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IEEJ Outlook 2022
Challenges toward carbon neutrality: Voyage in uncharted territory

Economic and Energy Outlook of Japan for FY2022

The Remaking of Africa's Future through Hydrogen

Gas Decarbonization and Energy System Integration
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The Institute of Energy Economics, Japan

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Energy, Environment and Economy

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Executive summary

Global energy supply and demand outlook (Reference Scenario)

India, MENA and ASEAN account for three quarters of the global energy consumption growth

- Under the Reference Scenario, which incorporates the expected effects of past trends and extends the energy and environmental policies and technologies to date, global primary energy consumption will increase by about 20% between the current level and 2050. As the macroeconomy expands beyond the increase rate for consumption, the world's energy consumption intensity is decreasing, reflecting efficiency improvements and energy conservation efforts.
- India, the Middle East and North Africa (MENA), and the Association of Southeast Asian Nations (ASEAN) will lead the global increase in primary energy consumption. The global share of these three will increase from 18% in 2019 to 28% in 2050. They will account for 76% of the increase in consumption between 2019 and 2050.
- Although non-fossil energy increases substantially in this scenario, it appears very difficult that they could alone cover all the energy consumption. In the timeline to 2050, it is realistic for the world to expect a combination of fossil fuels and non-fossil energy, especially in the Emerging Markets and Developing Economies where consumption will increase.

Middle Eastern oil producers lead oil supply at low production costs

- In the medium-term, until 2030, global oil demand will increase at an annual rate of 0.5%. In response, the Organization of Petroleum Exporting Countries (OPEC) and non-OPEC countries will both increase crude oil production. In the longer run, oil production in North America will peak out, while production in Middle Eastern OPEC countries, which boast abundant oil reserves, will continue to increase.
- As the main axis of crude oil production will shift to Middle Eastern oil producing countries, Asia's dependence on crude oil from the Middle East will once again intensify. Asia's share will reach almost 80% of the global crude oil imports in 2050, and the world's largest oil importer will shift from China to India, with future imports exceeding those of China today.

Sustained expansion of LNG market due to abundant supply potential

- In the United States, the world's largest producer and consumer of natural gas, production of shale gas will continue to increase at an annual rate of about 1% for a decade or so and stabilise thereafter. Liquefied natural gas (LNG) exports will play an important role in expanding sales channels and improving trade balance.

- East and West Africa, the frontier regions of the world's natural gas, will overtime increase supply. As there are offshore and, in some cases, small- and medium-sized gas resources in these regions, floating LNG production will be considered a practical option for development,.

Reduced supply flexibility and unstable supply-demand balance for coal

- Coal production will increasingly be limited to specific countries and regions, as the trend toward decarbonisation is gradually becoming accepted and coal-related investments and loans are severely constrained. Demand remains highly uncertain as the supply structure becomes less flexible.
- By type of coal, production of steam coal will temporarily expand due to an increase in demand for power generation but will decline after peaking around 2040. Coking coal used mainly as feedstocks for steel production will decrease from 1 050 Mt in 2019 to 800 Mt level by 2040.

Power generation is rapidly expanding in Asia. Natural gas will become the largest power source

- Global electricity generation will increase at an annual rate of 1.7%, and by 2050 will be 1.7 times the 2019 level. The increase is equivalent to 2.3 times China's current generation, the world's largest electricity generator. 95% of the increase is coming from the Emerging Markets and Developing Economies.
- Natural gas will be the largest source of energy for electricity generation by 2050. As the introduction of renewable energies increases, the role of balancing supply and demand of electricity will become more important than ever. Coal will continue to play a role as a base-load power source, but its share will fall below current levels.
- It has become difficult for Japan, Korea, the United States and some European countries to build new nuclear power plants as planned. On the other hand, China and a few other countries continue to promote the use of nuclear, while some Middle East countries, and others, are introducing nuclear. As a result, global capacity will gradually increase through 2050.
- Variable renewable energies, such as wind and solar photovoltaics, will generate 8 409 TWh in 2050, increasing their presence to 19% of the electricity generation mix. Achieving harmony with energy and social systems is an important issue.

Advanced Technologies Scenario

Advanced Technologies Scenario is still far from achieving global carbon neutrality in 2050, and it is necessary to mobilise all possible means to further promote energy conservation and climate change measures.

- In the 'Advanced Technologies Scenario', maximum reduction measures for carbon dioxide (CO_2) emissions are expected based on social opportunities and acceptability. Relative to the reference scenario, the reduction in primary energy consumption in 2050 will be 2.9 billion tonnes of oil equivalent (Gtoe) and the reduction in CO_2 emissions will be 15.8 Gt or 42% less than for the Reference Scenario. Although many countries have declared carbon neutrality targets since 2020, it would seem extremely difficult for the world to achieve carbon neutrality as early as 2050.

- The CO_2 emission reduction rates for 2030 will be 33% in the United States (compared to 2005), 40% in the European Union (compared to 1990), 37% in Japan (compared to 2013), and 10% in Canada (compared to 2005). All those reductions fall short of the nationally determined contribution (NDC) rate of reduction in greenhouse gas (GHG) emissions previously announced by those countries. It is clear that further policies and measures beyond those considered in the Advanced Technologies Scenario are required.
- China, the United States, the European Union and Japan have announced net zero emissions and carbon neutral targets. Scenarios from many of these countries and regions are expected to reduce emissions by around 80% in 2050, but none of them will reach their target. It is necessary to further develop and quickly introduce emission reduction technologies that are not commercialised yet.
- Compared to the Reference Scenario, investment in fossil fuels decreases while investment in renewable energy increases. The overall investment cost will be $34 trillion in the 2040s.

Road to carbon neutrality

- Since the Paris Agreement in 2015, many countries, including the United States, the European Union, China, Japan and the United Kingdom, have set carbon-neutral targets for the middle of this century. Carbon neutrality, however, is by no means an easy target given the current high dependence on fossil fuels and the path-dependent effects of existing infrastructure and supply systems.
- While there is of course a positive effect of green growth policies, we should not turn our attention away from the fact that climate change policies inherently have associated costs and growth constraints. Measures to achieve carbon neutrality should not be explained from the perspective of 'growth' but should be positioned as a global 'norm' that each country should pursue while bearing a certain burden.
- One of the major concerns in the process towards carbon neutrality is the emergence and potential expansion of new disparities. Factors such as economic conditions, resource endowment and technological capabilities naturally vary from country to country. Differences in these factors can produce new disparities by creating winners and losers.
- As we move towards carbon neutrality, we will see more electrification, and electricity security will become one of the most important energy security issues. The stable supply of mineral resources (critical minerals), which plays an important role in promoting the introduction of renewable energy and the electrification, is also a new important element for energy security.
- The suspension of new investment in crude oil production does not cause a tight supply-demand situation in a few months. However, in both the Reference Scenario and the Advanced Technologies Scenario in which demand growth slows down, the global oil

supply-demand balance will be a shortage of supply and an excess of demand in 2024. The suspension of new investment could lead to tight supply and demand and higher prices in the not too distant future.

Circular Carbon Economy/4Rs Scenario

- The concept of circular carbon economy is an extension of the conventional concept of circular economy. In contrast to the concept of circular economy in which the use of resources and the generation of waste are controlled through the three 'R's of 'reduce', 'reuse', and 'recycle', the concept of circular carbon economy is to control the total amount of CO_2 in the atmosphere through the four 'R's with 'remove' added.
- In the 'Circular Carbon Economy/4Rs Scenario', which anticipates the spread of more diverse decarbonisation technologies than in the Advanced Technologies Scenario, global CO_2 emissions in 2050 will be reduced to 15.7 Gt, less than half of the current level. Compared to the Advanced Technologies Scenario, more than half of the additional reductions will be in the non-power sector.
- Total primary energy consumption will increase slightly from the Advanced Technologies Scenario because the introduction of various decarbonisation technologies will generate additional demand for energy transformation. The share of fossil fuels in 2050 will be 60%, which is almost the same level as in the Advanced Technologies Scenario. By actively introducing decarbonisation technologies for fossil fuels, significant reductions in emissions can be achieved while continuing to use fossil fuels.
- Clean hydrogen (blue hydrogen and green hydrogen) plays an important role in various sectors and Asia is a particularly large market. The supply will mainly come from North America, the Middle East and Russia, where fossil fuel resources for blue hydrogen are abundant.

Economic and Energy Outlook of Japan for FY2022

Increasing energy expenditure and CO_2 emissions while back to a normal economic situation◆

Ryo Eto*

Introduction

In the third quarter of 2021, Japan's GDP contracted by 0.9%, the first decline in two quarters, as a state of emergency declaration was coupled with sluggish automobile production amid semiconductor shortages and the spreading COVID-19 infection in Southeast Asia as a major automobile parts supply source for Japan. Domestic demand contributed 0.9 percentage points to the contraction and external demand 0 points. The Japanese economy is expected to grow in the future as services and durable goods consumption expands, thanks to the lifting of the state of emergency declaration and the elimination of constraints on automobile production.

The average crude oil import price for Japan fell to \$25 per barrel in June 2020 due to a global oil demand decline. As COVID-19 constraints on economic activities have gradually decreased since then, oil demand increased. Currently, the price is staying above \$70/bbl, exerting downside pressure on the Japanese economy in a recovery process.

So far, applications for 27 nuclear power plants have been filed for conformity with the new regulatory standards in Japan. Of them, 17 have cleared the examinations, including 10 that have restarted. However, two of the 10 restarted plants had to suspend operations in FY2021 because of a delay in the completion of counterterrorism facilities.

As the feed-in tariff (FIT) scheme for solar photovoltaics power generation at households began to expire in November 2019, the tariff plunged from JPY48/kWh in FY2009 to a JPY8-12/kWh range, with storage batteries failing to diffuse due to their lack of economic efficiency.

Key assumptions behind the Reference Scenario

● COVID-19

With the two-shot vaccines rate rising to close to 80% in Japan, new COVID-19 infections began to decrease in October 2021 and the number of critical COVID-19 patients also declined substantially. Amid concerns over Omicron and other COVID-19 variants for the rest of FY2021, biosecurity measures such as social distancing continue to be in effect. With the third COVID-19 vaccination, the Japanese economy is expected to return to normal.

● Global economy

Global economic growth is assumed at 5.9% for 2021 and at 4.9% for 2022. As vaccination made progress in 2021, mainly in the United States, Europe and Russia, human mobility will recover under a strategy for coexistence with COVID-19. Pent-up demand will contribute to a substantial global economic growth that will continue well in 2022. Domestic demand will turn into economic growth in Asian and low-income countries that have been lagging in their economic recovery.

● Fossil fuel import CIF prices

Crude oil import prices for Japan are assumed to average \$71/bbl in FY2021 (\$70/bbl in the first half and \$72/bbl in the second) and \$68/bbl in FY2022, based on the international crude oil price outlook below. The average LNG import price for Japan is assumed to rise from \$11.1/Mbtu in FY2021 to \$11.9/MBtu in FY2022, reflecting earlier crude oil price

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◆ Created based on the published research in the 440th Forum on Research Works

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fluctuations. Steam and coking coal import prices are projected to decrease gradually from the second half of FY2021 to FY2022 as international supply shortages are phasing out due to the easing of supply constraints in China. Steam coal import prices are assumed to average $144/t in FY2021 and $142/bbl in FY2022. Coking coal import prices are projected to average $182/t in FY2021 and $198/t in FY2022. (IEEJ Ichihara "Outlook for International Oil Market in 2022," Hashimoto "Outlook for Gas Market in 2022," Ito "Outlook for International Coal Market in 2022.")

- **Exchange rate**

We assume the dollar's average exchange rate with the yen to stand at JPY111.6/USD in FY2021 and at JPY113.5/USD in FY2022.

- **Nuclear power generation**

Given progress in regulatory standards conformity examinations for nuclear power plants, more plants are assumed to restart. One nuclear power plant restarted in FY2021, bringing the cumulative number of restarted plants to 10 at the end of the fiscal year. As the suspension of two restarted plants has been prolonged due to a delay in the completion of counterterrorism facilities, however, the 10 plants in FY2021 will operate for an average of 10 months and generate 67.6 TWh. From FY2020 when more plants were suspended, however, the FY2021 power generation will score a sharp increase of 82.7%. In FY2022, two additional plants will restart, boosting the cumulative number of restarted plants to 12 at the end of the fiscal year. The suspension of one restarted plant will be prolonged. The 12 restarted plants will operate for an average of 9 months and generate 71.8 TWh, up 6.2% from the previous year.

- **Air temperature**

According to the Japan Meteorological Agency's three-month forecast, we assume normal temperatures in winter FY2021Later temperatures will be assumed normal. The average temperature in summer FY2021 was down 0.3°C from a year earlier while the winter average temperature will be down 0.9°C. The temperature will be up 0.2°C from a year earlier in summer FY2022 and remain unchanged in winter.

Macro economy

- **As the recovery from the COVID-19 crisis makes progress, GDP will score a real growth rate of 3.3% in FY2022 compared to 2.8% in FY2021. Fossil fuel import value will rise to the highest level in four years as prices remain high.**

Japan's GDP in FY2021 will post a real growth rate of 2.8% against a sharper contraction in the previous year. Private consumption will increase by 2.5% on a recovery in human mobility, despite lingering biosecurity measures. Private non-residential investment will rise by 2.6% due to a pickup in companies' appetite for investment. Private demand will thus contribute 1.8 percentage points to the GDP growth. Public demand will contribute 0.2 points through economic stimulus measures to tackle COVID-19, as well as a rise in healthcare spending. External demand will make a contribution of 0.8 points to the GDP growth thanks to a rebound in exports to the United States, Europe and China.

In FY2022, Japan's GDP will score a record real increase of 3.3%, topping the FY2018 growth, as the impacts of COVID-19 ease. Consumer confidence will continue to improve as employment and wages rebound on a pickup in face-to-face services amid human mobility growth under the easing COVID-19 impacts. The improvement will be coupled with the disappearance of constraints on automobile supply to push up private consumption by 3.3%. Private non-residential investment will expand by 4.3% thanks to growing investment in business efficiency improvements and digitalization, as well as in construction and decarbonization measures. Private demand's contribution to the GDP growth will be limited to 2.9 points, less than in FY2019. Public demand will hit a record high due to a public investment increase through the National Resilience Plan and a government consumption rise through an increase in healthcare and nursing care spending, contributing 0.4 points to the GDP growth. External demand will contribute 0.1 points to the GDP growth as exports including automobiles expand on a recovery in the Asian economy, as well as the United States, Europe and China, despite import growth led by domestic demand expansion.

Japan's fossil fuel imports will shoot up by 71.6% in FY2021 as a volume increase is coupled with price hikes. In FY2022, they will increase by 1.9% due to an LNG price rise. The trade balance will post a surplus for the third straight year thanks to sharp growth in exports including automobiles.

Table 1 Macroeconomic indicators

	Historical				Projection		Year-over-year		
	FY2010	FY2018	FY2019	FY2020	FY2021	FY2022	FY2020	FY2021	FY2022
Real GDP (JPY2015 trillion)	512.1	554.3	550.6	525.7	540.4	558.2	-4.5%	2.8%	3.3%
Private demand	383.7	415.9	411.8	386.2	396.0	411.5	(-4.7%)	(1.8%)	(2.9%)
Private consumption	290.5	302.4	299.3	282.9	290.1	299.7	-5.5%	2.5%	3.3%
Private residential investment	18.2	19.9	20.4	18.8	18.8	19.0	-7.8%	0.1%	0.8%
Private non-residential investment	73.7	91.3	90.8	83.9	86.1	89.9	-7.5%	2.6%	4.3%
Public demand	124.2	136.2	139.1	143.3	144.2	145.9	(0.8%)	(0.2%)	(0.4%)
Government consumption	98.1	108.7	111.0	113.8	116.0	117.3	2.5%	2.0%	1.1%
Public investment	26.2	27.6	28.1	29.5	28.2	28.6	5.1%	-4.3%	1.4%
Net exports of goods and services	4.7	2.3	-0.2	-4.2	0.0	0.6	(-0.6%)	(0.8%)	(0.1%)
Exports of goods and services	83.8	105.0	102.7	91.9	103.0	107.9	-10.5%	12.1%	4.8%
Imports of goods and services	79.2	102.7	102.9	96.0	103.0	107.3	-6.6%	7.2%	4.2%
Nominal GDP (JPY trillion)	504.9	556.3	557.3	535.5	546.9	567.4	-3.9%	2.1%	3.7%
Balance of trade (JPY trillion)	5.3	-1.6	-1.3	1.3	0.3	1.4	-201.2%	-77.3%	362.8%
Exports	67.8	80.7	75.9	69.5	84.7	88.8	-8.4%	21.9%	4.9%
Imports	62.5	82.3	77.2	68.2	84.4	87.4	-11.6%	23.7%	3.6%
Fossil fuels	18.1	19.1	16.6	10.6	18.2	18.5	-36.2%	71.6%	1.9%
Oil	12.3	11.3	10.1	5.8	10.0	10.0	-42.9%	74.2%	-0.4%
LNG	3.5	4.9	4.1	3.1	4.8	4.9	-23.1%	52.8%	2.7%
Current account (JPY trillion)	18.3	19.4	18.7	16.3	17.3	19.0	-12.7%	5.9%	9.8%
Domestic corporate goods price index (2015=100)	97.6	101.5	101.6	100.2	106.3	107.3	-1.4%	6.0%	0.9%
Consumer price index (2020=100)	94.7	99.6	100.2	99.9	99.8	100.6	-0.3%	-0.1%	0.8%
Unemployment rate (%)	5.0	2.4	2.3	2.9	2.8	2.6	[+0.6p]	[-0.1p]	[-0.2p]

Notes: GDP components may not add up to the total GDP due to stock changes and minor data deviations.
( ) stands for contributions. [ ] stands for changes from the previous year.

Production activities

- **Industrial production in FY2022 will exceed the FY2019 level as growth benefits from a production recovery for automobiles that has been delayed so far. Meanwhile, production in the four major energy-intensive industrial materials sectors will slip below levels before the COVID-19 crisis.**

In FY 2021, the industrial production index will rise by 7.0% from the previous year. Despite a delayed rebound in the automobile production, industrial machinery production increases on a global recovery from the COVID-19 crisis and domestic private non-residential investment. In FY2022, the index will increase by 5.5% and exceed the FY2019 level, supported by a delayed recovery in automobile production and demand mainly for heavy electrical machinery that had been pent up under the COVID-19 crisis.

Crude steel production in FY2021 will post a substantial increase of 12.7%. Domestic crude steel demand, though falling for shipbuilding, will rise back for machinery and building materials, and exports to Asia and the United States will recover. In FY2022, crude steel production will score a 3.8% rise. A recovery in domestic demand mainly in the automobile industry will be coupled with an increase in exports to ASEAN backed by an economic rebound. As steel demand for automobiles increases, converter steel output will rise, boosting its share of total crude steel production for the second straight year.

Ethylene production in FY 2021 will increase by 2.7% but fall short of restoring the FY2019 level. Domestic demand will rise thanks to an industrial production recovery. Exports to Asia including China will expand due to a decline in regular ethylene plant maintenance. In FY2022, ethylene production will decrease by 4.5%, slipping below 6 million tons for the first time since 1993. Due to an increase in regular plant repairs, both domestic shipments and exports will decrease.

Cement production in FY2021 will increase by 1.3%. Exports to ASEAN will expand substantially, while domestic demand declines due to a cement consumption fall through construction process changes and delayed construction under bad weather. In FY2022, exports will increase as demand in Southeast Asia and Oceania recovers. Domestic demand will also grow as construction of disaster prevention and reduction facilities under a metropolitan redevelopment program and the National Resilience Plan is normalized. Cement production in FY2022 will thus rise by 2.0% but represent the third lowest level between FY1970 and FY2019 before the FY2020-2021 COVID-19 impacts.

Paper and paperboard production in FY2021 will increase by 4.5% from the previous year thanks to a rise in advertisement paper consumption amid a recovery in industrial activities and tourism demand and in events, as well as the continued electronic commerce uptrend. Due to a fire accident at a paper plant in Korea, exports will also expand temporarily. In FY2022, paper and paperboard production will fall by 0.1% as demand for newsprint and communication paper continues a downtrend due to structural digitalization. Paperboard production will increase on a recovery in tourism demand and growing electronic commerce. As a production increase is limited due to a decrease in used paper supply for paperboard, exports will decline.

Automobile production in FY2021 will increase by 8.5% from the previous year thanks to an economic recovery in Japan and the rest of the world but it will fall short of reaching 9 million units due to difficulties in procurement of semiconductors and other parts. For the second straight year, production will slip below the FY2009 level of 8.865 million units just after the global financial crisis. In FY2022 when supply chains will be normalized, automobile production will post a substantial increase of 11.9%, including vehicles that were sold in FY2021 for delivery in FY2022. Both domestic demand and exports will top FY2019 levels.

Table 2 Production activities

		Historical				Projection		Year-over-year		
		FY2010	FY2018	FY2019	FY2020	FY2021	FY2022	FY2020	FY2021	FY2022
Production	Crude steel (Mt)	110.8	102.9	98.4	82.8	93.3	96.8	-15.9%	12.7%	3.8%
	Ethylene (Mt)	7.00	6.19	6.28	6.04	6.20	5.93	-3.8%	2.7%	-4.5%
	Cement (Mt)	56.1	60.2	58.1	56.1	56.8	57.9	-3.6%	1.3%	2.0%
	Paper and paperboard (Mt)	27.3	26.0	25.0	22.7	23.7	23.7	-9.5%	4.5%	-0.1%
	Automobiles (Million units)	8.99	9.75	9.49	7.97	8.64	9.67	-16.0%	8.5%	11.9%
Production indices	Mining and manufacturing (2015=100)	101.2	103.8	99.9	90.4	96.7	102.1	-9.5%	7.0%	5.5%
	Food and tobacco	100.7	99.6	100.6	96.9	97.8	99.7	-3.7%	0.9%	2.0%
	Chemicals	99.6	107.5	103.8	94.7	98.9	103.0	-8.8%	4.4%	4.1%
	Non-ferrous metals	100.0	104.3	99.2	90.0	98.6	104.3	-9.3%	9.5%	5.9%
	Machinery	99.4	105.6	100.3	89.7	98.0	105.1	-10.5%	9.2%	7.3%
Tertiary industry activity index (2015=100)		97.6	103.0	102.3	95.3	98.2	102.4	-6.9%	3.1%	4.3%

Notes: Chemicals include chemical fibers.
Machinery includes general machinery, electrical machinery, information and telecommunications equipment, electronic parts and devices, precision machinery and metal products.

Primary energy supply

- **In FY2022, energy consumption per GDP will fall, but energy demand will increase for the second straight year due to economic normalization. While surpassing the halfway point between FY2013 and FY2030, Japan will fall short of achieving half the FY2030 goal for energy self-sufficiency and CO_2 emission cuts.**

In FY2021, primary energy supply in Japan will post a substantial rise of 3.0% from the previous year due to industrial materials production and transportation growth on a recovery from the COVID-19 crisis, as well as a colder winter. In FY2022, energy consumption per GDP, or energy intensity, will decrease thanks to growth mainly in the machinery and services industries, but domestic primary energy supply will increase by 0.4% due to an economic recovery.

In FY2021, new energy supply including solar, wind and biomass energies will grow by 6.5% amid an economic recovery from the COVID-19 crisis. In FY2022, new energy supply will increase by 3.0%, and account for 6% of domestic primary energy supply. Non-residential solar photovoltaics power generation is the main contributor to the growth.

Nuclear power generation in FY2021 will score a sharp increase of 80.0% from the previous year as one nuclear plant is restarted and six other plants are resuming operations after their long shutdowns for such reasons as delays in completing their counterterrorism facilities. As two more plants will be restarted during the second half of FY2022, one will suspend operation until it completes its counterterrorism facility. The increase in nuclear power generation in FY2022 will thus be limited to 5.6%.

Oil supply in FY2021 will post a 3.0% increase from the previous year thanks to a recovery in production and transportation. In FY2022, gasoline and diesel oil supply will increase due to a transportation recovery, despite fuel efficiency improvement and fuel switching. But overall oil supply growth will be limited to 0.1% because of a naphtha supply drop amid reduced ethylene production.

Coal supply will increase by 4.9% in FY2021 reflecting a rise in the capacity factor for coal-fired power plants and a sharp rise in crude steel production. Coal supply in FY2022 will rise by another 2.4%, mainly for power generation, despite a slowdown in industrial materials production recovery, as five new coal-fired power plants go on stream in late FY2021.

Natural gas supply will decrease by 5.7% in FY2021 as supply for power generation decreases much faster than a rise in supply for city gas. In FY2022, natural gas supply will fall again by 2.4% as supply for power generation decreases in line with the launches of new coal-fired and solar PV power plants. LNG imports will decline for a sixth consecutive year to 0.6% above imports in FY2010, the year before the Great East Japan Earthquake.

Japan's energy self-sufficiency rate in FY2021 will increase by 2.3 percentage points due to a rise in nuclear power generation. In FY2022, the rate will rise by 0.3 points to 13.8%. Though passing the halfway point between FY2013 and FY2030, Japan will fall short of achieving half of the FY2030 goal of around 30%.

Japan's energy-related CO_2 emissions in FY2021 will increase by 1.9% to 986 Mt from the year before, the first time to rise since FY2013. In FY2022, emissions will further increase by 0.9% to 995 Mt, the equivalent of 19.5% below the levels of FY2013. One year beyond the halfway point between FY2013 and FY2030, Japan will fall short of achieving half the goal of a 45% cut for FY2030.

Table 3 Primary energy supply

	Historical				Projection		Year-over-year		
	FY2010	FY2018	FY2019	FY2020	FY2021	FY2022	FY2020	FY2021	FY2022
Primary energy supply (Mtoe)	515.9	455.4	444.6	414.9	427.6	429.4	-6.7%	3.0%	0.4%
Coal	119.1	121.5	120.4	110.6	116.0	118.8	-8.1%	4.9%	2.4%
Oil	212.0	176.2	170.1	155.1	159.8	160.0	-8.8%	3.0%	0.1%
Natural gas	95.7	106.6	102.4	102.5	96.7	94.3	0.1%	-5.7%	-2.4%
LNG imports (Mt)	70.6	80.6	76.5	76.4	73.7	71.0	-0.2%	-3.5%	-3.7%
Hydro	17.7	16.7	16.5	16.2	16.7	16.4	-1.6%	3.3%	-1.8%
Nuclear	60.7	13.3	13.0	7.9	14.3	15.1	-39.2%	80.0%	5.6%
New energy, etc.	10.7	21.1	22.2	22.6	24.0	24.7	1.6%	6.5%	3.0%
Self-sufficiency rate	20.2%	11.6%	12.0%	11.2%	13.5%	13.8%	-0.8p	2.3p	0.3p
Energy intensity (FY2013=100)	105.2	85.8	84.3	82.4	82.6	80.3	-2.2%	0.2%	-2.8%
Energy-related CO_2 emissions ($MtCO_2$)	1,137	1,065	1,029	967	986	995	-6.0%	1.9%	0.9%
Change from FY2013	-8.0%	-13.8%	-16.7%	-21.7%	-20.2%	-19.5%	-5.0p	1.5p	0.7p

Notes: New energy includes solar photovoltaics, wind, biomass, solar heat, and geothermal, etc.
Self-sufficiency rate is based on IEA standard.

Electricity sales, power generation mix, electricity prices (electric utilities)

- **In FY2022, electricity sales will increase for the second year thanks to a rise in industrial sales amid a recovery mainly in the machinery and services industries. Residential sales will drop on a fall in the stay-at-home rate. Non-fossil and coal-fired power generation will continue growing, while gas-fired generation declines substantially.**

In FY2021, electricity sales will increase by 1.3%. Sales to power service users will increase by 3.0% due to production growth in the steel and machinery industries, increased commercial operations and the effects of temperature changes. Meanwhile, those to lighting service users will decrease by 2.2% in line with a drop in the winter stay-at-home rate.

In FY2022, electricity sales will increase by 1.1% from FY2021 and surpass the relatively low level for FY2019 (including an abnormally warm winter) before the COVID-19 crisis. Sales to power service users will rise by 1.9% on a machinery production recovery. Sales to lighting service users will fall by 0.5% due to the easing of restrictions on outing with a lower stay-at-home rate and the diffusion of light-emitting diode bulbs and other energy efficient devices as well as more residential solar PV power generation. On the other hand, more all-electric homes increase the electrification of water heating and cooking equipment to push up sales to lighting service users.

Electricity prices for power and lighting service users in FY2022 will increase for the second straight year combining with continued increases in renewable energy surcharges and higher fossil fuel import prices since the second half of FY2020. The electricity price will rise by 10.4% for power service users and by 6.2% for lighting service users. The price for lighting service users in FY2022 will surpass the record high reached in FY1985 due to consumption tax, and petroleum and coal tax hikes in addition to the absence of renewable energy surcharge reduction.

Nuclear energy's share of total power generation in FY2021 will post a sharp rise of 3.2 percentage points due to one plant's restart and six restarted plants' resuming operation after their long suspension for such reasons as a delay in the completion of counterterrorism facilities in FY2020. The nuclear share in FY2022 will rise by 0.4 points as two more plants are restarted. The share for non-hydro renewables will increase by 1.2 points in FY2021 and by 1.1 points in FY2022 as non-residential solar PV capacity expands. Non-fossil energy sources' share of total power generation in FY2022 will rise for a second straight year to 31.8%. However, the share will still be 6.4 points lower than the 38.2% in FY2010 and must rise further.

Two new coal-fired power plants (Taketoyo Unit 1 and Kobe Unit 3 with total capacity at 2.26 GW) will be operational in late FY2021 and will be followed by three more (Higashi Unit 3, Misumi Unit 2 and Kobe Unit 4 with total capacity of 1.95 GW) in FY2022. Coal's share of total power generation will thus increase by 1.0 point. The share for power plants fired will drop by 0.3 points by fuel oil C and crude oil drop in FY2022. Due to growth in non-fossil and coal-fired power generation, the LNG share will decline by 2.0 points to 32.8% in FY2022. The LNG share will still be 3.5 points higher than 29.3% for FY2010 the year before the Great East Japan Earthquake which affected nuclear power generation and led to a sharp rise in gas-fired power generation.

Table 4 Electricity sales, power generation mix, electricity prices (electric utilities)

	Historical				Projection		Year-over-year		
	FY2010	FY2018	FY2019	FY2020	FY2021	FY2022	FY2020	FY2021	FY2022
Electricity sales (TWh)	(926.6)	852.6	836.1	820.9	831.2	840.3	-1.8%	1.3%	1.1%
Lighting service	304.2	270.3	266.7	278.0	271.9	270.6	4.2%	-2.2%	-0.5%
Power sercice	(622.4)	582.2	569.4	543.0	559.4	569.7	-4.6%	3.0%	1.9%
Extra-high and High voltage	(576.5)	544.6	533.2	506.6	522.7	532.3	-5.0%	3.2%	1.9%
Low voltage	(45.9)	37.6	36.3	36.3	36.7	37.4	0.2%	1.1%	1.9%
Electricity generated and purchased (TWh)	(1,028)	957.0	932.0	920.3	932.0	941.3	-1.3%	1.3%	1.0%
Hydro	(8.5%)	9.1%	9.3%	9.5%	9.6%	9.4%	0.2p	0.2p	-0.3p
Fossil fuels	(61.7%)	74.6%	73.1%	74.0%	69.4%	68.2%	0.9p	-4.6p	-1.2p
Coal	(25.0%)	28.5%	28.4%	27.8%	27.7%	28.7%	-0.6p	-0.2p	1.0p
LNG	(29.3%)	39.3%	38.1%	38.6%	34.7%	32.7%	0.5p	-3.9p	-2.0p
Oil, etc.	(7.5%)	6.9%	6.6%	7.5%	7.1%	6.8%	0.9p	-0.5p	-0.3p
Nuclear	(28.6%)	6.5%	6.5%	4.0%	7.2%	7.6%	-2.5p	3.2p	0.4p
Renewables (excluding hydro), etc.	(1.1%)	9.8%	11.0%	12.5%	13.7%	14.8%	1.5p	1.2p	1.1p
Electricity prices (JPY/kWh)	(16.7)	21.7	21.6	20.4	22.5	23.9	-5.4%	10.4%	6.2%
Lighting service	21.4	27.2	27.3	26.0	28.3	29.7	-4.9%	8.9%	5.1%
Power sercice	(14.4)	19.1	18.9	17.5	19.7	21.1	-7.0%	12.3%	7.3%

Notes: Figures in brackets are based on old statistical definitions, and discontinuous with other values.
"Electricity sales" is for electricity utility use, and does not include own use and specified supply.
"Electricity generated and purchased" is only for general electric utilities in FY2010, and its figures since FY2016 are estimated values.
Hydro includes pumped, and LNG includes city gas.

City gas sales and unit prices (gas utilities)

- **City gas sales in FY2022 will rise for the second straight year to the highest level since FY2017 reflecting a recovery in industrial production and commercial operations. However, sales to industrial and commercial users will slip below FY2019 levels, the year before the COVID-19 crisis.**

City gas sales[1] in FY2021 will increase by 3.9% from the previous year due to a rise in those to industrial and commercial users, despite a fall in those to residential users. In FY2022, city gas sales will expand by 2.2% to about 42 billion m3, the highest since FY2017 that featured an abnormally cold winter and an abnormally cool summer. However, the rise will reflect a substantial increase in sales to electric utilities, with sales to industrial and commercial users slipping below FY2019 levels.

Of residential sales, those for cooking have continued to structurally decrease due to the spread of induction heating cookers. Those for water and space heating have also structurally declined on the diffusion of more energy efficient water heaters and all-electric homes. In FY2021, residential sales will decline by 1.2% as sales for both cooking and heating decrease due to a fall in the winter stay-at-home rate, despite a colder winter. In FY2022, residential sales will continue to decrease by 0.6% as sales for both cooking and heating will reflect a warmer summer and a drop in the stay-at-home rate through the easing of restrictions on outing.

Industrial sales for manufacturing in FY2021 will increase by 7.6% on a production recovery. In FY2022, they will rise by 3.8% due to a pickup in automobile and heavy electrical machinery production, though falling short of topping the FY2019 level. Sales for electric utilities will remain unchanged in FY2022 as no new power plant using city gas is planned to start operation from FY2021. Overall industrial sales will rise by 6.7% in FY2021 and by 3.0% in FY2022.

Regarding business sales (commercial and other sales) in FY2021, air-conditioning demand decreased in a cooler summer, but water and space heating demand will increase due to a colder winter, despite continued energy efficiency improvement that works to cut gas sales. Commercial sales will increase 3.6% on a recovery in accommodation, food, living-related and personal, and amusement services sectors. The other sales will rise by 0.3% with a rise in those for schools, despite a drop in those for hospitals. In FY2022, air-conditioning demand will increase in a warmer summer, but water-

[1] Sales by gas utilities excluding former community gas utilities

heating demand will fall in the absence of any winter weather change. Commercial sales will increase by 6.3% due mainly to the rise in air-conditioning demand as business operations recover in accommodation, food, living-related and personal, and amusement services sectors. The commercial sales will top 4 billion m3 for the first time in three years, though slipping below the level for FY2019 that included an abnormally warm winter. The other sales will rise by 0.4% on the normalization of schooling, despite the spread of remote medical care and online classes.

City gas prices will rise for the second straight year due to LNG price hikes from the second half of FY2020, posting a 15.1% increase in FY2021 and a further 10.5% in FY2022. Prices for all sectors will hit highest levels since the liberalization of gas retail sales in FY2017.

Table 5 City gas sales and prices (gas utilities)

	Historical				Projection		Year-over-year		
	FY2010	FY2018	FY2019	FY2020	FY2021	FY2022	FY2020	FY2021	FY2022
City gas sales (Billion m^3)	39.28	41.58	40.42	39.51	41.06	41.96	-2.3%	3.9%	2.2%
Residential	9.79	9.24	9.38	10.02	9.90	9.84	6.8%	-1.2%	-0.6%
Commercial	4.75	4.26	4.16	3.65	3.78	4.02	-12.2%	3.6%	6.3%
Industrial	21.61	25.03	23.83	22.76	24.28	25.00	-4.5%	6.7%	3.0%
Manufacturing	(20.28)	20.51	19.68	17.43	18.75	19.47	-11.5%	7.6%	3.8%
Electric utilities	(1.34)	4.52	4.15	5.33	5.53	5.53	28.4%	3.8%	0.0%
Others	3.13	3.05	3.05	3.08	3.09	3.11	1.1%	0.3%	0.4%
City gas prices(JPY/m^2)	83.79	87.62	88.64	80.10	92.22	101.9	-9.6%	15.1%	10.5%
Residential	160.1	165.3	165.7	153.9	169.2	180.1	-7.1%	9.9%	6.5%
Commercial	81.95	87.84	88.84	79.76	91.86	102.4	-10.2%	15.2%	11.4%
Industrial	50.67	58.52	59.08	48.70	61.52	71.56	-17.6%	26.3%	16.3%
Others	76.67	90.68	82.50	72.60	87.51	97.59	-12.0%	20.5%	11.5%

Fuel oil/LPG sales and crude oil throughput

- **Despite an increase in fuel oil sales for transportation, fuel oil sales in FY2022 will decrease due to an even larger ethylene production cut. As transportation fuel exports increase, crude oil throughput will exceed fuel oil sales for the first time in three years.**

Fuel oil sales in FY2021 will increase by 2.0% from the previous year, centering on those for transportation. Despite a rise in sales for transportation fuels, fuel oil sales in FY2022 will decrease by 0.7%, due to less ethylene production. Fuel oil sales for industrial use will decline despite industrial production growth as crude oil price hikes encourage fuel switching and energy conservation.

Gasoline sales in FY2021 will rise by 1.2% due to a substantial recovery in the use of passenger car. While transportation volume continues to expand substantially in FY2022, gasoline sales growth will be limited to 0.3% because of improvements in fuel efficiency and an increase in hybrid vehicles. Gasoline sales dropped 6.6% since FY2019 and continue a long-term downtrend.

Naphtha sales in FY2021 will increase by 2.1% due to less frequent regular maintenance of ethylene plants. In FY2022, they will decrease by 4.9%, slipping below 40 million kl for the first time since FY1993. The drop reflects more anticipated frequent maintenance at ethylene plants.

Jet fuel sales will increase by as much as 38.0% in FY2021 and by 30.1% in FY2022 as air passenger traffic continues its recovery.

Despite a colder winter, kerosene sales in FY2021 will decrease by 2.0% due to a fall in the stay-at-home rate. In FY2022, they will drop by another 1.5% due to fuel switching, although space heating demand will level off.

Diesel oil sales in FY2021 will increase by 3.3% from the previous year despite fuel efficiency improvements as passenger and cargo transportation demand recovers along with industrial production and construction. In FY2022, diesel oil sales will rise by 1.7% on a continued recovery in transportation demand.

Heavy fuel oil A sales in FY2021 will drop by 0.8%. The increase in sales for space and water heating was outweighed by the drop in sales resulting from the crude oil price hikes that encouraged energy conservation and fuel switching, mainly in non-manufacturing industries. In FY2022, they will decline 2.6% due to a fall in water heating demand, energy conservation and fuel switching, slipping below 10 million kl for the first time in 53 years.

Heavy fuel oil B/C sales for industrial use will increase by 7.2% in FY2021 on a production recovery, despite fuel switching and energy conservation. In FY2022, they will decrease by 4.1% as fuel switching and energy conservation outpaces industrial production growth. Those for power generation will decline as oil-fired power plants' capacity factor declines, with gas-fired power generation with lower fuel costs being used to cope with peak winter electricity demand. Overall heavy fuel oil B/C sales will drop by 2.1% in FY2021 and by 6.3% in FY2022.

In FY2021, LPG sales will increase by 4.4%. While those for the residential sector decline on a fall in the stay-at-home rate, business recovery for food service providers, industrial production growth and commercial passenger traffic expansion will work to push up LPG sales. In FY2022, LPG sales will rise by 1.8% on a recovery in food service operations, industrial production and passenger traffic, although ethylene plant operations will decline.

Crude oil throughput in FY2021 will post a 4.2% increase, faster than the fuel oil sales growth, as transportation fuel exports expand. In FY2022, crude oil throughput will score a substantial increase of 6.5% despite a fuel oil sales drop, as fuel exports continue to rise. In the year, crude oil throughput will surpass fuel oil sales volume for the first time in three years.

Table 6 Fuel oil/LPG sales and crude oil throughput

	Historical				Projection		Year-over-year		
	FY2010	FY2018	FY2019	FY2020	FY2021	FY2022	FY2020	FY2021	FY2022
Fuel oil sales (GL)	196.0	167.7	161.6	151.5	154.5	153.4	-6.2%	2.0%	-0.7%
Gasoline	58.2	50.6	49.1	45.2	45.8	45.9	-7.9%	1.2%	0.3%
Naphtha	46.7	43.9	42.5	40.3	41.2	39.2	-5.2%	2.1%	-4.9%
Jet fuel	5.2	5.0	5.2	2.7	3.8	4.9	-46.9%	38.0%	30.1%
Kerosene	20.3	14.5	13.6	14.5	14.2	14.0	6.4%	-2.0%	-1.5%
Diesel oil	32.9	33.8	33.7	31.9	32.9	33.5	-5.3%	3.3%	1.7%
Heavy fuel oil A	15.4	11.1	10.2	10.2	10.1	9.9	0.7%	-0.8%	-2.6%
Heavy fuel oils B and C	17.3	8.8	7.4	6.7	6.5	6.1	-9.8%	-2.1%	-6.3%
For electric utilities	7.7	4.0	2.6	2.8	2.3	2.1	4.1%	-15.2%	-10.2%
For other users	9.7	4.9	4.7	3.9	4.2	4.0	-17.5%	7.2%	-4.1%
LPG sales (Mt)	16.5	14.2	14.1	12.9	13.5	13.8	-8.4%	4.4%	1.8%
Crude oil throughput (GL)	208.9	176.7	174.0	139.3	145.1	154.6	-19.9%	4.2%	6.5%

Renewable power generation (FIT power source)

- **Installed renewable power generation capacity will expand to 95 GW**

Renewable power generation capacity approved under the FIT scheme reached 105 GW in March 2017. As approval for some capacity before installation was canceled, however, the capacity subject to existing approval fell to 86.4 GW in March 2018. As 5 GW for solar PV and 7 GW for wind were added later, increasing the capacity to 98.9 GW (including 75.7 GW for solar PV, 13.4 GW for wind and 8.1 GW for biomass). The capacity is as approved by the end of June 2021.

If all the approved capacity of 98.9 GW, including already operational and transferred facilities[2], is operational, the cumulative burden on consumers will reach an estimated JPY73 trillion[3]. The estimated burden amounts to an electricity rate hike of JPY2,900/MWh, or 12% for residential users and 18% for industrial users.

Installed renewable power generation capacity (including capacity for which the FIT scheme has expired) will reach 95 GW at the end of FY2022. Non-residential solar PV capacity will expand to only to 57.8 GW by the end of FY2022, because the COVID-19 spread delays installation by restricting solar PV plant builders' communications with residents near plant sites and making it difficult to secure construction workers. Wind power generation capacity will rise to 6.5 GW as the establishment of deadlines for launching operation or cancelling approval for non-operational approved capacity increases pressure on planned approved capacity to become operational. Renewable power generation in FY2022 will total 183.0 TWh (including 87.4 TWh for solar PV, 40.9 TWh for small and medium-sized hydroelectric plants, 38.2 TWh for biomass and 12.8 TWh for wind), accounting for 17.8% of Japan's total power generation. If generation at large-sized hydroelectric plants is included, renewable power generation will command 22.4% of the total.

The sixth Strategic Energy Plan has set renewable energy's target share of the power generation mix at 36-38% for 2030. To achieve the target, Japan will be required to enhance all possible relevant policies. It is imperative to ensure harmony between power generation facilities and the environment and form agreements with residents near planned sites for such facilities. In FY2022, the feed-in premium (FIP) will be introduced to integrate large-scale solar PV and wind power generation capacity into the electricity market. It will be important to develop renewable energy into a major stable power source while securing renewable power generation's environmental harmony and market competitiveness.

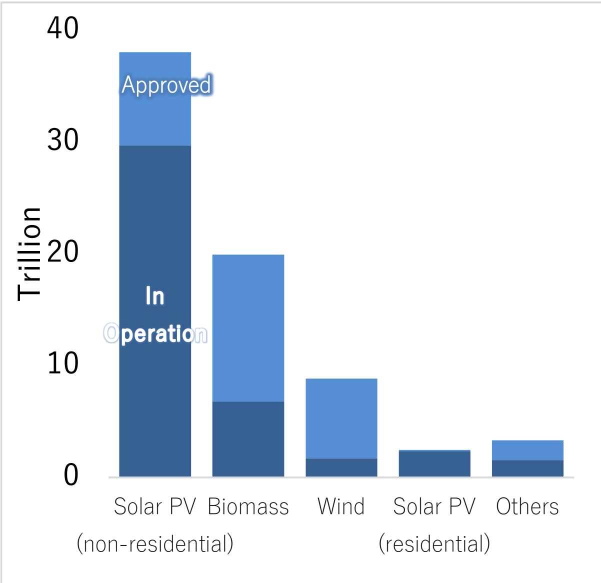

Fig. 1 Cumulative burden of FIT scheme over purchasing period (for capacity approved or in operation at the end of June 2021)

Note: The purchasing period is 10 years for residential solar PV, 15 years for geothermal and 20 years for others.

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[2] Transferred facilities are those that were installed before the introduction of the FIT scheme and later subjected to the scheme.

[3] The remaining FIT periods for transferred facilities are taken into consideration. The avoidable cost has been estimated by the IEEJ, based on various documents. The capacity factor is assumed at 24.8% for wind, 13.7% for solar PV, 70% for geothermal energy, 45% for hydro and 70% for biomass.

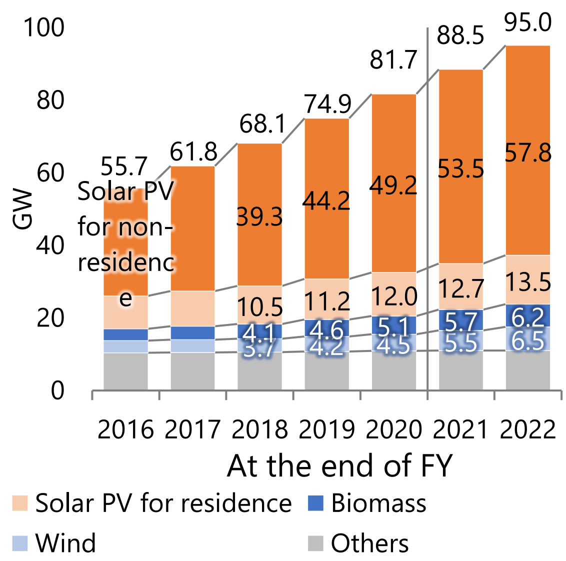

Fig. 2 Installed FIT power generation capacity (based on operation)

Note: Including capacity subjected to FIT contract expiration.

Topic [1] Impacts on the economy and the energy situation of a decline in production of automobiles

- **If automobile production fails to rebound, the failure would spill over to other industries, exerting downside pressure on energy sales and supply.**

- **While production in a wide range of industries has recovered from the COVID-19 disaster, automobile production falls have slowed down the economy since August 2021.**

Automobile production in Japan had picked up on robust demand since hitting bottom in the April-June quarter of 2020. Since August 2021, however, global semiconductor shortages combined with a stagnation in parts procurement from Southeast Asia under the COVID-19 spread, forced automakers to adjust production and shut down plants. Due to the production constraints, Japan's new automobile sales (including mini-vehicles) in October posted a 31% year-on-year fall to the lowest level for the month since 1968 when the statistics started.

Each automaker has been trying to increase production from the second half of FY2021. In the Reference Scenario, automobile production is assumed to rise back to 96.7 million units in FY2022, with parts supply and employment being secured. However, the semiconductor supply is not sufficiently stable to secure an automobile production recovery, indicating downside risks for future automobile production. Some plants that had planned to start full-blown production in December 2021 were in fact shut down. Even into FY2022, automakers could have difficulties in securing employment for production recovery. If some plants manage to increase their parts procurement to expand production, other plants may have difficulties in increasing production.

- **If automobile production fails to recover in FY2022, GDP would be pushed down by 0.3%, with the unemployment rate rising.**

Between August and October 2021, automobile production in Japan was about 710,000 units less than planned[4]. If the production decline fails to be covered in FY2022, automobile production in the year will decrease by 7.3% from the Reference Scenario level.

Production changes in the automobile industry (as a final assembly sector) exert impacts on a wide range of other

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[4] Nomura Research Institute, "Spreading automobile production cuts: Cuts totalling 710,000 units estimated to amount to JPY1.44 trillion in economic loss"

industries. Given the automobile industry's high value added, industrial production will decrease by 2.6% from the Reference Scenario level. The impact on the steel industry will be great, leading to a 2.4% drop in crude steel production. As impacts on services industries are limited, the GDP fall through the automobile production recovery failure will be limited to 0.3%, smaller than the 2.6% fall in industrial production. If non-regular employees in industries are adjusted to the automobile production drop in each industry, about 18,000 jobs will be lost to push the unemployment rate up by 0.03 percentage points. Attention should be paid to such impact on employment.

- **Large impacts on industrial materials industries may lead to a 0.7% fall in Japan's primary energy supply**

Such industrial production drop will affect energy demand. Among energy sales, city gas sales account for a large share of industrial users, city gas sales will suffer the largest drop of 0.8%. Electricity sales will drop by 0.5% with declines of industrial electricity sales. Fuel oil sales will decline by 0.4%, centering on fuel oil C and naphtha consumed in manufacturing.

As manufacturing industries account for a large share of Japan's primary energy supply, the decline in primary energy supply will exceed the GDP drop to 0.7%. Given that the automobile industry features lower energy intensity than other manufacturing industries, however, the primary energy supply fall will be lower than the industrial production drop. Natural gas supply will decrease by 1.1% through the city gas and electricity demand drop. Coal supply will drop by 1.0% through the crude steel production decline. The oil supply fall will be limited to 0.5% as oil for transportation accounts for a dominant share of oil supply. As non-fossil electricity sources remain unaffected, the CO_2 emission drop through the automobile production decrease will slightly exceed the primary energy supply fall of 0.9%.

Table 7 Impacts of automobile production decrease [FY2022]

		Reference	Decreased production of automobiles	Changes from Reference
Economy	Real GDP (JPY2015 trillion)	558.2	556.5	-0.3%
	Industrial production (CY2015=100)	102.1	99.4	-2.6%
	Crude steel production (Mt)	96.8	94.5	-2.4%
	Automobile production (million)	9.67	8.96	-7.3%
	Unemployment rate(%)	2.58	2.60	[+0.03p]
Energy	Primary energy supply (Mtoe)	429.4	426.5	-0.7%
	Oil (GL)	175.1	174.3	-0.5%
	Natural gas (Mt of LNG equiv.)	72.2	71.4	-1.1%
	Coal (Mt)	189.7	187.8	-1.0%
	Electricity sales (TWh)	840.3	836.0	-0.5%
	City gas sales (Billion m^3)	41.96	41.64	-0.8%
	Fuel oil sales (GL)	153.4	152.7	-0.4%
Environment	Energy-related CO_2 emissions (Mt)	913	905	-0.9%

Topic [2] Impacts of temperature changes on household energy spending

- **Household energy spending will increase for two consecutive years, potentially reaching the record high posted in FY2013 depending on changes in temperature. Support for energy efficiency improvement is required for low-income households.**

- **Increasing household energy spending**

Household energy consumption volume in Japan in the 2010s, though fluctuating depending on temperature changes, continued a downtrend. The energy intensity reduction factors include energy and fuel efficiency improvements, and the spread of an energy saving mind-set outdid energy consumption boosting factors such as increases in the number of households and private vehicle transportation volume. In FY2020, household energy consumption volume declined, despite the rise in the stay-at-home rate. Restrictions on outings under the COVID-19 pandemic increased telework and decreased private vehicle mobility. FY2020 also featured sharp energy price falls that made household energy spending in the year sink to JPY13.2 trillion[5], the lowest in four years.

In the first half of FY2021, from April 2021, gasoline prices rose substantially year on year on crude oil price hikes. Due to lower air conditioning demand in a cooler summer, however, year-on-year household energy spending growth was limited to 1.6%. In the second half until March 2022, household energy spending will post a substantial year-on-year rise of 17.7% due to a colder winter and sharp increases in all energy prices, despite a fall in the stay-at-home rate that followed the lifting of the state of emergency. In FY2021, household energy spending will increase by 9.4% from the previous year to JPY14.4 trillion, the highest in seven years.

In FY2022, household energy consumption volume will decrease for the second straight year due to a decline in the stay-at-home rate and progress in energy saving, while gasoline consumption will increase on a rise in outings. Energy price hikes in FY2022, however, will for the second straight year push up household energy spending by 3.6%.

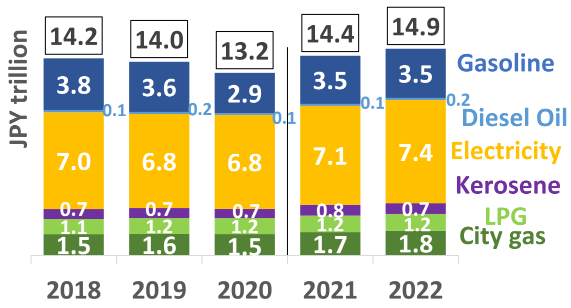

Fig. 3 Household energy spending

● **Depending on changes in temperature, spending may reach the record high posted in FY2013**

Household energy consumption is susceptible to air temperature changes over the short term, particularly regarding air conditioning and water heating demand. In the Reference Scenario, temperatures are assumed to be normal in FY2022. This means a hotter summer than in the previous year and no change in winter temperatures. However, temperatures are highly uncertain. Here, we assess the change in energy consumption of an average temperature increase of 1°C in the summer (July-September) and of a decrease of 1°C in the winter (December-February).

If the average temperature in the summer rises by 1°C from the Reference Scenario, water heating demand will decline in line with a water temperature increase, leading to a fall in city gas and liquefied petroleum gas consumption. However, air conditioning demand will increase to boost electricity consumption, resulting in an increase of JPY100 billion or 0.7% in household energy spending from the Reference Scenario. If the average temperature in the winter falls by 1°C from the Reference Scenario, space heating demand along with water heating demand will increase. As a result, electricity, city gas and kerosene consumption will expand, leading to a household energy spending increase of JPY260 billion or 1.8%. If the average temperature is 1°C higher in summer and 1°C lower in winter than the normal level in FY2022, household energy spending will be equivalent to the record high of JPY15.3 trillion posted in FY2013. That year featured the highest ever fossil fuel import prices as well as a severe summer heat and winter cold waves.

[5] Excluding community gas and heat supply

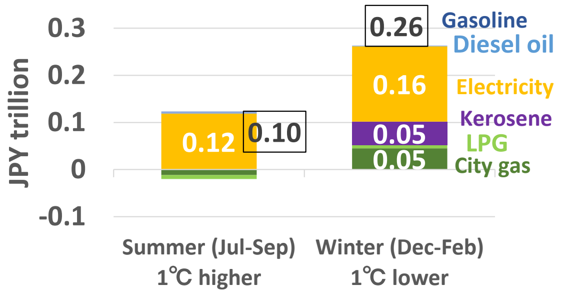

Fig. 4 Household energy spending changes caused by changes in temperature relative to the Reference Scenario

In the Reference Scenario, the energy Engel's coefficient[6], which indicates an effective household energy cost burden, will rise substantially in FY2021 but will limit growth to 0.01 points due to greater spending on cars and other durable goods and on food, tourism and amusement services. However, the coefficient will rise by 0.03 points through a 1°C rise in the summer average temperature and by 0.09 points through a 1°C fall in the winter average temperature. Depending on summer and winter temperature changes, energy spending's share of household final consumption expenditure will thus increase.

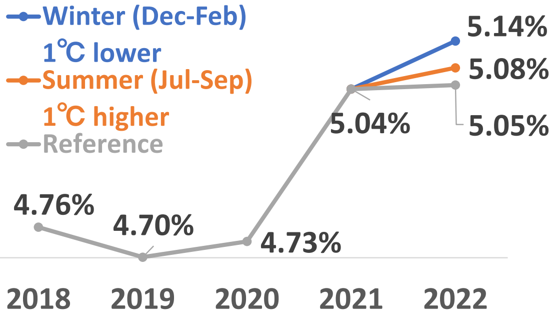

Fig. 5 Energy Engel's coefficient changes through temperature changes

- **Energy and environment policies should be integrated with redistribution policy**

Energy, mainly for air conditioning and water heating, is essential for our daily life. Income-based spending disparities for energy are far smaller than for other goods. Given that high-income households account for a larger share of residential solar photovoltaics capacity, low-income households feature a higher ratio of energy purchases to energy consumption than high-income households. Furthermore, high-income households have accumulated excessive savings under the COVID-19 crisis and may not have to reduce spending on non-energy goods and services even in the face of an increase in energy spending. This means that low-income households or families receiving less income under the COVID-19 crisis are hit harder by an energy spending increase. Support is required for these households to increase energy efficiency in order to reduce ordinary energy spending and additional energy costs for severe heat and cold waves. Such support includes subsidies for purchases of energy efficient housing, for housing reform to increase energy efficiency, for improving water heating and air conditioning efficiency and for introducing residential solar PV systems to cut electricity purchases. Energy and environment policies should thus be integrated with redistribution policy.

[6] Energy spending/household final consumption expenditure

Topic [3] Impacts of delays in completion of counterterrorism facilities and in nuclear plant restarts

- **Nuclear contributing to achieving to 3Es**

This analysis assesses the impacts of changes in nuclear power generation on the so-called 3Es – economic efficiency, energy security and environment.

In the Reference Scenario, two nuclear power plants will be restarted by the end of FY2022 in addition to the 10 plants that have already been restarted, with the shutdown of one of the restarted plants being prolonged due to delays in the completion of its counterterrorism facilities. Two other plants that have been approved by the regulatory authority as well as the relevant local governments for restarting will remain unable to begin operation within FY2022 due to delays in the completion of their counterterrorism facilities. We assume in the High Case that three plants will go into operation with their counterterrorism facilities completed within FY2022. The Low Case assumes that the two plants planned to restart in FY2022 in the Reference Scenario will fail to restart within the year. And lastly, the Highest Case refers to the Long-term Energy Supply and Demand Outlook set by the Ministry of Economy, Trade and Industry and assumes all 27 plants so far subjected to examinations for conformity to new regulatory standards will operate at the capacity factor of 80%[7].

Table 8 Impacts of changes in nuclear power generation [FY2022]

		Low Case	Reference Scenario	High Case	Highest Case	Changes from Reference		
						Low	High	Highest
Nuclear assumptions	Restarted nuclear reactors	10	12	14	27	-2	+2	+15
	Power generation (TWh)	64.5	71.8	90.1	193.4	-7.3	+18.2	+121.5
	Share in generation and purchases	6.5%	7.2%	9.0%	19.4%	-0.7p	+1.8p	+12p
Economy	Electricity unit cost[1] (JPY/kWh)	9.40	9.34	9.21	8.44	+0.06	-0.14	-0.90
	Fuel cost	5.75	5.69	5.55	4.79	+0.06	-0.14	-0.90
	FIT purchasing cost	3.65	3.65	3.65	3.65	-	-	-
	Total fossil fuel imports (JPY trillion)	18.56	18.49	18.33	17.38	+0.07	-0.17	-1.12
	Oil	10.00	9.99	9.97	9.90	+0.01	-0.02	-0.09
	LNG	5.00	4.94	4.79	3.91	+0.06	-0.15	-1.03
	Trade balances (JPY trillion)	1.31	1.36	1.50	2.27	-0.06	+0.14	+0.91
	Real GDP (JPY2011 trillion)	558.18	558.24	558.39	559.27	-0.06	+0.15	+1.03
Energy and environment	Primary energy supply							
	Oil (GL)	175.2	175.1	174.7	173.3	+0.2	-0.4	-1.8
	Natural gas (Mt of LNG eq.)	73.0	72.2	70.1	57.5	+0.9	-2.1	-14.7
	Self-sufficiency rate	13.3%	13.8%	15.0%	21.4%	-0.5p	+1.2p	+7.6p
	Energy-related CO_2 (Mt)	997	995	988	949	+3	-7	-46
	Changes from FY2013	-19.3%	-19.5%	-20.0%	-23.2%	+0.2p	-0.6p	-3.7p

1. Sum of fuel cost, FIT purchasing cost and grid stabilising cost divided by total power generation.

Regarding economic efficiency, fossil fuel imports in the High Case will be reduced by JPY170 billion from the Reference Scenario and those in the Highest Case by JPY1,120 billion. If crude oil and LNG prices increase from the assumed levels, due to changes in the international situation, the import fall resulting from fossil fuel-fired power generation cuts would be greater. Disposable income will increase through the fall in payments for fossil fuel imports, leading real GDP to rise by JPY150 billion in the High Case and by JPY1,030 billion in the Highest Case.

The unit cost of power generation will decrease by JPY0.14/kWh in the High Case and by JPY0.90/kWh in the Highest Case.

[7] Japan's target power generation mix for FY2030 includes nuclear energy's share at 20-22%, which is here assumed to be achieved in line with energy efficiency improvements and an electricity demand fall.

Given the growing geopolitical risks in the Middle East, energy security is now attracting interests. Japan's energy self-sufficiency rate as a representative energy security indicator will improve by 1.2 percentage points in the High Case and by 7.6 points in the Highest Case.

CO_2 emissions as an environment indicator will decline by 7 Mt in the High Case and by 46 Mt in the Highest Case. From FY2013 as the base year for Japan's CO_2 emission reduction target under the Paris Agreement, emissions will decrease by 20.0% in the High Case and by 23.2% in the Highest Case[8].

Given that deadlines for completing counterterrorism facilities will expire for an increasing number of nuclear power plants after FY2022, it is important for Japan's 3Es to facilitate the restart of nuclear power plants through adequate examinations with consideration given to the conditions of each plant.

Topic [4] Impacts of changes in oil prices on Japan's economy and on the energy situation

- **The Japanese economy's uncertainties will increase due to changes in crude oil prices. Japan should prepare for risks.**

If Japan's average crude oil import price increases or decreases by $10/bbl from the Reference Scenario, due to changes in the global oil supply-demand balance, GDP and production will decline or rise. Such price changes will exert the greatest impact on fuel oil sales. The reduction of renewable energy costs, the facilitation of nuclear power plant restarts and other measures to prepare for such risks are important for Japan.

Table 9 Impacts of a $10/bbl[9] crude oil price increase

		Historical	Reference scenario		Higher Oil Price Case			
							Changes from Refernce	
		FY2020	FY2021	FY2022	FY2021	FY2022	FY2021	FY2022
Prices	Crude oil, import, CIF ($/bbl)	43	71	68	73	78	3.5%	14.8%
	LNG, import, CIF ($/MBtu)	7.5	11.1	11.9	11.1	12.9	0.0%	8.7%
Economy	Real GDP (JPY2015 trillion)	525.7	540.4	558.2	540.3	557.7	0.0%	-0.1%
	Industrial production (CY2015=100)	90.4	96.7	102.1	96.7	102.0	0.0%	-0.1%
	Domestic corporate goods price index (2015=100)	100.2	106.3	107.3	106.4	108.1	0.1%	0.7%
	Consumer price index (2020=100)	99.9	99.8	100.6	99.8	100.8	0.0%	0.2%
	Balance of trade (JPY trillion)	1.3	0.3	1.4	0.0	0.1	-(0.3)	-(1.2)
	Fossil fuels(JPY trillion)	10.6	18.2	18.5	18.5	20.4	(0.4)	(1.9)
Energy	Primary energy supply (Mtoe)[1]	414.9	427.6	429.4	427.5	428.7	0.0%	-0.2%
	Electricity sales (TWh)	820.9	831.2	840.3	831.2	839.3	0.0%	-0.1%
	City gas sales[3] (Billion m^3)	39.51	41.06	41.96	41.06	41.93	0.0%	-0.1%
	Fuel oil sales (GL)	151.5	154.5	153.4	154.4	152.9	-0.1%	-0.3%

[8] The Japanese target calls for cutting GHG emissions in FY2030 by 46% from FY2013 and energy-related CO_2 emissions by 45%. Nuclear power generation, energy efficiency improvement, renewable energy expansion and other measures are assumed to contribute to achieving the target.

[9] For details about a $10/bbl increase and a $10/bbl decrease from the Reference Scenario, see IEEJ Ichihara "Outlook for International Oil Market in 2022."

Table 10 Impacts of a $10/bbl crude oil price decrease

		Historical	Reference scenario		Lower Oil Price Case			
							Changes from Refernce	
		FY2020	FY2021	FY2022	FY2021	FY2022	FY2021	FY2022
Prices	Crude oil, import, CIF ($/bbl)	43	71	68	68	58	-3.5%	-14.8%
	LNG, import, CIF ($/MBtu)	7.5	11.1	11.9	11.1	10.8	0.0%	-8.7%
Economy	Real GDP (JPY2015 trillion)	525.7	540.4	558.2	540.4	558.8	0.0%	0.1%
	Industrial production (CY2015=100)	90.4	96.7	102.1	96.7	102.2	0.0%	0.1%
	Domestic corporate goods price index (2015=100)	100.2	106.3	107.3	106.2	106.5	-0.1%	-0.8%
	Consumer price index (2020=100)	99.9	99.8	100.6	99.7	100.4	0.0%	-0.2%
	Balance of trade (JPY trillion)	1.3	0.3	1.4	0.6	2.6	(0.3)	(1.2)
	Fossil fuels(JPY trillion)	10.6	18.2	18.5	17.8	16.6	-(0.4)	-(1.9)
Energy	Primary energy supply (Mtoe)[1]	414.9	427.6	429.4	427.7	430.2	0.0%	0.2%
	Electricity sales (TWh)	820.9	831.2	840.3	831.2	841.3	0.0%	0.1%
	City gas sales[3] (Billion m^3)	39.51	41.06	41.96	41.06	42.00	0.0%	0.1%
	Fuel oil sales (GL)	151.5	154.5	153.4	154.7	154.0	0.1%	0.4%

Notes:

1. Mtoe = 1013 kcal

2. Conversion factors for oil: 9,139 kcal/L; Natural gas: 13,068 kcal/kg; Steam coal: 6,203 kcal/kg; Coking coal: 6,866 kcal/kg

3. Conversion factor: 1 m3 = 10,000 kcal

Outlook for International Oil Market in 2022
<Summary>◆

Akio Ichihara*

Key Points of the Report

1. Crude oil prices continued to rise in 2021 as crude oil demand growth amid an economic recovery from the COVID-19 crisis was coupled with production cuts by the OPEC-plus group of oil-producing countries and stagnant U.S. production to tighten the supply-demand balance. In the face of rising oil prices, such countries as the United States and Japan decided to release oil reserves. In late November, oil prices soared substantially as concern about the escalation of the COVID-19 pandemic grew due to increasing Omicron variant infections. In early December, the OPEC-plus group decided to retain its plan to increase oil production by 0.4 million b/d every month.
2. Oil demand in 2022 is projected to increase by 4.3 million bpd or 4.4% from 2021 to 100.6 million b/d on the premise that the COVID-19 pandemic would not escalate so much. Oil supply is projected to rise by 5.1 million b/d or 5.4% to 100.7 million b/d on the premise that the OPEC-plus group would retain the gradual production expansion plan.
3. The average Brent crude price in 2022 is projected at $70/bbl. Great uncertainties include the escalation of the COVID-19 pandemic and the OPEC-plus group's resumption of production cuts. If oil demand stagnates due to the escalation, the average may fall by $10/bbl from the projected level. If the supply-demand balance tightens due to the resumption of production cuts, the average may rise by $10/bbl.
4. As decarbonisation accelerates further, the oil industry is required to restructure business infrastructure while maintaining stable supply arrangements including those for gas stations during disasters and in depopulated areas.

Global Oil Supply and Demand

5. Global oil demand in the third quarter of 2021 increased by 5.5 million b/d or 6.0% year on year to 97.6 million b/d. While the global COVID-19 pandemic has yet to calm down, oil demand is picking up on economic reopening. On the premise that the pandemic would not escalate extremely, global oil demand in 2022 is projected to expand by 4.3 million b/d or 4.4% from the previous year to 100.6 million b/d.
6. Global oil production in the third quarter of 2021 increased by 5.4 million b/d or 5.9% year on year to 96.4 million b/d. The OPEC-plus group's production expansion and a U.S. production recovery have yet to catch up with demand growth. On the premise that the OPEC-plus group will continue to increase production though at a slower pace, global oil production in 2022 is projected to rise by 5.1 million b/d or 5.4% from the previous year to 100.7 million b/d.

Trends of OPEC and Major Countries

7. The OPEC-plus group produced 49.4 million b/d in the third quarter of 2021. The group at its meeting on December 2 decided to increase production in January, while being concerned about the escalation of the COVID-19 pandemic and other factors that would push down oil demand.
8. U.S. oil production in the third quarter of 2021 remained unchanged from a year earlier at 10.8 million b/d, while U.S. oil demand increased by 1.8 million b/d or 9.8% to 20.2 million b/d. U.S. production has begun to rise at last in line with price hikes. In 2022, U.S. production is assumed to increase by about 1 million b/d, topping the 2019 level.

Inventories and Financial Markets

9. OECD commercial oil inventories stood at a low level of 2,737.2 million barrels in September. In November, the

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United States orchestrated decisions to release oil reserves. The U.S. release was expected to start within 2021. The impact of the oil reserve release on prices is now expected to be limited.

10. In its World Economic Outlook released in October 2021, the IMF forecast global economic growth at 5.9% for 2021 and at 4.9% for 2022. It slightly revised the 2021 growth forecast downward from its July outlook. The escalation of the COVID-19 pandemic through Omicron variant infections would be a great downside risk for global economic growth.
11. Crude oil price hikes amid an economic recovery from the COVID-19 crisis have coincided with a U.S. stock market upsurge. U.S. interest rate hikes and the pandemic escalation expected in 2022 would affect stock prices, leading to a capital flight from risky assets.

Japanese Market

12. Japan's oil (fuel oil) demand in the third quarter of 2021 was 12.14 million kl per month on average (2.49 million b/d), up 0.16 million kl or 1.3% from a year earlier and up 4.5% from 11.59 million kl (2.4 million b/d) in the previous quarter. The oil refinery capacity utilization rate stood at 72% in the third quarter of 2021.
13. Domestic petroleum products prices reflect crude oil procurement costs (yen-denominated crude oil import prices) two to three weeks ago.
14. As decarbonisation accelerates further, the oil industry is required to transform its business structure while maintaining stable supply arrangements including those for gas stations during disasters and in depopulated areas.

Gas Market Outlook for 2022
<Summary>◆

Hiroshi Hashimoto*

Prices, Demand and Supply of LNG in 2022

1. Japan's average LNG import price is forecast to go up to USD 11.5 - 12.5 per million Btu in 2022 from estimated USD 9.98 in 2021. The assessed spot LNG price in Northeast Asia is forecast to remain high at USD 34 - 43 in the first quarter, declining to USD 23 - 26 in the following three quarters. Term-contract prices are forecast to be USD 9.2 - 10.6 on average.
2. The global LNG trades are forecast to expand by 6% - 7% to 400 million tonnes in 2022 from estimated 375 million tonnes in 2021, with supply capacity forecast to be larger than demand at around 413 million tonnes, assuming trouble-free operations of LNG production facilities.

Regional Trends in the Global LNG and Natural Gas Markets

3. The global natural gas demand, recovering from a 2% decline in 2020 to an estimated 3.5% increase in 2021, is expected to grow by 1.5% in 2022. The pace and size of growth are still subject to uncertainty caused by the pandemic. As natural gas and LNG cushion fluctuations of renewable and nuclear power outputs, unexpected changes of the global gas demand are still possible.
4. LNG trades registered a steady growth in 2021, rebounding from a restrained growth in 2020. In 2021, the LNG import growth was driven by China, becoming the largest importer in the world, followed by Korea, Japan and South America. While the United States dominated the export growth, Australia and Qatar, the current largest exporters, maintained their respective export levels in the year.
5. Spot gas prices in Asia and Europe sustained the highest levels in the history in 2021. Since July, those spot gas prices have been more expensive than crude oil. As seasonal demand fluctuations have been larger, the industry has had difficult challenges to cope with excessive fluctuations and surges of prices.

Notable Trends in Gas and LNG Demand

6. China has increased both domestic gas production and LNG import. Companies accelerated LNG procurement activities under long-term deals in the latter half of 2021. China's self-sufficiency ratio for natural gas has been below 60% since 2018.
7. India met its steady increase in natural gas consumption in 2021 with incremental gas production mainly from private-sector companies with LNG import staying at the same level.
8. Europe observed extreme price spikes in 2021 as LNG imports failed to fill the gap caused by steady increases in gas consumption and declining gas production in the region. Sizes and roles of gas storage vary between countries in the region, even though the low level of inventories has been often cited as one of the main causes of the price spikes.

Notable Trends in Gas and LNG Supply

9. The United States dominated the global LNG export growth in 2021 with volumes expected to be 74 million tonnes in 2021 and 87 million tonnes in 2022. LNG from the United States has had an effect to promote interactions and connections between regional markets.
10. The year 2021 observed delays of final investment decisions (FIDs) and construction, while the single largest FID on

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◆ Created based on the published research in the 440th Forum on Research Works

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an LNG production project ever was made in Qatar in February. Another FID was announced in Australia in November on a new gas field development and an additional liquefaction train.

Global Trends to Manage Methane Emissions

11. The United States, the European Union, along with more than 100 nations launched the Global Methane Pledge in early November. Specific measures to reduce emissions will be considered in the future. The United Nations Environment Programme (UNEP) with support from the European Union launched the International Methane Emissions Observatory (IMEO) at the end of October. IMEO will initially focus on methane emissions from the fossil fuel sector, and then expand to agriculture and waste sectors.

City-Gas Retail Liberalisation Developments in Japan

12. The numbers of retailing companies and customer switchings in the residential gas market in Japan have been steadily on the rise. Loss of customers from the former incumbent gas utility companies has slowed.

Remaining Challenges

13. The balances of LNG and gas markets during the ongoing Northern Hemisphere winter are susceptible to weather conditions and performances of LNG production facilities. Importance of LNG procurement under term contracts and investment in LNG production has been reaffirmed. Ways to determine assessed spot LNG prices should be also examined.
14. As discussions heat up on energy transitions and roles of natural gas and LNG in the pathway, ordinary citizens are expected to recognise issues related to natural gas prices and supply and demand further and better.

Outlook and Challenges for International Coal Market in 2022 <Summary>◆

Yoko Ito*

2022 Coal Price Outlook

1. Steam and coking coal prices will decrease in 2022. The average benchmark spot price of steam coal (the FOB price at New Castle Port in Australia) will decline from \$172/ton in the second half of 2021 to \$132/ton[1] in 2022. The average benchmark spot price of coking coal (the FOB price for Australian premium hard coal) will fall from \$321/ton to \$299/ton.
2. The spot steam coal price fell to \$50/ton under the COVID-19 pandemic between April and September 2020 before beginning to rise back in autumn. It topped \$100/ton in the second quarter of 2021, \$200/ton in autumn and \$250/ton later. In response to the Chinese government's order to increase domestic production, however, it has fallen back to around \$150/ton.
3. The spot coking coal price fell below \$100/ton in May 2020 and fluctuated before soaring from May 2021. In September, it shot up to a record high above \$400/ton.
4. International arguments for phasing out coal have grown dominant, including a call for phasing down coal at the 26th Conference of the Parties to the United Nations Framework Convention on Climate Change, or COP26. In 2021, meanwhile, concerns about stable energy supply increased as serious electricity shortages came on the tightening coal supply-demand balance in China and India. In 2022, coal phaseout initiatives will be implemented along with energy supply stabilization measures. While initiatives to cut energy consumption and hold down coal power generation are promoted under international frameworks, China and India will expand domestic coal production and imports over the short term, as indicated by China's decision to increase domestic production in September 2021. Southeast Asia will maintain coal consumption and imports.
5. If a rapid coal phaseout policy is implemented to sharply suppress coal demand or coal supply is remarkably restricted, the coal supply-demand balance and prices will fluctuate wildly. An important challenge is whether the world could quickly establish low-carbonization technology and economic efficiency for mixing ammonia with coal for combustion to demonstrate coal-fired power generation's role in smooth transition to carbon neutrality.

Demand trends

6. After continuing to increase between 2017 and 2019, global coal consumption turned down in 2020, with coal imports posting a sharp decline of 7.2% from the previous year. Steam coal imports increased in China and Vietnam while plunging in India. Coking coal imports decreased in China and Japan, while India steeply expanded coking coal imports and boosted its presence in global imports. In 2020, China accounted for 24% of global coking coal imports and India for 21%.
7. In the first nine months of 2021, China's steam coal imports decreased slightly year on year. As domestic production declined rapidly in June and July due to the government's coalmine safety measures, the coal supply-demand balance tightened amid robust economic activities. In response to a coal price upsurge, the government ordered the resumption and expansion of coal production at suspended coalmines. Since then, domestic production has recovered. The government also ordered some coalmines to increase production capacity. For the immediate future, China is likely to maintain steam import demand. China's coking coal imports in the first nine months of 2021 declined by some 40%.

◆ Created based on the published research in the 440th Forum on Research Works

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[1] The average CIF price will be \$147/ton, or 2.5 cents per million calories. The year's LNG import CIF price is predicted at \$11.5-12.5 per million Btu, or 4.6-5.0 cents per million kilocalories.

Under a policy of reducing pig iron production, coking coal imports are unlikely to increase.

8. India's steam coal imports in the first nine months of 2021 increased by 3.1% year on year, though falling short of restoring the 2019 level. Its coking coal imports in the period posted a rapid increase of 33.3%. While setting out a goal of expanding renewable energy to cover 50% of energy demand by 2030, the Indian government has opposed any rapid cut in coal consumption and plans to retain its traditional policy of giving priority to the use of domestic coal. For the immediate future, India is likely to maintain high-quality steam and coking coal imports.
9. As Vietnam and the Philippines have built new coal-fired power plants, Southeast Asia is expected to expand steam coal imports in the immediate future.

Supply Trends

10. Australia maintained its annual coal exports at around 390 million tons from 2015 to 2020 before seeing a 1.7% year-on-year fall in the first nine months of 2021. Exports to China, which had traditionally accounted for some 30% of Australia's coal exports, have remained at zero since January 2021. Other major coal-exporting countries expanded coal exports moderately in the first nine months of 2021.
11. Against the backdrop of international coal price hikes from the second half of 2020 and China's ban on coal imports from Australia, Indonesia has expanded steam coal exports. Given its robust domestic demand, however, its export growth will decelerate. In Australia, coalmine development is expected to gradually grow difficult. Russia, though being very ambitious to export coal, has problems regarding transportation infrastructure expansion, indicating limits on any expansion in coal exports to Asia. Overall potential to expand coal supply is limited.

Outlook and Issues Concerning Global Warming Policy in 2022 <Summary>◆

Takahiko Tagami*

International trends

1. In the run-up to COP26, Turkey, Russia, Saudi Arabia, Australia, and India announced net zero emissions/carbon neutrality targets, including during COP26. With these announcements, all G20 nations have now announced net zero emissions/carbon neutrality targets.
2. COP26 saw the adoption of rules for an international carbon market in connection with Article 6 of the Paris Agreement, aimed at avoiding carbon credit double counting and facilitating credit trading, which means the completion of detailed Paris Agreement rules. In addition, a work programme was established for scaling up 2030 targets and a decision was made to convene an annual high-level ministerial roundtable. With regard to climate finance, a decision was made to establish an ad hoc work programme and convene high-level ministerial dialogues aimed at setting a new collective quantified goal that will replace the existing goal, which is to mobilize $100 billion per year between 2020 and 2025.
3. As for 2030 target levels, along with the above-mentioned annual discussions over raising targets, a "global stocktake" (conducted every five years to assess the collective progress towards achieving the purpose and goals of the Paris Agreement) is scheduled for 2023, the first process for which will begin in 2022. Furthermore, as an ex post review of 2020 target achievement, developed nations will submit biennial reports on the said achievement. These two deliberative processes will happen simultaneously in 2022.

Policy trends by country

4. China: Attention is focused on the efforts to realize policies and measures to achieve targets laid out in the "Working Guidance for Carbon Dioxide Peaking And Carbon Neutrality" released by the Central Committee of the Communist Party of China and the State Council.
5. U.S.: Key here will be whether the Senate passes the social spending and climate bill that includes $555 billion in funding for clean energy. Much hinges on what policies or measures will be taken if the bill does not pass.
6. EU: Important here will be discussions between the European Parliament, the Council of the European Union, and the European Commission concerning proposals for policies and measures aimed at achieving 2030 goals.
7. India: The focus here is on how India plans to transition to natural gas and hydrogen and on policies and measures aimed at achievement of targets presented at COP26.
8. Other: Russia and several Southeast Asian countries including Indonesia have announced net zero emissions/carbon neutrality targets and have made plans to or are considering implementing carbon pricing schemes such as emissions trading systems or carbon taxes. The EU's efforts toward a carbon border adjustment mechanism are one factor behind this development. How carbon pricing will be globally implemented or discussed will be something to watch.

Policy trends in Japan

9. In 2021, the Plan for Global Warming Countermeasures was revised to include more ambitious targets for FY 2030. In 2022, there is a possibility that FY 2030 targets will be revisited or strengthened "as necessary." Additionally, further consideration will need to be given to more specific policies and measures, as well as whether and how carbon pricing should be implemented.

◆ Created based on the published research in the 440th Forum on Research Works

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Trends concerning climate-related financial disclosures

10. On October 14, the Task Force on Climate-related Financial Disclosures (TCFD) recommended that organizations should provide metrics including "Scope 3" greenhouse gas (GHG) emissions, which consist of all emissions other than a company's direct emissions and indirect emissions from purchased energy. TCFD also provided, as an example metric disclosed from financial organizations, GHG emissions financed by their loans and investment. While such disclosures are likely to become more common, measures should be taken to ensure that carbon intensive hard-to-abate economic activities be appropriately treated.

Outlook and Issues Concerning the Domestic and International Renewable Energy Market and Hydrogen in 2022

<Summary>◆

Yasushi Ninomiya*

Global renewable output to continue growing by 8% a year for 2022

1. Global energy output declined by just under 1% in 2020. However, despite similar declines in all other energy sources, renewables increased 6% year over year. Global renewable output for the year was 7,440 TWh, bringing the share of renewables in global electricity generation to 28% from the 2019 level of 26%.
2. Although total electricity demand in 2021 is expected to grow by around 6%, renewable output would also rise 6% to bring annual output close to 8,000 TWh. A similar or even more increase is expected for 2022. The share of renewables in global electricity generation is thus likely to approach 30% in 2022. However, an unexpected rise in electricity demand for 2021–2022 could stunt renewables share growth as power output from non-renewables will also increase.

Renewable generation capacity to grow even faster for 2021–2022

3. Despite the ongoing effects of the COVID-19 pandemic worldwide, 2020 was a record year for global renewables deployment. At 260 GW, 2020 far outpaced 2019's 180 GW, which itself was a new high. 2021–2022 is expected to see renewable power generation capacity deployed at a level that exceeds 2020. Fueling this acceleration is rising investor interest in renewables on account of the declaration of carbon neutrality goals, plans for renewables deployment, and policies to promote renewables by major countries, as well as a market environment that supports the deployment of renewables, one aspect of which is private enterprises' procurement of renewable electricity through means such as PPA.
4. 2020 saw China's share of annual growth in renewable generation capacity exceed 50% for the first time. With China stepping up its renewables deployment as it seeks to achieve carbon neutrality by 2060, 2021–2022 is set to see this single country account for nearly 50% of global growth in renewable generation capacity.
5. During 2021–2022, solar PV will come to account for 60% of annual growth in renewable generation capacity. In the 2010s, the growth of renewables saw the market gradually shift away from wind and toward solar PV. The 2020s will now be a time of even greater growth for solar PV.

Renewables market trends in Japan

6. In FY 2020, close to 6 GW of capacity was deployed as commercial solar PV facilities came online. This dropped to 5 GW in FY 2021, however, with a decline in FIT certifications. 2022 is expected to remain at a similar level due in part to uncertainty surrounding the transition to an FIP scheme. Meanwhile, onshore wind has seen new deadlines set for the start of operations and FIT certification expiration for projects that have received FIT certification but not yet commenced operations. Deployment could increase significantly 2021 onwards as operations gradually commence. However, offshore wind will yet not grow appreciably in the short-term market by 2022.
7. Renewable capacity, excluding large hydro more than 30 MW, would grow to 95 GW by the end of FY 2022, producing 183 TWh of electricity during FY 2021. Adding large hydro more than 30 MW into this, the share of renewables in total in electricity generation would reach 22.4% in FY 2022.
8. The 6th Strategic Energy Plan establishes 36–38% as the new FY 2030 target for renewables as a share of the energy

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mix. The 125 GW of renewable generation capacity, including large hydro, in 2020 needs to be increased to around 200 GW by FY 2030. This will require continuing renewables deployment at a pace of 7.5 GW annually, which exceeds the annual 7.1 GW average for the last five years. Target achievement will significantly depend on the effectiveness of policies going forward.

9. There are four pressing issues for renewables in Japan: (1) Deployment of considerable amount of renewable capacity to achieve the new 2030 targets, (2) Reduction of renewable generation costs, which still remain higher than the international average, (3) Overcoming power grid restrictions potentially holding back large-scale renewables deployment, (4) Increasing flexibility in the electricity systems in preparation for higher share of variable renewables in the near future.
10. FIP scheme will be implemented for selected new renewable projects starting in FY 2022. Under the FIP scheme, renewable power producers have to sell electricity to the wholesale electricity market by themselves and be required to conduct balancing according to estimates and accept responsibility for imbalances. This will be a major turning point towards renewable integration in the market.

Hydrogen trends

11. While predicting clean hydrogen production volume is difficult to do for the short-term (through 2022), in light of all projects currently being planned, hydrogen production could reach 17 Mt-H_2 a year by 2030. This breaks down to 8 Mt-H_2 a year for green hydrogen and 9 Mt-H_2 a year for blue hydrogen.
12. 13 nations had formulated national hydrogen strategies as of the end of 2021, a number that is expected to hit 20 over the next several years. The world's nations are increasingly realizing the importance of the role that hydrogen will play in achieving carbon neutrality.

Global and Domestic Nuclear Energy Outlook
<Summary>◆

Tomoko Murakami*

Overseas Nuclear Energy Outlook for 2022

1. During a televised speech he gave on November 9, 2021, French President Emmanuel Macron confirmed his intent to relaunch the construction of new nuclear reactors in France for the first time in decades. This is illustrative of the increasing focus on nuclear energy in the face of rising energy prices.
2. Despite President Macron's message, EDF, a French energy group, has yet to formulate a plan for new facility construction as of December 2021. The nuclear outlook internationally hinges on whether a concrete plan is hammered out.
3. Five commercial nuclear power plants went operational around the world in 2021: two in China, and one each in Pakistan, India, and the UAE, which are all non-OECD countries. China currently has more than 10 plants being built, while India has five and the UAE, Russia, South Korea, and other countries each have several. Although several of these plants are slated to commence operations in 2022, several facilities in developed nations such as the UK, U.S., and Germany will shut down. Consequently, global nuclear power generation capacity will either increase slightly or stay flat.
4. Without question, the international nuclear energy company garnering the most attention for its nuclear strategy and international expansion is Russian state-owned firm Rosatom. The company's strengths once lay primarily in uranium concentrates and uranium enrichment, and it supplied its plant technologies only to companies in Russia, Eastern Europe, and China. In recent years, however, the company has begun business talks with more than 30 countries around the world, including countries in the Middle East, Africa, and Latin America, and is developing businesses in areas outside of nuclear power that include hydrogen and advanced materials. With its continual efforts to gradually acquire experience in constructing new facilities while honing its technical prowess, Rosatom is likely to attempt things like hydrogen production and using renewable energy alongside nuclear, which is something that nuclear power producers in developed countries are doing. Future developments here bear watching.
5. On December 2, 2021, Canadian electric utility Ontario Power Generation (OPG) made the decision to use the BWRX-300 small modular reactor (SMR) for a new reactor it will build at its Darlington Nuclear Power Plant. With BWRX-300 vendor GE Hitachi Nuclear Energy as a technology partner, OPG is doing design and engineering work for SMR construction while formulating plans and preparing to apply for permits. The SMR is slated to be completed in 2028 and will be Canada's first commercial SMR.

Nuclear Energy Outlook in Japan for 2022

6. On June 29, 2021, unit 3 at Kansai Electric Power Company's Mihama Nuclear Power Plant went online for the first time in 10 years and one month (2011). This is now the 10th plant to resume operations under new regulatory standards. Mihama's unit 3 was shot down on October 23, 2021 after the deadline to take transitional measures for a specialized safety facility came and went. The reactor is expected to be restarted in 2022 after the facility is completed and approval is obtained.
7. Such deadlines are also coming in 2022 for units 3 and 4 at the company's Oi and Genkai plants (four units total). However, the probability of these plants shutting down due to the transitional measures is considered to be low. Kashiwazaki-Kariwa Nuclear Power Plant's unit 7 and Tokai No. 2 Power Station, which are BWRs that have been

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approved for construction, could be restarted in 2022.

8. More than a year has passed since a "literature survey" (the first phase of the process for selecting a final disposal site for high-level radioactive waste) was begun in November 2020. In Suttsu and Kamoenai in Hokkaido, where the Nuclear Waste Management Organization of Japan (NUMO) is conducting literature surveys, NUMO has held four "dialogue sessions" with residents where it has reported on its findings from the surveys and answered questions from attending residents. NUMO has also posted all its findings on its own and other websites.
9. Past reports have mainly focused on subjects such as the age of geological layers, volcanic activity, and mineral resources in the two regions. Going forward, NUMO will assess final disposal site suitability as it gathers more such data, ultimately submitting its results to local authorities for final decisions. It will not proceed to preliminary investigations in defiance of such decisions. As most of the results of the literature surveys are expected to be revealed by 2022, local authorities' decisions and subsequent steps taken will be something to watch.

Outlook and Issues Concerning Electric Power Business in 2022 <Summary>◆

Junichi Ogasawara*

State of electricity market competition in Japan

1. With day-ahead spot trading now accounting for 30% of all electricity sales, day-ahead spot prices have a significant impact on power generation facility profitability and retail competition. Since they began increasing in January of this year, day-ahead spot prices have moved more in step with LNG import prices. Day-ahead spot prices have steadily climbed on the back of raising LNG import prices since the second half of September, a development that bears watching the future.
2. Despite increasing day-ahead spot prices since January of this year, PPS' share of the market has increased in many areas. However, recent rises in day-ahead spot prices have fueled concern about the impact on PPS, which rely heavily on the spot market. Moreover, as the fuel cost adjustment system may not be sufficient for remedying the recent rise in LNG prices, raising electricity rates may be necessary.
3. Given customer interest in renewable value purchasing, the market for trading in non-fossil fuel value will be split into a market for renewable value trade (FIT non-fossil certificates) and market for meeting the obligations of the Act on Sophisticated Methods of Energy Supply Structures (non-FIT non-fossil certificates). FIT non-fossil certificates involve no "additionality," which may be needed to claim renewables value, and assessing such value will require keeping watch on how discussions unfold in the U.S. concerning similar certificates.
4. Regarding electricity supply and demand for this winter, while Japan has secured the 3% reserve margin needed at minimum for stable electricity supply in severe winters, supply could become tight if additional factors come into play. Reserve margin calculations factor in Power Supply I', which must be maintained in the event of a once-in-a-decade extreme weather event. If not factored in, the reserve margin is under 3% for eastern and central/western Japan. For this winter, in light of last winter's electricity shortage, power producers are working to ensure a stable electricity supply by monitoring efforts by companies in the northeastern U.S. (e.g., ISO New England and PJM) to secure fuel. As such, continued efforts to encourage power saving will be needed.

Stable supply

5. Electric power crises occurred around the world in 2021. While much of these was the result of heat waves and cold waves, it is conceivable that a declining "energy reserve" needed to ensure a stable supply of electricity is also a factor. Arguably, it is becoming clear that a fuel shortage could spark an electricity shortage if renewable output continues to drop, despite renewable capacity deployment expanding overall.
6. In Europe, rising natural gas prices have seen day-ahead spot prices maintain high levels since September, while in England retail electricity and gas companies are failing or pulling out of the market left and right. In France, a shutdown of nuclear power facilities this winter due to the effects of COVID-19 could create a power crunch. In the U.S., while spot prices may not be going up like in Europe, gradually rising gas prices are impacting the energy situation. In addition to the effects of fuel prices, rising surcharges and costs of transmission and distribution that owe to increasing renewable capacity deployment are making electricity rates go up in more countries. This is making solar PV self-generation profitable for an increasing number of countries and regions.
7. Due to increasing renewable capacity deployment and sluggish wholesale electricity prices, more and more developed countries are seeing decreasing traditional power capacity deployment. This summer, the California ISO asked

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consumers to conserve energy eight times. The North American Electric Reliability Corporation sees power crunch risk in the event of a severe winter for ERCOT, MISO, and SPP in Texas, while California and ISO New England face the same risk due to natural gas shortages.

8. In Asia, as well, Singapore has recorded several days where average daily electricity prices have exceeded ¥100/kWh. December 2 saw the country's highest price ever: ¥371.9/kWh. This situation has led to many retail suppliers pulling out of the market. Feeding this development has been power crunches caused by a large-scale decommissioning of superannuated gas-fired power plants in 2019. With gas-fired power accounting for more than 50% of its energy mix, Singapore is mulling over importing additional supply capacity due to the difficulty of building new gas-fired power plants. Japan also needs to consider new investment procurement policies that accord with its decarbonization goals.
9. Ireland, the UK, northern Europe, and the Electric Reliability Council of Texas, which all run relatively small power grids, are formulating additional measures to address the declining capabilities of synchronous generators, which provide inertial force (rotational energy used to stabilize grid frequency) due to the rise of asynchronous generators for energy sources such as wind and solar PV. Despite increasing frequency destabilization in the region, the UK has seen less frequency fluctuation due to a fast frequency response implemented in October 2020. Japan will need to consider its own measures in light of steps now being taken by other countries.

The Remaking of Africa's Future through Hydrogen

Masato Yoshida*

Introduction

Recent years have seen governments around the world raise their hopes for the use of hydrogen as a trump card for achieving carbon neutrality by 2050. The European Commission has formulated the Green Recovery Plan and is working to revive the European economy post COVID-19 while seeking to be a world leader in the market for climate change mitigation technologies, an area in which it excels. Hydrogen will play a central role in this endeavor. Europe has already achieved a considerable measure of renewable energy usage, and with efforts to decarbonize in the industrial field, where electrification is problematic, it is no wonder that hydrogen adoption is set to gain momentum. "Hydrogen in Africa," on the other hand, is a phrase that no doubt many would have a hard time believing. Yet surprisingly, Africa is in fact attempting to transform itself with hydrogen as a driving force. This paper begins by examining the context for Africa's increasing interest in hydrogen and specific efforts being made. It then looks at issues that hydrogen-adopting countries in Africa will need to overcome, as well as the implications for Japanese companies.

1. Context for Africa's Growing Interest in Hydrogen - Internal and External Factors Driving Hydrogen

Hearing that hydrogen is currently attracting attention in Africa might make some doubtful, both with respect to the need for and feasibility of hydrogen power in the region. The truth is, many African nations are struggling financially and cannot afford to fund massive projects. They are devoid of major infrastructure such as electrical grids and power generation equipment, and have inadequate legal systems. They possess no advanced technologies and have a shortage of people with the necessary skill sets. Yet while these nations may lack a great many things, through a combination of internal and external factors that are key to realizing hydrogen power and that are working together organically, Africa's hydrogen industry is developing for entirely rational reasons (Fig. 1).

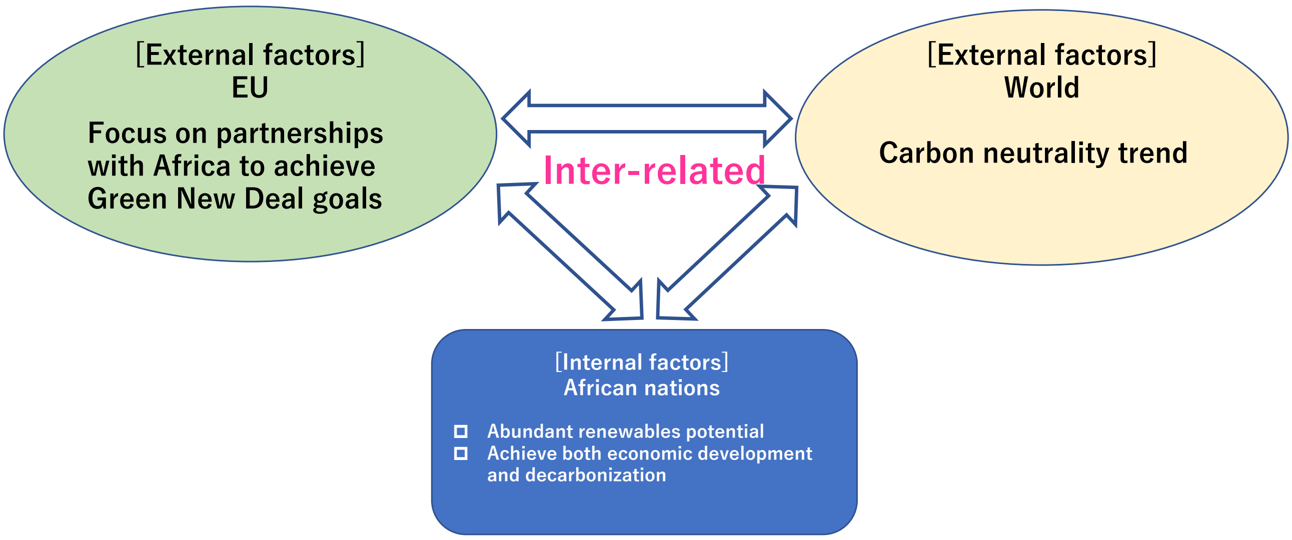

Fig. 1 Relationship between internal and external factors driving Africa's hydrogen industry

Source: This author

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[Internal factor 1] Advantaged renewable energy potential

One internal factor behind Africa's hydrogen industry's growth is the positively gigantic potential for renewables in the region. The map in Fig. 2 below shows solar energy resource quantities, with Africa in possession of **solar resources that exceed 2,200 kWh/m^2 across nearly the entire region.** The International Renewable Energy Agency (IRENA) estimates the **African continent to have a theoretical solar photovoltaic power (solar PV) potential of approximately 15 million TWh/year.**[1]

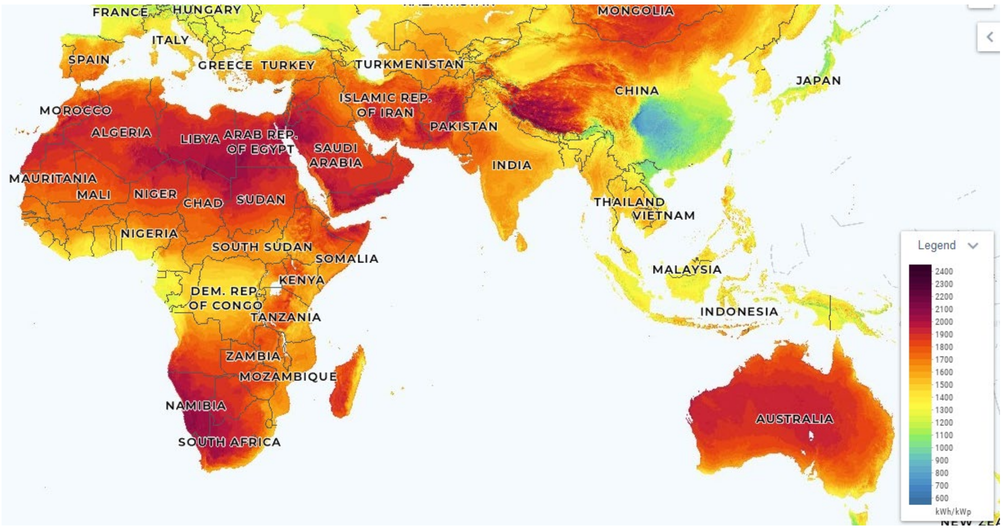

Fig. 2 Solar energy resources worldwide

Source: Global Solar Atlas, The World Bank Group, ESMAP, Solargis (2021)[2]

Africa's wind resource potential is also huge. Fig. 3 presents global wind power resources and indicates that **coastal regions in North and South Africa enjoy wind speeds that exceed 7m/s**. IRENA estimates that the **continent of Africa has a theoretical wind power potential of about 1 million TWh/year**.[3] Some nations even have abundant offshore wind resources.

[1] IRENA (2021), *The Renewable Energy Transition in Africa*, Abu Dhabi: International Renewable Energy Agency, pp.37-38
[2] World Bank Group (2021), https://globalsolaratlas.info/map?c=9.275622,23.642578,3
[3] IRENA (2021), *Ibid*., pp.37-38

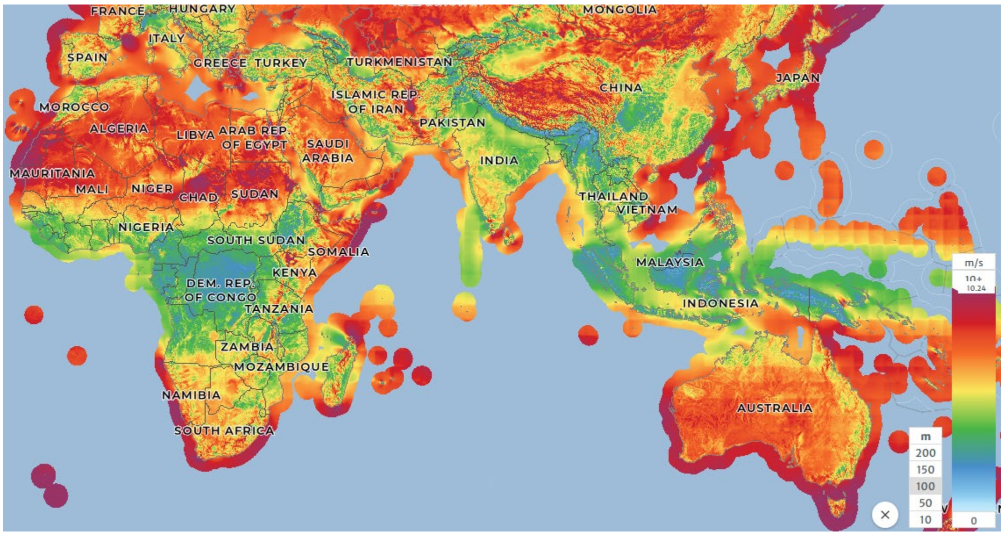

Fig. 3 Wind energy resources worldwide

Source: Global Wind Atlas, The World Bank Group, ESMAP, Vortex, DTU (2021)[4]

The key point here is that **Africa's total renewable output potential greatly exceeds the region's electricity demand**. According to an estimate by the International Energy Agency (IEA), total electricity demand in Africa could grow from 700TWh in 2018 to 1,600−2,300TWh in 2040, a potentially three-fold increase.[5] IRENA also estimates a theoretical potential output of 660,000TWh, 470,000TWh and 460,000TWh for solar PV, concentrating solar power (CSP) and wind energy resources respectively, for all of Africa in 2040 (this paper defines energy from renewables as "clean energy"). While these are just theoretical numbers and much has yet to be determined, clean energy has the potential to satisfy the total electricity demand for all of Africa 700 times over in 2040, which is an order of magnitude more than the current level.

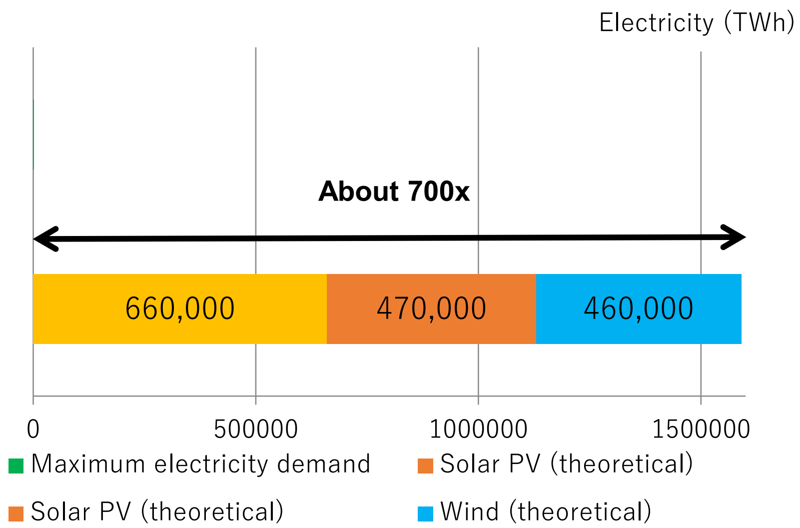

Fig. 4 Comparison of electricity demand and renewables potential throughout Africa (theoretical figures, 2040)

Source: Prepared based on data from IEA (2019), IRENA (2014)

[4] World Bank Group (2021), https://globalwindatlas.info/

[5] Electricity demand is defined as "total gross electricity generation less own use generation, plus net trade (imports less exports), less transmissions and distribution losses," IEA (2019), Africa Energy Outlook 2019, France: International Energy Agency, pp.190-191

[Internal factor 2] Hydrogen as a means to simultaneously drive economic development and solve energy poverty problems

Along with economic poverty, many African nations suffer from "energy poverty," whereby they lack access to electricity or harmless gas used for cooking. Unemployment remains high and the governments of these nations view it as a high-priority policy issue to develop the industry with the goal of creating more jobs. While the effects of COVID-19 have stalled economies in the short-term, these nations must skillfully get their economies back on track by making the most of a rapidly growing population and young workforce. Achieving a project that utilizes Africa's abundant renewable resources through hydrogen industry insourcing and external direct investment is an ideal undertaking for creating jobs and achieving economic development, while also attaining energy security.

[External factor 1] A partnership with Africa essential to realizing Europe's Green New Deal

Expressed differently, Africa's enormous renewable energy potential <u>**lies in the enormous amount of importable hydrogen usable for renewable power generation (defined as "clean hydrogen").**</u> This is because hydrogen is a means of transporting renewable energy (an energy carrier).

Europe, which is physically proximate to and shares historically tight relationships with African nations, will not be able to ignore the region's renewable energy resources as they will be a determining factor in whether European efforts to decarbonize succeed or fail. In December 2019, newly appointed European Commission President Ursula von der Leyen announced six commission priorities. One of these was the Green New Deal, which seeks to generate clean energy broadly and sustainably while furthering trade. This will involve building a hydrogen ecosystem mutually beneficial to Europe and Africa through collaboration between Eastern Europe (Ukraine) and North African nations (Morocco and Tunisia).[6] What has attracted investors' attention as a key action plan of the Green New Deal is the EU Hydrogen Strategy (Table 1).[7] This plan describes the building of and research and innovations into a hydrogen system mutually beneficial to Europe and Africa, as well as regulatory policies and collaboration on technology development to be implemented by Africa. It also details public-private support for boosting awareness for clean hydrogen through the Africa-Europe Energy Initiative, as well as a plan to consider potential projects using the European Fund for Sustainable Development.

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[6] EC (December 11, 2019), *The European Green New Deal*, Belgium: European Commission, p.21
[7] EC (July 8, 2020), *A hydrogen strategy for a climate-neutral Europe*, Belgium: European Commission, p.20

Table 1 EU Hydrogen Strategy summary

			Phase 1 2020–2024	Phase 2 2025–2030	Phase 3 2030–2050
Qualitative targets			- Implement GW-level renewable power generation - Enlarge water electrolyzers (<100 MW) - Recommend CCS technologies - Establish regulations and institutions	- Liberalize EU's hydrogen market (around 2030) - Boost renewable hydrogen cost competitiveness - Increased hydrogen demand in the industrial sector (steel, etc.) - Provide flexibility by utilizing hydrogen in renewables-centered power systems - Develop Hydrogen Valley - Develop a hydrogen supply chain and systems throughout Europe	- Use 25% of renewable power generation for hydrogen production - Use hydrogen in sectors where decarbonization is problematic (Promote sector consolidation) - Use biogas as a natural gas alternative
			Build a hydrogen ecosystem beneficial for both Europe and Africa (Green New Deal) **Research, innovation, regulatory policy, physical interconnections, and cooperation on technological development**		
Quantitative targets	Water electrolyzers	Installed capacity	6GW	Europe: 40 GW **Non-Europe: 40 GW** **Northern Africa: About 30 GW (*)** Ukraine: About 10 GW	Become a mature market
		CAPEX	300–600 euros/kW	250–500 euros/kW	Under 200 euros/kW
	Renewable hydrogen	Costs	17-34 yen/Nm^3 (similar to the cost of fossil fuel-derived hydrogen using CCS)	11–23 yen/Nm^3 (Similar to the cost of fossil fuel-derived hydrogen using CCS)	8–17 yen/Nm^3
		Production volume	1 million tons	10 million tons	Large-scale deployment in all sectors
	Investment		Producers: 180–470 billion euros End users: 100–120 billion euros		

Source: Prepared based on sources including "A Hydrogen Strategy for a Climate-Neutral Europe" (July 2020),"Green Hydrogen for a European Green New Deal A 2 x 40 GW Initiative" (March 2020)

To achieve its goal of becoming carbon neutral by 2050, the EU believes that taking concrete action over the next 10 years will be critical. The EU Hydrogen Strategy lays out specific quantitative targets concerning water electrolyzer installed capacity and CAPEX, and renewable hydrogen production costs and volume. The Strategy estimates that hydrogen demand as a proportion of final energy demand for Europe as a whole will be 17 million tons (665TWh) in 2030 (Fig. 5). Of the 17 million tons/year shown to the left, new demand will account for 6.1 million tons/year (238TWh). Roughly 70% of that, or 4.4 million tons/year, will be supplied via water electrolysis (40GW installed capacity. Own use in industry will account for 1 million tons while 3.4 million tons will go to hydrogen production), with the goal of satisfying approximately 25% of the EU's total demand, which is 17 million tons/year. The water electrolyzer installed capacity needed to achieve this target is estimated to be 40GW for the EU region.

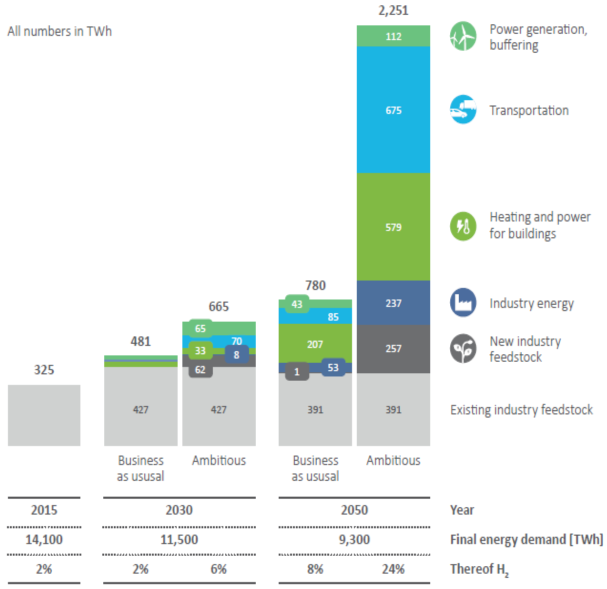

Fig. 5 Hydrogen demand projection for Europe (2030/2050)

Table 2 Water electrolyzer installed capacity (neighboring cooperating countries)

Electrolyser Capacity	2023	2024	2025	2026	2027	2028	2029	2030	Total 2030
Domestic Market [MW]									7,500
Ammonia North Africa	75	125	250	500	750	1,000	1,250	1,500	5,450
Ammonia Ukraine		50	100	200	250	300	400	500	1,800
Other (glass, steel, refineries)				10	20	30	40	50	150
Hydrogen refuelling stations					10	20	30	40	100
Export Market [MW]									32,500
Hydrogen North Africa (Hydrogen plants)		500	1,000	2,000	3,000	4,000	6,000	8,000	24,500
Hydrogen Ukraine (Hydrogen plants)			500	700	1,000	1,400	1,900	2,500	8,000
Total (MW)	75	675	1,850	3,410	5,030	6,750	9,620	12,590	40,000

Source: Hydrogen Europe[8]

Of particular interest is **how the European Commission is positioning the utilization of Africa's huge renewable energy potential as an essential component for achieving its 2050 carbon-neutral goal**. Specifically, along with the aforementioned hydrogen production volume within the European region (equivalent to 40GW using water electrolyzers), the European Commission is expecting **the deployment of 30GW of water electrolyzers in North Africa (realistically, Morocco), and the import of 2.3 million tons/year (24.5GW, 14% of Europe's total hydrogen demand of 17 million tons in 2030) outside of domestic demand (5.45GW equivalent, including for ammonia production)** (Table 2). African nations that utilize clean hydrogen will need state-of-the-art climate change mitigation technologies, an area where European companies have global dominance. Meanwhile, Europe also seems intent on deploying water electrolyzers and other such advanced technologies that are its forte by leveraging economic partnership agreements, while at the same time carrying out specific hydrogen production projects in North Africa and promoting decarbonization in the industrial sector by importing clean hydrogen produced through such projects.

[External factor 2] Global trends surrounding carbon neutrality

The majority of African nations are poised for full-fledged economic development. It is no surprise, then, that decarbonization efforts have so far been put on the back burner. However, this situation appears to be changing in dramatic fashion.

As Table 3 below shows, North African nations and South Africa have already established ambitious climate change mitigation targets. While these nations are naturally looking to join the ranks of developed nations, they seem to understand that showing their commitment to achieving a clean energy future will speed the inflow of foreign direct investment. This strategy shines light on these nations' aim to boost their energy self-sufficiency by developing hydrogen as an industrial cluster, while at the same time growing their economies and creating jobs.

[8] Hydrogen Europe (April 2020), *Green Hydrogen for a European Green Deal A 2 x 40GW Initiative*, Brussels: Hydrogen Europe, P.8 (Figure 4) & P.27 (Table 2)

Table 3 African nations' climate change mitigation targets

Country	Climate Change Mitigation Measures	Target Year
Morocco	52% share for renewables as a percentage of total power generation (solar PV 20%, wind 20%, hydro 12%) *10GW total new generation capacity: Solar PV 4.5GW, wind 4.2GW, hydro 1.3GW Reduce energy usage by 20% in the three largest energy consuming sectors (transport, housing and office buildings, and the manufacturing industry)	2030
Egypt	42% share for renewables as a percentage of total power generation	2035
Tunisia	41% reduction in greenhouse gas emissions compared to 2010 30% share for renewables as a percentage of total power supplied (3.8GW)	2030
South Africa	Large-scale deployment of solar PV and wind power generation facilities (6.8GW)	2022-2024
	0.5GW battery capacity deployment	By 2022 end
	Cessation of aging coal-fired power: Reduce share from 71.3% (as of 2018) to 42.6%	2030

Source: Prepared based on data from announcements made by each nation, including Egypt Vision 2030 (Egypt) and Integrated Resource Plan 2019 (South Africa)

2. Concrete Developments Concerning Hydrogen Industrialization in Africa

In the previous section, this paper looked at internal and external factors to provide a backdrop behind hydrogen industrialization in Africa based on the use of clean energy. This section will focus on North Africa (Morocco, in particular) and South Africa and look at specific efforts related to hydrogen industrialization.

[Morocco] A fossil fuel importer transforms into a major clean hydrogen exporter

Morocco is attempting to transform itself from an energy importer to an energy exporter by conducting clean hydrogen, Power-to-X (P2X) and other such clean synthetic fuel projects. Details are given below.

Developing clean hydrogen and P2X through economic partnerships with Europe

Morocco has set the most ambitious climate change mitigation targets of any North African nation. Despite fossil fuels accounting for a high 90% of the country's primary energy sources (as of 2018, see Fig. 6), it has an extremely low 10% energy self-sufficiency rate and imports almost all of its oil, coal, and natural gas. In the National Energy Strategy that Morocco released in 2009, the country aims to deploy 6GW of total generation capacity of solar PV, wind and hydro power (2GW each) and thereby increase the share of these capacities as a percentage of total installed capacity to 42% (14% each). In 2016, **Morocco established new targets to increase renewables as a percentage of total installed capacity to 52% and newly deploy at least 10 GW of renewable power generation capacity (4.5GW of solar PV, 4.2GW of wind, and 1.3GW of hydro) by 2030**. This has led to a sharp rise in the country's share of renewables in recent years. All renewables development is done through competitive bidding, and Morocco's political stability when compared to other North African nations has helped it attract foreign direct investment. This coupled with its potential for renewable energy development[9] is seeing successful progress being made on numerous projects without the need for incentives such as feed-in-tariffs. Additionally, in 2019 the country won a bid for an 850MW wind farm through one of the world's lowest tariffs: 0.028 euros/kWh, which is expected to fall to between 0.010 and 0.020 euros/kWh over the next 10 years.[10] Factors such as these make Morocco one of the most watched markets for renewables.

[9] The Sahara Desert in Morocco gets 3,000 to 3,600 hours of sunlight a year, among the highest levels in the world. Wind speeds reach 10 m/s on the country's 3,500 km coastline, which is estimated to provide wind power generation potential equivalent to 135 GW. Source: DLP Piper (February 2021),The Hydrogen Revolution in EMEA, p.27

[10] *Ibid., p.27*

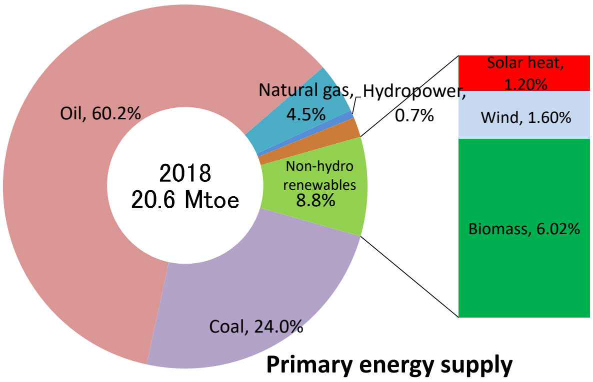

Fig. 6 Morocco's primary energy supply (2018)

Source: Prepared based on data from the IEA, World Energy Statistics and Balances 2020

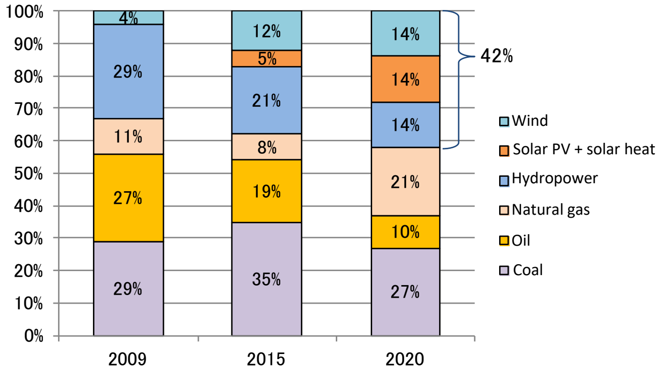

Fig. 7 Morocco's energy mix (2009–2020)

Source: Prepared based on data from MEME, "La nouvelle stratégie énergétique nationale : bilan d'étape," Janvier 2013, p.33.

Along with improving the country's energy self-sufficiency rate, the Moroccan government is also promoting clean hydrogen production with a view to creating surplus export capacity. In 2019 the country established a hydrogen roadmap and put together the Hydrogen Commission, an organization spanning multiple ministries.[11] In terms of international collaboration, the Moroccan government, which is looking to take advantage of advanced technologies and funding from Europe, shares complementary objectives with the European Commission, which sees Morocco as an important nearby partner to which it can sell water electrolyzers and other technologies in which Europe excels, as well as a country from which it can import the hydrogen needed to achieve carbon neutrality for the whole of Europe by 2050. Specific projects are currently being discussed between the parties based on an economic cooperation agreement (Table 4).

[11] Morocco World News (January 21, 2021), https://www.moroccoworldnews.com/2021/01/332775/energy-minister-celebrates-moroccos-green-hydrogen-achievements, Ministry of Energy, Mines and Environment, https://www.observatoirenergie.ma/en/actualites/energies-renouvelables-creation-dune-commission-nationale-de-lhydrogene/

Table 4 Morocco's collaborative relationships with and investments from other countries (renewables/hydrogen)

Field	FY	Country/Company	Details
Hydrogen	June 2020	Government of Germany (BMZ)	Signed a Memorandum of Cooperation for the development and use of clean hydrogen[12] ■ Conduct clean hydrogen and P2X projects proposed by the Moroccan government ■ Establish an R&D platform
	February 2021	Government of Portugal	Agreement to cooperate with regard to clean hydrogen[13]
	June 2021	IRENA (Abu Dhabi)	■ Jointly conduct technology and market forecast research for clean hydrogen, and promote public-private partnerships[14] ■ Jointly explore the construction of a hydrogen value chain for exporting clean carbon to global and regional markets
Renewables	October 2017	Siemens Gamesa (Spain)	Construct a wind turbine blade factory and training facility for markets in Morocco, Europe and Africa and directly and indirectly create 1,100 jobs[15]

While reducing generating costs will be key to reducing hydrogen production costs, Morocco is, as explained above, exceptionally competitive even globally when it comes to renewable generation costs. Hopes are therefore high for clean hydrogen produced in Morocco. Indeed, one estimate finds that **the cost of water electrolyzer equipment will fall to around 300 euros/kW, which translates into 1 euro/kg-H_2 if 80% capacity utilization is achieved**.[16]

With regard to P2X, this assessment was jointly conducted by the Research Institute for Solar Energy and New Energies (IRESEN) and German Corporation for International Cooperation and the German Moroccan Energy Partnership (GIZ-PAREMA), which suggest that Morocco has the **potential to capture 2-4% of the global P2X market by 2030**.[17]

Currently, Morocco seems to be formulating a P2X roadmap for 2050.[18]

Potential for a hydrogen-dedicated pipeline between North Africa and Europe

In the future, access to a pipeline exclusively for the transport of hydrogen and P2X products from North Africa to the European markets could see a dramatic decrease in transport costs compared to the use of liquid hydrogen transport vessels. According to Hydrogen Europe, the construction of a hydrogen pipeline extending from Egypt to Italy through Greece (indicated by the pink dotted line in Fig. 8, which will extend to Ethiopia and the Middle East in the future) is being mulled over that is estimated to levelize transport costs between Egypt and Italy to 0.2 euros/kg-H_2 (principal prerequisites are

[12] European council on foreign relations (January 2021), *Power surge: How the European Green Deal can succeed in Morocco and Tunisia*, United Kingdom: European council on foreign relations, pp.6-7

[13] Kingdom of Morocco (February 2, 2020), "Morocco, Portugal Strengthen Cooperation on Green Hydrogen," https://www.maroc.ma/en/news/morocco-portugal-strengthen-cooperation-green-hydrogen

[14] S&P Global Platts (June 14, 2021), "Morocco eyes green hydrogen exports with IRENA renewables collaboration," https://www.spglobal.com/platts/en/market-insights/latest-news/coal/061421-morocco-eyes-green-hydrogen-exports-with-irena-renewables-collaboration

[15] Siemens Gamesa (October 11, 2017), "Siemens Gamesa inaugurates the first blade plant in Africa and the Middle East," https://www.siemensgamesa.com/newsroom/2017/10/siemens-gamesa-inaugurates-the-first-blade-plant-in-africa-and-the-middle-east

[16] DLP Piper (February 2021), *op.cit.*, p.28

[17] Infomineo (April 13, 2020), "Power to X: What role could Morocco play in this new paradigm?," https://infomineo.com/power-to-x/

[18] IRESEN (June 2020), *Power-To-X In Morocco Driver of Mediterranean Energy Market Integration*, Morocco: Research Institute for Solar Energy and New Energies, p.12

shown in Table 5).[19] Considering geographical advantages (there is a maritime distance of 36 miles between Morocco (Tangier) and UK territory Gibraltar, the closest point to Morocco on the European continent; this is 1/37 the length of the aforementioned Egypt-Spain pipeline), a hydrogen pipeline between Morocco and Spain could significantly reduce transport costs.

Table 5 Pipeline transport prerequisites and preliminary calculations

Route	Egypt —> Greece —> Italy
Total length	2,500km (1,350 miles)
Capacity	66GW (2 x 48 inch diameter)
Investment	16.5 billion euros
Availability	4,500 hours/year
Hydrogen transport volume	7.6 million tons/year
Cost	0.2 euros/kg-H_2

Source: Prepared based on data from Van Wijk A. & Wouters (2019)

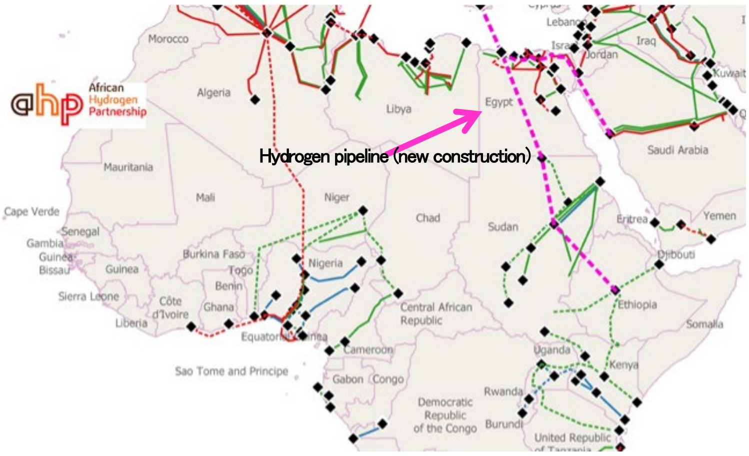

Fig. 8 Potential hydrogen transport infrastructure bridging the African continent with Europe

Source: Hydrogen Europe (2020), p.17

Let us now examine the price competition advantages of clean hydrogen produced in Morocco. Fig. 9 shows the price upon arrival in Spain for hydrogen produced in Morocco compared to hydrogen produced in the U.S. and Australia using a simple calculation. It assumes that Morocco will supply hydrogen via two methods, namely liquid hydrogen transport vessels and hydrogen pipelines, while the U.S. and Australia will use only liquid hydrogen transport vessels. No useful calculations exist for the Morocco-Spain pipeline cost. However, even though the distance differs, the conservative estimate of 0.2 euros/kg-H_2 shown in Table 5 above is used. In light of Morocco's competitive renewable energy generation costs and geographical advantage in being close to the European continent, **clean hydrogen produced in Morocco is extremely competitive**.

[19] Hydrogen Europe (June 2020), *op.cit.*, pp.15-17

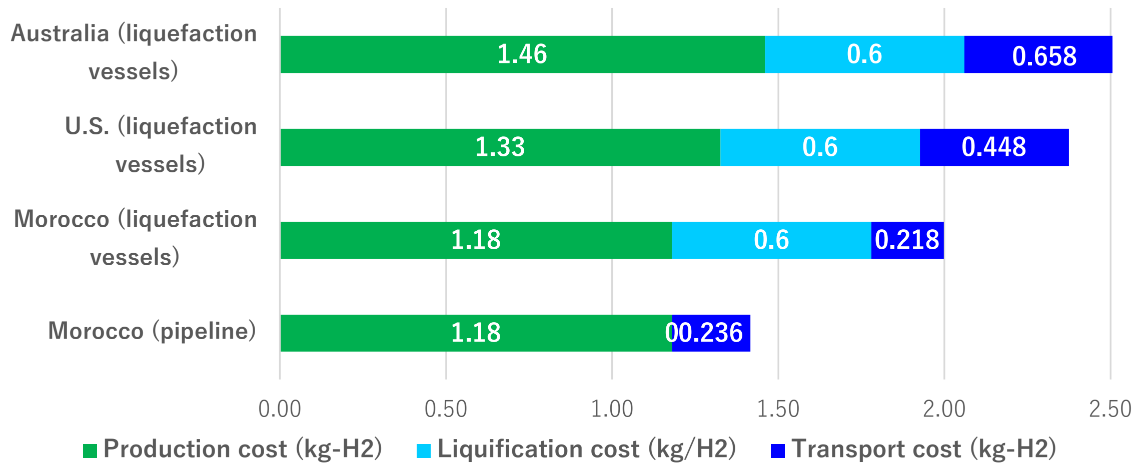

Fig. 9 Comparison of clean hydrogen cost competitiveness with Morocco (comparison with the U.S. and Australia, 2030)

Note: Clean hydrogen production costs: 2030 targets are assumed for Morocco (1 euro/kg-H_2) and Australia (2 AUD/kg-H_2)

Note: 0.6 USD/kg-H_2 is used as the provisional cost for liquefaction for all countries; Liquefied hydrogen transport vessel size: 11,000 tons-H_2

Note: No delivery costs are included in any case

Possibilities for clean energy exports, an area of rapidly growing demand in Europe

Renewables can also be exported as clean energy without being converted to hydrogen. There are currently two submarine power cables stretched between Spain and Morocco (1997: 0.7GW, 2016: 0.7GW, totaling 1.4GW). Spain once used to provide power to an electricity-impoverished Morocco, but the inverse occurred in 2019 and Morocco began sending power to Spain when its Safi coal-fired power plant went online (2 x 693MW).[20] Spain and Morocco have signed a memorandum[21] for the construction of a third submarine power cable (0.7GW), whose completion is projected to result in a total capacity of 2.1GW. Given the rapidly growing demand in Europe, the near future could see these power cables used to export clean energy from Morocco to Spain. This is due to a sharp uptick in demand for global data centers brought about by the explosive proliferation of data and digital services. The IEA predicts that total global Internet traffic will double between 2020 and 2022 to 4.2 zettabytes, one example that suggests demand for data and digital services will continue to grow at an exponential rate.[22] These factors put data center demand on an upward trajectory. In the energy sector, meanwhile, a key growth driver for decarbonization will be corporate PPA (Fig. 10).[23] Corporate PPA is seeing rapid growth among large IT companies such as GAFAM (Google, Amazon, Facebook, Apple and Microsoft) as a way to match 100% of their electricity consumption with purchases of renewable energy. In recent years, these companies are placing highly on offtaker rankings (Fig. 11). In Europe, business requests are already flooding in to power companies from customers in a development that is expected to see the scramble for clean energy only intensify. There are already numerous data centers online in Spain and southern France, with many plans being announced for the construction of new data centers in anticipation of future demand growth (Fig. 12). To achieve carbon neutrality for highly energy-consumptive data centers, hopes are expected to grow even further for clean energy in northern African nations.[24]

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[20] Since the European Commission began considering the implementation of a carbon border adjustment mechanism, fossil fuel energy selling by Spain has been declining; European Council of Foreign Relations (January 2021), *op.cit.*,p.12

[21] *Ibid*., p.12

[22] IEA (June 2020),"Data centres and data transmission networks," https://www.iea.org/reports/data-centres-and-data-transmission-networks

[23] Long-term contracts under which organizations such as corporations and local governments agree to purchase electricity from a renewable energy generator

[24] With support from the World Bank, a feasibility study was launched in May 2021 concerning a submarine power cable between Tunisia and Italy (0.6 GW, HVDC); MEED (August 5, 2021), "Team starts Italy-Tunisia power link study," https://www.meed.com/team-starts-italy-tunisia-power-link-study

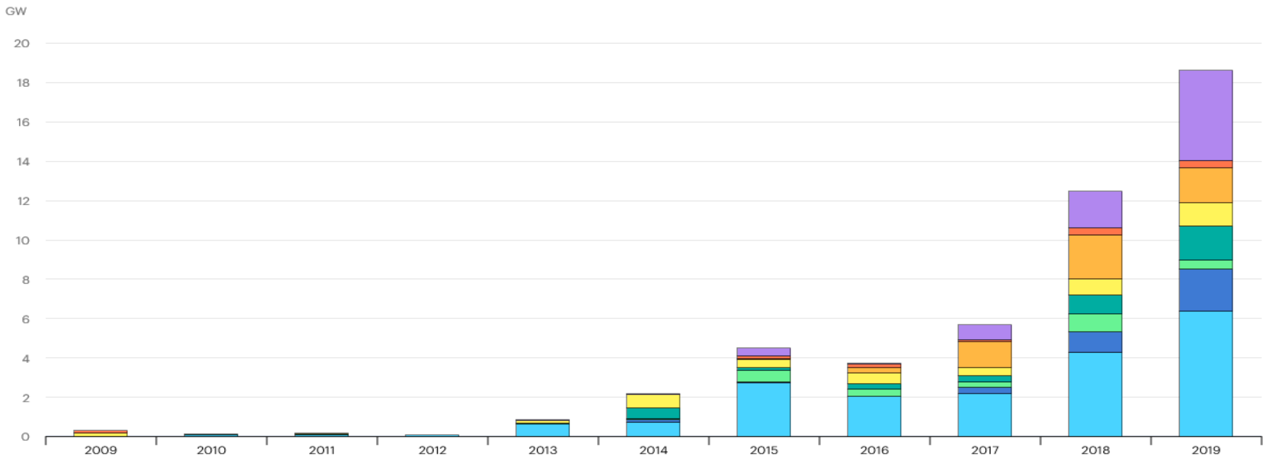

Fig. 10 Corporate PPAs around the world (by sector and capacity, 2009–2019)

Source: IEA (June 2020)

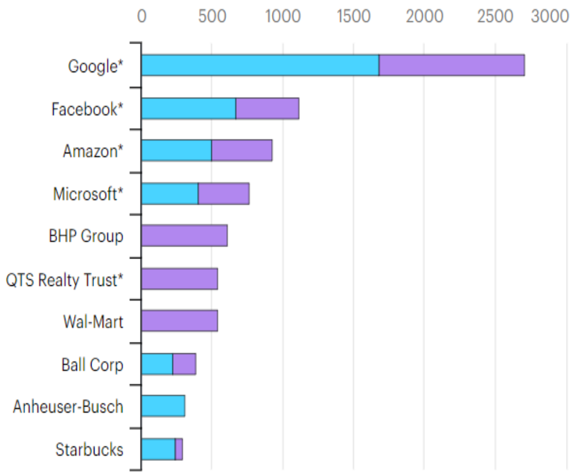

Fig. 11 Corporate PPA ranking (2019)

Source: IEA (June 2020)

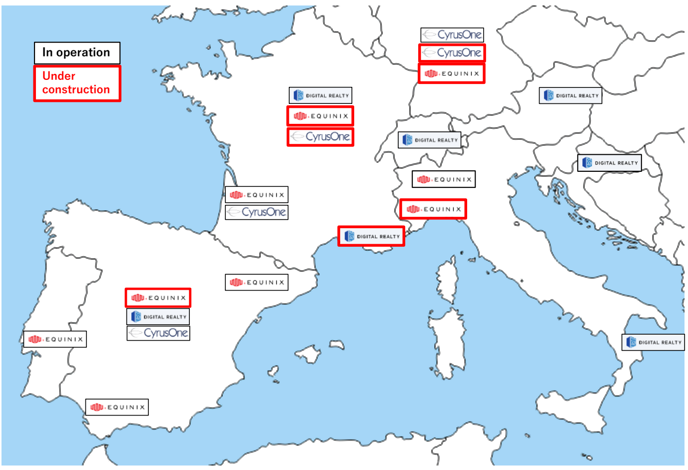

Fig. 12 Southern Europe data center map (top 3 companies, 2019)

Source: Prepared based on investor relations data from EQUINOX, Digital Reality and Cyrus One

[South Africa] Focusing on creating a mega supply center for zero carbon fuel

Now let us look at efforts under way in South Africa concerning clean hydrogen. Because of geographical distance, South Africa is not a key partner for economic cooperation aimed at achieving carbon neutrality for Europe. However, South Africa is looking to achieve both economic development and carbon neutrality through a focus on producing and supplying clean hydrogen that leverages the region's rich renewables potential, as well as zero-emission vessel fuels that include synthetic fuels and clean ammonia.

As indicated in Table 4 above, South Africa has set ambitious climate change mitigation targets that center on decommissioning aging coal-fired power plants and building large-scale solar PV and wind power generation facilities. As examples, the country is reducing its proportion of coal-fired power generation, which was 71% of its energy mix in 2018, to 43% by 2030 by decommissioning aging facilities, and will deploy 6.8GW of new solar PV and wind power facilities between 2022 and 2024 (Fig. 13 and 14). We will look at renewables potential next. With average sunshine of 2,500 hours a year and average amount of solar insolation of 4.5-6.5kWh/m^2 a year, South Africa is well-positioned for solar PV.[25] South Africa's Integrated Energy Plan 2016 (IRP 2016) calls for taking advantage of the abundant wind resources located on the country's southern coastline and coastal waters to deploy a minimum of 24GW of wind power generation facilities in base case scenario by FY 2050.[26, 27] More than 100 renewable energy projects are currently being bid on internationally (solar PV 1.0GW, wind 1.6GW, totaling 2.6GW).[28] IRENA and Sweden's Royal Institute of Technology estimate South Africa's theoretical solar PV and onshore wind power potential (facilities with availability factor of at least 20%) to be 83,000TWh/year.[29]

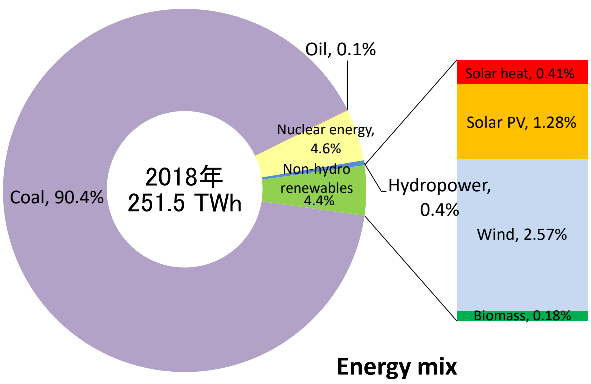

Fig. 13 South Africa's energy mix (2018)

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[25] Department of Energy, "Renewable & Alternative Fuels," http://www.energy.gov.za/files/renewables_frame.html
[26] Department of Energy (November 2016), "Integrated Energy Plan,"
http://www.energy.gov.za/files/IEP/2016/Integrated-Energy-Plan-Report.pdf
[27] IRP2019 was updated into a plan calling for the deployment of 17.7 GW of wind power generation facilities by 2030
[28] PV Magazine (August 23, 2021), "Sixty-three PV projects to compete in South Africa's 2.6 GW renewables tender,"
https://www.pv-magazine.com/2021/08/23/sixty-three-pv-projects-to-compete-in-south-africas-2-6-gw-renewables-tender/
[29] IRENA (2014), *Estimating the Renewable Energy Potential in Africa*, Abu Dhabi: International Renewable Energy Agency, p.36

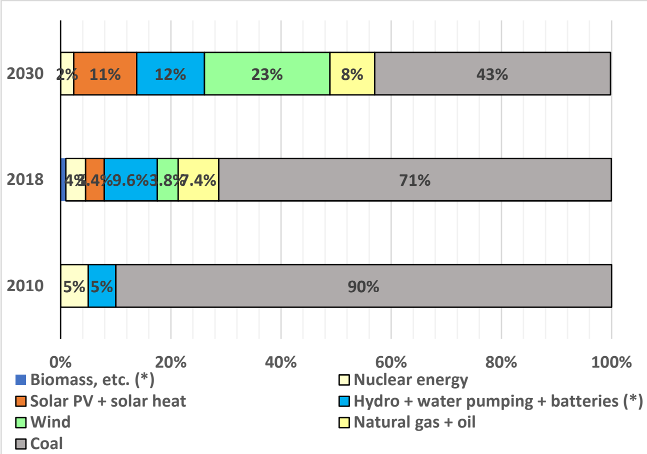

Fig. 14 South Africa's historical energy mix (2010–2030)

With regard to hydrogen, South Africa's Department of Science and Innovation is currently carrying out Hydrogen South Africa, otherwise known as HySA,[30] as part of the country's efforts in specific industries such as land transport, maritime transport and mining.

Approach for the land transport industry: SASOL to produce and use renewable hydrogen-based clean synthetic fuels

SASOL, a diversified energy and chemicals company of South Africa, is currently working towards decarbonization in the land transport industry. In April 2021, SASOL announced that it would be conducting a proof of concept for a clean hydrogen production, transport and utilization business together with Toyota South Africa.[31] The two companies will use heavy-duty, long-haul trucks powered by fuel cells on an arterial road running between Durban and Johannesburg. Toyota's headquarters in Japan will develop the fuel-cell trucks, while SASOL will make investments for the production of hydrogen-based clean synthetic fuels, as well as for fuel transport and supply equipment (Fig. 15). Having been involved in the development and commercialization of gas-to-liquid, coal-to-liquid, and other such synthetic fuel technologies, SASOL is now aiming to also become the market leader in synthetic fuel production and utilization.

[30] Hydrogen South Africa, https://www.hysasystems.com/

[31] SASOL (April 142021), "Sasol and Toyota South Africa Motors form green hydrogen mobility partnership, https://www.sasol.com/media-centre/media-releases/sasol-and-toyota-south-africa-motors-form-green-hydrogen-mobility

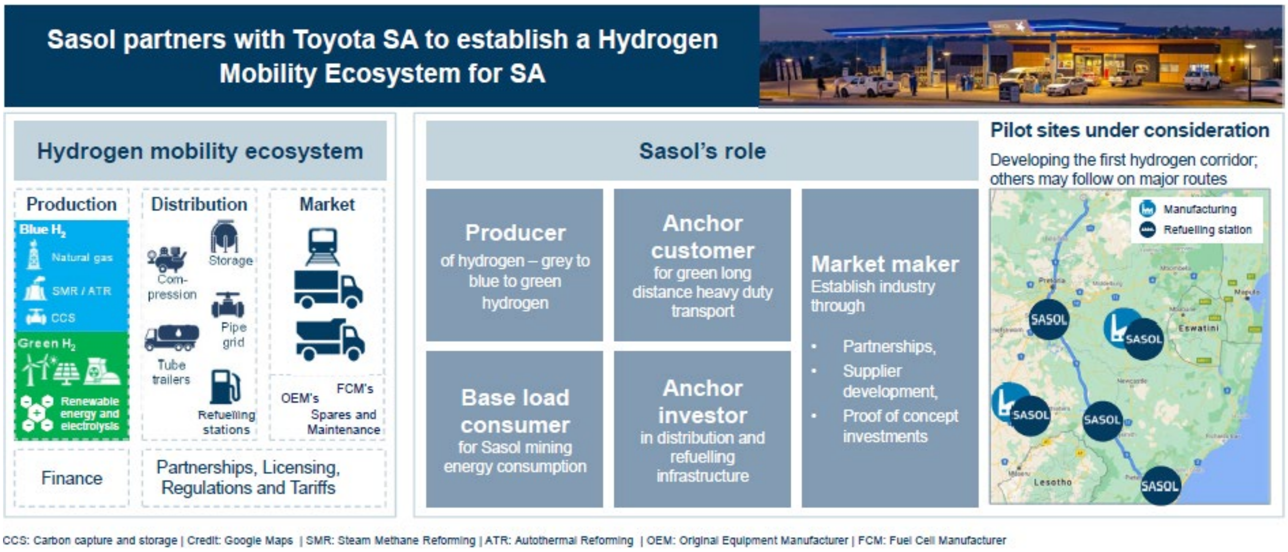

Fig. 15 Overview for mobility ecosystem using clean synthetic fuel-based hydrogen

Source: SASOL presentation materials[32]

Approach for the marine transport industry: Developing a production and supply base for zero-emission vessel fuel

Decarbonizing the marine transport industry is another essential step toward achieving carbon neutrality globally. Along with a potential for renewables that far exceeds the degree needed to satisfy its own domestic demand, South Africa is located at a strategic point on maritime shipping routes, positioning it quite favorably among the countries of the world (Fig. 16 and 17). Looking at the economy, while South Africa's biggest export has been coal, iron ore and metals, it cannot ignore the medium- to long-term decline in demand for such products as the world moves to decarbonize. This has prompted the development of a production and supply base for zero-emission vessel fuel that will ensure a new, stable revenue stream for the long-term while jumpstarting economic development. For example, the yearly energy usage of vessels calling at Richards Bay is a considerable 27TWh, with 71% of these vessels being bulk carriers engaged in international maritime transport. Because of this, clean ammonia, which has a higher energy density than hydrogen, is well suited for supplying to vessels. With the deployment of zero-carbon maritime transport technologies at major ports in South Africa, including Richards Bay, the country is said to have the potential to attract land infrastructure investment up to 175 billion rand (1,337 billion yen) by FY 2030.[33]

[32] SASOL (April 13, 2021), 2nd Renewable Hydrogen and Green Powerfuels Webinar, "SASOL's role in unlocking Hydrogen's significant potential to contribute to energy security and trade,"

[33] Ricardo & EDF (June 2021), *South Africa: fueling the future of shipping*, United States: Environmental Defense Fund, p.28

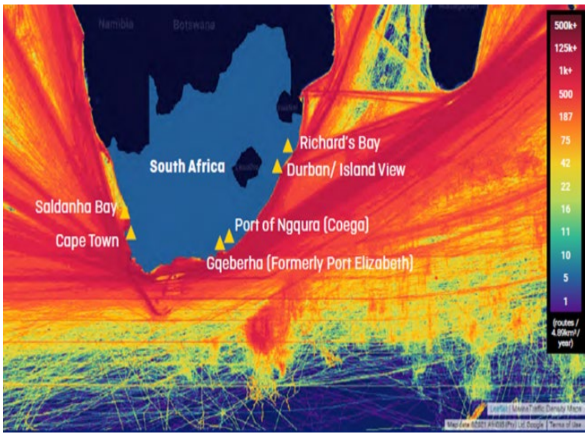

Fig. 16 Maritime transport traffic at major ports in South Africa

Source: Richard & EDF (Jun 2021)

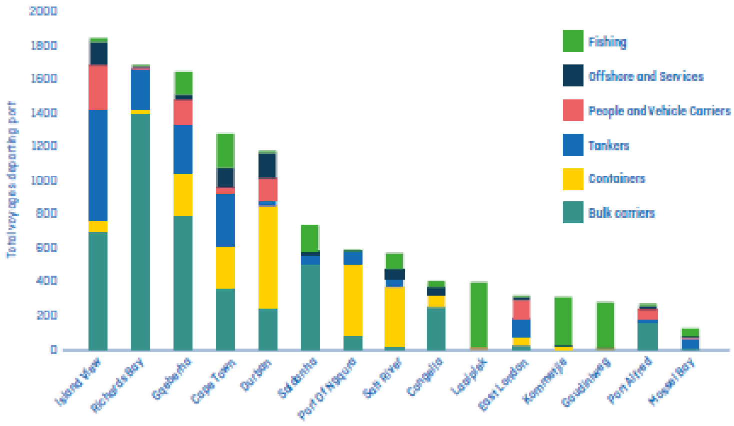

Fig. 17 Top 15 ports for port traffic (port departures, 2018)

Source: Richard & EDF (Jun 2021)

<u>Approach for the mining industry: UK-based Anglo American and France-based ENGIE to advance mining industry decarbonization</u>

Steps are also being taken towards decarbonization in the mining industry. In conjunction with France-based ENGIE, a diversified environmental services company, UK-based Anglo American is working to replace the large trucks used in mining operations with trucks powered by fuel cells. With this project, Anglo American is modifying the large diesel trucks (300-ton load)[34] while ENGIE is operating 3.5MW of water electrolyzers using solar PV deployed at Anglo American's Mogalakwena Platinum Group Metals mine to produce clean hydrogen and supply it to these trucks (Fig. 18).[35] This mine, together with science and technology parks, will serve as the launching point for the South African government's current Platinum Valley initiative to build up its hydrogen industry.[36]

[34] Diesel tanks will be converted to hydrogen tanks and engines will be modified to use hydrogen fuel cells and battery packs

[35] Anglo American (October 19, 2019, press release), “Anglo American partners ENGIE to develop world’s largest hydrogen powered mine truck,” https://www.angloamerican.com/media/press-releases/2019/10-10-2019

[36] allAfrica (October 19, 2020), “South Africa: Science and Innovation on South Africa's Platinum Valley Project,” https://allafrica.com/stories/202010200636.html

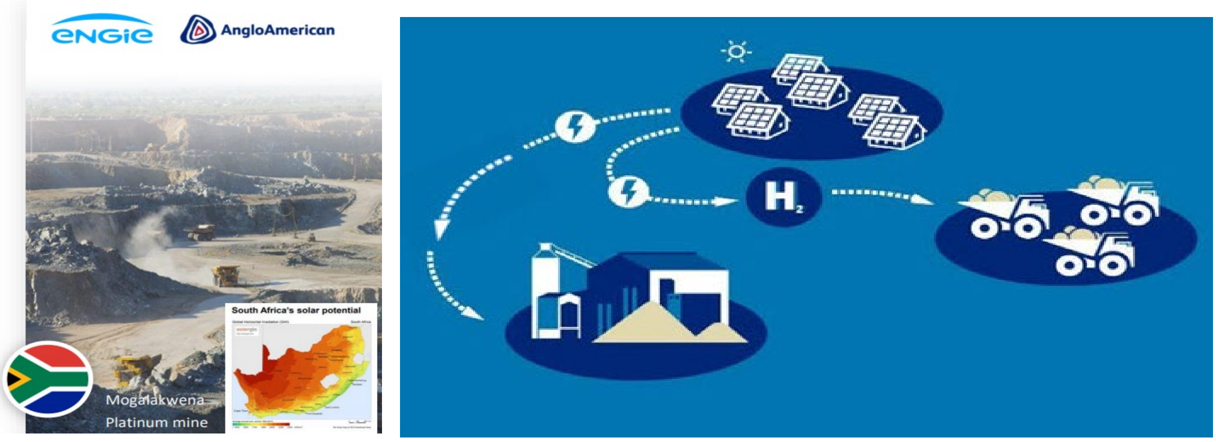

Fig. 18 Project Rhyno concept

Source: METI HEMM (October 14, 2020)[37], FuelCellsWorks[38]

3. Future Outlook

As this paper has so far examined, northern African nations and South Africa are making solid progress toward developing their hydrogen industries by leveraging their abundant renewables potential. What possible risks and challenges might they face going forward?

With clear climate change mitigation targets and plans to deploy large-scale renewable energy generation facilities, northern African nations (Morocco, in particular) are in recent years being aided by a number of large-scale projects led by foreign capital, with a focus on wind power. Nothing is more important than political stability if foreign direct investment is to continue, and one must watch for even small changes. With respect to hydrogen, the content of P2X Roadmap 2050 is something to monitor as it comes together. In terms of international cooperation, however, discussions surrounding specific projects between Morocco and Germany appear to have halted over a problem concerning interference into Morocco's internal affairs in Western Sahara,[39] posing a significant risk factor. Whether talks resume with Germany and specific projects take form thereafter will likely be key to advancing Morocco's hydrogen industry. Tunisia has immense renewables potential that is almost completely untapped, and is therefore being watched with interest by the European Commission. Achieving the greenhouse gas emission reduction targets in Table 3 above will require a transition of the energy sector, which currently accounts for 75% of all such emissions. An estimated capital investment of $18 billion will also be needed.[40] While the country's recent political instability is worrying, the stage is set for renewable energy projects to move forward with the help of economic cooperation with Europe.

Similarly, South Africa has established precise renewable energy facility deployment targets which should present attractive infrastructure investment opportunities in areas such as the production and supply of zero-emission vessel fuel. The biggest risks the country faces are political instability coupled with the financial instability of state-run power companies. As foreign direct investment will be essential for economic development, the government is likely to implement an attractive array of policies.

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[37] https://www.nedo.go.jp/content/100925659.pdf

[38] FuelCellsWorks (October 10, 2019), "Anglo American partners with ENGIE to develop World's largest Hydrogen powered mine truck," https://fuelcellsworks.com/news/anglo-american-partners-with-engie-to-develop-worlds-largest-hydrogen-powered-mine-truck/

[39] Morocco World News (May 31, 2021), "Morocco Blocks Green Hydrogen Deal With Germany Over Western Sahara," https://www.moroccoworldnews.com/2021/05/342672/morocco-blocks-green-hydrogen-deal-with-germany-over-western-sahara

[40] European council of foreign relations (January 2021), *Power Surge: How The European Green Deal Can Succeed in Morocco and Tunisia*, United Kingdom: European Council of Foreign Relations, pp.10-12

Wrap-up

A keyword to express the future of African nations is "Leapfrog." 46% of Africa's population still has no household access to electricity. Per-capita GDP is low and many countries are still suffering from poverty. Moreover, legal systems, power grids, and other such infrastructure remain inadequate. However, abundant potential is fueling the steady implementation of renewables, which makes high growth likely to continue in the future. This distinctive position could enable these countries to leapfrog away from the large-scale, centralized power production models that have been standard practice, and away from economic and energy poverty. While situations differ among European countries, southern European countries like Spain and Portugal are blessed with solar PV and wind power resources that give Europe as a whole greater renewables potential than Japan. Decarbonizing industry, for which electrification is problematic, will be essential for Europe to achieve its 2050 carbon neutrality goal. Hydrogen will play an important role in this. However, because hydrogen produced in Europe will be insufficient to satisfy total European demand, Germany and Portugal are taking steady and strategic steps that include forming economic partnerships with Morocco and other northern African nations to carry out specific projects. Although country risk for African nations is unfortunately not insignificant, these nations could become an arena for trying out advanced technologies related to hydrogen and ammonia that have been developed by European companies. What Japanese companies need to do is keep a close watch from their European business sites, scrutinize individual business risk and return, and seek to acquire knowledge concerning advanced technologies. With this goal in mind, they will have to form partnerships with European companies and weigh participation in hydrogen and ammonia production projects based on project merits. At the same time, taking cues from international cooperative efforts between Europe and African nations, the Japanese government is likely to utilize G2G to provide even more robust support for forging international cooperative frameworks with Australia, Chile and Middle Eastern nations that are targeting Japan as a consumer of hydrogen and ammonia.

Gas Decarbonization and Energy System Integration
- Situation in Europe and Implications for Japan -

Yoshiaki Shibata* Akiko Sasakawa** Takahiro Nagata**

Summary

This report presents an overview of efforts underway in Europe toward gas decarbonization and energy system integration (sector coupling) and describes the challenges and possibilities of these measures through comparison with the efforts and discussions underway in Japan.

Europe and Japan have major differences in their networks and regulatory systems, but are also similar in that both have scarce resources of biogas and their options for gas decarbonization are limited to hydrogen and hydrogen-sourced carbon neutral (CN) methane. The challenge for both parties boil down to one issue: how to obtain hydrogen and CN methane and inject them into the gas network. Europe is planning to increase the hydrogen blending ratio in existing gas networks in stages, with a view to repurposing the gas networks for 100% hydrogen and building new hydrogen infrastructure in the process. Meanwhile, Japan's main approach is to blend CN methane into city gas, and has set a policy course of reducing the standard CV to 40 MJ/m^3, close to that of methane.

Gas decarbonization requires significant amounts of hydrogen and CN methane, which Japan may need to purchase from other countries. However, it is also important to pursue the concept of energy system integration, in which the gas network, inclusive of Power to Gas (PtG) and cogeneration, is used to address output fluctuations associated with the mass introduction of domestic VRE to build a decarbonized society, while also decarbonizing the gas itself by including VRE in the process. This is because existing electric power networks alone will not be able to cope with the enormous amounts of VRE that will need to be introduced. New measures such as strengthening inter-regional transmission lines and battery cells will be necessary but these may not be sufficient. Meanwhile, existing gas networks are already equipped with an energy storage capability and flexibility owing to the physical characteristics of the gas; incorporating Power to Gas into the networks will allow these functions to be used to mitigate VRE output fluctuations. In other words, the gas network is inherently highly compatible with VRE. Needless to say, it will be necessary to evaluate and determine what kinds of measures will be economically efficient for dealing with the mass introduction of VRE, but based on the above, utilizing well-established existing gas networks is an option worth considering. Europe is making progress with discussions on energy system integration, and has begun specific discussions on revisiting the definition of energy storage technology and on providing grid balancing capability using water electrolysis. Thus, Europe is addressing gas decarbonization and energy system integration as an integrated whole, as shown in the figure below.

Energy system integration is also valuable from the perspective of resilience. From the efficiency perspective, it is preferable to use VRE-sourced hydrogen from PtG and CN methane for producing heat. However, by using water electrolysis and CHP to ease VRE output fluctuations and stored hydrogen and CN methane for emergencies, the overall resilience of the energy system will be enhanced. In this case, it may be possible to further optimize energy system operations if electricity and gas networks can be operated in a coordinated manner.

Meanwhile, as energy system integration involves both electricity and gas, various regulation-related issues must be resolved to achieve it, such as the definition of energy storage and the use of grid balancing capacity. Before this can be done, it is necessary to determine how much flexibility the entire gas network has, including gas holders and the line pack of pipelines.

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** Senior Researcher, New and Renewable Energy Group, Electric Power Industry & New and Renewable Energy Unit, IEEJ

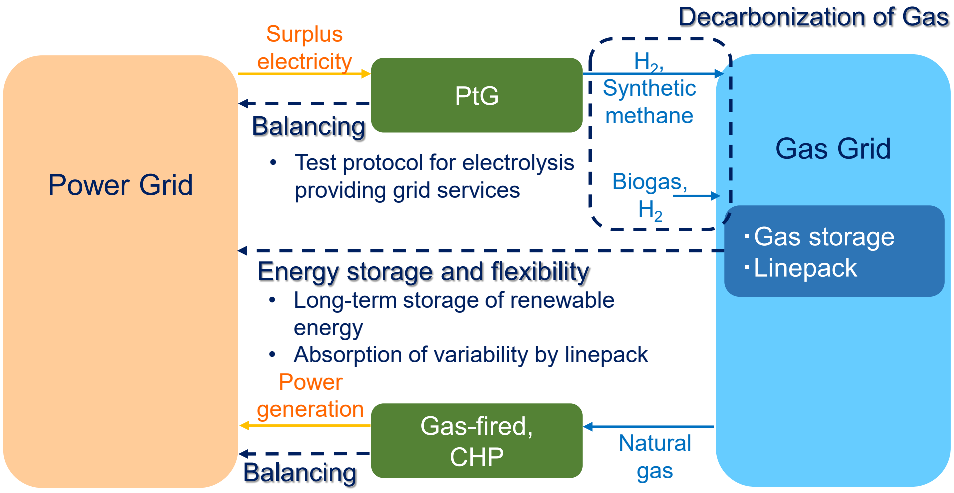

Fig. 1 Decarbonization of Gas and Energy System Integration in Europe

Introduction

Efforts to build a decarbonized economy by 2050 are accelerating in and outside Japan. While electricity is being decarbonized mainly by introducing renewable energy, the only technology for decarbonizing gas with a long experience so far is biogas, but the amount is limited. In Japan, discussions on gas decarbonization gained momentum in FY2020[1] and the gas industry is seeing the declaration of a series of carbon neutrality goals. The most promising decarbonization options are hydrogen and hydrogen-based synthetic methane (carbon neutral (CN) methane), with particularly high expectations for CN methane, as demonstrated by the launch of a "Public-private Council for Promoting Methanation". This is because CN methane, produced from hydrogen and CO_2, facilitates the use of hydrogen in the existing infrastructure for city gas, whose main component is methane; the CO_2 re-emitted when burning CN methane is offset with the CO_2 that has been sequestrated, and thus using CN methane is synonymous with using hydrogen[2].

Europe is also accelerating efforts toward gas decarbonization. Europe, like Japan, positions hydrogen and CN methane as key fuels, but characteristically places higher emphasis on hydrogen. Further, along with gas decarbonization, Europe is accelerating efforts toward Energy System Integration, aiming to decarbonize the entire energy system by incorporating variable renewable energy (VRE) effectively into the gas network. This is done by using the functions as energy storage and flexibility inherently equipped with the existing gas network infrastructure.

This report outlines the efforts toward gas decarbonization in Europe in Chapter 1. Chapter 2 maps out the correlation between Japan's calorific value regulation for gas and its gas decarbonization efforts. Chapter 3 examines Europe's efforts toward energy system integration, focusing on the role of gas networks. Based on the above, Chapter 4 presents implications to the role that the gas industry can play in Japan's decarbonization efforts.

1. Overview of Europe's Efforts toward Gas Decarbonization

Amid growing expectations for CN methane, which can be used in existing city gas infrastructure, as a means of gas decarbonization, Europe is also working on blending more hydrogen into its city gas infrastructure. Why is Europe pursuing hydrogen blending when it is clear—based on the composition of city gas—that CN methane is more suitable than hydrogen? To understand the objectives and the background of this move, the following sections discuss Europe's efforts on the blending of hydrogen and CN methane into city gas currently underway, referring to documents released by the European Commission and Europe's gas industry.

[1] Study Group on the Future of the Gas Business toward 2050, Ministry of Economy, Trade and Industry.
[2] Shibata, Otsuki, "*Essay on sources of carbon in recycled carbon fuels (1) – (4)*," IEEJ, May 2021.

1-1. Hydrogen blending

1-1-1. European Commission

(1) "Hydrogen Strategy"

Europe is working on the wider adoption of green hydrogen generated primarily from solar PV and wind power as one of the initiatives to achieve its 2050 carbon neutrality target. In July 2020, it released "A hydrogen strategy for a climate-neutral Europe", setting a roadmap for introducing electrolyzers for producing hydrogen and upgrading infrastructure to increase hydrogen to 13–14% of the EU's energy mix by 2050.[3] The strategy stresses that the large-scale, rapid spread of green hydrogen use would lead to the EU reducing its GHG emissions by 50–55% by 2030 in a cost-efficient way.

Based on this strategy, blending limited percentages of hydrogen into the existing natural gas network is considered to be an efficient way of using green hydrogen in the local network during the transition period. However, the strategy also expresses the concern that blending changes the quality of the gas and may affect the design of gas infrastructure, end-user applications, and cross-border system interoperability. It goes on to point out that blending risks fragmenting the internal market if neighboring member states accept different levels of blending and cross-border flows are hindered.

To mitigate this possibility, the technical feasibility of adjusting the quality and cost of handling the differences in gas quality need to be assessed.[4] Moreover, reinforcement of instruments may be needed to secure cross-border coordination and system interoperability to avoid impeding the flow of gas across member states.

(2) "Strategy for Energy System Integration"

On the same day as the hydrogen strategy, the European Commission released "An EU Strategy for Energy System Integration". This strategy charts a path towards decarbonization across all sectors of the EU. In addition to decarbonization efforts in the electricity, gas, heat, and transport sectors, its key objective is energy system integration, through which the entire energy system is decarbonized by integrating electricity with other sectors and utilizing renewable energy among them.

The Strategy also points out that green hydrogen will allow the integration of large amounts of VRE in sectors such as maritime transport, heavy-duty road and rail transport, steel, oil refining, and chemicals, where decarbonization by electrification is currently difficult technically. Since even a fully integrated energy system cannot completely eliminate CO_2 emissions from all parts of the economy, the strategy stresses the importance of utilizing carbon capture and storage (CCS), as well as the need to use synthetic fuels, produced by combining CO_2 and green hydrogen, in hard-to-decarbonize sectors.

For hydrogen blending, the strategy suggests that a blend of 5–20% by volume can be tolerated by most systems without the need for major infrastructure upgrades or other measures. However, the possible need for dedicated infrastructure for large-scale storage and transportation of pure hydrogen is also mentioned.

1-1-2. European gas industry

(1) Initiatives and scenarios for gas sector decarbonization

In April 2020, 10 gas companies and two biomethane associations from eight European countries including Italy, Belgium, Germany, and the Netherlands launched the European Hydrogen Backbone initiative, and released "Gas Decarbonisation Pathways 2020-2050", a report setting out the initiatives and pathways for decarbonizing the gas sector by 2050.[5]

The report points out that the policies outlined in the Clean Energy Package released by the European Commission in November 2016 and the European Green Deal in December 2019 are not sufficient and do not provide incentives for pursuing timely and cost-efficient decarbonization in the gas sector, and proposed four policy recommendations for more

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[3] See European Commission, "A hydrogen strategy for a climate-neutral Europe," COM(2020)301 final.
[4] *Ibid.*
[5] Parties involved in creating this report: 10 gas companies namely Enagás, Energinet, Fluxys Belgium, Gasunie, GRTgaz, ONTRAS, OGE, Snam, Swedegas, and Teréga, and two biomethane associations namely EBA and Consorzio Italiano Biogas.

rapid decarbonization of the sector.[6] First, adopt the EU regulatory framework to make gas infrastructure future-proof in an integrated energy system. Second, stimulate the production of biomethane and hydrogen by a binding mandate for 10% gas from renewable sources by 2030. Third, foster cross-border trade of hydrogen and biomethane by a Guarantee of Origin system, and clarify market rules for green and blue hydrogen including for hydrogen transport. Fourth, incentivize demand for hydrogen and biomethane by strengthening the EU Emissions Trading System (ETS) combined with targeted and time-bound Contracts for Difference.

The "Accelerated Decarbonisation Pathway", released in tandem with these initiatives, forecasts the 2050 supply and demand of gas to be as shown in Fig. 2. According to this scenario, between 2020 and 2030, the total gas demand will decrease as energy efficiency improves and electrification expands, while the share of renewable gases including biomethane will increase by around 10%. From 2030, gas supply will increase slightly as more blue hydrogen (fossil fuels + CCS) and synthetic fuels are produced, but gas demand will decrease again between 2040 and 2050, and total gas demand will be covered by renewable gas or low-carbon gas from 2050. Notably in this scenario, the natural gas supply is expected to tend to decline while green hydrogen will grow significantly in 2030 and beyond.

Under this scenario, which anticipates the growth of green hydrogen, hydrogen blending is considered to be an effective temporary solution for boosting hydrogen production and facilitating CO_2 emission reductions during the 2020s. A blend of 5–20% is considered to be technically feasible with minimal investment using existing gas networks. However, the actual feasibility of blending depends on the hydrogen tolerance of individual end-user appliances, based on the combustion characteristics of the blends. The scenario suggests that to move to higher blending percentages, changes need to be made to end-user appliances (such as burners) as well as the existing gas networks. While these points need to be considered, using green hydrogen locally and regionally by blending in gas distribution grids may be an effective temporary solution between 2020 and 2030.

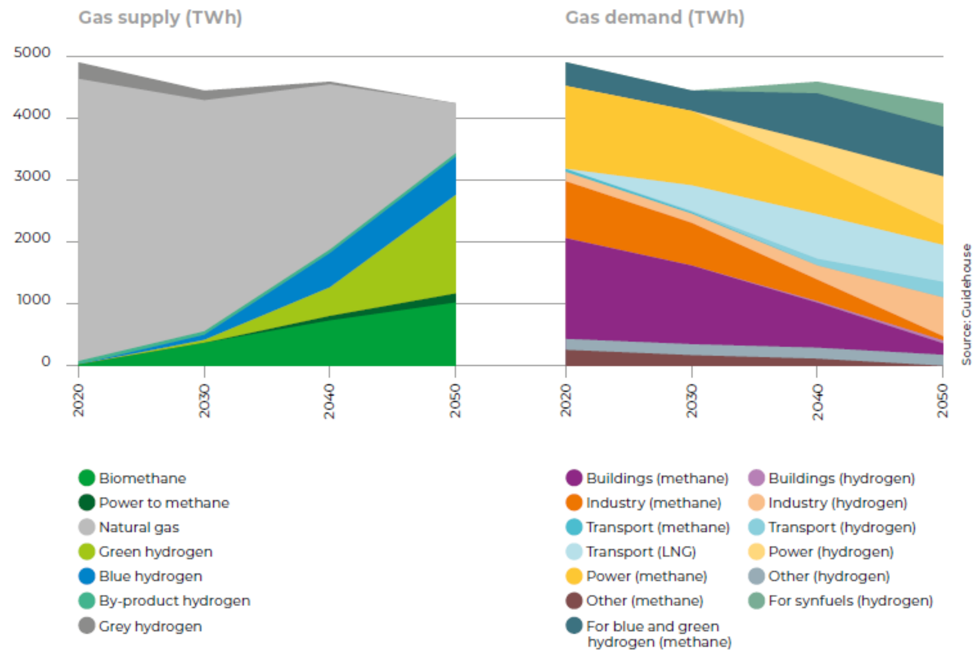

Fig. 2 Forecast for gas supply (left) and demand (right) (Accelerated Decarbonisation Pathway scenario)

Source: excerpted from Gas for Climate, "Gas Decarbonisation Pathways 2020-2050," April 2020, p.11

[6] Gas for Climate, "Gas Decarbonisation Pathways 2020-2050," April 2020, p.II.

(2) Infrastructure upgrade for hydrogen blending

The existing gas infrastructure is not sufficient for supporting the amount of hydrogen considered necessary for achieving carbon neutrality by 2050. First, dedicated hydrogen infrastructure needs to be built on a member state and regional level, and then on a Europe-wide level in the future.[7] Under the vision of the European Network of Transmission System Operators for Gas (ETNSO-G), a regulatory framework for this purpose will be established by 2024, the regions with particular demand for hydrogen will be identified and a network connecting those regions will start to be built by 2030, and EU-wide hydrogen infrastructure will be put in place by 2050. This pan-EU hydrogen infrastructure is planned to be 22,900 km in total length, with 75% coming from improving existing infrastructure and the remaining 25% by laying new hydrogen pipelines.[8]

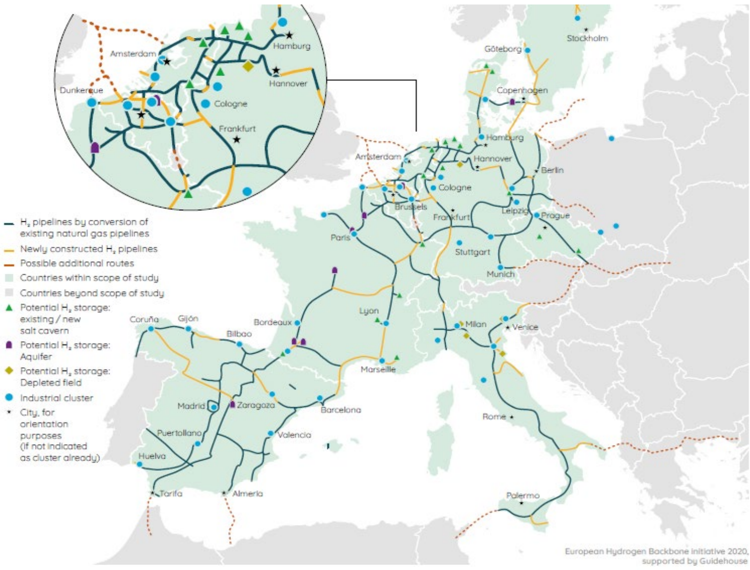

Fig. 3 Hydrogen pipelines envisaged for 2040

Source: Excerpted from Enagás, Energinet, Fluxys Belgium, Gasunie, GRTgaz, NET4GAS, OGE, ONTRAS, Snam, Swedegas, Terega, "European Hydrogen Backbone," July 2020, p.8

According to "ENTSOG 2050 Roadmap: Action Plan" published by ENTSO-G in October 2020, dedicated hydrogen infrastructure will be developed under the framework of the Ten-Year Network Development Plans (TYNDPs), which are being formulated at both the member state and EU levels.[9] The development will take into consideration interlinkage with the electricity sector, in line with the European Commission's EU Strategy for Energy System Integration. On the agenda of ENTSO-G's Action Plan is digitalized system design for the smooth handling of gas quality, to identify localized consumer needs for blending and aligning uses across the EU.

1-1-3. Major European countries

Let's now turn to major European countries. While many countries limit hydrogen blending in natural gas networks to 2%, some countries allow higher percentages, namely Germany with up to 10% (provided that no CNG charging stations are connected to the infrastructure), France 6%, Spain 5%, and Austria 4%[10]. The following sections outline the hydrogen blending efforts in Germany and France, which allow particularly high blending percentages.

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[7] Gas for Climate (2020), *op.cit.*
[8] Enagás, Energinet, Fluxys Belgium, Gasunie, GRTgaz, NET4GAS, OGE, ONTRAS, Snam, Swedegas, Teréga, "European Hydrogen Backbone," July 2020.
[9] ENTSOG, "2050 Roadmap: Action Plan."
[10] See IEA, "The future of Hydrogen: Seizing today's opportunities," June 2019, p.73.

(1) Status of hydrogen blending in Germany

In Germany, where there are still no domestic laws or regulations on hydrogen blending in natural gas networks, the percentage of hydrogen that can be blended is determined based on a test of the performance of major equipment in the gas transmission, distribution, storage, and end-user legs. Specifically, percentages of up to 2% are allowed for systems that have CNG charger stations connected, up to 0.2% for those without calibrated hydrogen measurement systems installed, and up to 10% for others.[11] According to German gas company MARCOGAZ, the allowable level of hydrogen blending in gas networks must be verified case-by-case and also depends on the quality of natural gas and licensing by the municipalities concerned.[12]

In Germany, which is the global frontrunner of Power to Gas (PtG) with many companies conducting PtG demonstration experiments, the installed capacity of electrolyzers has increased to nearly 600 MW according to the PtG plans released up to the end of 2019. In June 2020, the German government formulated the National Hydrogen Strategy and announced plans to expand the electrolyzer capacity to 5 GW and supply 350,000 tonnes (14 TWh) of green hydrogen by 2030. It has also set the target of increasing the electrolyzer capacity to 10 GW by 2040.

Under these targets, one of the hydrogen production demonstration projects in full swing is the Reallabor Westküste 100 project.[13] This project is demonstrating hydrogen production using the renewable electricity produced by offshore wind plants off the west coast of Schleswig-Holstein, the northernmost state of Germany, to reduce carbon emissions from the industrial and transport sectors, as well as the storage of hydrogen. Ten companies including Stadtwerke Heide (public corporation for electricity, gas, water, and heat), EDF Deutschland (energy company), OGE (electricity transmission company), Ørsted Deutschland (wind power operator), and Raffinerie Heide (petroleum refiner) have formed a cross-sector partnership and are participating in the project, to create a new cycle of resources across different industries using existing industrial infrastructure in the state. The project is scheduled to install 30 MW of electrolyzers within five years from the start of the project, and following operational and maintenance tests, expand it to up to 700 MW in the future. The green hydrogen produced in this project will be sent via a dedicated hydrogen pipeline to Heide public company, where it will be injected into the natural gas network. Blending of up to 20% is considered possible, and the goal is to supply 100% hydrogen by 2050.

(2) Status of hydrogen blending in France

In France, nine gas companies jointly analyzed the technical and economic requirements for hydrogen blending based on the government's hydrogen deployment plan for energy transition formulated in June 2018, and released a report titled "Technical and Economic Conditions for Injecting Hydrogen into Natural Gas Networks" in June 2019. The report states that while case-by-case verifications are necessary, up to 6% of hydrogen can be injected into the networks based on the current gas-related equipment specifications. Hydrogen blending of up to 10% is expected to be possible by 2030 with the progress in equipment performance as well as in research and development, but injecting 20% or higher would require significant investments and therefore any decision must be carefully considered in view of its rationality.[14]

The French government announced its national hydrogen strategy in September 2020 and has set the goal of installing 6.5 GW of electrolyzers and producing 600,000 tonnes of green hydrogen a year by 2030. Regional municipalities are also actively engaged in deploying hydrogen. For example, the Jupiter 1000 project, in which hydrogen is produced using solar PV and wind power, is being conducted in Fos-sur-mer, a community in the Provence-Alpes-Côte d'Azur region in southern France.[15] The project is attracting attention both in and outside the country as the first demonstration project that connects with France's live gas networks. A consortium of nine companies including GRTgaz (gas company), Rte (transmission

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11 MARCOGAZ, "ENTSO-G Workshop on Principles for EU Gas Quality, Handling of Hydrogen and CO2 Transportation" 29 April 2020.
12 *Ibid.*
13 For Reallabor Westküste 100 project, see Westküste 100 website (https://www.westkueste100.de/en/).
14 See GRTgaz, GRDF, Teréga, Storengy France, Géométhane, Elengy, Réseau GDS, Régaz-Bordeaux, SPEGNN, "Technical and economic conditions for injecting hydrogen into natural gas networks" June 2019.
15 For Jupiter 1000 project, see Jupiter 1000 project website (https://www.jupiter1000.eu/single-post/2017/11/14/ladaptation-du-r%C3%A9seau-en-action).

system operator), and CNZ (renewable electricity producer) are involved in the project and conducting demonstration experiments using two different types of electrolysis systems (both 0.5 MW): one produces renewable hydrogen and injects it directly into the gas network, while the other converts the produced renewable hydrogen into CN methane by methanation before injecting it into the network. For both methods, a section of the natural gas pipeline was diverted and connected to the electrolyzers, and it was possible to inject hydrogen and CN methane into it.

1-2. CN methane blending

CN methane can be injected into the existing natural gas infrastructure without any major barriers. Therefore, expectations are rising for the technology as a means to decarbonize city gas without incurring additional costs such as for precise verification of the required blending ratio and compatibility with equipment, or for preparation of new infrastructure, unlike hydrogen. However, it is a very expensive option because of the enormous costs required, particularly for supplying CO_2 and installing methanation equipment, posing a major challenge.[16]

Furthermore, the European Commission has pointed out that for synthetic methane to be recognized as completely carbon neutral methane (CN methane), the CO_2 must be sourced from biomass or the atmosphere.[17] The Commission has also stated that it is important to accurately measure the amount of carbon emitted during the production of synthetic methane by employing a system for appropriately monitoring and reporting the CO_2 emissions.[18] It also stresses the importance of creating incentives for including synthetic fuels in the market by introducing the carbon removal certification mechanism, a mechanism to guarantee the traceability of CO_2 advocated by the Circular Economy Action Plan.[19]

As described above, Europe tends to require decarbonization of not only synthetic methane itself but also the CO_2 used to produce it. This makes it necessary to consider the carbon intensity of the entire value chain, including the origin of the CO_2, when using synthetic methane. Nevertheless, there are high expectations for synthetic methane as the fuel is synthesized from renewable hydrogen and CO_2 and can be used for hard-to-decarbonize sectors, such as ships, railway, chemicals, steel, and oil refining, thereby widening the range of sectors that can be decarbonized, as well as having further scope for cost reduction. Based on such expectations, an EU gas industry report[20] predicts that synthetic methane produced from carbon-neutral hydrogen will be adopted widely in 2030–2050, and will be injected into the gas networks from 2040 as its production increases.

1-3. Wrap-up of gas decarbonization in Europe

As described above, in Europe, there are rising expectations for CN methane, which can be used in existing city gas infrastructure, as a means for decarbonizing city gas. Meanwhile, efforts are also underway to increase hydrogen blending in the city's gas infrastructure. Europe currently considers that hydrogen blending of 5–20% is possible without incurring additional investment costs or infrastructure development, and is therefore effective for expanding hydrogen supply to a certain level. Various efforts are already underway in Germany, France, and other countries. Meanwhile, some of the challenges of hydrogen blending include the decrease in energy intensity of the resulting gas mixture and possible adverse effects on facility operations and products caused by fluctuations in blending ratios.

Despite the current limitations on the blending ratio, the reason why Europe is proceeding with hydrogen blending is that it is seen as a useful and efficient way of deploying large amounts of green hydrogen and integrating it into the energy system in the early phase (the 2020s) as they work to accelerate the use of green hydrogen aiming to reach carbon neutrality by 2050. Hydrogen blending is also considered effective for creating an additional role for the gas sector in reaching carbon

[16] See IRENA, "Hydrogen: A renewable energy perspective," September 2019.
[17] See November 2018, "Vision for a long-term EU strategy for reducing greenhouse gas emissions" and July 2020 "Energy System Integration Strategy."
[18] See European Commission, "Powering a climate-neutral economy: An EU Strategy for Energy System Integration," COM(2020)299 final.
[19] *Ibid.*
[20] See Gas for Climate, "Gas Decarbonisation Pathways 2020-2050," April 2020, p.40.

neutrality, helping to prevent existing gas infrastructure from becoming stranded assets as natural gas demand is expected to decline in the future.

Key points for increasing hydrogen blending going forward include dealing with differences in gas quality, cost adjustment, formulating initiatives for reducing the risk of investments necessary for expanding blending, adjusting the different blending ratio regulations among countries, and securing cross-border system interoperability. To back these efforts, a framework for incentivizing gas companies to use green hydrogen will need to be set up. For CN methane, it is also necessary to conduct demonstration projects to support technological development and thereby reduce costs.

2. Japan's Calorific Value Regulation for Gas and Its Relevance to Gas Decarbonization

As with Europe, decarbonization of gas is a challenge for Japan as the country strives to reach carbon neutrality by 2050. The Study Group on the Future of the Gas Business toward 2050[21] established by the Ministry of Economy, Trade and Industry (METI) in FY2020 has clarified the role of gas and the efforts required, including enhancing resilience and the business base, as well as decarbonization. For decarbonization, the importance of methanation and hydrogen was emphasized. Accordingly, METI launched the Public-private Council to Promote Methanation in June 2021, and public-private efforts for solving technical, economic, and institutional challenges centered on methanation have just started.

Meanwhile, the Working Group to Study the Gas Business ("the Gas Business WG") launched in 2018 (under the Basic Policy Subcommittee on Electricity and Gas of the Electricity and Gas Industry Committee, Advisory Committee for Natural Resources and Energy) has been considering system reforms to create a more competitive gas market based on the outcome of the full-scale liberalization of the gas retail business in April 2017, and the calorific value (CV) regulation for gas was part of the scope.

This chapter examines the relationship between Japan's gas CV regulation and the moves toward gas decarbonization.

2-1. Overview of discussions on the CV regulation

(1) Background to the discussions

Japan's city gas is supplied under the "standard CV regulation," which sets a standard CV per unit volume of gas (the minimum monthly arithmetic mean) and limits fluctuations in the CV for the gas supplied. The standard CV regulation ensures that the gas supply has a certain CV, thereby ensuring the safety and efficiency of combustion appliances and user benefits such as fair fees, which in turn has helped expand and enhance the use of gas. As the CVs of LNG imported to Japan vary depending on its origin, the CV must be adjusted to meet the standard CV by mixing LPG into LNG in a CV adjustment plant during production. Gas companies that do not have such plants must either obtain one or outsource gas production to other companies, raising, as some point out, an entry barrier for the gas retail business.

Meanwhile, as the global carbon neutrality movement accelerates, there is growing attention on the injection of CN methane and hydrogen into gas pipelines as a way of decarbonizing city gas. As these gases have smaller CVs than city gas, the Gas Business WG has been considering revising the current CV regulation. The following section outlines the discussions at the Gas Business WG and summarizes the possibility of blending CN methane and hydrogen (injection into gas pipelines).

The recent discussions on the CV regulation commenced with the launch of the Gas Business WG (September 2018), as one of the challenges in spurring competition through the full liberalization of the gas retail business. The decision was made to conduct reviews based on the following:

1) A study on the possible impact of the transition to the band-based CV regulation on the safety and performance of gas equipment, and the measures to be taken for combustion equipment that will be affected
2) A survey on the actual situation of the band-based CV regulation in other countries

[21] https://www.meti.go.jp/shingikai/energy_environment/2050_gas_jigyo/index.html.

Thereafter, the impact of CV fluctuations was studied for a wide range of gas equipment including gas engines, industrial furnaces, air conditioners, household and commercial-grade burners, and fuel cells. The results are shown in Table 1.

Table 1 Impact of CV fluctuations on gas equipment

			Performance			Safety			Product Quality ＊1		
			43-45MJ/m^3	42-46MJ/m^3	40-46MJ/m^3	43-45MJ/m^3	42-46MJ/m^3	40-46MJ/m^3	43-45MJ/m^3	42-46MJ/m^3	40-46MJ/m^3
			±2%	±5%	±7%	±2%	±5%	±7%	±2%	±5%	±7%
Gas engine [200-9000kW]			▲	×	×	▲	×	×	▲	×	×
Industrial Furnace	Industrial Furnace (General)	Industrial combustion furnace (general)	▲	▲	▲	▲	▲	▲	▲	▲	▲
		Steel/Cupper heating furnace/RT burne	▲	▲	▲	▲	▲	▲	▲	▲	▲
		Ceramic heating furnace ＊2	▲	▲	▲	▲	▲	×	▲	▲	×
	Atmospheric gas generator		▲	▲	▲	▲	▲	▲	▲	×	×
	Glass melting furnace		×	×	×	×	×	×	×	×	×
Air conditioner		Absorption chiller/heater	×	×	×	▲	×	×	×	×	×
		GHP	▲	×	×	▲	×	×	▲	×	×
Commercial combustion equipment		Range	▲	▲	×	○＊3	○＊3	▲	▲	▲	×
		Rice cooker	▲	▲	××	○＊3	○＊3	○＊3	▲	×	××
		Continuous Rice Cooker	▲	×	×	○＊3	○＊3	○＊3	▲	×	×
		Noodle boiler	▲	▲	×	○＊3	○＊3	○＊3	▲	▲	×
		Steam convection oven	▲	▲	×	○＊3	○＊3	○＊3	▲	▲	×
		Small pottery furnace	▲	▲	×	○＊3	○＊3	○＊3	▲	▲	×
		Large continuous pottery furnace	▲	▲	×	○＊3	○＊3	○＊3	▲	×	×
Residential combustion equipment		Stove	○	▲	××	○	○	▲	○	▲	××
		Rice cooker/ Gas oven	○	○	▲	○	○	○	○	○	▲
		Water heater	○	▲	××	○	▲	××	○	▲	××
		Gas air condition	○	▲	×	○	○	○	○	▲	×
		Clothes dryer	○	▲	×	○	○	○	○	▲	×
Fuel cell		Residential/Commercial/Industrial	▲	××	××	○＊4	○＊4	○＊4	▲	××	××
		○：No impact ▲：Possible impact ×：Impact (Hearing results) ××：Impact (Actual device verification results)									

＊1: For industrial furnaces and commercial combustion equipment, products manufactured using the relevant products. For air conditioners, etc., the air to be controlled.
＊2: Except for glass furnaces
＊3: Only equipment that has been developed to comply with standards such as JIS S2103, which is a standard for household use, such as products certified by a third party.
＊4: The system is designed to automatically shut down before it reaches an unsafe state, so it was rated "no impact". (Operation cannot be continued and the original function cannot be performed.)
＊5: The gas appliances listed in the table are examples of major combustion appliances that are considered to have a significant impact on safety and performance, and do not cover all gas appliances used in Japan.
＊6: The ratings represent the majority of ratings for each device, and some devices may have different ratings.
Source: Report on the impact of the band-based CV regulation on equipment (December 25, 2019, Agency for Natural Resources and Energy), p.5

An interim report issued subsequently (at the 13th Gas Business WG on July 10, 2020) concluded as follows: "The impact of the transition to the band-based CV regulation on combustion equipment was studied and necessary modification costs were estimated. A comparison between options, namely a lower standard CV and four CV bands of different widths, indicated that wider bands cause greater increases in costs compared to their effects."

The actual situation of the band-based CV regulation has been studied in South Korea, Europe, and the United States, focusing on the charging method and installation of calorimeters. The interim report stated that: "The survey of the situation in various countries indicated that there is a difference in natural gas procurement method and the status of gas networks between Japan and Europe, which adopts the band-based CV regulation, and that measures are also being taken in Europe to ensure a stable CV for some consumers."

Thereafter, the charging method, the issue of who will bear the modification costs, and the timeline leading up to implementation were studied for three options: reduction of the current standard CV (44 MJ/m^3, etc.) and the narrower bandwidths of 44–46 MJ/m^3 and 43–45 MJ/m^3. As shown in Table 2, the modification costs were at least 10 times higher for the band-based CV than the reduction of standard CV. Also, setting a transition period of at least 20 years, rather than 10 years, was shown to significantly decrease the modification costs for appliances.

Table 2 Effects and necessary costs
(reduction of standard CV: 44 MJ/m^3, CV bands: 44–46 MJ/m^3, 43–45 MJ/m^3)

			Befor transition					After transition					
			Initial cost					Effect [year]	Mainenance cost [year]				Total [year]
			Equipment countermeasure	Manufacturing facilities, etc.	Calorimeters, etc.	Publicity	Total	LPG cost reduction	Equipment	Heat reduction material	Calorimeters, etc.	Manufacturing facilities, etc.	
Time to transition: 10 years	Standard Heat Value	Reduction (4.4MJ/m3)	4,605 (2,880)	67	0	39	**4,711 (2,986)**	-17	0	0.027	0	9	**-8**
	Heat Band	4.4-4.6 MJ/m3	86,761 (84,511)	1,117	971	112	**88,961 (86,710)**	-17	38	0	42	166	**229**
		4.3-4.5 MJ/m3	86,758 (84,508)	1,229	971	112	**89,070 (86,819)**	-42	38	0.0013	42	177	**215**
Time to transition: 20 years	Standard Heat Value	Reduction (4.4MJ/m3)	104 (295)	67	0	39	**211 (401)**	-17	0	0.027	0	9	**-8**
	Heat Band	4.4-4.6 MJ/m3	5,139	1,117	971	112	**7,339**	-17	52	0	42	166	**243**
		4.3-4.5 MJ/m3	5,142	1,229	971	112	**7,454**	-42	52	0.0013	42	177	**229**
Time to transition: 30 years	Standard Heat Value	Reduction (4.4MJ/m3)	103 (295)	67	0	39	**209 (401)**	-17	0	0.027	0	9	**-8**
	Heat Band	4.4-4.6 MJ/m3	2,104	1,117	971	112	**4,304**	-17	57	0	42	166	**248**
		4.3-4.5 MJ/m3	2,108	1,229	971	112	**4,420**	-42	57	0.0013	42	177	**234**

Note: Due to rounding, the total value of each item does not match the value in the total column.
Note: In the case of standard heat value reduction and heat band (4.3-4.5MJ/m^3), it may be necessary to install heat reduction equipment, but the cost of installation has not been recorded.
Note: No qualitative effects are recorded.
Source: Study on the band-based CV regulation (February 16, 2021, Agency for Natural Resources and Energy), p.14

(2) Conclusions of the study on the band-based CV regulation

In addition to the study above, in March 2021, the Gas Business WG issued its "Conclusions of the Study on the Calorific Value Band,"[22] anticipating the injection of CN methane (with a CV of 40 MJ/m^3) into the city gas network, which is regarded as an effective gas decarbonization method. The key points are as follows.

- A reduced standard CV is more appropriate for the new CV regulation than the band-based CV regulation.
- The transition period should be 15–20 years.
- At this point, the rational option would be to reduce the standard CV to 40 MJ/m^3.
- The reduction of the standard CV shall be scheduled for 2045–2050. The most appropriate new CV regulation shall be finalized in 2030 after prior testing.

2-2. Discussion on the calorific value regulation and the decarbonization of gas

(1) Conclusions of the study on the band-based CV regulation

The discussions on the calorific value regulation concluded that the reduction of the standard CV should be adopted, rather than the band, with a transition period of 15–20 years, as a means to reduce and eliminate carbon emissions from city gas in the future using CN methane and to achieve CV transition at the lowest cost.

For electricity, there is essentially no difference between the electricity generated from renewable, nuclear and other zero-emission sources and that generated from fossil fuels, and mixing them to reduce carbon emissions causes no problem. The situation is quite different for gas: when supplying gas with different CVs and compositions, modifications at the user end will be essential.

City gas was initially produced by gasifying coal and petroleum, contained hydrogen and CO_2 as well as methane, and was supplied as a gas with a lower CV than the current one. It then became possible to import the current gas of mostly methane in the form of LNG and thus supply gas with a higher CV. This change of CV was carried out over several years

[22] See URL for the conclusions of the study on the CV band by the Working Group to Study the Gas Business, Basic Policy Subcommittee on Electricity and Gas, Electricity and Gas Industry Committee, Advisory Committee for Natural Resources and Energy. https://www.meti.go.jp/shingikai/enecho/denryoku_gas/denryoku_gas/gas_jigyo_wg/20210407_report.html.

by adjusting the appliances of each consumer one by one. A similar process will be necessary when changing the CV. Therefore, the Gas Business WG's conclusion that the shift to the final CV should be conducted in one step after carefully studying the necessary changes in equipment specifications is rational to make the shift economically.

(2) Possibility of supplying hydrogen (hydrogen blending) in Japan

Efforts to utilize hydrogen are gaining momentum in Europe as described in Chapter 1, and discussions on hydrogen utilization and hydrogen blending are gathering momentum in Japan as well.

CN methane production involves both energy and costs for producing synthetic methane from hydrogen and CO_2, as well as for producing green hydrogen. In fact, there is no need to use CN methane if hydrogen can be used directly, but using hydrogen involves the following problems.

1) Developing and distributing hydrogen-ready equipment: The combustion characteristics of hydrogen differ significantly from the current city gas of mostly methane, and it is therefore essential to develop equipment that is compatible with hydrogen combustion. Turbines ready for the combustion of hydrogen and ammonia with conventional fuels and their eventual dedicated combustion are already being developed in the power sector, but to further spread the use of hydrogen, equipment that can burn hydrogen and policies to expand its use in non-power sectors are required.
2) Hydrogen supply (hydrogen blending): Before LNG was adopted in 1969, city gas contained hydrogen, and so it is considered that existing gas pipelines are capable of supplying gas containing a certain amount of hydrogen. However, as described earlier, changes in the CV and composition of gas will require adjustment of end-user appliances and therefore, raising the hydrogen content in stages is not considered realistic either from the safety or cost perspective. Meanwhile, supplying pure hydrogen would require the development and spread of equipment compatible with the gas, as described earlier, as well as designing pipelines that can avoid hydrogen embrittlement[23] and are fit for carrying gases with a smaller molecular weight. One possible reason why Europe is keener to supply hydrogen than Japan is the difference in the status of the pipeline network. Europe has a higher pipeline coverage ratio than Japan[24], which gives the region better access to lands suitable for renewable energies, the sources of green hydrogen.

As for the utilization and supply of CN methane through methanation, while it will be necessary to adjust gas appliances to cope with the change in CV, etc., the effort will be minor compared to developing and spreading hydrogen-ready appliances. Further, the supply itself is expected to require very little additional modification.

There is a regional hydrogen project currently underway in Fukushima prefecture. It is important to spread the use of hydrogen on a regional basis through projects such as this and to introduce more hydrogen in large facilities in the power and other sectors, in order to draw up a multi-path energy transition plan for decarbonizing gas.

3. The Role of Gas Networks in the European Energy System Integration

In addition to the approaches toward decarbonizing gas summarized in Chapter 1, Europe is also working to utilize the inherent functions of the gas network to decarbonize the overall energy system. These efforts are based on concepts called Energy System Integration or Sector Coupling, in which gas networks are used as a source of the additional flexibility essential for the power grid to accommodate large amounts of variable renewable energy (VRE) as a means to decarbonize the energy system, while also decarbonizing the gas itself.

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23 Embrittlement of metal resulting from absorption of hydrogen molecules by the metal.

24 Committee to Study the Technical Challenges for Installing Gas Pipelines for the current situation of natural gas infrastructure and natural gas pipelines on highways (first), August 2016.

3-1. Increasing the flexibility of the energy system using the gas network

Energy system integration is the concept[25] of increasing the flexibility of the entire energy system by coupling the electricity network with other sectors and networks (sector coupling), thereby enabling the mass introduction of VRE. Among the various sectors and networks, the gas network, which is well-established,[26] is regarded as a promising candidate in Europe. There are various options for energy system integration, such as utilizing VRE in the transport sector in EVs and using VRE to meet the heat demand that has shifted from gas to electricity. However, Europe's gas network is expected to be a highly promising means for accepting VRE through PtG as its coverage is as broad and dense as the electricity network and it can also store energy, giving it sufficient flexibility.

(1) Accommodating VRE by the gas network

An increase in VRE capacity gives rise to excess VRE electricity that the grid cannot accept. This excess electricity could be used in the gas network by converting it into hydrogen or CN methane through PtG, which has been considered for some time. Japan, for example, has a relatively large demand for city gas of roughly half that for electricity,[27] which makes the infrastructure highly promising for accepting hydrogen and CN methane sourced from VRE.

One study[28] indicated that the seasonal storage of VRE in the gas network through PtG would enhance flexibility. Another research[29] presented the possibility that VRE could be incorporated more efficiently into the energy system by the integrated operation of gas-fired power, which is increasingly in demand as a grid balancing capacity to cope with the growth of VRE capacity, with the electricity network, and utilizing the gas storage facilities of the gas network.

As suggested above, the source of the additional flexibility is the large gas demand itself and the inherent energy storage capability of the gas network. In particular, the energy storage facilities of the gas network, which are typically underground storage facilities and gas holders such as depleted gas fields and salt caverns, exist in abundance in Europe.[30] These energy storage facilities can provide flexibility by absorbing VRE fluctuations of relatively long cycles.

(2) Flexibility provided by the linepack of gas pipelines

Another possible source of additional flexibility is the linepack of gas pipelines for relatively short cycle flexibility. The linepack is the volume of gas that mainly high-pressure gas pipelines[31] can hold or are holding.[32] In this report, the former is referred to as linepack capacity and the latter as linepack. As gas takes longer to travel from the supply location to the demand location than electricity, a certain amount of gas, or linepack, must be held inside the pipelines to respond to sudden fluctuations in gas demand. The higher the gas pressure, the larger the linepack capacity. The amount of linepack changes with time. The linepack capacity is charged (and the linepack increases) typically during nighttime when gas demand is low; the linepack starts to decrease as gas demand increases in the morning and daytime, creating a margin (buffer) in linepack capacity. By season, the buffer in linepack capacity is greater in wintertime when gas demand is high than during summertime. As the linepack capacity of a gas pipeline is designed to be able to respond to seasonal and time-of-day fluctuations in gas demand, it has flexibility to respond to fluctuations.

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[25] Shibata, "*Potential of Power to Gas in Japan*," IEEJ Energy Journal, Volume 42, Issue 1 (March 2016).
[26] IEA "World Energy Outlook" 2019.
[27] Shibata, "*Renewable energy storage using hydrogen*," The Japan Institute of Energy Journal "enerumikusu," 100, 161–167 (2021).
[28] Stephen Clegg, Pierluigi Mancarella, "Storing renewables in the gas network: modelling of power-to-gas seasonal storage flexibility in low-carbon power systems," IET Generation, Transmission & Distribution, 2016, Vol. 10, Iss. 3, pp. 566–575
[29] Hossein Ameli, Meysam Qadrdan, Goran Strbac, "Value of gas network infrastructure flexibility in supporting cost effective operation of power systems," Applied Energy 202 (2017) 571–580.
[30] Shibata, "*Potential of Power to Gas in Japan*," IEEJ Energy Journal, Volume 42, Issue 1 (March 2016).
[31] "FLEXIBILITY IN THE ENERGY TRANSITION, A Toolbox for Gas DSOs", CEDEC, eurogas, GEOED, February 2018
[32] "Flexibility in Great Britain's gas networks: analysis of linepack and linepack flexibility using hourly data", UK Energy Research Centre, May 2019

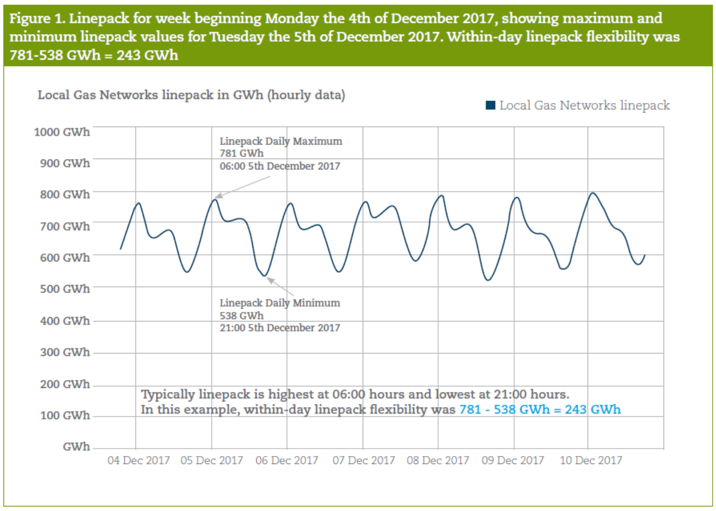

Fig. 4 Change in linepack in Britain's gas distribution network (one-week sample from December)

Source: "Flexibility in Great Britain's gas networks: analysis of linepack and linepack flexibility using hourly data," UK Energy Research Centre, May 2019

Fig. 4 presents the linepack in Britain's gas distribution network for one week in December based on hourly data. The linepack is charged to the maximum (reducing the linepack capacity to the minimum) every morning (around 6:00) to meet the day's gas demand, and declines to the lowest level at nighttime (around 21:00) when the day's highest space heating demand is reached (the linepack capacity reaching the day's highest level). The difference between the highest and lowest levels of linepack is used as the benchmark for the linepack flexibility of the gas pipeline.

The electric power system maintains a stable frequency and voltage by keeping the electricity supply and demand in balance on an hourly basis using the inertia and grid balancing capability provided by synchronous generators. While supply and demand match on an hourly basis, transmission lines have no such ability to keep supply and demand in balance.[33] Meanwhile, in a gas system, in which the supply and demand of gas are connected via pipelines that provide a buffer (i.e., the inertia of the gaseous material generated by a change in pressure or flow rate), supply (production and charge) and demand (discharge) are not in balance on an hourly basis[34] (Fig. 5 and 6); when demand arises, the linepack inside the pipeline is pushed out first to reach the place of demand, rather than the gas supply source reacting immediately. There is no need to keep supply and demand in balance on an hourly basis, and a balance on a daily (within-day) basis would suffice.[35, 36] In other words, a gas pipeline is able to balance the supply and demand automatically; its ability to decouple fluctuations in demand from those of supply to a certain extent is one of its characteristics.

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[33] Note that synchronous stability becomes lower with longer transmission line connecting supply and demand.

[34] The discussions on the full liberalization of gas retail conducted at Japan's Gas Systems Reform Subcommittee (ended in FY2016) considered reforms to the hourly balancing system of gas (which requires gas suppliers to keep the discrepancy between the charge and discharge of gas within 10% every hour). As a result, the load curve supply system, in which the gas charging patterns of new gas retailers are aligned with the charging pattern of the entire gas network concerned, was introduced. The "time-based balancing system" is a system concept; physically, the supply (production, charging) and demand (discharge) for gas are not in balance on an hourly basis (supply and balance match every hour).

[35] "Flexibility in Great Britain's gas networks: analysis of linepack and linepack flexibility using hourly data," UK Energy Research Centre, May 2019.

[36] "FLEXIBILITY IN THE ENERGY TRANSITION, A Toolbox for Gas DSOs," CEDEC, eurogas, GEOED, February 2018.

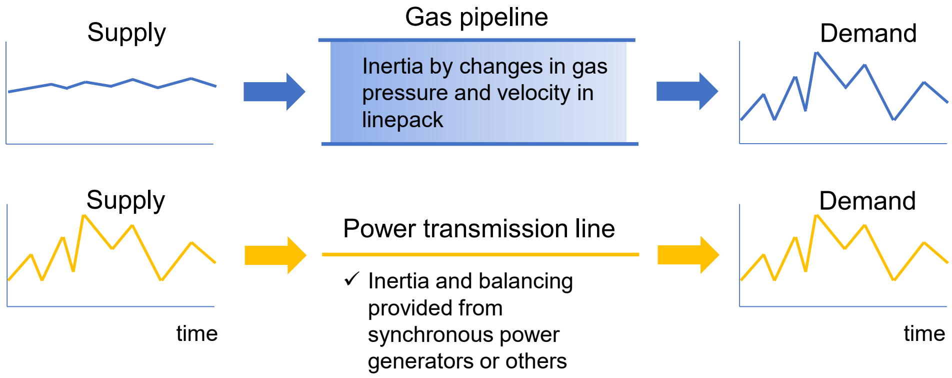

Fig. 5 Difference in Balancing of Supply and Demand between Gas and Power Sector

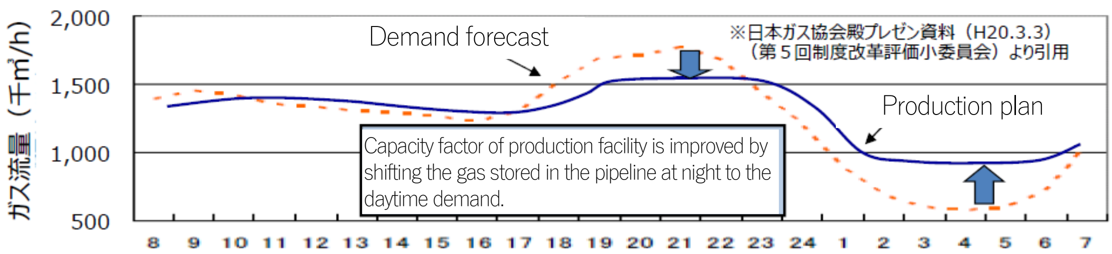

Fig. 6 Sample of Hourly Profile of Gas Demand and Production in Japan

Source: 25th Gas Systems Reform Subcommittee meeting, Material 4,
"*Detailed system design for the full-scale liberalization of retail business*," November 10, 2015

Fig. 7 presents how linepack decouples the fluctuations in gas supply and gas demand. These are sample results from a simulation of gas consumption and gas supply patterns of gas-fired power, which will be required as a grid balancing capacity upon mass introduction of wind power (it is assumed that the gas network and the power network are connected via gas-fired power). "MISOCP" and "MILP" represent the optimum operation result with linepack considered; "No linepack" is the result without linepack. Whereas gas consumption and supply follow more or less the same for the "No linepack" case (see figure (f) in the bottom row), in "MISOCP" and "MILP," in which gas was charged and discharged as linepack (see figures (a) and (b) in the bottom row), we can see that gas supply remains more or less level while gas consumption fluctuates (see figures (d) and (e) in the bottom row).

The above analysis examined energy system integration between the gas and electricity networks by way of gas-fired power. However, it also indicates that gas pipelines have "inherent linepack flexibility of the (gas) grid"[37] that helps maintain the supply-demand balance. Some consider that linepack should be incorporated as a factor when evaluating energy system integration in which the gas produced by PtG is used in the gas network.[38]

[37] Christopher J. Quarton, Sheila Samsatli, "Power-to-gas for injection into the gas grid: What can we learn from real-life projects, economic assessments and systems modelling?," Renewable and Sustainable Energy Reviews 98 (2018) 302–316.
[38] *Ibid.*

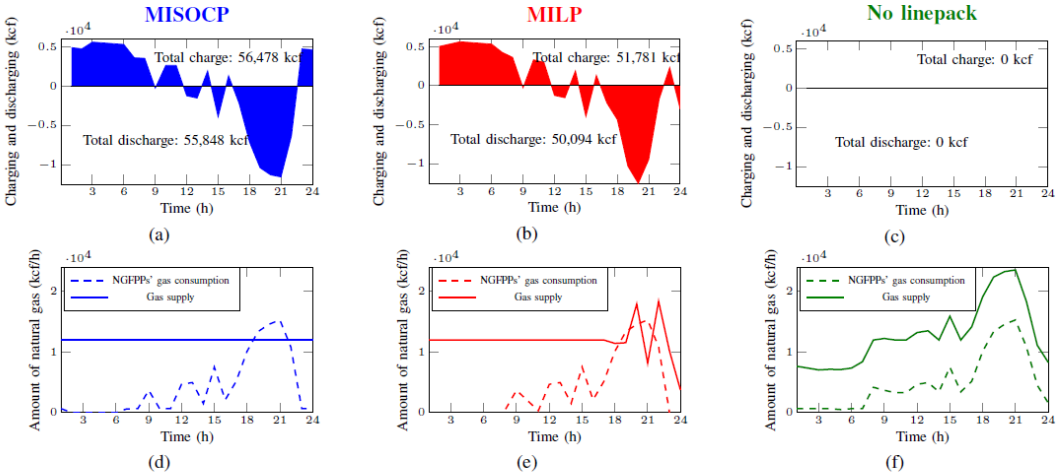

Fig. 7 Gas consumption and supply patterns of balancing gas-fired power with and without linepack

Source: Schwele, Anna; Ordoudis, Christos; Kazempour, Jalal; Pinson, Pierre, "Coordination of Power and Natural Gas Systems: Convexification Approaches for Linepack Modeling," Proceedings of IEEE PES PowerTech 2019

Note: MISCOP: Mixed-Integer Second-Order Cone Program; MILP: Mixed-Integer Linear Program. The simulation represents 50% wind penetration.

An analysis has been conducted on the economic efficiency and CO_2 emission reduction effect of injecting VRE-sourced hydrogen and CN methane into city gas through PtG considering the energy storage capacity of a gas pipeline in Japan,[39] in which a simulation was conducted assuming, for simplification, that the gas pipeline is an energy storage facility similar to a gas holder, and that VRE-sourced gas is stored and discharged instantaneously (i.e., city gas supply and demand are in balance hourly). However, for a more precise evaluation of the grid balancing capability of the linepack's storage capability, a fluid dynamic analysis that considers the pressure and flow rate of the gas is required.[40]

3-2. Providing grid services through water electrolysis

Water electrolysis is a necessary piece in the production of hydrogen (and CN methane), playing a key role in decarbonizing gas, and various analyses have been conducted on the possibility of providing grid services, such as grid balancing, using water electrolysis as a means for demand response (DR).[41] This is an idea for reducing costs across the entire hydrogen production process by producing hydrogen through water electrolysis while at the same time receiving compensation by providing grid services. In addition to reducing the cost of hydrogen production by raising revenues from grid services, it also helps secure the additional power grid flexibility required for the mass introduction of VRE.

In recent years, efforts for socially implementing this idea have been taking shape in Europe. An EU project named QualyGridS,[42,43] launched in 2017 (under the FCH2 JU (Fuel Cell and Hydrogen 2 Joint Undertaking framework)) (Fig. 8), has been formulating the test protocol for water electrolysis in order to establish the standard technical requirements for offering water electrolysis as a grid service, and in June 2020, a draft proposal was drawn up.[44] Discussions are also underway at ISO/TC 197 (hydrogen technologies) to set international standards for test protocols and performance evaluation.[45]

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[39] Shibata, Nagata, "*Economic efficiency analysis for injection of hydrogen and carbon neutral methane into existing gas networks*," 37th Conference on Energy, Economy, and Environment, January 2021.
[40] Jing Liu, Wei Sun and Jinghao Yan, "Effect of P2G on Flexibility in Integrated Power-Natural Gas-Heating Energy Systems with Gas Storage," Energies 2021, 14, 196.
[41] Shibata, "*Power to Gas business model based on timelines: providing balancing capacity, multi-purpose use, contribution to making renewables a main power source,*" August 2018, IEEJ.
[42] https://www.qualygrids.eu/
[43] Shi You et al. "Facilitating water electrolysers for electricity-grid services in Europe through establishing standardized testing protocols," Clean Energy, 2020, Vol. 4, No. 4, 379–388.
[44] "Qualifying tests of electrolysers for grid services, Finalized testing protocol," QualyGridS.
[45] ISO/AWI TR 22734-2 - Hydrogen generators using water electrolysis — Part 2: Testing guidance for performing electricity grid service.

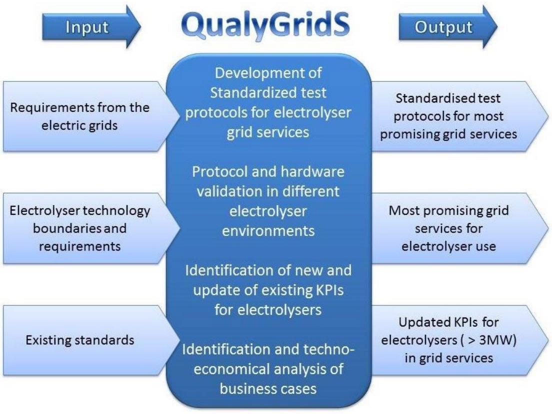

Fig. 8 Overview of QualyGridS

Source: https://www.qualygrids.eu/

As shown in Table 3, water electrolysis is technically compatible with many of the grid services purchased by TSO and DSO of Europe, and combining hydrogen production and grid services is considered extremely rational also from the standpoint of reducing hydrogen production costs. Accordingly, demonstration experiments such as HyBalance[46] and Demo4Grid[47] are being conducted with the support of FCH2 JU.

[46] http://hybalance.eu/.

[47] https://www.demo4grid.eu/.

Table 3　Possibility of providing grid services from water electrolysis

Service requester	Service name	Requirements identified by most service requesters	Justification	WE potential
TSO	FCR	Capacity ≥1MW, activation time ≤30s, duration ≥15 min, high ramping requirement, auto symmetrical and dynamic response.	Service designed for generator, normally requires very rapid auto symmetrical dynamic response. In UK, the required activation time for a new service so-called enhanced frequency control is less than 1s. Technically, WEs can meet the requirements if they are designed for such purpose, e.g. running the WEs at 50% load in order to meet the requirements on identical up/down regulation.	Medium
	aFRR	Capacity ≥ 1MW, activation time (second to 15 min) slower than FCR, duration ≥15 min, ramping requirement, auto/remote-controlled symmetrical/asymmetrical dynamic response.	Requires less critical dynamic characteristics than FCR, but higher capacity and longer duration. Technically viable for MW class WEs, provided some technical improvements are made. Use an aggregation-based portfolio to provide such service is feasible. The market might be dominated by generators and large loads.	High
	mFRR	Capacity ≥ several MW, activation ≤15, min duration ≥15 min (up to hours), no ramping requirement, manual controlled messaged-based asymmetrical dynamic/non-dynamic response.	Requires less critical dynamic characteristics than aFRR, but higher capacity and longer duration. Technically viable for MW class WEs, provided some technical improvements are made. Use an aggregation-based portfolio to provide such service is feasible. The market might be dominated by generators and large loads.	High
	RR	Capacity ≥ several MW, activation from 15min to hours, duration ≥15 min (up to hours), no ramping requirement, manual controlled messaged-based asymmetrical static response.	Requires slower response than mFRR, but can be higher capacity and longer duration. Technically viable for electrolysis.	High
	DSR	Requirements are case dependent, can to large extent resemble FCR, aFRR, mFRR and RR.	Tailored for demand to provide TSO services. For countries like UK, DSR is started to be used to provide different kinds of balancing services.	Very high
	Congestion management	Requirements can to certain degree resemble RR. Capacity requirement is normally high.	The remuneration scheme is usually not clear due to the service is very location dependent. This implies only a few large-case WEs sited in designated locations can provide this service.	Medium
	Capacity management	Requirements can to certain degree resemble RR. May also need storage-alike abilities for load shifting etc.	Normally acquired through TSO tailored DSR.	Medium
	Voltage control	Requires WEs to offer reactive power support.	Location dependent. Normally offered by designated large scale units. Remuneration scheme is not clear.	Low
DSO	Congestion management	Requirements can to certain degree resemble RR, but the capacity required will be much lower (e.g. tens of kWs to several MW) and location dependent.	Normally implemented through DSO tailored DSR, are relevant for both MW scale and kW scale WEs.	High
	Capacity management	Requirements can to certain degree resemble RR. May also need storage-alike abilities for load shifting etc.	Normally acquired through DSO tailored DSR.	High
	Voltage control	Requires location dependent WEs to offer reactive power support.	Can be relevant for WEs in microgrids, may require improved ability of grid inverters and the associated control logic.	Medium
	PQ	Location-based service, requirements depend on the specific criteria of PQ service, such as unbalance, voltage management etc.	For WEs, this may require improved ability of grid inverters and the associated control logic. It is possible that the grid operators include the PQ requirements in grid codes, so it is an obligation for WEs to meet the corresponding PQ requirements.	Low
BRP, P2P and other service requesters	Self-balancing	Depends on the requester's portfolio, SCADA and EMS systems etc. Requirements on the dynamic characteristics can be comparable to aFRR, mFRR, and RR when services are about self-balancing. Energy trading oriented energy management will need to consider characters related to unit commitment (e.g. capacity, start/stop time, must on/off duration) and optimal dispatch (e.g. the ability of being modulated).	Notable examples of using WEs to avoid wind curtailment, to improve the portfolio performance (e.g. an integrated wind-hydrogen system) exist. Today, this is one of the major applications for using WEs to support renewable integration.	Very high
	Portfolio optimization			
	Energy trading			

Source: Deliverable Report - Electrical Grid Service Catalogue for Water Electrolyser (D1.1), QualyGridS

4. Implications for Japan

Along with gas decarbonizing using hydrogen and CN methane, Europe is working on using the inherent energy storage capability and flexibility of existing gas networks to ease fluctuations in VRE. In other words, Europe is handling the electric power network and the gas network as components of a comprehensive energy system, and is aiming for a VRE-centered decarbonized society, as shown in Fig. 9. This concept is the embodiment of energy system integration itself.

The following sections discuss the challenges and possibilities for Japan in using the gas network for gas decarbonization and mass introduction of VRE, respectively, based on the suggestions taken from the developments in Europe.

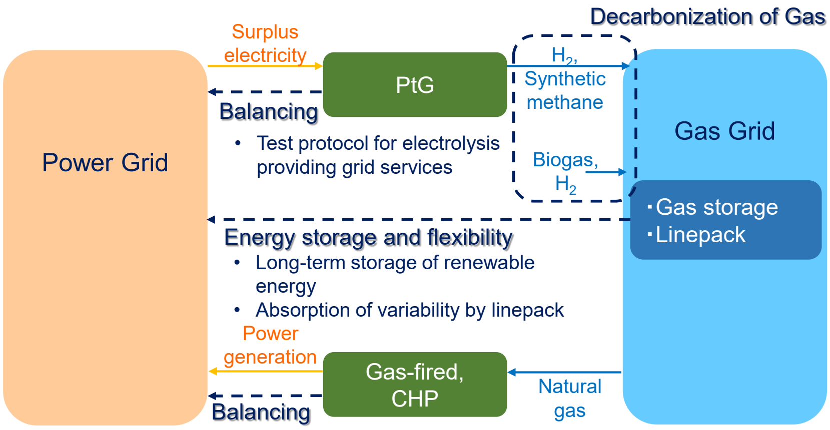

Fig. 9 Concept of Energy System Integration in Europe

4-1. Decarbonization of gas: Injection of hydrogen and CN methane in city gas

It would seem that the main method for approaching the decarbonization of gas is hydrogen in Europe and CN methane in Japan. Needless to say, the amount of hydrogen and CN methane that will be necessary to replace the entire present demand for gas is vast and sourcing them will take a long time. Therefore, the more common approach is to inject hydrogen and CN methane in small amounts step wisely into the present gas infrastructure. In fact, as shown by France's plan (see 1-1-3), Europe envisions increasing the hydrogen blending ratio each year, aiming to repurpose the existing gas infrastructure for hydrogen and build new infrastructure for 100% hydrogen in the process. However, there are various issues regarding blending hydrogen into gas as described in Chapter 2; Europe fully recognizes these barriers and challenges but apparently plans to proceed by trial and error and revise plans as issues arise. Since the amount of VRE-sourced hydrogen that can be produced changes depending on the VRE capacity, measures must be taken to adapt to the change in the hydrogen blending ratio each year. Responding to time-based fluctuations and regional differences is also a challenge. As described later, it is necessary to verify the extent to which the flexibility of the gas network can be used in energy system integration for coping with these fluctuations.

Meanwhile, Japan is primarily aiming to blend CN methane into city gas, which poses fewer technical barriers regarding blending. Furthermore, the standard CV of the CV regulation system is set to be reduced to 40 MJ/m^3, a value that is close to the CV of methane (see Chapter 2), which also makes the injection of methane easier. However, CN methane has a disadvantage; it is more costly to produce than hydrogen because its production involves the process of separation and capture of CO_2 and methanation in addition to hydrogen production. While the Public-private Council for Promoting Methanation is focusing more on importing CN methane than producing it domestically, regarding this point, it must be noted that CN methane will not help diversify sources of energy import and improve energy security as the existing LNG infrastructure is anticipated to be used. Furthermore, as CN methane generates emissions again when used, the ownership of those emissions will complicate the system design.[48] In particular, imported CN methane will involve the formulation of bilateral rules and international authorization. Designing these institutional systems will be a lengthy process.

[48] Shibata, Otsuki, "*Essay on sources of carbon in recycled carbon fuels (1) – (4)*," IEEJ, May 2021.

Fig. 10 presents an option that could allow Japan to circumvent both the challenges concerning injecting increasing amounts of hydrogen into the gas network, and the risks associated with the economic efficiency and system design of CN methane. Currently, Japan is supplying imported LNG into the city gas infrastructure and it is the consumers who generate CO_2 emissions; this process can be transformed as shown in Step 1, in which LNG is reformed near LNG terminals to produce hydrogen, which is then supplied to a 100% hydrogen infrastructure built separately. With Step 1, CO_2 will be emitted in the reforming process and consumers will be using gray hydrogen, meaning that this process is basically unchanged from the current process as CO_2 will still be emitted—just at a different place. The next step is importing carbon-neutral LNG (Step 2), which is already underway, and then finally, importing hydrogen in the future (Step 3). By preparing 100% hydrogen infrastructure from the beginning rather than decarbonizing the gas, it will be possible to fully decarbonize in the future just by changing which fuel to import. Furthermore, the key point of this option is that it allows renewable-sourced hydrogen (green hydrogen) made in Japan to be injected into the 100% hydrogen infrastructure without any barriers. Currently, hydrogen, which has a significantly different CV and combustion characteristics, is a "foreign substance" for city gas and is difficult to mix, but blending hydrogen with hydrogen will cause no issues: it will solve all kinds of issues associated with "blending" different gases. Also, the separation and capture of CO_2 and methanation, which are necessary for producing CN methane, will no longer be necessary.

Needless to say, it is not easy for any region to prepare 100% hydrogen infrastructure. Converting city gas infrastructure into hydrogen infrastructure in large cities involves numerous challenges as well as time and costs. Therefore, it is worth considering introducing this scheme within a limited area, in regions that have a high energy demand density and where building new hydrogen infrastructure is likely to be fairly easy (such as in industrial regions). However, if some consumers in the industrial region need fossil fuel-sourced carbon for special industrial purposes (such as carburizing metals and super-high-temperature heating furnaces), individual responses such as on-site LPG treatment may be necessary.

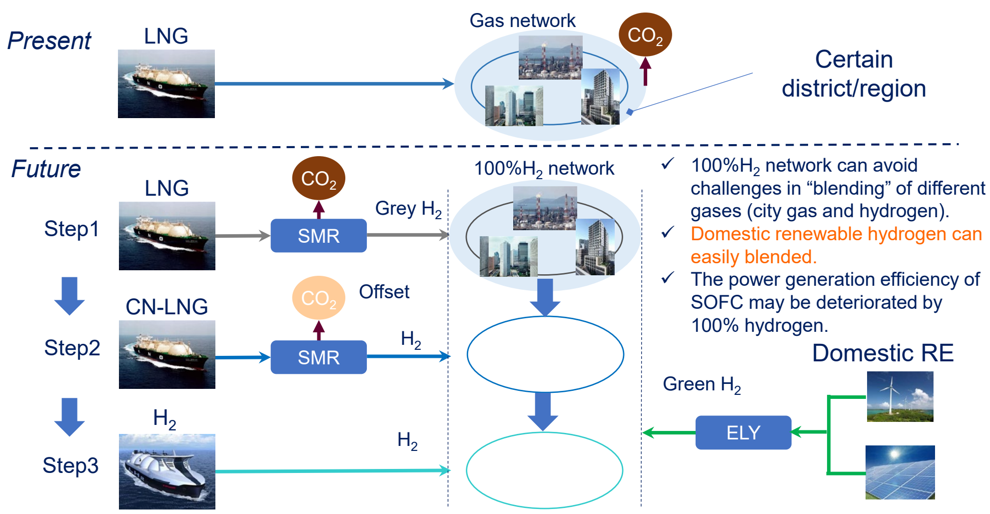

Fig. 10 Advantages of building 100% hydrogen infrastructure first

Source: Shibata, "Significance and challenges of new fuels – various forms of hydrogen use –"; Japan Society of Energy and Resources, Research Committee on "Energy Supply and Demand for Japan toward 2050,", FY2020 Second Symposium (Tenth ESI Symposium), February 4, 2021

4-2. Possibilities and challenges of energy system integration

Europe is pursuing an energy system integration in which electric power and gas networks are handled as components of an integrated whole. This approach suggests that Europe aims to use the flexibility of the gas network, such as energy storage, for expanding VRE capacity, while simultaneously decarbonizing the gas itself. In 2018, ENTSO-E and ENTSO-

G jointly announced[49] plans to work together toward energy system integration through PtG, and a significant number of demonstration experiments[50] are underway.

(1) Need for designing new systems: energy storage by PtG, etc.

However, energy system integration through PtG, though technically possible, involves regulatory issues. In February 2021, the European Union Agency for the Cooperation of Energy Regulators (ACER) and the Council of European Energy Regulators (CEER) proposed a basic policy in response to the European Commission's EU Strategy for Energy System Integration (see 1-1-1) released in July 2020, in which they summarized the challenges of energy system integration by PtG from the legal system perspective.[51] The proposal recommends that, as energy system integration through PtG covers both the electricity and gas domains, it is necessary to first revisit the definitions of the functions and roles of PtG and competing technologies, while observing the EU's principle of technological neutrality and the selection of technology in a competitive market. In particular, the function and role of energy storage require attention. A PtG plant in itself is not an energy storage facility, though it does contribute to energy storage when including downstream facilities, and therefore, the proposal suggests an amendment of the definition of energy storage set forth in the 2019 Electricity Directive[52] ('energy storage' means, in the electricity system, deferring the final use of electricity to a moment later than when it was generated, (…), and the subsequent reconversion of such energy into electrical energy or use as another energy carrier). It goes on to suggest that when defining PtG as an energy storage facility, it is necessary to distinguish between a PtG facility that is connected only to an electricity network (such as for on-site water electrolysis to cover the hydrogen demand for a plant) or to both the electricity and gas networks. A PtG installation would be considered as an electricity user in the former case. However, as for the latter, it would be considered as an integrating element between the gas and electricity sectors that enables operation of the energy system "as a whole," as formulated in the European Commission's Energy System Integration Strategy.

Regarding energy storage, the regulatory design for leased transmission fees would be an issue. According to a study,[53] many European countries waiver or give preferential treatment to leased transmission fees for energy storage technologies. However, for PtG, the interpretation of its energy storage function is complex because the gas produced by PtG is used in non-electric sectors such as city gas and transport. In revisiting the definition of energy storage, including PtG, it must be taken into account that the concept of energy system integration treats electricity and gas as an integrated whole.

As described above, the main issue of energy system integration is how to handle PtG's energy storage function. Other issues include the handling of the flexibility and grid balancing capability inherent to the gas network described in Chapter 3, as well as determining which functions can and cannot be shared between the electricity and gas networks. It may be necessary to integrate parts of the regulatory design of electricity and gas, which is currently conducted separately.

(2) Exploration of energy system integration in view of economic efficiency and other benefits

Economic efficiency is a vital factor in considering the design of energy system integration. As an example, compare converting the hydrogen produced by PtG back into electricity versus a battery cell. The former has a roundtrip efficiency of just less than 50% (80% for water electrolysis × a generation efficiency of 60% for fuel cells) whereas the latter has an efficiency of 80% (90% for charging × 90% for discharging), making the former far more inefficient; using the hydrogen produced by water electrolysis for power generation is clearly irrational. Therefore, when evaluating fuel cell generation,[54]

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49 Power to Gas – A Sector Coupling Perspective, ENTSO-E – ENTSOG Joint Paper, October 2018

50 "*Production of hydrogen from renewables: ideal form of Power to Gas*," Aichi Prefecture "Hydrogen Energy Society Formation Study Group, FY2019, second seminar," November 28, 2019.

51 Regulatory Treatment of Power-to-Gas "European Green Deal" Regulatory White Paper series (paper #2) relevant to the European Commission's Hydrogen and Energy System Integration Strategies, 11 February 2021.

52 DIRECTIVES DIRECTIVE (EU) 2019/944 OF THE EUROPEAN PARLIAMENT AND OF THE COUNCIL of 5 June 2019 on common rules for the internal market for electricity and amending Directive 2012/27/EU.

53 Shibata, "*Power to Gas business model based on timelines: providing balancing capacity, multi-purpose use, contribution to making renewables a main power source*," August 2018, IEEJ.

54 Kawakami, "*The Value of Energy Storage in the Decarbonized Energy System: An Energy System Optimization Approach Considering Non-*

its advantages such as the use of waste heat, distribution of energy sources, and resilience must be taken into account; likewise, for hydrogen gas turbine generation, the inertia of synchronous generators must be considered.[55]

We must also remember that the basic aim of energy system integration by PtG is to use the VRE-sourced hydrogen produced by water electrolysis for non-electricity sectors and purposes. However, it is necessary to compare the economic efficiency of energy system integration by PtG, such as injecting VRE-sourced hydrogen and CN methane into existing gas networks to meet the heat demand of the residential and commercial sector, with that of using VRE electricity directly to meet heat demand. The former has an efficiency of about 70% (80% for water electrolysis × 90% for water heaters) and the latter 90–300% (from electric water heaters to heat pump hot-water suppliers), making the former decisively more inefficient.

As described, energy system integration through PtG offers little benefit if we look only at energy and economic efficiency. This makes it important to explore how to create value from the energy storage function and flexibility of "well-established (IEA)" existing gas networks, such as using them to ease fluctuations associated with the mass introduction of VRE, as described in Chapter3, and to design a regulatory system for implementing this concept.[56] However, for this to be done, it is necessary to technically evaluate the flexibility of gas holders, storages in underground caverns in some regions (in Niigata, etc. in Japan), and linepacks of pipelines, which is a challenge.

Resilience is another important perspective. The additional resilience of the entire energy system obtained by operating electric and gas networks as an integrated whole has been presented as a benefit of energy system integration at the Study Group on the Future of the Gas Business toward 2050.

(3) Short-term perspective: Supply-demand grid balancing by water electrolysis

Evaluating the additional flexibility and resilience provided by gas networks involves numerous tasks including preparing necessary data and establishing analysis systems, and will take a long time when including the subsequent regulatory system design process. Therefore, in the short term it is important to discuss how to utilize water electrolysis, which is the core technology of PtG, as a supply-demand balancer of electricity (see Chapter 3). In Japan, NEDO is conducting demonstration projects in this area. The idea of using gas cogeneration (CHP) as a source of the grid balancing capability necessary for mass introduction of VRE is already underway primarily in the gas industry, but efforts should also be launched as soon as possible on using water electrolysis for supply-demand balancing as well. Providing grid balancing capability through demand response using water electrolysis will generate profits, which in turn will help reduce the cost of hydrogen production.[57]

(4) Other points to note

- Value of excess renewable electricity

As described above, using water electrolysis for supply-demand balancing requires grid electricity supplies, and as such, the CO_2 emission coefficient of the hydrogen produced will be determined by the power generation mix. There is no issue if the power source is sufficiently decarbonized, but to produce hydrogen with a low CO_2 emission coefficient, the ideal source would be excess VRE electricity. In particular, from the standpoint of energy system integration, it would be rational to use VRE preferentially for electricity, and to supply any excess VRE-sourced electricity to the gas network. Here, the price of excess electricity is crucial. It is often thought that excess electricity is inexpensive because when it arises, wholesale electricity prices are zero or negative, and therefore, excess electricity can greatly reduce the cost of hydrogen production.

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synchronous Power Generation Constraints," Transactions of the Institute of Electrical Engineers of Japan. B (a publication of the Power and Energy Society), IEEJ Transactions on Power and Energy, Vol. 141 No. 5 pp. 326–335.

55 Shibata, "*The form of Power to Gas necessary for reaching carbon neutrality in 2050,"* Japan Society of Energy and Resources FY2021 Third Energy Policy Roundtable, "*Expectations for and Challenges of Power to Gas and Hydrogen Carriers toward Carbon Neutrality*," September 17, 2021.

56 Shibata, "*Renewable energy storage using hydrogen*," The Japan Institute of Energy Journal "enerumikusu," 100, 161–167 (2021).

57 Shibata, "*Power to Gas business model based on timelines: providing balancing capacity, multi-purpose use, contribution to making renewables a main power source*," August 2018, IEEJ.

However, excess electricity is inexpensive only for small water electrolyzers with no impact on the electricity supply-demand balance; when electrolyzer capacities increase, so does the demand for electricity at times when excess electricity is generated, pushing up wholesale electricity prices as a result.

In other words, producing hydrogen from excess electricity creates a demand for excess electricity, and at that moment the electricity is no longer an "excess" and its price increases. Therefore, it is impossible to secure excess electricity inexpensively for producing hydrogen in amounts large enough to decarbonize gas; in conclusion, it will be necessary to significantly reduce the generation cost of VREs themselves to improve economic efficiency.

- Additionality of renewable energy

The reason for mentioning above that the use of excess electricity is ideal for hydrogen production concerns additionality.[58] The meaning of additionality here is that when producing hydrogen from renewable energy, it must be produced from a renewable energy supply introduced additionally. If the renewable energy that is already in operation for decarbonizing electricity is diverted to hydrogen production, other power sources must be installed to cover the decrease in output, which would be irrational. To avoid this, Germany and others have been working on formulating relevant standards since around 2017.[59] As it is difficult to set a precise standard, the standard is based on the number of years a renewable energy plant has been in operation.

Meanwhile, since excess electricity is something that the electricity grid cannot use and will be discarded, the debate on additionality does not arise. Even so, when using excess electricity to produce hydrogen, its economics must still be compared with other grid integration measures such as batteries, use of inter-regional transmission lines, and so on.

Conclusion

This report presented an overview of efforts underway in Europe toward gas decarbonization and energy system integration, and described the challenges and possibilities of these measures through comparison with the efforts and discussions underway in Japan.

Europe and Japan have major differences in their networks and regulatory systems, but are also similar in that both have scarce biogas resources and their options for gas decarbonization are limited to hydrogen and hydrogen-sourced CN (carbon neutral) methane. The challenge for both parties is how to obtain hydrogen and CN methane and inject them into the gas network. Europe is planning to increase the hydrogen blending ratio in existing gas networks in stages, with a view to repurposing the gas networks for 100% hydrogen and building new hydrogen infrastructure in the process. Meanwhile, Japan's main approach is to blend CN methane into city gas, and has set a policy direction to lower the standard CV to 40 MJ/m^3, close to that of methane.

Gas decarbonization requires significant amounts of hydrogen and CN methane, which Japan may need to purchase from other countries. However, it is also important to pursue the concept of energy system integration, in which the gas network, inclusive of Power to Gas and cogeneration, is used to address output fluctuations associated with the mass introduction of domestic VRE to build a decarbonized economy, while also decarbonizing the gas itself by including VRE in the process. This is because existing electric power networks alone will not be able to cope with the enormous amounts of VRE that will need to be introduced. New measures such as strengthening inter-regional transmission lines and batteries may not be sufficient. Meanwhile, existing gas networks are already equipped with an energy storage capability and flexibility owing to the physical characteristics of the gas; incorporating Power to Gas into the networks will allow these functions to be used to mitigate VRE output fluctuations. In other words, the gas network is inherently highly compatible

[58] Shibata, "*Role of Power to Gas and methanation toward a low-carbon society,*" "Inorganic film opens path into the future: Environment and Energy Technology Symposium, RITE, November 7, 2019.

[59] The green hydrogen standard of Germany's third-party test certification organization TÜV SÜD CMS 70 Standard (12/2017) requires that electricity from new renewable plants (within 3 years after construction) must account for a certain level (30% or more). The Clean Energy Partnership's standard stipulates that at least one-third must be from a renewable energy plant within 6 years and another one-third from a plant within 12 years after construction.

with VRE. Needless to say, it will be necessary to evaluate what kinds of measures will be economically efficient for dealing with the mass introduction of VRE, but based on the above, utilizing well-established existing gas networks is an option worth considering. Europe is making progress with discussions on energy system integration, and has begun specific discussions on revisiting the definition of energy storage technology and on providing grid balancing capability using water electrolysis.

Energy system integration is also valuable from the perspective of resilience. From the efficiency perspective, it is preferable to use VRE-sourced hydrogen from PtG and CN methane for producing heat. However, by using water electrolysis and CHP to ease VRE output fluctuations and stored hydrogen and CN methane for emergencies, the overall resilience of the energy system will be enhanced. In this case, it may be possible to further optimize energy system operations if electricity and gas networks can be operated in a coordinated manner.

Meanwhile, as energy system integration involves both electricity and gas, various regulation-related issues must be resolved to achieve it, such as the definition of energy storage and the use of grid balancing capacity. Before this can be done, it is necessary to determine how much flexibility the entire gas network has, including gas holders and the linepack of pipelines.

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