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Impacts of Coronavirus Crisis

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Grid Flexibility Offered by Distributed Combined Heat and Power Using Carbon-neutral Methane Produced from Renewable Surplus Electricity

The Institute of Energy Economics, Japan

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Covid-19 and the Outlook for Oil, Natural Gas, and LNG Demand in 2021

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Introduction

The Covid-19 epidemic continues to spread. Three months have passed since January 31, 2020 when the epidemic was declared a public health emergency of international concern (PHEIC) by the World Health Organization, but there is still no end in sight. Lockdowns imposed to restrict the movement of people and goods have brought economic and social activities to a halt worldwide, causing energy demand to collapse. This has triggered an unprecedented supply glut on the international market and major instability, causing oil prices in the international energy market to crash.

Global economic growth is projected to sink into negative territory in 2020 for the first time since the 2008-2009 financial crisis, and demand for oil and gas will suffer its worst decline in history[1] according to the special flash report "Demand for Oil, Natural Gas, and LNG under the Worst Global Economic Conditions since the Great Depression (IEEJ, April 17, 2020)" by the authors of this report. That report focused on demand in 2020, but did not examine the demand in 2021 after the possible end of Covid-19. While the most pressing issue for the international energy market is to respond to the unprecedented supply glut and resulting collapse in oil prices, the supply-demand situation going into 2021 and whether oil prices and other factors will stabilize are also serious concerns. To answer these questions, the authors will examine the trends in the global energy demand toward 2021 as a baseline. Following our previous report, this report analyzes the global demand for oil, natural gas, and LNG using three scenarios for the world economy in 2021, and examines the implications for the international energy market.

1. Analytical framework

In this estimate, we forecasted the demand up to 2021 based on the report "Demand for Oil, Natural Gas, and LNG under the Worst Global Economic Conditions since the Great Depression" noted above. The two scenarios in that report, namely the Reference Scenario and the Longer Pandemic Scenario, were used again in this estimate as the major assumptions for economic growth and other factors up to 2021, and a new scenario assuming that a second outbreak of the pandemic strikes in 2021 was added.

The Reference Scenario (RS)

Based on the World Economic Outlook of the International Monetary Fund (IMF) released in April 2020, we assumed that the pandemic will end in the second half of 2020 and the economy will bottom out in Q2 and then start to recover. The world economy will grow by 5.8% year-on-year in 2021, a massive increase from the 3.0% contraction in 2020.

The Longer Pandemic Scenario (LPS)

Based on the "longer outbreak in 2020," the IMF's alternative scenario in which the virus continues to spread for 50% longer than the reference scenario, we prepared the LPS in which the spread of the virus is prolonged and has a more serious impact on economic activity in 2020. The LPS assumes that global economic activity will not bottom out until Q3 and the 2020 GDP growth rate will fall 6.0% year-on-year, but will recover quickly thereafter and grow by 7.0% year-on-year in 2021.

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[1] The greatest decline since at least the 1960s (BP Statistics)

The Pandemic Second Outbreak Scenario (PSOS)

Based on the "longer outbreak in 2020 plus new outbreak in 2021" scenario suggested by the IMF (the pandemic ends temporarily in 2020 before a second outbreak strikes in 2021), we assumed that a second outbreak occurs in 2021, resulting in a sustained impact on economic activity. We assumed that the second outbreak will have less impact than the first and will occur from Q1 to Q2 of 2021. As a result, the global economy would grow by only 1.3% year-on-year in 2021 (the growth rate for 2020 would be −6.0% year-on-year as estimated under the LPS)[2].

Under the RS and LPS, the world GDP will recover rapidly in 2021 and exceed 2019 levels. Meanwhile, under the PSOS, GDP growth in 2021 will be positive and higher than in 2020 but remain far lower than 2019 levels, and economic activity will remain sluggish.

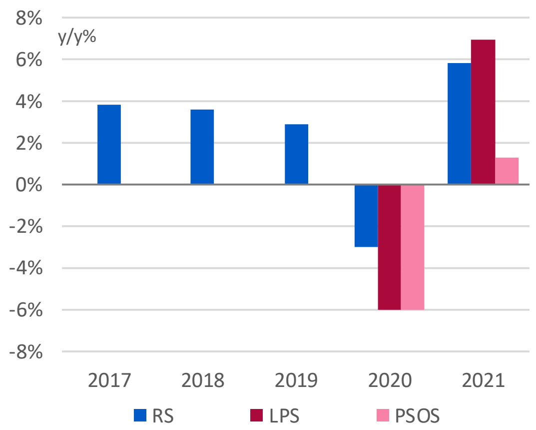

Fig. 1 World GDP growth rate

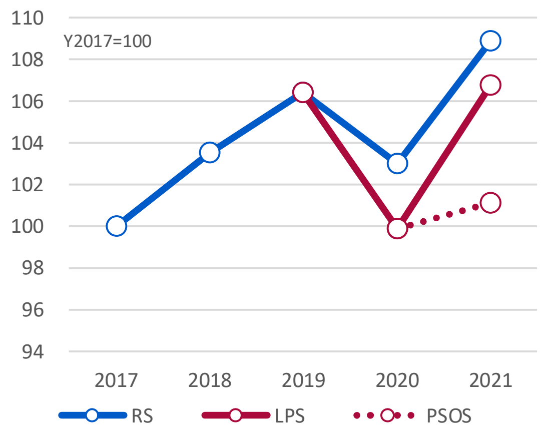

Fig. 2 World GDP level (2017 = 100)

2. Outlook for oil demand

Under the RS, oil demand is projected to fall to 90.7 Mb/d (down 9.3 million B/D year-on-year) but bounce back to 100.7 Mb/d in 2021 (up 11.0% year-on-year). Oil demand will surpass 100.0 Mb/d marked in 2019 and reach record-high levels next year. Meanwhile, under the LPS, oil demand will decrease to 87.2 Mb/d in 2020 (down 12.8% year-on-year) and recover to 99.0 Mb/d in 2021 (up 13.5% year-on-year), but not quite reach 2019 levels. In both scenarios, demand for transportation fuel will decline drastically during the pandemic due to movement restrictions, but social life will return to normal after the pandemic ends and oil demand will recover to normal levels as economic activity resumes.

With regard to quarterly trends in demand, under the RS, demand will bottom out in Q2 (the second quarter) of 2020 with 83.3 Mb/d, and thereafter rise gradually to 92.3 Mb/d in Q3 and 94.3 Mb/d in Q4. A supply glut of 7–8 Mb/d is expected in Q2 even if the OPEC Plus production cut of 9.7 Mb/d starts in May, and oil prices will face particularly strong downward pressure. If this joint production cut continues, even with ever-smaller curtailments, the oil supply glut may shrink dramatically in the second half of the year as demand increases. Then, in 2021, the quarterly oil demand will recover almost to 2019 levels under the RS, with 98.0 Mb/d in Q1, 100.1 Mb/d in Q2, 101.9 Mb/d in Q3, and 102.9 Mb/d in Q4. This will allow OPEC Plus to unwind the production cut to pre-coronavirus levels, setting a path for supply and demand to stabilize.

Under the LPS, the low point of demand occurring in Q2, 2020 will be lower than under the RS with 82.1 Mb/d and the

[2] The global economic growth rate under the PSOS was determined by the authors, referring to the IMF Outlook, etc.

supply glut will be more serious. Demand will remain weak for longer with 84.9 Mb/d in Q3 and 89.1 Mb/d in Q4. It will be crucial to continue with, and not ease, the joint production cut during this period. In 2021, demand will be much lower year-on-year in Q1 with 95.2 Mb/d but will rise to 2019 levels with nearly 100 Mb/d in Q2 onwards, making it likely that the market will stabilize.

However, under the PSOS which expects a second outbreak in 2021, oil demand will remain sluggish in 2021 with 89.0 Mb/d (though rising 2.1% year-on-year), remaining below 90 Mb/d for the second consecutive year. We assumed that the second outbreak occurs in Q1 to Q2, 2021 and that the movement of people is restricted again through border controls and city lockdowns, though to a lesser extent than in 2020[3]. Trends in demand will be similar to that of the LPS, though a second low point of demand will occur in Q2 in 2021, with demand falling short of 2019 levels by around 10 Mb/d in each quarter with 90.0 Mb/d for Q1, 84.9 Mb/d for Q2, 88.4 Mb/d for Q3, and 92.9 Mb/d for Q4.

In this case, it will be necessary to keep oil production around 10 Mb/d lower than 2019 levels from Q2, 2020 through Q4, 2021 in line with the global decline in demand. WTI, which is currently in the $10 range, will remain low and under downward pressure for almost two years until 2021, including a possible fall to single-digit territory. Meanwhile, the oil market will face the crucial question of whether it is possible to maintain an enormous reduction of roughly 10 Mb/d for nearly two years. Under the PSOS, however, such a prolonged and enormous supply cut is critical, otherwise oil prices will inevitably fall to extreme levels. Such extreme low prices would not only have devastating consequences for oil-producing economies but, from a broader perspective, cause damage to consumer countries as well as the entire world as a result of the negative impact on energy security due to instability in oil-producing countries and by causing a supply crunch down the road by deterring necessary investment in energy. To avoid this situation, both oil-producing and -consuming countries, including developed countries, must consider and implement all possible options, including production adjustments and more stockpiling. In other words, prices will remain volatile until some sort of cooperation is established between producer and consumer countries.

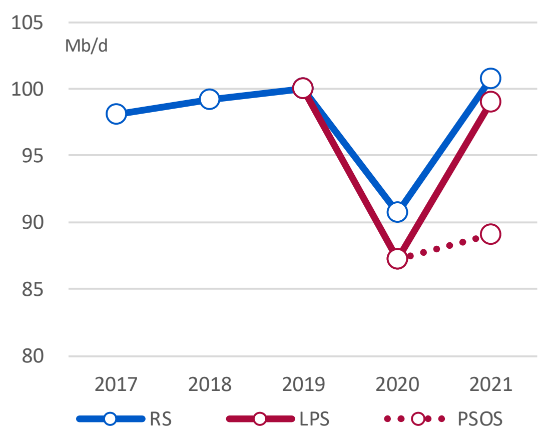

Fig. 3 Oil demand (annual)

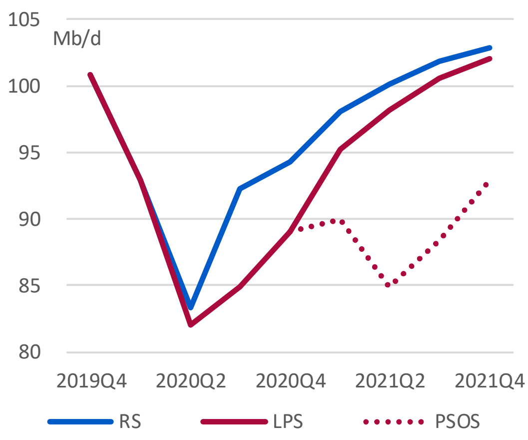

Fig. 4 Oil demand (quarterly)

3. Outlook for natural gas and LNG demand

Under the RS, natural gas demand is projected to fall by 7.2% year-on-year to 3,682 Bcm in 2020 but increase rapidly to

[3] This assumption reflects the IMG's Outlook that the second outbreak will be milder than the first, and the second outbreak was set to occur one year after the first.

4,053 Bcm in 2021 (up 10.1% year-on-year) and exceed 2019 levels. LNG demand will also fall by 7.8% year-on-year to 325 million tonnes in 2020 and rebound to 363 million tonnes in 2021 (up 11.5% year-on-year), exceeding 2019 levels. For both natural gas and LNG, demand will decline only in 2020 and reach a record high in 2021.

The trend is similar for LPS, under which demand will recover rapidly in 2021. Natural gas demand will increase to 3,961 Bcm, up 11.1% year-on-year, and LNG to 353 million tonnes, up 13.0%. However, demand will not quite reach 2019 levels for both natural gas and LNG. Nevertheless, as with the RS, both natural gas and LNG will face extreme declines in demand only in 2020, and the demand for these clean energies will start to recover as the pandemic subsides and the economy recovers, returning mostly to 2019 levels after one year.

However, the situation is quite different under the PSOS. Under this scenario, natural gas demand will increase by 3.2% year-on-year to 3,681 Bcm and LNG demand by 4.2% to 325 million tonnes in 2021, but the recovery will be slow and fall far short of 2019 levels. Demand will decline again as the second outbreak strikes, limiting the recovery to a small one on a full-year basis. As a result, the supply glut will continue in these markets in 2021. In the LNG market, for example, a supply-demand gap (excess supply) of around 60 million tonnes over the 2019 supply capacity levels may persist for two years, imposing downward pressure on the market.

As a supply-side solution to this supply-demand gap, the supply of US LNG, which has some flexibility, may play a role. Further, adjustments may also be made in an increasing number of individual projects by fully leveraging operational flexibility. Needless to say, a significant supply glut will exert sustained downward pressure on spot LNG prices if it continues for a long time. Further, considering the oil market trends under the PSOS, low oil prices may cause declines in long-term contract LNG prices that are linked to oil prices, causing overall LNG prices to remain low in 2021.

Another key point is the possibility that falling prices triggered by the supply-demand gap may stimulate demand. Low LNG prices may stimulate LNG demand in emerging markets that have growth potential if the price becomes low enough to be relatively competitive over its rival coal; future developments must be watched closely. The increase in residential gas and electricity demand resulting from spending more time at home during lockdowns also deserves attention. Electricity demand is expected to rise with the increase in ICT usage if teleworking remains to some extent even after Covid-19 subsides. This in turn may lead to an increase in gas-fired thermal power generation and demand for natural gas and LNG. We must continue to watch and analyze these possibilities going forward.

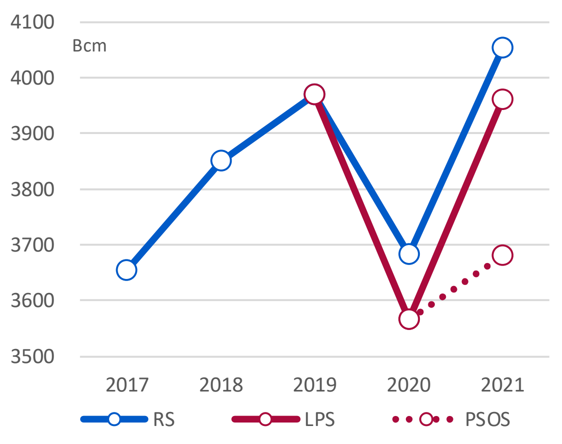

Fig. 5 Natural gas demand

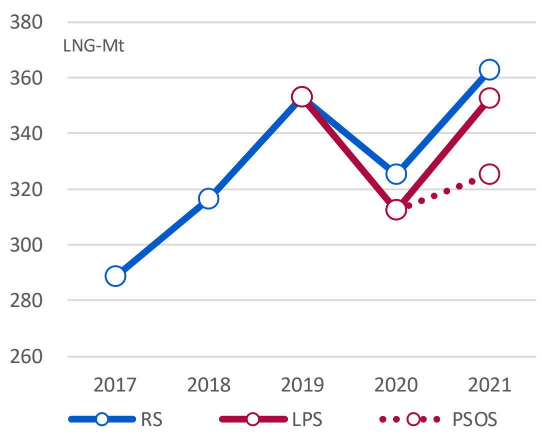

Fig. 6 LNG demand

Conclusion

If Covid-19 is eradicated in 2020, economic activity will recover rapidly in 2021 and demand for oil, natural gas, and LNG will return to or even exceed their levels during normal times. However, if the virus cannot be eliminated completely and a second outbreak occurs, the demand for oil, natural gas, and LNG will all remain low and have a strong, sustained effect on the supply-demand balance and prices, causing a major impact on the entire international energy industry as well as the global economy and international politics.

Past pandemics (the Spanish flu (1918–1920) and the Asian flu (1957–1958)) both suggest that a second outbreak could occur and that the battle against Covid-19 could last several years. This possibility cannot be ignored; we must closely monitor developments in the Covid-19 pandemic in analyzing the international energy market.

Demand for Oil, Natural Gas, and LNG Facing the Worst Global Economic Conditions since the Great Depression

Ken Koyama *, Shigeru Suehiro **

Introduction

As the coronavirus (COVID-19) pandemic rages worldwide, the world economy is sinking to unknown depths. In the latest update of its quarterly World Economic Outlook released on April 14, the International Monetary Fund (IMF) projected a drastic slump in the world economy of minus 3.0% in 2020. This far exceeds the decline in 2009 following the financial crisis (the "Lehman shock"), which was considered at the time to be a once-in-a-century crisis, of minus 0.1% and is believed to be the worst since the Great Depression that began in 1929. The decline is especially severe in the United States and advanced European countries that have been hit particularly hard by COVID-19.

This drastic economic slump, combined with restrictions on the movement of people and goods by city lockdowns and the like to prevent further contagion as well as a collapse in the number of international travelers and demand for transportation, is starting to have a massive impact on the global energy demand. This, in turn, is causing an unprecedented glut in international markets and major uncertainty, as represented by the crash in oil prices, for the international energy market, the world economy, and international politics. The extent of the decline in energy demand going forward will determine the path to stability not only for the international energy market but for international affairs as a whole.

Accordingly, this report analyzes the global demand for oil, natural gas, and LNG using two scenarios for the world economy in 2020, which we prepared based on the IMF World Economic Outlook and our previous special report[1], to examine the implications of such demand on the international energy market.

1. Analytical framework

For this estimate, we had to make key assumptions about the economic growth rate in 2020. We took the economic growth rates in various regions of the world from the latest World Economic Outlook (released in April 2020) of the IMF, and established the following two scenarios.

The Reference Scenario (RS)

Based on the latest IMF outlook, we assumed that the world economy would record negative growth for the first time since 2009 caused by the financial crisis, declining by 3.0% year-on-year under the RS. We assumed that the pandemic would end in the second half of 2020 and the economy would recover after bottoming out in Q2. The Chinese economy was projected to recover in Q2 after falling significantly in Q1.

The Longer Pandemic Scenario (LPS)

The IMF's outlook suggests different possibilities for the COVID-19 pandemic aside from the above scenario in which the world economy shrinks by 3%. Based on the IMF's assumptions for a "longer outbreak in 2020" (the virus will continue to spread for 50% longer than the reference scenario), we prepared the LPS in which the spread of the virus is prolonged and has a more serious impact on economic activity. The LPS assumes that global economic activity will not bottom out

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1 Koyama and Suehiro, "Analysis of the Impacts of COVID-19 on the Global Demand for Oil, Natural Gas and LNG" (IEEJ, March 23, 2020)

until Q3 and the 2020 GDP growth rate will fall 6% year-on-year.

For the analytical framework other than the economic growth rate described above, refer to Koyama and Suehiro (2020)[2] mentioned earlier.

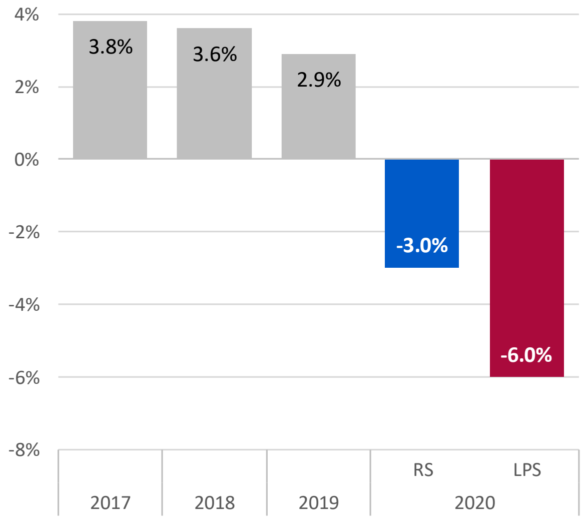

Fig. 1 GDP growth rate

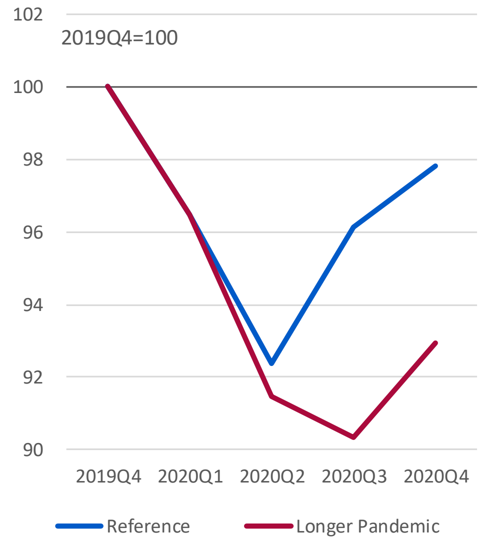

Fig. 2 GDP level (quarterly)

2. Outlook for oil demand

Under the RS, oil demand is projected to fall by 9.3 million B/D (9.3 Mb/d, down 9.3% year-on-year) to as low as 90.7 Mb/d in 2020. This is equivalent to the level of demand in around 2012. The global oil demand has decreased in the past, such as the decline in 2009 caused by the financial crisis and those caused by the oil crises in the 1970s, but the estimated decline this time is the largest ever since at least the 1960s.

Demand will fall particularly sharply in Q2 to 83.3 Mb/d (down 16.0% from the same quarter a year earlier). City lockdowns have been in place since March in Europe, the United States, and other countries, covering half of the world population. While declines in macroeconomic activity do cause a decline in oil demand, it is these lockdowns that are believed to exacerbate the decline in terms of volume[3]. We assumed city lockdowns of a maximum of two months in this estimate, which is why the decline in demand focuses on Q2[4].

One notable result of this analysis is the far smaller demand for transportation fuel resulting from restrictions on the

[2] Koyama and Suehiro, "Analysis of the Impacts of COVID-19 on the Global Demand for Oil, Natural Gas and LNG," (the IEEJ, March 23, 2020)

[3] See Suehiro and Koyama, "An Estimate on the Impact of a "City Lockdown" on the Global Energy Demand" (IEEJ, April 9, 2020).

[4] Considering the large decline in demand caused by city lockdowns, differences in assumptions for the conditions, duration, scope (target country or region), etc. of such lockdowns may produce a considerable difference in the size of the decline. For example, this estimate projects a global oil demand of 83.3 Mb/d for Q2, 2020 while the IEA projects 76.1 Mb/d for the same period. For the IEEJ's assumptions on the conditions, duration, and scope of city lockdowns, see "An Estimate on the Impact of a 'City Lockdown' on the Global Energy Demand" (IEEJ, April 9, 2020).

movement of people. The fall in demand for gasoline, diesel oil, and jet fuel (plus heating oil) accounts for nearly 80% of the fall in oil demand. The full-year demand for jet fuel (plus heating oil) is projected to fall by 26% year-on-year as the demand for international flights will take time to recover even after the lockdowns are lifted. By region, demand will fall drastically in North America and Europe which are under city lockdowns and have high rates of car ownership. Under this scenario, China, where the pandemic started, will manage to contain the pandemic relatively quickly, enjoy an economic recovery sooner than other regions (1.2% growth in 2020), and suffer a relatively smaller decline in oil demand than Europe and the United States even though the decline will reach nearly 1 Mb/d full-year.

Under the LPS, oil demand is projected to fall by 12.8 Mb/d (12.8%) year-on-year to as low as 87.2 Mb/d. As with the RS, demand will be the lowest in Q2, but the infection will continue to spread for longer and the recovery of demand in the second half of the year will be slower. As the fall in demand for transportation fuel due to restrictions on the movement of people (the city lockdown effect) will be factored in mainly in Q2, and as the fall accounts for a very large proportion of the overall decline, the fall in oil demand will comprise a smaller share of the additional fall in GDP (of another 3%) under the LPS compared to the RS.

These predictions suggest that along with the degree of decline in the macroeconomy, the length of the lockdowns will have a major impact on the pattern of the future decrease in demand for both the LPS and RS. We assumed that lockdowns would continue for 60 days in this estimate, but should they become even longer, oil demand would fall even further under both the RS and LPS.

Even under the RS, the full-year decline in oil demand will reach 9.3 Mb/d year-on-year (down 9.3%), with an enormous fall of 15.9 Mb/d year-on-year (down 16.0%) in Q2. The decline is so great that it is making OPEC Plus's 9.7 Mb/d joint production cut agreed on April 12, one of the biggest in history, looks weak in comparison, putting further downward pressure on oil prices. On April 15, the WTI crude oil futures closed at $19.87, falling below the $20 threshold for the first time in 18 years.

Some expect that the joint production cut will far exceed 10 Mb/d, with a cut of 9.7 Mb/d from OPEC Plus and contributions from other non-OPEC oil producers. Even if this happens, however, an enormous supply glut will be inevitable at least in Q2. The world's stocks of petroleum are stored in land-based stockpiling facilities, tankers, pipelines, and so on. Based on the current supply-demand situation, land-based stockpiling facilities may reach their operating capacity by around May or June, making it necessary to mobilize all other options to absorb the oversupply and prevent oil from flooding the market.

Oil market players are keenly aware of this possibility, which continues to impose downward pressure on oil prices. If oil demand declines in line with the pattern in the LPS and not the RS, there could be a massive crash in oil prices.

A slump in oil prices or excessively low price levels could destabilize international financial markets by straining or destroying the finances of oil producer economies, affecting their stability, hampering essential medium- to long-term investments, and triggering further falls in stock markets, leading to various other critical problems. The G20 is already discussing ways to address this problem through international cooperation. For the stability of both oil producer and consumer countries and of the world, initiatives and international collaboration for stabilizing supply and demand in the international oil market are needed.

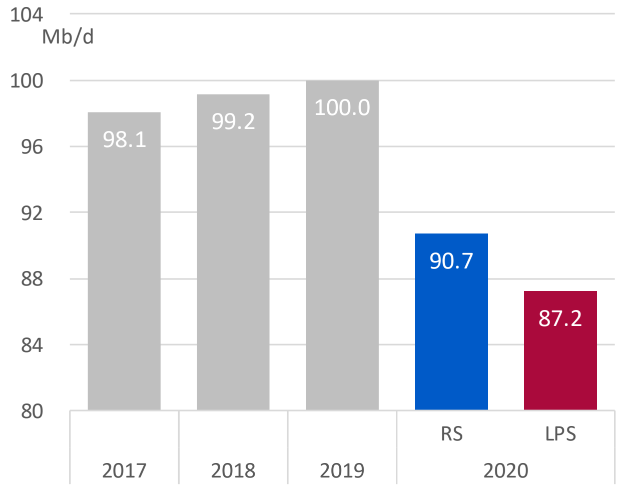

Fig. 3 Oil demand (annual)

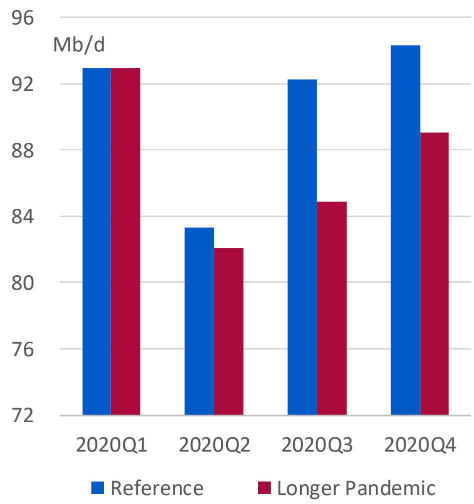

Fig. 4 Oil demand (quarterly)

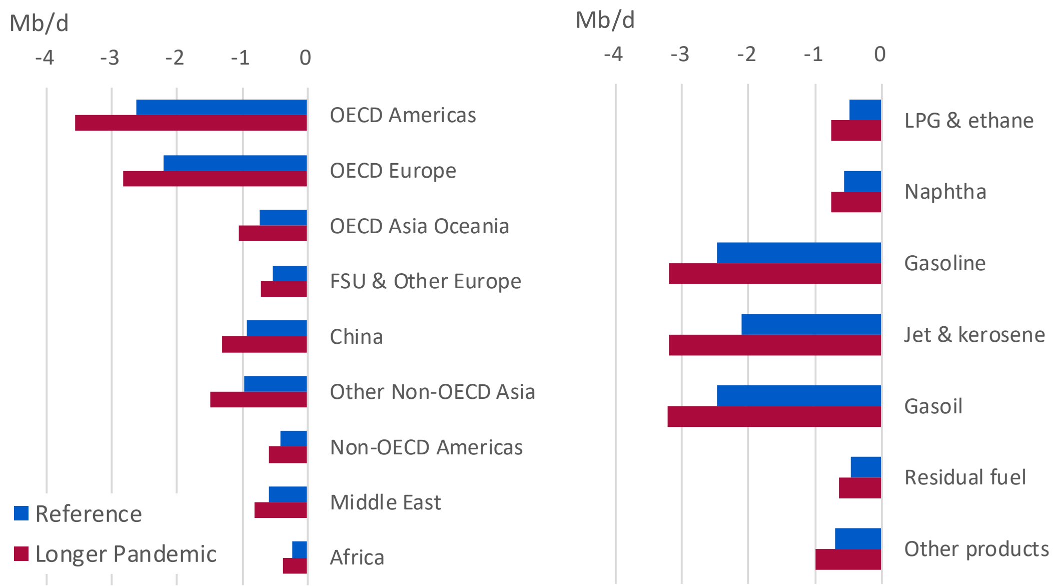

Fig. 5 Year-on-year change in oil demand (2020)

3. Outlook for natural gas and LNG demand

3-1. Natural gas

Under the RS, natural gas demand is projected to fall by 7.2% year-on-year to 3,682 Bcm in 2020, which is close to the level of demand in 2017. The scale of this decline is striking considering that natural gas demand fell only 2.0% in 2009 after the financial crisis. The main cause of a drop in natural gas demand is a fall in electricity demand; the significant fall in demand for power generation accounts for nearly half of the drop in natural gas demand as a whole.

In terms of timing, the decline will be greatest in Q2 when economic activity hits the bottom, shrinking more than 10 percent with minus 13.1% year-on-year. In particular, the decline will be sharp in North America, Europe, and former Soviet regions which are major natural gas consumers and have been hit hard by the pandemic, together accounting for three-fourths of the global decline. These regions together account for nearly 60% of the global demand for natural gas and are also active in gas-fired thermal power generation.

Under the LPS, global natural gas demand is projected to fall by as much as 10.2% year-on-year to 3,566 Bcm. The regional pattern of decline is the same as for the RS, with massive declines in North America, Europe, and former-Soviet regions. By quarter, however, unlike the RS, global natural gas demand will be the lowest in Q3 in line with economic activity. As for oil, the impact of the fall in transportation fuel demand due to city lockdowns is extremely large and thus, the demand becomes the lowest in Q2 when city lockdowns take place. Meanwhile, natural gas demand will bottom in Q3 under the LPS as the impact of lockdowns is smaller than for oil and therefore the macroeconomy play a bigger role.

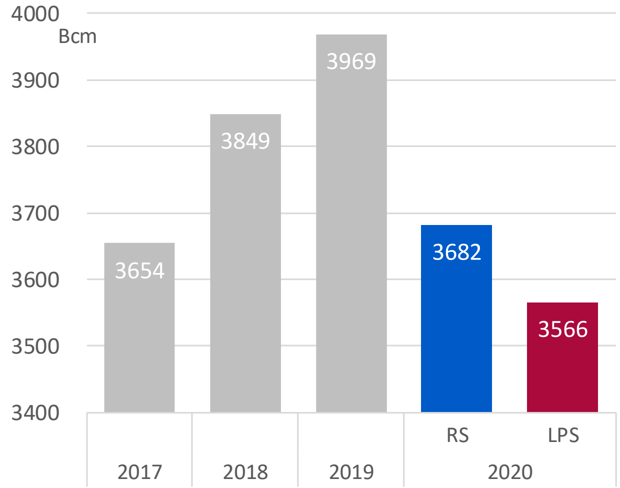

Fig. 6 Natural gas demand (annual)

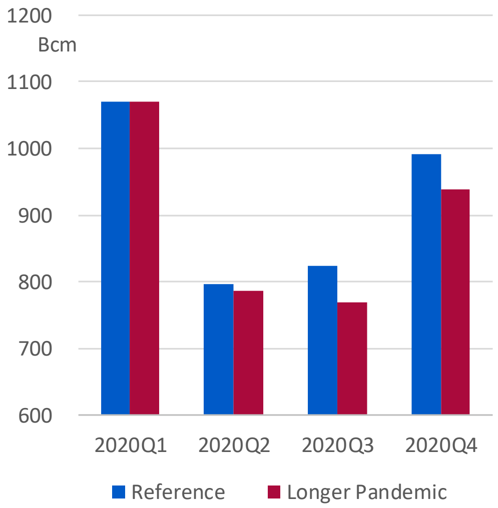

Fig. 7 Natural gas demand (quarterly)

3-2. LNG

Under the RS, LNG demand is projected to fall by 28 million tonnes year-on-year (7.8%) to 325 million tonnes in 2020. Global LNG demand grew steadily by 6.3% even in 2009 after the financial crisis and has seen near-double-digit growth in recent years, but in this estimate, demand will fall sharply by 7.8% as the global economy plummets.

As with natural gas, the largest falls in demand will occur in major LNG consumer regions, namely Asia and Europe. Demand will decrease by 13 million tonnes in OECD Europe, 7 million in OECD Asia, and 4.7 million in non-OECD Asia, amounting to 24.7 million tonnes in total and accounting for 90% of the loss in global LNG demand. In terms of timing, the decline will be greatest in Q2 and then will recover gradually toward the second half of the year. However, the process of recovery in LNG demand will depend on the different timings of economic recovery among countries.

Under the LPS, the global LNG demand is projected to fall by an additional 13 million tonnes from the RS to 312 million tonnes, or by 11.5% year-on-year, falling below 2018 levels. The regional characteristics and the timing of the decline in demand will basically be similar to that for the RS.

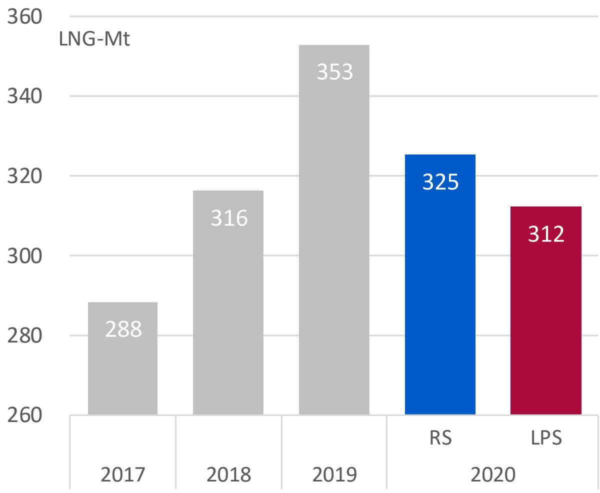

Fig. 8 LNG demand (annual)

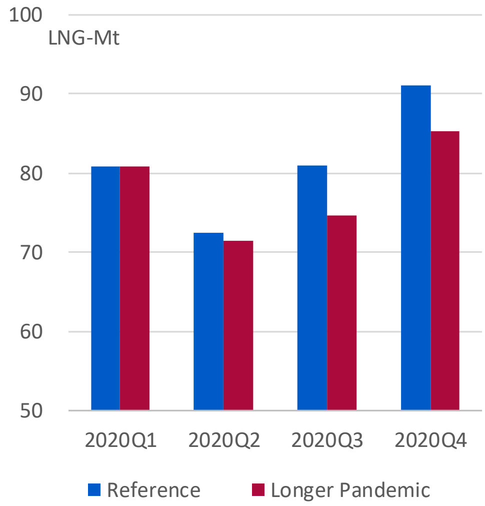

Fig. 9 LNG demand (quarterly)

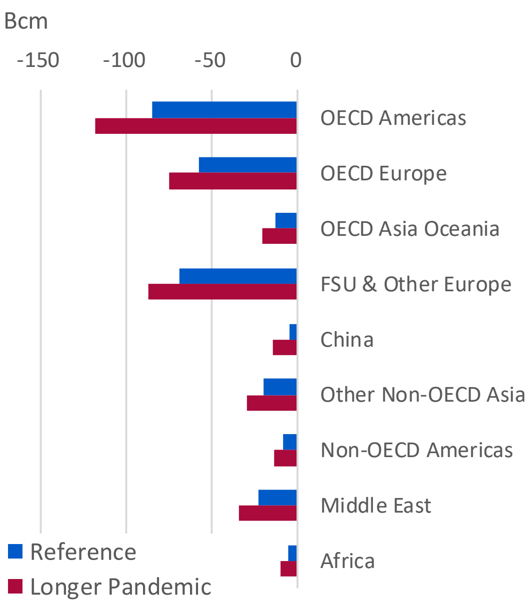

Fig. 10 Year-on-year change in natural gas demand (2020)

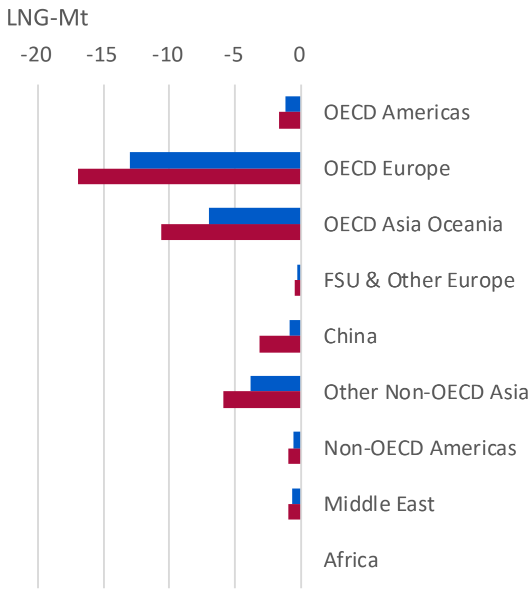

Fig. 11 Year-on-year change in LNG demand (2020)

If a decline like the one in this estimate occurs in the LNG market which has grown rapidly to date, it is likely to cause a large glut. Even without the impact of COVID-19, the LNG market was projected to be oversupplied in 2020. The 2020 outlook of the IEEJ released in December 2019 forecasted an oversupply with an estimated global LNG demand of 369 million tonnes against a supply of 381 million tonnes. If demand falls to 325 million tonnes as projected in this estimate under the RS and to 312 million tonnes under the LPS, the supply-demand gap (oversupply) would reach 56–69 million tonnes based on the supply above. This huge oversupply would impose strong downward pressure on the LNG spot price which is already down to the mid-$2 range per million BTU.

Further, considering that the prices of long-term LNG contracts, which form the bulk of LNG supply in Asia, are basically linked to crude oil prices, and as oil prices are expected to remain low according to the oil market outlook above or could fall even further, long-term LNG contract prices are most likely to fall drastically in the future, following oil prices with a time lag. Incidentally, the average LNG arrival price in Japan, which buys mainly through long-term contracts, has mostly been in the $9-10 range per million BTU from April 2019 and is at $9.3 as of March of this year.

Factors that will further complicate the market situation and make management decisions difficult for those in the LNG business include what will happen to the correlation between long-term LNG contract prices, which will go down with oil prices with a time lag, the LNG spot price, which will face downward pressure as the supply-demand balance eases, and the US LNG price, which is based on domestic natural gas prices plus a "fixed costs".

Will a rapid fall in LNG prices stimulate demand? What will happen to forward-looking investments in LNG in a low-demand, low-price environment? The answers are not yet clear.

4. Conclusion

The impact of the COVID-19 pandemic will cause declines in economic activity and energy demand far exceeding those during the 2008–2009 financial crisis (the "Lehman shock"), which was regarded at the time to be a once-in-a-century event. Notably, the decline in oil demand consists mostly of a decrease in demand for transportation fuel due to restrictions on the movement of people and goods, and is thus different in nature from a simple slump in economic activity. Also, LNG demand, which grew steadily even during the previous financial crisis, is expected to fall sharply this time.

This unprecedented decline in demand will result in a sustained, massive supply glut in the international oil, natural gas, and LNG markets at least during 2020, and continue to place downward pressure on the prices of these energy commodities. It is crucial to consider negative factors in the international energy market, global economy, and international politics resulting from the collapse in demand and prices, and to proceed with initiatives to stabilize the markets through international cooperation.

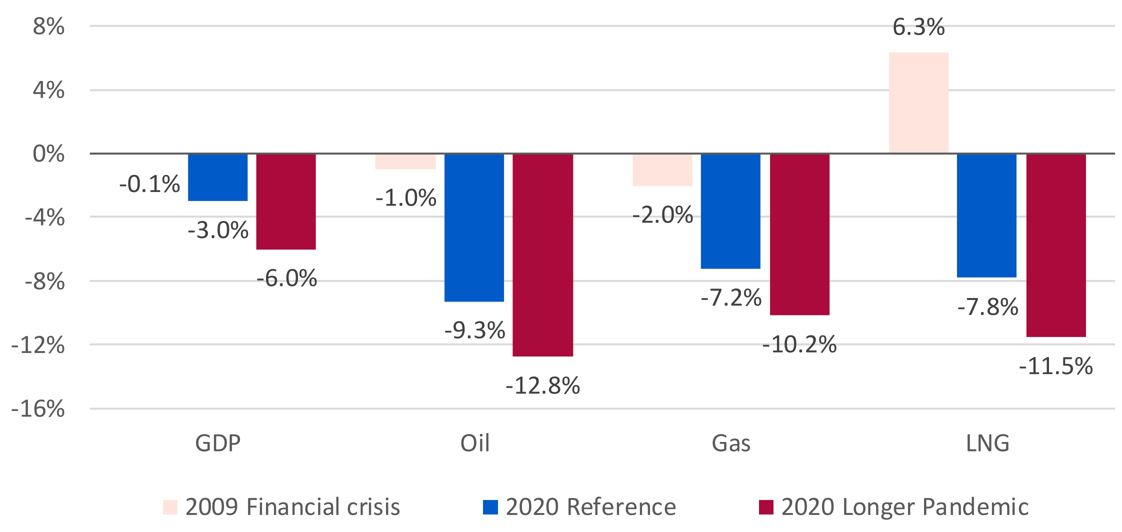

Fig. 12 Year-on-year change in GDP and demand for various energy sources

An Estimate on the Impact of a "City Lockdown" on the Global Energy Demand

Shigeru Suehiro *, Ken Koyama **

Introduction

The new coronavirus (COVID-19) pandemic is now spreading worldwide. According to the World Health Organization (WHO), 1.28 million people have been infected and 73,000 have died as of April 7. To prevent further contagion, many countries around the world are taking measures including imposing a "city blockade" or "city lockdown" that limits people from leaving their homes or traveling and imposes restrictions on economic activity and the daily lives of citizens mainly in highly-populated cities. A state of emergency was declared also in Japan on April 7 and a large-scale stay-at-home request was issued in seven prefectures, including Tokyo.

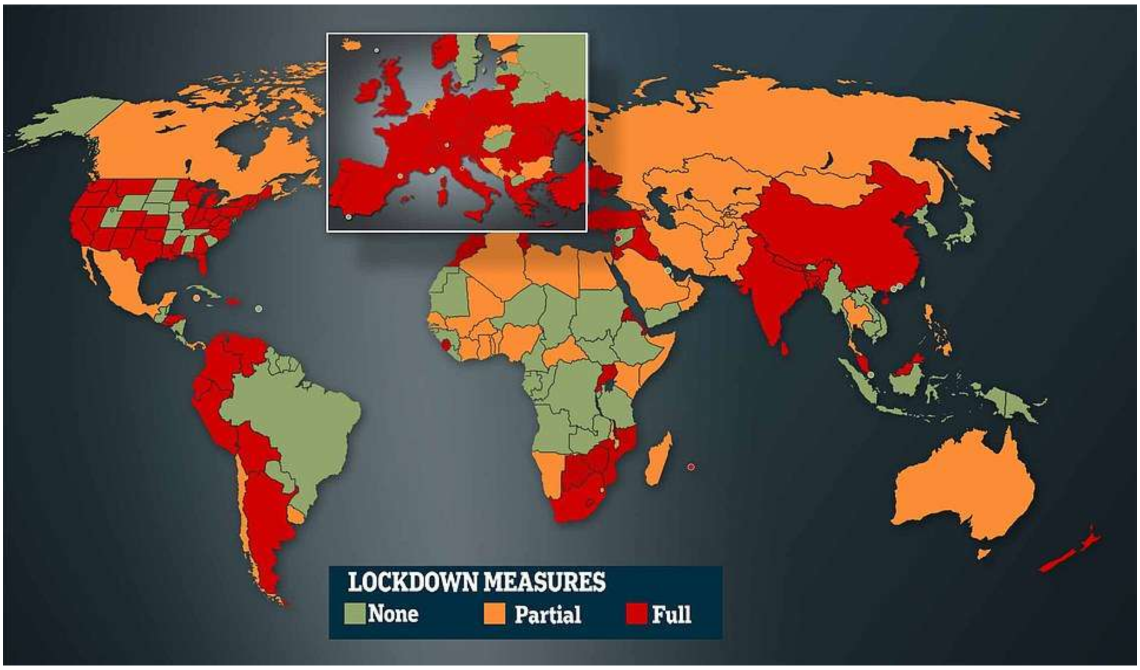

Fig. 1 Lockdown measures in place (as of April 2)

Source: Mail online
https://www.dailymail.co.uk/news/article-8181001/3-9-billion-people-currently-called-stay-homes-coronavirus.html (date accessed: 2020/4/6)
Note) Full: restrictions on movement imposed on all or most residents/hours. Partial: restrictions on movement imposed on some residents/hours.

According to an estimate based on media reports, more than 120 countries are limiting residents from leaving their homes and approximately 4.1 billion people, or more than half of the world's population, are under a city lockdown, though the strength of the policies, such as binding power, varies. About half of the total population under lockdown are concentrated in Asia (Fig. 2). In particular, India has prohibited its entire population of 1.3 billion from leaving their homes, accounting

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for the majority of the figures for Asia. Meanwhile, in China, the lockdown was lifted in Wuhan, which was where the pandemic started and the first to be locked down, on April 8. In advanced European countries where the contagion is spreading quickly, more than 90% of the population is under lockdown. Further, in the United States, more and more states are imposing lockdowns, covering an estimated three-quarters of the population.

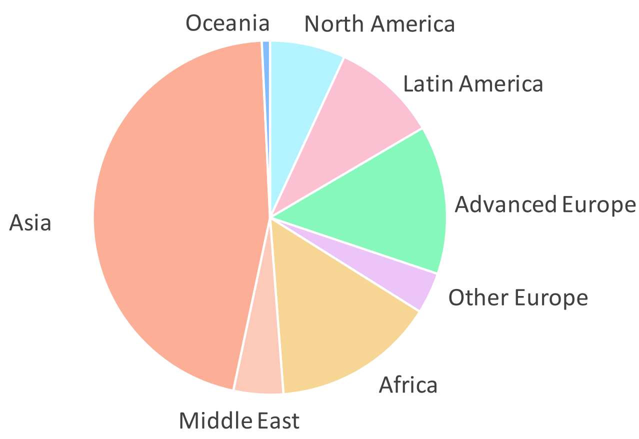

Fig. 2 Ratio of the number of people under lockdown

Clearly, restricting the movement of people and economic and social activities in highly-populated cities where economic activity is concentrated is likely to cause a significant decrease in energy demand. The impact on the international energy market has already been enormous. In particular, in the oil market, the collapse of the joint production cut by oil producers in early March acted as a supply-side shock together with the COVID-19 pandemic as a demand shock, causing oil prices to crash. Going forward, this demand shock will continue to have a massive impact on the international markets for natural gas and LNG, as well as oil. Accordingly, this report estimates the impact on the global energy demand by hypothesizing the decline in activity levels in each country and area under lockdown, based on national energy data from the International Energy Agency (IEA). Note that this estimate adds up the impact of lockdown in different areas and obtains the value per day, which is the equivalent of an "instantaneous wind speed" of the impact of lockdown measures in place. In that respect, it differs in nature from the "Analysis of the Impacts of COVID-19 on the Global Demand for Oil, Natural Gas and LNG (Koyama and Suehiro, IEEJ, March 2020)," which calculated the annual and quarterly impact of COVID-19 on energy demand using a macroeconomic model.

1. Framework for the calculation

If we look at the countries and cities where a lockdown is already in place, lockdown measures vary considerably in the conditions and strength of restrictions. Many advanced European countries are issuing legally-binding orders to prohibit residents from leaving their homes, imposing fines on offenders in some cases. Meanwhile, in some countries including Japan, the government and municipalities can only request, without legal force, that residents voluntarily refrain from certain activities. Furthermore, in some countries, only the elderly are required to stay at home. Lockdown measures imposed on facilities also vary greatly, from closing all facilities and shops except for the bare minimum (groceries, pharmacies, etc.) to closing just those facilities with a high risk of infection (restaurants, entertainment facilities, religious facilities, etc.) Also, night-time curfews have been imposed in some African countries but their impact on energy demand could be limited.

As discussed above, lockdown measures vary in conditions and strength and it is difficult to incorporate the exact impact in each country and city into the calculation. Therefore, for simplicity of calculation, lockdowns are categorized into two types based on Fig. 1: "Full (restrictions on movement imposed on all or most residents/hours)" and "Partial (restrictions on movement imposed on some residents/hours)."[1] Then, the following assumptions on the impact on energy demand were applied in full to the countries categorized as "Full" and by half to those countries in the "Partial" category[2].

This estimate focuses on the energy demand in the industrial (including chemical materials), residential, business (commercial), and transport sectors; the demand in areas such as agriculture, forestry, and fishery and international transport are not included. The assumptions on the impact on energy demand in each sector were set as follows by referring to Suehiro and Koyama (2020)[3].

The impact on **energy demand from industry** was estimated by sector. As the supply of daily necessities is critical, we assumed that the final demand for food, medical supplies, and daily consumables (sanitary paper products, detergents, cosmetic products, etc.) will be met. We also assumed that the production of supplies necessary to maintain the minimum necessary services such as energy and water supply, telecommunications and broadcasting, cargo and passenger transport, and retail will continue. In the case there is no demand for goods and services other than the bare minimum above, the rate of decrease in production (i.e. the rate of suspension of operation) in each industry was estimated using the input-output table[4].

The impact on the food sector is estimated to be small with a reduction of around 6–12% and relatively small for the pulp and paper and chemical sectors with around 20–30%. Meanwhile, sectors with a relatively large impact include the construction sector (around 90%) and ceramics, stone, and clay products sector (around 60–80%).

The impact on **residential energy demand** was estimated by purpose of use. Energy demand for the kitchen, and power and lighting are expected to increase as more people stay at home during the daytime due to requests to stay home and telework. The demand for air conditioning was estimated based on the average temperature in April in each country, but we assumed that there is no impact on demand in many countries, though with a few exceptions.

We estimated an increase of about 0–30% in air conditioning and a 10–30% increase in the use of lighting equipment and household appliances including TV depending on the country. Kitchen work is expected to increase by around 6% for preparing day-time meals. We assumed no impact on demand for hot water supply, refrigerators, and washing machines as there is no change in their use. Based on these assumptions, we estimated the impact on residential energy demand considering the number of people per household in each country.

The impact on **demand for business-use energy** was estimated by sector and purpose of use. Many offices and shops will close as the bulk of office workers switch to teleworking and more people refrain from going outside unless essential, but supermarkets (food), pharmacies, and hospitals will continue to operate. All schools and entertainment facilities will close, as well as most restaurants. The decrease in energy demand for air conditioning, hot water supply, and kitchen work is estimated to be equivalent to the suspension rate in relevant sectors. However, the decline for power and lighting was set considering that they will continue to be used even during a business suspension.

Based on the number of workers in each sector in each country, we estimated the energy demand for each sector and calculated the impact on energy demand for each purpose of use. The results indicated a decrease of around 0–70% for air conditioning depending on the country, 60% for hot water supply, 70% for kitchen work and 50% for power and lighting. We estimated the impact on energy demand based on these assumptions and taking into account the floor space of businesses

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[1] The strength of the policy (whether it is an order, request, etc.) is not considered. Fig. 1 is as of April 2, but the changes thereafter were incorporated to the extent possible. Lockdowns have ended in China as of April 8. For Japan, the seven cities under a state of emergency are incorporated as "Full" into the estimate.

[2] The estimate is based in principle on the energy demand of each country.

[3] Suehiro and Koyama, "An Estimate on the Impact of a 'City Lockdown' on Japan's Energy Demand"

[4] The input-output table issued by OECD was used. http://www.oecd.org/sti/ind/input-outputtables.htm

in each country.

The impact on **energy demand for transportation** was estimated by type of vehicle and means of transportation. Most passenger vehicles and motorcycles will stop being used as people refrain from going out except for essential purposes, but public transportation systems such as buses and railways will remain in operation to a certain extent for minimum transport. Further, freight transportation must continue for the logistics of goods and services to maintain the minimum supply needed for society.

Operation was estimated to decrease by 80% for passenger cars and by 50% for freight vehicles and buses. The rate of operation of domestic airlines, railways, and ships was also estimated to go down by 50% for each. Note that the impacts on international airlines and maritime transport are excluded from this estimate.

Based on the assumptions above, we calculated the impact on energy demand in countries under lockdown. The impact was calculated on a per-day basis, so it would be greater if the lockdown is protracted. Note that the assumptions of impact represent a "Full" city lockdown, and the impact was discounted by 50% for countries under "Partial" lockdown.

2. Results of the calculation

Based on the assumptions and prerequisites for this estimate, the global final energy demand is estimated to be decreasing by 3.4 Mtoe (Mtoe: million tonnes of oil equivalent) per day due to city lockdown (Fig. 3). This is a 14% decrease from normal times (the daily average demand for 2017). The impact is the greatest in the transportation sector, accounting for about 60% of the overall decrease. By type of fuel, the demand for oil is seeing the greatest impact, accounting for about 70% of the overall decline of fuel demand. There is a very large impact on gasoline and diesel for vehicles as restrictions on going out suppress the movement of people and goods to extremely low levels. Industry sector is seeing the second greatest decline in energy demand while the impact on demand in households and businesses is relatively small. The relatively small impact on electricity demand may be attributable to the Asia region, which has the largest population under lockdown but a relatively low electricity consumption per person.

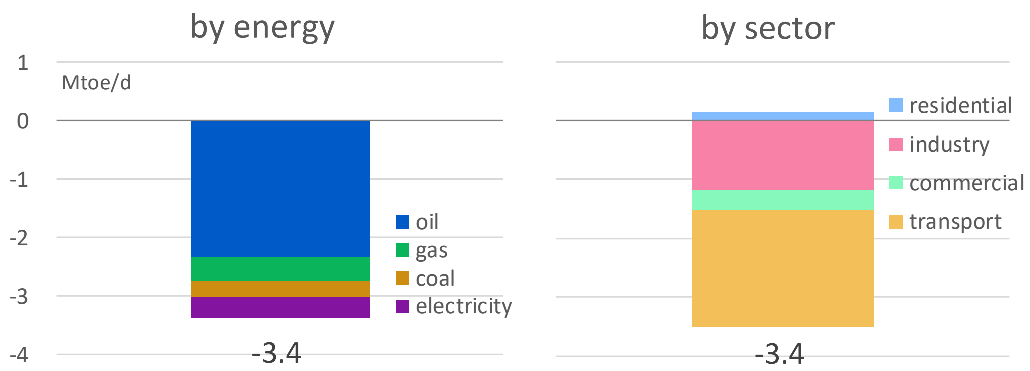

Fig. 3 Estimated impact of lockdown on the global final energy consumption (by energy and sector)

By region, the impact is greatest in North America and advanced European countries (Fig. 4). The two regions together account for about 60% of the global decline in energy. This indicates that lockdowns in advanced countries with a high rate of car ownership can have an extremely large impact on oil demand. Meanwhile, the decrease in energy demand is relatively small in Asia, which is home to half the population under lockdown, relative to its population, accounting for only about 20% of the global decrease. The reason for the relatively small decrease in Asia may be the low energy consumption per person due to the low rate of ownership of cars and electric appliances, and to the region's manufacturing industry which is still in the development stage (typically India).

On a primary energy basis[5], a global city lockdown lowers the energy demand by 4.1 Mtoe per day (Fig. 5). This is an 11% decrease from normal times. Oil is seeing the greatest impact and is decreasing by 18.1 Mb/d (barrels per day) or 20% from normal times globally. As expected, the bulk of the decrease in oil demand is due to Europe and North America which are under strict city lockdowns and have a high rate of car ownership. The decline in oil demand is 5.7 Mb/d in North America and 5.0 Mb/d in advanced European countries, accounting for 31% and 27% of the total decrease, respectively. In Asia, the decrease in oil demand is 2.8 Mb/d (15%). Meanwhile, the demand for natural gas and coal decreases by 11% and 8%, respectively, from their global consumption in 2017. The impact on these energies including power generation fuel is not as high as that on oil, because the impact on electricity demand is relatively small. The decrease in the overall global demand for gas is 1.1 Bcm/d (1.1 billion cubic meters per day), or about 780,000 tonnes per day in LNG-equivalent[6]. Here again, the greatest decline in demand comes from Europe and North America which are under strict city lockdowns and have a large natural gas consumption. The decrease in natural gas demand in Asia is approximately 90,000 tonnes per day in LNG-equivalent, and the combined decreases in Asia and advanced European countries, which are major net natural gas importers, stands at approximately 290,000 tonnes per day in LNG-equivalent. If the city lockdowns causing this decline continue for 30–60 days, the cumulative decrease in gas demand would be approximately 8.7–17.4 million tonnes in LNG-equivalent and have a serious impact on Russia and other gas-producing countries and the international gas and LNG industries.

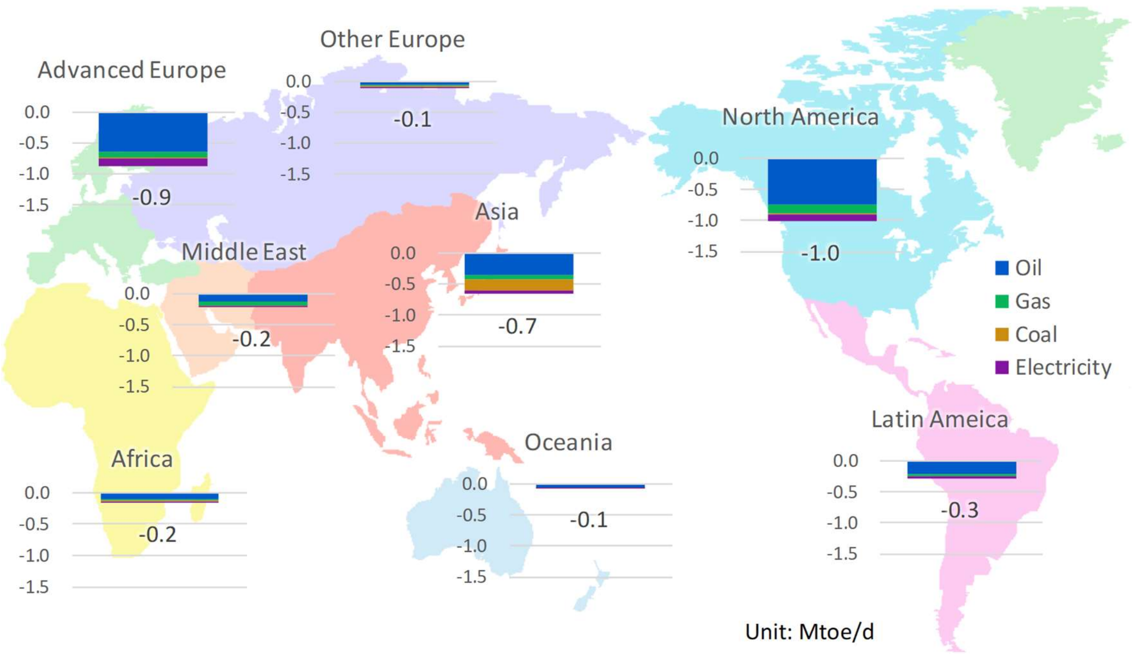

Fig. 4 Estimated impact of a city lockdown on the final energy demand of each region

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[5] The decrease in electricity demand was converted into generation fuel input based on the average thermal power efficiency in each region.

[6] There are two possibilities regarding the decrease in natural gas demand for the entire world (1.1 billion cubic meters, approx. 780,000 tonnes of LNG-equivalent): decrease in pipeline supply or as demand for LNG. In the actual market, this will depend on the economic efficiency and supply availability of the two sources.

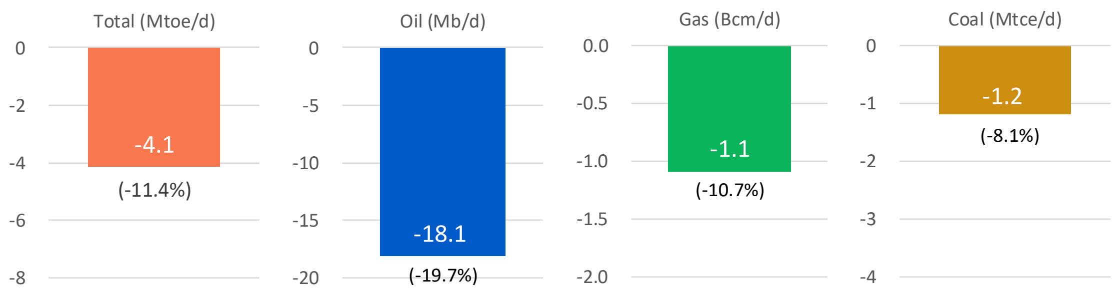

Fig. 5 Estimated impact of a city lockdown on the global primary energy demand

Note: The percentage in parentheses is the change from normal times (the average demand per day in 2017). The use of traditional biomass is excluded.

Conclusion

The daily energy demand will see a significant drop as a result of city lockdowns. Based on this estimate, the demand for oil, mainly for transportation in particular, will decrease by as much as 20%. The longer the city lockdowns continue, the harder total demand will be hit. This massive decline in demand, if it continues or worsens, will inevitably exacerbate the supply glut in the international energy market. Since the beginning of April, the world has been keenly watching moves to reinstitute the joint production cut by oil producers. However, unless the producers can agree on drastic cuts, oil prices will be subject to powerful downward pressure. Some consider that even if a production cut is agreed, the decline in oil demand is so large, as indicated by this estimate, that a supply glut cannot be avoided completely. Nevertheless, a production cut, if achieved, could delay the time when oil stocks exceed the total stockpiling capacities of countries and start flooding the market, and buy time to ramp up capacity to hold stock. At the very least, the market will start to face powerful downward pressure if oil producers fail to agree to cut production.

This estimate was obtained through calculations based on hypotheses set up for various forms of city lockdowns. The results should be viewed with caution as the availability of detailed data on each country and area is limited to a certain degree. It should also be noted that the slowdown in the global economy will also affect economic and social activities in countries not under lockdown, but such countries are not included in this estimate. Furthermore, the decline in energy demand associated with COVID-19 is being caused not only by city lockdowns but also by declines in macroeconomic activity. Thus, the actual decrease may exceed that caused just by city lockdowns considered in the present estimate. While recognizing these issues, we hope that the results presented here will be a useful reference to all those involved in the international energy market.

An Estimate on the Impact of a "City Lockdown" on Japan's Energy Demand

Shigeru Suehiro *, Ken Koyama **

Introduction

The novel coronavirus (COVID-19) infection has become a pandemic and its impact is expanding in scale and severity. To prevent the contagion from spreading further, the governments of the world's major countries have issued emergency declarations and similar statements, taking powerful measures such as blocking or locking down cities, and imposing restrictions on the movement of people, economic activity, and the daily lives of citizens in highly-populated cities. Since the end of March, there has been a growing possibility of a state of emergency or a kind of "city lockdown" for Tokyo and other cities in Japan.

Measures such as greatly restricting the movement of people, economic activity, and the lives of citizens in cities with large populations and high levels of economic activity will inevitably cause a significant drop in energy demand. Actual lockdown measures already imposed in other countries and cities vary considerably; the magnitude of the fall in energy demand will also depend on the measures and level of restrictions. The scale of the fall in demand, and for which type of energy, will have a major impact on Japan's energy sourcing and securing of supplies, as well as on the energy industry and the international energy market.

In view of these issues, this report estimates[1] the decrease in energy demand if a kind of "city lockdown" is enforced. Using cities with a population of 2.5 to 10 million, we set up various hypotheses for the decrease in activities in different sectors based on the energy data for each prefecture (national data was also used in some cases). The following sections describe the framework of the calculation for each area and sector and assess the decrease in energy demand per day.

1. Framework of the calculation

This report focuses on activities within a city and calculates the decrease in energy demand for the manufacturing and construction industries, households, businesses, and automobiles. Areas such as agriculture, forestry, and fishery and inter-city transport are not included. Therefore, the calculated decrease in energy demand does not represent the entire decrease in energy demand that a kind of "lockdown" would actually cause. As the scale of "lockdown" is not yet clear, the impact on energy demand was estimated for each industry based on the conditions of "lockdowns" already imposed in Europe and the United States, as follows.

The impacts on the manufacturing and construction industries were estimated at the sector level. As the supply of daily necessities is critical, we assumed that the final demand for food, medical supplies, and daily consumables (sanitary paper products, detergents, cosmetic products, etc.) will be met. We also assumed that the production of supplies necessary to maintain the minimum necessary services such as energy and water supply, telecommunications and broadcasting, cargo and passenger transport, and retail will continue. The rate of decrease in production (i.e. the rate of suspension of operation)

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[1] There are 12 "major cities" in Japan, including the Tokyo Metropolis (population of 13.7 million, including 9.3 million in the special wards), Yokohama City (3.7 million), and Osaka City (2.7 million) (as of 2017). These cities together account for 27% of Japan's total population. Prefectures with the largest populations include the Tokyo Metropolis, Kanagawa (9.2 million), Osaka (8.8 million), Aichi (7.5 million), Saitama (7.3 million), and Chiba (6.2 million).

of goods and services other than the bare minimum described above was estimated using the input-output table for the whole of Japan.

Table 1 Assumptions for the impact on energy demand for the manufacturing and construction industries (major sectors)

Sector	Construction	Foods	Paper	Chemicals	Ceramics	Metals	Machinery
Operation suspension rate	92%	20%	42%	26%	67%	54%	68%

The impact on residential energy demand was estimated by purpose of use. Energy demand for the kitchen, and power and lighting are expected to increase as more people stay home during the daytime due to requests to stay at home and telework. Air conditioning was assumed to have no impact on demand as it is hardly used in April, which is the "lockdown" period in this report, though this depends on the region.

Table 2 Assumptions for impact on energy demand for households

Purpose	Impact	Assumption
Air conditioning	0%	No impact as air conditioning will hardly be used during a "lockdown" in April, though this depends on the region.
Hot water supply	0%	No increase or decrease expected as it is used mostly at night.
Kitchen work	Up approx. 10%	For lunch: Increases in line with the number of people staying home during the daytime (from 0.7 → 1.8 persons on average). For dinner: Increases in line with the decrease in eating out (which is usually around once every 10 days).
Power / lighting	Up approx. 15%	Increases for day-time lighting and use of TV, PCs, and gaming devices as more people stay at home during the daytime.

The impact on demand for business-use energy was estimated by sector and purpose of use. Many offices and shops will close as the bulk of office workers switch to teleworking and more people refrain from going outside unless essential, but supermarkets (food), pharmacies, and hospitals will continue to operate. The decrease in energy demand for hot water supply and kitchen work is estimated to be equivalent to the suspension rate in relevant sectors. However, the decline for power and lighting was set considering that they will continue to be used even during a business suspension.

Table 3 Assumptions for impact on energy demand for business-use (by sector)

Sector	Suspension rate	Assumption
Offices	70%	Bulk of employees telework. Commuting to offices needed for some government offices and companies.
Supermarkets	20%	Department stores close. General merchandise stores close floors not selling food.
Other wholesalers & retailers	50%	Wholesalers and retailers other than food and medical supplies close.
Food services	80%	Some remain open for take-out service.
Schools	100%	All schools close.
Hotels	50%	Many continue to operate but occupancy rate falls significantly.
Hospitals	0%	Operate as usual.
Entertainment	100%	All stores and facilities suspend operations.
Other	70%	Welfare facilities continue to operate.

Table 4 Assumptions for impact on energy demand for business-use (by purpose of use)

Purpose	Impact	Assumption
Air conditioning	0%	No impact as air conditioning would hardly be used during a lockdown in April, though this depends on the region.
Hot water supply	Down approx. 60%	Based on the collective suspension rate of different sectors.
Kitchen work	Down approx. 60%	Based on the collective suspension rate of different sectors.
Power / lighting	Down approx. 50%	Based on the collective suspension rate of different sectors. Assumed that 20% of demand remains for purposes which are uninterrupted by business suspension (ventilation, refrigerators, servers, etc.).

The impact on energy demand for automobiles was estimated by type of vehicle. Most private vehicles and taxis will stop being used as people refrain from going out except for essential purposes, but buses and freight trucks will continue to operate for the minimum transport of goods and people.

Table 5 Assumptions for impact on energy demand for automobiles

Vehicle type	Impact	Assumption
Private vehicles	Down 80%	Voluntary stay-at-home except for essential purposes.
Taxis	Down 80%	Voluntary stay-at-home except for essential purposes.
Buses	Down 70%	Tourist buses are suspended. Minimum transport secured for commuting to work, visiting hospitals, etc.
Freight vehicles	Down 50%	There is demand for the delivery of goods such as food and other daily necessities, and mail and parcel delivery.
Motorcycles	Down 50%	There is demand for transport such as for delivery of parcels, food, and mail.

2. Results of the calculation

Based on the assumptions above, we calculated the impact on energy demand depending on the size of population under “lockdown”. The impact was calculated for each day, so the impact would be greater if the lockdown is protracted.

The energy which saw the greatest impact on demand was oil products including car fuel, accounting for most of the decline in demand in our calculation (Fig. 1). In particular, the voluntary restraint on using private vehicles will significantly affect gasoline demand. For example, in a “lockdown” of a city with 10 million people, which is the largest population case included in our calculation, energy demand would fall by 19,000 tonnes of oil equivalent per day, of which 57% is attributable to the decline in demand for oil products for automobiles and manufacturing. Incidentally, a decline of 19.0 ktoe (ktoe: 1,000 tonnes of oil equivalent) in demand corresponds to 36% of the final energy consumption for a city of this size (Fig. 2). The demand for oil products will decline by 13,800 kl per day (or 86,800 B/D, with approximately 70% of the fall attributable to gasoline and diesel oil for automobiles). This is equivalent to a 50% decline in oil products consumption for a city of this size.

Demand for coal (and others) and Electricity will see the second largest impact. The impact on industrial energy, especially on coal, etc., will vary significantly depending on the presence of large factories. Moreover, the impact on electricity demand grows with the size of the city due to the shutdown of offices which consume relatively large amounts of electricity. For example, in a “lockdown” of a city with around 10 million people, electricity demand would fall by 39.30 GWh (accounting for 18% of the fall in overall energy demand), equivalent to 25% of electricity demand for a city of this size. Meanwhile, electricity demand of households will increase only modestly and have only a small impact on energy demand change.

By size of population, energy demand for residential/commercial and transportation use increases mostly in proportion to population. Meanwhile, for the manufacturing industry, the impact is higher in cities with 5.0–7.5 million people as factories, especially large ones, are located in the suburbs. As a result, the impact on energy demand as a whole is the greatest in cities with a population of 7.5 million in our calculation (Fig. 1). Further, as shown by the case of the Tokyo Metropolitan area, the impact on energy demand for business tends to be greater than the city’s population as cities with large populations normally have a high concentration of commercial businesses. Meanwhile, cases for regional cities show that cities with a smaller population tend to have a relatively higher rate of car ownership per population and hence, the impact on energy demand for cars is relatively greater.

Depending on the situation, a “lockdown” could be enforced over an area larger than the respective case of the cities considered in this calculation. While not illustrated in this paper, if, for example, the assumptions for this calculation are applied to a “lockdown” of a “city areas” with 30 million people, the fall in overall energy demand would reach 83 ktoe per day, equivalent to 10% of Japan’s final energy consumption. In that case, the demand for oil products would fall by 48,600 kl per day (306,000 B/D), a significant decline equivalent to 11% of Japan’s total energy demand.

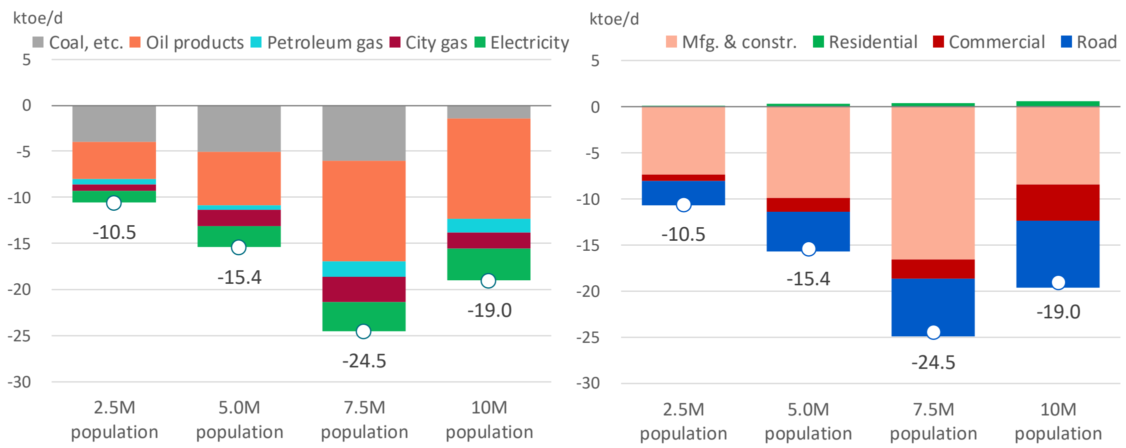

Fig. 1 Estimated impact of a city “lockdown” on energy demand

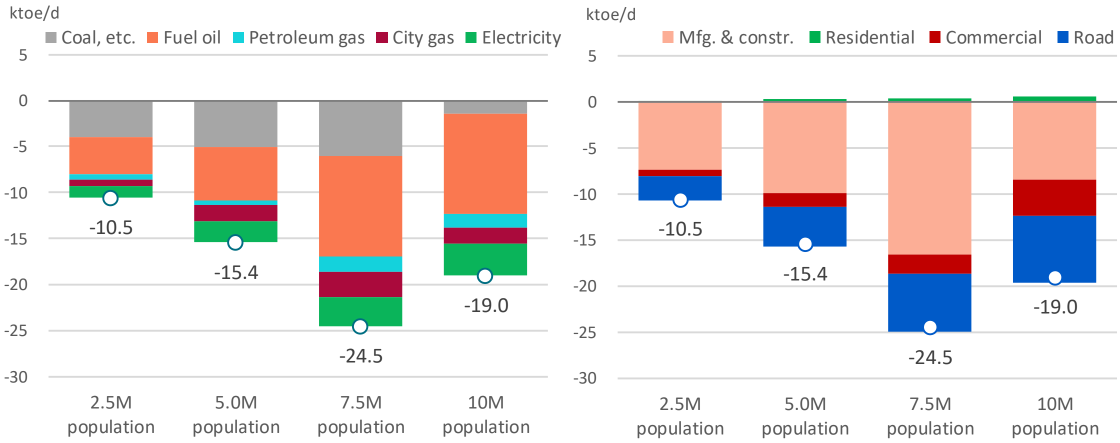

Fig. 2 Estimated impact of "lockdown" on energy demand: city with a population of 10 million

Note: The percentage in parentheses is the change from the estimated average sales per day in 2019.

Conclusion

Based on the described assumptions and prerequisites, the estimations showed that a "lockdown" would result in a significant drop in energy demand, mainly for oil products such as gasoline and diesel oil. The decline will naturally expand if a larger population is placed under "lockdown", as will its impact on the energy market. In this study, the possible decline in energy demand under a "lockdown" was calculated on a per-day basis. Therefore, for actual energy markets and energy industries, the duration of the "lockdown" and the resulting impact on the total amount, as well as these per-day values, are also important factors.

Finally, it should be noted that there are limits on the availability of data for the energy demand of large cities, there is significant uncertainty as to the kind of restrictions that might be imposed in a "lockdown" and how rigorously they would be enforced, and the calculations in this estimate were performed based on certain prerequisites and conditions in view of these uncertainties. Further, this estimate assumes that the "lockdown" takes place in April; if imposed in summer or winter, the calculation results would be different due to the factors such as the impact of air conditioning. Our estimates need to be refined by taking these points into account and performing further analyses using more detailed data and by reflecting the situations of actual lockdowns.

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Analysis of the Impacts of COVID-19 on the Global Demand for Oil, Natural Gas and LNG

Ken Koyama *, Shigeru Suehiro **

Introduction

The new corona virus (COVID-19) pandemic continues to spread worldwide. According to the World Health Organization, the number of persons infected by the virus had reached 292 thousand on March 22, causing 12,784 deaths, with cases of infection found in more than 170 countries. With the risks of the virus showing no sign of ending, the spreading pandemic poses a grave threat to the world economy and a drop in the world economic growth rate appears unavoidable. As a result, energy demand has begun to shrink worldwide, causing prices in global energy markets to plunge[1]. The magnitude and duration of the fall in demand will greatly influence the supply-demand balance in global energy markets and also crude oil and LNG prices, severely affecting global energy industries, the economies of oil/gas-producing countries and the economies of consumer countries.

Considering the gravity of the situation, for this special flash report we developed a demand analysis model and used it to analyze the slowdown of the world economy in 2020 due to COVID-19 and the resulting fall in the demand for oil, natural gas and LNG. Since the situation remains highly uncertain, we prepared for the following two different scenarios, the "early stabilization scenario" and the "protracted pandemic scenario", in addition to the baseline scenario based on the demand forecasted without taking account of the impacts from COVID-19, and analyzed the fall in demand by region, product and sector of use. The key findings of the analysis are discussed below.

1. Analytical Framework

We had to make important assumptions about the economic growth rates in different regions of the world. For the baseline scenario, namely without COVID-19, we took the economic growth rates from the latest edition (January 2020) of the World Economic Outlook published by the International Monetary Fund (IMF). Then, considering the uncertainty in predicting the worldwide spread of COVID-19, we prepared for the following two scenarios.

Early Stabilization Scenario (ESS):

Infection by COVID-19 has peaked in China, and is assumed to peak also in Japan and South Korea in March or April, and in April or May in Europe, North America and Iran. In the Middle East countries other than Iran, and also in South America, Africa, South/Southeast Asia, Russia, Central Asia and Australia, the infection will not spread to a serious level. The risks caused by infection will mostly end during July and August, after which economic activity will begin to recover to normal levels.

Protracted Pandemic Scenario (PPS):

Infection by COVID-19 has peaked in China, and as under the ESS, is assumed to peak also in Japan and South Korea in March or April. However, in Europe, North America and Iran, infection will continue to spread until peaking in July, August or September. It is also assumed that infection will spread to the Middle East countries outside Iran, and also to

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[1] On March 18, 2020, the WTI crude oil futures price fell to US$20.37, barely above the US$20 threshold. It is nearly one third of the average WTI crude oil price in 2019, which was US$57.04.

South America, Africa, South/Southeast Asia, Russia, Central Asia and Australia. As the world economy slows down, economies in East Asia will continue to be impacted negatively by the impact on tourism and trading even after infection in the region reaches its peak. The fall in prices of crude oil and other energy commodities will continue to impact the economies of Middle East countries, Russia and other producing countries that are heavily dependent on the export of energy commodities. Economies will keep plunging throughout 2020 and be unable to recover to normal levels by the end of the year.

Figure 1 compares forecasts for the world economy under the different scenarios, while Figure 2 shows the predicted falls in quarterly GDP from the baseline scenario ("without COVID-19").

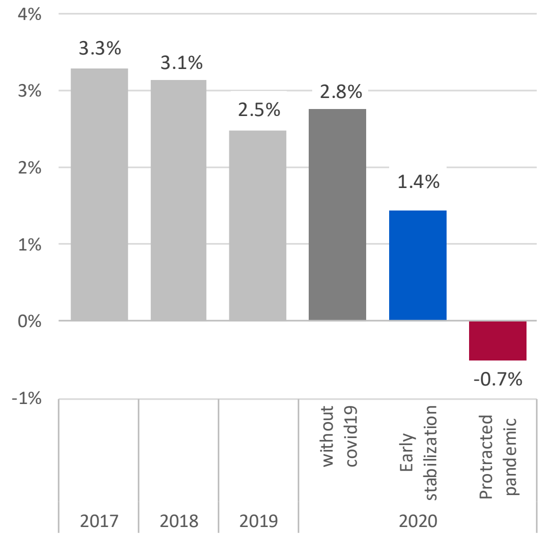

Fig. 1 World economic growth rate forecasts under different scenarios

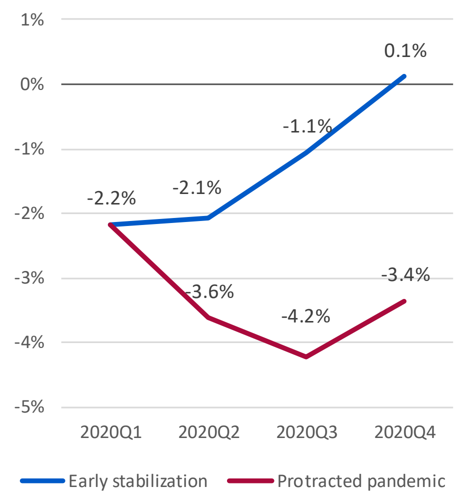

Fig. 2 Forecasted falls in quarterly GDP from the baseline scenario

Source: Forecasts produced by IEEJ

It is still difficult to predict when the risks of infection by COVID-19 will stabilize. We prepared for the above two scenarios for this analysis based only on what we can assume at present. We will continue to monitor the related developments and may review the assumptions as necessary.

We performed the analysis using quarterly economic growth data by region, for which we divided the world into four OECD regions (North America, Europe, Japan + South Korea and Oceania) and eight non-OECD regions/country (China, India, ASEAN, Middle East, former Soviet countries, and three other regions).

We analyzed the oil demand in these 12 regions, dividing oil products into the following categories for product-by-product analysis: LPG, naphtha, gasoline, jet fuel, kerosene, diesel oil, heavy fuel oil, and others. We also analyzed the natural gas demand for the 12 regions, distinguishing the demand for power generation from that for other purposes, determining the natural gas global trade volume from the total demand, and using it to forecast LNG demand[2].

[2] When forecasting demand by product and by sector, we referred to various statistics, forecasts, etc., and also employed our own "expert judgment".

For the 2019 actual figures (including estimated actual figures) used as the starting point for forecasting, data from the International Energy Agency (IEA) were used for oil demand. Concerning natural gas demand, IEA data were used for OECD countries while various statistics were used for non-OECD countries. For LNG, data from Cedigaz were used.

2. Outlook for Oil Demand

Figure 3 shows the outlook for global oil demand during 2020 under the different scenarios indicated by our analysis. In the baseline scenario (without COVID-19), global oil demand in 2020 is expected to reach 101.1 MBD (million barrels per day), which is 1.1 MBD (1.1%) above the 2019 level of 100.0 MBD. Much of the demand is expected to come from Asian nations including China, India and ASEAN countries.

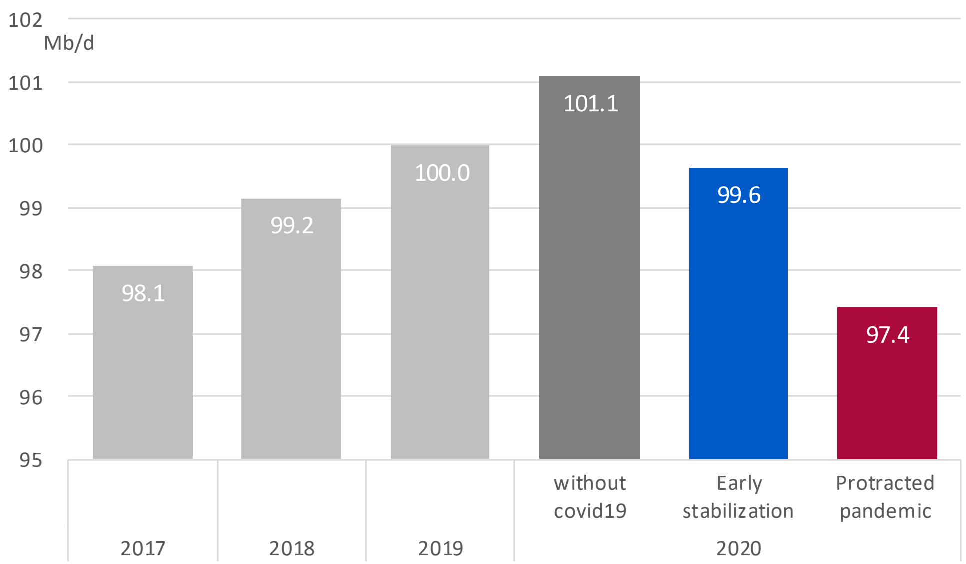

Fig. 3 Outlook for global oil demand during 2020 under different scenarios

Sources: Data from IEA "Oil Market Report." Forecasts produced by IEEJ.

When impacts from COVID-19 are taken into account, global oil demand is expected to fall significantly. Even under the early stabilization scenario (ESS), global oil demand in 2020 is expected to fall to 99.6 MBD, which is 0.4 MBD less than the 2019 level, and a major fall of 1.5 MBD less than the baseline scenario. Under the protracted pandemic scenario (PPS), global oil demand in 2020 is expected to fall further, to 97.4 MBD, a severe fall of 3.7 MBD (3.7%) less than the baseline scenario. This would be the lowest level of demand experienced in the last four years, even lower than that recorded in 2017.

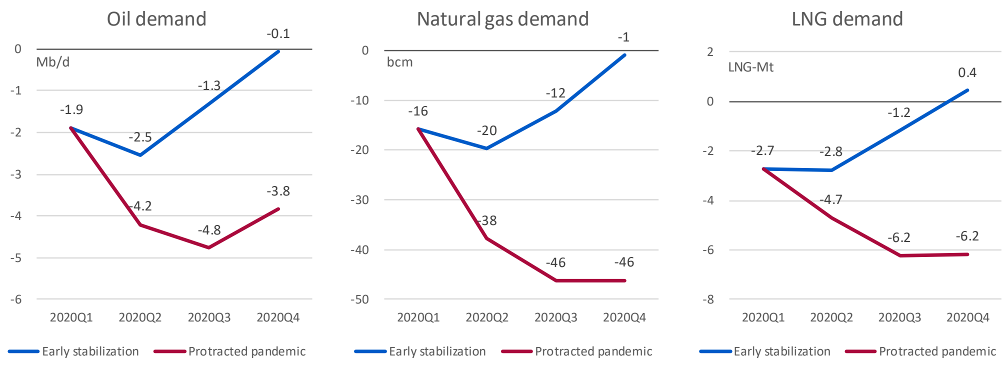

Fig. 4 Divergencies in the forecasted quarterly global demand for oil, natural gas and LNG from the baseline scenario

Source: Forecasts produced by IEEJ

Figure 4 shows divergencies in the forecasted quarterly global demand during 2020 for oil (and also for natural gas and LNG) from the baseline scenario. Under the ESS, the fall in oil demand from the baseline scenario hits the bottom in the second quarter, and recovers to that comparable with the baseline scenario in the fourth quarter. Under the PPS, demand falls dramatically, reaching a fall of 4.8 MBD from the baseline level in the third quarter, and continuing to be significantly lower in the fourth quarter. Due to the diminished demand from the second quarter, the market will be under great pressure to rebalance supply and demand. While COVID-19 spreads, price competition accelerates as the "OPEC Plus" gave up to continue coordinated action to reduce oil production. In this situation, it has already been predicted by many that the supply surplus will become as large as 3 to 4 MBD plus during the first half of 2020. If the fall in demand occurs as predicted by our analysis under the ESS or PPS, the degree of oversupply will worsen. This may accelerate the destabilization of the oil market and requires monitoring the situation.

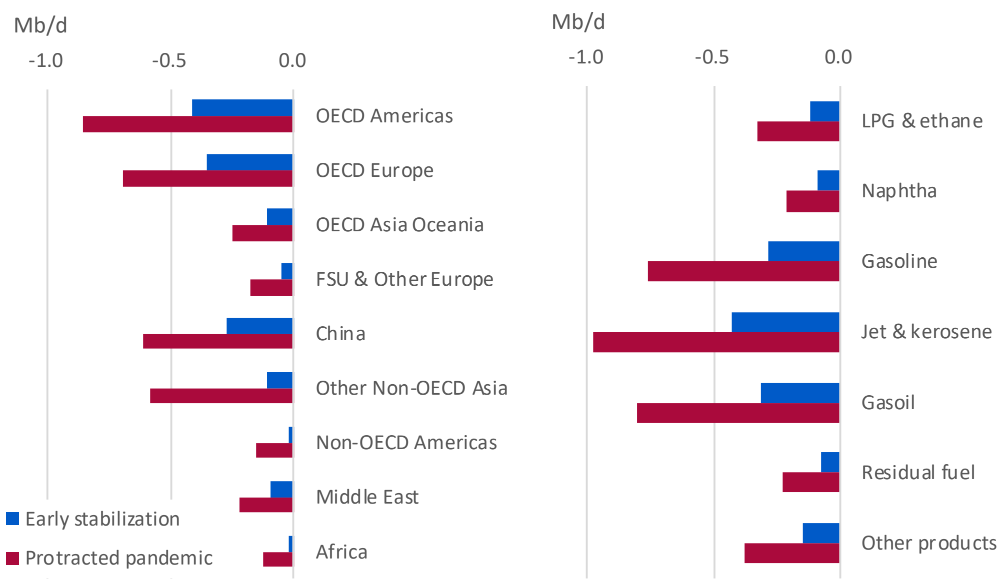

Fig. 5 Fall in demand from the baseline scenario (by region, by product)

Source: Fkinakorecasts produced by IEEJ

Figure 5 shows, by region and by product, the forecasted divergence of demand from the baseline scenario for oil products during 2020 under the two scenarios (ESS and PPS). By region, the fall in demand is expected to be significant not only in China and emerging countries in Asia, which have so far driven the increase in global demand, but also in Europe and North America where infection by COVID-19 is widespread. By product, demand for fuels used mostly in the transportation sector, namely jet fuel, diesel fuel and gasoline, will plunge. As many countries impose lockdowns or request voluntary self-isolation, the longer the infection continues to spread, the longer the impact will last. The reduction in economic activity will also reduce the demand for gasoline and diesel oil.

3. Outlook for Natural Gas and LNG Demand

First, we examine the impacts on the natural gas demand. Under the baseline scenario without COVID-19, global natural gas demand in 2020 was projected to expand to 4,053 BCM (billion cubic meters), achieving the growth of 84 BCM (2.1%) from the previous year. As natural gas is considered a relatively clean energy option, demand for natural gas has increased steadily throughout the world in recent years, and the baseline scenario anticipated that this trend would continue. Under the ESS, demand in 2020 is projected to be greater than in the previous year, but by only 35 BCM, which is less than half of the increase forecasted under the baseline scenario. Under the PPS, the demand in 2020 is projected to be 60 BCM less than the previous year (Figure 6). If global natural gas demand decreases from the previous year, it would be the first time in 11 years since 2009 when demand was hit by the Lehman shock.

By sector, the fall in demand for natural gas for power generation is projected to be significant: 10 BCM (0.8%) down under the ESS and 54 BCM (3.9%) down under the PPS. This would occur not only because power demand would decrease due to the reduction of economic activity, but also because some developing countries would choose more affordable energy options as their economies slow down, causing a relative decrease in the demand for natural gas.

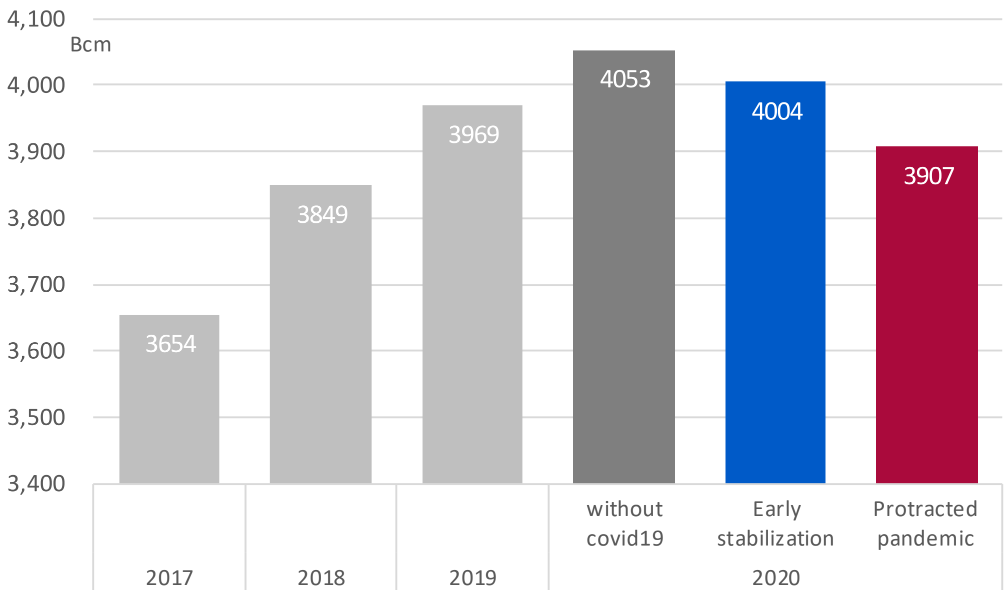

Fig. 6 Outlook for global natural gas demand during 2020 under different scenarios

Sources: Data from BP Statistical Review of World Energy 2019. Forecasts produced by IEEJ.

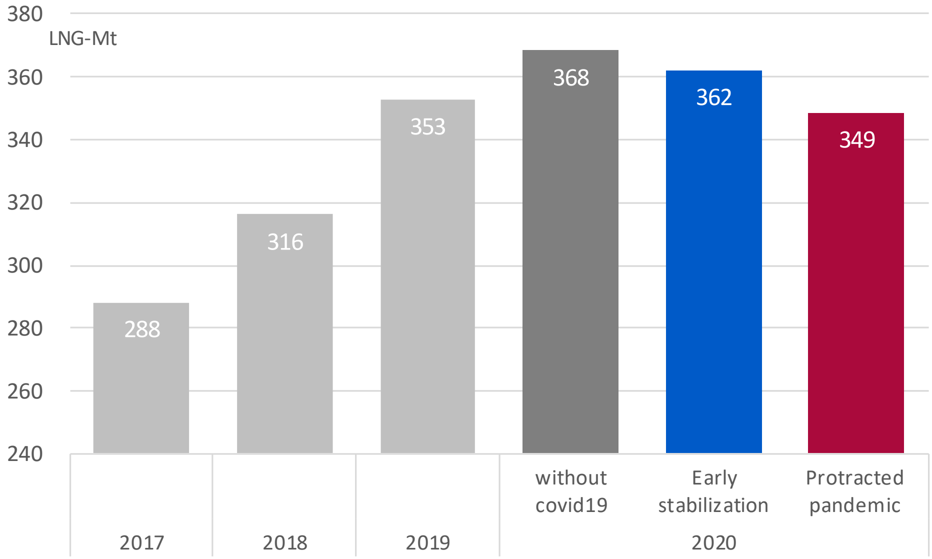

Fig. 7 Outlook for global LNG demand during 2020 under different scenarios

Sources: Data from statistics produced by Cedigaz. Forecasts produced by IEEJ.

Figure 7 compares the outlook for global LNG demand during 2020 under the different scenarios. Although the forecasted trend for LNG is similar to that for natural gas, the fall in demand could be more striking for LNG for certain reasons. The global LNG demand (import volume) has increased far more strongly than natural gas demand in recent years, with a year-on-year growth rate of 9.6% in 2018 and 11.6% in 2019, for example. The major factors were expanding LNG demand in China and other emerging countries in Asia and strong LNG demand in Europe. Under the baseline scenario, growth of demand in 2020 was projected to be at 4.4 %, milder than during the last two years, but still, the annual demand was forecasted to be as large as 368 MT (million tons). However, under the ESS, demand is projected to grow more slowly to 362 MT, while under the PPS, demand in 2020 is expected to be 349 MT, which is 5 MT down from the previous year. That is, global LNG demand, which has grown by around 10% in recent years, may plunge due to the impacts from COVID-19. This may happen as LNG demand decreases significantly as the worldwide natural gas trade volume diminishes due to the stagnating demand for natural gas. Demand for natural gas will also fall due to competition with other energy options (like coal) as well as for LNG due to competition with not only other energy options but also with pipeline gas. Note that if LNG prices fall significantly (in comparison with other energy options including pipeline gas), the situation may be affected in various ways.

Figure 4 shows divergencies in the forecasted quarterly global demand during 2020 for natural gas and LNG from the baseline scenario. Under the ESS, both the natural gas demand and the LNG demand will fall the greatest from the baseline scenario in the second quarter, and will both recover nearly to the baseline scenario in the fourth quarter. Under the PPS, however, both demands are projected to remain very weak throughout 2020, with low demand persisting through the third and fourth quarters.

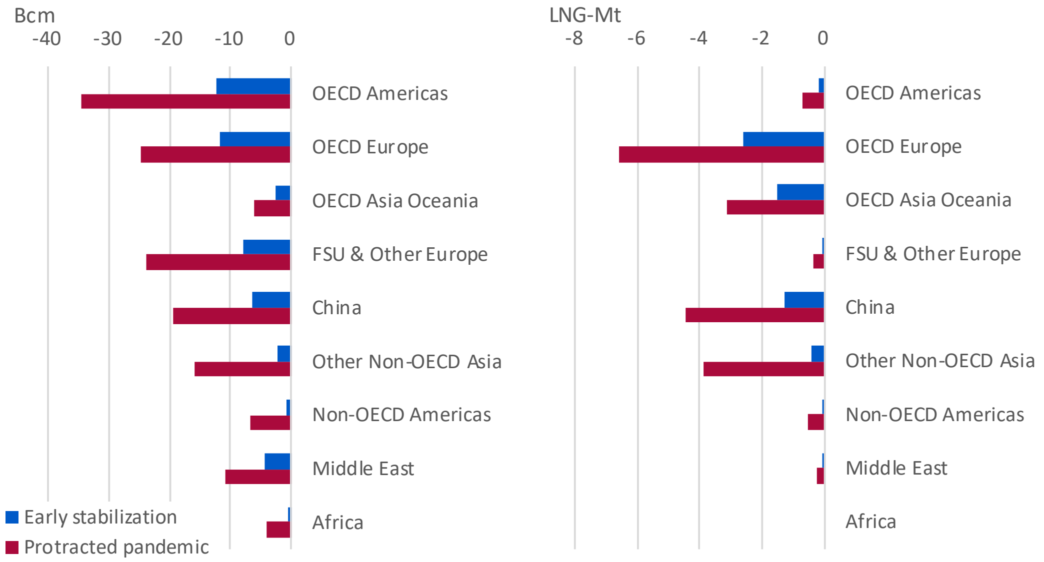

Fig. 8 Fall in demand from the baseline scenario (for natural gas on the left, for LNG on the right)

Source: Forecasts produced by IEEJ

Figure 8 shows, by region, the fall in forecasted demand during 2020 from the baseline scenario for natural gas and LNG. As to natural gas, although the fall in demand is expected to be significant also in emerging and developing countries in Asia and elsewhere, the projected fall in demand in major natural gas consuming regions of the world, namely, in Europe, North America, former Soviet countries, and so on, is more significant. A similar trend is expected regarding the fall in LNG demand by region. Since the center of LNG demand in the world is Asia, the fall in LNG demand is projected to be significant particularly in China and other emerging countries of Asia, and also in Asian OECD countries like Japan and Korea due to the economic slowdown and other factors. Under the PPS, LNG demand is projected to fall significantly also in Europe, another center of LNG demand, due to the protracted worsening of the risks of infection by COVID-19.

4. Conclusion

Compared with the forecasts made under the baseline scenario without COVID-19 impact, the forecasts made under the "Early Stabilization Scenario" assuming that the risks of infection stabilize relatively early and the economy returns to normal, and the forecasts made under the "Protracted Pandemic Scenario" assuming that the risks are protracted and spread in certain regions, predict significant falls in the demand for oil, natural gas and LNG depending on the extent of the economic slowdown, etc.

Although the extent by which demand falls will be chiefly determined by the degree of economic slowdown, the demand for oil products will be influenced also by various secondary factors such as the fall in demand for transportation services, the competitive position in relation to other energy options, and whether or not a given region is a major consumer of a given product.

Particularly under the Protracted Pandemic Scenario, the forecasted fall in demand is extremely large for every energy commodity. If the scenario materializes, it will lead to a significant oversupply in global markets, causing the prices of given products to collapse. The falling prices and shrinking demand will suppress the profits of global energy industries, and severely impact the economies of oil and gas producing countries.

Although the fall in prices of oil and gas commodities is favorable for net-import and consuming countries, it is not entirely good news since the root cause of the fall is a global economic depression. Furthermore, the situation may lead to instability in oil and gas producing countries which are important for the global energy supply security/stability, and such instability and uncertainty over the future could later cause insufficient investment in global energy resources supply chain which is essential for energy security.

Closing note:

When performing the analysis for this report, we decided to prioritize the timely release of the results, considering the importance of the problem and rapidly changing situation, and therefore relied on information available at present when making assumptions. The COVID-19 crisis may unfold in various ways and must be closely monitored. As to the demand for oil, natural gas, LNG, etc., we must keep watching market trends and changes in demand, with detailed attention to various aspects such as by region, product and sector. Considering such uncertainty and changing situation, we may need to update the analysis if required.

Hydrogen Production from Offshore Wind and Hydrogen Infrastructure Development in Europe

Sichao KAN *

Summary

Offshore wind is positioned as one of the key energy supply sources in Europe's energy and environment strategy. According to the International Energy Agency, offshore wind power is expected to account for one-fifth of electricity supply in the European Union in 2040 (Sustainable Development Scenario)[1]. Furthermore, the power generation cost of offshore wind has declined in line with the capacity expansion of wind power. Recent auctions have indicated that successful bid prices are now below \$0.05/kWh (operation starts beyond 2025). Meanwhile, as a means to make best use of offshore wind resources, power transmission infrastructure development plays an important role. But hydrogen production is attracting attention in Europe as well for the same reason. The United Kingdom, Germany, the Netherlands and other North Sea countries have already started their efforts to promote hydrogen production with electricity from offshore wind. As for hydrogen transportation, which is another important issue to be considered in the hydrogen strategy, some European countries are planning to increase hydrogen blending ratios for gas pipelines as a short-term measure. They also have a plan to modify existing gas pipelines into those dedicated for hydrogen as a long-term strategy.

In Japan, offshore wind power generation projects were promoted after the enactment of the "Act of Promoting Utilization of Sea Areas in Development of Power Generation Facilities Using Maritime Renewable Energy Resources." However, constraints in grid connection capacity and the high cost of grid connection for offshore wind power are identified as the key problems for further development of offshore wind. In this regard, European experiences may suggest that hydrogen production with offshore wind power will be an option to avoid the grid interconnection constraints.

To achieve an 80% cut in greenhouse gas (GHG) emissions by 2050, Japan will have to low-carbonize the gas sector. It is necessary to accelerate policy discussion on how to transform the existing gas infrastructure to accommodate low-carbon gases including hydrogen.

1. Background

In December 2019, the European Commission released the European Green Deal aiming for net-zero greenhouse gas emissions by 2050[2]. In France and the United Kingdom, net-zero emissions by 2050 has already been legislated. Combining low carbon electricity with electrification of final energy consumption is one of the economical ways for GHG reduction. However, since not all the sectors could be electrified easily, CO2-free hydrogen is getting more and more attention as a green substitute for fossil fuels in areas where electrification is difficult. Hydrogen production with renewable electricity can also absorb variable renewable energy's intermittency and ease its impact on the electric grid. It is for these reasons that hydrogen coupled with renewable energy is expected to be one of the key technologies to support a low-carbon society.

Offshore wind is positioned as one of the key energy supply sources in Europe's energy and environment strategy. From 2010 to 2019, offshore wind power capacity in Europe expanded about 6.5-fold (from 2,931 MW to 21,984 MW[3]). Meanwhile, the power generation cost of offshore wind continued to decline. From 2010 to 2018, the average offshore wind

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1 IEA, Offshore Wind Outlook 2019, https://www.iea.org/reports/offshore-wind-outlook-2019

2 In December 2019, new European Commission President Ursula von der Leyen released the so-called European Green Deal seeking to achieve net-zero GHG emissions by 2050.

3 IRENA, Renewable Capacity Statistics 2020, https://www.irena.org/publications/2020/Mar/Renewable-Capacity-Statistics-2020

power generation cost decreased by 14% from \$0.156/kWh to \$0.134/kWh[4]. In some offshore wind auctions, the successful bidding price has dropped below \$0.05/kWh (operation starts beyond 2025)[5]. To make the best use of this low cost renewable resource, countries around the North Sea, which is the hottest spot of Europe's offshore wind development, are looking to using offshore wind for hydrogen production and have announced a number of feasibility studies and demonstration projects.

At the same time, how to develop hydrogen infrastructure to support the scaling up of the CO2-free hydrogen[6] market, especially how to transform and utilize the existing gas infrastructure to accommodate hydrogen, has become one of the central issues in European countries' recent discussions on hydrogen development. This paper reviews the latest trends in offshore wind hydrogen production and hydrogen infrastructure development in 3 North Sea countries: the United Kingdom, Germany, and the Netherlands. And by studying the cases in these countries, this paper also looks at what the implications for Japan's offshore wind power and hydrogen development are.

2. European trends for hydrogen production with offshore wind and hydrogen use

2-1. U.K.

The United Kingdom has the world's largest offshore wind power generation fleet. By the end of 2019, installed offshore wind power capacity in the United Kingdom has reached 9,800 MW and its power generation accounted for around 10% of the country's total[7]. The country intends to further expand its offshore wind power deployment to 30,000-40,000 MW by 2030. Given that the United Kingdom has legislated net-zero GHG emissions by 2050, decarbonization of non-electricity energy demand will also be required and CO_2-free hydrogen is one of the answers. With these contexts, hydrogen production with offshore wind power naturally is one of the promising solutions for the country's long-term energy supply. Two examples of the government supported initiatives on offshore wind hydrogen production are: the Gigastack project and the Deepwater Offshore Local Production of Hydrogen (DOLPHYN) project.

The Gigastack project uses electricity from the 1,400 MW Hornsea 2 wind farm[8] (operation starts in 2022) for hydrogen production and the hydrogen will be provided to an oil refining facility[9]. The project is led by electrolyser system manufacturer ITM Power with partners including Hornsea Wind Farm developer and operator Ørsted, oil refiner Phillips 66 Limited, and energy consultant Element Energy. One of the Gigastack project's major objectives is to develop a large low-cost electrolyser stack (Table 1). After a feasibility study that ended in 2019, the project has entered its second phase, which includes the design of a 100 MW hydrogen production system and the development of a business case for green hydrogen in the United Kingdom[10].

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4 IRENA, Renewable Power Generation Cost in 2018, https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2019/May/IRENA_Renewable-Power-Generations-Costs-in-2018.pdf

5 IEA, Offshore Wind Outlook 2019, https://www.iea.org/reports/offshore-wind-outlook-2019

6 CO_2-free hydrogen includes green hydrogen from renewable energy sources and blue hydrogen from fossil fuels combined with CCS (Carbon Capture and Storage).

7 Department for Business, Energy & Industrial Strategy, Wind powered electricity in UK, https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/875384/Wind_powered_electricity_in_the_UK.pdf

8 The Hornsea Wind Farm covers four subsites for total capacity at 6 GW. Its construction started in 2018 and Hornsea 1 is already in operation. Completion of all the subsites is expected to be in 2028.

9 https://investor.phillips66.com/financial-information/news-releases/news-release-details/2020/Industrial-scale-renewable-hydrogen-project-advances-to-next-phase/default.aspx

10 Phase 2 received a 7.5-million-pound subsidy.

Table 1 Electrolyser system performance improvement and cost reduction targets in the Gigastack project

FCH 2 JU Multi-Year Annual Work Plan Targets		State of the Art (2017)	2020	2024	2030	Gigastack
KPI1	Electricity Consumption @ Nominal Capacity (kWh/kg)	58	55	52	50	54
KPI2	Capital Cost (£/kW)[1]	1,090	820	640	450	300-400
KPI3	Degradation (%/1,000hrs)	0.25	0.19	0.125	0.12	0.09
KPI4	Hot Idle Ramp Time (s)	10	2	1	1	<1
KPI5	Cold Start Ramp Time (s)	120	30	10	10	<30

1: Assuming €1.10/£
KP4 & KP5 shall be considered as optional targets to be fulfilled according to the profitability of the services brought to the grids thanks to the addition of flexibility and/or reactivity (considering also potential degradation of the efficiency and lifetime duration.

Source: Element Energy, Gigastack Bulk Supply of Renewable Hydrogen, January 2020[11]

The DOLPHYN project's focus is on long-term green hydrogen supply and is looking at hydrogen production with floating offshore wind power. As offshore wind development goes further, sites suitable for bottom-fixed wind farms (in shallow water areas where the water depth is up to 50-60 meters) will become more and more scarce, and floating wind farms (deep water areas where the water depth is more than 50-60 meters) need to be developed in the long term. The United Kingdom and other European countries are also working on the commercialization of floating offshore wind power generation. Since floating wind farms are usually far away from onshore, the DOLPHYN project is considering a system design with on-site hydrogen production (with a water desalination and electrolyser system installed on a 10 MW floating wind platform) (Figure 1) and using an undersea pipeline to bring hydrogen onto land[12]. The project will start with a 2 MW prototype platform (the U.K. government will provide a 3.12-million-pound subsidy to the project[13]) and partners of the project include: Environmental Resources Management Limited, Tractebel Engie, ODE and others. The DOLPHYN project has set a target to cut hydrogen production cost to 1.15 pounds/kg ($1.41/kg[14]) or less beyond 2030.

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11 https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/866377/Phase_1_-_ITM_-_Gigastack.pdf

12 According to an economic assessment by the project partners, on-site hydrogen production combined with an undersea hydrogen pipeline is more economically efficient than onshore hydrogen production from electricity transmitted from offshore wind power farms because, in this case, the offshore wind farm is far from the coast and the power transmission cost is high.

13 https://www.gov.uk/government/publications/hydrogen-supply-competition/hydrogen-supply-programme-successful-projects-phase-2#dolphyn

14 Cost of hydrogen production using natural gas combined with CCUS (carbon capture, utilization and storage) stands at $1.4-1.5/kg. (IEA, The Future of Hydrogen, https://webstore.iea.org/download/direct/2803)

Fig. 1 Floating wind farm platform designed for hydrogen production

Source: Department for Business, Energy & Industrial Strategy, Dolphyn Hydrogen Phase 1 Final Report, October 2019[15]

In the United Kingdom, CO_2-free hydrogen is perceived as a promising option for decarbonizing the gas sector. In 2018, heating demand accounted for 66% of the U.K.'s natural gas consumption (12% for the industry sector[16], 35% for the residential sector, 9% for the commercial sector and 10% for others)[17]. Therefore, switching from natural gas to hydrogen to meet the heating demand will dramatically reduce natural gas consumption in the United Kingdom. To achieve the fuel switching, the United Kingdom has already kickstarted initiatives ranging from safety testing of consumer side hydrogen appliances to hydrogen infrastructure development.

For example, the Iron Mains Replacement Programme (IMRP)[18] which is already underway at present would save significant funding for hydrogen infrastructure development. In this programme, iron gas mains in the natural gas distribution grid is replaced with polyethylene (PE) ones (<7bar), which are suitable for hydrogen delivery. When the program is completed around 2031, about 90% of the gas distribution network in the United Kingdom is expected to be hydrogen ready[19].

Currently, the hydrogen blending ratio in natural gas pipelines is limited at below 0.1 vol% in the United Kingdom. As the first step to scale up usage of CO_2-free hydrogen, demonstrations are carried out to test the feasibility of higher hydrogen blending. One example is the HyDeploy project which is co-led by ITM Power and Keele University. In this project, the safety of 20 vol% hydrogen blending to natural gas distribution pipelines and gas appliances without changes to these facilities is tested within the Keele University gas networks (this project was granted a special exemption from the Health and Safety Executive to the current hydrogen blend limit[20]). Like the HyDeploy project, the HyNET NW project also considers higher hydrogen blending into the existing gas infrastructure without replacement of the current gas appliances. At the same time, there are also projects focusing on the feasibility of switching from natural gas to 100% hydrogen such as the H4Heat project, H21 (H21 Leeds City Gate Project, H21NIC and H21 North of England) project, and the H100 project.

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15 https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/866375/Phase_1_-_ERM_-_Dolphyn.pdf

16 Including the energy conversion process in the industry sector

17 Gas (DUKES) (updated in July 2019), https://www.gov.uk/government/statistics/natural-gas-chapter-4-digest-of-united-kingdom-energy-statistics-dukes

18 This programme was implemented for safety considerations

19 https://www.icheme.org/media/11593/transitioning-to-hydrogen-report.pdf

20 https://www.itm-power.com/news/hydeploy-uk-gas-grid-injection-of-hydrogen-in-full-operation

2-2. Germany

Germany has the world's second largest offshore wind power generation capacity (7,745 MW at the end of 2019) with a target of installing 15,000 to 20,000 MW offshore wind by 2030. Germany will phase out nuclear power by 2022 and coal-fired power by 2038 and is committed to renewable energy development, aiming to raise the country's renewable energy's share in the power generation mix to 65% by 2030.

In Germany, most of the wind farms are located in the north part of the country, while electric power load centers are in the south. Because of the constraints of north-south power transmission capacity, Germany proactively promotes the so-called Power-to-Gas (PtG) projects in which electricity from renewable energy is converted into hydrogen and the hydrogen can be used in various sectors. Since offshore wind farms are also in the north, further expansion of offshore wind will put more pressure on the already stringent power transmission limitations. Using offshore wind for hydrogen production is a possible solution to grid constraints and is gathering more and more attention.

In 2019, oil refiner Raffinerie Heide launched the Westküste 100 project in the northern German state of Schleswig-Holstein in cooperation with partners including Thyssenkrupp, EDF (Germany), Holcim Germany (a cement company), Open Grid Europe (OGE), Ørsted, Thüga Aktiengesellschaft (an investment company), the Heide Region Development Agency (a local government development organization) and Stadtwerke Heide (a local government-owned utility), etc. The project plans to produce carbon-neutral synthetic jet fuel from green hydrogen (hydrogen produced from renewable energy) and CO2 captured at a nearby cement plant[21]. Green hydrogen will be produced with surplus electricity (electricity that otherwise would be curtailed) from the nearby offshore wind farm. For the initial phase of the project, a 30 MW electrolyser system will be installed within the 5-year project period[22]. Based on experiences from the initial phase, the electrolyser capacity might further be scaled up to 700 MW, and more applications of green hydrogen are also under consideration.

Because of the power transmission constraints and the increasing demand for CO_2-free hydrogen, hydrogen production with offshore wind is expected to further increase in Germany. In the National Hydrogen Strategy published in June 2020 it is mentioned that the framework for harnessing offshore wind for green hydrogen will be further developed[23].

In terms of hydrogen infrastructure, utilization of existing natural gas infrastructure is given high priority in Germany. Germany allows hydrogen to be blended into natural gas pipelines at the ratio of 2 to 10 vol%[24] (differed by region) and there are already a number of demonstrations of blending hydrogen into natural gas pipelines. Projects of producing carbon-neutral synthetic fuels (such as methane and liquid fuels) from green hydrogen and CO_2 (as in the abovementioned Westküste 100 project) are also being carried out. Carbon-neutral synthetic fuels can not only contribute to CO_2 emission reduction but the utilization of such fuels does not require major changes to existing infrastructure or energy appliances.

Existing natural gas networks will also play a central role in the development of hydrogen infrastructure for the long term. At the Gas 2030 Dialogue, which was set up by the Federal Ministry for Economic Affairs and Energy (BMWi)[25] to consider the future development of gas infrastructure, how to handle hydrogen in the current gas networks is one of the key topics. The first draft report from the Dialogue suggests that hydrogen network development should be coordinated with the scaling up of hydrogen demand and dedicated hydrogen networks for industry and transportation sector users in some regions will be needed. It also emphasizes that existing natural gas infrastructure (including pipelines and storage facilities) should be utilized for developing hydrogen networks (for example the retrofitting of natural gas pipelines for hydrogen

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[21] Framework of the project can be found at https://www.westkueste100.de/

[22] https://www.heiderefinery.com/en/press/press-detail/cross-sector-partnership-green-hydrogen-and-decarbonization-on-an-industrial-scale/

[23] Federal Ministry for Economic Affairs and Energy (BMWi), The National Hydrogen Strategy, https://www.bmwi.de/Redaktion/EN/Publikationen/Energie/the-national-hydrogen-strategy.pdf?__blob=publicationFile&v=6

[24] IEA, Limits on hydrogen blending in natural gas networks, 2018, IEA, Paris https://www.iea.org/data-and-statistics/charts/limits-on-hydrogen-blending-in-natural-gas-networks-2018

[25] December 2018

delivery).

In response to such government policy, FNB Gas, a group of gas transmission pipeline operators in Germany, has released a hydrogen network vision including dedicated hydrogen pipelines totaling 5,900 km (Figure 2). Of the hydrogen network vision, 90% of the hydrogen networks will be pipelines or storage caverns converted from existing natural gas infrastructure (retrofit). In May 2020, FNB Gas announced the H2 Startnetz 2030 plan which is a proposal for a 1,200 km hydrogen grid in northern Germany by 2030 (1,100 km converted from existing natural gas pipelines and 100 km of new hydrogen pipelines). Investment requirement for the 1,200km hydrogen network is estimated to be around 660 million euros (1% increase of pipeline fees[26]). FNB Gas is also going to incorporate hydrogen into its new Gas Network Development Plan 2020-2030 and has conducted studies on mapping future hydrogen supply and demand (the distribution of domestic PtG facilities, hydrogen import terminals, and hydrogen end use facilities).

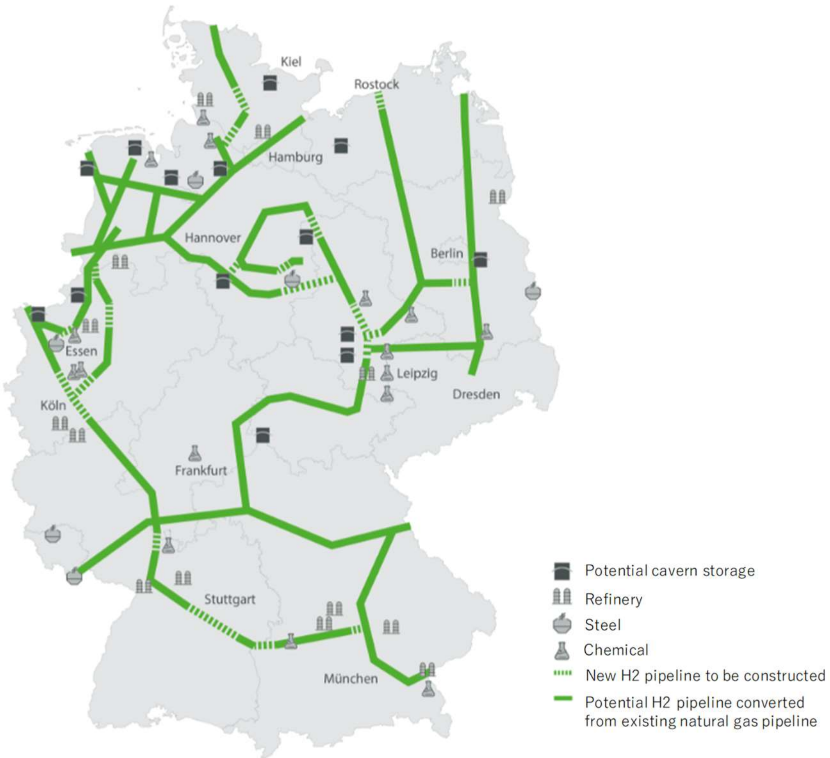

Fig. 2 Hydrogen network vision

Source: FNBGas[27] (Modified by the author)

Demonstrations on building a hydrogen network using existing gas infrastructure have already begun. One of such efforts is the GET H2 Nukleus project[28], led by BP, RWE, chemical manufacturer Evonic, and gas pipeline operators Nowega and OGE. The project seeks to build a green hydrogen production facility (a 100 MW electrolyser system using wind power) in Lingen, Lower Saxony States, northwestern Germany, and use a 130 km pipeline to deliver the green hydrogen to chemical facilities and oil refinery plants in Gelsenkirchen, Westphalia State. The pipeline is expected to start operation by the end of 2022. Most of the pipeline will be from existing natural gas pipeline retrofitted to handle 100% hydrogen with a small part of new hydrogen pipeline.

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[26] FNB Gas, https://www.fnb-gas.de/media/h2-startnetz_2030_mit_erlaeuterung.pdf

[27] https://www.fnb-gas.de/fnb-gas/veroeffentlichungen/pressemitteilungen/fernleitungsnetzbetreiber-veroeffentlichen-karte-fuer-visionaeres-wasserstoffnetz-h2-netz/

[28] GET H2 Nukleus project https://www.get-h2.de/en/get-h2-nukleus/

2-3. Netherlands

The Netherlands has set a target of cutting GHG emissions by 49% from the 1990 level by 2030 and as one of the efforts to achieve the target the country also decided to legislate a plan for phasing out coal-fired power generation by 2030. At the same time, the Netherlands will halt its domestic gas production (shut down the Groningen gas field) by 2022. Gas produced at the Groningen gas field is the so called low-calorie gas with a nitrogen content of 14%[29]. Pipelines and end use appliances for the low-calorie gas are different from those for high-calorie gas (for example, gas imported from Russia). With the shutdown of the Groningen gas field, substitutes for the low-calorie gas will be needed and hydrogen is perceived as one of the promising options. The Dutch government, though accepting blue hydrogen (hydrogen from fossil fuels combined with CCS) for short-term use for economic reasons, plans to use mainly green hydrogen in the long term and positions hydrogen production with electricity from offshore wind as one of the key technologies for its future energy supply.

By the end of 2019 the Netherlands has about 1,118 MW of offshore wind power generation capacity and the country is looking to raise the capacity to 11,500 MW by 2030. To bring down green hydrogen production cost, the country has also set a target for electrolyser systems installation. According to the Climate Agreement published in June 2019, the Netherlands is going to install 3,000 to 4,000 MW electrolyser systems by 2030[30].

Under the environmental and energy context, hydrogen production with offshore wind power is getting more and more attention in the Netherlands, not only from the government but also from energy companies. Oil giant Shell Netherlands, Dutch gas grid operator Gasunie and Groningen Seaports have jointly launched one of the world's largest green hydrogen projects, the NortH2 project, planning to install a 3,000-4,000 MW[31] electrolyser system by 2030. The project is going to use electricity from offshore wind farms in Eemshaven for hydrogen production. The project also seeks to further scale-up the hydrogen production capacity to 10,000 MW with 0.8 million tons of annual hydrogen production by 2040. In the same region with the NortH2 project (Groningen region), German energy companies RWE and Innogy are also conducting a feasibility study on hydrogen production using offshore wind power. The Dutch government plans to construct an energy island in the North Sea with offshore wind power generation and hydrogen production facilities by 2030. The government is also considering auctions of combined offshore wind power and hydrogen production projects.

For the long-term environmental policy, the Netherlands supports the European Commission's 2050 carbon neutral proposal and is preparing a bill to cut domestic GHG emissions by 95% from the 1990 level by 2050. CO_2-free hydrogen is expected to play an important role in the Netherlands' long-term energy strategy. And the period through 2030 is perceived as a critical preparation period towards scaling up of CO_2-free hydrogen deployment and supply in the long-term. The budget requirement for the government's hydrogen strategy by 2030 is estimated to be around 1.5-2.0 billion euros (Table 2).

Like Germany, the Netherlands is also putting great emphasis on effectively utilizing the existing natural gas infrastructure for hydrogen network development. For the short-term, hydrogen blending into existing natural gas pipelines is what the government is looking to (raising hydrogen blending from 2vol% to 10-20vol%) for scaling up hydrogen deployment. The country's hydrogen strategy[32] published in April 2020 indicates that there might even be a mandatory requirement for green hydrogen blending into the existing gas pipelines.

Gas pipeline operator Gasunie and other companies have launched several demonstration projects on converting existing natural gas pipelines for hydrogen delivery. For example, the Hydrogen Symbiosis project implemented in 2016 in the

[29] The Oxford Institute for Energy Study, The great Dutch gas transition, 2019, https://www.oxfordenergy.org/wpcms/wp-content/uploads/2019/07/The-great-Dutch-gas-transition-54.pdf

[30] Seeking to cut costs from 1 million euros/MW at present to 0.35 million euros/MW in 2030 (Climate Agreement page 181).

[31] In line with the Dutch government's target of installing a 3,000-4,000 MW electrolyser system by 2030.

[32] Government Strategy on Hydrogen.
https://www.government.nl/documents/publications/2020/04/06/government-strategy-on-hydrogen

Netherlands' Zeeland region retrofitted a 12 km gas pipeline for hydrogen delivery purpose[33]. The pipeline has already started operation, with the hydrogen blending ratio around 70%[34] at the initial phase and is able to deliver more than 4,000 tons of hydrogen per year[35]. Gasunie is also implementing several other projects on pipeline hydrogen delivery for industry users in Eemshaven, North Sea Canal, Rotterdam, etc.

Table 2 Estimated budget required on hydrogen programmes until 2030

Item	Target year	Estimated budget (in millions of euros)
Program development	Continuing	0.2-0.5/year
Realizing large-scale (gigawatt-class) hydrogen production	2030	1,000 or more
Construction of a hydrogen backbone in the Netherlands and hydrogen storage	2030	Undecided (including some private sector investment)
Deployment of controllable and flexible power plants using hydrogen	2030	250 or more
Pilot projects of hydrogen in the built surroundings (3-5 projects)	2025	10-0
Mobility on hydrogen (including hydrogen stations)	2025	10-20
Pilot and demo projects for hydrogen in industry	2025-2030	50-100
Integration of decentralized sustainable electricity production via hydrogen	2025	10-20
Designing and constructing an energy island for demonstration	2030	100 or more
Preconditions (including safety, legislation and regulations, gas quality, standardization)	2020-2021	10-20
Medium- to long-term R&D agenda	2020-2030	5-10/year

Source: Prepared by the author from TKI New Gas documents[36]

2-4. Others

In addition to the United Kingdom, Germany and the Netherlands, Denmark is also working on hydrogen production using electricity from offshore wind. In December 2019, the Danish government provided a more-than-$5-million subsidy to the

33 Deliver by-product hydrogen generated at a Dow Benelux plant to fertilizer plants of Yara and ICLIP.

34 http://www.vndelta.eu/files/4014/7573/9067/Europees_werkbezoek_LSNED_SDR_08092016.pdf

35 https://www.weltenergierat.de/wp-content/uploads/2018/03/Bringing-North-Sea-Energy-Ashore-Efficiently.pdf

36 TKI New Gas, Multi-year Programmatic Approach for Hydrogen, https://www.topsectorenergie.nl/sites/default/files/uploads/TKI%20Gas/publicaties/Waterstof%20voor%20de%20energietransitie%20-%20innovatieroadmap%20(jan%202020).pdf

H2RES project that is undertaken by 7 companies including Ørsted, the largest offshore wind power generator. Under the project, a 2 MW electrolyser system and a hydrogen storage facility will be built at the Avedore power plant in suburban Copenhagen, and electricity from an offshore wind farm operated by Ørsted will be fed into the system for hydrogen production (planned hydrogen production capacity is 600 kg per day). The hydrogen will be supplied to fuel-cell buses and trucks.

Ørsted has also proposed to the Danish government a plan for building an energy hub of offshore wind power and green hydrogen near Bornholm Island. The proposal includes an auction of around 1,000 MW offshore wind near Bornholm Island and construction of power transmission lines connecting Denmark and Poland via Bornholm Island, which is located between the two countries. Offshore wind power generation capacity could be further expanded to 3,000-5,000 MW to provide electricity also to other neighboring countries including Sweden and Germany. Using the electricity from the offshore wind farms for green hydrogen production is also within the scope of the project.

To effectively use the offshore wind resources in the North Sea region, multilateral cooperation is required. The North Sea Wind Power Hub (NSWPH) programme, which has been proposed by several power/gas network operators (Energinet for Denmark, Gasunie for the Netherlands and TenneT for Germany and the Netherlands) and the largest European port, the port of Rotterdam, is one of such multilateral efforts. According to the NSWPH programme, several existing long-term scenarios suggest that offshore wind deployment in the North Sea could be as much as 150,000 MW by 2040[37]. For future offshore wind development in the North Sea, the programme proposes a Hub-and-Spoke concept (Figure 3): constructing several artificial islands in the North Sea with offshore wind power generation and water electrolysis facilities and the artificial islands will be used as energy hubs providing renewable electricity and green hydrogen to the surrounding North Sea countries.

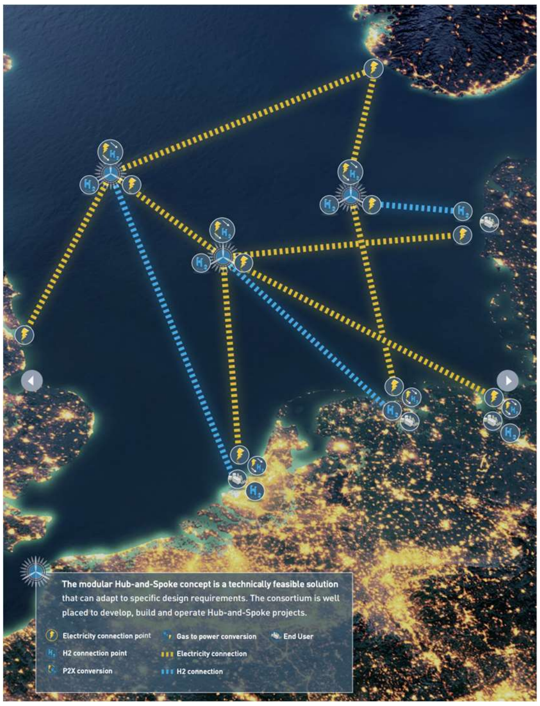

Fig. 3 Hub-and-Spoke

Source: North Sea Wind Power Hub[38]

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[37] NSWPH report, The Challenge, https://northseawindpowerhub.eu/wp-content/uploads/2019/07/Concept_Paper_1-TheChallenge.pdf

[38] https://northseawindpowerhub.eu/wp-content/uploads/2019/11/NSWPH-Drieluik-Herdruk_v01.pdf

3. Conclusion and implications for Japan

Further scaling up of Europe's offshore wind deployment is not without challenges. For example, in order to make sure that electricity from offshore wind is delivered to users in inland areas, additional investment for reinforcing the onshore power transmission and distribution networks will be required. If a large amount of low-marginal-cost offshore wind electricity flows into electricity exchange markets, market prices will substantially be pulled down, which in turn will erode the revenue of offshore wind projects (the so-called cannibalism phenomenon). However, the challenges could partly be addressed by converting some of the offshore wind electricity into hydrogen.

Offshore wind exhibits a higher capacity factor (40-50% for new projects in Europe) and lower output intermittency compared with other variable renewable technologies such as onshore wind or solar PV, which makes it preferable for hydrogen production. Offshore wind has also been getting more and more economically competitive in Europe in recent years, with electricity prices even falling below $0.05/kWh for some auctions. The Hydrogen Council expects that hydrogen production cost with offshore wind power in Europe could become as low as $2.6/kg if proactive policies are in place[39].

The North Sea is at the center of Europe's offshore wind development and demonstrations of feasibility studies on hydrogen production with offshore wind have already been launched in several North Sea countries. Some countries are even considering auctions of offshore wind combined with hydrogen production. Hydrogen production also plays a key role in multilateral initiatives for scaling up offshore wind deployment such as the North Sea Wind Power Hub programme.

In Japan, offshore wind power generation projects were promoted after the enactment of the "Act of Promoting Utilization of Sea Areas in Development of Power Generation Facilities Using Maritime Renewable Energy Resources." However, constraints in grid connection capacity and the high cost of grid connection for offshore wind power are identified as two of the key problems for further development of offshore wind power. In this regard, European experiences suggest that hydrogen production with offshore wind power might be an option to avoid the grid interconnection constraints.

Japan's technical potential for offshore wind is estimated to be around 1.5-1.6 billion kW[40]. In the case of a 35% capacity factor, offshore wind could supply about 5,000 TWh electricity per year, which is 4.7 times of Japan's current total annual power generation (1,051 TWh[41] in FY2018) and is equivalent to more than 80% of Japan's total primary energy supply (19,728 PJ[42] in FY2018). If offshore wind resources in Japan are utilized to the maximum extent, it could provide not only green electricity but also green hydrogen to the country's energy users.

However, given that Japan's offshore wind power generation costs are still high and that the domestic supply chain for offshore wind is still underdeveloped, large-scale hydrogen production with offshore wind power in Japan is not considered practical in the short term. Even if technical and engineering barriers could be cleared, hydrogen production with offshore wind power would still face challenges such as the economic competitiveness against other CO_2-free hydrogen supply options, ensuring enough domestic offtakers (that is, scaling up of domestic hydrogen deployment) and so on. Given the cases in the European countries studied in this paper, however, hydrogen production with offshore wind power could become one of the options for long-term energy supply.

In most European countries' hydrogen strategies, how to develop hydrogen infrastructure is one of the central issues. The countries studied in this paper (the United Kingdom, Germany and the Netherlands) all intend to develop their future hydrogen infrastructure with maximum utilization of existing natural gas networks. Shifting from natural gas to hydrogen

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[39] Hydrogen Council, "Path to hydrogen competitiveness: A cost perspective," 2020, https://hydrogencouncil.com/en/path-to-hydrogen-competitiveness-a-cost-perspective/

[40] Offshore wind resources in areas that are not allowed to be developed are excluded in the technical potential estimation. However, in the technical potential estimation, economic efficiency is not taken into account. Source: NEDO, "Renewable Energy White Paper," https://www.nedo.go.jp/content/100544818.pdf

[41] METI, Comprehensive Energy Statistics, https://www.enecho.meti.go.jp/statistics/total_energy/pdf/stte_030.pdf

[42] Op. cit.

is a long-term process which will require technical and regulatory changes to the existing natural gas networks and some of the natural gas appliances. The European countries are looking to raise hydrogen blending ratios into natural gas pipelines as a short-term measure to scale up the use of CO_2-free hydrogen and at the same time to gradually convert existing gas pipelines into dedicated hydrogen networks for the long term. In Europe, gas pipeline operators are actively engaging in developing hydrogen infrastructure.

Japan has set a target of cutting GHG emissions by 80% by 2050. Low-carbonization or decarbonization of the gas sector would be indispensable for achieving the target. While the natural gas network in Japan is not as developed as those in European countries, natural gas infrastructure in Japan will also need to be ready to accommodate low-carbon gases such as biomethane, carbon-neutral methane, as well as hydrogen. Given that a long-term viewpoint is required for infrastructure development, it is necessary for Japan to accelerate policy discussions on how to transform the existing gas infrastructure to accommodate those low-carbon gases.

A Study on the Feasibility of 80% GHG Reduction in Japan Using a Bottom-up Energy System Model: The Effect of Changes in Meteorological Conditions◆

Yasuaki Kawakami *, Yuhji Matsuo **

Abstract

This paper presents the effect of changes in meteorological conditions in a study on the feasibility of reducing greenhouse gas (GHG) emissions by 80% in Japan toward 2050. The authors develop a bottom-up energy system model which incorporates a high-temporal-resolution power sector and analyze the feasibility under 18 patterns of variable renewable energy (VRE) power profiles. The simulation results show that changes in meteorological conditions, namely the duration of periods without sun and wind, would substantially impact the installed capacity of electricity storage systems. Since the capacity may differ by as much as 300 GWh in 2050, it is essential to consider several VRE power profiles when studying future massive decarbonization where VRE is expected to account for more than 50% in the power generation mix. Although the effect of changes in meteorological conditions on the degree of electrification and the technology choice in the final demand sectors is relatively small, even minor differences may lead to huge variations in GHG marginal abatement cost.

Key words: GHG 80% Reduction, Battery Installation, Variable Renewables, Energy System Model, Linear Programming

1. Introduction

In recent years there has been growing awareness of the importance of tackling global warming. In Japan, the Cabinet approved the Plan for Global Warming Countermeasures[1] in May 2016, setting a goal of reducing greenhouse gas (GHG) emissions by 80% by 2050. Based on this plan, Japan's Long-term Strategy under the Paris Agreement as Growth Strategy[2] released in June 2019 aims to make Japan's energy system carbon-neutral by as early as possible in the second half of this century. Meanwhile, the government has yet to present any specific quantitative estimates regarding how to achieve these targets with combinations of energy technologies.

Regarding Japan's target to reduce GHGs or energy-related CO_2 by 80% by 2050, several studies using bottom-up energy system models have been conducted. Oshiro et al.[3] used the AIM/Enduse model, which divides Japan into 10 regions, to present the extent of reduction measures required to reduce GHGs by 80% as well as the effect of expanding the electricity interconnection capacity on alleviating the cost of reducing emissions. Akimoto et al.[4] conducted a study using the DNE21+ model to demonstrate that the carbon intensity of the power sector must become net negative and fossil fuel consumption must be minimized to achieve the 2050 target. As with MARKAL/TIMES and others, these bottom-up energy system models have a low temporal resolution for the power sector compared to models specializing in the power sector[5), 6)].

In previous analyses of the power sector using dedicated models, only several tens of time slices represent one year, employing the electricity demand curves of typical days[7]. However, such representations cannot explicitly express the fluctuating output of variable renewable energy (VRE), namely solar PV and wind turbines, and various constraints regarding demand-and-supply management of the power system. This methodology may over- or under-estimate the optimum amount of VRE to be introduced or the cost of reducing CO_2 in situations where large amounts of VRE may be introduced, such as for significant GHG reduction[8]. As such, it is becoming increasingly common to model the power

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sector with an hourly time resolution (with 8,760 time slices per year)[9), 10)]. However, this level of detailedness is still achieved only for studies specializing in the power sector; when modeling the entire energy system, it has been difficult to appropriately assess the impact of introducing large amounts of VRE with consideration of its hourly output variability, mainly due to computational restrictions[15), 16)].

To address this issue, Ueckerdt et al.[11)], for example, presented a method that used residual load duration curves (RLDC) to incorporate the impact of large-scale use of VRE in an integrated assessment model (IAM), instead of directly handling 8,760-hour power supply-demand profiles. This approach has been, in fact, incorporated in IAMs targeting the global energy system, such as the REMIND and MESSAGE models, and used for analyses[12), 13)]. However, as the RLDC-based approach cannot appropriately represent the electricity supply and demand management mainly during windless periods, it has been suggested that this approach may not be able to fully assess the economic impacts when large amounts of VRE are installed[14)]. Accordingly, we developed a bottom-up energy system model, for Japan to begin with, which fully models the power sector based on 8,760 hourly time slices[15), 16)]. This enabled us to appropriately assess the economic and technological impacts of large-scale VRE installation, while maintaining the advantages of the bottom-up energy system model, such as the ability to assess the competition among fuels (promotion of electrification) in the final consumption sectors (industry, residential and commercial, and transportation sectors), and use of excess electricity.

However, the estimated power profiles used in our previous reports were based on meteorological data for 2012. In reality, the results of the evaluation, such as the installed battery capacity and power generation cost, depend heavily on meteorological conditions (sunshine and wind conditions) and will not be reliable enough unless the study is based on multi-year data[14), 17)]. Thus, in this report, we employed an energy system model that incorporates a high-temporal-resolution power sector to estimate what kind of energy system is needed to reduce GHGs by 80%, while adopting multi-year meteorological data, to analyze the impact of meteorological factors on electricity demand (technology choice in the non-power sector), introduction of excess electricity management technologies, and the marginal GHG abatement cost.

Regarding considering the meteorological conditions for multiple years, some studies considered the meteorological conditions over several years[18)], with a number of studies assessing changes in meteorological conditions over longer periods (10 to more than 20 years)[19)]. However, there are perhaps just one study on Europe[20)] and one on Japan[14)] that actually estimate the electricity supply and demand in detail by incorporating multi-year data into a model. In addition, those studies were model analyses focusing on the power sector; to our knowledge, there had been no study on the entire energy system using multi-year data.

2. Analytical Framework

We conducted the analysis using the bottom-up energy system optimization model that we developed. This model is a techno-economic dynamic linear programming one and minimize the objective function, which is the discounted total energy system cost for the analyzing period, under multiple constraints. The key feature of this model is that it assesses the power sector on an hourly basis (8,760 hourly time-slices per year) even though it can model the entire energy system of Japan. The model also takes into account such excess electricity management technologies as EV charging and conversion into hydrogen as well as pumped hydro storage and batteries, and incorporates their hourly performance as well. The main exogenous variables of this model are energy service demand and the economic and technological characteristics of each technology comprising the energy system (such as conversion, distribution, and final consumption technologies); see previous reports[21), 22)] for details on the model. Unlike the power sector for which a hourly temporal resolution is adapted, for the non-power sectors, the supply-demand balance is satisfied on just annual basis. Improving the temporal resolution for the sectors is a challenge for the future. The main assumptions for the GHG reduction technologies used in this report are listed in Table 1.

This study was conducted for the period up to 2050 (at five-year intervals from 2015), dividing the entire Japan except Okinawa into five regions (Hokkaido, Tohoku, East Japan, West Japan, Kyushu), and taking into account power interchange between regions.

Table 1 Key GHG reduction technologies

Power sector	Natural gas-fired with CCS, Coal-fired with CCS, Solar PV, Wind power (onshore, offshore), Geothermal, Biomass, Hydrogen-fired, Ammonia-fired, Pumped hydro, Batteries (NAS batteries, Li-ion batteries)
Other conversion sector	Hydrogen production from coal and natural gas, Hydrogen production by water electrolysis, Hydrogen storage, Methanation, CO_2 Direct Air Capturerom (DAC), EV charging
Industry sector	Innovative furnace technology, CO_2 recovery at furnace, Electric furnace, CO_2 recovery at cement production, High performance cement production, Black liquor recovery boiler, High efficiency industrial furnace, High efficiency boiler, High performance motor
Residential/Commercial sector	High efficiency air-conditioner, High efficiency gas air conditioner, Latent heat recovery water heater, High efficiency HP water heater, High efficiency lightings and power, Solar water heater
Transport sector	Hybrid electric vehicle (HEV), Plug-in hybrid vehicle (PHV), Electric vehicle (EV), Fuel cell vehicle (FCV), CNG vehicle (freight), LNG vehicle (freight), LNG fuel ship

For solar PV, and onshore and offshore wind power, the impacts of changes in meteorological conditions on their output were taken into account. The hourly power profiles of these VRE technologies were estimated using AMeDAS data. The PV output per kW was estimated based on the amount of global solar radiation from the AMeDAS data. For wind power, the output was estimated by correcting the wind speed data from AMeDAS to the wind speed at the height of the hub (estimated to be 60 meters above ground), then assuming that the output per wind-receiving area corresponds to the cube of the wind speed. The cut-in wind speed for the wind power generator was estimated to be 3 m/s, the rated wind speed 11 m/s, and the cut-out wind speed 24 m/s. Since the electricity demand curve is likely to change with meteorological conditions as well, we used an artificial neural network (ANN) to estimate the demand profile for each region using past meteorological data. The actual electricity demand data of electric utilities (FY2012–2016) was fed into an ANN (three layers × 50 neurons) as past electricity demand data. For details on VRE power profiles and power demand settings, see Reference 17.

This report uses the data for 18 years from 2000 to 2017 calculated by the method above. The estimated annual average capacity factors for VRE power generation were more or less constant throughout these years (Figure 1), with 13.1% for PV (0.2% standard deviation), 23.9% for onshore wind power (0.1%), and 29.9% for offshore wind power (0.1%). However,

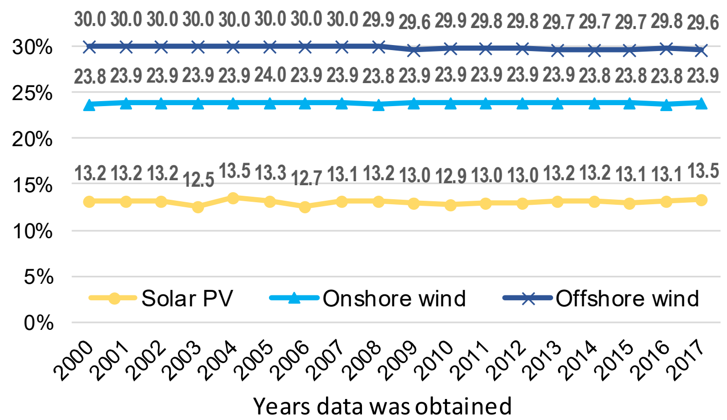

Fig. 1 Annual average capacity factor of VRE power

there was greater variation among regions. For PV, for example, in 2003 and 2006 when the average capacity factor was low, low capacity factors were observed in East Japan and West Japan where demand is greater than in other regions. Specifically, the annual average capacity factor for East Japan was lower than the full-term regional average of 12.6% in 2003 with 11.7% and in 2006 with 11.6%. West Japan's annual average was lower than the full-term regional average of 13.2% in 2003 with 12.3% and in 2006 with 12.6%. Meanwhile, in 2010, the national average capacity factor was lower than in other years but the regional deviation was smaller, with a capacity factor of 12.5% for East Japan and 13.2% for West Japan.

Note that this report does not consider the growth in PV generation efficiency or the improvement in capacity factor associated with the growth in size of the wind turbines and thus the height of the hub over the target 18 years and in the future.

For GHG emissions other than energy-related CO_2, we excluded the Land Use, Land Use Change and Forestry (LULUCF) sector from the study, and assumed that GHG emissions from fossil fuel incineration and leakage are proportional to the endogenously-determined amount of fossil fuel consumption. For freon gas, we assumed, based on Reference 23, that the emissions from refrigerators and air-conditioners, which account for most of the freon emissions, can be reduced at a cost of \$40/t-CO_2eq. The paths for other GHG emissions were set exogenously up to 2050 taking into account the rate of change in recent years. Here, the modeling was simplified and has much room for improvement.

In terms of size, the model contains approx. 14 million endogenous variables and about 24 million constraints. The optimum solution was obtained using the software Xpress.

3. Assumptions

3.-1. Assumptions about the power sector

Our assumptions about the cost and operational features of each power generation and electricity storage technology are based on References 22 and 24, and are listed in Table 2 and Table 3. The costs and prices used in this study are in 2014

Table 2 Exogenous variables of power plants

	Nuclear	Coal	LNG CC	LNG ST	Oil	Hydrogen
Construction cost [kJPY/kW]	370	272	164	120	200	164
Rate of fixed operation and maintenance cast	5.2%	4.0%	3.0%	3.0%	3.2%	3.0%
Efficiency (sending end, LHV)	-	39~41%	54~57%	42%	38~39%	57%
Annual average capacity factor Maximum	80%	80%	80%	80%	80%	80%
Peak capacity factor Maximum	90%	90%	95%	95%	95%	95%
Maximum load following [%/h]	0	26	44	44	44	44
Minimum load following [%/h]	0	31	31	31	31	31
Operational lifetime [year]	60	40	40	40	40	40
DSS operation rate	0	0	0.5	0.3	0.7	0.7
Minimum output rate	0.3	0.3	0.3	0.3	0.3	0.3

	Hydro	Biomass	Geo-thermal	Solar PV	Onshore wind	Offshore wind
Construction cost [kJPY/kW]	640	398	790	294~152	284~227	591~506
Rate of fixed operation and maintenance cast	1.4%	6.8%	4.2%	1.4%	2.1%	3.5%
Efficiency (sending end, LHV)	-	18%	-	-	-	-
Maximum capacity factor	55%	80%	70%	Refer to Fig. 1	Refer to Fig. 1	Refer to Fig. 1
Maximum load following [%/h]	5	30	5	-	-	-
Minimum load following [%/h]	5	30	5	-	-	-
Operational lifetime [year]	60	40	40	20	20	20

constant prices. The assumption about each item is common to all regions, and all ranges of numbers in the tables represent improved efficiency with time and technological progress. The decrease in construction cost of VRE power toward 2050 was obtained by extrapolating the decrease up to 2030 presented in Reference 24. The assumptions about ammonia-fired power generation are the same as those for hydrogen-fired power. Note that co-generation and autoproducer power plants are not considered in this study.

For the installed capacity of nuclear power, we assumed that the 33 power plants in operation as of October 2019 will continue to operate for a total of 60 years. The installed capacity will be 21.2 GW in 2050. The estimated maximum VRE and geothermal capacity that can be introduced in each region are as shown in Table 4 based on References 25 and 26. The maximum capacity for hydraulic power and pumped hydro were set to their values in 2015. It was assumed that inter-regional transmission lines are not expanded unless they are already scheduled for expansion.

Table 3 Exogenous variables of storage technologies

	Pumped storage	NAS batteries	Li-ion batteries
Construction cost [kJPY/kW]	190	35	40
Construction cost [kJPY/kWh]	10	40~30	150~5
Rate of fixed operation and maintenance cast	1%	1%	1%
Maximum capacity factor	90%	90%	90%
Cycle efficiency	70%	85%	85%
Self discharge rate [1/h]	0.1%	0.5%	0.5%
Maximum kWh/kW ratio	6	∞	∞
C-rate	-	0.14C	2.0C
Cycle lifetime [cycle]	∞	4,500	6,000
Operating lifetime [year]	60	15	8

Table 4 Maximum capacity of VRE and geothermal power in 2050 (GW)

	Hokkaido	Tohoku	East Japan	West Japan	Kyushu	Total
Solar PV	18.0	42.2	89.6	129.2	49.9	328.9
Onshore wind	125.9	58.8	7.1	30.5	13.3	235.5
Offshore wind	86.7	5.5	10.9	8.5	0.3	111.8
Geo-thermal	0.6	3.4	0.5	0.2	1.5	6.2

3-2. Other assumptions

For the CCS storage potential in 2050, many papers[4), 27)] estimate that large amounts of CO_2 of 91–150 Mt-CO_2/year can be stored, but this report adopted 30 Mt-CO_2/year, which is relatively small. We set the maximum amount of hydrogen import in 2050 to 150 billion Nm^3, the target level of the Basic Hydrogen Strategy of the Ministry of Economy, Trade and Industry, and assumed that the same amount of ammonia in calorific equivalent can also be imported. The assumptions for hydrogen production by water electrolysis, methanation, and hydrogen storage are based on References 28 and 29 (see Reference 30 for the value setting). Energy service demand was calculated using an econometric technique. Real GDP is estimated to grow by 1.7% per annum until 2030 and by 1.2% per annum thereafter till 2050, and accordingly, energy service demand will grow by around 0.5% per annum from 2015 through 2035 and remain mostly flat thereafter.

GHG emission constraints were set for emissions in and after 2030. Emissions were capped at 1,079 Mt-CO_2eq., the level indicated by METI's Long-term Energy Supply-Demand Outlook, for 2030, and at the level 80% lower than FY2014 for 2050. For all the years in between, linear interpolations between these two values were used as the caps.

3-3. Scenario

As mentioned earlier, this report uses the meteorological data for the 18 years from 2000 to 2017. Further, for examining the impact of CCS storage potential and the maximum amount of hydrogen import, we conducted a sensitivity analysis using the data for two years with representative meteorological conditions.

4. Results

4-1. The energy system for 80% GHG reduction

Taking the meteorological data for 2005 as an example, we outline the features of the energy system that can reduce GHGs by 80% in 2050. We selected 2005 as a typical year because the solution obtained using the year's data produced the median of the solutions for the 18 years in terms of installed battery capacity and marginal GHG abatement cost.

Figure 2 shows the power mix of Japan in 2035 and 2050 and of each region in 2050. In 2035, fossil fuel power sources, mainly LNG combined cycle (CC) power, account for 49% of power generation because GHG reduction constraints are still relatively relaxed. Coal-fired thermal and LNG CC both have a capacity factor of 45%. Meanwhile, in 2050, the power sector, which has a relatively large number of CO_2 reduction technologies, is required to achieve net-zero emissions. Based on the operating lifetime assumptions in Table 2, even though 14 GW of coal-fired thermal power and 98 GW of LNG CC capacities exist in 2050, their capacity factors will be zero. Instead, the share of VRE power will increase from 22% in 2035 to as much as 47% in 2050.

The measures for achieving net-zero emissions in the power sector vary by region. In the Hokkaido and Tohoku regions which have a large onshore wind power potential, the energy source will account for the majority of the output while other regions will have a high percentage of solar PV and hydrogen-fired and ammonia-fired power. Hokkaido has the highest potential for offshore wind power, but the technology will not be introduced due to large amounts of cheap onshore wind power and constraints in transmission capacity to Tohoku.

With the large-scale use of VRE, batteries will also be introduced in large amounts by 2050 (158 GW, including 9 GW of NAS batteries and 149 GW of Li-ion batteries, or 1,223 GWh, including 65 GWh of NAS and 1,158 GWh of Li-ion). GW capacity tends to increase more in regions with a large PV capacity, increasing the most in West Japan (54 GW) which will have the largest PV capacity (129 GW in 2050). Note, however, that the amount of batteries and other technologies to be introduced and the cost of GHG reduction will also be affected by the operating lifetime settings of the technologies. For example, if we assume that Li-ion batteries have the same operating lifetime as NAS batteries of 15 years, the relative economic efficiency of Li-ion batteries will increase as they require fewer replacements, resulting in 177 GW / 1,561 GWh of Li-ion batteries and fewer NAS batteries being introduced in 2050. An increase in battery capacity will cause a change in the amount of new capacity and the output of each VRE power source, but the change will remain small as VREs will be installed up to their limit under the 80% GHG reduction target in any case.

In the final consumption sector, electrification will make progress as well as advances in energy conservation (Figure 3). The rate of electrification will increase from 33% in 2035 to as high as 49% in 2050, resulting in electricity demand reaching 1,416 TWh in 2050. The difference from the electricity output shown in Figure 2 corresponds to the amount of electricity consumption in the conversion sector, that is, EV chargings, methanation, etc. The amount of methane produced by methanation will reach 4 Mtoe in 2050, equivalent to 9% of the final consumption of city gas of 48 Mtoe. Electrification will advance particularly in the residential/commercial and the transport sector, with all passenger vehicles becoming electrified by 2050 (Figure 4). For freight vehicles, various types of vehicles will be chosen, including LNG trucks and FCV trucks.

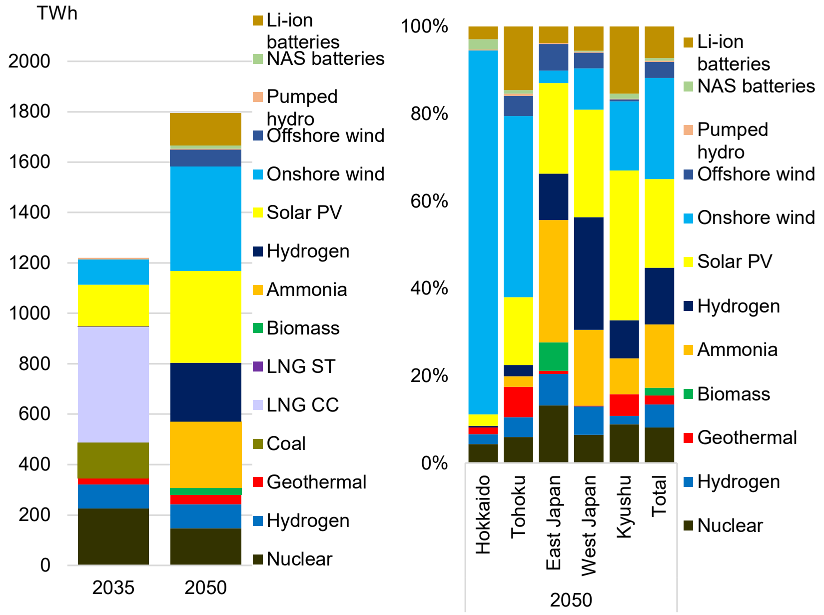

Fig. 2 Power generation mix in 2035 and 2050, and the composition by region in 2050

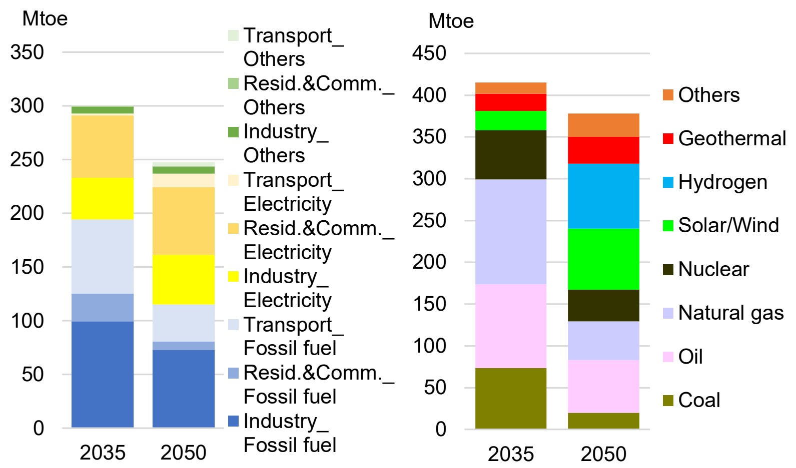

Fig. 3 Final energy demand and primary energy supply

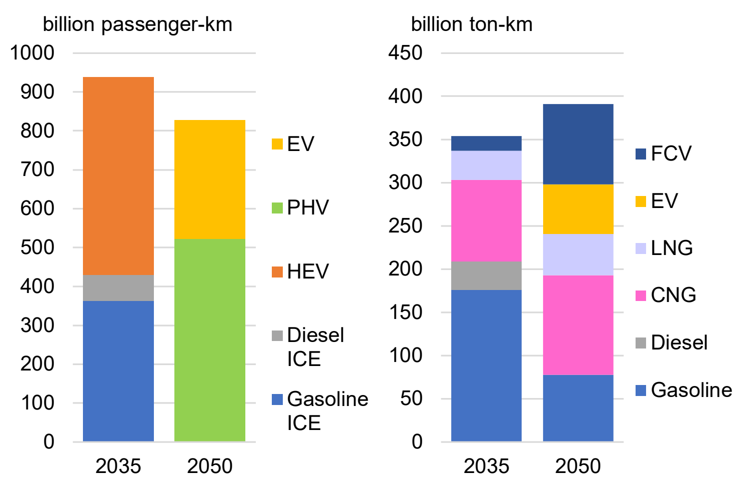

Fig. 4 Share of transportation demand by vehicle (left: passenger sector, right: freight sector)

4-2. Comparison using multi-year meteorological data

(1) Introduction of electricity storage technologies

Figure 5 shows the estimated battery capacity in 2050 (NAS and Li-ion combined) based on the meteorological data of each year. The battery capacities depend on the VRE power profile used and have an average of 164 GW / 1,252 GWh, with a standard deviation of 9.5 GW / 106 GWh. Both values were greatest when the 2003 meteorological data was used (186 GW / 1,436 GWh).

To identify how the battery capacity is determined, we illustrated the electricity demand and supply management in total Japan for the day with the highest electricity storage level in the year, and for the 10 days before and after that day, using the meteorological data for 2003, which results in the 2050 installed Li-ion battery capacity (GWh) becoming the largest (1,371 GWh), and for 2004, which produces the smallest Li-ion battery capacity in 2050 (1,049 GWh), as shown in Figure 6 and Figure 7. In the figures, "Day 0" indicates the day when the electricity storage level is the highest. With the 2003 data, the electricity storage level decreased as large amounts of electricity were discharged to maintain the supply-demand balance even though there was a shortage of sunshine for about one week from two days after Day 0 and the battery capacity was not being charged as fully as on other days. Meanwhile, with the 2004 data, the electricity storage level decreased two days after Day 0 due to low solar PV output but came back up from the third day as sufficient VRE output was obtained. This suggests that battery capacity (GWh) is determined based on the number of consecutive days without enough sunshine or with poor wind conditions ("windless period"). The difference in capacity between 2003 and 2004 would be equivalent to a difference in facility investment of 1.6 trillion yen in 2050.

Storage systems for hydrogen produced by water electrolysis will be introduced in the Hokkaido and Tohoku regions. Regarding their capacity, the GW capacity does not vary greatly by the year the data was obtained, as shown in Figure 8, but the GWh capacity is affected significantly by the VRE power profile of each year. The GWh capacity varies by year particularly for Tohoku. Figure 9 shows the changes of the region's hydrogen storage level for representative years. Well-suited for long-term storage, hydrogen is generally stocked up in early summer when the VRE power output is high and drawn down in autumn when the output is low. As any excess electricity is stored in batteries to supply as much zero-emission electricity as possible, hydrogen production by water electrolysis is conducted mainly when the VRE power output is large enough to trigger curtailments or when the electricity storage level is sufficiently high. The data for 2006 implies that because there are few chances to meet these conditions and stock up hydrogen during the summer, preparations must be made for drawdowns by increasing the GWh capacity and the storage level. However, it must be noted that this study sets the construction cost of the hydrogen storage system (the Wh part) to \$700/kg31), which is lower than that of Li-ion batteries in per unit energy stored cost. In Figure 8 and Figure 9, the installed capacity in GW of the hydrogen storage systems is the highest calorific value of hydrogen produced per hour expressed in watts (GW), and the installed capacity in GWh and the amount of hydrogen stored are the calorific value of stored hydrogen expressed in watt-hours (GWh).

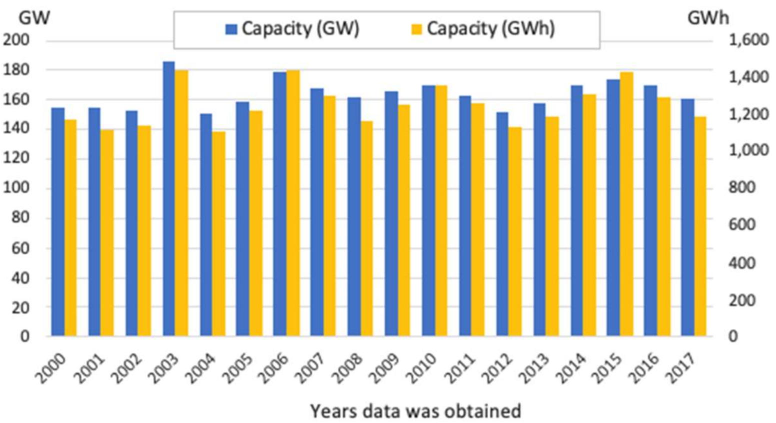

Fig. 5 Battery installed capacity in 2050

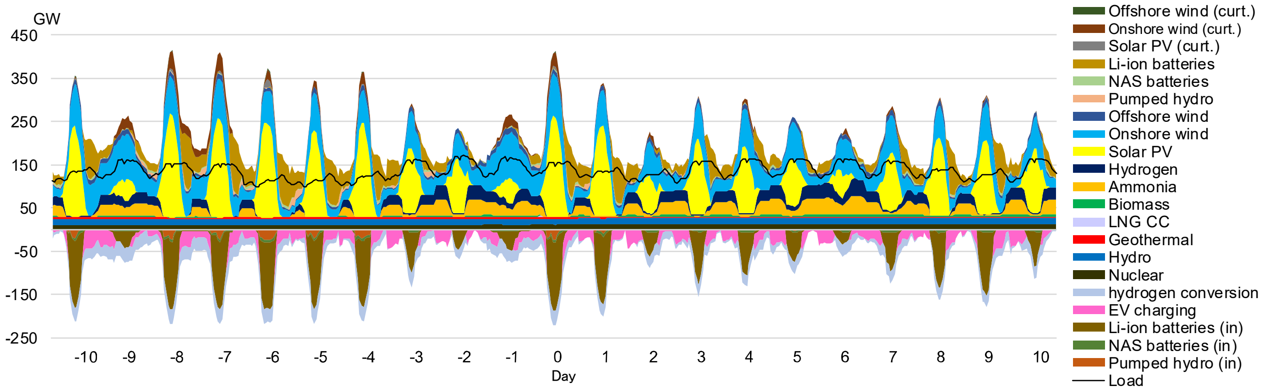

Fig. 6 Power dispatch for the ten days before and after the day with the highest electricity storage level in 2050 based on 2003 data

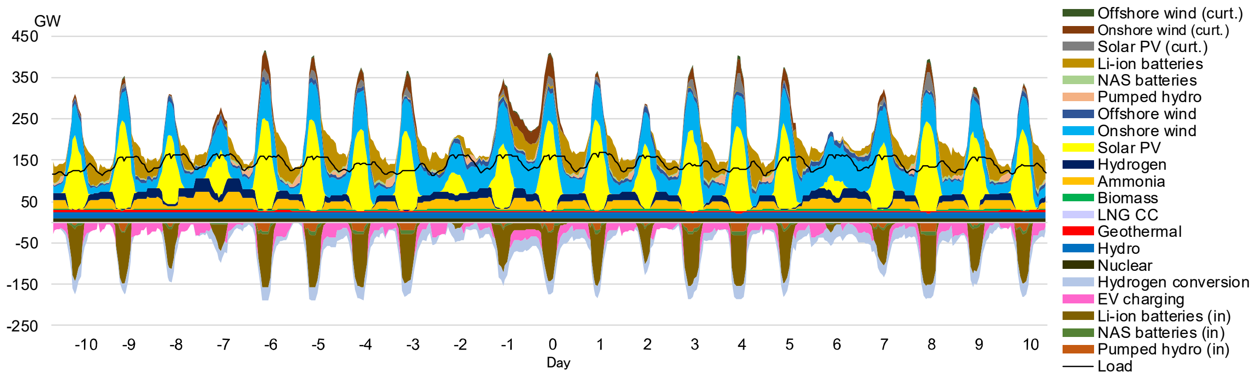

Fig. 7 Power dispatch for the ten days before and after the day with the highest electricity storage level in 2050 based on 2004 data

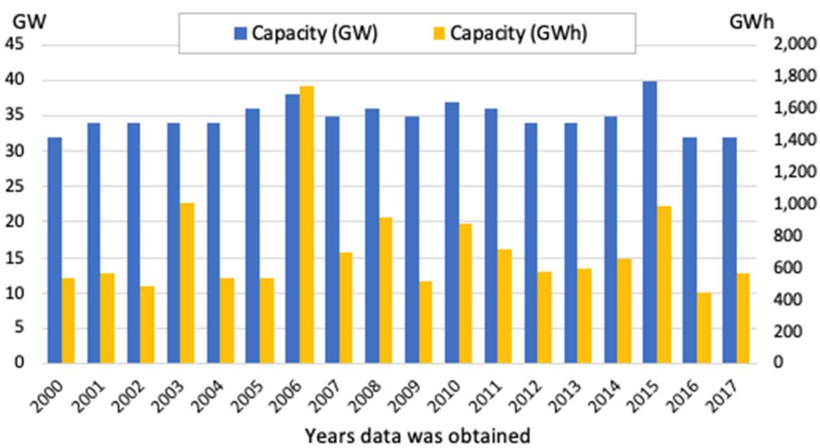

Fig. 8 Hydrogen storage system capacity in 2050

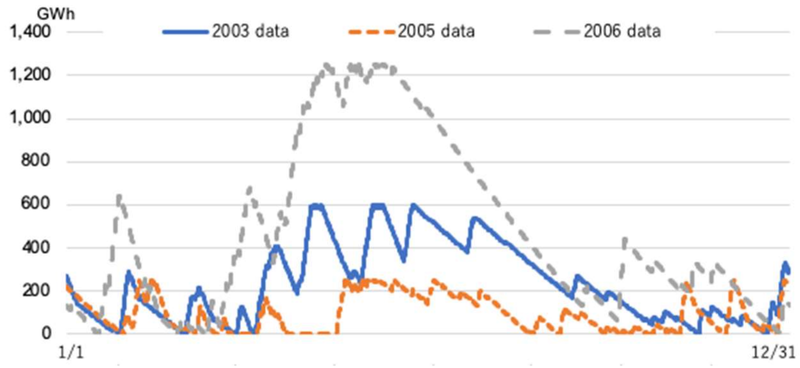

Fig. 9 Changes in hydrogen storage in 2050 (Tohoku)

(2) Power generation mix and electricity demand

Figure 10 shows the power generation mix (excluding VRE output curtailments) and the electricity demand in the final consumption sector. Unlike battery capacity, both the total power generation and the electricity demand in the final consumption sector vary little due to the VRE power profile. In 2003 and 2006 only, the total power generation is smaller than in other years due to the slightly lower average capacity factor for solar PV, resulting in the electricity demand becoming around 10 TWh lower. Figure 11 shows the installed capacity of VRE power, which also varies only slightly depending on which year's data is used. The average installed capacity of each power source was 319 GW for solar power, 200 GW for onshore wind power, and 25 GW for offshore wind power, with standard deviations of 5.6 GW, 2.9 GW, and 0.0 GW, respectively. For all years whose data was used, VRE power generation will be introduced up to the maximum capacity shown in Table 4 in all regions except Hokkaido. In Hokkaido, due to low local demand, the installed capacity of all VRE power sources falls below the upper limit except for PV under the 2015 data. As mentioned in Section 4-1, zero-emission electricity and further electrification of the final consumption sector are critical for achieving an 80% GHG reduction. This report sets limits on the installed capacity of VRE power and zero-emission thermal power such as fossil-fuel fired with CCS and hydrogen fired; thus, there is a limit to the amount of zero-emission power supply in each region. Since the annual average capacity factor of VRE power varies only slightly year to year as shown in Figure 1, electricity demand, power generation mix, and installed VRE capacity will be almost the same regardless of the year of the data. On the other hand, the management of supply and demand of electricity will be affected significantly by the VRE profiles when large amounts of VRE are introduced, and will result in large differences in the installed battery capacity, as described in the previous section.

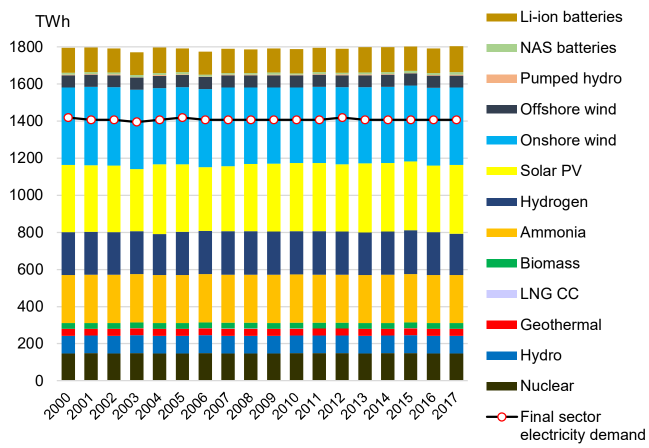

Fig. 10 Power generation mix in 2050 (excluding curtailments of VRE output)

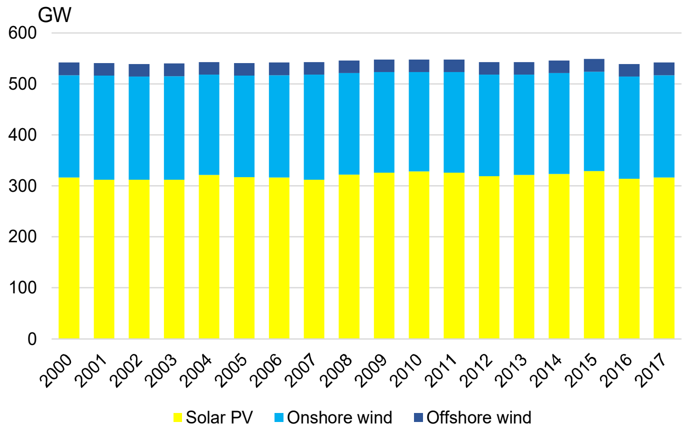

Fig. 11 VRE Installed capacity in 2050

(3) Marginal abatement cost

Figure 12 shows the marginal abatement cost of GHG in 2050 based on the meteorological data of each year. For the data of 2005, for which the selection of major technologies was explained in Section 4-1, the marginal abatement cost of 472,000/t-CO_2eq. was obtained. This value is in the upper portion of the estimated marginal cost for reducing the energy-related CO_2 emissions of Japan by 80% in 2050, which is roughly several hundred to several thousand dollars per t-$CO_2$32). The marginal cost in this report is relatively high presumably because this report aims to reduce GHG by 80% and this requires reducing energy-related CO_2 by more than 80%, the maximum amount of CO_2 storage is set lower than in previous papers[4), 27)], and the energy service demand is set assuming a relatively high GDP growth rate.

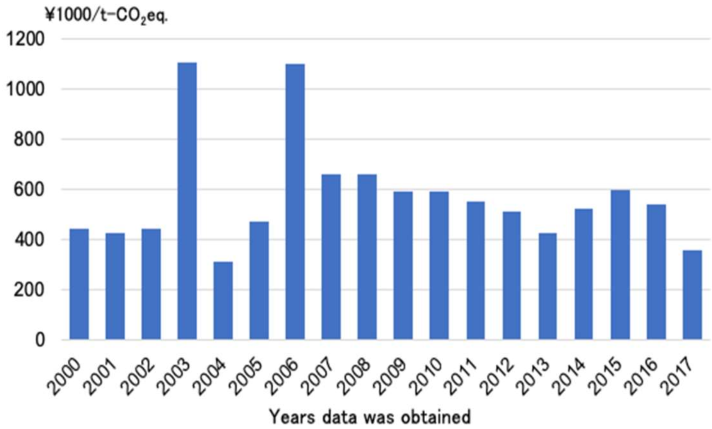

Fig. 12 Marginal abatement cost of GHG in 2050

The cost of 472,000/t-CO_2eq., for example, is equivalent to about 1,080 yen per liter of gasoline. This suggests that it is not easy to reduce GHG by 80% in light of the high economic burden on GDP and households.

While the marginal abatement cost lies between 400,000 and 600,000 yen/t-CO_2eq. for most years, it is significantly higher in 2003 and 2006 at about 1,100,000 yen/t-CO_2eq. and, in contrast, is around 350,000/t-CO_2eq. in 2004 and 2017. One of the reasons for the high cost for the 2003 and 2006 data is because the PV capacity factor is smaller than in other years in East and West Japan, which have a large electricity demand and limited ability to increase wind power, resulting in only a small amount of VRE power being connected to the grid in those regions (Figure 13). This limits the zero-emission power supply in those regions and results in the need for more expensive investments in energy conservation in the final consumption sector. The average capacity factor of PV is low also in 2010 according to Figure 1, but this is due to the relatively low utilization rate of VRE in Hokkaido and Tohoku which have a high VRE power generation potential and which do not act as a constraint on zero-emission electricity supply. When VRE power output is relatively low, the output curtailment rate for VRE is set low so as to maximize the zero-emission power supply, as shown in Figure 13. This is one of the reasons for the increases in battery capacity (particularly GW capacity) and GHG reduction cost.

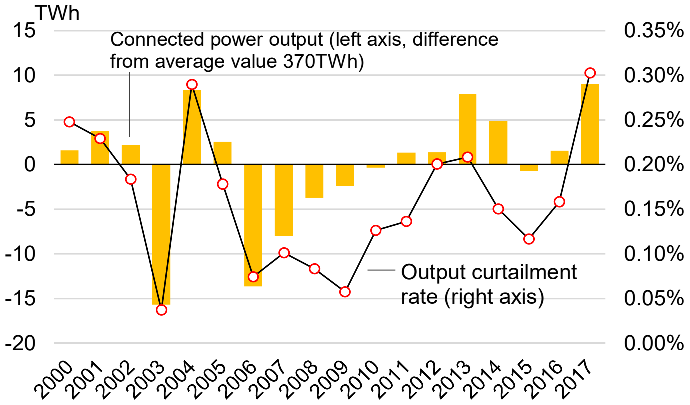

Fig. 13 Amount of VRE power connected to the grid in East Japan and West Japan, and the output curtailment rate in 2050

4-3. Sensitivity analysis

We conducted a sensitivity analysis for the two factors, namely, the maximum amount of CCS storage and hydrogen import, which are likely to determine the degree of difficulty of achieving an 80% GHG reduction. We assume that the two factors will be higher than the baseline set in Section 3-2, using the 2003 and 2004 meteorological data which resulted in the battery capacity and the marginal cost of GHG reduction being the highest and the lowest in 2050 in the previous section. Here, the maximum CCS storage amount in 2050 was set to 50 Mt-CO_2 and the maximum hydrogen import to 300 billion Nm^3.

Figure 14 shows the variation in the power generation mix and the final consumption composition between the cases with elevated maximum CCS storage capacity or hydrogen import and the baseline case. In the CCS case, the output of LNGCC with CCS increases and replaces onshore wind power due to an increase in CCS storage capacity. For the hydrogen case, the amount of hydrogen used in the power generation sector increases, replacing VRE power generation. As a large amount is replaced, the battery capacity and the amount of discharge also decrease sharply. For 2003, the battery capacity decreases to 65 GW / 450 GWh, down 121 GW / 985 GWh from the baseline case.

In both cases, extremely large reductions in the marginal abatement cost of GHG in 2050 were observed, with decreases down to 287,000 yen/t-CO_2eq. (2003) and 229,000 yen/t-CO_2eq. (2004) for the CCS case and to 105,000 yen/t-CO_2eq. (2003) and 106,000 yen/t-CO_2eq. (2004) for the hydrogen case. Any change in the operating lifetime of each technology mentioned in Section 4.1 will affect not only the capacity of each technology to be introduced but also the electricity price through an increase or decrease in the total capital cost, and as a result, the marginal abatement cost may also change. For example, when the operating lifetime of Li-ion batteries was set to 15 years as with NAS batteries under the 2005 data, the marginal cost of reduction decreased by approx. 10% to 427,000/t-CO_2eq.

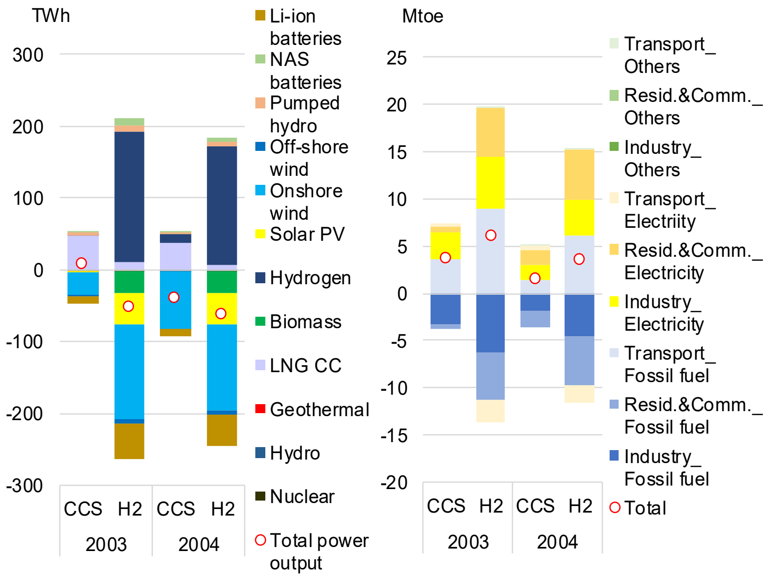

Fig. 14 Changes in the power generation (excluding VRE output curtailment) and final energy consumption in 2050

5. Conclusion

In this report, we analyzed the effect of meteorological conditions on the selection of energy technologies and the marginal GHG abatement cost when a significant GHG reduction is required, employing an energy system model that incorporates a high-temporal-resolution power sector. We analyzed the selection of technologies for reducing GHG by 80% in Japan using the meteorological data for the 18 years from 2000 to 2017. The results suggested that variations in VRE power profiles, specifically, the maximum consecutive number of days with poor sunlight or wind conditions in a year, significantly affect the amount of battery capacity installed. The amount can change by around 300 GWh at most depending on the availability of CCS and imported hydrogen and how those profiles are set. Thus, in the cases studied here where large amounts of VRE power will be introduced, it is important to use the meteorological data of multiple years to, for example, correctly evaluate the cost of GHG reduction technologies. Meanwhile, the impact of meteorological conditions on the final consumption sector was relatively small. Nevertheless, a zero-emission power sector and further electrification of the final consumption sector are essential for achieving an 80% GHG reduction, and VRE power profiles do affect the available supply of zero-emission power. This will have an impact, albeit a small one, on the electricity demand in the final consumption sector, and as a result, may cause a significant change in the marginal abatement cost of GHG.

It must be noted that this study assumes a relatively high GDP growth rate, which is one of the reasons for the high GHG marginal abatement cost. The relationship between economic growth scenarios and the cost needed for 80% GHG reduction should be considered further in a future study.

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Grid Flexibility Offered by Distributed Combined Heat and Power Using Carbon-neutral Methane Produced from Renewable Surplus Electricity◆

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Abstract

This study evaluated a renewable energy grid integration model (CNM-CHP) that provides grid flexibility by ramping up the output margin of combined heat and powers (CHPs) when renewable energy output reduces, using city gas decarbonized by carbon-neutral methane (CNM) blended into the city gas network. CNM is produced through methanation -reacting electrolytic hydrogen from renewable surplus electricity and CO_2 from facilities like fossil fuel-fired power plants, biomass power plants and industries. CNM being able to utilize the existing city gas network has economic advantages over hydrogen that requires new infrastructure to be delivered. CHPs expected as Virtual Power Plants (VPPs) to provide grid flexibility a need decarbonized way. With an assumption that 300 GW of solar photovoltaics, 100 GW of wind power and 34 GW of CHP are deployed in Japan, it was revealed that CNM-CHP shows the same economics as or superior to grid flexibility offered by batteries. Power-to-Gas systems using existing infrastructure have advantages in decarbonizing the entire energy system over batteries that can discharge only a fraction of stored electricity due to grid constraint when large scale renewables are deployed.

Key words: Grid flexibility, CHP, Power to gas, Methanation, CCU

1. Introduction

As carbon-neutral methane (CN methane) is synthesized (in a methanation process) from hydrogen that is produced by renewable energy through electrolysis, and CO_2 that is emitted through biomass power plants, fossil fuel-fired power plants, and large-scale industries, it can be called as a "renewable synthetic fuel" that is produced through a combination of power-to-gas (PtG) as grid integration measures and carbon capture and utilization (CCU). CN methane reuses CO_2 that has already been emitted, and for this reason, became one of the key focuses in the Roadmap for Carbon Recycling Technologies prepared by the Agency for Natural Resources and Energy in June 2019.

One of the options of hydrogen application is its injection into city gas infrastructure[1)]. However, as hydrogen has a low volumetric calorific value, it has only a limited decarbonization effect on city gas. There are also other challenges, including compatibility with special applications that require carbon, such as metal carburizing and super high-temperature furnaces, and calorific adjustment of gas appliances. On the other hand, CN methane, which is a feedstock for city gas, poses few problems with regard to injection into the city gas infrastructure, and there are high expectations for it as a decarbonization technology for city gas[2)]. There are existing researches that show huge potential of producible CN methane in Japan and that CN methane can suppress supply costs more effectively than hydrogen that requires new infrastructure[3), 4)]. With these advantages, advance efforts led by Germany and other European countries, such as the demonstration of CN methane, have also been progressing in Japan in recent years[5), 6), 7), 8)].

Meanwhile, distributed combined heat and power (CHP), which uses largely city gas, is expected to mitigate the output fluctuation of renewable energy by acting as a virtual power plant (VPP). In short, alongside regular CHP operations under normal conditions, output fluctuation is offset by utilizing CHP margin output capacity to increase output when the output of renewable energy falls. As CHP has high total efficiency, we can expect more reduction in CO_2 emissions through the mitigation of output fluctuation than LNG thermal power; nevertheless, CHP is accompanied by a certain degree of CO_2

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emissions as it uses city gas. However, by producing CN methane from surplus electricity that is generated through the increase in output from renewable energy, and using CN methane in CHP via the city gas infrastructure, it is possible to achieve grid flexibility with lower carbon levels. Moreover, CHP was originally introduced as a cogeneration for consumers, and its application to mitigating output fluctuation may be more economically viable in comparison with output fluctuation mitigation through other energy storage techniques that need to be introduced additionally.

In light of that, this study analyzes the contributions that CHP using CN methane makes to grid flexibility, and the possibility of achieving decarbonization for electricity and city gas.

2. Flow of analysis

2-1. Definition of the CNM-CHP model

Based on the above approach, this study defines "grid flexibility offered by distributed CHP using CN methane produced from renewable surplus electricity" (hereafter, "CNM-CHP") as follows (Figure 1).

- Produce CN methane from hydrogen derived from surplus electricity of variable renewable energy (solar photovoltaic and wind power) as well as CO_2 emitted intensively through biomass power plants, industries, and fossil fuel-fired power plants, and inject it into the city gas infrastructure (decarbonization of city gas).
- CHP, like other applications (such as heat demand), uses city gas that has been decarbonized by CN methane, via the city gas infrastructure.
- CHP regular operation is based on combined heat and power supply. At the same time, when the output of renewable energy falls, margin output capacity is used to increase output (CHP ramp-up = downward demand response).

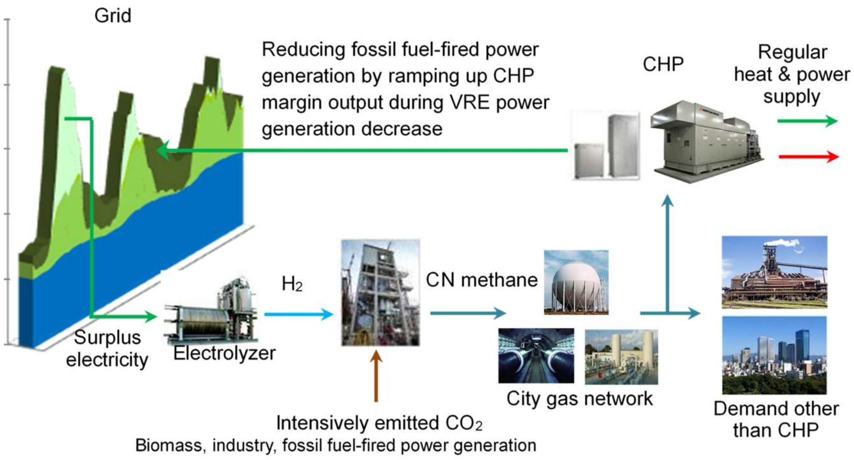

Fig. 1 Structure of CNM-CHP Model

2-2. Simulation structure and assumptions

(1) Structure of the power generation mix simulation / Operation of power plants

In this study, Japan is hypothetically treated as a single region for the sake of simplification. Data granularity in the analysis is one hour, and the target period is one year. The operation of the power plants are presented as follows.

[Common operations]

- Baseload power plants (nuclear, hydro, geothermal, biomass) and regular CHP operation are assumed to be "must run". (Verified that there is no curtailment of the baseload power plants)
- Load frequency control thermal power plants are assumed to cover 10% of the hourly power demand.
- For surplus electricity, pumped-storage hydro is used first. Stored electricity is discharged immediately,

whenever possible.

[CNM-CHP]

- Surplus electricity from variable renewable energy, which spill over from the grid even after the abovementioned common operation, will be used for producing hydrogen. Producible CN methane is hourly identified based on the amount of hydrogen and intensive CO_2 emissions (hourly CO_2 emissions are described later). If CO_2 emissions for CN methane production are not sufficient, surplus electricity will be curtailed.
- Only when the grid has space to accept and CHPs have margin output capacity, CHPs ramp up.
- Electricity demand - (base-load power output + LFC power output + variable renewable output + discharge from pumped storage hydro + CHP ramp-up) is met by fossil-fired power generation.

[Battery] (For comparison of economics described later)

- Surplus electricity from variable renewable energy, which spill over from the grid in the abovementioned common operation, is charged into batteries. If batteries are fully charged, surplus electricity will be curtailed.
- Batteries immediately discharge whenever possible.
- Electricity demand - (base-load power output + LFC power output + variable renewable output + discharge from pumped storage hydro + discharge from batteries) is met by fossil-fired power generation.

(2) Electricity demand / Capacity of the power generation

Taking into account long-term electrification trends and energy conservation, it is assumed that electricity demand will increase by about 10% from the current level to 1,040 TWh. Nuclear power generation is assumed to be at the level of the amount introduced for 2030 in the "Long-term Energy Supply and Demand Outlook," while power generation from small- and medium-scale hydro plants, biomass power plants, and geothermal power plants are assumed to be at a level that is slightly higher than the amount introduced for 2030 (13 GW, 8 GW, and 3 GW respectively). No assumptions are made for newly constructed large-scale hydro and pumped-storage hydro. From the long-term perspective, all thermal power generation is assumed to be LNG-fired power.

Regular CHP operation is assumed to be "must run". It is assumed that only when the grid has space to accept and CHPs have margin output capacity (when operating at a level below rated output), CHPs can ramp up. Pumped-storage hydro operation (charging and discharging or renewable energy) is prioritized. It is assumed that the capacity of CHP introduced is 30 GW for commercial and industrial use + 5.3 million stationary fuel cells for residential use ≒ 34 GW, which is the government and gas industry target.

Scenarios are established in which solar photovoltaic ranges from 70 GW to 500 GW, and wind power ranges from 10 GW to 300 GW.

(3) Hourly intensive CO_2 emissions

With regard to biomass power generation and industries, annual intensive CO_2 emissions nationwide is specified based on previous studies.2), 3) It is assumed that biomass power generation is operating at a constant output, and allocates annual CO_2 emissions volume by each hour. The hourly CO_2 emissions in industries is assumed to follow a similar profile for all power demand, and is allocated by each hour. The hourly CO_2 emissions volume for thermal power generation is specified through the operation pattern, based on the simulation for power generation mix.

(4) Identification of a regular operation pattern for CHP and technological specifications

To figure out how much CHPs can ramp up to mitigate renewable energy output fluctuations, the regular operation pattern should be identified. With regard to residential CHP, the operation pattern of PEFC is estimated based from measurement survey in the existing research.[9), 10)] For SOFC, a flat operation at rated output through the year is assumed (some gas companies purchase SOFC surplus electricity). All residential CHP is assumed to be fuel cells (rated output of 0.7 kW), and the ratio for the number of PEFC and SOFC is assumed to be 1:1. With regard to CHP for commercial use, the measurement data by subsector × by season × by weekday/weekend from the existing research[11)] are averaged weighted by introduced capacity by subsector[12]. As for industrial use, it is assumed to be 80% of rated output for daytime and 65% for nighttime, based on hearings to experts.

Figure 2 shows CHP power generation patterns and margin output capacity by sector for a representative week during summer in cases where the CHP target (34 GW) is achieved. As CHP is operated mainly in the daytime, margin output capacity is larger during nighttime. It is physically possible to ramp up CHP output by about 7 to 10 GW in the daytime and about 17 GW at nighttime.

For the sake of simplification, the power generating efficiency of CHP is assumed to be 55% regardless of the type and age. Waste heat recovery efficiency is assumed to be 35% during regular operation, and 25% during ramp-up (According to interview from experts, CHPs generally suspend operations during nighttime because cheap nighttime electricity rates from the grid are favorable, but not because heat demand decreases. Therefore, it is assumed that even if CHPs are operated during nighttime, exhaust heat can be consumed by heat demand to some extent).

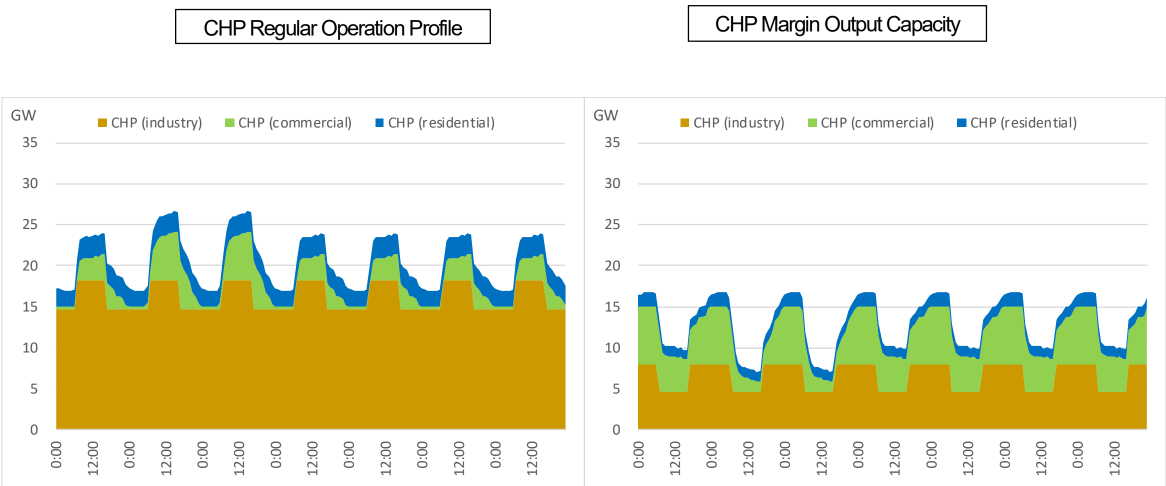

Fig. 2 CHP Regular Operation Profile and Margin Output Capacity

Note: A representative week in summer. The cumulative installed CHP capacity is assumed to be 22.72GW, 0.728GW and 0.371GW in industry, commercial and residential, respectively.

(5) Technical specifications for CO_2 capture and CN methane production

Regarding energy consumption related to the CO_2 capture, the CO_2 compression accounts for the largest share of power consumption in CCS (for CCS process, CO_2 pressure is raised up to 7 MPa to make CO_2 critical state for efficient transportation to storage sites). However, higher compression is not required for CN methane production process, no more than 0.1-0.5 MPa. As a result, power consumption in CO_2 capture is 10 kWh/t-CO_2 and heat requirement is 1,800 MJ/t-CO_2 (Table 2-3), based on future estimate in the existing research13). As surplus electricity from renewable energy occurs whenever CN methane is produced, adding electricity consumption for CO_2 capture to the specific electricity consumption of CN methane (18.32 kWh/Nm^3-CH_4)[2], it would be 18.34 kWh/Nm^3-CH_4. Assuming that the heat needed is supplied by city gas, heat consumption would be 4,436 kJ/Nm^3-CH_4 (assuming boiler efficiency of 80%). CO_2 capture rate is assumed to be 90%.

3. Results of analysis for the CNM-CHP model

Figure 3 shows the results of simulation for the representative one-week in summer. A part of the surplus electricity is used for the CN methane production, but its volume is dependent upon the volume of CO_2 that is available (Figure 4), and the rest of the surplus electricity is curtailed. It is found that CHP ramps up majorly during nighttime when CHP margin output capacity is available (Figure 5). As renewable energy deployment expands, wind power generates electricity during nighttime, reducing the room for CHP ramp-up. Figure 6 shows power generation mix. As more surplus electricity is generated more frequently due to renewable energy large-scale deployment, with priority given to pumped storage hydro, a decline is observed in the grid's acceptance for accommodating CHP ramp-up. This trend is described in detail in Figure 7, which shows the status of use of margin output capacity of CHP.

Figure 8 shows city gas consumption and CN ratio (CN methane's share in city gas demand). City gas here represents a blend of conventional city gas and CN methane. When renewable energy introduction scale is small, there is large space for CHP ramp-up and city gas demand increases accompanying CHP ramp-up. However, as surplus electricity from renewable energy is limited, CN methane production (and city gas consumption for CO_2 capture) is also limited. Producible CN methane volume is 8.4 billion Nm^3-CH_4 with 3GW of solar PV + 100GW of wind power, and 22.5 billion Nm^3-CH_4 with 5GW of solar PV + 3GW of wind power, equivalent to 21% - 57% of the methane calorific value equivalent of city gas consumption in FY2016 (39.7 billion Nm^3-CH_4). The city gas consumption required for CO_2 capture accounts for a small percentage of overall city gas consumption.

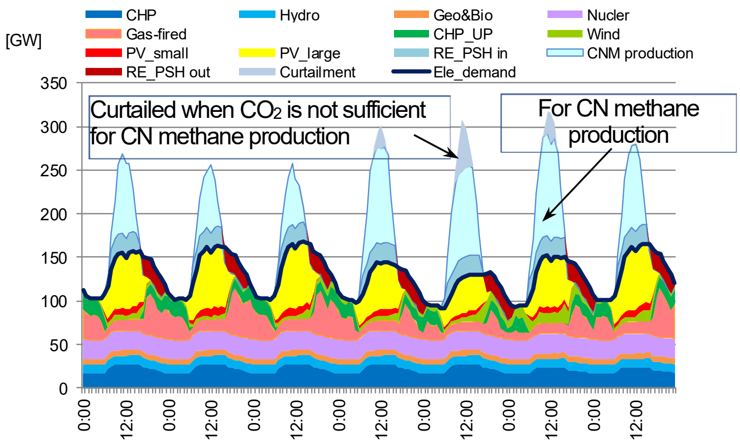

Fig. 3 Hourly Power Generation Mix (CNM-CHP)

Note: A representative week in summer. 300GW of Solar PV + 100 GW of wind

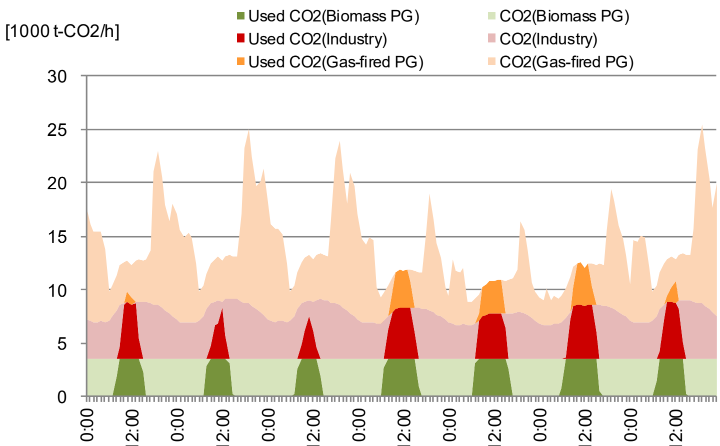

Fig. 4 CO_2 **utilization for CN methane production (CNM-CHP)**

Note: A representative week in summer. 300GW of Solar PV + 100 GW of wind

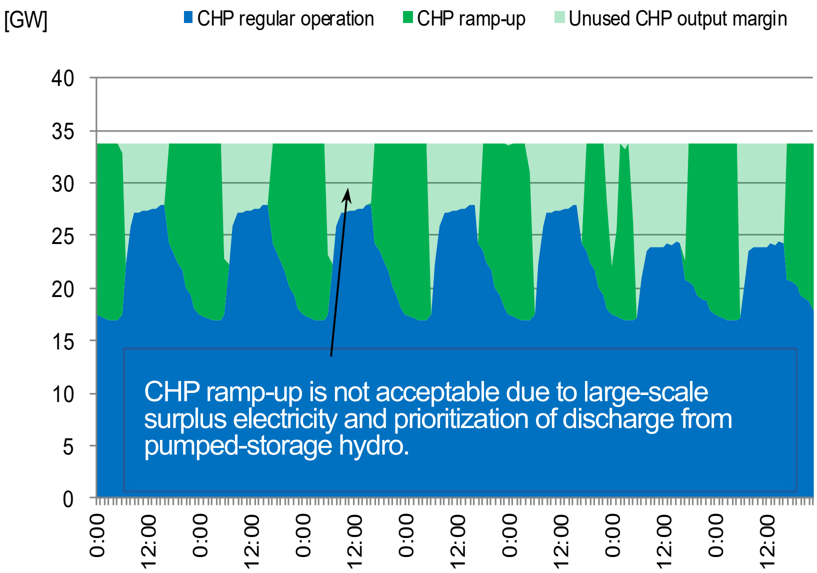

Fig. 5 CHP ramp-up (CNM-CHP)

Note: A representative week in summer. 300GW of Solar PV + 100 GW of wind

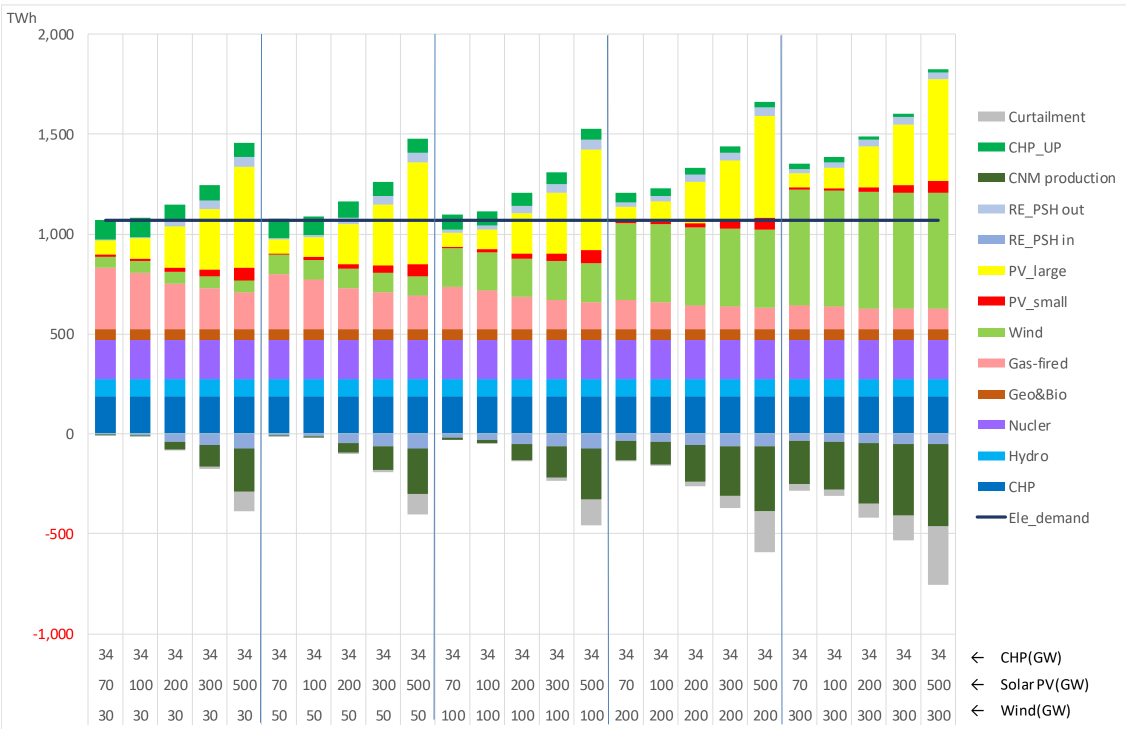

Fig. 6 Power Generation Mix (CNM-CHP)

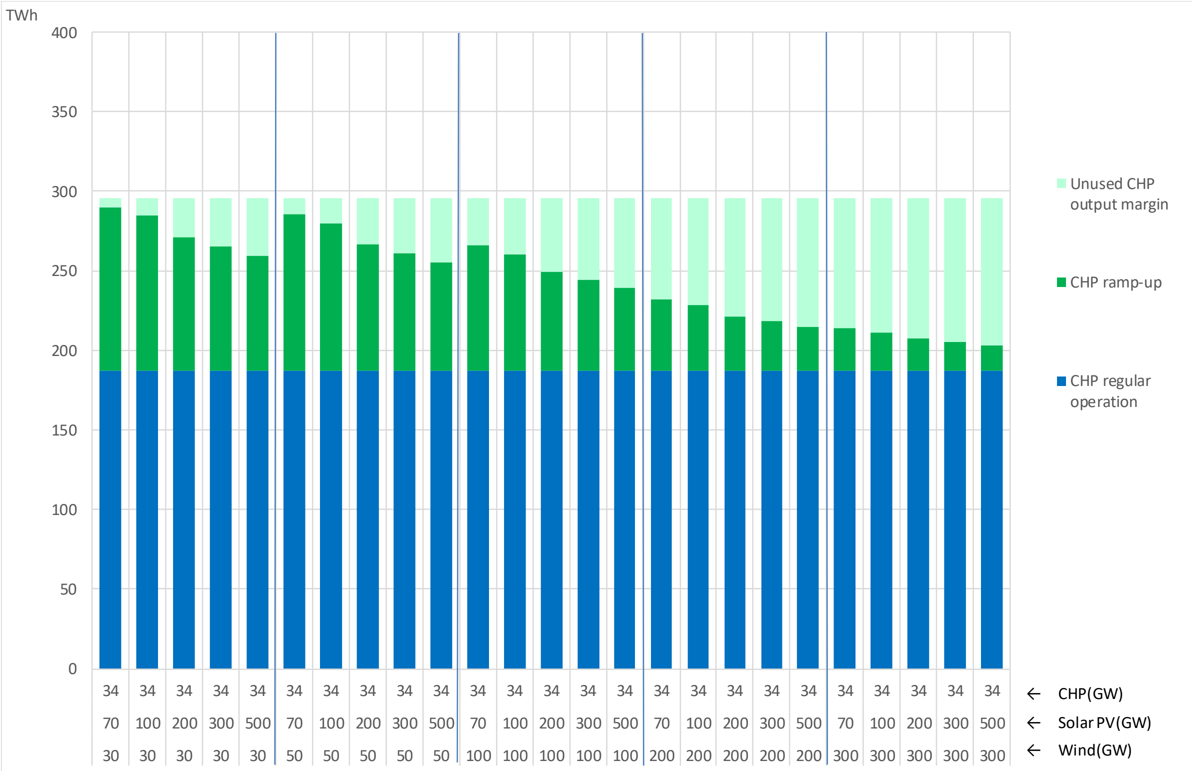

Fig. 7 Utilization Status of CHP Output Margin

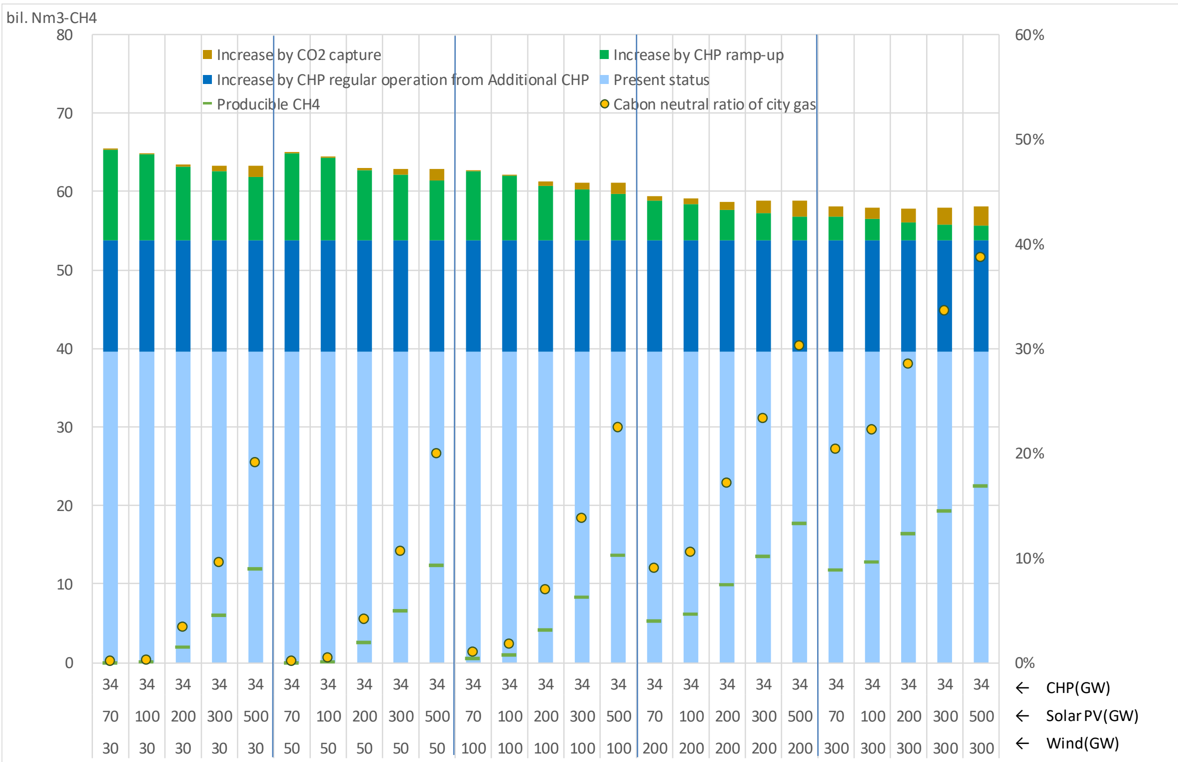

Fig. 8 City Gas Demand and Carbon Neutral Ratio

Note: Carbon neutral ration = CN methane production/city gas demand. City gas demand is expressed by methane calorific equivalent.

4. Analysis of economics

Batteries are chosen to compare with CNM-CHP. At present, batteries are increasingly used for load frequency control as short-term application mainly in Europe and the United States where the markets have been developed. As battery prices decline, however, batteries are expected to be used for long-term application to charge and discharge surplus renewable electricity, which is a similar function as that performed by CNM-CHP. In comparing the "CNM-CHP case" and the "Battery case," the total CO_2 emissions from electricity and city gas combined is used as an indicator. The capacity of CHP introduced for both cases is fixed at 34 GW, with the following assumptions:

- In the "CNM-CHP case," margin output capacity of CHP is utilized as a means of mitigating output fluctuation of renewable energy by ramping up CHP output.
- In the "Battery case," the regular operation of CHP is set to be "must run", and additionally introduced battery is used for mitigation of output fluctuation of renewable energy (2.2).

The following is a comparison of economics between the "CNM-CHP case" and the "Battery case," under conditions where CO_2 emissions are at the same level, and capacity is identified. The charge/discharge efficiency of the battery is assumed to be 90%×90%, while self-discharge rate is assumed to be 0.02%/h.

4-1. Hourly generation mix ("Battery case")

Figure 9 shows the hourly power generation mix for a representative one-week period in summer. The curtailment of surplus electricity from renewable energy is dependent upon the storage capacity of the battery (kWh).

Figure 10 shows the power generation mix. In four scenarios where solar PV + wind power is 100 GW + 30 GW, 200 GW + 50 GW, 300 GW + 100 GW, and 500 GW + 300 GW respectively, battery storage capacity ranges from 0 to 500 GWh.

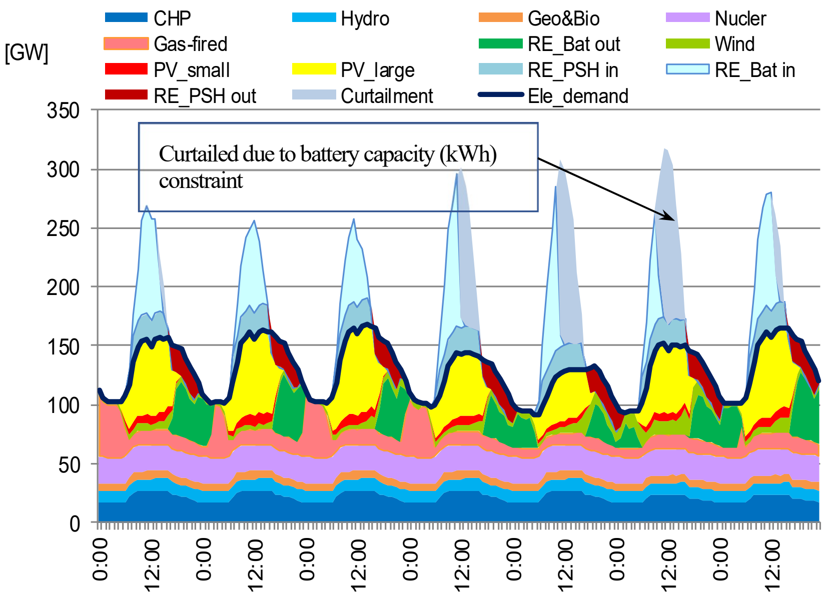

Fig. 9 Hourly Power Generation Mix (Battery case)

Note: A representative week in summer. 300GW of Solar PV + 100 GW of wind. The scale of battery is 0.386 TWh (153 GW) based on the analyses hereafter.

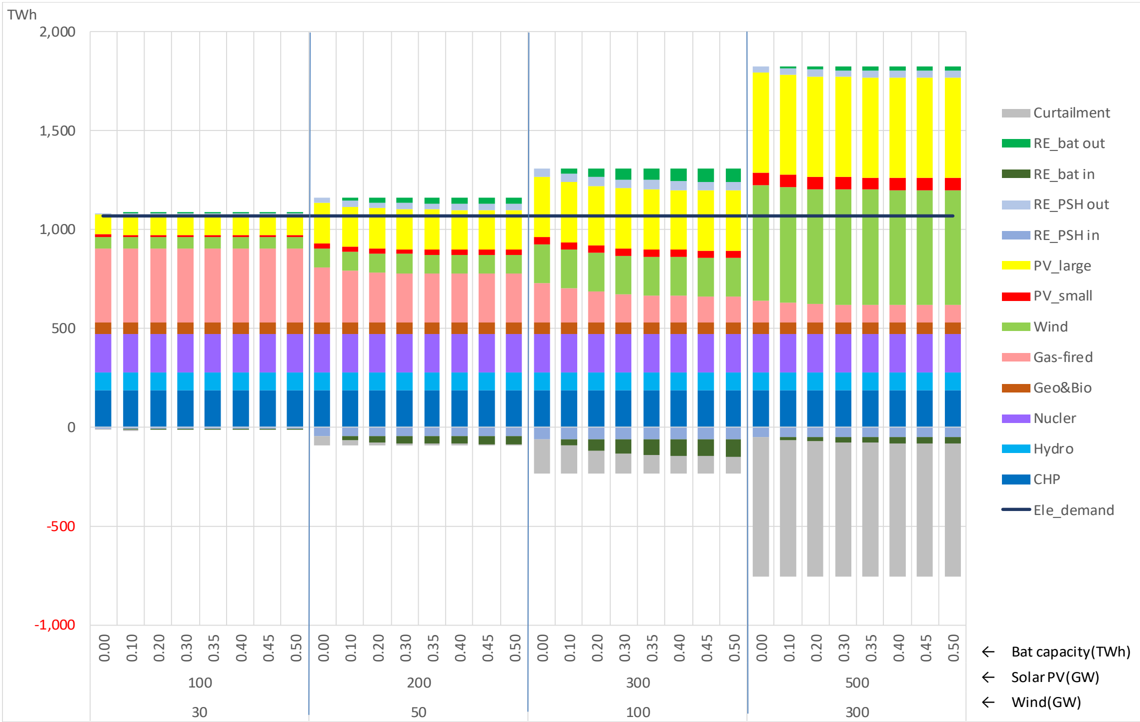

Fig. 10 Power Generation Mix of "Battery case"

Charging and discharging are rarely operated in the presence of limited surplus electricity for a 100 GW of solar PV + 30 GW of wind power. Therefore, expanding battery capacity is meaningless, failing in replacing fossil-fired power generation.

As surplus electricity increases in line with renewable energy capacity expansion, opportunities for batteries to charge and discharge electricity increase. Then, expanding battery capacity leads to a remarkable decrease in fossil-fired power generation. However, if renewable energy expands to 500 GW of solar PV + 300 GW of wind power, battery capacity expansion does not necessarily lead to greater decrease in fossil-fired power generation. This is because as massive solar PV and wind power deployment boosts the frequency and amount of surplus electricity throughout the year, opportunities for batteries to discharge electricity decrease substantially. In such a situation, battery capacity expansion does not make sense.

It is observed that when renewable energy capacity is small, CHP ramp-up exceeds the battery discharge (Figure 6). This is because CHP plants can ramp up irrespective of CN methane production while batteries cannot discharge electricity in the absence of sufficient electricity stored.

4-2. CO_2 emissions volume of electricity and city gas

Figure 11 shows CO_2 emissions from power generation and city gas in the "CNM-CHP case" and the "Battery case" by renewable energy deployment scenario. The four clusters represent the four scenarios of solar PV + wind power introduced. In each cluster, the right-end bar represents the CO_2 emissions for "CNM-CHP case" and the remaining eight bars represent CO_2 emissions for the "Battery case." In case of 100 GW of solar PV + 30 GW of wind power, surplus electricity, or in short, CN methane production volume, is extremely low. However, CHP ramp-up, regardless CN methane production, can reduce the CO_2 emissions (even with CN methane production limited) because of higher total efficiency of CHP than LNG-fired power generation.

When the surplus electricity increases alongside an expansion in the scale of renewable energy introduced, the charge/discharge operation of the battery becomes effective. Hence, increasing the storage capacity of batteries bring about the CO_2 emissions reduction by replacing thermal power generation. However, the impact diminishes gradually.

When renewable energy deploys up to 500 GW of solar PV + 300 GW of wind power, CN methane production rises substantially to promote the decarbonization of city gas. In the "Battery case", however, battery capacity expansion cannot curb CO_2 emissions to a lower level than in the "CNM-CHP case"

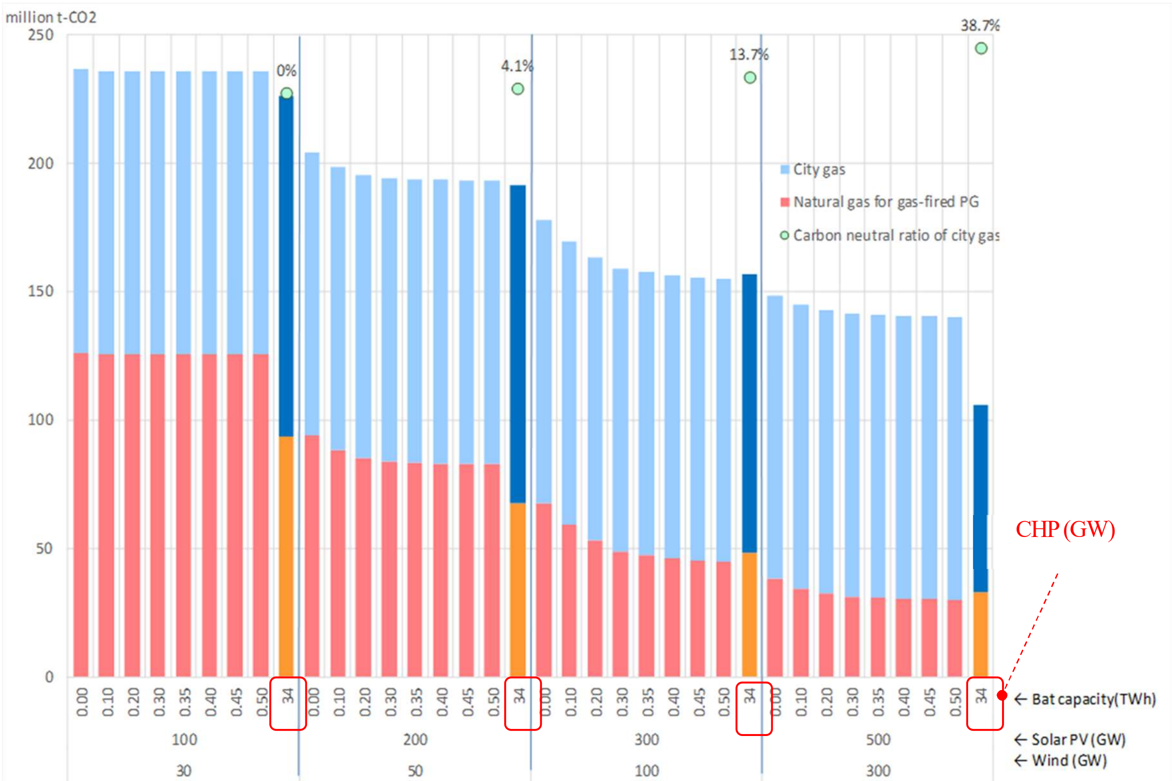

Fig. 11 Comparison of CO_2 emissions in CNM-CHP and battery cases

4-3. Identification of Capacity

Taking the scenario of solar PV 300 GW + wind power 100 GW as an example, the situation is identified where CO_2 emissions volume becomes the same for both the "CNM-CHP case" and the "Battery case".

According to simulations, the maximum hourly CO_2 capture comes to 13,180 t-CO_2/h. With the CO_2 capture rate at 90%, CO_2 capture capacity is identified 14,650 t-CO_2/h. The maximum electricity input into CN methane production process is 122.65 GW. With the specific electricity consumption for CN methane production including CO_2 capture, CN methane production capacity is 6.69 million Nm^3-CH_4/h.

In the scenario of solar PV 300 GW + wind power 100 GW + CHP 34 GW, CO_2 emissions for the "CNM-CHP case" is 157 million t-CO_2.

The scale of battery with which the CO_2 emissions in the "Battery case" is the same as the "CNM-CHP case" is found at 386 GWh of storage capacity with 153 GW of rated input/output (the larger of input and output).

4-4. Comparison

(1) Assumptions

The assumptions shown in Table 1 are made based on the existing research[3)] on CN methane production and the Strategic Roadmap for Hydrogen and Fuel Cells. Assumptions for CAPEX related to CO_2 capture are presented in Table 2 based on the existing research[13)]. The CAPEX of batteries is assumed to be 40,000 yen/kW for power conditioner systems (PCS) and 10,000 – 20,000 yen/kWh for battery cells.

Table 1 CAPEX Assumption for CN Methane Production

	CAPEX	Number of unit
Water electrolysis	JPY 0.215 mil /(Nm^3-H2/h)	4
Methanation	JPY 0.50 mil /(Nm^3-CH_4/h)	1
CN methane production system	JPY 1.36 mil /(Nm^3-CH_4/h)	1

Table 2 CAPEX Assumption for CO_2 Capture

Equipment	Item		Assumption
CO_2 capture	Scale		118t-CO_2/h
	CAPEX		JPY 6.67 bln
	Annual OPEX	Capital-relevant	JPY 0.6 bln /year
		Solvent	JPY 0.12 bln /year
		Sub-total	JPY 0.72 bln /year
	CAPEX per unit CO_2 capture scale		**JPY 92 mil /(t-CO_2/h)**
Boiler	Scale		127t-CO_2/h (260t-s/h of steam)
	CAPEX		JPY 5.42 bln
	CAPEX per unit CO_2 capture scale		**JPY 43 mil /(t-CO_2/h)**
TOTAL per unit CO_2 capture scale			**JPY 0.134 bln /(t-CO_2/h)**

(2) Energy costs

It is assumed that the electricity needed for CO_2 capture is provided by surplus electricity from renewable energy, and is reflected in the specific power consumption for CN methane production. In the "CNM-CHP case" and the "Battery case", the difference in energy consumption lies in natural gas and city gas. Table 3 shows the demand for city gas and natural gas in the "CNM-CHP case" and the "Battery case". In the "CNM-CHP case," city gas demand increases mainly through an increase in CHP output, while demand for city gas derived from natural gas is less than that in the "Battery case" due to CN methane production. On the other hand, demand for natural gas from gas-fired power generation is higher in the "CNM-CHP case". As there is no significant gap in total demand for city gas and natural gas between the two cases, the difference in energy cost is disregarded.

Table 3 City gas and Natural gas Consumption

	City Gas			Natural gas	Total
(Billion Nm^3-CH_4 Methane equivalent)	Total	CNM	Natural gas	Gas-fired PG	
No measures	53.8	0	85.3	31.5	85.3
CNM-CHP	61.2	8.4	75.4	22.6	75.4
Battery	53.8	0	75.5	21.7	75.5

(3) Comparison of CAPEX

CAPEX is shown in Figure 12. In the "CNM-CHP case", total CAPEX is 11 trillion yen. On the other hand, total CAPEX comes up to 14 trillion yen in the "Battery case" (If the cost of battery cells is reduced to 10,000 yen/kWh, total CAPEX would be 10 trillion yen).

In this study, Japan is regarded as a single region. In reality, however, CO_2 capture, CN methane production, and batteries are introduced in a regionally distributed manner, there is a need to carry out an analysis that takes economies of scale into consideration. Nevertheless, the results of the analysis conducted in this study showed that the economics of CNM-CHP, which makes use of existing city gas infrastructure and CHP, is comparable to batteries as a means of mitigating output fluctuations in the introduction of large scale renewable energy.

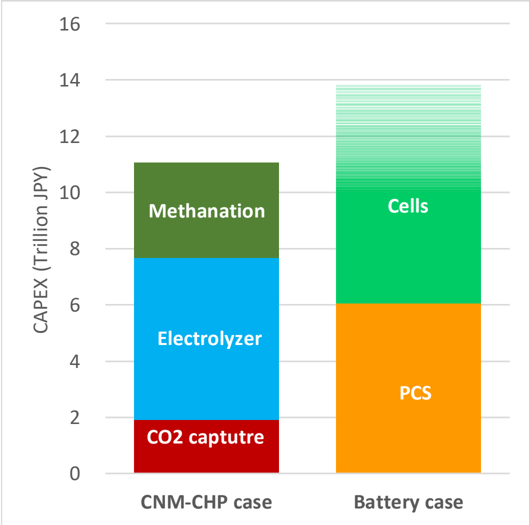

Fig. 12 CAPEX Comparison

5. Conclusion

This study assessed a "CNM-CHP model" that offers grid flexibility through offsetting renewable energy output fluctuations by utilizing the margin output capacity of existing combined heat and power (CHP) for ramping-up, while blending carbon-neutral (CN) methane, that is produced from surplus renewable electricity, into the existing city gas network to decarbonize city gas.

There is trade-off relation that the room for CHP ramp-up declines while CN methane production grows as renewable energy increasingly deploys. Nevertheless, even if the room for CHP ramp-up decreases, there is an advantage that CN methane can be used for city gas consumption other than CHP, which brings about significant decarbonization. This is an advantage over batteries, which have fewer opportunities to discharge when the large scale renewable energy is deployed, even if charging were possible.

In the economic analysis based on the premise of the introduction of 300GW of solar PV + 100 GW of wind power + 34 GW of CHP, it was shown that the CNM-CHP model offers the same level of economics as the model for mitigating output fluctuations of renewable energy through batteries.

Batteries play a role in the grid integration of the renewable energy to a certain extent, but there is a limit to how much they can contribute with regard to the large-scale integration of renewable energy. This is due to the limitations of the "power to power" approach, which considers the integration of renewable energy within the closed system of a power grid. On the other hand, the "power to gas" approach, in which surplus electricity from renewable energy flows from the power grid to city gas and the transport sector, encompasses the concept of sector integration. Hence, it is able to go beyond the unique constraints in "power to power" and achieve decarbonization of the whole energy system while accommodating large-scale renewable energy. In the "power to gas" approach, CN methane, unlike hydrogen, has the advantage of being able to utilize existing city gas infrastructure. Moreover, CHP, which is expected to serve as VPP, is able to achieve grid integration that utilizes margin output capacity with less carbon, through the use of CN methane.

CN methane poses issues that should be reviewed technically, including the enhancement of the efficiency of electrolysis and Sabatier reaction, and the application of SOEC co-electrolysis and bioreactors. Nevertheless, as this study showed, it contributes significantly to the decarbonization of energy systems. As existing city gas infrastructure includes gas pipelines, satellite terminals and gas production plants representing a huge energy storage system, and also CHPs as discharging equipment, only adding a CN methane production system as a function to charge surplus renewable electricity may contribute to the decarbonization of electricity and city gas, as well as to the mitigation of renewable energy output fluctuations in a lower carbon manner.

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