nuclear power, the larger the absolute amount, and the higher the reading (ranking). When (a) and (c) are compared, there is a divergence of about 2 to 3 trillion yen in both the total cost of power generation and transmission and real GDP.

This is because, in addition to the lower cost of power generation and transmission considered to be a strength in the past, nuclear power has a high ripple effect on capital investment due to its large-scale construction costs and high domestic production rate of materials and equipment (increase in private capital investment), consumption is stimulated due to an increase in employee income etc. (increase in private consumption expenditure), and the import amount of fuel such as hydrogen is also suppressed (decrease in fuel imports), which is expected to boost GDP.

(2) In terms of hydrogen prices, "less expensive is not always better"

Generally speaking, it is believed that "the lower the price of fuel including hydrogen, the better for both electric utilities and the Japanese economy," but different results were obtained in the Integrated Energy-Economy Model.

First of all, as can be confirmed by looking left to right in the upper graph of Fig. 2, the total cost of power generation and transmission of electric utilities falls under the belief "the lower the hydrogen price, the better." All dashed lines in the upper graph show that the decrease in hydrogen price leads to a decrease in the total cost of power generation and transmission. Furthermore, this is because at the time it reaches a plateau from (3), (7), and (11) to (4), (8), and (12) on the right, as hydrogen prices increase, they are completely replaced by gas-fired power plants with CCS that demonstrate the same adjusted power supply functions.

However, the real GDP of the lower graph is different from that of the top in that it the curves outward on top. On the right side from the vicinity of (3), (7), and (10), which are the tops of the arc, the decrease in the total cost of power generation and transmission and the increase in real GDP are both realized, resulting in "the lower the fuel price, the better," but on the left side of the top, "the lower the fuel price, the worse," which is the opposite.

First, on the right side of the apex, hydrogen thermal power (gas thermal power with CCS when hydrogen price is 40 yen / Nm^3 or more) is treated as "adjusted power source", and it compensates for the insufficient amount of power that cannot be generated by renewable energy and nuclear power introduced in large quantities. The "downward effect" of the increase in fuel imports due to soaring hydrogen prices will act more strongly than the "upward effect" in real GDP due to the large introduction of renewable energy and storage batteries and due to capital investment and consumption stimulus. For this reason, the higher the hydrogen price (the lower), the lower the real GDP, and the lower (the higher) the fuel price, which means "the lower the fuel price, the better." However, the domestic production rate of renewable energy is set closely to the current state at 27% for solar power generation, 23% for onshore wind power, and 22 % for offshore wind power. By increasing the domestic production rate of renewable energy, there is a possibility that real GDP can be increased in response to the increase in fuel imports under high hydrogen prices.

On the other hand, on the left side of the top of the lower graph of Figure 2, hydrogen thermal power is treated as the "main power source," most of the renewable energy is withdrawn from the market, and in some cases such as (9) in Table 8, withdrawal of nuclear power is also started. At this time, for real GDP, all of the case (1), (5) and (9) in group (a) to (c) sink to the lowest (4th) of, and (1) nuclear power decommissioning case was naturally the lowest overall (12th). The first reason for this is that renewable energy has a low overall utilization rate, and since there is a need to introduce more installed capacity (kW) than hydrogen thermal power per amount of power generation, when the introduction is suppressed, the total construction investment is rapidly reduced. PV generation (102,000 yen/kW), which sees a significant withdrawal when hydrogen thermal power plants are cheaper, has a lower capital cost than hydrogen thermal power (128,000 yen/kW), has a lower domestic production rate, and the multiplier effect is smaller than hydrogen thermal power, exceeding the reduction effect of the aforementioned investment. The second is that hydrogen thermal power, which is introduced instead of renewable energy without the need for fuel, requires continuous fuel imports.

(3) Substitutability of hydrogen thermal and gas thermal with CCS

In the cases of hydrogen price 40 yen / Nm^3 of (4), (8), and (12), hydrogen thermal power is replaced by gas thermal power with CCS of the same adjusted power source and withdrawal occurs, while in cases of hydrogen price 30 yen / Nm^3 (3) of (7) and (11), conversely, the share of hydrogen thermal power is 100%. At a hydrogen price of upper 30 yen/Nm^3, hydrogen thermal power and gas thermal power with CCS competed for a share of 100-0. On the assumption that it is completely substituted depending on the price as the same adjustment power source, such extreme results are derived, but it results in the difficult problem of optimization analysis of equipment and technology selection. In fact, it is difficult to construct hydrogen-fired or gas-fired power plants with CCS in advance after predicting the hydrogen price around 2050 based on price fluctuations. In addition to the difficulty of changing the equipment capacity immediately, it is also expected that the flexibility and stability of the procurement quantity of the fuel contract will be difficult at the same time, suggesting the possibility that both may actually have to be mixed.

(4) Evaluation Results under the Integrated Energy-Economy Model

If only the calculation results of these 12 cases are compared, the minimization of the total cost of power generation and transmission (1st overall) is case (9) (Nuclear Power New Facility Tolerance Case, 5th in real GDP at 12 yen/Nm^3) and the maximization of real GDP due to the spread of the power generation mix to the entire Japanese economy (1st overall) is said to be divided from the case (10) (Nuclear Power New Facility Tolerance Case, 20 yen/Nm^3, total cost of power generation and transmission) and the evaluation was divided.

Fundamentally speaking, however, it is a higher priority to aim at improving Japan's macroeconomic capacity as a whole rather than minimizing the total cost of power generation and transmission, and for the choice to eliminate renewable energy by requesting hydrogen thermal power, a situation (10) in which the baseload nuclear power, peak-compatible hydrogen thermal or gas thermal with CCS, and renewable energy contributing to CO_2 reduction are well balanced, even under carbon neutrality is believed to constitute the optimal power generation mix for 2050.

4. Conclusion

In this study, the authors input the 12 scenario assumptions of targeting Japan's electric power sector in 2050 repeatedly into the Integrated Energy-Economy Model, which combines two different models, for power generation mix such as nuclear power, hydrogen thermal power, gas-fired thermal power with CCS, renewable energy, and storage batteries, and factually confirmed that the minimized total cost of power generation and transmission by electric utilities even under strict restrictions of carbon neutrality does not necessarily maximize the real GDP of the Japanese economy.

Although this finding is from calculation results, there is a gap of about 200 billion yen between the difference in total cost of power generation and transmission of 1.0 trillion yen and real GDP of 1.2 trillion yen between cases (9) and (10). It is possible that economic rationality as a whole is higher in case (10).

Therefore, in Japan's pursuit of carbon neutrality, considering the degree of influence on the macroeconomics to a certain extent, in addition to minimizing the general total cost of power generation and transmission for power generation mix, may provide a new way of thinking on the assumption of energy mix and energy prices. Recently, discussions are taking place in Japan and abroad on the risk of stable supply of electric power when the power generation mix is biased toward LNG thermal power. Although it bears repeating, it must be recognized that the state in which some power supply -- hydrogen thermal power in this study -- culls other power sources in the future may not always be rational from a macroeconomic point of view, and at the same time, narrowing the width of the power generation mix raises the risk of hindering stable supply.

Paradoxically, it can be said that one possibility of growing the Japanese economy while considering power generation and transmission and achieving carbon neutrality by closely coordinating policy makers and electric utilities and appropriately carrying out energy and economic policies has been shown.

In this study, assuming that the technology and cost that can be estimated at present, the authors intended to propose the impact of changes in power generation mix and fuel prices on the macro economy for the cross section of 2050 to achieve carbon neutrality.

In the real economy, the model cannot reflect the situation such as the continuous change in the cost of CO_2 disposal due to market prices and other factors acting on hydrogen and gas prices and CCS prices, the difficulty of foreseeing the future price of fuel at the start of power source construction, and the construction of power sources requires several years of construction and that installed capacity cannot be changed overnight.

Regarding the setting of preconditions, it should be noted that the evaluation results can change due to changes in the preconditions such as soaring or crashing fuel prices such as gas and hydrogen, construction investment amounts of each power source and storage battery, domestic production rate of materials and equipment, changes in equipment efficiency and utilization rate, continuous occurrence of windless and non-sunshine periods, occurrence of inter-border adjustment measures based on energy and CO_2 prices, and changes in international competitiveness.

As far as the authors know, there is no prior study that uses concrete numbers to comprehensively discusses the relationship between the total cost of power generation and transmission and various economic indicators, focusing on the change in fuel prices under carbon neutrality restrictions and the social tolerance of each power source, and it is expected that this research will be a starting point for presenting a useful direction to both policy makers and electric utilities.

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Evaluation of Saudi Arabia's Climate Change Policy: Circular Carbon Economy and Green Initiatives◆

Shigeto Kondo*

Abstract

Saudi Arabia announced on October 23, 2021, that it aims for net zero greenhouse gas emissions by 2060 and will reduce 278 million tons in 2030 compared to the business-as-usual (BAU) scenario. However, there is not yet a detailed path to reach the 2060 goal. The 2030 goal may not necessarily be an ambitious goal if it permits increase of emissions from the 2019 level. The direction Saudi Arabia has taken, however, can be highly appreciated. The Circular Carbon Economy, which explored various ways to utilize carbon, is an important perspective in the debate on climate change. In addition, the Green Initiatives focus on renewable energy, afforestation, and clean energy technology which are widely welcomed by the international community as an important direction. Therefore, although the feasibility of the 2060 target cannot be fully foreseen, the direction of Saudi Arabia's climate change policy itself can be positively evaluated.

Key words: Saudi Arabia, Circular Carbon Economy, Green Initiatives, Net Zero

1. Introduction

On October 23, 2021, Saudi Arabia announced that it would seek to achieve net zero greenhouse gas emissions by 2060 and reduce GHG emissions in 2030 by 278 million tons from the business-as-usual scenario. As an approach to these goals, Saudi Arabia has adopted the concepts of the Circular Carbon Economy (CCE) and the Green Initiatives. This paper attempts to clarify the characteristics of the two concepts and consider the feasibility of the 2030 and 2060 goals.

2. CCE

Saudi Arabia took maximum advantage of its chairmanship for a Group of 20 summit in 2020 to promote the CCE concept. At the G20 summit, the CCE was defined as "a voluntary, holistic, integrated, inclusive, pragmatic and complementary approach to promote economic growth while enhancing environmental stewardship through managing emissions in all sectors including, but not limited to, energy, industry, mobility and food." In other words, it refers to a system to run an economy while circulating carbon.

The CCE concept was developed in 2019 by Eric Williams[1], a research fellow at the King Abdullah Petroleum Studies and Research Center (KAPSARC), based on the idea of regarding atmospheric carbon as circular and U.S. architect William McDonough's idea of considering carbon as a usable resource[2].

Supporting the CCE are 4R (reduce, reuse, recycle and remove carbon) technologies. Table 1 indicates representative 4R technologies. These technologies had been individually cited. The CCE concept has made a difference by systematizing them.

◆ This article is a presenting paper at the 38th Conference on Energy, Economy, and Environment that Japan Society of Energy and Resources (JSER) hosted.

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1 William McDonough, "Carbon Is Not the Enemy," Nature, Vol. 539 (November 2016) pp. 349-351.

2 Eric Williams, *Achieving Climate Goals by Closing the Loop in a Circular Carbon Economy*, November 6, 2019, King Abdullah Petroleum Studies and Research Center.

Table 1 4R technologies in the CCE concept[3]

Reduce	Reuse	Recycle	Remove
Energy saving Renewable energy Nuclear	Enhanced oil recovery (EOR)	Conversion to chemical products Conversion to fuels	Direct air capture (DAC) Carbon capture and storage (CCS) Afforestation

Notably, the CCE concept does not necessarily regard carbon as evil. Carbon is regarded as useful for enhanced oil recovery and available for conversion to chemical products and fuels. Hopes are placed on direct air capture (DAC) technology to capture emitted carbon. The CCE concept sheds light on technologies to utilize and capture carbon and paves the way for an argument that fossil fuel consumption emitting carbon dioxide would have no climate change problem if such technologies were developed. As a matter of course, DAC and carbon capture and storage (CCS) technologies still have cost problems and are not available for immediate commercialization. The CCE concept places hopes on future technological development.

3. Green initiatives

The green initiatives are the Saudi Green Initiative and the Middle East Green Initiative announced by Saudi Arabia in March 2021. The Saudi Green Initiative calls for planting 10 billion trees in Saudi Arabia in several decades, boosting renewable energy's share of its power mix to 50% by 2030 and utilizing clean hydrocarbon technologies. The Middle East Green Initiative seeks to plant 40 billion trees in countries neighboring Saudi Arabia in several decades and promote cooperation between Saudi Arabia and its neighbors in the clean energy field.

The green initiatives indicate how technologies given in the CCE concept would be used for climate change countermeasures. Particularly, they cite afforestation, renewable energy and clean hydrocarbon technologies. The technologies are expected to include carbon capture, utilization and storage (CCUS), cutting methane leaks and using renewable energy to extract fossil fuels[4]. These initiatives thus pick up technologies that are easier to commercialize among CCE-related technologies.

Specifics of the green initiatives were clarified at the Saudi Green Initiative Forum and the Middle East Green Initiative Summit in October 2021. At the forum, Saudi Arabia set a goal of cutting greenhouse gas emissions by 278 million tons from the business-as-usual scenario by 2030 and presented the Updated First Nationally Determined Contribution (NDC) including the goal. The NDC clarified a policy of focusing on energy saving, renewable energy, green hydrogen, ammonia, CCUS, blue hydrogen, gas utilization and methane reduction[5]. At the Middle East Green Initiative Summit, a plan was given to invest $10.4 billion in clean energy projects.

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3 Adam Sieminski, "Circular Carbon Economy," International CCUS and Hydrogen Symposium, hosted by the Ministry of Environment, Japan, March 12, 2021, p.10, http://www.env.go.jp/earth/Speech%2012.pdf/Speech%2012.pdf (access date: 2021.10.27)

4 "Saudi Arabia aims for 50% renewable energy by 2030, backs huge tree planting initiative," 2021.3.31, https://www.climatechangenews.com/2021/03/31/saudi- arabia-aims-50-renewable-energy-2030-backs-huge-tree-planting-initiative/ (access date: 2021.10.27)

5 Kingdom of Saudi Arabia, "Updated First Nationally Determined Contribution," 2021 Submission to UNFCCC, https://www4.unfccc.int/sites/ndcstaging/PublishedDocuments/Saudi%20Arabia%20First/KSA%20NDC%202021%20FINAL%20v24%20Submitted%20to%20UNFCCC.pdf (access date: 2021.10.27)

4. Feasibility of 2030/2060 goals

At the forum, Saudi Energy Minister Abdulaziz bin Salman explained that the reduction of 278 million tons in GHG emissions by 2030 would result in the year's emissions between 741 million and 849 million tons. This estimate, which was not included in the Updated First NDC, means that GHG emissions would increase from 660 million tons in 2019. While Saudi Arabia has emphasized that the emission reduction goal more than doubles from the initial goal of 130 million tons before updating, it admits that emissions in 2030 would increase from 2019. Thus the new goal may not necessarily be an extremely ambitious one. Fig. 1 indicates that Saudi Arabia's CO_2 emissions have persistently increased. Even the new goal confirms the trend.

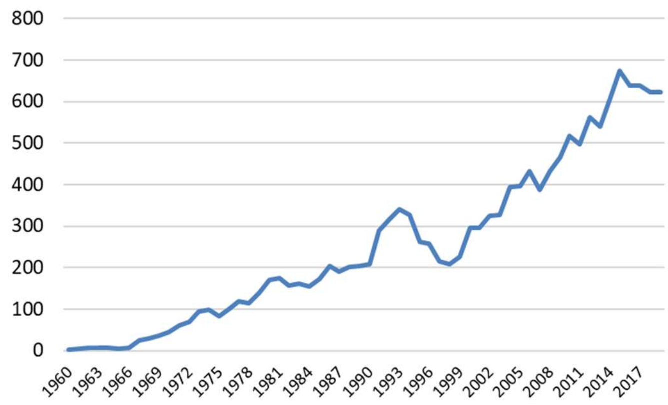

Fig. 1 CO_2 emissions in Saudi Arabia (in millions of tons)[6]

Various efforts may be required to achieve net zero emissions in 2060. Energy Minister Abdulaziz explained that the target year was set at 2060 because many technologies for reducing emissions would fail to mature before 2040. These technologies apparently include CCUS that has failed to diffuse due to high costs. This means that the resolution of the cost problem would hold the key to the achievement of the net zero emission goal for 2060.

In addition, Saudi Arabia will have to rapidly increase renewable energy's share of the power mix. In April 2021, Saudi Arabia managed to open its first commercial-scale solar photovoltaics plant. Earlier, the renewable energy share was close to zero. Many renewable energy projects are being launched, but how fast the renewable energy share would rise is difficult to predict. This is the same case with progress in energy savings and the diffusion of electric vehicles. The 2060 zero emission goal represents hopes, failing to provide any specific path to the goal or having any concrete ground.

Nevertheless, the direction given by Saudi Arabia may be commendable. The CCE concept exploring various carbon uses has caused a stir in climate change talks. The direction of the green initiatives seeking renewable energy expansion, afforestation and clean energy technology development is also unarguable in the international community. While the feasibility of the 2060 goal is uncertain, the direction of Saudi Arabia's climate change countermeasures is apparently commendable.

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6 Global Carbon Project, http://www.globalcarbonatlas.org/en/CO2-emissions (access date: 2021.10.27)

Economics of Hydrogen Production from Electrolyzer-Battery Hybrid System Using Surplus Electricity◆

Yoshiaki Shibata* Yu Nagatomi**

Abstract

The production of hydrogen from electrolyzers using surplus electricity faces the challenge of high cost due mainly to the low capacity factor of electrolyzers. Smoothing the input power to electrolyzers by using a battery may be one way to elevate the capacity factor. This study developed an hourly simulation model for hydrogen production by an electrolyzer-battery hybrid system, and evaluated the impact on the hydrogen production cost, using the surplus electricity profile in the Hokkaido region determined by the power generation mix optimization model. The results showed that introducing the battery had no effect on reducing the cost of hydrogen production. This is because the cost of the battery far exceeded the reduction in hydrogen production cost gained by improving the capacity factor of the electrolyzer. In order to identify the positive contribution of the battery, further analyses are required based on a larger scale of surplus electricity or direct input of variable renewable energy to the hybrid system.

Key words: Hydrogen, Electrolyzer, Battery, Surplus electricity, Power to gas

1. Introduction

Batteries and electrolysis are currently both attracting strong interest as a means to ease the output fluctuations of power from variable renewable energy (VRE). Many studies have been published on easing output fluctuations for both batteries and electrolysis. In recent years, studies have also been conducted to assess the combination of these technologies, which have distinctly different technical characteristics, for their potential to increase grid flexibility and reduce hydrogen production cost. For instance, one research[1)] analyzed the coordinated operation of batteries and electrolysis by retailers for the purpose of compensating the VRE imbalance.

Meanwhile, from the perspective of hydrogen production cost, another research[2)] indicated that the cost can be reduced by using batteries to level the solar PV power input into electrolyzers and thereby improving their capacity factor. As well as the direct supply of VRE described above, hydrogen can also be produced using surplus electricity.[3)] However, as surplus electricity is assumed to be generated less frequently and on a smaller scale than by solar PV generation, it is not clear whether the reduction in hydrogen production cost achieved by using batteries to level the supply of surplus electricity to electrolyzers would exceed the additional costs of installing batteries.

Accordingly, this study assesses the economics of hydrogen production of the electrolyzer-battery hybrid system using surplus electricity by identifying a surplus electricity profile that is expected to occur in real life using the power generation mix optimization model[4)]. The profile was identified for the Hokkaido region, where relatively large amounts of surplus electricity can be expected.

2. Analytical framework

First, we began by establishing multiple VRE capacity scenarios and identifying the full-year surplus electricity profile for each scenario using the power generation mix optimization model. Several combinations of electrolyzer and battery capacities were prepared for the surplus electricity capacity for each scenario. Then, a simplified simulation was conducted for each combination to determine the amount of surplus electricity supplied directly into the electrolyzers and via batteries

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(Fig. 1), and based on these results, the capacity factor of the electrolyzers and hydrogen production costs were analyzed.

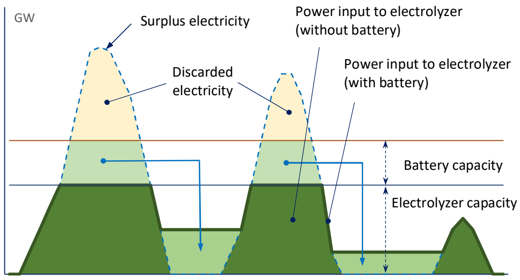

Fig. 1 Operation Pattern of Electrolyzer-Battery Hybrid System for Hydrogen Production Using Surplus Electricity

3. Surplus Electricity Profile

In this study, we used the power generation mix optimization model developed through joint research by the Institute of Energy Economics, Japan and the Fujii-Komiyama Laboratory of the University of Tokyo. The model employed the linear programming method to simulate an economically-rational electricity supply-demand operation with the minimum total cost. Xpress was used as the optimization software. Refer to Reference 4) for details.

3-1. Assumptions

The target region of this study was Hokkaido. However, as the surplus electricity generated in this region is affected by other regions through inter-regional transmission lines, we conducted an analysis of the entire country using the power generation mix optimization model, and determined the surplus electricity profile for Hokkaido based on the result of the nationwide analysis. The following assumptions were adopted.

- Electricity demand: We referred to the user-end demand data for each area published by the Organization for Cross-regional Coordination of Transmission Operators, Japan (OCCTO) (up to 2030). For 2031 and beyond, the figures for 2030 were used.
- Cross-regional operation: The thermal capacity limit of OCCTO's forecasts was adopted as the upper limit for the amount of electricity carried through HVDC Hokkaido-Honshu and other inter-regional transmission lines.
- Thermal power: Both existing plants and planned ones were taken into account.
- Nuclear power: For the Hokkaido region, we assumed that Tomari Units 1-3 had restarted. For the capacity factor, we referred to the data from the Electricity Systems Working Group (hereafter, "the Systems WG") under METI's Advisory Committee for Natural Resources and Energy[5].
- Large-scale hydropower: The increase in capacity anticipated under the Sixth Strategic Energy Plan[6] (hereafter, "the new Strategic Plan") was included in the assumption in accordance with the Systems WG. We referred to the capacity factor indicated by the Systems WG (around 30%).
- Biomass: We assumed that the FIT-licensed capacity in the new Strategic Plan would be reached in 2030, considering the rate of implementation.
- Geothermal: We assumed that capacity would increase toward the 2030 new Strategic Plan target, considering the projects being planned. The capacity was allocated proportionally to all regions.
- Pumped storage hydropower: We adopted the same assumption as the Systems WG.
- Solar PV: For 2030, the nationwide target capacity in the new Strategic Plan was allocated proportionally to all regions based on the FIT licensing information, considering the rate of implementation. For 2030 through 2040, we referred to the rate of increase in the IEA's Stated Policies Scenario (STEPS) cases[7].

- Wind power: For 2030, the nationwide target capacity in the new Strategic Plan was allocated proportionally to all regions, considering the rate of implementation based on environment assessment data information[8]. For 2040, we referred to the figures for the 45 GW offshore wind power scenario of OCCTO's *Master Plan Study Committee*[9].
- For batteries, no additional capacities other than the already installed battery substations were considered.

The VRE capacity assumption for Hokkaido is given in Table 1. Scenario 1, which represents our estimate for 2030, anticipates 2.5 GW of solar PV and 5.4 GW of wind power. Scenario 2, which represents a longer-term estimate for 2040, anticipates 3.19 GW of solar PV and 16.1 GW of wind power.

Table 1 VRE Deployment Scenarios

	Solar PV	On-shore Wind	Off-shore Wind
Scenario 1	2.5GW	5.4GW	
Scenario 2	3.19GW	1.48GW	14.65GW

Note: Scenario 1 represents our estimate for 2030 and Scenario 2 for 2040.

3-2. Results

Fig. 2 indicates the duration curve for the surplus electricity in each scenario. For Scenario 1, the VRE surplus rate (i.e. surplus electricity divided by the possible generation output) is 15% and the load rate of surplus electricity (i.e. average surplus electricity output divided by the maximum surplus electricity output) is 5%. Meanwhile, for Scenario 2, which has a larger VRE capacity, the surplus rate of VRE is higher with 46% and the load rate of surplus electricity with 14%.

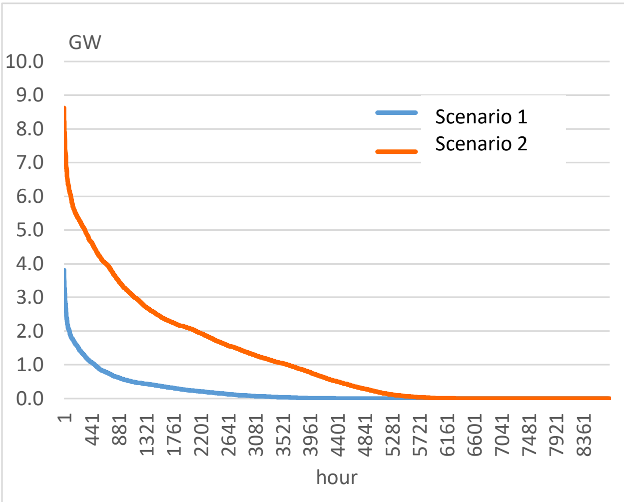

Fig. 2 Duration Curve of Surplus Electricity

4. Economics of Hydrogen Production from Electrolyzer-Battery Hybrid System

4-1. Assumptions

The specific electricity input of hydrogen production from electrolysis was set to 4.72 kWh/Nm^3-H_2 (i.e. 52.9 kWh/kg-H_2), assuming the use of pressurized hydrogen production and including the motor required for pressurizing. The charging/discharging efficiency of the battery was set to 90% × 90% and the self-discharge rate to 0.02%/h. Facility costs of 50,000 yen/kW for electrolysis, 20,000 yen/kWh for battery cell stacks, and 40,000 yen/kW for power conditioner systems (PCS) were also factored in. The capacity storage time of the batteries was set to 5 hours. The product life of all facilities was set to 20 years, with a discount rate of 5%.

4-2. Analysis results

The analysis results for the economics of hydrogen production are shown in Fig. 3 for Scenario 1 and in Fig. 4 for Scenario 2. As the purpose of this study is to assess the reduction in the hydrogen production cost when batteries are installed to improve the capacity factor of electrolyzers, among the levelized costs of hydrogen (LCOH), only the levelized cost related to facilities (LCOH_CAPEX) was considered as the economic efficiency indicator.

When installing batteries, it is necessary to take into account the roundtrip efficiency of batteries and additional electricity cost arising from self-discharge losses. However, for simplification these factors are disregarded in the following discussions.

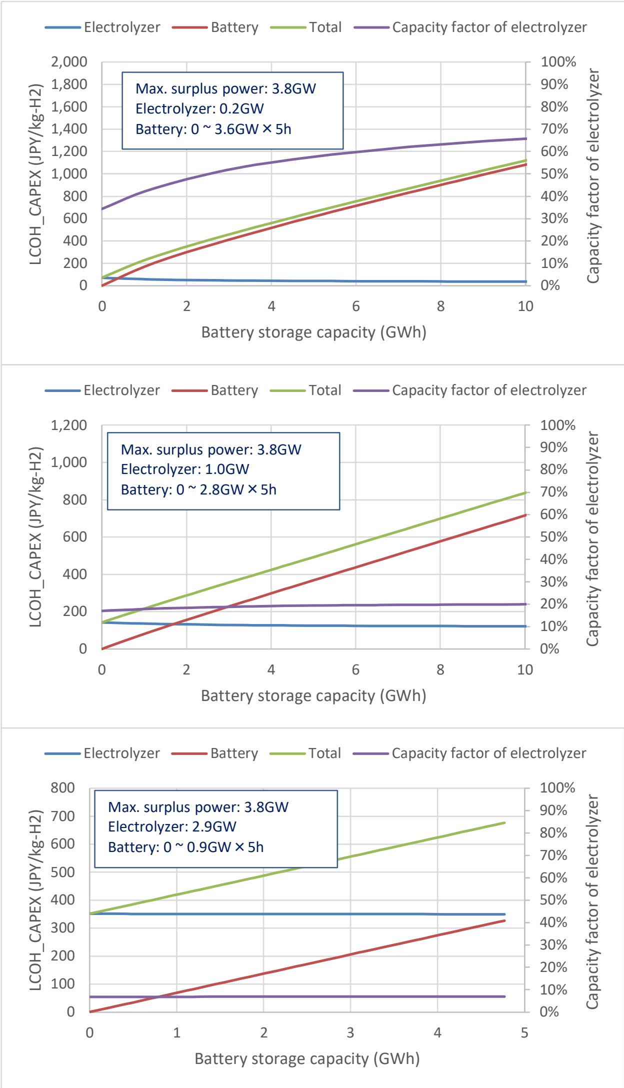

Fig. 3 CAPEX in LCOH: Scenario 1

For Scenario 1, which has maximum surplus electricity of 3.8 GW, the results are indicated for three cases, namely with an electrolyzer capacity of 0.2 GW, 1.0 GW, and 2.9 GW, respectively (Fig.3). For each of these cases, the difference between the maximum surplus electricity and the electrolyzer capacity represents the maximum battery capacity that can be introduced (in GW), and analyses were conducted for a battery capacity ranging from 0 GW to the maximum battery capacity. The battery capacity (GW) multiplied by 5 hours (described earlier) is the battery capacity and is plotted on the horizontal axis. For the case where the electrolyzer capacity is 0.2 GW (top row in Fig. 3), we can see that the electrolyzer capacity factor improves as more battery capacity is installed: the electrolyzer capacity factor is 34% when the battery capacity is 0, but it goes up to nearly 70% when 10 GWh (i.e., 2 GW x 5 hours) of battery capacity is introduced. However, the additional cost associated with introducing battery capacity is far greater than the decrease in hydrogen production cost resulting from an improved electrolyzer efficiency, and as a whole, there is no reduction in hydrogen production costs resulting from introducing batteries. As the electrolysis capacity increases (from the top row to the middle, and then to the bottom in Fig. 3), the capacity factor improvement effect of introducing batteries decreases.

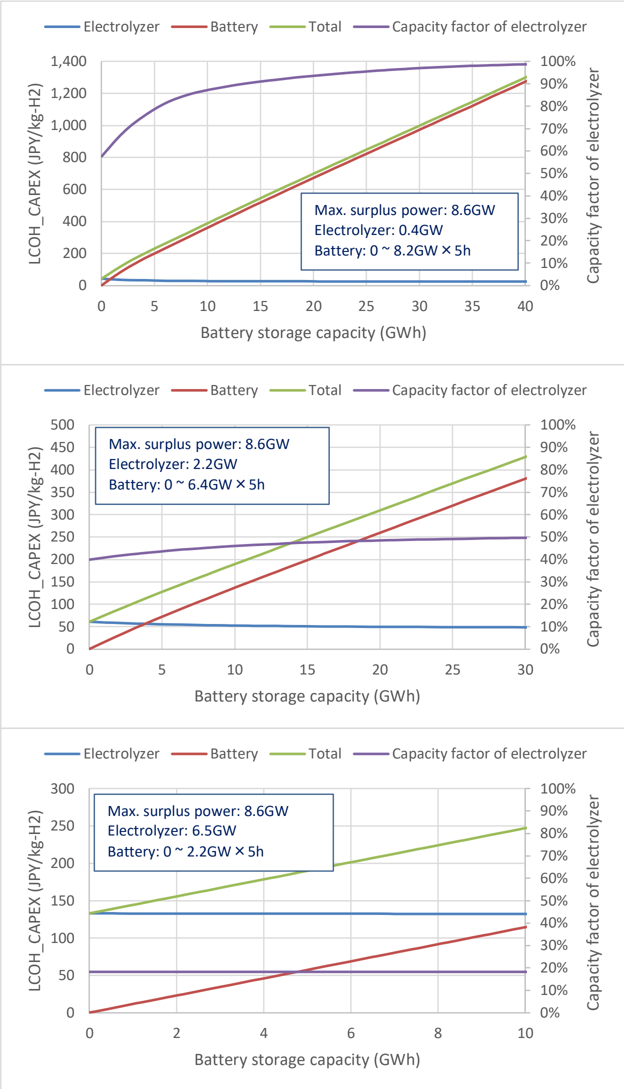

Fig. 4 CAPEX in LCOH: Scenario 1: Scenario 2

This occurs because as the electrolyzer capacity increases, so does the amount of surplus electricity supplied directly into the electrolyzer, and thus the electricity to be supplied via the batteries becomes less in amount and frequency. The same trend can be observed in Scenario 2 (Fig. 4) which has a larger amount of surplus electricity.

As mentioned earlier, since battery costs would increase even more when the roundtrip efficiency and self-discharge losses of batteries are taken into account, it is not worth installing batteries to improve the electrolyzer capacity factor in terms of reducing hydrogen production costs.

Needless to say, the effect of battery installation also depends on the relative relationship between the costs of electrolyzers and batteries. When the anticipated facility cost for electrolyzers was set at a fixed level and that for batteries was gradually lowered to find the conditions at which LCOH_CAPEX becomes the smallest, the lowest point was found to be one-twentieth of what we expected (Fig. 5).

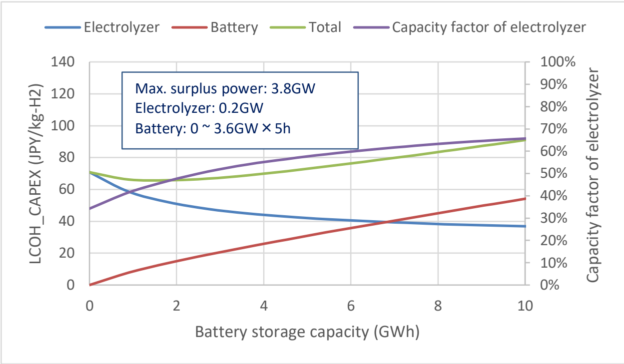

Fig. 5 CAPEX in LCOH: Scenario 1 & Battery cost reduction

Note: CAPEX of battery is assumed to be 1/20.

5. Conclusion

This study assessed the economics of hydrogen production of the electrolyzer-battery hybrid system using surplus electricity. Installing batteries would level the supply of surplus electricity into electrolyzers and thereby improve their capacity factor. However, the study found that the additional facility cost associated with introducing batteries is far greater than the reduction in the hydrogen production cost resulting from an improved electrolyzer efficiency, and therefore it is not realistic to produce hydrogen with an electrolyzer-battery hybrid system using surplus electricity.

This means that with the VRE capacity adopted in this study, neither the frequency of occurrence nor the amount of surplus electricity is adequate and the amount of surplus electricity remaining after it is supplied directly into the electrolyzers is small, and therefore the process of storing such small quantity of surplus electricity in batteries and supplying it into electrolyzers is not economically rational.

Although the effect of battery installation also depends on the relative relationship between the costs of electrolyzers and batteries, if battery costs were one-twentieth of the levels we assumed, there could be a combination in which hydrogen production with an electrolyzer-battery hybrid system could become the least expensive. However, it is unrealistic to assume that battery costs will decrease to such levels.

Meanwhile, when solar PV or wind power, rather than surplus electricity, is supplied directly to electrolyzers, there could be cases in which the electrolyzer-battery hybrid system would be effective, though it depends on the capacity factor of these power sources. Furthermore, while this study did not closely examine the volume of hydrogen production, it may be possible to identify the optimal combination of electrolyzer and battery capacities by taking the hydrogen production volume as the constraint function and the hydrogen production cost as the objective function. These different cases remain to be verified in the future.

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Modeling Potential Installation of Solar and Wind Energy Considering Cannibalization Effect◆

Hideaki Obane* Seiya Endo* Yuji Matsuo**,* Toru Genkai*** Yoshiteru Nagao***

Abstract

Increasing variable renewable energies with zero marginal cost cause the decline of wholesale electricity prices and undermine their own value by "cannibalization effect". While capital costs of renewable energies are expected to decline, their income is also to decrease because of declined wholesale electricity prices. This study integrated GIS (geographic information system) model that assesses business feasibility into an optimal power generation mix model that assess wholesale electricity prices. By developing an integrated model, it is possible to assess potential installation capacity of solar and wind energy by considering both economic rationality and land use restrictions. In the case of Japan, this study revealed that increasing solar and wind energies cause the significant decline of wholesale electricity prices in specific electric network area such as Hokkaido. Even if capital costs of these energies decrease through learning effect, economic potential of installed renewable capacities is significantly limited if business feasibility is considered. Thus, the decline of electricity prices by cannibalization effect can seriously stagnate installation of both solar and wind energies. This study implies that further cost reduction faster than previous trend is needed to realize "subsidy-free" energy sources.

Key words: Renewable energy, Solar energy, Wind energy, Energy model, Cannibalization effect

1. Introduction

Photovoltaic systems (PV systems) and wind energy systems are expected to a large-scale reduction of greenhouse gases. When examining future measures for the utilization of PV and wind energy systems, it is important to assess the installation potential of each system after considering such factors as economic rationality and land use restrictions.

Up to now, the Feed-in Tariff (FIT) has been introduced in Japan in July 2012. From April 2022, it will shift to Feed-in Premium (FIP), which adds a certain premium to wholesale electricity prices. Accordingly, the business potential of PV and wind energy systems in the future will be influenced by wholesale electricity prices that fluctuate depending on time and power generation mix.

On the other hand, previous studies [1)-4)] have shown that when large-scale PV and wind energy systems are installed occurs the "cannibalism effect", that the more power is generated by these systems, the lower the wholesale electricity price is during the time zone and the value of its own kWh. In the initial stage of the introduction of PV systems, it contributes a certain amount to reduce power demand peak and has the effect of reducing fuel costs such as gas-fired power generation with high fuel cost. However, as PV systems significantly increase, it replaces coal- fired power generation where fuel costs are low; thus, the effect of reducing fuel costs becomes smaller. Therefore, in order to assess the installation potential of PV and wind energy systems considering economic rationality over the long term toward 2050, it is important to consider the impacts of this "cannibalism effect."

Previously, there have been a number of studies that assess the economic potential of PV and wind energy systems considering economic rationality[5)-8)]. As an example, in a study in the United States[5)], the economic potential at each point is assessed from the difference between the levelized cost of electricity (LCOE) of each power supply and the levelized avoided cost of electricity (LACE) by using geographic information (GIS) system. In addition, the research of MacDougall et al.[9)] assesses the internal rate of return (IRR) according to the level of policy support by using GIS.

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In Japan, several studies have assessed the economic rationality of renewable energy under the scenario of a certain selling price for a specific year[10)-12)]. For example, a report by the Japanese Ministry of the Environment[10)] assessed the economic potential of renewable energy using the premise that generated electricity is sold at a fixed price by FIT. Additionally, study assessing the potential of PV systems considering the distance from transmission line affecting the initial investment[13)] and study on the economic assessment of the installation of PV systems for residential use under the FIT have also been carried out[14)].

Like this, studies on the assessment of installation potential considering the economic rationality of PV and wind energy systems have been abundantly carried out. However, detailed research considering the influence of the cannibalism effect has not been conducted. In Japan, since the current FIT will shift to sales based on wholesale electricity prices, it is more important to consider the effects of cannibalism in chronological order in assessing the potential installation capacity of each power supply.

Following this fact, in order to solve such problems, this study aims to examine the potential assessment model of PV and wind energy systems considering the cannibalism effect by integrating the power generation mix model and the GIS model that spatially assess the economic rationality of each location. By using this model, it is possible to reflect the impacts of the wholesale electricity price decrease in the mass introduction of each power supply, and to assess the installation potential of PV and wind energy systems by considering economic rationality more clearly.

2. Potential Assessment Model

2-1. Overview

The potential assessment model proposed in this study is a model that integrates a power generation mix model, which outputs wholesale electricity prices every 8,760 hours using input values such as the amount of introduction of each power supply and the installed capacity, and a GIS model, which spatially assesses the IRR for each 100-500 m grid mesh using the wholesale electricity price and the capital cost of each power supply as input values (Fig. 1).

In this model, when the installed capacity of PV and wind energy systems in a specific year is given as an initial value, the wholesale electricity price for every 8,760 hours is output first by the power generation mix model. Then, the GIS assessment model outputs the installed capacity that satisfies the specified IRR using wholesale electricity prices as input values. The installed capacity obtained by considering a constant introduction rate in this installed capacity is again the input value of the power generation mix model. In this model, by performing the loop calculation every year, it is possible to assess the transition of wholesale electricity prices over the medium to long term and the transition of the installed capacity of PV and wind energy systems that satisfy economic rationality.

As the introduction of PV and wind energy systems progresses, the value of kWh during the time zone when each power supply is generating power decreases due to the cannibalism effect, but when electricity is sold through the wholesale electricity market, the IRR by the power generation business of each power supply contributes toward the decrease. On the other hand, if the capital cost decreases due to the learning effect of the power generation facility, it will contribute to the increase of IRR. In this model, considering these mutual effects, it is possible to assess the effect of the large-scale introduction of each power supply more clearly.

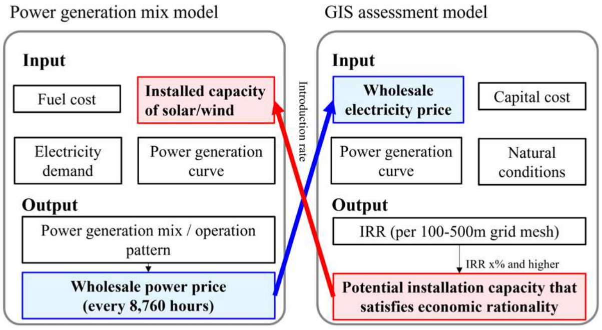


Fig. 1 Overview of Potential Assessment Model

2-2. Power Generation Mix Model

The power generation mix model used in this study was originally developed by the FUJII-KOMIYAMA Laboratory[15] and improved by Komiyama et al. (2014)[16], Komiyama et al. (2017)[17], Matsuo et al. (2018)[18], Nagatomi et al.[19], and Matsuo et al. (2020)[20]. This model outputs wholesale electricity prices and operation patterns of each power supply every 8,760 hours when the sum of capital cost and variable cost of the entire power system is minimized using the input value such as the installed capacity and fuel cost of each power generation facility. The objective function is obtained by equation (1).

$$min.TC = \sum_i \left(g_i \cdot pf_i \cdot K_i + \sum_{d,t} pv_i \cdot X_{i,d,t} \right) + \sum_j CS_j \quad (1)$$

$$CS_j = gs1_j \cdot pfs1_j \cdot KS1_j + gs2_j \cdot pfs2_j \cdot KS2_j + pfs3_j \frac{TCha_j}{cycle_j} \quad (2)$$

$$TCha_j = \sum_{d,t} Cha_{j,d,t} \quad (3)$$

Where, g_i: annual fixed cost factor of generator *i*, initial investment cost of generator i pf_i, K_i: generator *i* rated output [GW], generator *i* variable cost pv_i, $X_{i,d,t}$: generator *i* day *d*, output in time *t* [GW], $gs1_j$: fixed cost factor per output of storage battery *j*, $pfs1_j$: initial investment cost per output of storage battery *j* [JPY/GWh], $Ks1_j$: Rated output of storage [GW], *gs2*: fixed cost coefficient per storage capacity of storage battery *j*, $pfs2_j$: initial investment cost per storage capacity of storage battery *j* [JPY/GWh], $Ks2_j$: Rated storage capacity [GWh], $pfs3_j$: external cost associated with deterioration of storage battery [JPY], *cycle*: maximum number of charging and discharging of storage batteries, *Cha*: power charged to storage batteries [GW].

As constraints, power supply and demand constraints at each time, spare power constraints, and balance constraints of energy storage facilities are given. This study describe a linear planning problem by pyomo, a library of Python, and obtained a solution by operating Xpress, which is a solver.

The target areas of the power generation mix model were the 10 areas of Hokkaido, Tohoku, Tokyo, Chubu, Hokuriku, Kansai, Chugoku, Shikoku, Kyushu, and Okinawa, which are under the authority of general transmission and distribution business operators. Each area is connected by interconnection lines, and it is assumed that the interconnection lines are enhanced based on "power supply uneven distribution scenario (30 GW) of the Organization for Cross-regional Coordination of Transmission Operators (OCCTO)[21]. In addition, the wholesale electricity price in each area was treated as a shadow price of the supply-demand balance constraint type of each area obtained as the optimal solution of the dual problem. Although there is no wholesale electricity market in the Okinawa area, it was treated as electricity sales based on the potential price.

The power generation amount of PV and wind energy systems was calculated in advance using a normalized power generation pattern based on the data of the regional meteorological observation system (AMeDAS) in each area and a value of 8,760 hours based on the installed capacity for each area. In practice, while the power generation pattern of each power supply changes gradually by the installation of power generation facilities in various places, the power generation pattern is constant in this model for simplicity.

2-3. GIS Assessment Model

The GIS assessment model outputs the IRR for each mesh by inputting capital cost of power generation facilities and wholesale electricity price based on mesh information related to land use and sea area use. By applying a certain lower limit to this IRR, the installed capacity of the power generation facility which satisfies economic rationality is obtained. In this model, as in previous studies[24)-26)], the territory of Japan was divided into 100 m mesh and the territorial waters of Japan were divided into 500 m grid mesh using ArcGIS, and various data related to land and sea area use were stored in each mesh. Based on this developed data, this study extracted the places where PV and wind energy systems can be physically installed in advance, and calculated the IRR at each point from data such as sunlight and wind speed.

IRR is given by r in equation (4) and is determined by the initial investment amount CI [JPY] and annual cash flow CF_t [JPY]. The initial investment is mainly equivalent to the capital cost of the power generation facility in the year installed. In addition, the cash flow is determined by the sales revenue dependent on the power generation amount E_i [kWh] and the wholesale electricity price W_i [JPY /kWh], the premium FIT price which is the difference between FIP_{base} [JPY/kWh] and the FIP reference price FIP_{ref} [JPY/kWh], and the annual maintenance cost OM [JPY/kWh], and is shown in equation (5).

$$\sum_{t=1}^{30} \frac{CF_t}{(1+r)^t} - CI = 0 \qquad (4)$$

$$CF_t = \sum_{i=1}^{8760} \left(E_i \cdot W_i + E_i \left(FIP_{base} - FIP_{ref} \right) \right) - OM \qquad (5)$$

3. Assumptions

3-1. Target years and Power Sources

The forecast of cumulative introduction of PV and wind energy systems by 2030 was indicated at the Basic Policy Subcommittee (April 13, 2020)[22)], based on the lead time of construction and the implementation status of environmental assessments. Therefore, in this study, 2030 was the starting point of the assessment, and the target period of this assessment spanned until 2050.

In this study, the three types of power supplies were ground-based PV systems, onshore wind energy systems, and offshore wind energy systems. Since it is considered that the introduction incentives for building-based PV systems are considered to affect the introduction incentives such as self-consumption and mandatory installation of PV systems, this study excludes their assessment.

Referencing the installation capacity forecast indicated by the Basic Policy Subcommittee[22)], the initial value of the installation capacity of each power supply in 2030 was 41.6 GW for ground-based solar power, 15.3 GW for onshore wind power, 3.7 GW of fixed-type offshore wind power, 0.02 GW for floating offshore wind power, 19.3 for building-based solar power (detached houses) and 26.7 GW for building-based solar power (non-detached houses). The amount of introduction by grid area in 2030 was estimated by estimating the installed capacity certified by FIT as of June 2021 and the equipment capacity of the project in which the environmental assessment consideration and method documents were submitted by grid area and prorated from the total introduction volume forecast for all areas in 2030 (Fig. 2).

For building-based PV systems, the installation capacity is assumed to be advanced by self-consumption and mandatory installation of PV systems, and the installation capacity was given exogenically in the model. In this study, referencing the "social acceptability-oriented scenario" of the Central Research Institute of Electric Power Industry[23)], the cumulative installation capacity in 2050 reached 45 GW of PV systems installed in detached houses and 62 GW of PV systems installed in non-detached houses.

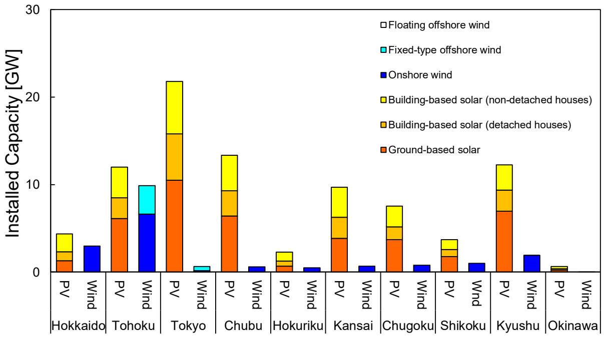


Fig. 2　Assumption of installed capacity by grid Area in 2030 [GW]

3-2. Correlation between Natural Conditions and Installed Capacity

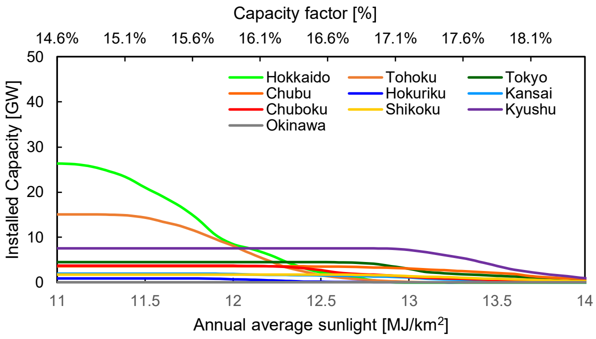
Referencing bane et al.[24), 25)], the site of ground-based PV systems and onshore wind energy systems were installed in places excluding natural parks, natural environmental conservation areas, and bird and animal sanctuaries (normal and special protection) among the four types of land categories: grassland, shinochi (bamboo grove), bare land, and difficult-to-regenerate degraded farmland, taking into account the land use competition and natural environment effects of each power source. Based on this approach, the Japanese contiguous land was divided into 100 m grid meshes, and the available area was estimated to be 3,321 km^2 when the in available area was extracted using the latest GIS data obtained as of April 2021. In addition, since it is assumed that land use competition will occur between ground-based PV systems and onshore wind power system when large-scale introduction of PV and wind energy systems is assumed, ground-based PV systems will be installed at a place with an average wind speed of less than 5.0 m/s per year (980 km^2) and onshore wind power at a location with an average wind speed of 5.0 m/s or more (2,341 km^2). In these places, up to 65.7 GW of ground-based PV systems and 23.4 GW of onshore wind power were assumed able to be installed.

Referencing the Moderate conflict scenario of Obane et al.[26)] considering legal restrictions and social acceptability, the site of offshore wind power was assumed to be 5.0 - 22.2 km (in territorial waters), among sea areas that meet the designated requirements of "promotion zone" stipulated by the Act of Promoting Utilization of Sea Areas in Development of Power Generation Facilities Using Maritime Renewable Energy Resources where the traffic volume of ships equipped with automatic ship identification system is less than 21 ships/month, and sea areas that satisfy all the sea areas where fishery rights are not set. Following the study, when the sea area was extracted using the latest GIS data as of April 2021, the area was estimated to be 28,865 km^2. Of these, if fixed-type offshore wind power is installed in sea areas (5,137 km^2) with a depth of less than 60 m and floating offshore wind power in sea areas from 60 m to less than 200 m (23,728 km^2), the maximum installed capacity of fixed-type offshore wind power would be 30.8 GW and floating offshore wind force 142.3 GW.

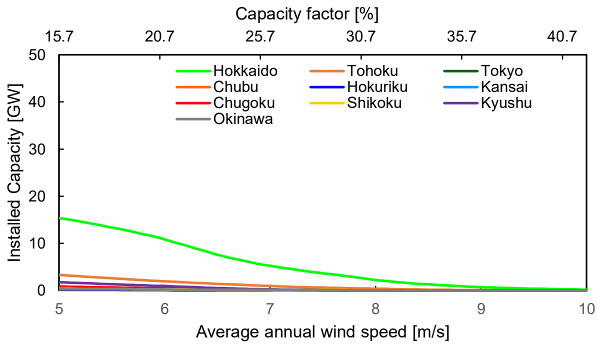
Fig. 3 shows the relationship between natural conditions and equipment capacity in each power area based on the above assumptions. The facility utilization rate is simply converted from the average annual wind speed and the average annual sunlight, as in each study[24)-26)], and it is assumed that overloading is performed for ground-based PV systems.

From Fig. 3(A) and (B), the available of ground-based PV systems and onshore wind power is mainly concentrated in the Hokkaido area. Since the wind conditions in the Hokkaido area are also better than the other areas, onshore wind power will be introduced preferentially with the decrease in capital costs of power generation facilities. On the other hand, since the irradiance in the Hokkaido area is lower than the other areas, ground-based PV systems will be introduced later when compared with other areas.

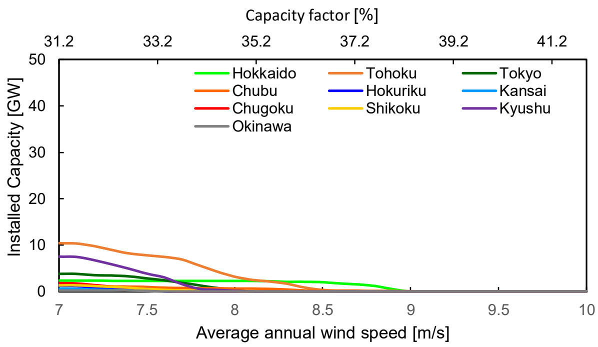
For fixed-type offshore wind and floating offshore wind power shown in Fig. 3(C) and (D), there are many installation sites in Tohoku and Kyushu area. In particular, since the wind conditions are better in Tohoku, offshore wind power will be introduced preferentially.



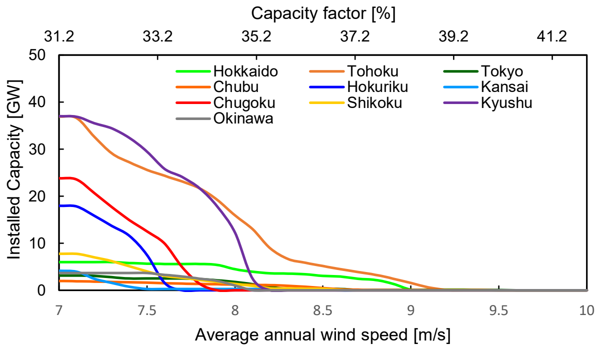
(A) Ground-based PV systems



(B) Onshore wind power



(C) Fixed-type offshore wind power



(D) Floating offshore wind power

Fig. 3 Correlation between Natural Conditions and Installed Capacity

3-3. Assumptions on Capital Costs and Required IRR

Assumptions such as capital costs and necessary IRRs in this study were based on actual or assumed values shown by the Procurement Price Calculation Committee[27]. Table 1 shows the preconditions related to these assumptions and the transition of capital expenses assumed in Fig. 4 until 2050.

The capital cost is the sum of equipment cost, connection cost, and operation maintenance cost (O&M cost), and the equipment cost is assumed to decrease the cost based on the learning curve. In addition, the learning rate applied the value corresponding to the middle of the estimated value range shown in each literature[28], and the installation capacity used in the estimation of the learning curve was the assumed installation capacity of the entire world until 2050 in the Stated Energy Policies Scenario (STEPS) of IEA WEO 2020[29].

The actual value of equipment cost in FY2019 is the average value of the equipment for PV systems of 250-500 kW (204,000 JPY/kW) shown by the Procurement Price Calculation Committee, the estimated value of the equipment cost of onshore wind power in the FIT purchase price calculation (269,000 JPY/kW), and the estimated cost of offshore wind energy systems equipment (512,000 JPY/kW) in the "promotion area." Referencing Stehly et al.[30] for floating offshore wind power, it was assumed that the capital cost was 1.3 times larger than fixed-type offshore wind power, and the learning rate was the same as the fixed-type offshore wind power. In this study, all prices were treated as real prices in 2019.

The IRR required for each power supply to obtain economic rationality was 5% for ground-based PV systems, 7% for onshore wind power, 10% for fixed-type offshore wind power, and 10% for floating offshore wind power, referring to the Procurement Price Calculation Committee[27].

Table 1 Assumptions on Capital Cost and Required IRR

<table>
<tr><th></th><th>Ground-based solar</th><th>Onshore wind</th><th>Offshore wind (fixed)</th><th>Offshore wind (floating)</th></tr>
<tr><td>Equipment cost (2019) [JPY/kW]</td><td>204,000</td><td>269,000</td><td rowspan="2">512,000</td><td rowspan="2">665,600</td></tr>
<tr><td>Connection cost [JPY/kW]</td><td>9,100</td><td>13,000</td></tr>
<tr><td>O&M cost [JPY/kW]</td><td>4,900</td><td>9,300</td><td>18,400</td><td>18,400</td></tr>
<tr><td>Learning rate (equipment cost)</td><td>15%</td><td>7%</td><td>10%</td><td>10%</td></tr>
<tr><td>Required IRR</td><td>5%</td><td>7%</td><td>10%</td><td>10%</td></tr>
</table>

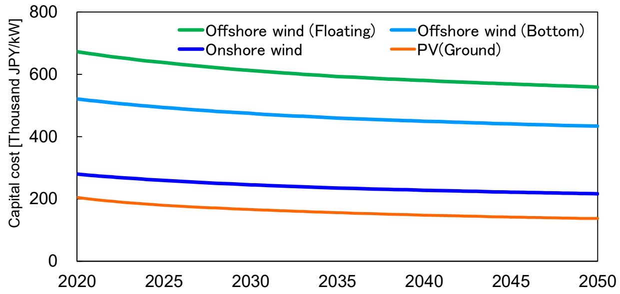


Fig. 4 Assumptions on Capital Cost [Thousand JPY/kW]

3-4. Assumptions on Thermal Power, Nuclear Power and Electricity Demand

The installed capacity of coal-fired power generation and gas-fired power generation in the power generation mix model is based on the capacity of existing equipment remaining in 2050 when operating for 40 years, and the lower limit was coal-fired power at 13.7 GW and gas-fired power generation at 24.7 GW. For nuclear power generation, 30.6 GW is set as a fixed value referring to the technical progress scenario of IEEJ Outlook 2021[31].

The coal and LNG prices used in thermal power generation referenced STEPS (2040) of IEA WEO 2020[29], making coal: 77 USD2019/t and LNG: 9 USD2019/MMBtu. CO_2 emissions were considered at carbon prices, and 52 USD2019/t-CO_2 of STEPS (2040) was used.

The annual electricity demand in the power generation mix model was 1,027 TWh, which deducted the loss factor of plant-home use of 3.5% from the amount of power generated in 2030 in the long-term energy supply and demand outlook. Although fuel prices, carbon prices, and electricity demand fluctuate year by year, in this study, these were constant regardless of time, in order to clearly assess the decrease in capital costs of solar and wind energy systems and the decrease in electricity sales revenue due to the decrease in wholesale electricity prices.

3-5. Assumptions on FIP

In Japan, FIP will be intro duced to be used to sell electricity generated by renewable energy by increasing the power price by adding a certain premium to the wholesale electricity price. Therefore, in this study, four types of cases were assumed for the FIP premium price determined by the difference between the FIP standard price and the FIP reference price (Table 2).

First, referencing the difference between current FIT purchase price and avoidable cost (assumed to be 8 JPY / kWh) as of 2021, the FIP premium price was 3 JPY /kWh for ground-based PV systems/ kWh, 9 JPY /kWh for onshore wind power, landing type offshore wind force 24 JPY/kWh for fixed-type offshore wind power, and 28 JPY / kWh for floating offshore wind power. This was set as the “(1) current FIT level case.”

Second, these premium prices were set to 2/3 as “(2) 2/3 level case,” and the same price was set to 1/2 in the “(3) 1/2 level case.” In addition, assuming that each power supply will become a “subsidy-free power supply” that does not depend on the subsidy system in the future, the premium price of each power supply was set as 0 JPY / kWh in “(4) case without FIP.”

It should be noted that in Japan, since offshore wind power is in the initial introduction stage, the assumed premium price of offshore wind power is significantly higher than PV systems and onshore wind power.

Table 2 Assumption of FIP Premium Prices (JPY/kWh)

	Ground-based PV	Onshore wind	Fixed-type offshore wind	Floating offshore wind
Current FIT Level	3	9	24	28
2/3 level	2	6	16	18
1/2 level	1.5	4.5	12	14
Without FIP	0	0	0	0

4. Results and discussion

4-1. Single Year Assessment Targeting 2030

Fig.5 shows the evaluated wholesale electricity price of each power area by the power generation mix model for 2030, the first year of the assessment. Since PV and wind energy systems are variable power sources, weights are given to wholesale electricity prices that fluctuate at each time by the amount of power generated at each hour, and the weighted average wholesale electricity price for one year is calculated.

As the result, it was shown that the weighted average wholesale electricity price tended to be comparatively lower in the Hokkaido area and Kyushu area out of 10 electric grid areas. One of the factors contributing to this is that the ratio of power generation by PV and wind energy systems is high compared to the electricity demand in these power areas. In particular, in the Kyushu area, 13 GW of PV systems will be introduced as of 2030. Hence, the wholesale electricity price in the daytime time zone, when PV systems are generated, will be particularly low.

Then, by inputting the wholesale electricity price of each power area and using the GIS assessment model, the potential installation capacity (hereinafter referred to as the installed capacity that satisfies economic rationality) of the power generation facility that satisfies the specified IRR was assessed for 2030 (Fig. 6). In the figure, the far right bar graph (gray) shows the technical potential determined only by the land use restrictions assumed in Section 3.2, and does not take economic rationality into account. In addition, the bar graph on far left (gray dashed line) shows the installation capacity as of 2030 assumed in Section 3.1. Since the installation capacity as of 2030 includes much equipment introduced under the high FIT price at the beginning of FIT introduction, the installation capacity is more than in the case where the subsidy by FIP is assumed to be the current level.

For ground-based PV systems, if the premium price of FIP is maintained at the current subsidy level of 3 JPY/kWh, the potential installation capacity that satisfies economic rationality will be 6.5 GW. Until now, under the FIT purchase price of 11 JPY/kWh (equivalent to the subsidy level of 3 JPY/kWh), certain PV systems have been certified by FIT auction. However, if the wholesale electricity price decreases in the future, economic rationality will not be obtained in many places except in those where sunlight conditions are enough.

For offshore wind power, on the other hand, when the premium price of FIP is maintained at 24 JPY/kWh (Bottom-fixed) and 28 JPY /kWh (floating), which corresponds to the current subsidy level, the installed capacity that satisfies economic rationality is equal to the maximum installation capacity determined by land use restrictions. However, this is because the supplementary level of FIT in 2020 is set high, and there is no guarantee that the same level will be maintained even after 2030. When the FIP premium price is 12 JPY/kWh (Bottom-fixed) and 14 JPY/kWh (floating), which is half of the current subsidy level, there are few facilities that satisfy economic rationality. Therefore, in order to install offshore wind power without subsidy in Japan, it is necessary to significantly reduce the cost.

In addition, when there is no subsidy in all power supplies, the potential installation capacity that satisfies economic rationality is almost zero under the assumed various conditions. Therefore, this indicates that it is difficult to achieve “subsidy-free” when cost reduction advances based on the learning rate estimated from the previous trends.

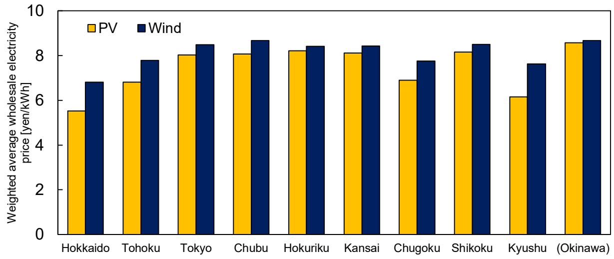


Fig. 5 Weighted Average Wholesale Electricity Price in 2030 (Shadow price for Okinawa area) [JPY/kWh]

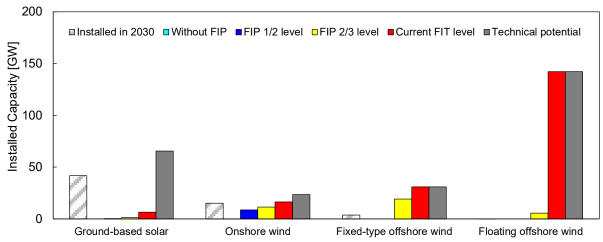


Fig. 6 Potential Installation Capacity that Satisfy Economic Rationality based on FIP Premium Price in 2030 [GW]

4-2. Time-series Assessment to 2050

The assessment for 2030 showed that it was difficult to introduce PV or wind energy systems without subsidies such as FIP. Therefore, assuming that support by FIP will continue after 2030 for the expansion of PV and wind energy systems, under the assumption that the FIP premium price corresponding to 2/3 of the current subsidy level is set, the transition of the potential installation capacity that satisfies economic rationality by 2050 was assessed. The premium unit price of FIP assumed here is 2 JPY/kWh for ground-based PV systems, 6 JPY/kWh for onshore wind power, 16 JPY/kWh for fixed-type offshore wind power, and 18 JPY/kWh for floating offshore wind power. In particular, it should be noted that a significantly high FIP premium unit price is set here for offshore wind power.

When focusing on onshore wind power, wholesale electricity prices in the Hokkaido area where electricity demand is low gradually decrease because onshore wind power is introduced mainly from the Hokkaido area (Fig. 7 [A]). As a result, the installed capacity of onshore wind and fixed-type offshore wind that satisfies economic rationality also decreases because electricity sales revenue also decreases (Fig. 8 [A]). In other words, under the conditions assumed in this study, economic rationality cannot be obtained after a specific year because the influence of the decrease in electricity sales revenue caused by the decrease in wholesale electricity prices exceeds the decrease in capital costs of onshore wind energy systems. Here, focusing on the relationship between potential installation capacity and cumulative installed capacity in the Hokkaido area (Fig. 9), it has been shown that the introduction of onshore wind power will stagnate after 2035, since the cumulative installation capacity reaches the installed capacity that satisfies economic rationality in 2035.

From the potential installation capacity (Fig. 8 [B]) which satisfies economic rationality nationwide, the capacity of the onshore wind power decreases with the passage of time. As shown earlier, this is mainly due to the decrease in wholesale electricity prices in the Hokkaido area.

On the other hand, for ground-based PV systems and floating offshore wind power, the installed capacity that satisfies economic rationality tended to increase because the influence of the decrease in capital costs was greater than the decrease in electricity sales revenue due to the decrease in wholesale electricity prices. However, although potential installation capacity will increase due to the decrease in capital costs, the growth of the increase will plateau around 2040. Although The technical potential of ground-based PV systems considering only land use restrictions was 65.7 GW, the potential installation capacity that satisfies economic rationality remains at 14.6 GW in 2050. This is due to the fact that many of the places to be installed ground-based PV systems are in the Hokkaido area where irradiance is poor and wholesale electricity prices are decreasing. Hence, almost all PV systems do not satisfy economic rationality.

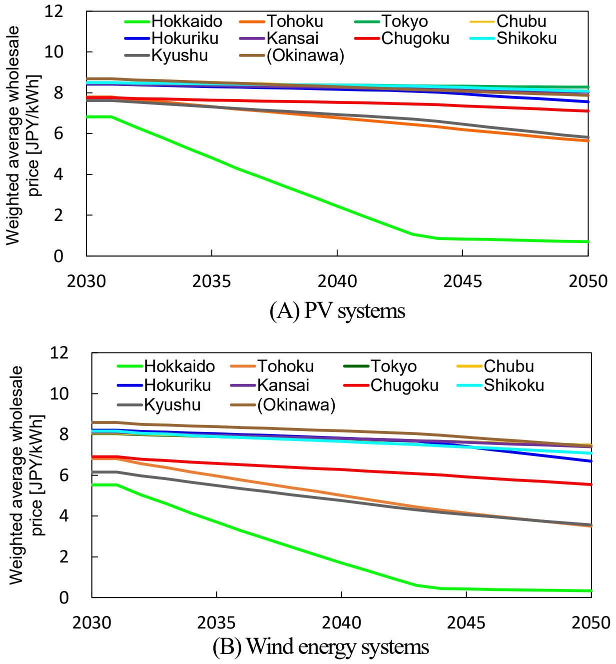


Fig. 7 Weighted Average Wholesale Electricity Price up to 2050 [GW] (FIP premium price: 2/3 current level case)

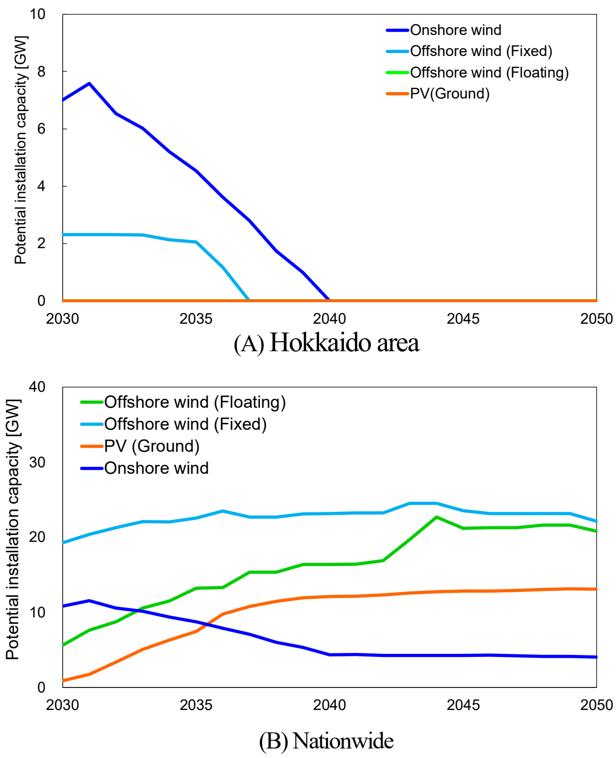


Fig. 8 Installed Capacity that Satisfies Economic Rationality [GW] (FIP premium price: 2/3 current subsidy level case)

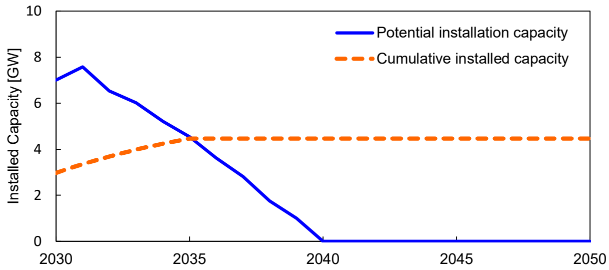


Fig. 9 Correlation of Potential installation capacity and Cumulative Installed capacity of Onshore Wind Power in the Hokkaido Area [GW]

4-3. Single Year Assessment for 2050

Focusing on 2050, the last year of the assessment period, this study assessed potential installation capacity that satisfies economic rationality according to the FIP premium price as in Section 4.1 (Fig. 10).

Focusing on the potential installation capacity of ground-based PV and onshore wind power, the result showed that the potential installation capacity of the case where the same level was raised to 2/3 was slightly lower than the case where the FIP premium price was set to 1/2 of the current level. This is because in the current level of 2/3 cases, the wholesale electricity price decreases due to the priority introduction of offshore wind power, and the electricity sales revenue of ground-based PV systems and onshore wind energy systems decreases. Following this, when a specific power plant is intensively introduced, it may have a large influence on the economic rationality of other power sources.

Focusing on the case without any subsidies for each power supply, even if the capital cost decreases toward 2050, the potential installation capacity that satisfies economic rationality was limited. Here, even if the FIP premium price was raised to 2/3 of the subsidy level of the current FIT, the potential installation capacity did not increase significantly compared with 2030 because the influence of the decrease in electricity sales revenue due to the decrease in wholesale electricity prices is large. Following this, in order to promote the expansion of PV and wind energy systems by 2050, it is necessary to reduce costs at a pace that greatly exceeds the previous learning effect.

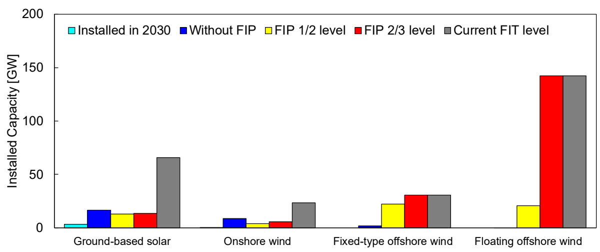


Fig. 10 Potential installation capacity that Satisfy Economic Rationality based on FIP Premium Price in 2050 [GW]

5. Conclusion

This study examined the potential assessment model of PV and wind energy systems considering the cannibalism effect by integrating the power generation mix model and GIS model which spatially assess the economic rationality of each location. As the result, it was shown that the decrease of the wholesale electricity price by the expanded introduction of PV and wind energy systems was assessed in chronological order, and the effect on the economic rationality of each power supply could be quantitatively assessed.

Issues posed by this model include consideration of capital cost of power generation facilities different by geographical factors such as water depth and consideration of the influence of self-consumption. Especially in the case of self-consumption, even during times when wholesale electricity prices are decreasing, the power purchased by retail electricity charges can be offset with power generated by PV or the other systems. Thus, considering the power of this offset, the substantial business income of the power generation business may increase. It is expected that more practical assessments will be carried out on these issues in future improvements.

In the previous model for assessing the economic potential of PV and wind energy systems, the sale of electricity at a fixed price by FIT was assumed. However, when electricity is sold based on wholesale electricity prices in the future, the potential installation capacity that satisfies economic rationality is limited, suggesting the possibility that the introduction may be sluggish. In order for PV and wind energy systems to become subsidy-free power sources, it is necessary to reduce costs at a pace that greatly exceeds the previous learning effects.

The potential assessment model examined in this study is effective for the assessment of the economic rationality of PV and wind energy systems from a medium- to long-term viewpoint, and it is expected to contribute to the examination of the policy making for the expansion of PV and wind energy systems in the future.

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FINAL REPORT

STUDY ON THE ECONOMICS OF THE GREEN HYDROGEN INTERNATIONAL SUPPLY CHAIN

OCTOBER 2021

THE INSTITUTE OF ENERGY ECONOMICS, JAPAN

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FINAL REPORT

STUDY ON THE ECONOMICS OF THE GREEN HYDROGEN INTERNATIONAL SUPPLY CHAIN

EXECUTIVE SUMMARY

Japan needs large amounts of hydrogen in order to decarbonize its energy system by 2050. As domestic resources for hydrogen are presumably limited in Japan, hydrogen will need to be imported. There is a variety of options for importing hydrogen, in terms of potential exporting countries and hydrogen resources. Japan has carried out or is currently carrying out demonstration projects for the establishment of international hydrogen supply chains with Australia, Brunei and Saudi Arabia, and forging dialogues on future collaboration with other countries like Argentina and Russia. Chile would also be a promising candidate as an exporter of hydrogen to Japan, as its renewable energy potential, including solar and wind power, is huge and its renewable energy costs are substantially low.

This study reveals the costs and carbon footprint across the whole green and blue hydrogen supply chains from potential suppliers to Japan; green hydrogen from Australia, Chile and the USA and blue hydrogen from Australia and Saudi Arabia.

When using liquified hydrogen or methylcyclohexane as the hydrogen carrier, the cost of green hydrogen from Chile is the lowest among green hydrogen supply chains and can also compete with blue hydrogen supply chains if the electrolyzer cost is reduced to a third of today's level, which is expected to be realized internationally by 2030. However, in the case of using ammonia as the hydrogen carrier, the cost of blue ammonia from natural gas of Saudi Arabia is the lowest. Assuming a carbon price of \$100/t-CO_2 is imposed, Chilean green hydrogen by means of liquified hydrogen or methylcyclohexane becomes a more attractive option for Japan, as the carbon footprint of green hydrogen is much smaller than blue hydrogen, while the cost advantage of blue ammonia from natural gas still remains due to the lower production cost.

In order for green hydrogen to be even more attractive, production costs should be further reduced by, for example, elevating the capacity factor of electrolyzers through smoothing the power input by combining solar and wind. Another option would be employing electrolyzers, not only for producing hydrogen from renewable energy, but also as a grid service provider through demand response, which in turn will reduce the hydrogen production cost by remuneration from the grid services. If ammonia is selected as the hydrogen carrier for early-stage long-distance hydrogen transportation to Japan, green ammonia production technologies that can cope with variable input from renewable energy should be further developed.

However, it should be noted that possible applications of ammonia are rather limited, such as power generation and shipping fuels. For the decarbonization of the energy system, sectors such as industry and

mobility bear crucial roles. Hydrogen transported in the form of liquified hydrogen or methylcyclohexane can contribute to decarbonization of these sectors.

In addition to green hydrogen exports, domestic hydrogen applications in the exporters should also be addressed, as these can help decarbonize the exporter's energy system and develop related-industries including fuel cell that are expected to contribute to mobility and stationary combined heat and power. Furthermore, it should also be remembered that storing hydrogen over long periods is much easier than storing electricity in batteries, thus giving hydrogen high potential for seasonal storage. This characteristic allows hydrogen to be a key mechanism for facilitating integration of higher shares of renewable energy into power grids that are isolated from the national grid system. Hydrogen will bear an important role in improving national energy security, securing a stable energy supply and enhancing resiliency in a decarbonized manner by stockpiling renewable energy.

From Japan's point of view, critical aspect other than hydrogen cost is energy security, which is often overshadowed by decarbonization discussions, despite its significance for Japan, as it depends heavily on energy supply from overseas. Green hydrogen promises to play a significant role in improving Japan's energy security by diversifying its energy supply resources, especially in geographical terms. For example, Chile's location in the APAC region can alleviate concerns over sea lane security. This study revealed that the shipping cost of hydrogen/ammonia does not have a significant impact on the overall supply cost, and thus the disadvantage of the long-distance transportation of hydrogen/ammonia to Japan is limited.

Collaboration between Japan and hydrogen exporters in establishing an international hydrogen supply chain and developing domestic applications of hydrogen will open windows of more concrete business opportunities. Areas for government to government cooperation and business matching, along with experience-sharing may be explored through in-depth discussions among stakeholders, including government, academia, businesses, and financial institutions. Such actions will eventually contribute to the development of the international hydrogen/ammonia market.

CHAPTER 1. BACKGROUND AND OBJECTIVES OF STUDY

Discussions on how Japan should procure hydrogen started in 2012, one year after the Great East Japan Earthquake. It was when Japan was faced with challenges in decarbonizing its energy system, especially its electric power system, given issues with nuclear power generation and difficulties in rapidly deploying renewable energy. Since then, Japan has been accelerating its efforts to procure affordable hydrogen from abroad. The Japanese government and private sector have recently been jointly negotiating with oil & gas and coal producing countries to import blue hydrogen. The then Prime Minister Suga's announcement of Japan's goal to achieve carbon neutrality in 2050 has increased the importance of hydrogen import and has thus added momentum to actions taken toward importing hydrogen.

In general, blue hydrogen is regarded inexpensive for the moment. However, blue hydrogen entails inherently challenging issues: the carbon footprint of blue hydrogen is larger than that of green hydrogen, international pressures on fossil fuel use is being strengthened, and blue hydrogen will not contribute to improving Japan's energy security if it is imported from the same oil & gas producing countries from which Japan currently imports fossil fuels. Given these challenges pertaining to blue hydrogen, green hydrogen is a promising alternative. For example, Chile has huge potential for green hydrogen production from renewable energy at the lowest cost in the world[1]. Furthermore, its geographical location in the APAC region, like Australia and the USA, will contribute to improving Japan's energy security through the diversification of hydrogen supply chains, avoiding heavy dependence on oil & gas producing countries.

This study will reveal the costs and carbon footprint across entire green hydrogen supply chains from potential suppliers to Japan and discuss their potential advantages, as well as the challenges to be addressed by comparison with blue hydrogen supply chains.

[1] "The Future of Hydrogen", IEA, 2019

CHAPTER 2. SCOPE OF STUDY AND METHODOLOGY

The green hydrogen resources considered in this report are solar photovoltaics and wind power. The green hydrogen producing countries addressed are Chile, Australia and the USA. For blue hydrogen, the resources considered are natural gas and coal and the producing countries are Saudi Arabia and Australia (Table 1).

TABLE 1. SCOPE OF HYDROGEN EXPORTING COUNTRIES AND RESOURCES

	Country	Resources for hydrogen
Green H_2	Chile	Solar PV and wind
	Australia	Solar PV and wind
	USA	Solar PV and wind
Blue H_2	Saudi Arabia	Gas
	Australia	Gas and coal

Note: Ammonia is included in hydrogen.

The hydrogen supply chain from the exporting country to Japan covers hydrogen production, domestic transportation in resource countries (hydrogen pipeline), conversion to hydrogen carriers, export ports, international shipping, receiving ports, and reconversion in Japan. Liquefied hydrogen (LH_2), methylcyclohexane (MCH) and ammonia (NH_3) have been selected as hydrogen carriers. This study assumes reconversion is not needed for liquefied hydrogen, but needed for MCH (dehydrogenation) and NH_3 (cracking). On the other hand, In Japan's strategy to achieve carbon neutrality, NH_3 has both the role of a hydrogen carrier and a clean fuel for power generation, either co-fired with coal or 100% NH_3 combustion. For this reason, the case in which the reconversion of NH_3 is unnecessary is also addressed.

For NH_3 production this study assumes two conditions. If the hydrogen for NH_3 production comes from green hydrogen or hydrogen produced with brown coal + CCS, the study assumes hydrogen production and NH_3 conversion (Haber-Bosch process) separately (Figure 1). However, since the process of NH_3 production from natural gas is already a mature and widely-used technology, the study assumes hydrogen production and NH_3 production are integrated in the case of blue NH_3 production from natural gas (Figure 2).

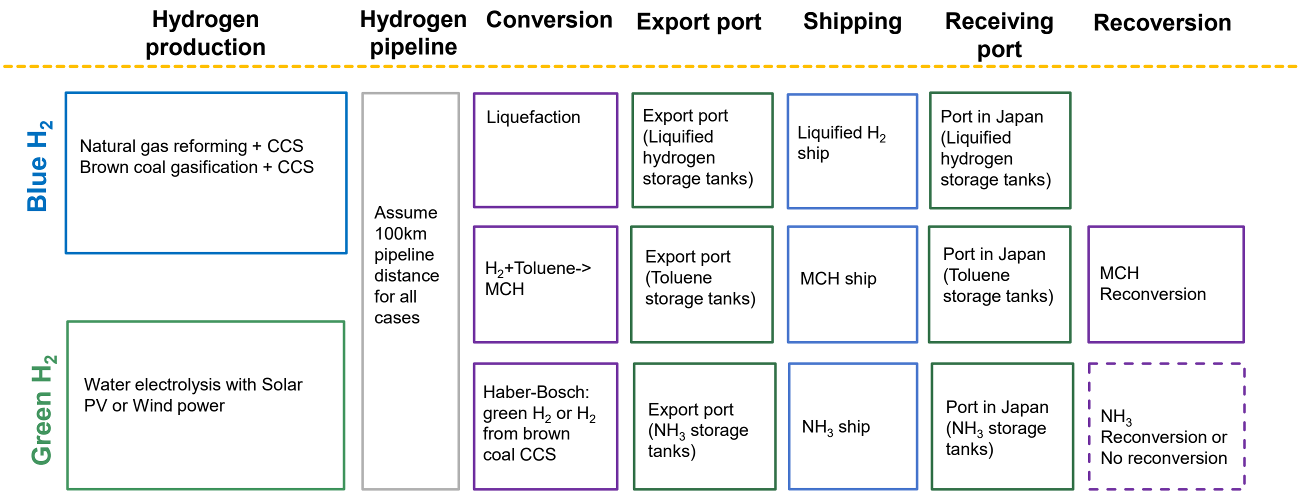

FIGURE 1. HYDROGEN SUPPLY CHAIN

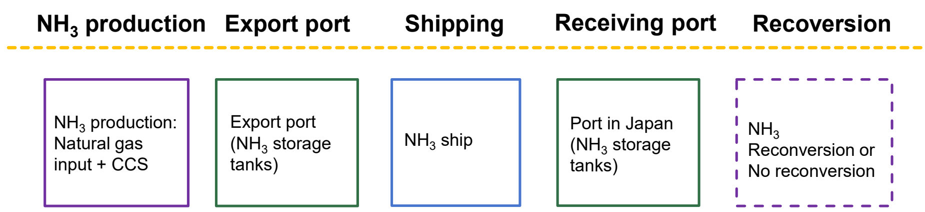

FIGURE 2. BLUE AMMONIA SUPPLY CHAIN WITH NATURAL GAS AS FEEDSTOCK

To compare the economics and GHG emission (CO_2 equivalent: CO_2eq) among different supply chains, this study assumed the same scale of hydrogen production for each supply chain: 225,000 tons of hydrogen production per year, which is equivalent to the annual volume of hydrogen to be used for 1 GW of hydrogen-fired gas turbine power generation. The study uses 2030 as the reference year for evaluating the economics and GHG emissions.

Hydrogen supply costs are impacted by many factors. Engineering details associated with each process of the hydrogen supply chain are not included within the scope of this study. The figures presented in this study only indicate one possible case under certain assumptions; and therefore, the hydrogen supply cost and GHG emissions of the hydrogen supply chain in a real case could be different from the study's evaluation results. However, the assumptions used in this study have been derived from reliable sources: IEA, government studies, etc.

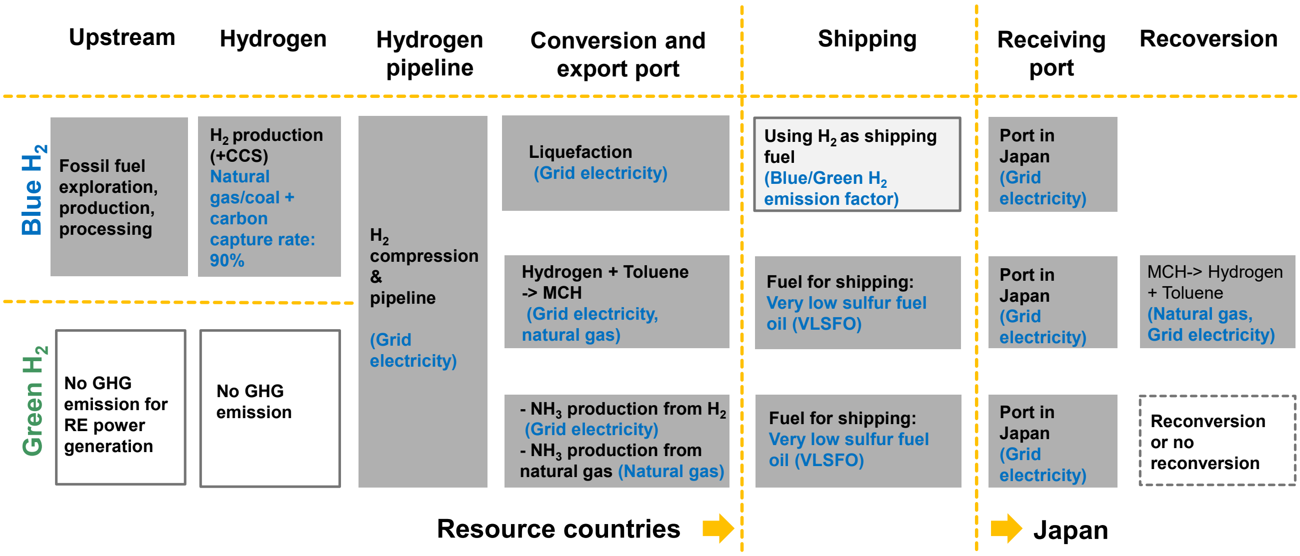

FIGURE 3. HYDROGEN SUPPLY CHAIN & GHG EMISSION EVALUATION FLOW AND EMISSION SOURCES FOR EACH PROCESS

This study will identify GHG emissions from the entire hydrogen supply chain (Figure 3). However, it should be noted that this does not mean that this study has conducted a life-cycle GHG (LCGHG) assessment that includes GHG emissions from the manufacturing process of all equipment and facilities across the supply chain. LCGHG assessments often complicate the interpretation of analysis results when international comparisons are involved. For the sake of simplicity and maintaining clear messages from analysis results, this study includes GHG emissions from the individual processes across the hydrogen supply chain. Upstream fugitive emissions also include methane, which is converted to CO_2 equivalent.

CHAPTER 3. MAJOR FINDINGS

Based on the methodology above, the supply cost to Japan ($/kg-$H_2$) and the carbon footprint of green and blue hydrogen (kg-CO_2eq/kg-H_2) are compared among different supply chains.

This study considers two major cases for the economic evaluation of hydrogen supply chains. The difference between the two cases lies in the assumptions for the electrolyzer cost: $700/kW for the Base Case, and $336/kW for the Low Electrolyzer Cost Case (today's cost is $900/kW). The technology for blue hydrogen production is already mature and thus has limited potential for cost reduction. On the other hand, electrolyzers have much room for further cost reduction. However, there is much uncertainty involved with the cost reduction of electrolyzers, which is impacted by many factors, and therefore, this study considers two cases for future electrolyzer costs. In addition to these two cases, a case considering a carbon price under the Low Electrolyzer Cost Case is also included in order to analyze economic implications of carbon footprint differences.

3.1. ECONOMICS OF HYDROGEN SUPPLY CHAIN

Figure 4 shows the hydrogen supply cost for each supply chain. In case of NH_3, ammonia is assumed to be cracked into hydrogen so as to compare different hydrogen carriers at level playing field. Looking at LH_2 as hydrogen carrier, Chile_Wind ($4.8/kg-$H_2$) is the most competitive among green hydrogen supply chains, followed by Chile_PV ($5.1/kg-$H_2$) for the Base Case. Only green hydrogen from Chile_Wind can compete with blue hydrogen from Australia (AUS_CoalCCS and AUS gasCCS), while blue hydrogen from Saudi Arabia is the least expensive. If the electrolyzer cost is reduced by half (Low Electrolyzer Cost Case), the supply cost of green hydrogen from Chile (Chile_Wind and Chile_PV) can be curbed to $4.5/kg-$H_2$, which is lower than blue hydrogen from Australia ($4.8~4.9/kg-$H_2$), but still higher than Saudi_GasCCS ($4.1/kg-$H_2$).

Lower elyctrolyzer cost allows green hydrogen supply options to be more competitive than blue hydrogen. Not only green hydrogen from Chile, but also green hydrogen from Australia (AUS_PV) can be cheaper than blue hydrogen from Australia. However, green hydrogen production costs exhibit different sensitivity to electrolyzer costs due to the difference in renewable energy capacity factors. Electrolyzer CAPEX has less impact on hydrogen production cost when the capacity factor is higher.

The relative relationship among hydrogen supply costs of different supply chains using MCH as the hydrogen carrier is observed not to differ largely from that for LH_2. However, in the case of NH_3, the supply cost of green ammonia from Chile in the Low Electrolyzer Cost ($3.7~3.8/kg-$H_2$) case remains higher than that of blue ammonia from Saudi Arabia (Saudi_GasCCS: $2.8/kg-$H_2$) and Australia (AUS_GasCCS: $3.3/kg-$H_2$). As blue ammonia production from natural gas is a mature technology with optimized processes, the production cost of blue NH_3 from natural gas is lower than that of green NH_3 or of blue NH_3 produced from coal.

With regard to comparisons among different hydrogen carriers (LH_2, MCH and NH_3) for green hydrogen, MCH (ranging from $3.7/kg-$H_2$ to 4.8/kg-H_2 for the Base Case and $3.4/kg-$H_2$ to 4.2/kg-H_2 for the Low Electrolyzer Cost Case) is the most competitive option due to lower conversion costs and shipping costs for MCH (even if reconversion is included).

If ammonia is assumed to be directly used for power generation, either co-firing with coal-fired power plants or 100%-ammonia gas turbines[2], there is no need to crack ammonia into hydrogen at the import terminal, then the supply cost can be reduced. Figure 5 shows the ammonia supply cost without cracking (reconversion). The least expensive green NH_3 is $2.9/kg-$H_2$ of Chile_wind and Chile_PV for the Low Electrolyzer Cost Case, which is cheaper than blue ammonia of AUS_coalCCS, while more expensive than the blue ammonia of Saudi_gasCCS.

When taking a closer look at the shipping cost, as Chile is located farthest from Japan among the countries addressed in this study, the longer transportation distance of hydrogen/ammonia may arise concerns of larger shipping costs. However, this study reveals that the shipping cost of hydrogen/ammonia accounts for a limited percentage of the whole supply cost; and therefore, the longer distance between Chile and Japan does not cause much disadvantage.

[2] 100%-ammonia gas turbines in fact can be regarded as 100%-hydrogen gas turbines that crack ammonia into hydrogen by exhaust heat from gas turbines, then the hydrogen is fed into gas turbines.

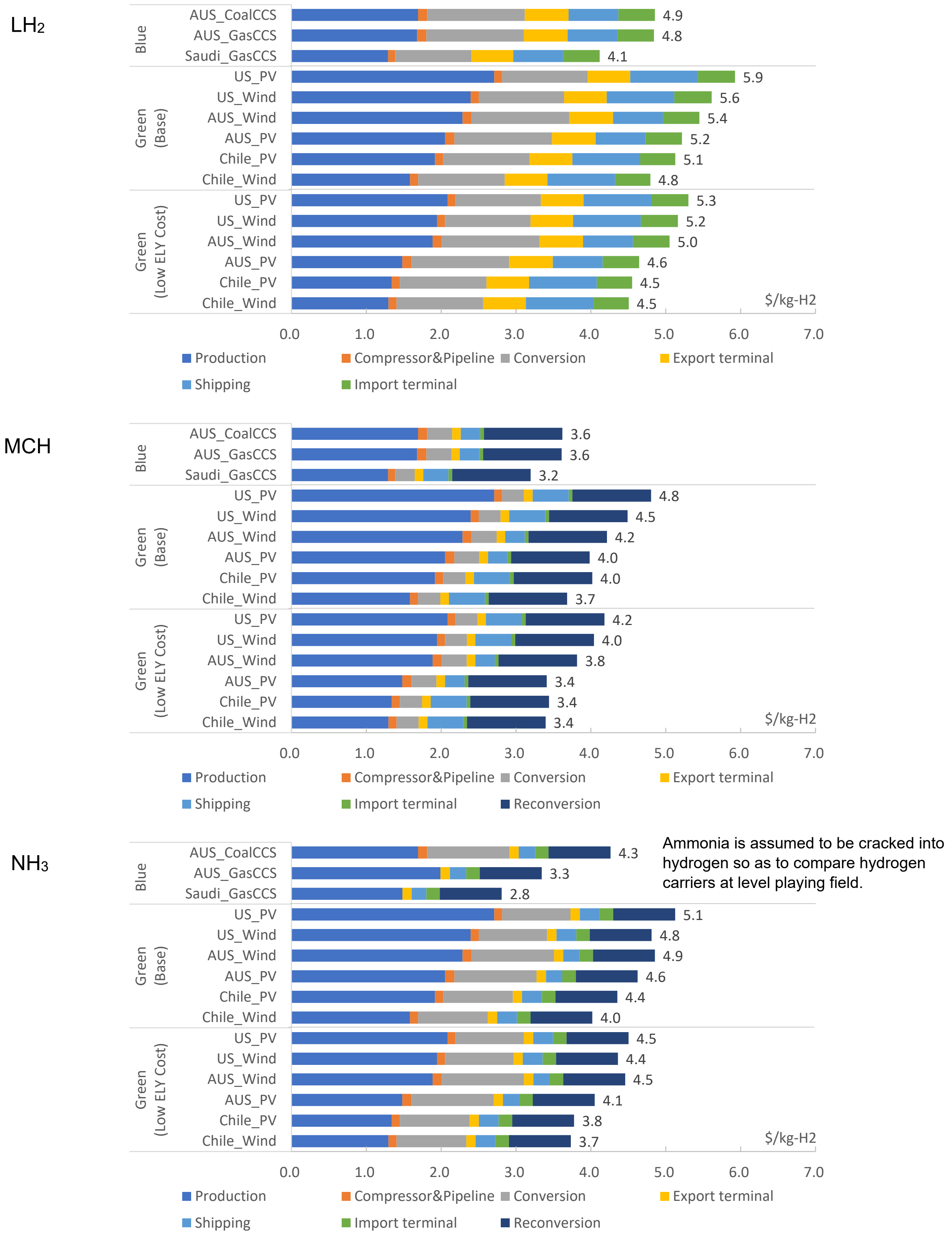

FIGURE 4. HYDROGEN SUPPLY COST

Note: “Base” stands for Base Case and “Low ELY Cost,” for Low Electrolyzer Cost Case.

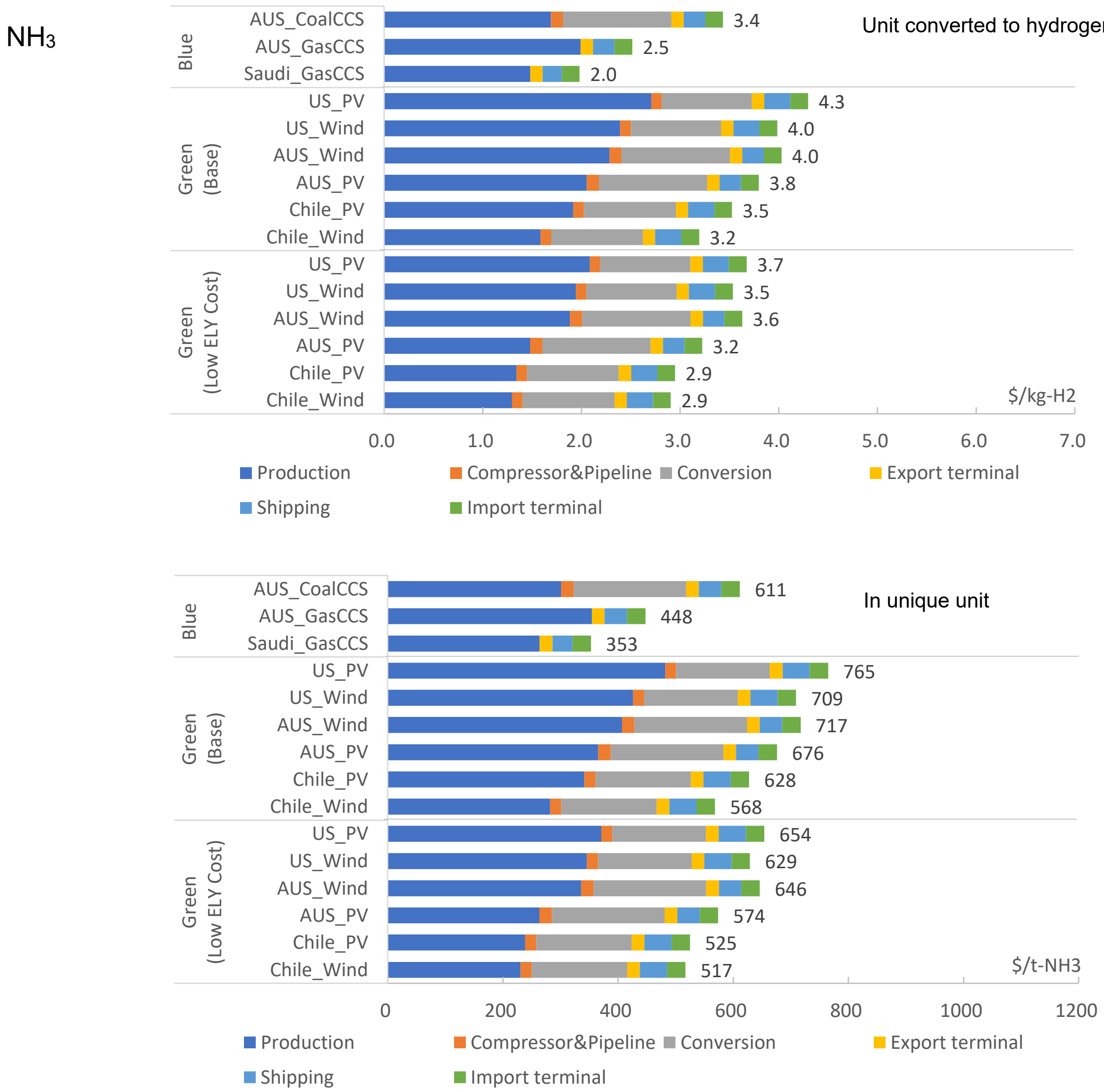

FIGURE 5. AMMONIA SUPPLY COST (WITHOUT CRACKING)

Note: “Base” stands for Base Case and “Low ELY Cost,” for Low Electrolyzer Cost Case.

3.2. ECONOMICS OF HYDROGEN SUPPLY CHAIN INCLUDING CARBON FOOTPRINT

The carbon footprint of each hydrogen supply chain is shown in Figure 6. As with the economics of hydrogen supply, the carbon footprint of hydrogen supply chain is affected by many factors. In general, the green hydrogen supply chain exhibits smaller carbon footprint than that of blue hydrogen due to lower GHG emissions from the hydrogen production process. However, GHG emissions associated with other processes also constitute a large part total GHG emissions from the hydrogen supply chain. For example, the conversion processes of LH_2 and NH_3 are electricity intensive. This study assumes that the electricity input for conversion comes from the grid, and as a result in countries with lower grid emission factors[3], such as Chile, the conversion process involves lower GHG emissions. Furthermore, since the study assumes that 90% of GHG emissions associated with blue NH_3 production is captured, in some cases, the blue NH_3 supply chain can involve less GHG emissions compared even to green NH_3 (from the US and Australia) .

With regard to comparisons among different hydrogen carriers (LH_2, MCH and NH_3), LH_2 exhibits the lowest carbon footprint due partly to the fact that hydrogen is used for driving the shipping while others are assumed to be driven by heavy fuels, and partly to the fact that reconversion process is not needed. If ammonia is assumed to be cracking-free (reconversion-free), its carbon footprint can be reduced.

[3] Grid emission factor is calculated based on the expected power generation mix of 2030. The power generation mix is derived from published literature.

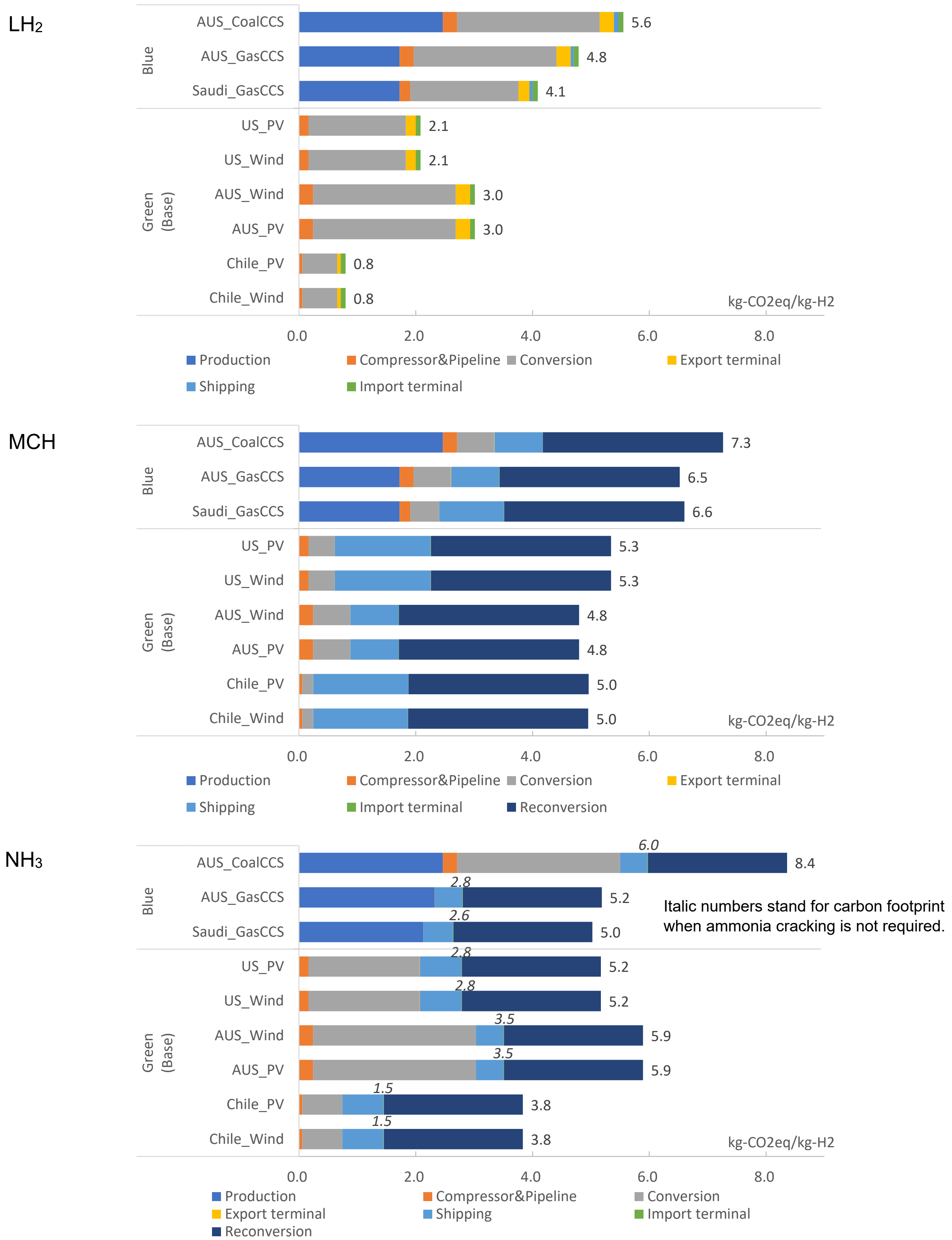

FIGURE 6. CARBON FOOTPRINT (GHG EMISSION) OF HYDROGEN SUPPLY CHAIN

In the GHG emissions evaluation of the supply chain, fugitive GHG emissions associated with fossil fuel exploration and production are also included. However, due to a lack of reliable information, this study applies the calculated average fugitive emissions factor of coal mining and natural gas systems (exploration, production, and processing) in the United States to all cases. The U.S.' average emission factor has been calculated based on the U.S. Environmental Protection Agency's GHG emissions report[4] and statistics for natural gas[5] and coal production[6]. Upstream GHG emissions are dependent on case-specific factors and further studies will be required to evaluate the emission more correctly and precisely.

With more and more countries committed to carbon neutrality and considering placing a price on GHG emissions, GHG emissions associated with the hydrogen supply chain could translate into economic costs. To see how the carbon cost, if introduced[7], can impact the economics of hydrogen supply, the study assumed a carbon cost of \$100/t-CO_2 to be added to the hydrogen supply chain (Figure 7) and ammonia supply chain (Figure 8). Adding a carbon price results in higher hydrogen supply costs for both green hydrogen and blue hydrogen. However, the carbon cost associated with blue hydrogen is larger than that of green hydrogen. Therefore, when a carbon cost is considered, green hydrogen from Chile (Chile_Wind and Chile_PV) for the Low Electrolyzer Cost Case can compete with the cheapest blue hydrogen from Saudi Arabia in the case of LH_2 and MCH. However, when the hydrogen carrier is NH_3, the cost of green ammonia from Chile remains higher than blue ammonia from Saudi Arabia (Saudi_gasCCS) and Australia (AUS_gasCCS).

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[4] United States Environmental Protection Agency, Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2019, https://www.epa.gov/sites/default/files/2021-04/documents/us-ghg-inventory-2021-main-text.pdf?VersionId=wEy8wQuGrWS8Ef_hSLXHy1kYwKs4.ZaU

[5] Natural gas production data from U.S. Energy Information Administration (EIA): https://www.eia.gov/dnav/ng/ng_prod_sum_a_EPG0_FPD_mmcf_a.htm

[6] Coal production data is also in the same EPA report

[7] This report stands neutral with regard to Japan's policy decision on carbon price. Carbon cost of \$100/t-CO_2 is assumed purely for the purpose of economic analysis to take into account carbon footprint differences.

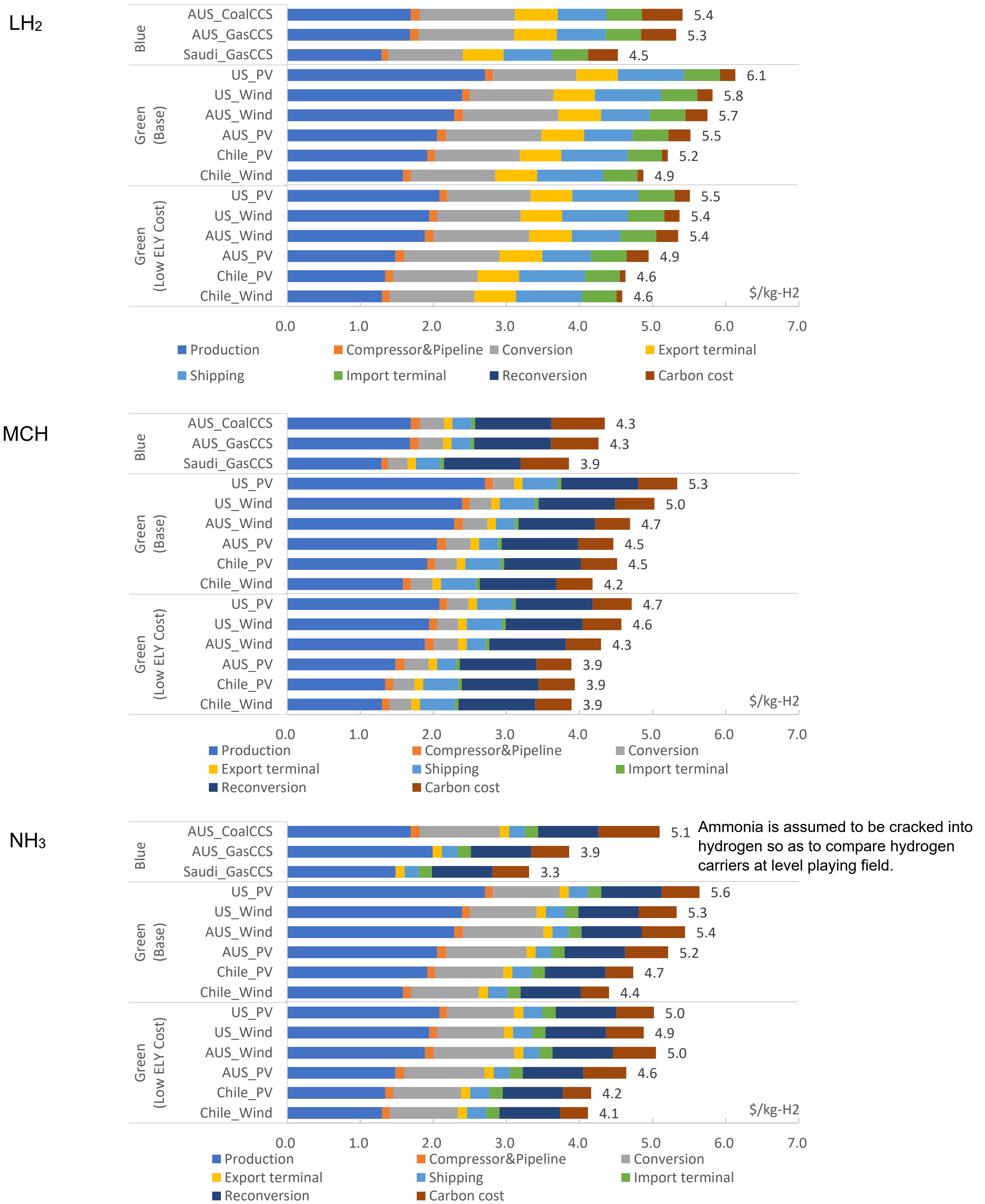

FIGURE 7. HYDROGEN SUPPLY COST INCLUDING CARBON COST

Note: The carbon price is assumed to be $100/t-$CO_2$.

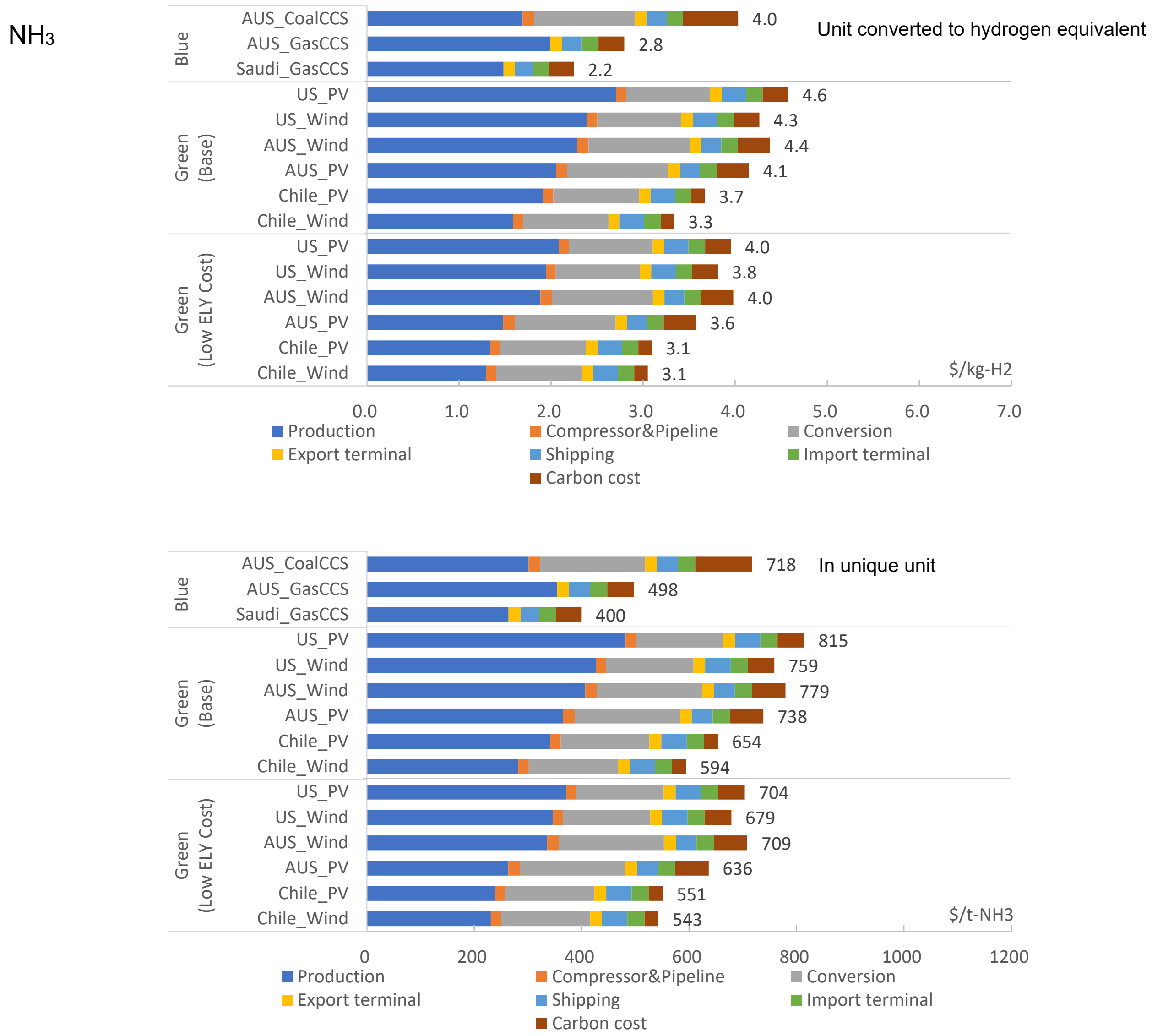

FIGURE 8. AMMONIA SUPPLY COST INCLUDING CARBON COST (WITHOUT CRACKING)

Note: The carbon price is assumed to be $100/t-CO_2$.

3.3. Issues in Analyses

It should be noted that there are uncertainties in the assumptions made in this study (See Appendix). For example, blue hydrogen/ammonia is assumed to be produced with an additional cost for CCS with a carbon capture rate of 90%. This can be realized in steam methane reforming of gas for blue hydrogen. However, in the case of blue ammonia, the current carbon capture rate for the entire blue ammonia production from gas is, in general, 50% to 60%[8]. Hence the assumption for blue ammonia may be too optimistic. If a carbon capture rate of 90% is sought for all blue ammonia production, costs could be higher. On the other hand, in terms of green ammonia production, this study assumes the same process as blue ammonia production from gas. However, the large-scale and constant operation assumed for this process is not appropriate for variable input from renewable energy. To realize green ammonia production costs of the same level as blue ammonia, technology development for coping with variable input is necessary.

[8] 70% of CO_2 emissions come from the main (intensive) process and 30% from the remaining (distributed) process. Therefore, if the carbon capture rate of the main process is assumed to be 90%, the whole capture rate will be around 60%.

Chapter 4. Recommendations

4.1 Potential hydrogen demand in Japan

Under the Green Growth Strategy[9], Japan seeks to create hydrogen demand of 3 million tons in 2030 and 20 million tons in 2050[10]. Commercial vehicles, including fuel cell (FC) trucks and hydrogen-powered ships will be introduced through 2030. In the power sector, stationary fuel cells and small-scale hydrogen turbines will be locally introduced in the short term, with an aim to install large-scale hydrogen gas turbines in around 2030, when a commercially viable hydrogen supply chain has been established globally. Pilot projects to decarbonize manufacturing processes using clean hydrogen will be continued through 2030.

During the transition to a hydrogen economy, fuel ammonia will be first used for co-firing at existing coal-fired power plants[11]. To this end, the demonstration project in Chubu-area is expected to be completed around 2025. Therefore, Japan will need to rely on ammonia imports to decarbonize its fuel supply in the short to medium term.

In the industry, commercial and household sectors, fossil fuels will be replaced with hydrogen for heat demand by installing either hydrogen burners/boilers for industrial use or fuel cells and boilers for commercial and residential use, as well as through newly built pipeline distribution of hydrogen or through delivery of synthetic methane produced from hydrogen by the existing city gas pipeline. Given limited domestic resources, clean hydrogen imports will be key to mainstreaming hydrogen in Japan.

While it is true that Japan needs to import hydrogen, it should be noted that Japan's energy security cannot be improved if hydrogen is imported from the countries from which Japan is currently importing fossil fuels. In this sense, green hydrogen from for example Chile promises to play a significant role in improving Japan's energy security through diversifying its energy supply resources, especially in terms of its geographical location in the APAC region, which can alleviate concerns over sea lane security. The longer distance between Chile to Japan compared to other hydrogen/ammonia supply chains may arise concerns of larger shipping costs. However, this study reveals that the shipping cost of hydrogen/ammonia does not have a significant impact on the overall supply cost, Therefore, the disadvantages of the longer-distance transportation of hydrogen/ammonia from Chile to Japan is limited.

From the viewpoint of hydrogen carriers, this study has found that MCH is the most competitive option due to lower conversion costs and shipping costs for MCH even if reconversion is included. If it is assumed that NH_3 does not need reconversion (cracking) to hydrogen, NH_3 is the less expensive option through 2030. However, it should be noted that possible applications of ammonia are rather limited, such as power

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[9] Ministry of Economy, Trade and Industry (2020) *Green Growth Strategy Through Achieving Carbon Neutrality in 2050*, https://www.meti.go.jp/english/press/2020/pdf/1225_001b.pdf

[10] Domestic hydrogen demand for large-scale power generation is estimated to be 5-10 million tons per year. Around 6 million tons will be needed to fuel commercial vehicles such as FC trucks, and 7 million tons, for green steel.

[11] For example, if 20% co-firing is implemented at all coal-fired thermal power plants in Japanese major power companies, an estimate of about 10% of CO_2 emissions from the domestic electric power sector will be reduced.

generation and shipping fuels. In fact, Japan aims to use ammonia first for co-firing with coal-fired power generation where toxic ammonia can be centrally managed and controlled. If ammonia is to be used for distributed applications, such as industrial heat or fuel cells, the process of ammonia cracking to hydrogen will be required; and this may result in raising the supply cost. Hence, attention should be paid to the fact that ammonia can be used only for rather limited applications, while Japan needs hydrogen for other sectors as well, including high temperature industrial heat demand and mobility. For these applications, hydrogen imported by means of MCH and LH_2 can be candidates. Selection of hydrogen carriers should be discussed based on hydrogen applications.

4.2 Enabling the hydrogen economy in Green Hydrogen Exporters

According to the economic analysis herein of hydrogen exports to Japan, the prices of green hydrogen are still higher than Japan's target price, which is JPY30/Nm^3-H_2[12] in 2030 and JPY20/Nm^3-H_2[13] beyond 2030[14]. However, potential reductions in hydrogen shipping costs are heavily dependent on future developments in LH_2 and MCH technologies in Japan. Furthermore, ammonia shipping technology has almost reached maturity. Hence, further reductions in overall costs to meet Japan's target will call for lower green hydrogen production costs in producing countries.

Specific measures to reduce costs of green hydrogen production from electrolyzers should be established. Points that should be highlighted are how the power inputs to electrolyzers can be smoothed and how electrolyzers can be employed as grid service providers. This study assumed solar PV and wind separately as sources of green hydrogen/ammonia. However, in reality, smoothed power input to electrolyzer from a combination of solar PV and wind can be an option, thus contributing to elevating the capacity factor of electrolyzers and leading to lower hydrogen production costs. To make this happen, the optimal power supply from a combination of solar PV and wind should be identified, taking account of geographical location. Another option to improve the capacity factor of electrolyzers may be using grid electricity. This would involve optimizing the electrolyzer operation pattern to minimize the hydrogen production cost based on two factors: the power procurement cost and capacity factor. By expanding the operating capacity of electrolyzers at during the hours when the wholesale power price is low (i.e. when the share of renewable electricity is high), and *vice versa*, the hydrogen production cost can be minimized and the use of renewable electricity can be maximized. However, it should be noted that the carbon footprint of hydrogen depends on the power generation mix. Above all, electrolyzers can be used for LFC

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[12] USD3/kg-H_2 = USD0.47/kg-NH_3
[13] USD2/kg-H_2 = USD0.31/kg-NH_3
[14] Hydrogen and Fuel Cell Strategy Council (2019) *The Strategic Road Map for Hydrogen and Fuel Cells - Industry-academia-government action plan to realize a "Hydrogen Society" –* (https://www.meti.go.jp/english/press/2019/pdf/0312_002b.pdf)

(Load Frequency Control) through demand response. This will allow electrolyzer costs to be compensated by providing grid services, thus leading to reducing hydrogen production cost.

In addition to the measures above, cost reductions in green hydrogen production can be pursued by advancing production technology development. However, scaling up electrolyzer capacity should be accompanied by increased domestic application. The domestic use of hydrogen will also contribute to decarbonizing the energy system of green hydrogen exporters. Increased demand in the industrial, transport and household sectors may enable the achievement of economies of scale. Formulating a roadmap for domestic applications and thus presenting policy direction will facilitate the uptake of such technologies.

Furthermore, it should also be remembered that storing hydrogen over long periods is much easier than storing electricity in batteries, thus giving hydrogen high potential for seasonal storage. This characteristic allows hydrogen to be a key mechanism for facilitating integration of higher shares of renewable energy into power grids that are isolated from the national grid system. Hydrogen will bear an important role in improving national energy security, securing a stable energy supply and enhancing resiliency in a decarbonized manner by stockpiling renewable energy.

4.3 Potential areas of collaboration between Japan and Exporters

Various solutions can be explored through bilateral cooperation and other forms of collaboration among various players in Japan and green hydrogen exporters. Channels for cooperation should be sought across the entire supply chain, covering hydrogen production, transport, storage and application.

As one of the first countries in the world that formulated a hydrogen strategy and roadmap, Japan can offer its support in designing a roadmap for hydrogen deployment in green hydrogen exporters. Clear political will promises to attract foreign investment in target areas.

Hydrogen transport and energy carrier technologies, as well as port infrastructure technologies are important areas for collaboration between Japan and green hydrogen exporters. In addition to realizing future exports of green hydrogen to Japan, collaboration should be sought in the domestic application of hydrogen as an option for decarbonizing the domestic energy system. Some proposed areas for collaboration are, as aforementioned, harnessing electrolyzers for smoothing the increased fluctuation caused by the integration of solar PV and wind power into the power grid. In Japan, such technologies are currently being tested in several demonstration projects, including the Fukushima Hydrogen Energy Research Field (FH2R), which aims to balance supply and demand in the power grid while establishing low-cost green hydrogen production technology.[15]

[15] NEDO (2020) “The world's largest-class hydrogen production, Fukushima Hydrogen Energy Research Field (FH2R) now is completed at Namie town in Fukushima” Press release (March 7, 2020) (https://www.nedo.go.jp/english/news/AA5en_100422.html)

Regarding ammonia production, Harber-Bosch process was originally designed for constant operation and large-scale production. However, technologies for ammonia production based on variable input from renewable energy is currently being developed in Japan. Sharing these experiences would be promising areas of cooperation.

Other potential areas of cooperation include decarbonizing the final energy demand (industry, residential and transport sectors), by promoting the hydrogen application in the industry and the use of commercial and residential stationary fuel cells, as well as deploying fuel cell vehicles and hydrogen fueling networks to support them.

It should also be noted that while hydrogen plays an important role for decarbonization, the carbon footprint of hydrogen is a critical issue. Japan and hydrogen exporters should collaboratively lead international discussions on standards for hydrogen carbon footprint. It is also expected that the development of hydrogen/ammonia and fuel cell technologies through collaboration between Japan and hydrogen exporters can contribute to the development of relevant international markets.

Collaboration will open windows of more concrete business opportunities. Areas for government to government cooperation and business matching may be explored through workshops and in-depth discussions among stakeholders, including government, academia, businesses, and financial institutions.

APPENDIX: MAJOR ASSUMPTIONS

For hydrogen production, this study uses the same assumptions as in IEA's "The Future of Hydrogen"[16] (2030 cost assumptions). However, for green hydrogen production, this study considers two cases. The base case assumes an electrolyzer CAPEX of $700/kW in 2030 (IEA), and the low-cost case assumes an electrolyzer CAPEX of $336/kW based on interviews with global electrolyzer manufacturers, as reported by the Ministry of Energy, Chile.

The study also uses figures provided in IEA's "The Future of Hydrogen" for the cost evaluation of hydrogen liquefaction, MCH conversion and reconversion, NH_3 production, hydrogen shipping, and hydrogen export/receiving ports. However, since this study treats hydrogen production and NH_3 production as separate processes in the cases of green hydrogen and blue hydrogen production with coal, this study also uses NH_3 conversion cost estimations from the Institute of Applied Energy's report[17].

Feedstock cost assumptions have a significant impact on hydrogen production costs. and since this study applies the same cost and technical specification assumptions to all the countries, the differences in hydrogen supply cost and carbon footprint among the countries addressed are largely attributable to the country-specific differences in feedstock and fuel costs and emission factors (Table A1).

Projections of future renewable power generation costs or fossil fuel costs are not included within the scope of this study. For Chile, the renewable power generation cost and capacity factor for 2030 was provided by the Ministry of Energy of Chile. For Australia, assumptions for the future cost and capacity factor have been derived from a study by the Australian national science agency, CISRO[18]. For the United States, the data for renewable power generation is from EIA's annual energy outlook study[19].

Shipping distance is another important factor that affects hydrogen supply costs. Assumptions of shipping distances is shown in Table A2. For Chile, since solar PV resources are located in the northern part of the country and wind resources in the south, the study considers two different ports: one in the North and the other in the South.

As mentioned above, for the CAPEX of blue hydrogen production, this study uses IEA's assumptions, in which the CCS cost is already incorporated in the overall CAPEX. According to IEA's assumptions, CAPEX for hydrogen production with natural gas reforming will have a nearly 50% markup with CCS compared with no CCS ($910/$kW_{H2}$ without CCS and $1,360/$kW_{H2}$ with CCS (2030)), and 4% markup for coal gasification ($2,670/$kW_{H2}$ without CCS and $2,780/$kW_{H2}$ with CCS (2030)). For blue NH_3 production from natural gas, CCS results in 28% CAPEX cost increase ($905/ton-$NH_3$ without CCS and $1,260/ton-$NH_3$ with CCS).

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[16] IEA (2019), The Future of Hydrogen, IEA, Paris https://www.iea.org/reports/the-future-of-hydrogen

[17] The Institute of Applied Energy (2016). "*Research on the introduction scenario of an energy carrier total system / Cost analysis of energy carrier technologies, Impact evaluation of long term global energy supply and demand, Development of scenario on hydrogen technologies and utilization*." Research commissioned by NEDO.

[18] Graham, P., Hayward, J., Foster J. and Havas, L. 2021, *GenCost 2020-21: Final report*, Australia.

[19] U.S. EIA, "*Levelized Cost of New Generation Sources in the Annual Energy Outlook 2021*", https://www.eia.gov/outlooks/aeo/pdf/electricity_generation.pdf

TABLE A1. MAJOR ASSUMPTIONS ON FEEDSTOCK AND FUEL COSTS AND EMISSION FACTORS

<table>
<tr><th rowspan="2"></th><th colspan="2">Grid Electricity</th><th colspan="2">PV</th><th colspan="2">Wind</th><th colspan="3">Natural gas</th><th colspan="2">Coal</th><th colspan="2">Very low sulfer fuel oil (VLSFO)</th><th>Water</th></tr>
<tr><th>Price ($/kWh)</th><th>Emission factor (kg-CO2/kWh)</th><th>LCOE ($/kWh)</th><th>Capacity factor</th><th>LCOE ($/kWh)</th><th>Capacity factor</th><th>Price ($/mmbtu)</th><th>Combustion emission factor (kg-CO2-eq/mmbtu)</th><th>Upstream emission factor (kg-CO2/mmbtu)</th><th>Price ($/ton)</th><th>Upstream emission factor (kg-CO2-eq/ton)</th><th>Price ($/ton)</th><th>Emission factor (kg-CO2/MJ)</th><th>Price ($/ton)</th></tr>
<tr><td>Chile</td><td>0.07</td><td>0.10</td><td>0.017</td><td>32%</td><td>0.021</td><td>64%</td><td>5.2</td><td rowspan="5">53.1</td><td></td><td></td><td></td><td rowspan="4">400</td><td rowspan="4">0.078</td><td>0.5</td></tr>
<tr><td>Australia</td><td>0.09</td><td>0.40</td><td>0.019</td><td>32%</td><td>0.031</td><td>46%</td><td>6.2</td><td>4.4</td><td>16.2</td><td>74.03</td><td>1.5</td></tr>
<tr><td>US</td><td>0.07</td><td>0.27</td><td>0.031</td><td>29%</td><td>0.031</td><td>41%</td><td>4.2</td><td></td><td></td><td></td><td>1.0</td></tr>
<tr><td>Saudi Arabia</td><td>0.05</td><td>0.30</td><td></td><td></td><td></td><td></td><td>4.0</td><td>4.4</td><td></td><td></td><td>0.03</td></tr>
<tr><td>Japan</td><td>0.17</td><td>0.42</td><td></td><td></td><td></td><td></td><td>8.5</td><td></td><td></td><td></td><td></td><td></td><td></td></tr>
</table>

TABLE A2. ASSUMPTIONS ON SHIPPING DISTANCE

<table>
<tr><th>Resource country</th><th>Port in Resource country</th><th>Port in Japan</th><th>Distance (nautical miles)</th></tr>
<tr><td>Chile (North)</td><td>Mejillones, Antofagasta</td><td rowspan="5">Yokohama</td><td>9,192</td></tr>
<tr><td>Chile (South)</td><td>Cabo Negro, Magallanes</td><td>9,259</td></tr>
<tr><td>Australia</td><td>Melbourne</td><td>4,907</td></tr>
<tr><td>US</td><td>Houston (via Panama canal)</td><td>9,254</td></tr>
<tr><td>Saudi Arabia</td><td>Ras Tanura</td><td>6,593</td></tr>
</table>

Source: https://sea-distances.org/

Nature of and Comparison Among Oil and Natural Gas Upstream Business Strategies by Major Companies

Masayoshi Noguchi*

Note

This paper is a report that appeared on the website of the Institute of Energy Economics, Japan on February 2, 2022. The information herein is therefore based on information obtained as of February 2. However, the business environment involving five major companies, namely Shell, BP, TotalEnergies, Exxon Mobil, and Chevron (hereinafter referred to as "Major Companies"), is currently changing as a result of Russia's launch of a military operation in Ukraine at the end of February. This operation prompted BP to announce its intention to exit its stake in Rosneft on February 27. Shell has also indicated that it will withdraw from business with Gazprom and multiple joint ventures with related entities. While at the time of this writing (early March) it is not yet clear how this situation will conclude, changes with respect to Russia, one of the world's largest oil and gas producers, could impact the Major Companies' upstream business strategies over the medium- to long-term.

Abstract

- A comparison of the oil and natural gas upstream business strategies by Major Companies has illuminated an across-the-board understanding of the importance of a purposeful pursuit of lower costs and a focus on natural gas.
- Trends differ among[1] Major Companies, however, with regard to future natural gas and liquid production volume.

Comparison of upstream business strategies among major companies

Commonalities	Purposeful pursuit of lower costs (specific methods differ among the companies)	(Specific measures) - Regional consolidation of exploration operations (bp) - Business asset divestment - Improving operational efficiency through digitization, etc.				
	Recognition of natural gas importance	- Natural gas will play an important role as a low carbon fossil fuel in the energy transition				
Differences	Companies' liquid / natural gas production volume change trends (2020-2025)	Shell N.A.	bp ↓ Down	TotalEnergies ↑ Up	ExxonMobil → Flat	Chevron ↑ Up

- While the purposeful pursuit of lower costs appears to be something shared among all upstream business operators, the nature of production volume changes (whether to increase, decrease, or maintain) is subject to change based on each company's situation and outlook on the future.

1. Introduction

Day by day, international public opinion is growing increasingly supportive of achieving net zero emissions. According to the United Nations[2], over 130 countries have set or are planning to set goals to achieve net zero emissions. In

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1 In general, liquids include things such as crude oil and NGL. However, liquids can refer to slightly different substances depending on the company. For more information, see the note concerning each company's production volume.

2 https://www.un.org/en/climatechange/net-zero-coalition (Viewed on December 2021)

October 2021, major oil producer Saudi Arabia also announced a net zero target.

There is a global trend toward achieving net zero emissions, and upstream business strategies tailored to this trend will be needed by oil and natural gas upstream business operators, as well. Although low carbon and carbon removal technologies are attracting attention amid a movement to achieve net zero emissions, the global oil and natural gas demand will not dry up overnight. As such, there will continue to be a need for upstream business operators to supply a certain level of oil and natural gas. However, upstream business continuation will rely not only on traditional business strategy but also on strategy that takes this global trend into account.

Unfortunately, the need to address an opaque business environment will create certain difficulties when it comes to strategy formulation among these businesses. Along with the aforementioned international sentiment, there are many unknown variables that could impact oil and natural gas demand, including the extent to which these countries achieve economic development and develop and proliferate low carbon technologies in the future. Various institutions, factoring in these unknown variables, have devised demand scenarios that have significant differences. Suppliers, on the other hand, will need to optimize their businesses to avoid stranded capital[3] while still achieving monetization amid considerable demand uncertainty.

This paper explores and compares strategies formulated by five Major Companies as illustrative examples of upstream business strategies. Major Companies have upstream operations around the world and face wide-ranging risks as the world shifts toward net zero emissions. The strategies of such companies at the top of their industry should provide useful hints for other upstream business operators.

A comparison of the oil and natural gas upstream business strategies by Major Companies has illuminated an understanding of the importance of a purposeful pursuit of lower costs and a focus on natural gas. Trends differ among Major Companies, however, with regard to future natural gas and liquid production volume. The methods employed by these companies to reduce costs by implementing state-of-the-art technologies and strict investing standards should prove instructive for other upstream business operators. There does not seem to be, however, any generally-accepted "right answer" on production volume changes (whether to increase, decrease, or maintain), and companies could take different paths in accordance with business strategies that are based on their individual situations and outlooks on the future.

Chapter II of this paper presents an overview of current production volume and reserves among individual companies, as well as their future strategy. Chapter III then provides a comparison of these companies' strategies.

2. Current Production Volume and Reserves among Major Companies, and Their Future Strategies

This chapter presents an overview of current production volume and reserves, as well as future strategies, at Shell, BP, TotalEnergies, Exxon Mobil, and Chevron, in that order, with published data from these companies provided as reference.

(1) Shell

Shell has stated its intention to establish core business domains and regions, and to continue its upstream businesses while shifting production to gas and lowering costs. While the content of strategy announced by the company prior to May 2021 could be in the process of being reconsidered, this paper is primarily based on that original strategy.

① Current production volume and reserves

A look at natural gas and liquid production[4] in 2020 by region shows the key producers to be Asia and North and South America (Fig. 1). By type of resource, the U.S., Brazil, and Oman are the largest producers of liquid, while Australia, the U.S., and Malaysia produce the most natural gas. Shell is also continuously working to improve operations,

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[3] The IEA defines stranded capital as "capital investment in fossil fuel infrastructure that is not recovered over the operating lifetime of the asset because of reduced demand or reduced prices resulting from climate policies" (IEA, 2021 *Net Zero by 2050*, p.102 note).

[4] Liquids include crude oil, NGL, and synthetic crude oil. Daily production by region is calculated by dividing annual production by region by days per year. Natural gas volume is converted to liquid volume using a coefficient utilized by Shell.

including by reducing production costs. For example, the company reduced its unit development cost[5] (UDC) and unit operating cost[6] (UOC) by 51% and 26%, respectively, between 2015 and 2020.

As of the end of 2020, Asia and North and South America also have the largest proportions of proven reserves of liquid and natural gas[7] (about 9,124 Mboe) by region. The company's liquid to natural gas ratio is 51:49.

The amount that the company invests in its upstream segment as a proportion of its total cash capex[8] dropped from about 50% to 42% between 2018 and 2020. Total investment for both upstream and integrated gas[9] segments decreased from 66% (2018) to 65% (2020), a slighter change than for the upstream segment itself.

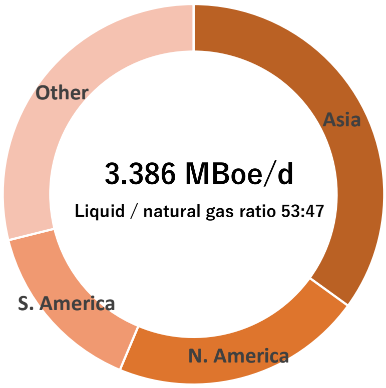

Fig. 1 Liquid and natural gas production by region (Shell, 2020)

Source: Prepared based on data from Shell, *ANNUAL REPORT AND ACCOUNTS 2020*

② **Future strategy[10]**

Shell sees cash flows from its upstream business as a means to fuel shareholder return and low carbon investment, and has indicated an intention to continue such business. It has indicated that it believes natural gas will play an important role in the energy transition. This is because natural gas is an energy source that could be used in the power production sector (to compensate for the intermittency of renewables) and sectors where electrification is problematic, as well as a possible means to reduce overall carbon emissions.

Although Shell's data does not state specific production volume target values, the company aims to make natural gas at least 55% of all liquid and natural gas production by 2030. Liquid production, meanwhile, peaked in 2019, and the company expects liquid to decrease 1-2% by 2030 due to natural decline and divestments. In materials released prior to May 2021, the company stated that it aimed to eliminate routine flaring at its operations by 2030. It has since moved this goal up to 2025[11].

Shell will also continue reducing production costs through 2025. By 2025, Shell aims to reduce UDC by up to 10%, UOC by up to 20%, and total OPEX (operating expenses) by 20-30% compared to 2019 levels. Along with simplifying,

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5 Calculated by dividing the amount of Shell's concession share as a portion of its project capital costs by the production volume of its concession share.

6 Calculated by dividing the amount of Shell's concession share as a portion of its operating costs by the production volume of its concession share.

7 "Proved developed and undeveloped oil and gas reserves" from *ANNUAL REPORT AND ACCOUNTS 2020.*

8 Definition from the company's publicized literature: "Cash capital expenditure comprises the following lines from the Consolidated Statement of Cash Flows: Capital expenditure, Investments in joint ventures and associates and Investments in equity securities."

9 Included in integrated gas segment business is certain operations concerning liquid and natural gas production, exploration, development, and transport infrastructure, along with LNG operations, new energy business operations, and operations to conversion of natural gas to "gas to liquid fuel" and other products.

10 The content of this paper is primarily based on upstream business strategies released through May, 2021. In May 2021, after the strategy was announced, the Hague Court ruled that Shell should establish additional carbon reduction targets as its current targets are inadequate and lack specificity. Shell CEO Ben van Beurden said that he interprets the ruling as Shell needing to accelerate, but not change, its strategy. The company has since sold its U.S. Permian assets, which were one of the company's core positions in September. Under the circumstances, the company may be rethinking the strategy it announced prior to the ruling. It has not made a proper strategy announcement since the ruling, however.

11 https://www.shell.com/inside-energy/zero-routine-flaring-by-2025.html

standardizing, and replicating facility design aimed at reducing UDC, it will also promote digitalization in order to reduce UOC.

Shell has specified three areas of focus for the future, namely deep water, shale, and traditional crude oil and natural gas extraction, and has established regions (nine regions in total) that will serve as core business positions (Fig. 2). The specific core positions will be Brazil and the Gulf Coast for deep water extraction, U.S. Permian for shale drilling (but was sold after the announcement of its strategy), and the UK, Nigeria, Oman, Kazakhstan, Brunei, and Malaysia for conventional oil and gas production. Shell says it will concentrate 80% or more of all future cash capex into these core positions (with a particular emphasis on deep water business). It sees attractive opportunities for frontier exploration through 2025, after which it will cease frontier exploration in order to de-risk[12].

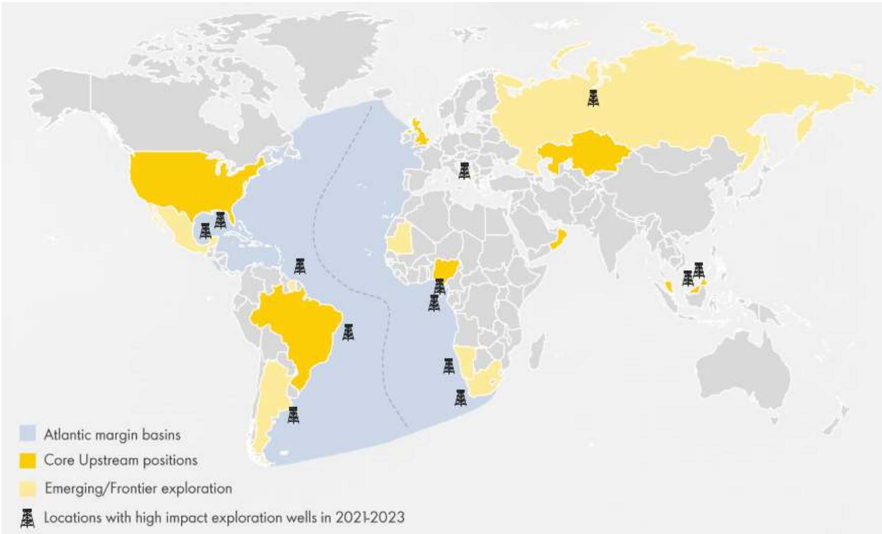

Fig. 2 Upstream exploration program map

Source: Shell, *"SHELL INSIGHTS: UPSTREAM STRATEGY"*

Shell has selected new business regions and aims to implement stricter investing standards. It assumes commodity prices post 2025 of $60/bbl for Brent crude and $3/MBtu for Henry Hub (HH). A hurdle rate (IRR) of at least 18% is a basic requirement for investment, with investment return before 2035. As far as this author was able to gather from published data, Shell is the only one among the Major Companies to disclose specific investment return dates. It also makes its own carbon cost projections and factors that in as potential cost in its business economic assessments.

The company's divestments suggest the possibility that investment targets could be selected from among lean positions (assets other than core positions).

For investing (cash capex) allocation in the future, it will gradually transition from upstream to growth segments (marketing, renewables, and energy solutions businesses). The company plans to establish three business pillars—"upstream," "transition," and "growth"—and increase its investment in the upstream pillar from about 42% in 2020 to 30-40% by 2025 and 25-30% thereafter.[13] It will also increase third party LNG business. Apparently this will contribute to increasing sales while minimizing upstream investment in and business risk from feed gas production.

(2) BP

BP has indicated that it intends to continue its upstream businesses while working to reduce production costs. However,

[12] The company refers to these as under-explored basins in the same materials (*"Brazil Shareholder visit 2016"* p.15).

[13] Transition pillar investment will change from around 43% in 2020 to 35-40% by 2025 and about 30-40% thereafter. For its growth pillar, Shell plans to gradually increase its investment allocation from roughly 16% in 2020 to 25-30% by 2025 and 35-40% afterwards.

it will only conduct new exploration operations in a limited number of regions and will reduce liquid production volume in stages until 2030. The company has a 19.75% stake in Rosneft but this portion is not included in BP's production and emissions targets.

① Current production volume and reserves

BP's liquid and natural gas production in 2020[14] **was about 2.4 Mboe/d if excluding Rosneft and 3.473 Mboe/d if including Rosneft** (Fig. 3). A look at BP's production volume by region inclusive of Rosneft shows places like Russia and North America to be key production regions. Broken down by country and resource, liquid production is largely from deep water drilling by Rosneft and in the Gulf Coast, while natural gas is mostly from Trinidad and Tobago, the onshore in the U.S. lower 48, and Rosneft.

As of the end of 2020, Russia accounts for about 50% of proven reserves of liquid and natural gas[15] **(about 17,982 Mboe) by region, followed by Asia (excluding eastern Indonesia) and the U.S.** The company's liquid to natural gas ratio is 59:41.

The company's investment allocation in its upstream segment, which is a part of its organic capex (total capex minus outflows for acquisitions, etc.), stayed mostly flat at around 78-79% from 2018 through 2020.

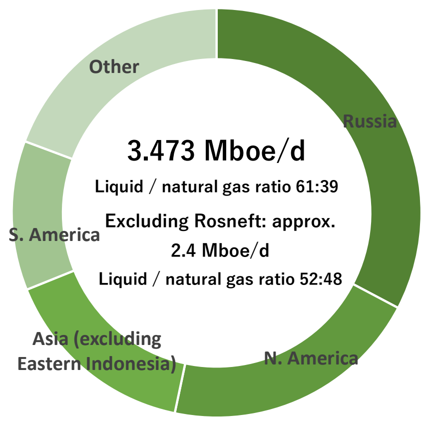

Fig. 3 Liquid and natural gas production (BP, 2020)

Source: Prepared based on data from BP, *BP Annual Report and Form 20-F 2020*

② Future strategy

BP has said that it expects a certain measure of liquid and gas demand to remain over the intervening decades until 2050, and that it will continue its upstream business. The company sees upstream business as a necessary source of funding for transitioning into its two growth segments: low carbon energy, and improvement of customer convenience and mobility. It sees natural gas as playing an important role in the global energy transition.

However, it plans to reduce liquid and natural gas production (excluding Rosneft) up until 2030. It will gradually reduce production from around 2.4 Mboe/d in 2020 to under 2.0 Mboe/d by 2025 and around 1.5 Mboe/d by 2030. BP CEO Bernard Looney has given three reasons for reducing production by 2030. The first is to realize growth with cash flows and returns in good balance, in line with a policy of emphasizing quality over quantity, as part of a companywide effort to achieve business reform. The second is to decarbonize and diversify its businesses by reallocating capital to lower carbon business, thereby reducing risk. The third is to achieve alignment with the process to achieve net zero emissions by 2050. BP aims to be net zero on an absolute basis across all upstream oil and gas production operations by 2050. Milestones toward this goal are achieving emissions cuts of 20% and 35-40% by 2025 and 2030, respectively, compared to 2019. It says it will work to keep a liquid to natural gas production ratio of about 50:50 until 2025.

[14] Liquids include crude oil, condensate, bitumen, and NGL. Natural gas volume is converted to liquid volume using a coefficient utilized by BP.
[15] Net estimated proved reserves as stated in *BP Annual Report and Form 20-F 2020.*

It will also reduce unit production costs from $6.84/boe in 2019 to under $6/boe in 2025. Some of the ways it will do this are digitizing operations management, improving maintenance and inspections, and shortening unscheduled operational downtime.

Regarding new investment, BP has announced that it will not embark on new exploration in countries it does not have a presence in, and will instead focus on exploration and development in hub-adjacent areas in existing core regions (Fig. 4, 5)**.** The reasoning behind this is that directing upfront investment toward new business will help reduce production costs, while also reducing total production volume, as mentioned above. BP's liquids business will focus on tieback development and infill drilling, in particular[16]. Its exploration investment is already declining, a trend that the company expects will continue.

Fig. 4 Liquids business investment options

Source: BP, *Resilient and focused hydrocarbons*

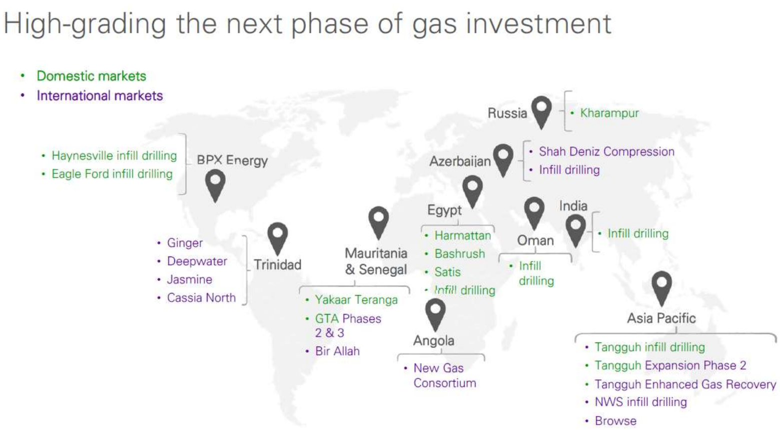

Fig. 5 Natural gas business investment options

Source: BP, *Resilient and focused hydrocarbons*

With a need for a resilient and competitive hydrocarbon business, BP is looking to implement strict investment standards. The company assumes average commodity prices up until 2050 of $55/bbl for Brent crude and $2.90/MBtu for

[16] BP will drill new production wells in between existing production wells as a means to boost production capacity from existing oil reservoirs (https://oilgas-info.jogmec.go.jp/termlist/1000201/1000292.html).

HH, has set a hurdle rate particular to the business sector (about 10-15%), and forecasts an investment return period of less than 10 years for upstream liquids and less than 15 years for upstream natural gas. It has also made its own carbon cost projections and factors some of those costs into its business economic assessments. Cash flow volatility is among the other factors it considers in these assessments.

As for future investment allocation, it will gradually shift focus away from resilient hydrocarbons (including upstream business, refinement, and trading) and toward other growth segments. All BP business falls into four categories—resilient hydrocarbons, low carbon electricity and energy, convenience and mobility, and other—and total investment into low carbon electricity and energy and convenience and mobility, which were around 15% in 2019, will be increased to at least 40% by 2030. Some third-party LNG is expected to be included in LNG sales, presumably because it will contribute to feed gas development investment and de-risking.

Concerning divestment, the company will sell roughly 600 kboe/d in assets between 2019 and 2025. Among its liquid assets, low-margin assets will be sold more aggressively. About 200 kboe/d have been sold as of September 2020.

(3) TotalEnergies

TotalEnergies has indicated that it intends to increase overall production and continue its upstream businesses, while reducing production costs and producing more gas.

① Current production volume and reserves

Broken down by region, liquid and natural gas production in 2020[17] was concentrated in Europe, Central Asia, Africa (excluding North Africa), and the Middle East and North African (MENA) (Fig. 6). By country and type of resource, countries such as UAE and Angola produce the most liquids while Russia and the UK are among the largest natural gas producers.

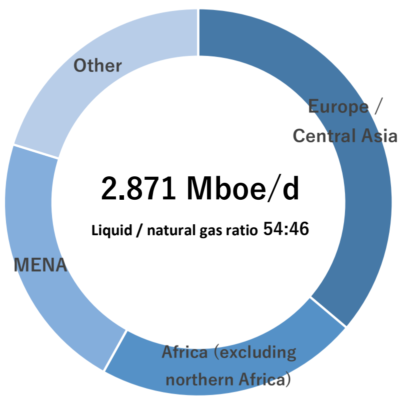

Fig. 6 Liquid and natural gas production (TotalEnergies, 2020)

Source: Prepared based on data from TotalEnergies, *Factbook 2020.*

MENA and Russia account for a relatively large proportion of proved liquid and natural gas[18] (about 12,328 Mboe) by region as of the end of 2020. The company's liquid to natural gas ratio is 47:53.

TotalEnergies' investment in the Exploration & Production segment as a proportion of total investment dropped from 62% in 2018 to 44% in 2020. Total investment for both the Exploration & Production and Integrated Gas and Renewables & Power segments declined from 85% (2018) to 84% (2020), a slighter change than for the Exploration & Production segment itself.

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[17] Production volume in the Exploration & Production segment and Integrated Gas, Renewables & Power (iGRP) segment. Liquids include crude oil, bitumen, condensate, NGL.

[18] Proved developed and undeveloped reserves from *Factbook 2020.*

② **Future strategy**

TotalEnergies will continue its upstream hydrocarbon business with the view that it is a source of cash flows for its energy transition and shareholder return. TotalEnergies sees natural gas as an important energy source that produces relatively little carbon emissions and compensates for the intermittency of renewables while contributing to the global energy transition. The company therefore anticipates LNG demand will see strong growth over the next several years in mainly Asian countries that are focused on increasing energy supply and reducing carbon emissions. It believes its formidable asset portfolio will allow it to supply sufficient LNG to meet this demand.

TotalEnergies will increase liquid and natural gas production by an average of 3% annually between 2021 and 2026, primarily through LNG production increases. An expected liquid and natural gas production volume of 2.85 Mboe/d for 2021 translates into a 3% average annual production increase, and 3.21 Mboe/d in 2025 (Fig. 7). The company is shifting production more toward gas, aiming to make it around 60% of total production by 2035. Liquid production, on the other hand, will peak over the next 10 years while following the overall market trend, and then gradually decline thereafter. As an emissions target for its upstream businesses, TotalEnergies has announced that it will achieve a 40% reduction in net emissions (Scope 1+2) from current liquid and natural gas operations by 2030 compared to 2015.

TotalEnergies will also cut unit production costs. As a near-term goal, the company will bring OPEX for its upstream business to around $5/boe in 2022. Digitizing operations will be among its measures for reducing costs.

New investment will prioritize low-cost and low-carbon projects, with "low-cost" defined as capex and opex of less than $20/boe and an after tax break-even price of less than $30/boe. It forecasts commodity prices of $50/bbl for Brent crude and $2.50/MBtu for HH, giving a return of over 15% for the company's liquids business. TotalEnergies has its own carbon cost projections and factors these in to its business economic assessments. The company's requires that GHG emission intensity for all new businesses be below the average intensity for its overall business portfolio.

For companywide investment between 2022 and 2025, roughly 50% will go toward maintaining the business base (mainly upstream and downstream liquids businesses), with the remaining 50% going to growth segments. In terms of allocation toward growth segments, the company plans to allocate about half to natural gas, and LNG in particular, while the other half will go toward new energy, primarily renewables and electricity. Some third-party LNG is expected to be included in LNG sales, presumably because it will contribute to feed gas development investment and de-risking.

Concerning divestment, the company has indicated that, as a near-term target, it will sell 12 assets equivalent to a total of about 65 kboe/d for 2020 to 2021 (Fig. 8)**.** This selloff program is said to be in line with the company's strategy for assets that have high technical costs and emission intensity.

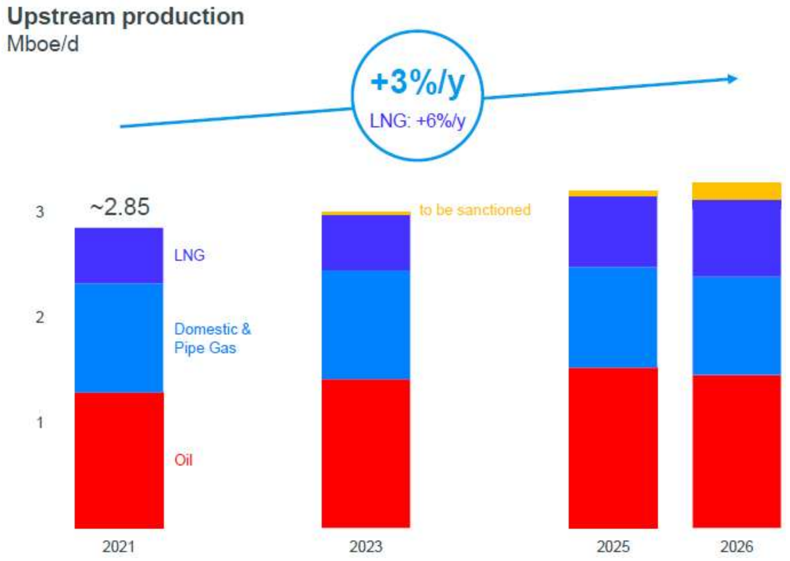

Fig. 7 Liquid and natural gas production projections

Source: TotalEnergies, *Strategy and Outlook*

Fig. 8 2020-2021 Divestment activities

Source: TotalEnergies, *Strategy and Outlook*

(4) ExxonMobil

ExxonMobil has indicated that it intends to continue its upstream businesses while working to lower production costs. However, it will do this with an emphasis on improving asset quality rather than increasing production, and expects liquid and natural gas production in 2025 to be roughly on par with 2021 levels.

① Current production volume and reserves

In terms of natural gas and liquid production volume in 2020[19] by region, Asia[20] and North and South America are the key producers (Fig. 9). The U.S. is the largest producer by far among all the regions, both for liquids and gas.

Asia and the U.S. account for roughly 80% of ExxonMobil's total proved liquid and natural gas reserves as of the end of 2020 (about 15,211 Mboe). The company's liquid to natural gas ratio is 58:42.

ExxonMobil's investment in upstream segments[21] as a proportion of capex dropped from 78% to 68% from 2018 to 2020. Downstream segment investment increased from 13% to 20% during this period, while chemical segment investment grew from 9% to 13%. However, total capex shrank in 2022 due to adverse market conditions — the upstream decrease is not the result of reallocation to these segments.

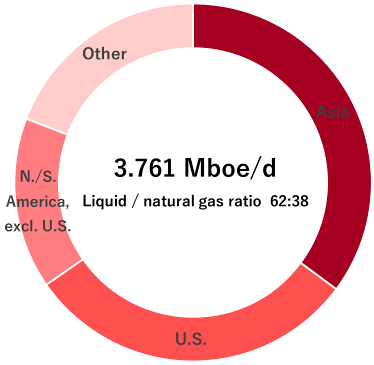

Fig. 9 Liquid and natural gas production (ExxonMobil, 2020)

Source: Prepared based on data from ExxonMobil, *2020 Annual Report*.

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[19] Liquids include crude oil, NGL, bitumin, and synthetic crude oil.

[20] On page 16 of its *2020 Annual Report*, ExxonMobil lists Azerbaijan, Indonesia, Iraq, Kazakhstan, Malaysia, Qatar, Russia, Thailand, and the UAE as countries of "principal ongoing activities" in Asia.

[21] Segments pertaining to exploration and production of crude oil and natural gas.

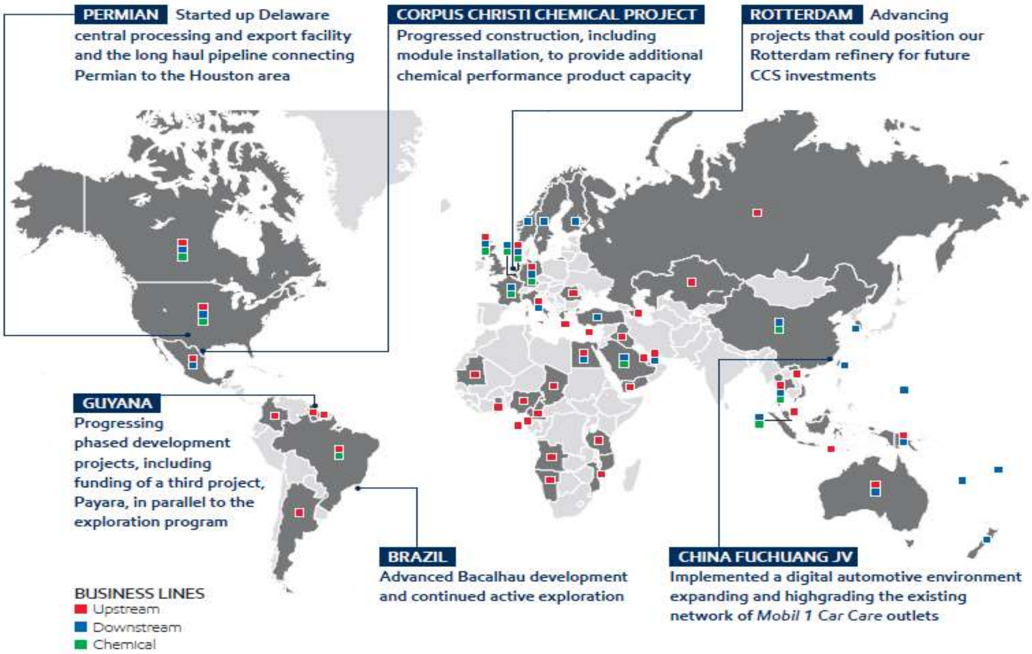

Fig. 10 Core business regions

Source: ExxonMobil, *2020 Annual Report.*

② **Future strategy**

ExxonMobil has indicated that it intends to continue its upstream businesses. The company's analysis points to oil and natural gas continuing to be an important energy source through 2040 based on IEA and IPCC projections, with a need for significant new investment in upstream businesses to satisfy demand. It says that natural gas will play an important role in transitioning away from coal that is being used in power production and industrial applications to low-emission fuels. It says it will also meet future demand with its extensive and diverse business asset portfolio.

However, ExxonMobil's liquid and natural gas production targets for 2025 are nearly identical to its expected production level for 2021 (about 3.7 Mboe/d). It says the reason for this lack of increase is because of a focus on strengthening its portfolio competitiveness, including by reducing costs, rather than increasing volume. The company did, however, release GHG emissions reduction targets in upstream businesses in December, 2020. Strengthening leak detection and restoration functions and improving facility design are some of the specific measures it will take to achieve these targets.

It will also reduce production costs. Digitizing operations will be one way it will reduce costs. One example of this, according to its website[22], is the company's use of big data in the Permian Basin. Gathering production data using sensors installed in a broad range across the oil fields and using it to optimize performance and automate workflows will allow the company to reduce costs and boost production.

New investment will be concentrated on low-cost liquids and LNG. ExxonMobil is focusing on business that promises high returns and low GHG intensity, namely its liquids business in Guyana and Suriname, and its deep water drilling business in Brazil. As for new business, the company aims to keep cost of supply to below $40/bbl for Brent crude, while allocating about 90% of upstream investment toward generating returns of at least 10%, even with Brent crude at $35/bbl or below (Fig. 11). As a result, the company projects that about 40% of liquid and natural gas production in 2025 will be supplied by businesses that commenced operations in or after 2020. It also says that cash flows will increase by as much as 20%, even if production levels remain on par with 2021 (Fig. 12).

For divestments, the company will make an approximately 50% reduction in its dry gas assets in North America, which have relatively less value. Dry gas refers to natural gas that that has almost no added condensates or liquids at the time of production[23].

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[22] https://corporate.exxonmobil.com/Energy-and-innovation/Digital-technologies
[23] https://glossary.oilfield.slb.com/en/Terms/d/dry_gas.aspx

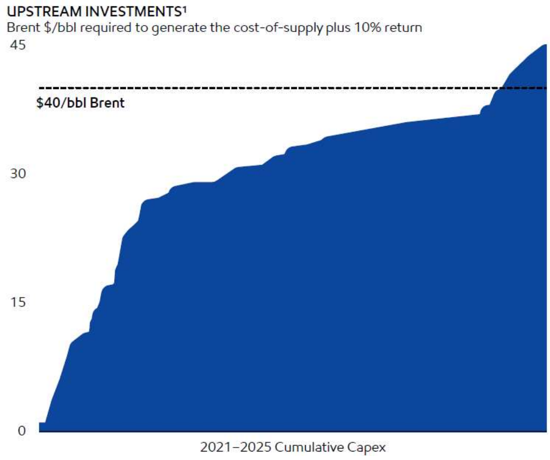

Fig. 11 Total investment per Brent level that generates >10% return

Source: ExxonMobil, *2021 Investor Day*

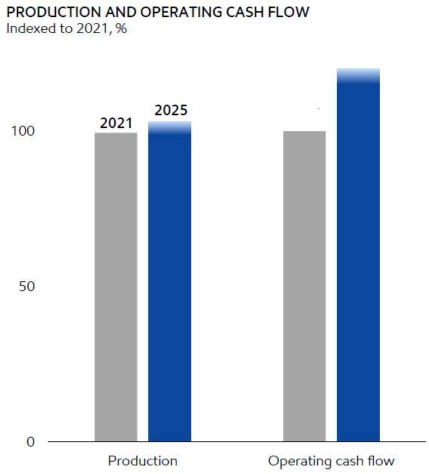

Fig. 12 Ratio of 2025 production and operating cash flow to 2021 levels

Source: ExxonMobil, *2021 Investor Day*

(5) Chevron

Chevron has indicated that it will continue its upstream businesses while working to reduce production costs and increase production.

① Current production volume and reserves

For liquid and natural gas production volume in 2020[24] by region, the U.S., Asia, and Oceania are Chevron's major regions of production (Fig. 13). By country and type of resource, countries such as the U.S. and Kazakhstan produce the most liquids while AUSTRALIA and the U.S. are among the largest natural gas producers (Fig. 14).

[24] Liquids include crude oil, condensate, NGL, and synthetic crude oil.

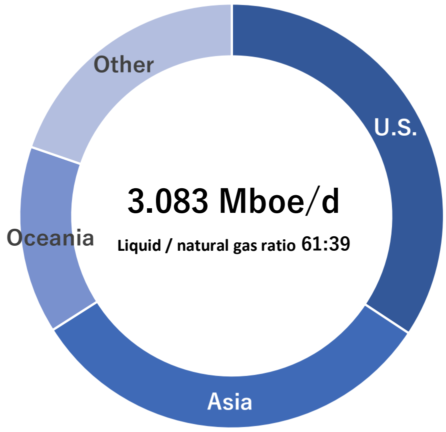

Fig. 13 Liquid and natural gas production (Chevron, 2020)

Source: Chevron, *2020 Supplement to the Annual Report*

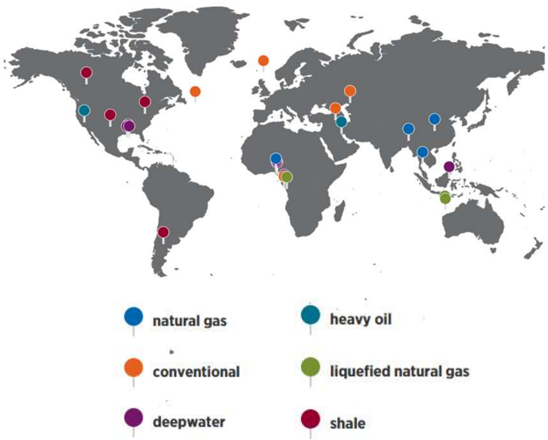

Fig. 14 Core business regions

Source: Chevron's website

A breakdown of proved reserves as of the end of 2020 (about 11,134 Mboe) shows the U.S. and Asia to have the largest reserves. The company's liquid to natural gas ratio is 55:45.

Chevron's investment in upstream segments[25] as a proportion of capex dropped from 88% to 81% from 2018 to 2020. This segment includes businesses that fall outside of LNG -related activities and other liquid and natural gas exploration and development business. However, downstream segment investment as a percentage of total investment increased by around 6% during this period. However, total capex declined in 2022 — the upstream decrease is not the result of reallocation to the downstream segment.

In 2020, Chevron acquired Noble Energy and strengthened its portfolio with the addition of proved reserves and undeveloped resources. With this acquisition, the company enhanced its unconventional position in the U.S. Denver-Julesburg Basin (DJ Basin) and the Permian, as well as its position in the Eastern Mediterranean Sea assets (Israel, etc.).

② **Future strategy**

Chevron will continue its upstream business with the view that its upstream portfolio will provide a foundation

[25] Among the company's core businesses are the exploration, development, production, and transport of crude oil and natural gas; the liquification, transport, and vaporization of LNG; the transport of crude oil via international pipelines; the processing, transport, storage, and sale of natural gas; and the operation of a GTL plant.

for future growth. In March 2021, CEO Michael Wirth stated that he expected global oil and natural gas demand over the next 10-20 years to exceed current demand. Consequently, the company is aiming to be a supplier of low carbon oil and natural gas. At an industry event that month, he also expressed the view that natural gas will play an important role in the coming low carbon economy.[26]

Chevron predicts that liquid and natural gas production will follow the current production increase trend through 2025. This author was unable to ascertain specific production targets for 2025 from published data (however, the production volume projections graph in Fig. 15 has been released that states $50/bbl or below, with conditions). A companywide production increase through 2025 will consist of increasing mainly U.S. Permian and other unconventional resource production, and will be facilitated by a ramping up of FGP-WPMP operations (a liquid development business in Kazakhstan). Chevron will concentrate two-thirds of upstream investment over the next four years into six assets (DJ Basin, Permian Basin, Gulf Coast, Eastern Mediterranean Sea, Kazakhstan, and Australian LNG). The company also released GHG reduction targets in October 2021 among which is an upstream carbon intensity[27] reduction target for 2028 for its upstream business. As some of its measures to achieve its targets, Chevron will prioritize the development of low UCI businesses, modify how its drilling rigs are powered, and reduce routine flaring.

Chevron will also reduce production costs. Its specific measures include digitizing its operations management and improving on its drilling and production technologies.

For its investing standards, the company stands out for having expressed an intent to boost its short cycle business[28] investment ratio (Fig. 16). The focus on its short cycle business is aimed at achieving competitive and predictable returns in response to changing market conditions with less risk. About 60% of its upstream investment in 2021 has been allocated to its short cycle business. By raising its short cycle business investment ratio and carefully selecting major capital projects (MCP) for the long-term cycle, the company will bring its short cycle business investment ratio to around 75% by 2025. Although it has made long-term projections for crude oil, natural gas, and carbon prices, it has not disclosed these figures for competition-related reasons.

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[26] https://innovateenergynow.com/resources/ceraweek-recap

[27] UCI includes crude oil and natural gas production, as well as flaring and methane related emission intensity. The formulas for calculating each are given on page 61 of the company's Climate Change Resilience report. (https://www.chevron.com/-/media/chevron/sustainability/documents/2021-climate-change-resilience-report.pdf)

[28] This author was unable to find a definition in published materials for the company's specific investment return dates for its short cycle business.

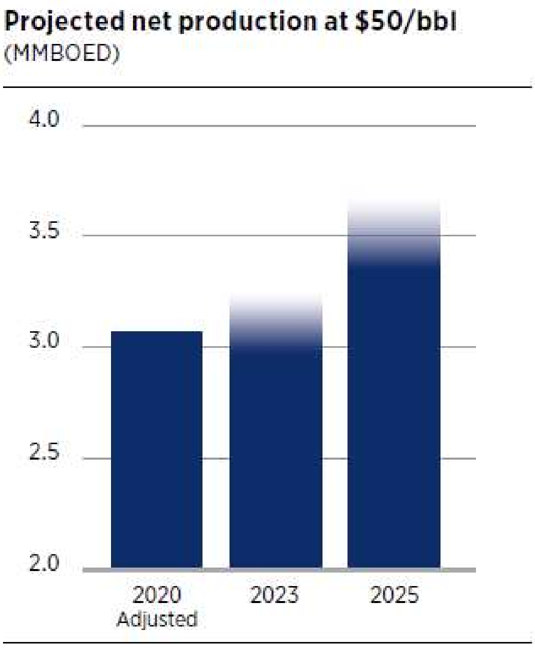


Fig. 15 Liquid and natural gas production projections ($50/bbl or below)

Source: Chevron, *2020 Supplement to the Annual Report*

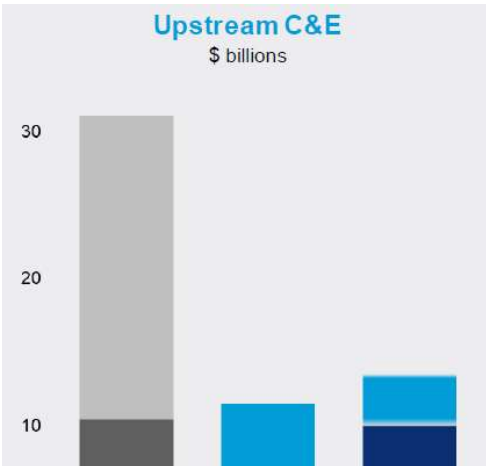


Fig. 16 Upstream business segment investment

Source: Chevron, *2021 Virtual Chevron Investor Day*

*Investment for 2016-2020 not shown in the graph trended downwards for total investment, and not just the upstream segment, due to low oil prices and measures to combat the COVID-19 crisis.

3. Comparison of the companies' strategies

This chapter will look at similarities and differences among the upstream business strategies of the five companies discussed in the previous chapter. Unfortunately, it was not possible to do an apples to apples comparison as not all companies use the same types of and definitions for the indicators in their published materials. Nevertheless, all companies stated a commitment to aggressively pursuing cost-cutting and acknowledged the importance of natural gas. However, there were differences among the companies in terms of future production volume trends.

(1) All companies will aggressively cost cut

As uncertainty grows with regard to the liquid and gas upstream business environment, every company researched has indicated an intention to cut costs in its businesses. The general idea is to cut business costs and thereby generate relatively abundant cash inflows, even if commodity prices drop or carbon costs rise. With abundant cash flows, these companies will find it easier to prevent stranded capital and to acquire capital for reinvestment and dividends. Cutting costs in upstream businesses is not a new concept. However, amid growing uncertainty concerning the business environment due to society's interest in achieving net zero emissions, many companies see cash obtained from upstream businesses as a source of funding to bolster low carbon investment. Cutting business costs is therefore likely to emerge as a key issue.

Moreover, cost cutting will also play an important role in "limiting and shortening investment return periods," as multiple companies have laid out as one strategy for new investment. In general, achieving shorter investment return periods will require cutting costs while getting big revenues quickly. Good progress in cutting costs could therefore translate into shorter investment return periods. However, carbon costs are a cost category with an uncertain future. Carbon cost projections as obtained from published data tend to either trend upwards as time horizon lengthens, or to hold steady but be accompanied by sensitivity analyses based on higher costs as time goes on (Fig. 17). This overall expectation of future carbon cost increases could be an indirect cause of companies' focus on limiting or shortening investment return periods.

		2021	2025	2030	2040	2050	Reference
	$/tCO2	N.A.	N.A.	5～110	N.A.	>100	Figures used within a range differ with the country
bp	$/tCO2	50	50	100	200	250	Central case figures
TotalEnergies	$/tCO2	40	40	40	40	40	Current price used when >$40/tCO2 For 2030 and beyond, $100/tCO2 sensitivity analysis, too

Fig. 17 Carbon cost projections

Source: Prepared based on companies' published data.

* No projection data was found for ExxonMobil. Chevron does not disclose such projections.

While each company is going about it differently, all of them are cutting costs in various ways through business activities, new investment, and investment involving portfolio assets. One method that many companies cited for cutting costs in business activities involving portfolio assets is digitization. Methods outside of digitization include more simplified and efficient facility design, and the shortening of unplanned operational downtime.

The consolidation of new exploration in fewer regions by Shell and BP as part of their new investment strategy will also contribute to cost reduction. Consolidating new exploration in existing business regions could allow even new businesses to benefit from investment assets developed in the past (e.g., existing production and transport facilities and local back-office functions). Furthermore, as denoted by Shell's use of the term "de-risking," if the risk of exploration near existing business regions is smaller than that for regions that companies have little information about, it should be easier to curtail the necessary investment to achieve the same level of production.

Divestment, too, could help with cutting average costs across companies' business portfolios. Although the companies' published materials had only a limited amount of information on future divestments, there was a general tendency to consider asset profit margin as a factor in asset selection (mention was made about liquid assets by BP, for example, and North American dry gas assets by ExxonMobil). Low asset profit margin ratios seem to be affected by high unit production cost levels. Companies able to sell relatively low profit margin assets from their business portfolios stand to improve average profit margins.

(2) "Natural gas is key during the energy transition" is a refrain common to all companies

All Major Companies have indicated that they believe natural gas will play an important role in the energy transition. One factor fueling this belief is that natural gas, because of its low carbon emissions among fossil fuels, is a promising candidate for replacing coal and compensating for the intermittency of renewables as a fuel for power generation.

Although limited to companies' published data, this author was able to find future targets for natural gas as a percentage of total production for BP, TotalEnergies, and Shell's European operations. Shell and TotalEnergies have indicated that they will shift production to primarily natural gas (Fig. 18). However, as every company has different target achievement dates, it was not possible to compare how quickly the companies are each shifting to gas.

(3) A difference of liquid and natural gas production change rates (2020-2025) among the companies

One difference in strategy among the companies lies in liquid and natural gas production change rates (2020-2025) (Fig. 19)**.** Although Shell does not appear to have included targets in its published materials, liquid and natural gas production change rate data from the other four companies shows ExxonMobil will stay mostly flat, and TotalEnergies and Chevron will seek to boost production by more than 10% while BP will decrease production by over 15% from 2020 to 2025. However, it is unlikely that the main reason for BP's production decrease is due to its thinking that the global fossil fuels market is much smaller than the other companies think it is. In a comparison of initial fossil fuel consumption projections among BP, TotalEnergies, and the IEA (which cites ExxonMobil and Chevron's published data), BP's projection is not significantly lower.

Although it is difficult to accurately identify the differences of philosophy that inform these different production change rates, one factor could be that BP is more inclined than other companies to believe that liquid and natural gas demand, or business economy, could swing downward. As shown in Fig. 17 above, BP's carbon cost projection profile is higher than that of other companies'. This might be because BP sees a greater risk in businesses that produce carbon emissions. Also, while BP had the largest proved reserves among the five companies as of the end of 2020, BP CEO Looney says that "reallocating capital to low carbon businesses will lead to decarbonization and diversification of business, while reducing risk."

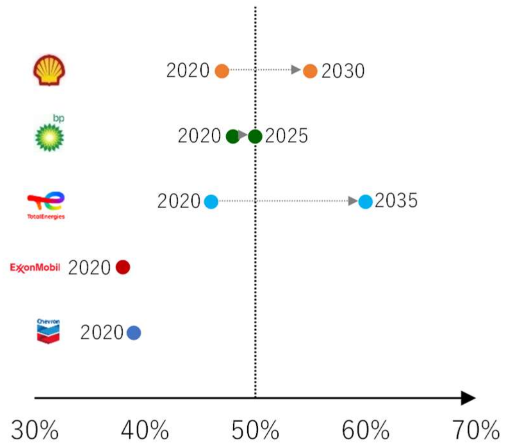


Fig. 18 Actual and target values for natural gas as a percentage of total liquid and natural gas production

Source: Prepared based on companies' published data.

*Shell's figures for 2030 are the bottommost line of the target range (> 55%).

*BP's figures exclude Rosneft.

*Target percentages could not be found for ExxonMobil and Chevron.

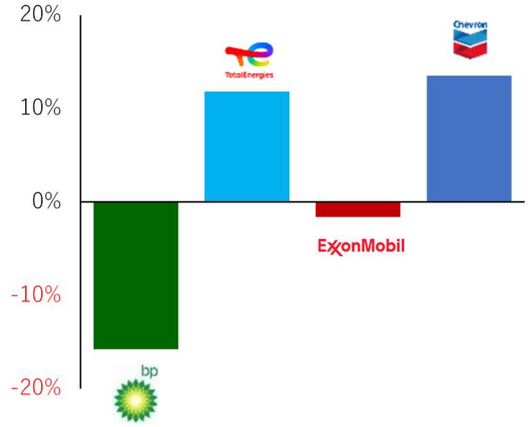


Fig. 19 Liquid and natural gas production change rates (2020-2025)

Source: Prepared based on companies' published data.

*For Chevron, change rates were calculated using an estimate of 3.5 Mboe/d for 2025 production volume, as shown in Fig. 15.

4. Conclusion

This paper has looked at how all Major Companies' strategies recognize the importance of aggressively reducing costs and focusing on natural gas as a means to handle uncertainty surrounding the business environment as society transitions toward net zero emissions. However, the companies differed in how they view future production volume trends.

Aggressive cost cutting is likely to be a measure taken by even upstream businesses outside of the Major Companies. Reducing production costs appears to be one of the most probable measures businesses will take to boost resilience in the face of a business environment that is "worsening" due to factors such as declining demand and plummeting commodity prices. The stricter investment standards and measures to improve portfolio asset management that Major Companies are implementing are likely to be instructive for other upstream businesses.

There does not seem to be, however, any generally-accepted "right answer" on production volume changes (whether to increase, decrease, or maintain), and companies could take different paths based on their individual situations and outlooks on the future. As is clear from the company's different paths, businesses will need to make decisions based on their own business and asset structure, as well as the demand picture in key markets. Although every Major Company discussed above asserts the importance of natural gas going forward, it is not that liquid assets should be consolidated or sold off with high priority because they "have a higher carbon emission factor than natural gas"; focus deserves to be placed on the fact that companies are instead calmly considering the merits and demerits of individual business economy[29].

While it is difficult to imagine global oil or natural gas prices seeing a short-term crash, domestic and international conversations about, and the development of low carbon technologies toward, achieving net zero emissions will continue. Unforeseen external factors, such as the ruling against Shell, can also arise. What business strategies Major Companies and other upstream businesses will hammer out according to business environment changes, and how they will implement them, bears continued monitoring.

[29] For example, TotalEnergies, which is aiming to transition more into gas, is planning a low-cost, low-GHG emissions liquids project in Mero, Brazil and at Lake Albert in Uganda.

Referenced data published by Major Companies in this paper

Institution name	Document name
Shell	· STRATEGY DAY 2021 PRESENTATION, TRANSCRIPT · SUSTAINABILITY REPORT 2020 · SHELL ENERGY TRANSITION STRATEGY · ANNUAL REPORT AND ACCOUNTS 2020 · SHELL INSIGHTS: UPSTREAM STRATEGY · Shell LNG Outlook 2021
bp	· Second quarter 2020 financial results and strategy presentation · BP sets ambition for net zero by 2050, fundamentally changing organisation to deliver · From International Oil Company to Integrated Energy Company: bp sets out strategy for decade of delivery towards net zero ambition · Resilient and focused hydrocarbons · bp capital markets days · bp Annual Report and Form 20-F 2020 · BP plc 112th Annual General Meeting: Webcast Transcript · bp sustainability report 2020
TotalEnergies	· Universal Registration Document 2020 including the Annual Financial Report · Factbook 2020 · Total Energies Energy Outlook 2021 · Strategy and Outlook, Transcript
ExxonMobil	· 2021 INVESTOR DAY, webcast · Energy & Carbon Summary · 2020 Annual Report
Chevron	· 2021 Virtual Chevron Investor Day · 2021 Virtual Chevron Investor Day Edited Transcript: Part I · 2021 Virtual Chevron Investor Day Edited Transcript: Part II · 2020 annual report · 2020 supplement to the annual report · Energy Transition Spotlight · Climate Change Resilience

Strategic Energy Plan Overview and Analysis on 2030 Power Supply/Demand

Seiya Endo*

1. Overview of 6th Strategic Energy Plan

The Agency for Natural Resources and Energy in July 2021 compiled and published the Sixth Strategic Energy Plan[1] after a yearlong consideration at the Strategic Policy Committee of the Advisory Committee for Natural Resources and Energy. The government made a Cabinet decision on the plan, prior to the 26th Conference of Parties to the United Nations Framework Convention on Climate Change starting in the last October.

The Strategic Energy Plan features the goals of carbon neutrality by 2050 and a 46% reduction in greenhouse gas emissions from 2013 to FY2030. It indicates challenges and initiatives to realize stable and affordable energy supply while achieving the ambitious goals. This paper sums up the plan and considers challenges regarding the 2030 energy mix in particular.

2. 2030 energy mix overview and challenges

The GHG emission reduction goal is more ambitious than the 26% reduction from 2013 in the previous Strategic Energy Plan, but the fundamental direction of the energy policy to achieve the goal remains unchanged. Energy efficiency improvement and transition to non-fossil energy sources are combined and deepened to reduce fossil fuel consumption and GHG emissions.

(1) Thorough energy efficiency improvement

An energy consumption cut through energy efficiency improvement is set at about 62 million kiloliters of crude oil equivalent, up some 20% from the previous plan. This amounts to as much as 18% of total energy demand. An appendix to the plan specifies target energy consumption cuts and measures by sector. Table 1 indicates targets, results and major measures for energy efficiency improvement.

The energy consumption cut between FY2013 and FY2019 came to 16.55 million kL, covering some 25% of the target energy consumption cut at 62 million kL. If the remaining 75% were to be cut by 2030, energy consumption would have to be reduced some 1.5-fold faster.

* Economist, Econometric and Statistical Analysis Group (ESA), Energy Data and Modelling Center (EDMC), IEEJ

[1] Agency for Natural Resources and Energy, Strategic Energy Plan
https://www.enecho.meti.go.jp/committee/council/basic_policy_subcommittee/opinion/data/01.pdf

Table 1 Target energy consumption cut and major measures by sector

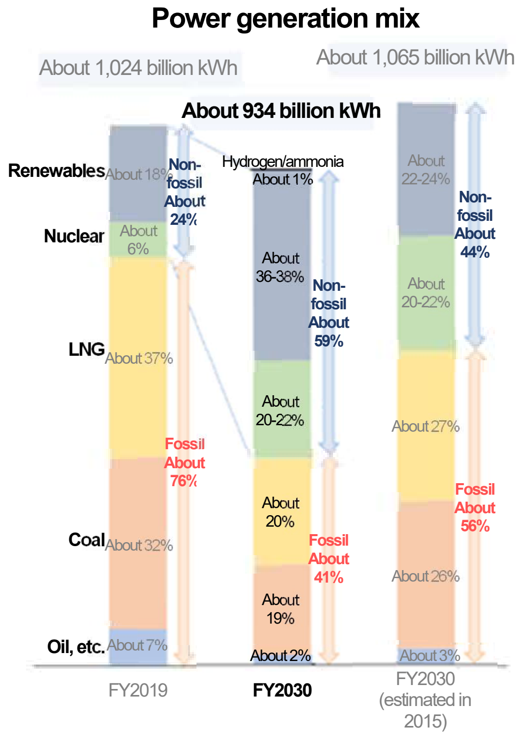
In 10,000 kL of crude oil equivalent	2019 results	2030 targets	Major measures
Industry sector	332	1,042	Introduction of low-carbon industrial furnaces and other efficient equipment
Commercial sector	414	1,227	Achievement of net zero energy for new houses and buildings, promotion of insulation retrofit, diffusion of efficient equipment
Residential sector	357	1,160	
Transport sector	562	1,607	Improvement of vehicle fuel efficiency and transport systems
Total	**1,655**	**6,200**	

Source: Agency for Natural Resources and Energy "FY2030 Energy Supply and Demand Outlook (Appendix)"

(2) Transition to non-fossil energy sources: power generation mix

The target energy consumption cut through energy efficiency improvement and a downward economic outlook revision reflecting the COVID-19 pandemic are estimated to allow total power generation in FY2030 to decline by about 10% from FY2019 to about 934 billion kilowatt hours. Non-fossil power sources account for 59% of the total power generation, representing a substantial increase from 44% for the previous plan (Fig. 1).

Most non-fossil power sources are renewable energy capturing 36-38% of total power generation. In particular, the share for solar photovoltaics featuring a short lead time has been substantially raised from the previous plan to 14-16% through positive zoning under the revised Act on Promotion of Global Warming Countermeasures and the enhanced solar PV introduction for the public sector and airports.



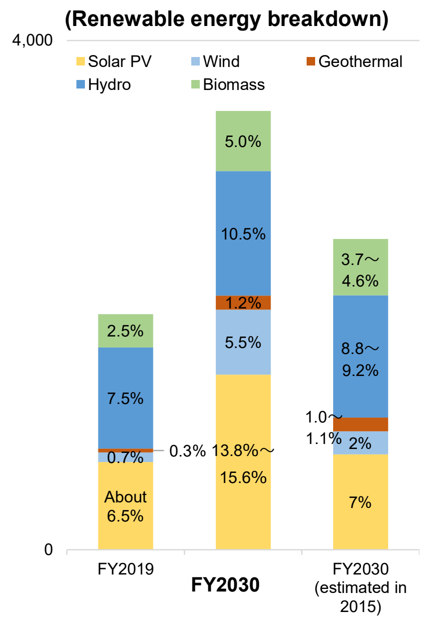


Fig. 1 Power generation mix and renewable energy breakdown

Source: Agency for Natural Resources and Energy "FY2030 Energy Supply and Demand Outlook (Appendix)"
The renewable energy breakdown was prepared by the author, based on the source.

The share for nuclear among other non-fossil energy sources is left unchanged at 20-22%. To achieve this share by FY2030, around 17 nuclear reactors would have to be restarted in the remaining nine years, following the 10 reactors that have already been restarted (Fig. 2). Hydrogen and ammonia are planned as new energy sources to account for some 1% of the power generation mix. Most of the ammonia may be co-fired with coal at existing coal-fired power plants.

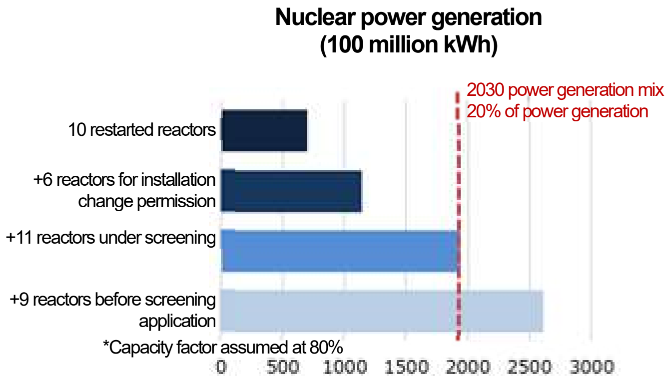


Fig. 2 Nuclear power generation outlook

Source: Prepared by the author from Japan Atomic Industrial Forum, Inc. "Data collection: Nuclear energy in Japan"

(1) Rise in output control frequency and fall in capacity factors for fossil-fired power plants

The relationship between the projected power supply capacity and demand will change dramatically from the present to FY2030. Combined capacity of nuclear, hydro, solar PV and wind power plants slipped below the annual average demand in FY2020 but will exceed the average and maximum demand in FY2030 (Fig. 3). This means that the output control frequency will increase as surplus power supply in high capacity factor periods for wind and solar PV plants, as well as low demand periods, becomes more frequent. Even if surplus power supply is prevented, nuclear, hydro, solar PV and wind capacity will cover most demand more frequently, leading to lower capacity factors for fossil-fired power plants.

During output control periods in which supply will exceed demand, regional wholesale electricity prices will fall close to zero. If such periods become more frequent, power generators' profit from the electricity wholesale market may decrease.

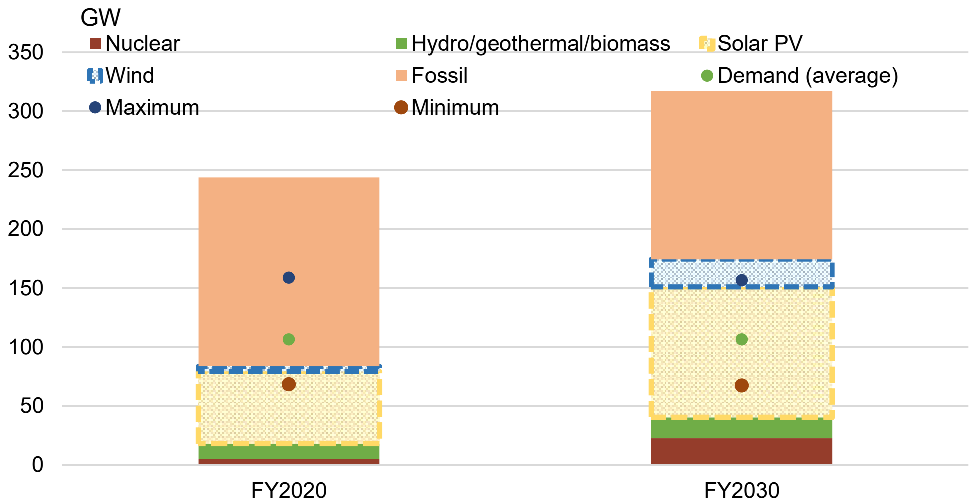


Fig. 3 Power supply and demand capacity outlook

Source: The author estimated FY2020 power supply capacity based on "FY2020 supply plans" by the Organization for Cross-regional Coordination of Transmission Operators, Japan, and projected FY2030 capacity based on "FY2020 supply plans" and "FY2021 supply plans" by the organization and "Strategic Energy Plan" by the Agency for Natural Resources and Energy. The author estimated power demand based on "FY2020 supply plans" by the organization and data at power utilities.

(2) Securing stable supply

FY 2030 supply capacity excluding variable renewables, which means stable supply capacity, is projected to total 183 gigawatts, exceeding the projected maximum demand at 160 GW. However, stable FY2030 supply capacity could be lower than projected due to the current policy-oriented reduction of coal power plant capacity or fossil-fired power plant operators' curtailment of capacity amid the abovementioned deterioration of their business environment. If the lower-than-projected stable supply is combined with a decline in capacity factors for variable renewable energy power plants under bad weather, power generation and transmission equipment troubles or global fossil fuel procurement difficulties seen in 2021 winter and expected in the coming winter, stable power supply may be endangered. Sufficient preparations for such event will be required.

3. 2050 goal and challenges

While the Strategic Energy Plan does not show specific, power generation mix for 2050, it describes challenges and initiatives in power and non-power sectors toward the carbon neutrality goal.

Energy supply and demand will have to undergo a general structural transition to achieve carbon neutrality by 2050. Any moratorium on such transition would be limited. Given the average service life of some 12 years for automobiles, for instance, sales of new gasoline hybrid vehicles as well as new gasoline and diesel vehicles would have to be terminated by the middle of the 2030s. If not, some of such vehicles may be left available to continue emitting CO_2. (If a ban is imposed on sales of new gasoline, diesel and gasoline hybrid vehicles, however, automobile supply chains may be required to undergo a large-scale transition. A sufficient strategy for such transition will have to be formulated.)

Electrofuels and other alternative fuels that do not emit CO_2 may be used for remaining gasoline and hybrid vehicles under a transitional measure. However, technological and economic challenges must be overcome. A similar transition will be required for ships, aircraft and all other energy-consuming equipment. Carbon neutrality will fail to be achieved if the current situation continues. Discontinuous changes will be required to achieve carbon neutrality.

Even if maximum efforts are made, it may be difficult to make machines, vehicles and other products in Japan carbon neutral by 2050. There may be areas where decarbonization is difficult (in the absence of alternative technologies) or any equipment transition by 2050 is unrealistic. Emissions from these areas will have to be offset by direct air capture, biomass carbon capture and storage, and other negative emission technologies.

A power generation mix proposal for 2050 was given at the Strategic Policy Committee to deepen talks, but no specifics are included in the Strategic Energy Plan. In the course of talks at the committee, multiple research institutes provided scenarios for 2050, which were compared for talks on relevant challenges. Talks will have to be deepened to determine desirable future pathways.

4. Conclusion

When the previous (fifth) Strategic Energy Plan was formulated, a dominant view at the Strategic Policy Committee was that goals should be attainable with a high likelihood for 2030 and ambitious for 2050. However, the sixth plan includes the substantially ambitious goal for 2030 as well as 2050. While it is important to make full efforts to achieve the goals, but preparations for failure to achieve the goals (including the securement of alternative power generation capacity and the formulation of fossil fuel supply plans to meet increased fossil fuel demand) may also be required.

The goals of cutting GHG emissions by 46% in 2030 and achieving carbon neutrality in 2050 in the Strategic Energy Plan are considerably ambitious. There are a lot of challenges to overcome to achieve the goals. Rapid efforts are required toward the 2030 and 2050 goals. To realize the virtuous cycle of economy and environment pursued under recent environmental and energy policies, however, Japan should promote relevant measures in a manner to lead and follow other countries and should make arrangements to develop goods and services that are influential in international markets.

Energy price hikes bringing about inflation

Gasoline subsidies as a measure to support the needy?

Akira Yanagisawa*

Summary

As the Japanese economy recovers from the COVID-19 disaster, inflation has become a challenge. The inflation rate in Japan is lower than in Western countries. A breakdown of the rate indicates that a government-led cut in mobile phone fees has pushed down the inflation rate. Excluding telecommunication and accommodation prices under policy-related temporary pressure, the consumer price index posts a 1.8% increase. From April 2022 when the impact of the mobile phone fee cut will expire, Japan's inflation rate will become higher.

Currently, energy price hikes are the largest factor behind inflation. As energy is essential to life, it is difficult to adjust energy consumption. Energy price hikes are viewed as a heavy burden on households including low-income households. To quantify the burden, we estimated the inflation rate and its breakdown by expenditure category for each of annual income quintile group. The estimation indicated that inflation pressure is greater for lower-income households. From April 2022, lower-income households will be exposed to the impact of the rising inflation rate.

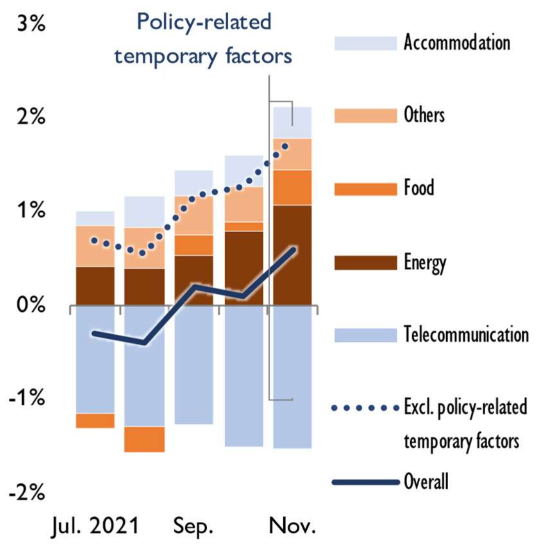


Fig. 1 Inflation and component contributions (year-on-year change)

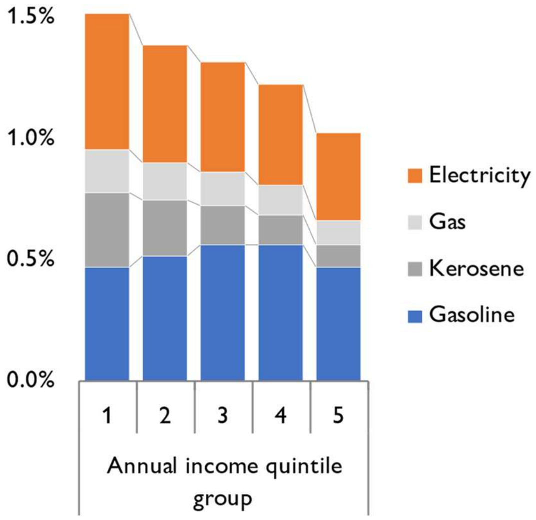


Fig. 2 Energy price hikes' contributions to inflation (year on year, November 2021)

"Gasoline subsidies", though designed to mitigate the inflation burden, give greater benefits to middle- and middle-high-income households than to low-income households as gasoline consumption is larger for households with higher income. Like the reduced value added tax on food and drinks, gasoline subsidies fail to support low-income households sufficiently. Among petroleum products, subsidies for kerosene may provide greater policy benefits to low-income households that consume more kerosene than higher-income households.

Electricity subsidies may also benefit low-income households selectively. An important point here is that electricity prices are destined to rise further. Even if oil price and the dollar-yen exchange rate remain unchanged, electricity prices will continue to rise until the summer of 2022. Future electricity price hikes will be the same as seen in the second half of 2021 when energy price hikes became remarkable. They will push up inflation.

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1. Inflation is unexpectedly high and will accelerate from April 2022

As the Japanese economy recovers from a substantial contraction caused by the COVID-19 disaster, inflation through supply constraints has become a challenge. Since September 2021, Japan's consumer price index (CPI) has remained above the year-before level. In November 2021, the CPI posted a 0.6% year-on-year increase, the highest since March 2020 just before the spread of COVID-19 infections. Japan's inflation, even though rising, has still been lower than European and U.S. inflation. As a deflationary mindset is deep-rooted among Japanese consumers, companies have reportedly been hesitant to revise prices of final consumption goods on concern about customer losses through price hikes, despite substantial price hikes for imports and corporate goods.

However, a breakdown of the low inflation rate below 1.0% indicates some features. In fact, a telecommunication price cut has made a major contribution to lowering inflation (Fig. 3). The mobile phone fee cut led by the Suga administration has pushed down the inflation rate by 1.1%-1.5% since April 2021. Meanwhile, accommodation price hikes as another policy-related factor have pushed up the inflation rate. Accommodation prices have risen since late December 2020 when the government suspended the Go To Travel Campaign that it introduced in July 2020 to cover some portion of domestic travel costs to support the tourism industry affected by the COVID-19 disaster.

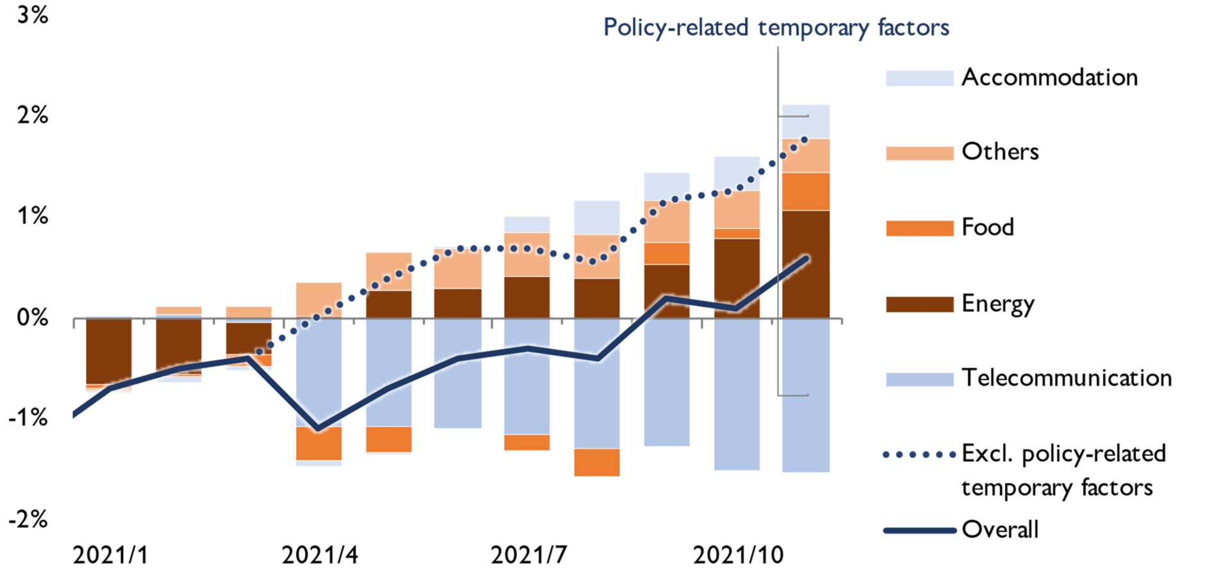

Fig. 3 Inflation and component contributions (year-on-year change)

Source: Estimated from Statistics Bureau, Ministry of Internal Affairs and Communications "Consumer Price Index"

However, the policy-related factors' contributions to pushing up or down the CPI are temporary. The telecommunication factor will disappear in April 2022 one year after the mobile phone fee cut. The accommodation price factor will vanish in January 2022 unless the Go To Travel Campaign is resumed. Excluding these policy-related temporary factors, the inflation rate reaches 1.8%. From April 2022 when the mobile phone fee cut's contribution to lowering inflation will end, the inflation rate will rise substantially.

2. Price hikes for energy essential to life exert a greater impact on lower-income households

While food price hikes have become controversial, the largest factor behind the current inflation is energy price hikes triggered directly by an increase in international oil prices. As energy and food are essential to life, it is difficult to adjust their consumption. Their price hikes are viewed as a heavy burden on households including low-income households. To quantify the burden, we used a component-by-component breakdown of consumption expenditure in the Family Income and Expenditure Survey by the Statistics Bureau of the Ministry of Internal Affairs and Communications to simply estimate a rise in the CPI (excluding imputed rents for owner-occupied houses) and component contributions to the rise for each of the annual income quintile group in the survey[1]. Each group's major indicators are given in Table 1.

Table 1 Major indicators of annual income quintile groups (2019-2020 average)

Annual income quintile group	1	2	3	4	5
Income (JPY10,000)	256	389	534	727	1,205
Consumption expenditure (JPY10,000)	227	290	330	373	493
of which: Basic expenditure	*73%*	*67%*	*61%*	*54%*	*47%*
Number of Household members (persons)	2.39	2.65	3.06	3.27	3.45

Source: Statistics Bureau, Ministry of Internal Affairs and Communications "Family Income and Expenditure Survey"

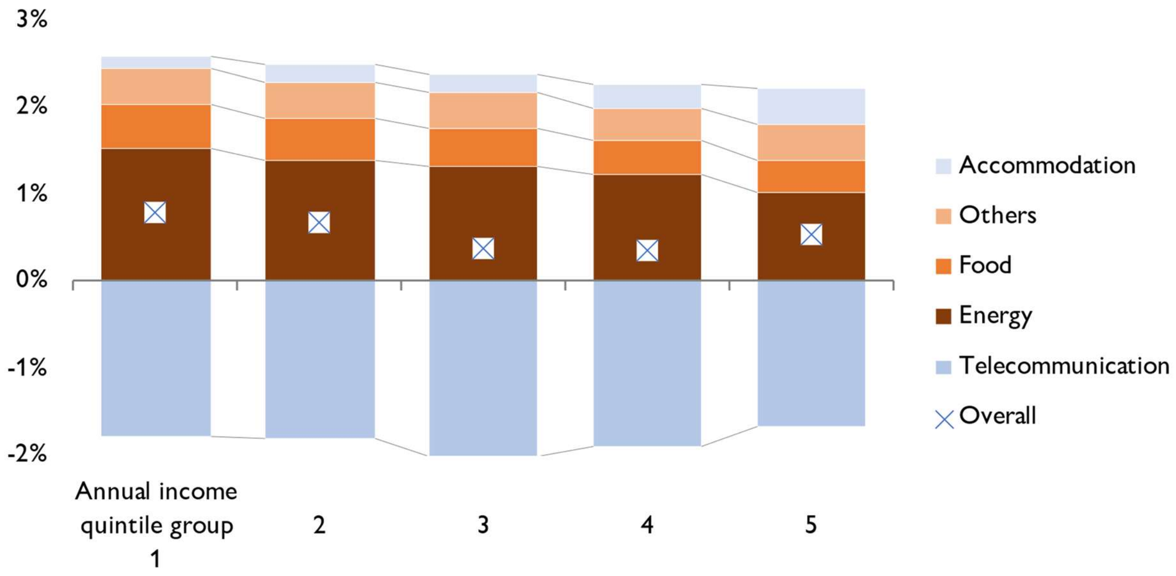

Fig. 4 Inflation rates and component contributions (year-on-year, November 2021)

Sources: Estimated from Statistics Bureau, Ministry of Internal Affairs and Communications, "Consumer Price Index" and "Family Income and Expenditure Survey"

The inflation rate is the highest for annual income quintile group 1 for the lowest income households and falls as income rises (Fig. 4). Exceptionally, however, the inflation rate for annual income quintile group 5 for the highest income households is higher than for annual income quintile group 3 for the middle-income households. This is because:

① While telecommunication spending for annual income quintile group 5 is the largest among the five groups, its share of total expenditure is the lowest due to the higher total expenditure close to JPY5 million. Therefore, the mobile phone fee cut's contribution to pushing down the CPI is smaller.

② Accommodation spending for annual income quintile group 5 more than doubles from the average to a remarkably high level, meaning that the contribution of the Go To Travel Campaign suspension to pushing up the CPI is large.

As telecommunication and accommodation prices subjected to great policy-related temporary impacts are excluded from the CPI, contributions from energy and food (warm colour portions in Fig. 4) essential to life become dominant, indicating the negative correlation relationship between annual income and the inflation rate more clearly. Inflation pressure is higher

[1] All components other than pocket money (for unknown purposes), social expenses and remittance are adopted. In principle, computation is on a middle classification basis.

for lower-income households. From April 2022, lower-income households will be exposed more to the impacts of rising food and energy prices.

3. How gasoline subsidies should be viewed

Given this point, the government apparently decided to adopt a subsidy program for mitigating sharp fuel price hikes (hereinafter referred to as "gasoline subsidies")[2] "as a temporary emergency radical change alleviation measure to suppress the impact of gasoline and other price hikes on national livelihood"[3]. However, details of energy price hikes' contribution to inflation indicates that there are various problems with viewing gasoline subsidies as supporting poor households[4].

Gasoline price hikes have pushed up the CPI by 0.5%-0.6%. Due to automobile ownership differences[5], however, gasoline price hikes' contribution to the CPI rise for low-income households is smaller than for middle- and middle-high-income households (Fig. 5)[6]. This means that the gasoline subsidies give greater benefits to middle- and middle-high-income households than to low-income households. Like the reduced value added tax on food and drinks, gasoline subsidies fail to support low-income households sufficiently[7].

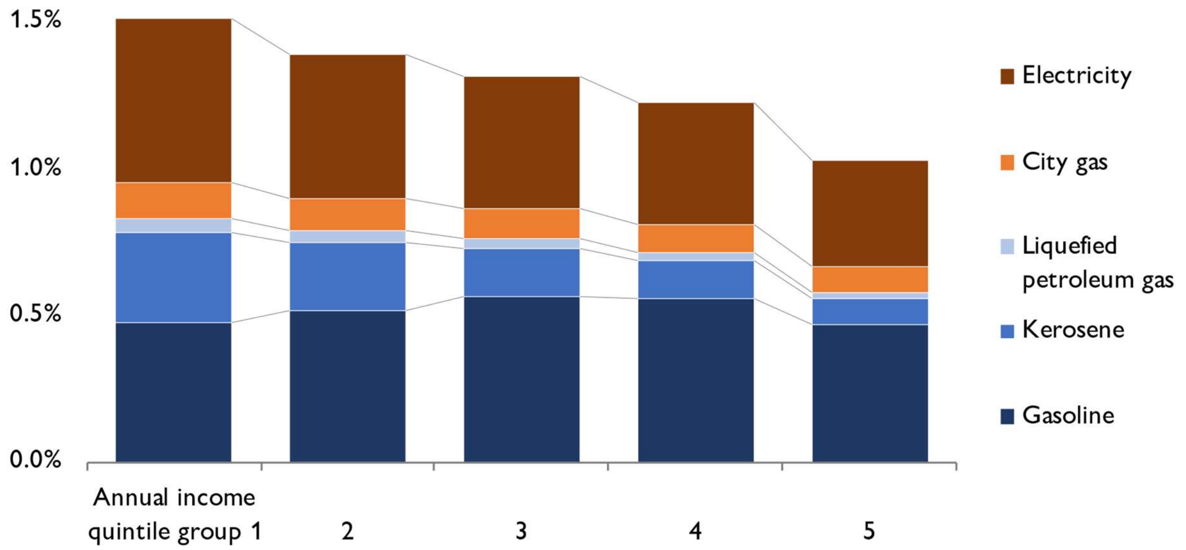

Fig. 5 Energy price hikes' contributions to inflation (year-on-year, November 2021)

Sources: Estimated from Statistics Bureau, Ministry of Internal Affairs and Communications, "Consumer Price Index" and "Family Income and Expenditure Survey"

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2 If the nationwide average gasoline price exceeds 170 yen per litre, the government may pay up to JPY5/L for gasoline, diesel oil, kerosene and heavy fuel oil to cover wholesale price hikes caused by fluctuations in yen-denominated oil prices.
https://www.meti.go.jp/main/yosan/yosan_fy2021/hosei/pdf/hosei_yosan_pr.pdf

3 Remark by Koichi Hagiuda, Minister of Economy, Trade and Industry, at a press conference on 19 November 2021.
https://www.meti.go.jp/speeches/kaiken/2021/20211119001.html

4 The gasoline subsidies are not targeted at poor households other than high income households. As they cover petroleum products consumption by companies as well as households, they may support transportation business operators that have yet to introduce a fuel surcharge system. However, the budget size for the gasoline subsidies is limited to JPY80 billion, indicating that it is too small for an economic stimulus measure. Naturally, the measure may be understood at a direct support program. If so, the measure should have been designed to give priority to supporting the needly.

5 According to the Cabinet Office's Consumer Confidence Survey, the car ownership rate as of March 2021 stood at 86.6% for households with annual income between JPY5.5 million and less than JPY7.5 million, against 67.4% for those with annual income less than JPY3 million. The number of cars per 100 households was 144.6 for households with annual income between JPY5.5 million and less than JPY7.5 million, against 94.2 for those with annual income less than JPY3 million.

6 As is the case with telecommunication spending, gasoline spending is the largest for annual income quintile group 5 for the highest income households, with its share of total consumption expenditure being the smallest. Therefore, gasoline price hikes' contribution to the CPI rise for the highest income group is relatively smaller.

7 The value added tax burden is regressively higher for low-income households. In response to the regressivity, food and drinks other than liquors and eating-out are subjected to the reduced tax rate. While food is essential to life, food consumption is more for high-income households than for low-income households. This means that benefits from the reduced tax rate are larger for high-income households and lower for low-income households. The reduced tax rate contributes to mitigating the regressivity less than assumed generally.

If energy subsidies are proposed to support the needy, subsidies for kerosene that is more consumed at low-income households may be appreciated as producing a policy effect more selectively among petroleum products. However, attention must be paid to interregional gaps in kerosene consumption.

Subsidies for electricity as well as kerosene may also support low-income households more than the gasoline subsidies, although the current government energy subsidy program does not cover electricity. Like gasoline consumption, electricity consumption is less at lower-income households. As electricity is more essential to life than gasoline, however, income-based gaps in electricity consumption are narrower than in gasoline consumption. Even if income at a household is 10% less than the average, its electricity consumption may not be 10% or more less. Therefore, electricity price hikes impose a greater impact on lower-income households.

It is important that electricity prices are certain to rise further in the future. If international oil prices and the dollar-yen exchange rate stay at present levels, with other conditions remaining unchanged, gasoline prices may not rise month on month. This means that gasoline prices will not exceed the threshold of JPY170/L for the payment of subsidies until the gasoline subsidy program expires in March 2022 (Fig. 6).

In contrast, electricity prices will continue to rise until the summer of 2022 even if oil price and the dollar-yen exchange rate stay at present levels. This is because:

① Fuel price changes take some time to be reflected in electricity prices under the fuel price adjustment system for electricity prices[8].

② Prices for liquefied natural gas, a major fuel for power generation, take some time to reflect oil price changes (hikes).

Future electricity price hikes will be the same as seen in the second half of 2021 when energy price hikes became remarkable. Electricity prices will continue to push up the CPI throughout 2022.

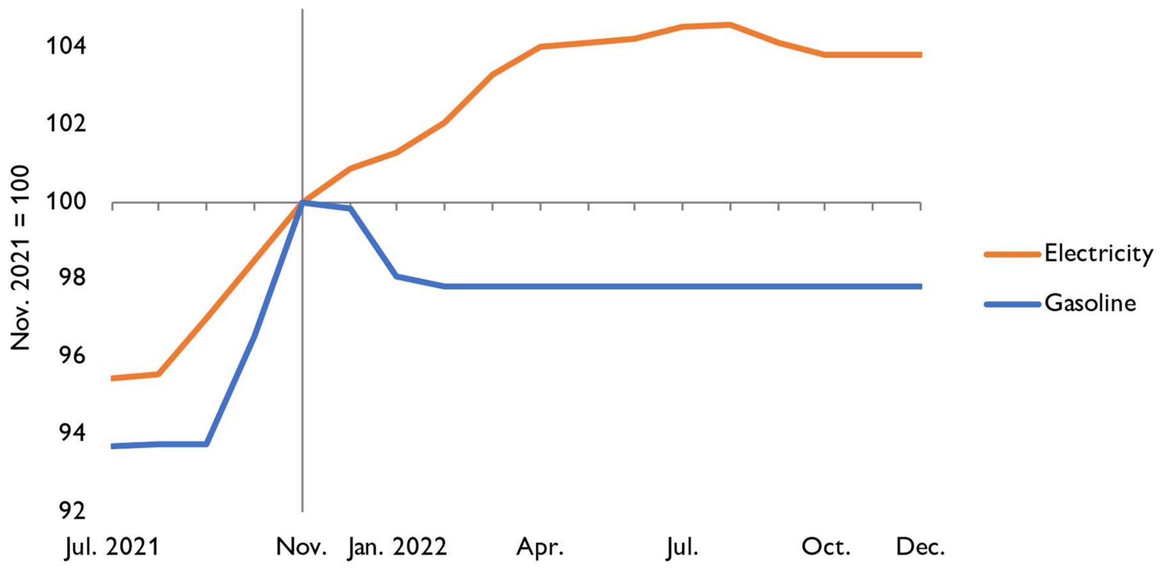

Fig. 6 Gasoline and electricity price outlook

Note: Estimated under an assumption that international oil price will stay at $75/bbl, with the U.S. dollar remaining at 115 yen, from December 2021.

[8] For instance, fuel import prices in January will be reflected in electricity prices for the April-June. This is the same case with city gas prices under the feedstock cost adjustment system.

The gasoline subsidies have a problem as a measure to support low-income households, but they are expected to produce an effect. Price changes for gasoline that is frequently purchased, as well as for fresh food, reportedly exert great impacts on consumer sentiment. If the subsidies to suppress gasoline price hikes stimulate gasoline consumption, the private sector may welcome the effect, apart from the problem of uneven distribution. If the subsidies push up consumption by 1.2% during the three-month subsidy program period (until March 2022), the government sector may offset the gasoline subsidies planned at JPY80 billion with an increase in value added tax revenue.

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