Advisory Committee for Natural Resource and Energy
Strategic Policy Committee

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Some additional data is added to the original material. (Ver. June 11th, 2021)

Scenario Analyses for 2050 Carbon Neutrality in Japan (Interim Report)

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Acknowledgement: We thank Dr. Yuji Matsuo, the Institute of Energy Economics, Japan, for his cooperation on the integration cost analysis of power grid.

1. Overview of Climate Change Mitigation for Carbon Neutrality

Image of Primary Energy in Japan for Net Zero Emissions (1/2)

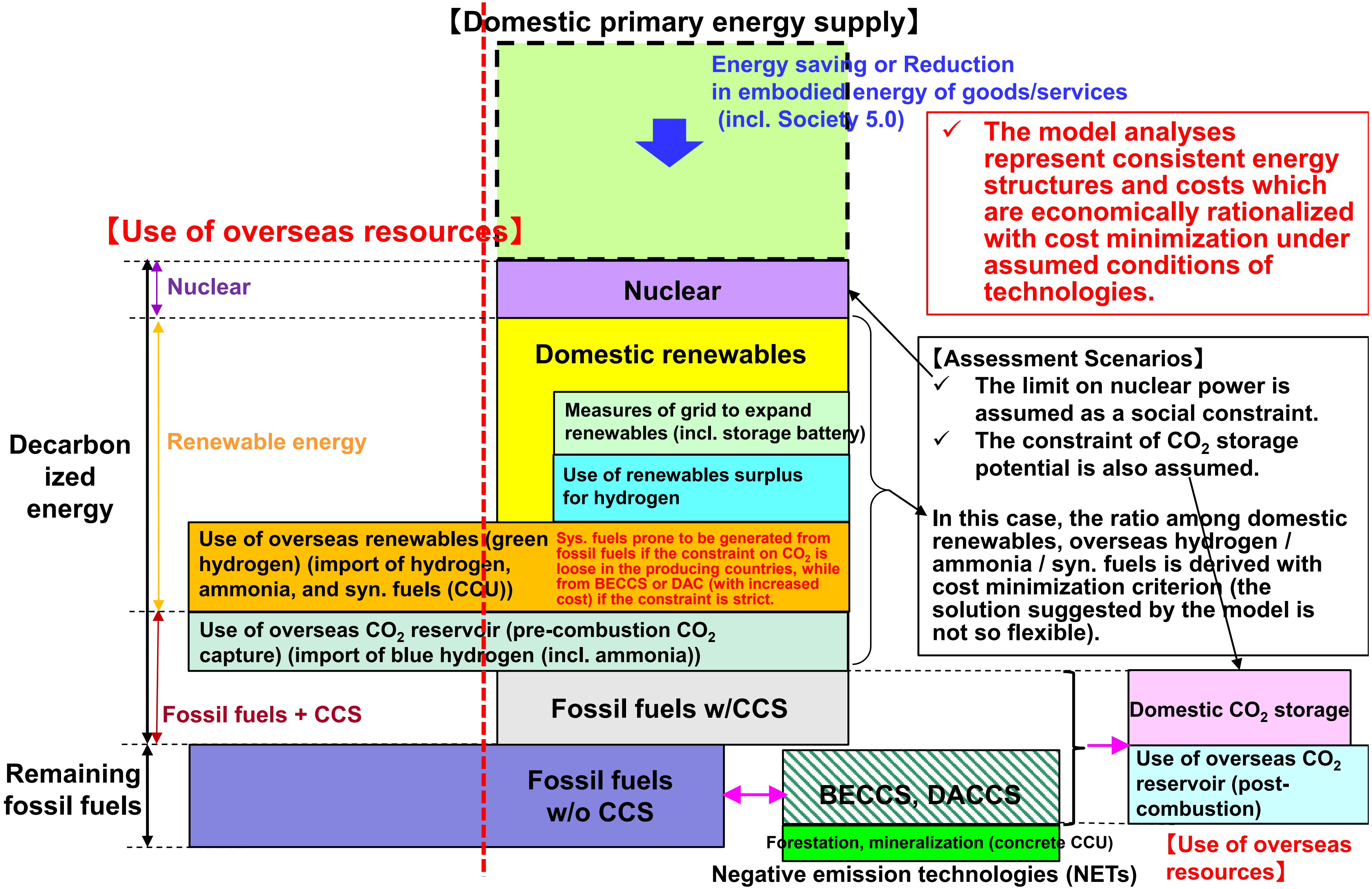
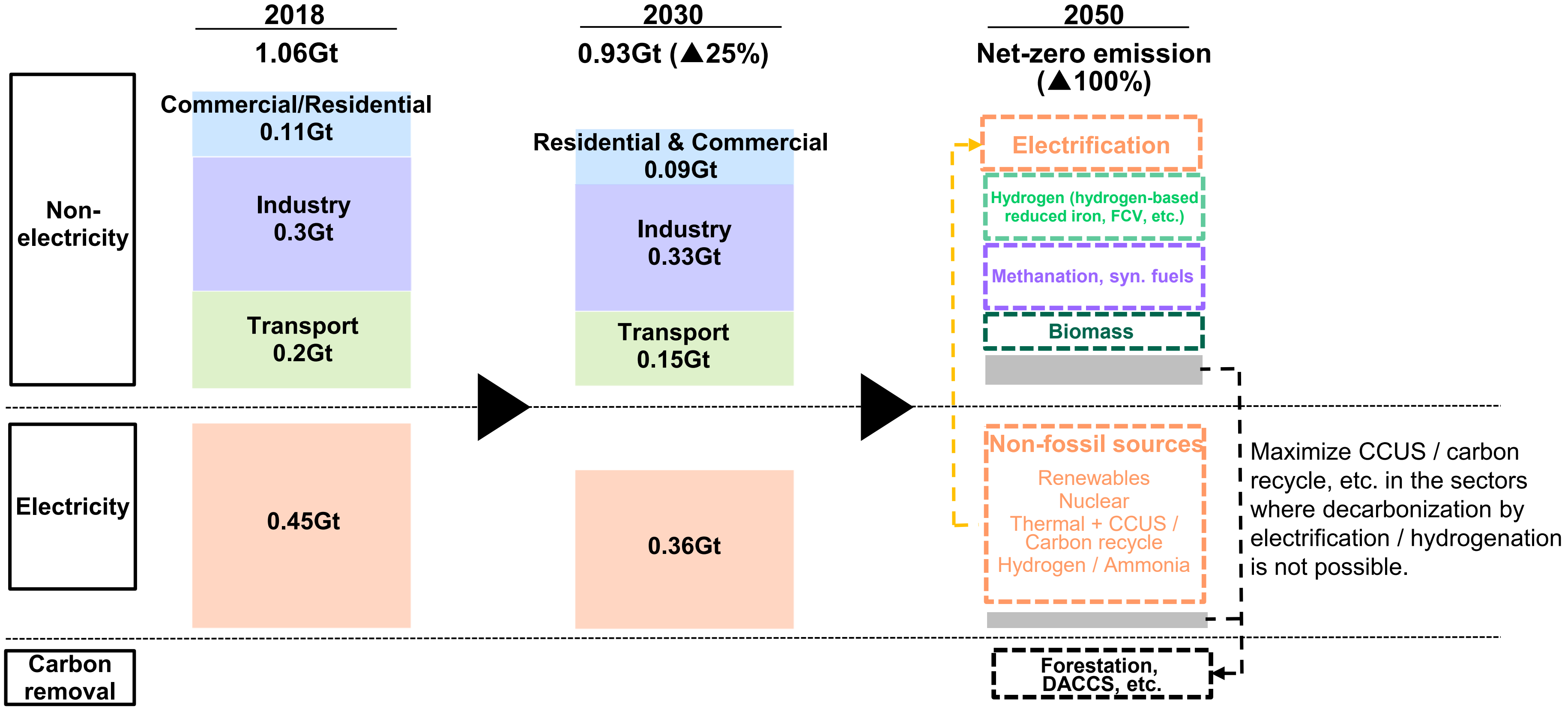


Image of Primary Energy in Japan for Net Zero Emissions (2/2)

- ✓ The whole system including non-electric power sectors is analyzed in the model.
- ✓ Electricity generation amount is determined by combined factors such as followings: energy demand change induced by social structural change (basically↓although it depends on socio-economic pathways] + [electrification increase by energy usage structural change (↑)] + [demand decrease by power saving (↓)] + [electrification of non-electricity demand (↑)] + [increase of loss in increased power storage, e.g., storage battery, due to VRE expansion (↑)] + [increase of electricity demand to produce green hydrogen and e-fuels (syn. fuels) (↑) (however, electricity demand in Japan would not be affected in case of overseas manufacturing)].



Source) Strategic Policy Committee, Advisory Committee for Natural Resource and Energy, 2020

* The figures indicate CO_2 from energy sources.

2. Assessment using Global Energy and Climate Change Mitigation Model: DNE21+

The model-driven scenarios represent quantitative features of energy and global warming response measures which are globally consistent in a given time-frame under assumed conditions, and specify the energy systems which are economically rationalized with cost minimization.

Energy Assessment Model: DNE21+
(Dynamic New Earth 21+)

- Systemic cost evaluation on energy and CO_2 reduction technologies is possible.
- Linear programming model (minimizing world energy system cost; with 10mil. variables and 10mil. constrained conditions)
- Evaluation time period: 2000-2100
  Representative time points: 2005, 2010, 2015, 2020, 2025, 2030, 2040, 2050, 2070 and 2100
- World divided into 54 regions
  Large area countries, e.g., US and China, are further disaggregated, totaling 77 world regions.
- Interregional trade: coal, crude oil/oil products, natural gas/syn. methane, electricity, ethanol, hydrogen, CO_2 (provided that external transfer of CO_2 is not assumed in the baseline)
- Bottom-up modeling for technologies on energy supply side (e.g., power sector) and CCUS
- For energy demand side, bottom-up modeling conducted for the industry sector including steel, cement, paper, chemicals and aluminum, the transport sector, and a part of the residential & commercial sector, considering CGS for other industry and residential & commercial sectors.
- Bottom-up modeling for international marine bunker and aviation.
- Around 500 specific technologies are modeled, with lifetime of equipment considered.
- Top-down modeling for others (energy saving effect is estimated using log-term price elasticity.

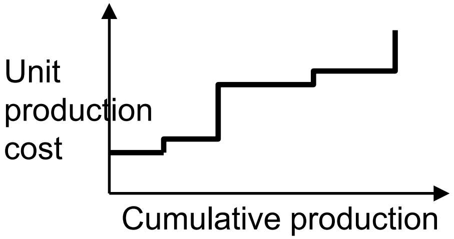
- **Regional and sectoral technological information provided in detail enough to analyze consistently.**
- **Analyses on non-CO_2 GHG possible with another model RITE has developed based on US EPA's assumptions.**

- **Model based analyses and evaluation provide recommendation for major governmental policy making on climate change, e.g., cap-and-trade system and Environmental Energy Technology Innovation Plan, and also contribute to IPCC scenario analysis.**

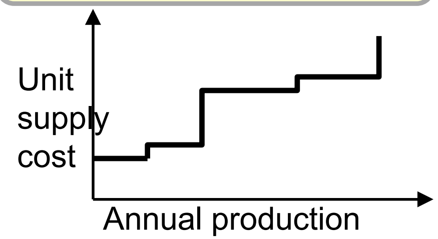
Technology Descriptions in DNE21+

Oil prices in baseline assuming no climate measures are exogenously assumed, and other price factors, e.g., unit production costs, concession fees, are adjusted. In emission reduction case, prices are endogenously decided accordingly.

Fossil fuels
- Coal (coal, lignite)
- Oil (conventional, unconv.)
- Gas (conventional, unconv.)



Renewable energies
- Hydro power & geothermal
- Wind power
- PV / CSP
- Biomass, Marine energy



Nuclear power

Facility cost and efficiency of each technology are exogenously assumed.

Energy conv. processes (oil refinery, coal gasification, bio-ethanol, gas reforming, water electrolysis, etc.)

Electric Power generation

CCUS

DAC

Industry
- Iron & steel
- Cement
- Paper & pulp
- Chemical (ethylene, propylene, ammonia)
- Aluminum
- Solid, liquid and gaseous fuels, and electricity

Transport
- Vehicle, shipping, aviation
- Solid, liquid and gaseous fuels, and electricity

Residential & Commercial
- Air conditioner, refrigerator, TV, etc.
- Solid, liquid and gaseous fuels, and electricity

For main sectors modeled in a bottom-up way, economic activities and service demands (e.g., production of crude steel and cement, passenger service demand) are exogenously assumed.

Limitation and Challenge of the Model

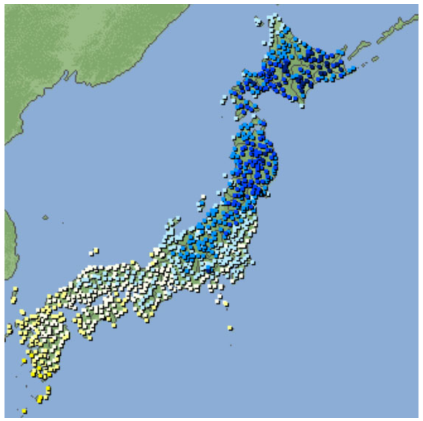
- In DNE21+ model, which enables the assessment of the whole world with consistency regarding energy import / export amounts and prices, the prerequisites are assumed considering consistency in the global system. Regarding the assumption for PV, wind power generation and CO_2 storage potential, for instance, the potentials for each country are assumed using a common assumption logic based on the global GIS data.
- Therefore, it is suitable for the comparison and assessment of technological and economic potentials among countries while it does not significantly consider country-specific circumstances (e.g., social and physical constraints on nuclear power and renewable energy in Japan).
- In-depth analyses for Japan should be conducted separately taking into account more detailed conditions. For instance, the domestic power grid structure is not specified in DNE21+, making difficult to assess the differences in system costs depending on the renewable energy installation sites.
  → Analysis results of Power Generation Mix Model by Univ. of Tokyo and IEEJ is utilized.
- As DNE21+ is a dynamic optimization model, it can provide assessment for time points, e.g., 2050, in accordance with the future features in 2100. Also, any arbitrary scenario assumption is supposed to be excluded as the assessment is made based on a cost minimization criterion. On the other hand, the model could show extreme changes, e.g., all the predicted technologies are replaced with others once economic rationality is completed. (The real world usually follows a technology diffusion curve without extreme changes as there are various actors. Compared to macro econometric models, which is superior for representing such situations, this type of optimization models could sometimes show extreme changes.)

Assumption of Integration Cost: Power Generation Mix Model by Univ. of Tokyo and IEEJ

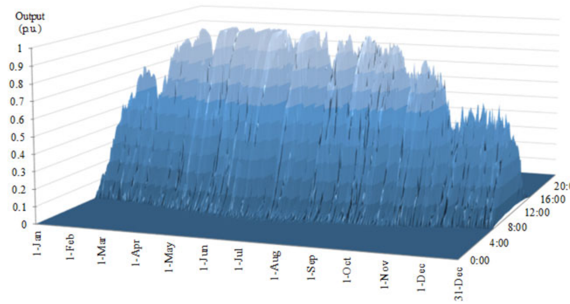
- As DNE21+ is a global model and not suitable for the analysis regarding internal power grid and regional conditions of renewable energy, it applies the results of the study on the assumption of integration cost under high VRE penetration based on an optimal power generation mix model, by Fujii-Komiyama Laboratory, the University of Tokyo and the Institute of Energy Economics, Japan[1), 2)].
- Time fluctuation of VRE output is modeled based on nationwide meteorological data, e.g., AMeDAS, to estimate the optimal configuration (power generation and storage system) and the annual operation by linear programming.
- Calculated with hourly modeling by 5 divided regions (Hokkaido, Tohoku, Tokyo, Kyushu and others). Prerequisites for power generation cost, resource constraint, etc, are defined in line with DNE21+.

Considered in modeling･･･ Output control, power storage system (pumped hydro, lithium-ion battery and hydrogen storage), reduction of power generation facility utilization, inter-regional power transmission lines, electricity loss in storage and transmission

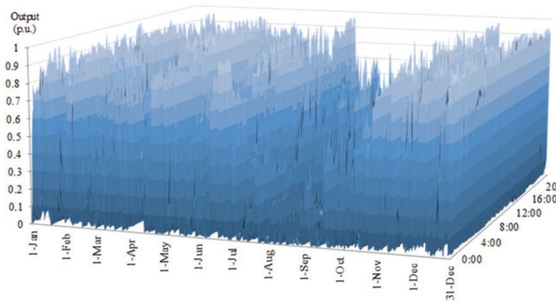
Not considered in modeling･･･ Intra-regional power transmission lines, power grid, influence of decrease of rotational inertia, grid power storage by EV, prediction error of VRE output, supply disruption risk during dark doldrum



Meteorological data
（AMeDAS: 1300 nodes）



Output example of PV



Output example of wind power

1) R. Komiyama and Y. Fujii, (2017). *Energy Policy*, 101, 594-611.
2) Y. Matsuo et al., (2020). *Applied Energy*, 267, 113956.

Acknowledgement: We thank Dr. Yuji Matsuo, the Institute of Energy Economics, Japan, for his cooperation.

Prerequisites and Assumptions in DNE21+ Model (1/4)

Sector		Assumption method	Example	Supplementary
Population		UN median estimate	Refer to appendix	As DNE21 is an energy system model, population and GDP are exogenous and used for the assumption such as for service demand.
GDP		Estimated by country based on assumed population, GDP per capita, etc. Consistent with IPCC SSPs scenarios.		
Service demand, etc.	Iron & steel, Cement, Chemical, Paper & pulp Aluminum, Road transportation, Domestic aviation, International aviation, International marine bunker	Assumed by country / region divided in the model based on past records, population, GDP, etc. For iron & steel, total production of crude steel is assumed, and also, as its internal number, electric furnace steel production assumed based on the available iron scrap estimate. For chemical, ethylene, propylene, BTX and ammonia are assumed. For road transportation, demands are assumed by car (small and large), bus and truck (small and large). For aviation, demands by 4 flight zones are assumed.	Refer to appendix for selected sectors	Service demand can be significantly reduced in the case that GDP losses are huge due to high costs of emission reduction or that there are large differences in countermeasure cost among nations. It should be noted that the feedback in such cases are not considered in DNE21+ as it is a partial equilibrium model.

Prerequisites and Assumptions in DNE21+ Model (2/4)

Sector		Assumption method	Example	Supplementary
Fossil fuel	Amount of resources	Based on the reports of United States Geological Survey (USGS) for oil / gas, and World Energy Council (WEC) (Survey of Energy Resources 1998) for coal. Assumed from the article by H-H. Rogner (1997) for unconventional oil / gas.	Globally, conventional oil (incl. NGL): 241 Gtoe, conventional natural gas: 243 Gtoe, coal (incl. lignite): 2576 Gtoe, etc.	
	Price	Based on the article by H-H. Rogner (1997) for mining cost. FOB price in baseline scenario is adjusted as concession fee referring to IEA WEO, etc.	Refer to appendix	
Biomass	Residue	Food residue and wood residue are estimated by country.	Potential in 2050 is about 9EJ/yr globally.	
	Plantation and forestation potential	Using RITE GLaW (Grid-based model for agricultural Land-use and Water resource assessment) model, potentials are estimated for food production according to food consumption and meteorological forecast, land-use areas and surplus land. Potential for plantation biomass (and forestation) is estimated.	About 900 Mha is available in 2050 globally.	
Hydrogen		Several production technologies are assumed, such as produced **from fossil fuel** (grey hydrogen), **fossil fuel + CCS** (blue hydrogen) and **by renewable energy** (green hydrogen), and the model endogenously decides the one with minimized cost under the emission reduction target. Transportation cost is modeled referring to a reported case of liquid hydrogen transportation cost, provided that long-distance transportation is not specified.	Refer to appendix	For methanation, Sabatier reaction and SOEC co-electrolysis are assumed.
	Synthetic fuel (CCU)	**Petroleum-based synthetic oil** and **synthetic methane** are assumed. CO_2 from biomass, **DAC**, and fossil fuel is assumed. The model endogenously decides the one with minimized cost under the emission reduction target.		

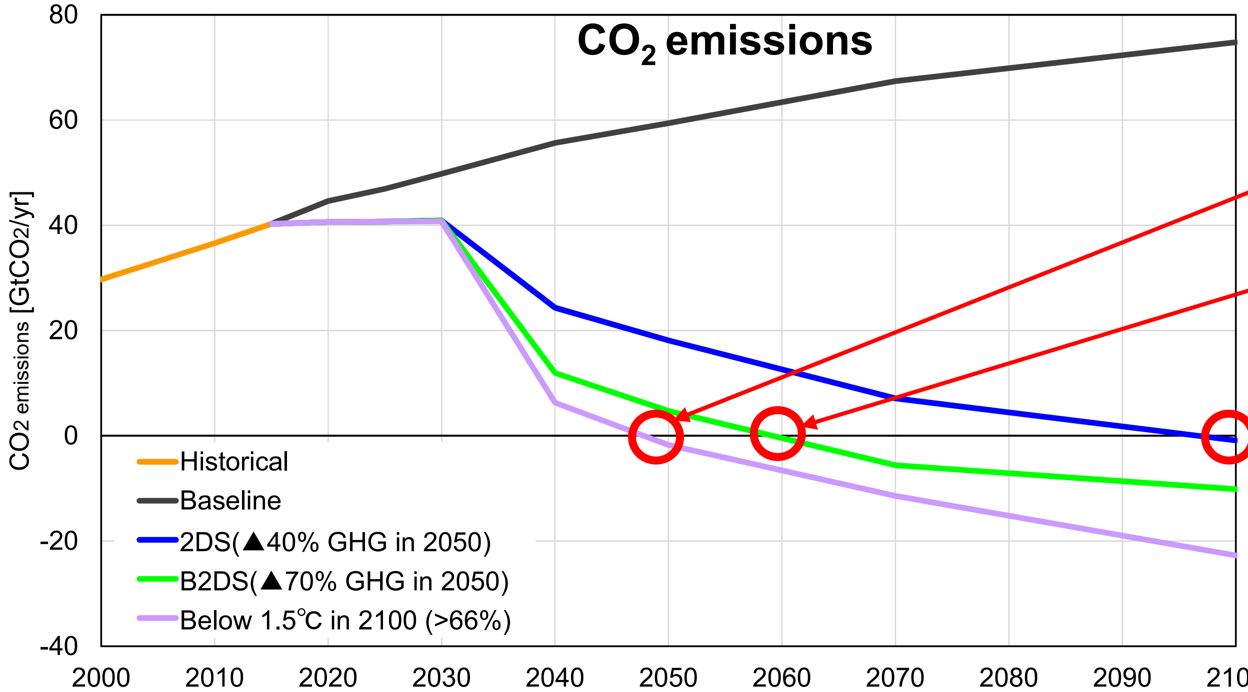
Prerequisites and Assumptions in DNE21+ Model (3/4)

Sector		Assumption method	Example	Supplementary
Power generation	Fossil / biomass	Facility cost is assumed based on the reports of OECD/NEA, cost verification committee, etc. For fuel cost, based on FOB price described in the fossil fuel price, CIF price considering transportation distance is assumed.	Refer to appendix	
	Nuclear power	Facility cost is assumed based on the reports of OECD/NEA, cost verification committee, etc.	Refer to appendix	For countries not planning to adopt nuclear power, no deployment is assumed regardless economic efficiency. For Japan, in line with the 2030 energy mix as 20% nuclear power, the upper limit is set as 10% in Reference case. Sensitivity is analyzed.
	Renewable energy	PV: Grid-based potential is estimated based on insolation data and land use data of NASA GIS. Wind power: Grid-based potential is estimated based on wind speed data and land use data of NOAA GIS. For VRE, grid costs are assumed as rising as the VRE ratio in total power generation increases (using Power generation mix model by Univ. of Tokyo and IEEJ). Hydro power: Cost and potential are assumed by country based on WEC Survey of Energy Resources 1998. Geothermal power: Assumed generation cost as 172$/MWh-258$/MWh based on several literature. CSP: Grid-based potential is estimated based on insolation data and land use data of NASA GIS.	VRE: p.24-30	Assumption is made from GIS data based on a world atlas for global consistency. The scenario that facility cost is reduced over time is exogenously assumed. More precise data for Japan regarding GIS accuracy, land use cost, etc. should be further examined.
CCS	Capture	Facility cost and energy to capture CO_2 are assumed based on several literature.	Refer to appendix	Assumption is made from GIS data based on a world atlas for global consistency. More precise data for Japan should be further examined.
	Transport	Pipeline and liquid CO_2 transportation (tanker) are assumed.	Refer to p.34	
	Storage	Storage potential is estimated based on geological data of United States Geological Survey (USGS). (Refer to Akimoto et al., IEA GHG, 2004.)		
Direct Air Capture of CO_2 (**DAC**)		Based on M. Fasihi et al., (2019), which conducts many surveys on DAC, facility cost and energy amount for capture of 2 systems are assumed.	Refer to appendix	For captured CO_2, same as transport and storage in CCS. For CCU use, same as synthetic fuel.

Prerequisites and Assumptions in DNE21+ Model (4/4)

Sector		Assumption method	Example	Supplementary
Industry	Iron & Steel	Energy saving technologies (e.g., COURSE50), **CCS**, gas-based DRI, and **H_2-based DRI** are assumed. Facility cost and energy balance are assumed referring to several literature (J. Oda et al., Energy Economics, 2007, etc.). The installation amount of electric furnace is constrained according to availability of scrap iron.	Refer to appendix for availability of H_2-based DRI and scrap iron.	By BF-BOF + CCS, about 30% CO_2 emission reduction is possible, but net-zero emission is not possible.
	Cement / Concrete	Energy saving technologies, conversion from coal to gas, hydrogen or synthetic methane, **CCS** (only available above 3000 t-clinker/day) are assumed, which are endogenously determined with total optimization. Facility cost and energy balance are assumed referring to several literature. Concrete **CCU** is assumed.	Concrete CCU Max. 1.9kgCO_2/t-cement (net absorption considering the CO_2 amount by natural absorption is modeled.)	
	Chemical	Methods to produce ethylene, propylene, BTX and ammonia are assumed, as well as energy saving technologies for each. Production of ethylene and propylene from ethane, and production of ethylene, propylene and BTX via methanol (produced from hydrogen and CO_2 (CCU)) are also assumed.		
Residential & Commercial	Residential & Commercial	Assuming demands for refrigerator, lighting, cooking equipment, hot-water supply and cooling & heating, various equipment, e.g., heat pump and cogeneration, is modeled. City gas infrastructure cots is also assumed.	Transport infrastructure cost to convert from city gas to hydrogen is assumed as twice as from gas and **syn. methane**.	
Transport	Road transportation	Conventional engine car (gasoline, light oil and bio fuel), HV, PHV, EV and FCV are assumed by vehicle type (passenger car (small / large), bus and truck (small / large)). Car body price is assumed referring to sales price and cost reduction outlook. Additional costs for infrastructure for EV and FCV are assumed (hugely decreasing toward 2050). Syn. Fuels are assumed. Share mobilities (car-/ride-sharing) scenario induced by fully autonomous car is also assumed.	Refer to appendix for the example of small passenger car. Refer to p.36 for car-/ride-sharing scenario assumption.	It is assumed that fully autonomous car is available in 2030 in share mobilities scenario.
	Aviation	Energy saving, transition of jet fuel to biofuel / syn. jet fuel, hydrogen aircraft and electric aircraft are assumed. The scope that technologies can meet the demand by flight zone is assumed. Fuel cost is endogenously determined in the model. Aircraft cost is assumed referring to several literature.		
	International marine bunker	Heavy oil, light oil, biodiesel fuel, LNG carrier and hydrogen ship are assumed.		

Global Baseline Emissions and Assumed Emissions Scenarios under 2°C and 1.5°C



Net zero CO_2 emissions around 2050

Net zero CO_2 emissions around 2060

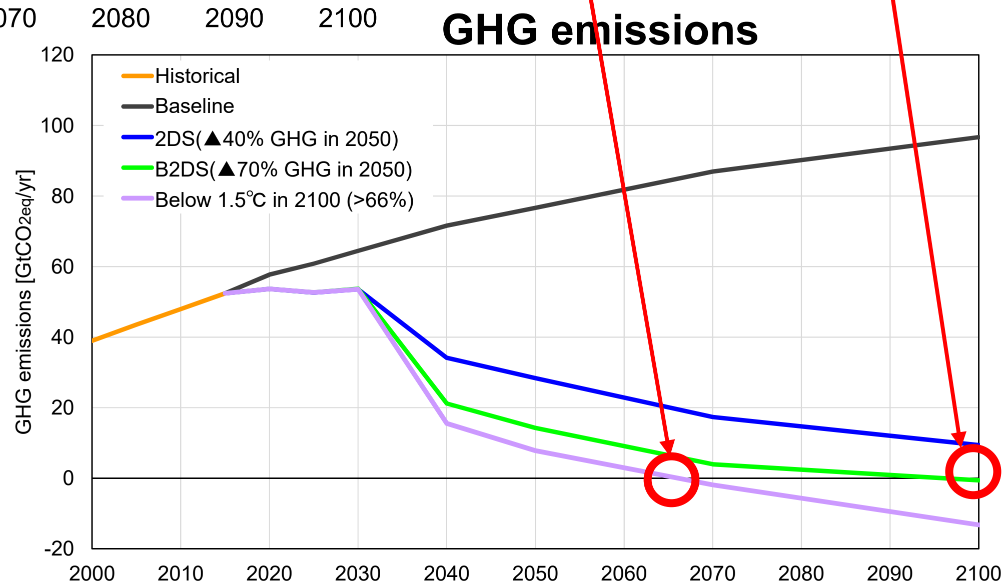
Net zero CO_2 emissions around 2100

Net zero GHG emissions around 2065

Net zero GHG emissions around 2100

Note) Emissions for baseline shows model estimates results under SSP2, not assumed scenario

※ 2DS, B2DS, B1.5OS scenarios assume emission constraints equivalent to NDCs of each nation up to 2030



In the scenario analyses of Japan's 2050 carbon neutrality, 1.5°C global scenarios are assumed in addition to Japan's emissions reduction scenarios, for the global competition for carbon neutral resources to be considered.

3. Assumed Scenarios

Overview of Assumed Scenarios

<table>
<tr><th colspan="2"></th><th>GHG emission reduction in 2050</th><th>Technology assumption (cost / performance)</th><th>Technology deployment scenario</th></tr>
<tr><td colspan="2">Reference case</td><td rowspan="7">▲100%

(For other than Japan, ▲100% for each western country, and ▲100% for the others as a whole)</td><td rowspan="2">Standard case

(Note: It is premised that RE is diffused due to suspected inertial force in high share RE scenario.)</td><td>Decided endogenously (cost minimization), with constraints for nuclear power up to 10% and CO_2 storage.</td></tr>
<tr><td>Assuming high share RE in model's standard assumption under Reference case</td><td>1
Renewable Energy 100% (RE100)</td><td>Renewable energy nearly 100%
(Nuclear power 0%)</td></tr>
<tr><td rowspan="5">Assuming each technology is further accelerated or expanded.</td><td>2
Renewable Energy Innovation</td><td>Acceleration of RE cost reduction</td><td>Decided endogenously, with constraints for nuclear power up to 10% and CO_2 storage.</td></tr>
<tr><td>3
Nuclear Power Utilization</td><td>Expansion of nuclear power deployment</td><td>Decided endogenously, with constraints for nuclear power up to 20% and CO_2 storage.</td></tr>
<tr><td>4
Hydrogen Innovation</td><td>Acceleration of hydrogen cost reduction</td><td>Decided endogenously, with constraints for nuclear power up to 10% and CO_2 storage.</td></tr>
<tr><td>5
CCUS Utilization</td><td>Expansion of CO_2 storage potential</td><td>Decided endogenously, with constraints for nuclear power up to 10%. Large CCS storage potential assumed.</td></tr>
<tr><td>6
Demand Transformation</td><td>Expansion of car-/ride-sharing</td><td>Dramatic expansion of car-/ride-sharing due to fully autonomous car implementation assumed.
Other assumptions are same as Reference case.</td></tr>
</table>

*As for demand side transformation, scenario analyses will be continued including other factors than car-sharing.

Scenario Description in Modeling Analyses (1/4)

	Scenario	Challenges to realize scenario	Model Input
Reference case	**Scenario in which the challenges of each power source to realize Reference case, presented for deeper discussion in the 35th Strategic Policy Committee, are overcome.** Image of power generation mix **RE 50-60%, Nuclear power 10%, Hydrogen / Ammonia 10%, CCUS thermal 20-30%** → Determined in the model with cost minimization	**<Renewable energy>** **(1) Securing load balance** For VRE expansion, need to secure demand & supply balance to cope with output fluctuation due to natural conditions. **(2) Securing transmission capacity** Need to promote large-scale capital investment and local consensus for construction to increase the transmission capacity that connects areas potential for deployment of renewables and areas in demand. **(3) Securing inertial force** Need to secure a constant "inertial force" (to keep turbines rotating) in an entire system to prevent blackout due to accidents such as power loss. **(4) Response to natural conditions and social constraints** For RE expansion under disadvantageous natural conditions in terms of insolation and wind, e.g., flat land excluding forests is half that of Germany and shallow sea area is 1/8 that of the UK, need coordination with local community and concerned parties, considering the impact on environment, ecosystem, shipping routes, etc. **(5) Cost** Additional costs can be required for land preparation, connection and coordination if the deployment amount increases under the geographical conditions such as scarce flat land and shallow sea. Need to reduce the total RE deployment costs by securing suitable sites and developing highly efficient power generation equipment.	**<Renewable energy>** **Assumption for stable grid operation** • Assuming VRE expansion by overcoming the challenges, such as securing power demand & supply balance, securing transmission capacity to deal with unevenness of RE suitable sites, and securing inertial force in an entire system to cope with blackout in case of power loss. **Assumption for deployment based on natural / physical conditions** • Assuming power generation amount above the current Germany's (about 640TWh) and above 2 times of UK's (about 330TWh) under limited natural conditions. • Assuming power generation amount based on the case that solar and offshore wind power deployment expands by installing PV on rooftops or in abandoned croplands and utilizing Act of Promoting Utilization of Sea Areas. **Economic assumption** • Assuming that capital cost and O&M cost be reduced according to the international price as securing suitable sites progresses with the current technological level (provided that cost increase due to location restriction is not precisely considered). → Assumed power generation costs are PV: ¥10-17, wind power: ¥11-20 and integration cost: about ¥4.
		<Nuclear power> **(1) Restoring public trust** Need to restore public trust through pursuing safety, coexisting with local community, establishing sustainable back-end system, improving feasibility, maintaining and strengthening human resources / technologies / industrial bases, and working on nuclear power innovation. **(2) Securing installed capacity** The installed capacity of nuclear power will decrease significantly after 2040 to be 23.74GW (166.3TWh) (about 10% of power generation mix) in 2050, and 9.56GW (67TWh) in 2060, even assuming that all 36 nuclear plants (incl. under construction) operate for 60 years. Need to secure installed capacity.	**<Nuclear power>** **Assumption for sustainability** • Assuming power generation amount in the conditions that nuclear power is continuously utilized on a certain scale and new reactors are commissioned by tackling issues such as safety improvement, final disposal site problem and nuclear fuel cycle. **Economic assumption** • For power generation cost, the global standard is used on the premise of the current technological level. → Power generation amount is constrained up to 10% of the power generation mix considering social restrictions. Assumed power generation cost is ¥13, same as global standard .

Scenario Description in Modeling Analyses (2/4)

<table>
<tr><th></th><th>Scenario</th><th>Challenges to realize scenario</th><th>Model Input</th></tr>
<tr><td rowspan="2">Reference case</td><td rowspan="2">Scenario in which the challenges of each power source to realize Reference case, presented for deeper discussion in the 35th Strategic Policy Committee, are overcome.

<u>Image of power generation mix</u>
RE 50-60%, Nuclear power 10%, Hydrogen / Ammonia 10%, CCUS thermal 20-30%
→ Determined in the model with cost minimization</td><td><Hydrogen / Ammonia>
<u>(1) Supply side</u>
Considering supply is highly likely prioritized in the sectors where electrification is difficult, such as industrial, residential & commercial, and transportation, need to secure about 20Mt of hydrogen in Japan.
If domestic procurement is not enough, need to develop transportation technologies and port facilities for large-scale and low-cost import.
<u>(2) Demand side</u>
In developing combustors to ensure stable combustibility of hydrogen and ammonia power generation, need technological development to ensure suppression of NOx generation and stable combustibility.
For expanding demand & supply of hydrogen and securing the supply amount used for power generation, need to expand the demand in other sectors than power generation, e.g., FC truck and hydrogen ship in transportation and expanded usage in industry.
<u>(3) Cost</u>
In the context that hydrogen supply chain has not been established, need to reduce the costs of cargo bases and liquefied hydrogen carriers in addition to the costs required for hydrogen production and liquefaction.</td><td><Hydrogen / Ammonia>
<u>Assumption for technological development</u>
• A major premise is to overcome technical issues for hydrogen / ammonia power generation.
<u>Assumption for large-scale procurement</u>
• On top of that, it is assumed that after being used preferentially in industrial / residential & commercial / transportation sectors, the supply greatly exceeding the 2030 forecast should be secured. (LNG needs to increase at a higher pace than quadruple incremental rate of supply in 30 years from 1980s to 2010s.)
<u>Economic assumption</u>
• Assuming manufacturing and transportation cost is one fifth of about ¥170/Nm^3 or less, on the premise that inexpensive manufacturing equipment and a global supply chain are developed.
→ Assumed power generation cost is ¥16-27.</td></tr>
<tr><td><CCUS>
<u>(1) Technology / Cost</u>
Need to develop efficient technology to separate and capture CO_2, establish low-cost CO_2 transportation technology, and reduce storage cost. Also, for practical use of carbon recycle, need cost reduction and application enhancement.
If domestic CCUS is not enough to handle, for transportation overseas, need to overcome further technical issues such as establishing ship transportation technology for low-temperature and low-pressure liquefied CO_2, which is unprecedented in the world yet.
<u>(2) Securing potential sites and expanding application</u>
Considering CCUS is highly likely applied for electrification in industrial / residential & commercial / transportation sectors or for GHG emissions from the sectors where utilizing hydrogen / ammonia is difficult, need to secure substantial suitable lands and application development in order to utilize CCUS for power generation.</td><td><CCUS>
<u>Assumption for technological development</u>
• Overcoming technical issues for practical use of CCS and carbon recycling, e.g., technology to improve separation and storage efficiency, is a major premise. Assuming the cost will be reduced to 70% or less of the current level through technological development.
<u>Assumption for large-scale storage</u>
• On top of that, it is assumed that after being used preferentially in industrial / residential & commercial / transportation sectors and for non-energy sources, CCS will be implemented in excess of about 0.3Gt / year. In Reference case, assuming it possible to transport about 0.2Gt overseas.
→ Assumed power generation cost is around ¥12. In Reference case, CCS storage potentials are 90 $MtCO_2$ in domestic and 240 $MtCO_2$ overseas.</td></tr>
</table>

Scenario Description in Modeling Analyses (3/4)

	Scenario	Challenges to realize scenario	Model Input
1 Renewable Energy 100%	**Scenario in which carbon neutrality is realized with only RE.**	**<Renewable energy>** In case that **+40%** (about 300TWh) or so of RE compared to Reference case is implemented, in addition to further securing load balance, transmission capacity and inertial force, the following capacity needs to be deployed additionally on the premise of the current technologies. ✓ If half of the capacity is realized by PV (about 150TWh) and another half by offshore wind power (about 150TWh), the following amount is required. ✓ For PV, about 110GW (about 130TWh) is necessary in addition to Reference case. If it is covered by 1 MW mega solar, additional **110,000** locations will be required, meaning, for instance, that all of the approximate 1,700 municipalities need to secure 65 sites on average additionally to the amount already deployed in Reference case. ✓ For offshore wind power, the 2040 target amount of 45 GW (about 130TWh) is necessary in addition to Reference case. ✓ The outlook for RE deployment in 2050 in the UK BEIS scenario* is about 400-430TWh, and about 2.5-2.7 times this amount needs to be deployed in RE 100% case. * BEIS, Net Zero and the Power Sector Scenarios, 2020.12	**Image of power generation mix** **RE 100%** →RE volumes are exogenously assumed. **Power generation cost** Same as Reference case
2 Renewable Energy Innovation	**Scenario in which RE installation expands due to dramatic reduction of RE cost and with the challenges of grid operation, e.g., natural & physical constraints and inertial force, overcome by innovation, more significantly compared to Reference case.**	**<Renewable energy>** In order to realize further cost reduction than Reference case and tackle physical and social constraints, need to overcome technical issues through technological innovation, such as development and commercialization of innovative technologies, e.g., tandem solar cell and perovskite solar cell, and wind power with significantly improved power generation efficiency. For overcoming the problem of inertial force, need to develop and implement a system with suspected inertial force and apply inertial force in power storage system. Also, if +10% (about 130TWh) is deployed additionally to Reference case, need to install the same RE setup as any shown in 1 Renewable Energy 100% case.	**Image of power generation mix** **RE 60-70%** **Power generation cost** RE cost: PV ¥6-10, Wind power ¥8-15 Same as Reference case for other power sources

Scenario Description in Modeling Analyses (4/4)

	Scenario	Challenges to realize scenario	Model input
3. Accelerated utilization of nuclear power	A scenario in which replacement and new expansion are realized as a result of progressing public understanding of nuclear power and overcoming social and technical issues such as ensuring safety and establishing a back-end system	**＜Nuclear power＞** If all 36 units have been in operation for 60 years, it will be about 10%. To further increase it by 10%, **approximately 20 new furnaces (20 million kW) are required through replacement or new expansion** by overcoming issues such as restoration of public trust, understanding of local community, final disposal and establishment of back-end systems such as the nuclear fuel cycle.	**Power generation mix** **Nuclear power: 20%** **Power generation cost** Same as the Reference Case **Upper limit** 20% for nuclear power
4. Dramatic reduction in hydrogen/ ammonia prices	A scenario in which technological innovations in the hydrogen production and transportation process significantly reduce prices of hydrogen production and transportation	**＜Hydrogen/ammonia＞** Assuming a reference value case in which manufacturing and transportation costs are 1/5 or less from the current level, **it is necessary to further reduce these costs by further technological innovation and market expansion through expansion of private investment.** In addition, if **+ 10% (about 130 billion kWh)** is additionally introduced from the case of the reference value, it is necessary to additionally procure **5 to 10 million tons of hydrogen** domestically or from overseas. If all are procured domestically, a total of 1,000 to 2,000 plants of the same scale as FH2R are required, and if all are procured from overseas, it is necessary to additionally secure about 90 vessels from the reference value, in which the hydrogen loading capacity of the vessel (currently about 75 tons per vessel) expands to about 100 times or more (about 10,000 tons per vessel) from the reference value.	**Power generation mix** **Hydrogen/ammonia: 20%** **Power generation cost** Hydrogen price: ¥20 – 35 /Nm3 (Power generation cost ¥13 – 21/kWh) Other than hydrogen, costs are the same as Reference Case
5. Dramatic increases in CO2 storage in CCUS	A scenario in which the amount of transportation is significantly increased by significantly expanding domestic storage areas through technological innovation and overcoming the challenges of overseas transportation of CO2.	**＜Thermal power generation with CCUS＞** Assuming a reference value case in which costs are less than half of the current level because of technological development and market expansion, **it is necessary to further expand the storage capacity by further technological innovation and market expansion through expansion of private investment.** In addition, if **+ 10% (about 130 billion kWh)** is additionally introduced from the case of the reference value, a total of **550 million tons** of CCS storage is required. This means that a total of **600 drilling wells** (injection rate of 500,000 tons / y per well) will be required for domestic storage by 2050. Moreover, it is necessary to **realize a scale of CCS which is 900 times or more** of the cumulative injection amount (300,000 tons in about 3 years) of the Tomakomai demonstration project **every year**. In addition, about **300 CO2 transport vessels** (assumed to be 20,000t-CO2 / vessel) are required for overseas storage.	**Power generation mix** **CCUS power generation: 30% - 40%** **Power generation cost** Same as Reference Case **Upper limit** Domestic storage for CCS: 270 million tons, Overseas transportation volume expands to 280 million tons.

Scenario Assumption and Share of Renewables in Total Electricity(in 2050)

Scenario	Cost of renewable energy	Ratio of nuclear power	Cost of hydrogen	CCUS (Storage potential)	Fully autonomous driving (Car ride sharing)	Share of RE in power mix
Reference Case[*1]	Standard cost	10%	Standard cost	Domestic storage:91MtCO_2/yr, Overseas transportation：235MtCO_2/yr	Standard assumption (no fully autonomous cars)	**54%** (Optimization results)
1. Renewable Energy 100% (RE 100)		0%				**Almost 100%** (Assumption)
2. Renewable Energy Innovation	Low cost	10%		Domestic storage: 91MtCO_2/yr, Overseas transportation: 235MtCO_2/yr		**63%** (Optimization results)
3. Nuclear Power Utilization[*2]	Standard cost	20%				**53%** (Optimization results)
4. Hydrogen Innovation		10%	Hydrogen production such as water electrolysis, hydrogen liquefaction facility cost: Halved			**47%** (Optimization results)
5. CCUS Utilization			Standard cost	Domestic：273MtCO_2/yr、Overseas：282MtCO_2/yr		**44%** (Optimization results)
6. Demand Transformation				Domestic: 91Mt, Overseas: 235Mt	Realization and diffusion of fully autonomous driving and expansion of car ride sharing after 2030, and decrease in material production due to reduction of the number of automobiles	**51%** (Optimization results)

＊Regarding changes on the demand side, further scenario analysis that takes into account factors other than car sharing will be conducted.

*1：There is no feasible solution without DAC, and DAC is assumed to be available in all scenarios.

*2：Nuclear power utilization scenarios up to a ratio of 50% are separately examined.

【ref.】Concept of Innovation in Power Supply Ref. Value

- Each power source must overcome a large hurdle to achieve the reference values for power sources in 2050 as presented at the Strategic Policy Committee.
- Under these conditions, for the 30 to 40% of nuclear power and fossil+CCUS, in case the upper limit of nuclear power is 10%, it is necessary to cover 20-30% with fossill+CCUS, thus it is assumed a considerable amount of CO2 is stored at home/abroad including CCUS required amount other than the electric power sector. For hydrogen/ ammonia and carbon recycled fuel, it is assumed that infrastructure development, etc. is expected to execute a large-scale transportation without setting the upper limit of supply on the model.
- It should be noted that in this analysis, the conditions were set by mechanically assuming such CCS storage amount based on the above reference values.

2020/12/21 Strategic Policy Committee Material

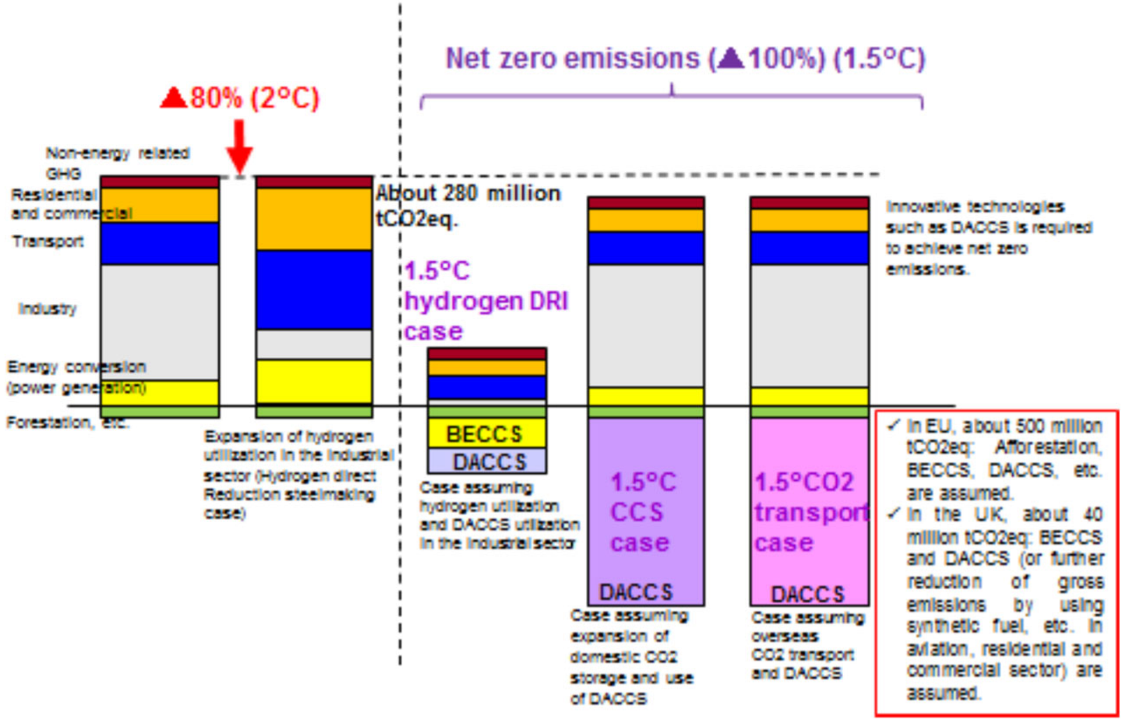
In order to aim for carbon neutrality in 2050, stable power supply from decarbonized power sources is indispensable. From the perspective of 3E+S, multiple scenarios will be analyzed without limiting to the following. In deepening the discussion, the positioning of each power source is suggested as follows.

Established decarbonized power source	Renewable Energy		・Continue to aim for maximum introduction as the main power source in 2050. ・Immediately work on issues to promote the maximum introduction such as adjustment amount, transmission capacity, ensuring inertial force, responding to natural conditions and social constraints, maximizing cost control, and increasing social transformation to cost increases. ・How about deepening discussions on covering 50-60%(approx.) of the generated power (* 1) with renewable energy in 2050 as a reference value (* 2)?
	Nuclear power		・As an established decarbonized power source, aim for a certain scale of utilization on the premise of safety. ・In order to restore public trust, make an increased effort to improve safety, gain understanding and cooperation of the location area, solve back-end problems, secure business feasibility, maintain human resources and technical capabilities, etc. How about deepening discussion on covering 30-40% (approx.) with nuclear power which is a carbon-free power source other than renewable energy and hydrogen/ammonia, along with fossil+CCUS/carbon cycle in 2050 as a reference value (* 2)?
Power sources required innovation	Thermal power	Fossil + CCUS	・While having the advantages of supply capacity, adjustment power, and inertial force, decarbonization of fossil-fired power is the disadvantage. ・Aim to utilize on a certain scale iimmediately by developing technology and suitable sites, expanding applications and reducing cost, etc., toward the implementation of CCUS / carbon recycling. How about deepening discussion on covering 30-40% (approx.) together with nuclear power which is a carbon-free power source other than renewable energy and hydrogen/ammonia in 2050 as a reference value (* 2)?
		Hydrogen, Ammonia	・While having the advantages of adjusting power and inertial force without emitting carbon during combustion, the challenges are establishing technology for large-scale power generation, reducing costs, and securing supply. Aim to build a stable supply chain immediately by promoting co-firing of gas-/coal-fired power, increasing supply and demand. ・Aim for a certain scale of utilization as a carbon-free power source, taking into account competition with industrial and transportation demand. Based on the fact that procurement required for future power generation is estimated to be 5-10-million ton as basic hydrogen strategy, how about deepening discussion on covering 10% (approx.) of generated power with hydrogen/ammonia in 2050 as a reference value (* 2)?

1: The amount of power generated in 2050 will be about 1.3-1.5 trillion kwh as a reference value (2) based on the power generation estimation by RITE presented at "the 33rd Strategic Policy Committee".
*2: This is not as a government goal, this is one guideline / option for future discussions. This will be the one of options to deliberate in considering multiple scenarios in the future.

【ref.】Conditions to Realize Carbon Neutrality in Japan by 2050

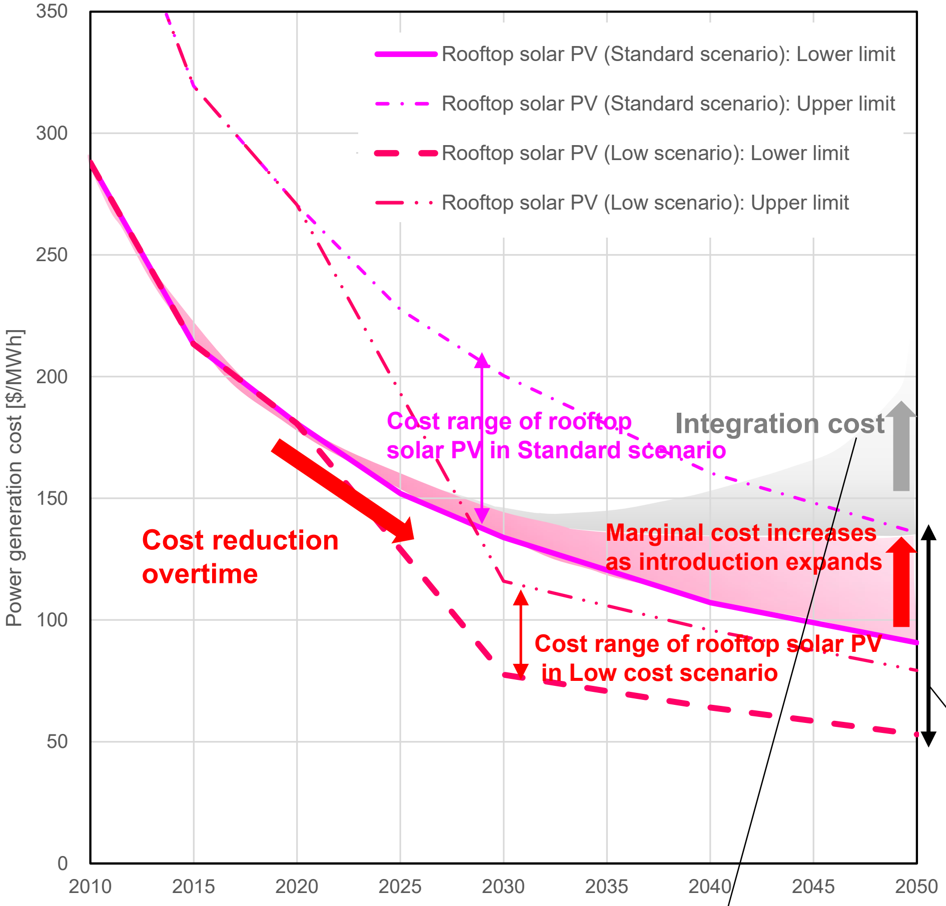
- **Under the medium socio-economic scenario SSP2 (see appendix), Direct Air Carbon Capture and Storage (DACCS), which realizes negative emission reduction, is a necessary condition for realizing carbon neutrality in Japan in 2050. Furthermore, our analysis shows that hydrogen direct reduction steelmaking in the iron and steel sector needs to be put into practical use by 2050, or the domestic CO2 storage capacity in 2050 needs to be larger than 91 MtCO2/year that is assumed as standard. (reported at the Green Innovation Strategy Meeting in November, 2020)**
- **Therefore, in all the scenarios<u>, it is assumed that DACCS and hydrogen direct reduction steelmaking will be available by 2050.</u>**



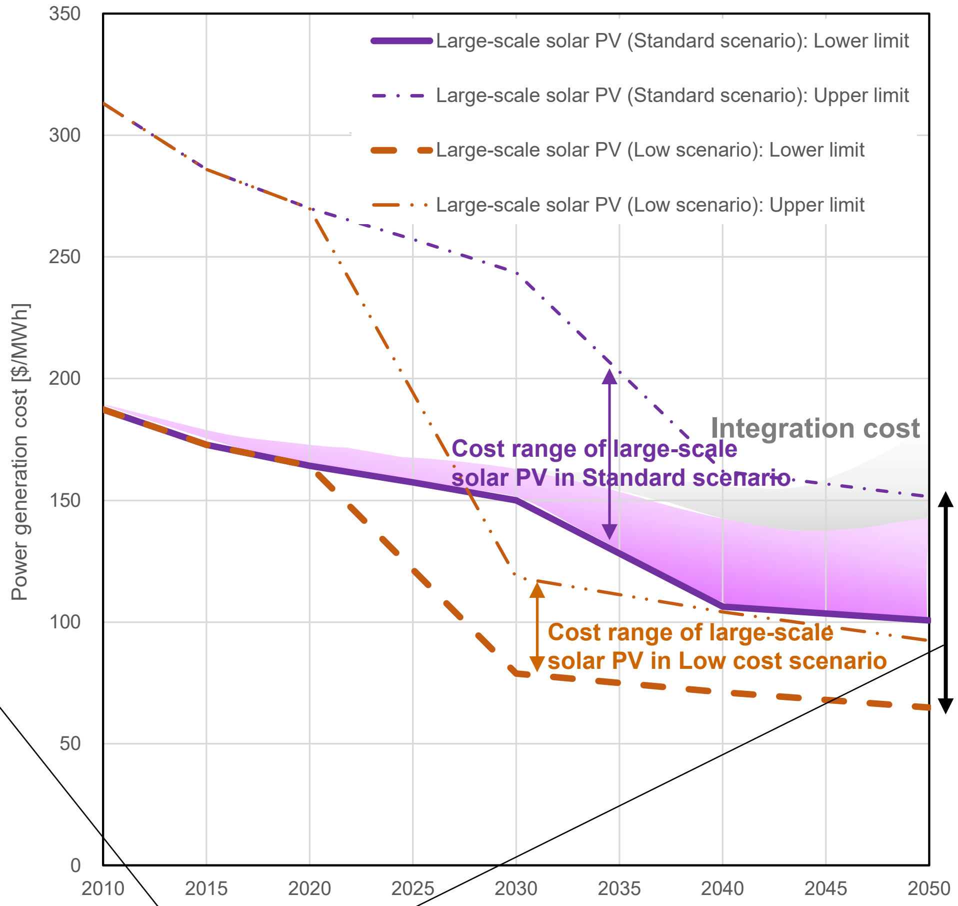
(Source) Document from the Green Innovation Strategy Meeting (November, 2020)

Assumption for Solar PV Power Generation Costs in Japan：Time Series

Rooftop solar PV power generation



Large-scale solar PV power generation

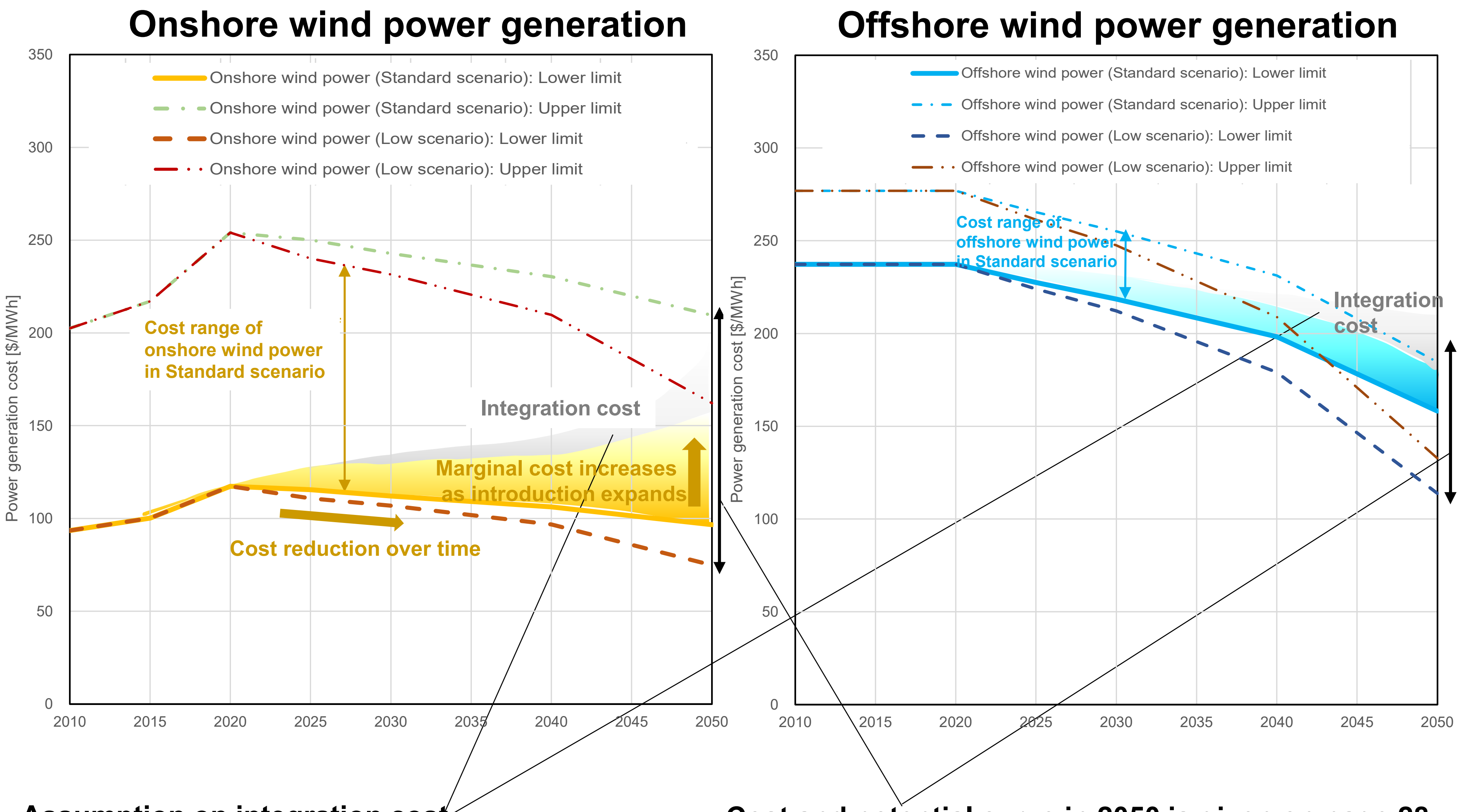


Assumption on integration cost is given on page 30.

Cost and potential curve in 2050 is given on page 28.

*It should be noted that this is the average cost of the facility stock installed at each point in time, and is not the cost limited to new facility installed at that point in time.
(Note) The gradation part is just an image of model calculation.

Assumption for Wind Power Generation Costs in Japan : Time Series



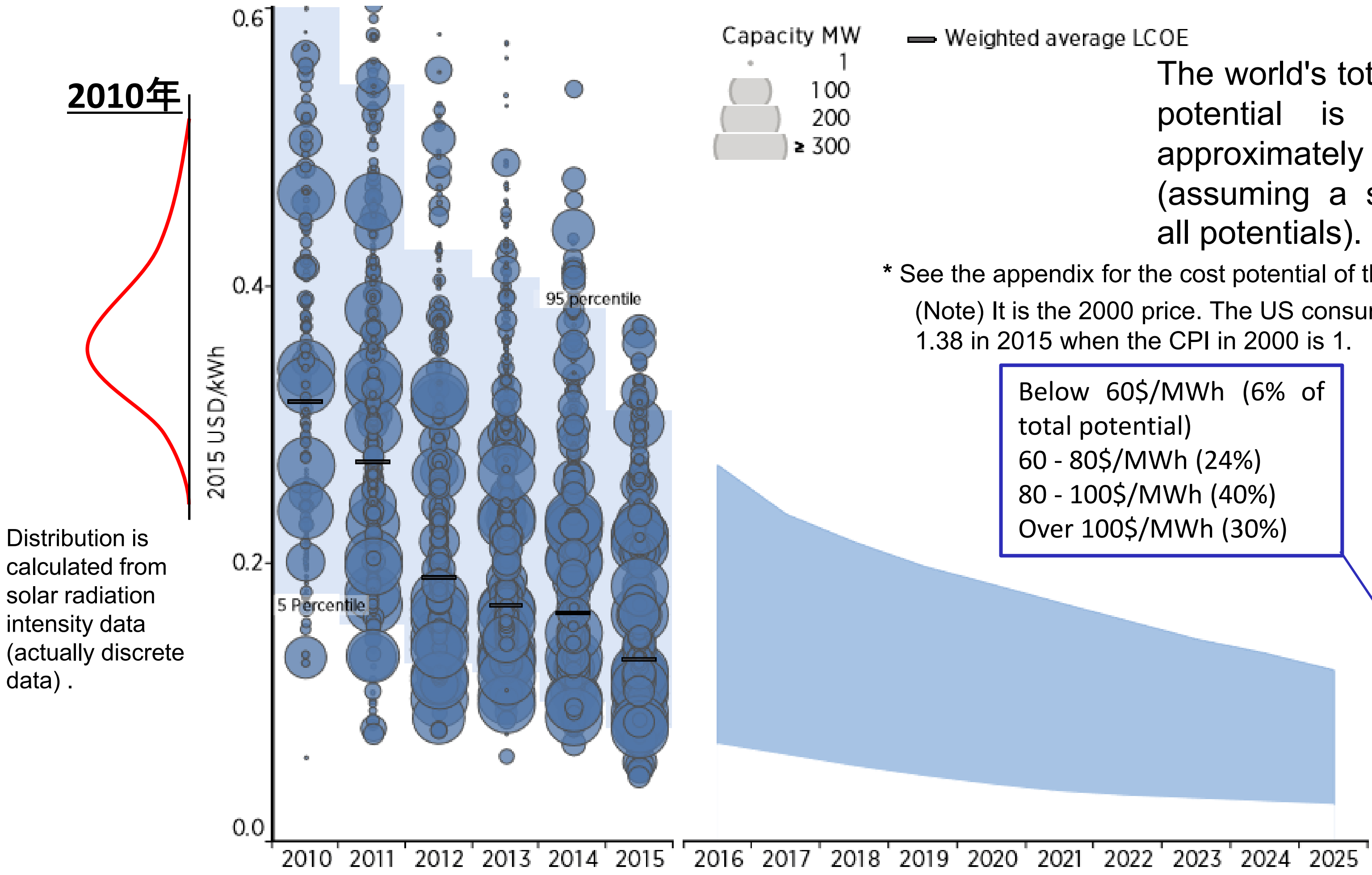
Assumption on integration cost is given on page 30.

Cost and potential curve in 2050 is given on page 28.

*It should be noted that this is the average cost of the facility stock installed at each point in time, and is not the cost limited to new facility installed at that point in time.

(Note) The gradation part is just an image of model calculation.

【ref.】Assumptions for Global Solar PV Power Generation



Source) IRENA

The world's total power generation potential is estimated to be approximately 1,270,000 TWh/yr (assuming a sufficient supply for all potentials).

* See the appendix for the cost potential of the actual model assumption

(Note) It is the 2000 price. The US consumer price index (CPI) is 1.38 in 2015 when the CPI in 2000 is 1.

In 2050

Standard scenario

Below 60$/MWh (6% of total potential)
60 - 80$/MWh (24%)
80 - 100$/MWh (40%)
Over 100$/MWh (30%)

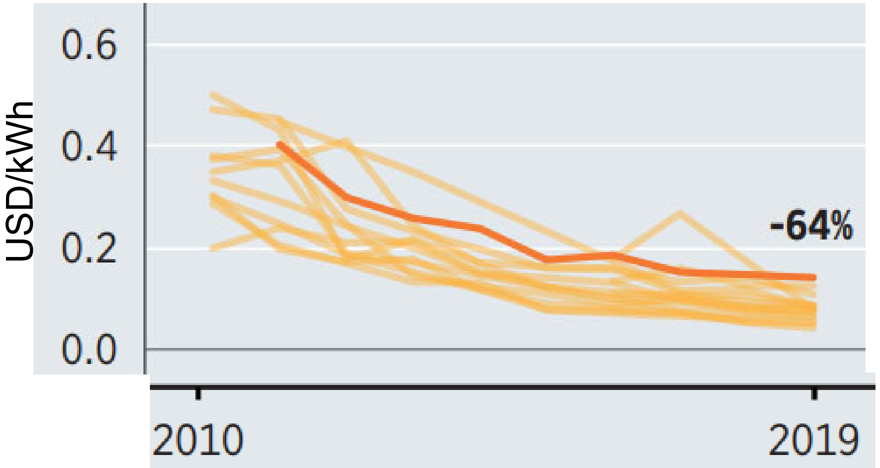
Low cost scenario

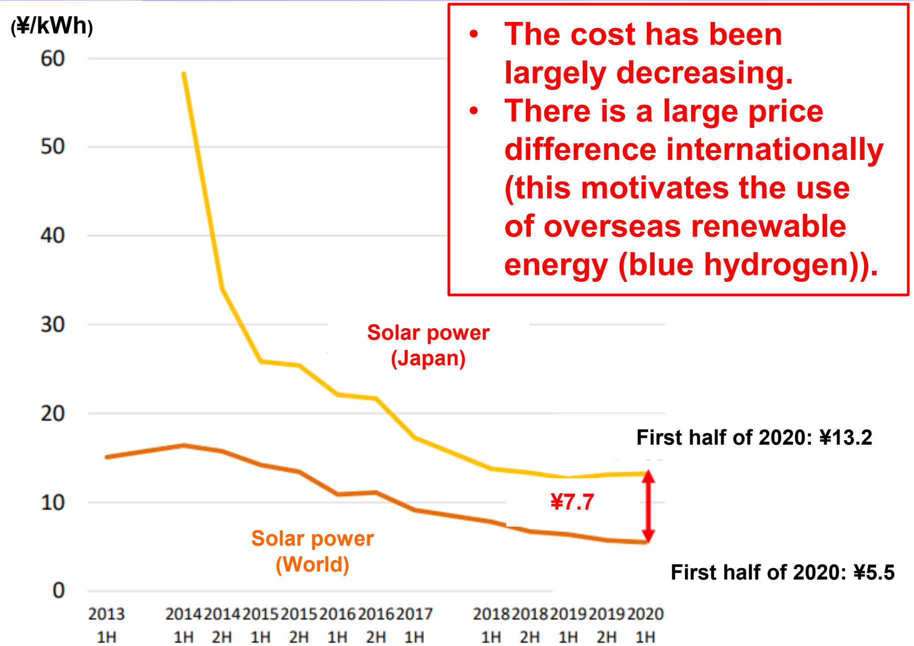
Below 30$/MWh (15% of total potential)
30 - 40$/MWh (14%)
40 - 60$/MWh (30%)
Over 60$/MWh (41%)

* In the DNE21 + model, it is assumed that additional costs for system stabilization will be required as the share of VRE increases.

【ref.】Changes in Solar & Wind Power Generation Costs

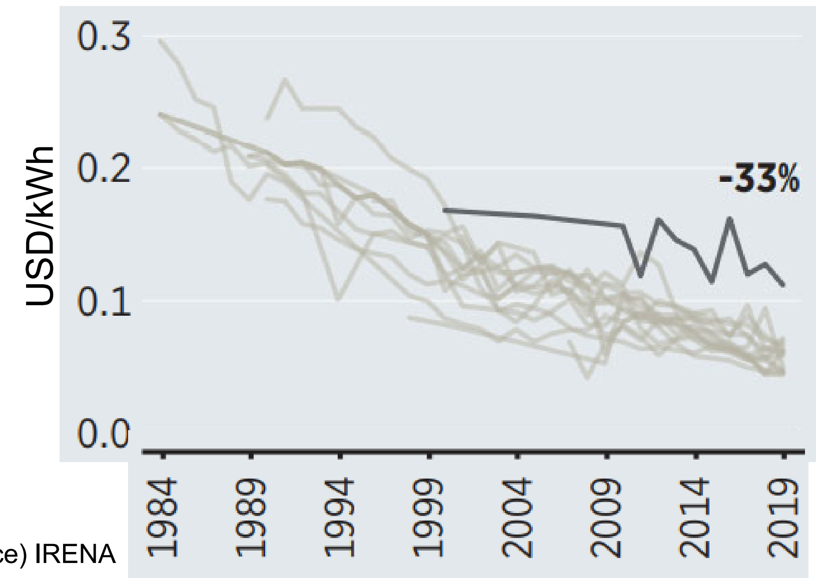
Solar power generation



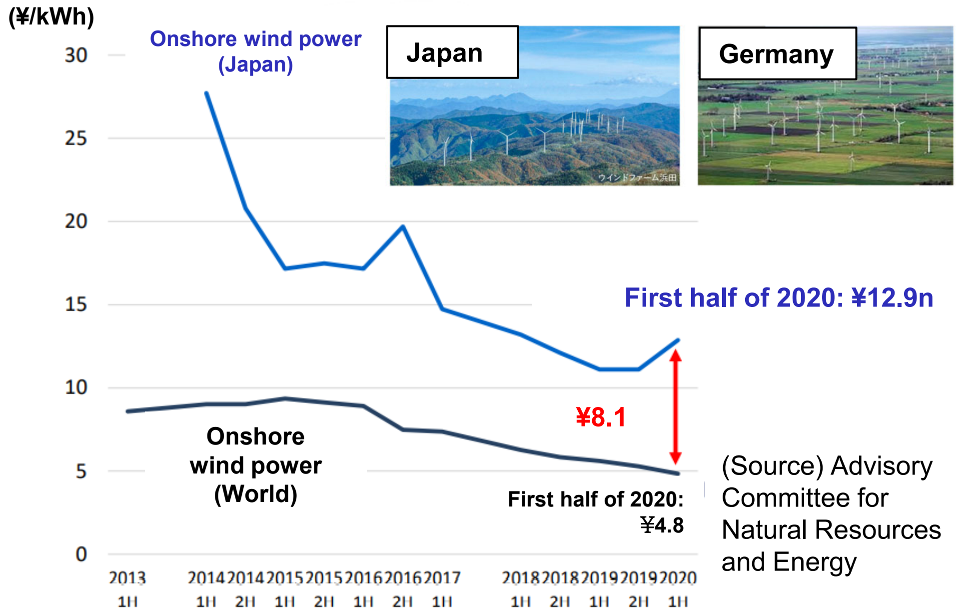


- **The cost has been largely decreasing.**
- **There is a large price difference internationally (this motivates the use of overseas renewable energy (blue hydrogen)).**

Wind power generation

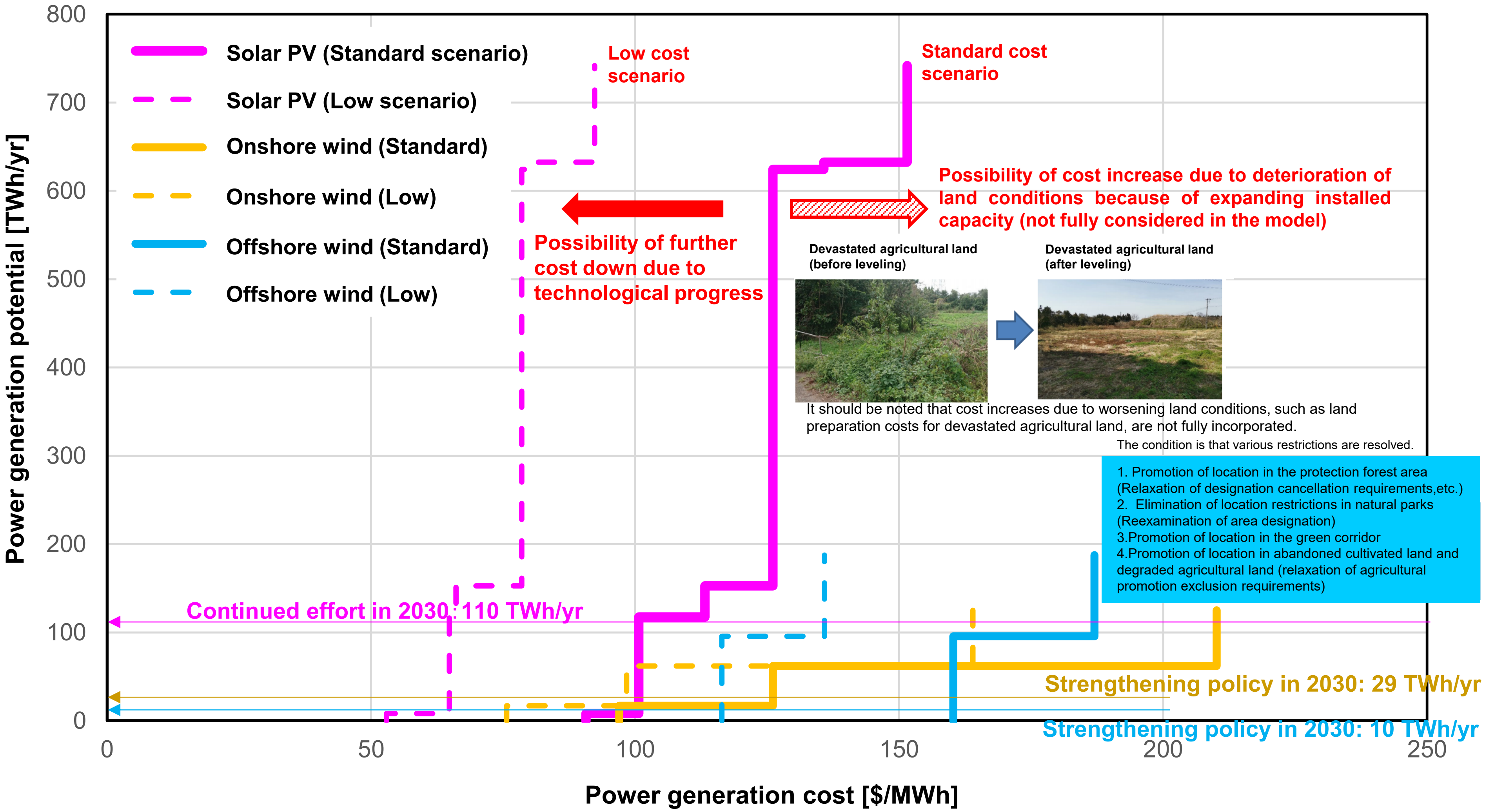


(Source) IRENA



(Source) Advisory Committee for Natural Resources and Energy

Assumption for Japan's Variable Renewable Energy Cost and Potential in 2050



*Cost and potential of solar PV power generation is estimated by RITE based on the GIS data for the amount of solar radiation and land use, and facility costs, etc. Both rooftop and large-scale solar power generation are included in this Figure. Cost and potential of onshore wind power generation is estimated by RITE based on the GIS data for wind conditions and land use, and facility costs, etc.

Assumptions for Estimating Integration Cost in the Univ. Tokyo - IEEJ Model

Regional aggregation

Divide Japan into 5 regions ([1] Hokkaido, [2] Northeastern area, [3] Tokyo, [4] Western area other than Kyushu, [5] Kyushu)

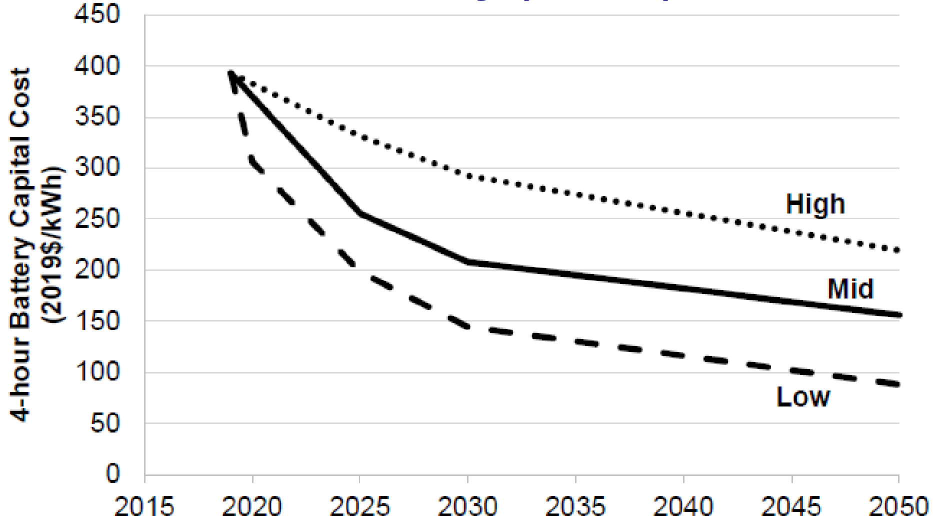
Target time period

Assuming costs and electricity supply and demand in 2050

Power generation costs for each power source

Based on assumption in RITE DNE21+ model

Expected cost reduction of Lithium-ion battery (NREL)



(Source) W. Cole and A. W. Frazier, “Cost projections for utility-scale battery storage: 2020 update,” NREL/TP-6A20-75385.

Power storage system

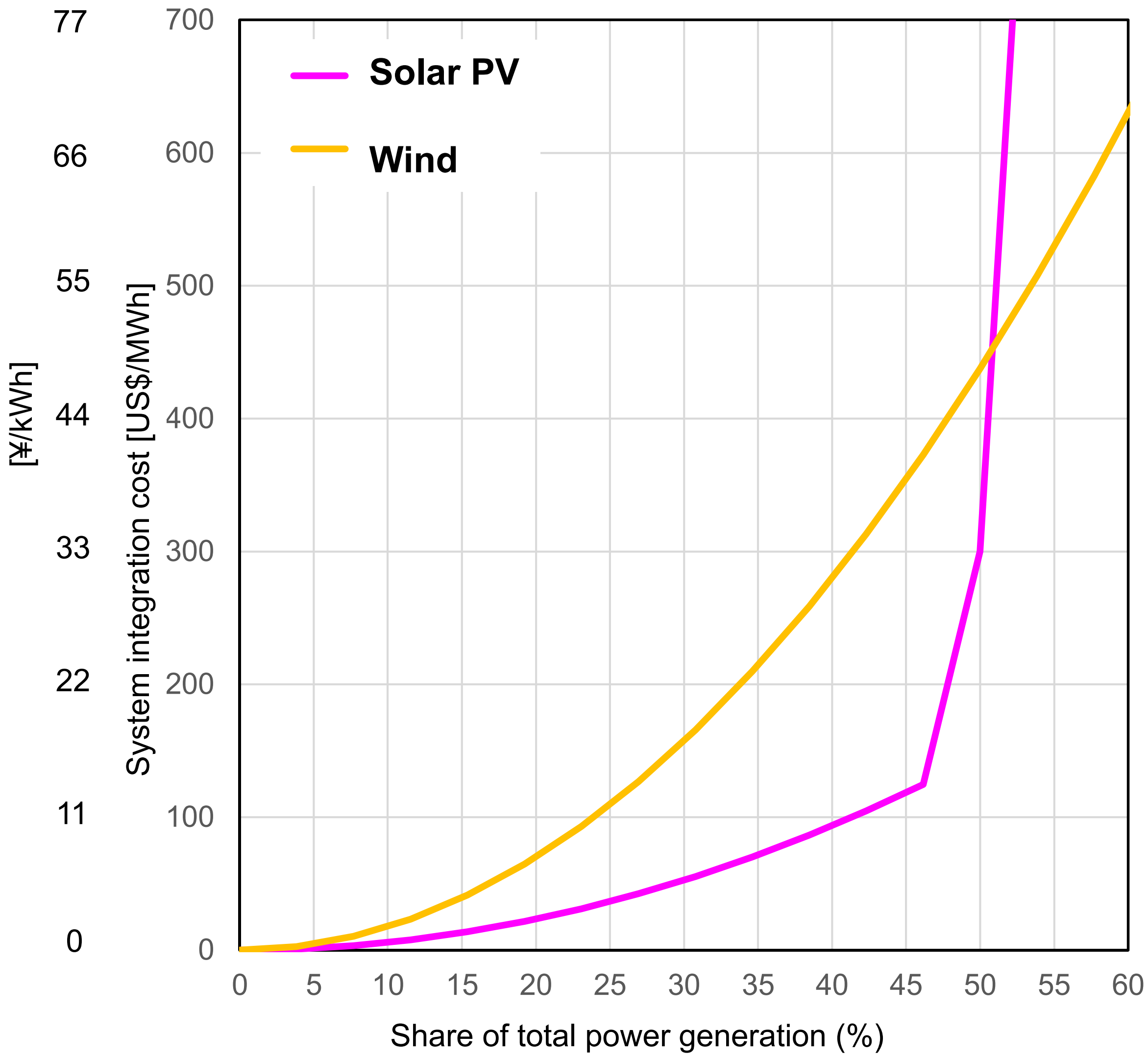
Mainly with Lithium-ion battery (setting 150$/kWh in 2050 based on estimation by the National Renewable Energy Laboratory (NREL)), it is assumed that existing pumped-storage hydropower and hydrogen storage will be used together.

Cost of interconnection lines

With reference to the plan by the Organization for Cross-regional Coordination of Transmission Operators, costs of interconnection lines are assumed to be ¥200,000/kW between areas [1] [2] and [3][4], and ¥30,000/kW in other areas, with an annual expense ratio of 8%. Underground transmission lines and submarine cables between Hokkaido and Tokyo are not considered.

Assumption for Integration Costs for Grid Measures (in 2050)

Grid integration costs approximated from the analysis of the Univ. of Tokyo – IEEJ power generation mix model＝Assumption on grid integration costs in DNE21+ (Marginal cost when each implementation share is realized)



* The total cost is calculated as an integral value.

As the VRE ratio increases, marginal integration costs tend to rise relatively rapidly. This is because under the circumstance where a large amount of VRE has already been installed, if it is further installed, it will be required to maintain an infrequently used power storage system or transmission line to deal with the risk that cloudy weather and windless conditions will continue for several days or more.

*According to the IEEJ model analysis results, the integration cost differs depending on the combination of wind power and solar power installed shares. In the DNE21+ model, first of all, we approximately assume a function based only on the share of wind power and solar power, respectively, using integration costs of the combination of the share of wind power and solar power derived from the IEEJ model. Then, the difference value is calculated for each share, and the limited value of the integration costs for each share is estimated and incorporated into the DNE21+ model.

(Note) The potential of each VRE is as described in the previous slide. As the share described in this Figure is limited by the assumed potential, it may not be feasible.

Assumption for Nuclear Power Generation Cost

Year	Facility cost ($/kW)		Power generation unit price ($/MWh)	
	Year 2000 price	Year 2018 price	Year 2000 price	Year 2018 price
2020	2763	4029	75	110
2030	2779	4053	76	111
2050	2794	4075	78	114
2100	2824	4117	79	115

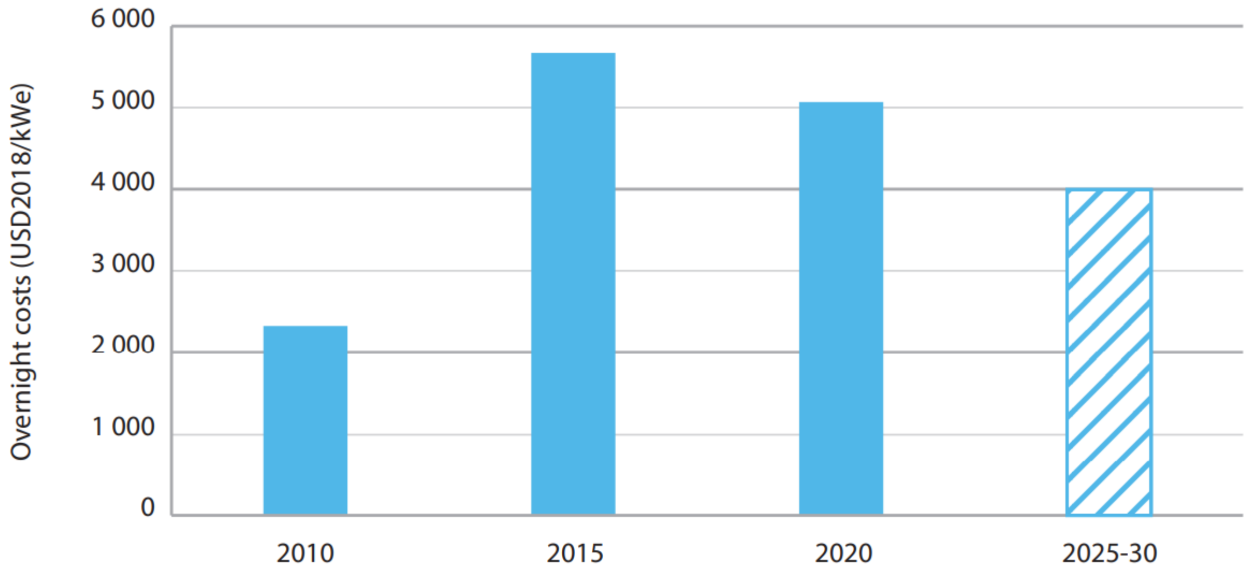
***1 The figures in the table are assumed values for Japan. For the rest of the world, location factors are multiplied, resulting in slightly different assumptions.**

***2 Since the base year of the model is 2000, the 2000 price is also shown; the conversion from the 2000 price to the 2018 price is multiplied by 1.46 (based on CPI of U.S.).**

***3 The conversion to cost per unit of electricity generated is based on a capacity factor of 85%.**

【Ref.】Projected Cost of Nuclear Power Generation by IEA/NEA

Figure 8.1: Trend in the projected cost of new nuclear in OECD countries



Source: IEA/NEA (2005, 2010, 2015, 2020).

♦New installation prices in OECD countries have been extremely high in recent years, exceeding the current model assumptions, but are expected to decrease in the future.

(Source) IEA/NEA, Projected Costs of Generating Electricity 2020

Table 8.2: Construction costs of recent FOAK Generation III/III+ projects

Type	Country	Unit	Construction start	Initial announced construction time	Ex-post construction time	Power (MWe)	Initial announced budget (USD/kWe)	Actual construction cost (USD/kWe)
AP 1000	China	Sanmen 1, 2	2009	5	9	2 x 1 000	2 044	3 154
	United States	Vogtle 3, 4	2013	4	8/9*	2 x 1 117	4 300	8 600
APR 1400	Korea	Shin Kori 3, 4	2008	5	8/10	2 x 1 340	1 828	2 410
EPR	Finland	Olkiluoto 3	2005	5	16*	1 x 1 630	2 020	>5 723
	France	Flamanville 3	2007	5	15*	1 x 1 600	1 886	8 620
	China	Taishan 1, 2	2009	4.5	9	2 x 1 660	1 960	3 222
VVER 1200	Russia	Novovoro-nezh II-1 & 2	2008	4	8/10	2 x 1 114	2 244	**

* Estimate. ** No data available.

Notes: MWe = megawatt electrical capacity. kWe = kilowatt electrical capacity.

Source: NEA (2020).

Assumption for CO_2 Capture Technology

	Capital costs (price in 2000) ($/kW)	Generating efficiency (LHV%)	CO_2 recovery rate (%)
IGCC/IGFC with CO_2 Capture*1	2800 – 2050	34.0 – 58.2	90 – 99
Natural gas oxy-fuel power*1	1900 – 1400	40.7 – 53.3	90 - 99
	Capital costs (price in 2000) (1000$/(tCO2/hr))	Required power (MWh/tCO2)	CO_2 recovery rate (%)
Post-combustion CO_2 capture from coal-fired power plants*1	851 – 749	0.308 – 0.154	90
Post-combustion CO_2 capture from natural gas-fired power plants*1	1309 – 1164	0.396 – 0.333	90
Post-combustion CO_2 capture from biomass-fired power plant*1	1964 – 1728	0.809 – 0.415	90
CO_2 capture from gasification*1	62	0.218	90 – 95
CO_2 capture from steelworks blast furnace gas*1	386 - 319	0.171 – 0.150	90
	Capital costs (price in 2000) (1000$/(tCO2/hr))	Required fuel (GJ/tCO2) Recovered power (MWh/tCO2)	CO_2 recovery rate (%)
CO_2 capture from clinker manufacturing*2	2485 - 2246	4.87 – 3.66 0.199 – 0.150	90

*1 The range of values in the table indicates improvement from 2015 to 2100.
*2 It is assumed that the assumed values have a range shown in the table depending on the fuel type used in the kiln body, CO2 capture, and compression equipment.
Note) It is 2000 price. The US consumer price index (CPI) in 2018 is 1.46 when the CPI in 2000 is 1.

Not only the CO_2 capture technologies in the power sector, but also CO_2 capture from gasification (during hydrogen production) and CO_2 capture from steelworks blast furnace gas and from clinker manufacturing are explicitly modeled.

Assumption for CO_2 Transportation and Storage

	CO_2 storage potentials ($GtCO_2$)		【References】 IPCC SRCCS (2005) (GtCO2)	Storage costs ($/$tCO_2$)*1
	Japan	World		
Depl. oil well (EOR)	0.0	112.4	675–900	92 – 227*2
Depl. gas well	0.0	147.3 – 241.5		10 – 32
Deep saline aquifer	11.3	3140.1	10^3–10^4	5 – 85
Coalbed (ECBMR)	0.0	148.2	3–200	47 – 274*2

Note 1: It is assumed that the CO2 storage potentials of depl. gas well could be expanded to the upper limit in the table with the increase of future mining volume.

Note 2: It is assumed that the storage costs could rise within the range in the table with the increase of accumulated storage amount.

*1 The costs for CO_2 capture are not included. They are assumed separately.

*2 Oil and gas profits from enhanced oil recovery and enhanced methane recovery are not included in this figure, but they are assumed separately.

- **The constraint on CO_2 storage expansion is assumed considering the difficulties of its rapid expansion, e.g. limited number of drilling rigs; storage can be expanded by 0.02%/yr until 2030 and afterwards by 0.04%/yr for domestic/regional total storage implementation in the baseline scenario. (The maximum storage potential in 2050 is 91MtCO_2/yr in Japan's case, where CCS is assumed to be available after 2030.)**
- **It can be expanded up to 3 times (273 MtCO2/yr) that in CCUS innovation scenario. (Total storage potential is fixed.)**

CO_2 transportation cost

- **CO_2 transportation costs from the sources to the reservoirs are assumed separately as 1.36$/t$CO_2$ (per 100km) and 300km for average transport distance in Japan's case.**
- **For large area countries which are disaggregated in the models (US, Russia, China and Australia), the interregional CO_2 transportation costs are estimated according to the transportation distance.**
- **Cross-border CO_2 transportation is also assumed. In CCUS standard scenario, such as Reference value case, the upper limit of export from Japan is 235 MtCO2 (equivalent to one-sixth of 2013 GHG emissions). (In CCUS utilization scenario, it is 282 MtCO2 (equivalent to one-fifth of 2013 emissions)).**

Assumption for Hydrogen Production and Transport-Related Technologies

Hydrogen production technologies

	Facility cost (US$/(toe/yr))	Conversion efficiency (%)
Coal gasification	1188 - 752	60%
Gas reforming	963 - 733	70%
Biomass gasification	1188 - 752	60%
Water electrolysis	2050 - 667	64 - 84%

Liquefaction technology

	Facility cost (US$/(toe/yr))	Electricity consumption (MWh/toe)
Natural gas/Synthetic methane	226	0.36
Hydrogen	1563	1.98

Transport cost

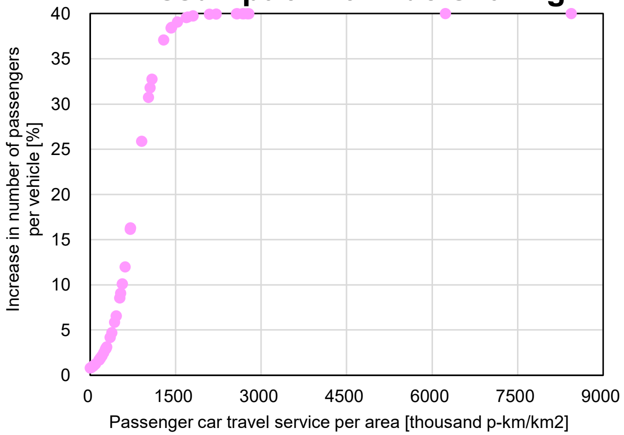
		Facility cost	Variable cost*1
		Electricity: \$/kW Other energy: US\$/(toe/yr) CO_2: US\$/(tCO_2/yr)	Energy: US\$/toe CO_2: US\$/tCO_2
Electricity*2		283.3+1066.7L	-
Hydrogen	Pipeline*3	210.0L	5.0L
	Tanker	69.5L	7.26+0.60L
CO_2	Pipeline*3	99.4L	2.35L
	Tanker	47.5L	1.77L
Natural gas (The same applies to synthetic methane.)	Pipeline*2	128.3L	3.5L
	Tanker	35.1L	8.09+0.39L

L: Distance between regions (1000km)
*1 For ships, the distance-independent term assumes fuel costs. For pipelines, the distance-dependent terms assume fuel costs and compression power costs, respectively.
*2 For submarine transmission lines, fixed costs are assumed to be 10 times higher than the above.
*3 For submarine pipelines, fixed costs are assumed to be three times higher than above.

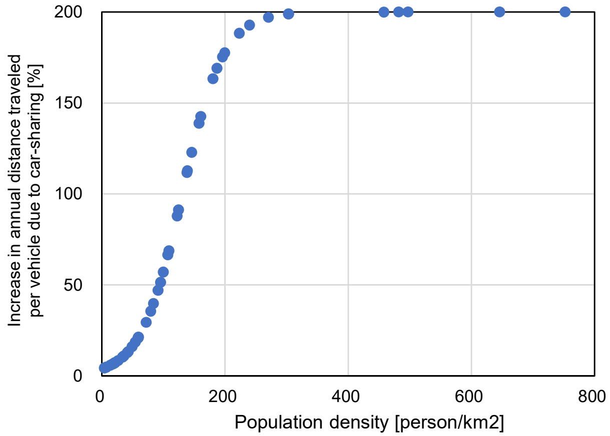
Assumption for Shared Mobility Induced by Fully Autonomous Cars

- **In the case where demand decreases through car-sharing, <u>fully autonomous shared cars can be available after 2030</u>, and key parameters are assumed as below, mainly following Fulton et al. (2017).**

Assumption for ride-sharing



Assumption for car-sharing



	Traditional car (private car)	Fully autonomous car (shared car)
Car body price	Assumed precisely depending on car types	2030: +10000$ 2050: +5000$ 2100: +2800$ (compared to traditional cars)
Lifespan of car	13-20 years	4-19 years
Number of passengers per vehicle	2050: 1.1-1.5 passengers 2100: 1.1-1.3 passengers	2050: 1.17-2.06 passengers 2100: 1.11-1.89 passengers

- **Opportunity costs of time required for driving and costs related to safety are considered.**
- **<u>Impacts of the reduction in the number of cars induced by car- & ride-sharing are considered.</u>**

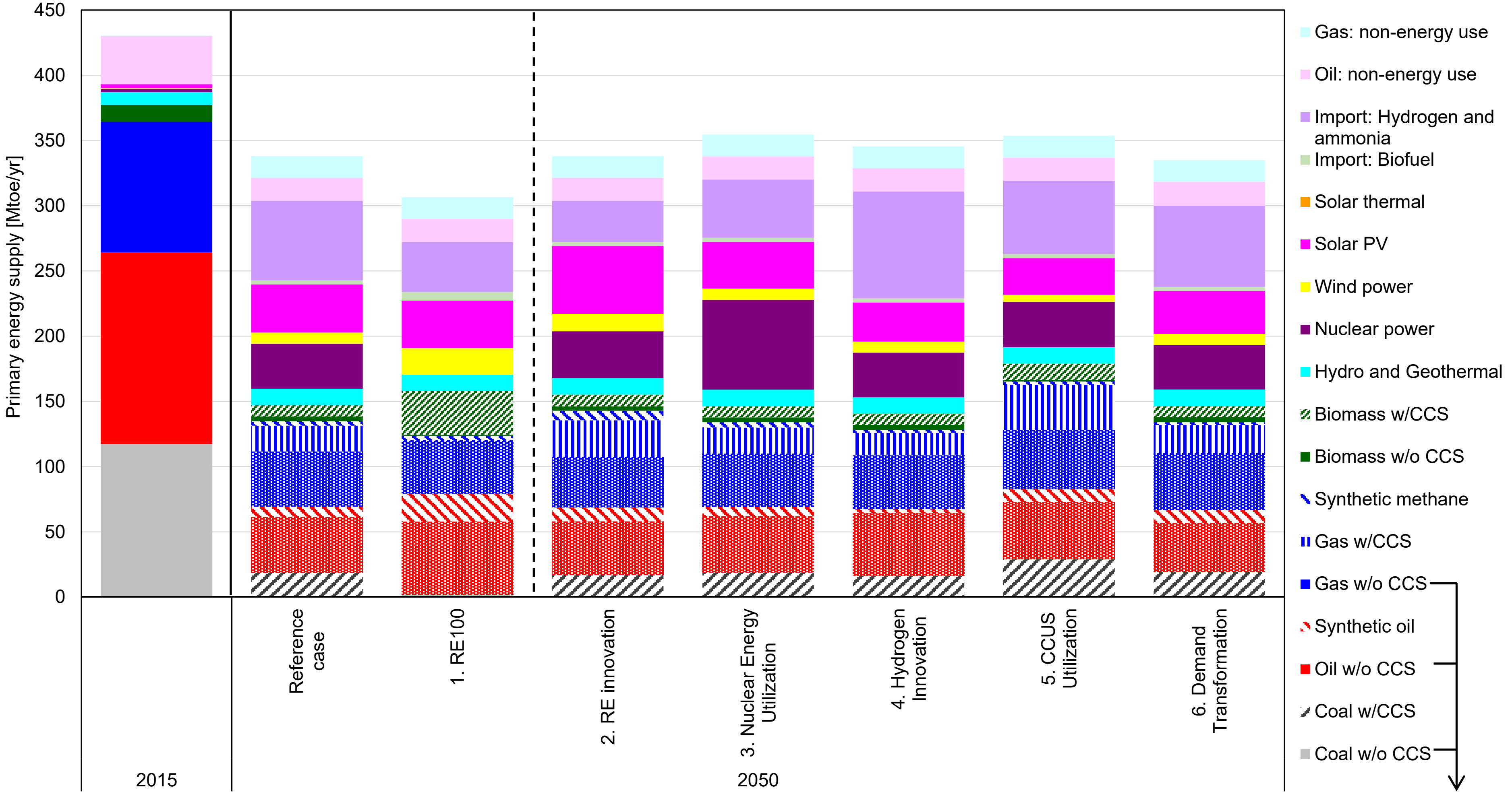
Following impacts driven by decrease in the number of cars are considered: 1. decrease in steel products and plastic products, 2. decrease in concrete and steel products due to the decrease in multi-storey car park space.

In our assumption, the actual natural and social constraints are not precisely incorporated as cost and upper bound constraints. If these factors are taken into consideration more precisely, there is a possibility that the cost will increase / decrease further depending on the power source.

		Reference Case in 2050			Innovation Case in 2050		
		Assumption	**Description**		**Assumption**	**Description**	
Renewable energy	**Price**	**PV: about ¥10-17/kWh** **WT: about ¥11-20/kWh**	Capital cost	Based on Working Group for Power Generation Costs (Assuming decrease in facility such as panels, as well as construction and land development)	**PV: about ¥6-10/kWh** **WT: about ¥8-15/kWh**	Capital cost	Assumed with reference to future projection by IRENA, WEO, etc.
			O&M cost			O&M cost	
			Capacity factor	Based on GIS data (solar radiation, wind conditions), consistent with the world		Capacity factor	Based on GIS data (solar radiation, wind conditions), consistent with the world
	Integration cost	**About ¥4/kWh** (Integration cost for solar and wind power by IEEJ model analysis)	Battery cost	About ¥15,000/kWh Cost projection by NREL	**About ¥4/kWh** (Integration cost for solar and wind power by IEEJ model analysis)	Battery cost	About ¥15,000/kWh Cost projection by NREL
			Grid expansion cost	Based on documents by such as OCCTO		Grid expansion cost	Based on documents by such as OCCTO
	Upper limit	**PV: about 750 billion kWh** **WT: about 300 billion kWh**	Upper limit	Based on GIS solar radiation, wind speed data and land use data	**PV: about 750 billion kWh** **WT: about 300 billion kWh**	Upper limit	Based on GIS solar radiation, wind speed data and land use data
Nuclear power	**Price**	**About ¥13/kWh** (2018 price conversion)	Capital cost	Facility cost 4075$/kW Assumed with reference to cost report by NEA and Power Generation Cost WG	**About ¥13/kWh** (2018 price conversion)	Capital cost	Facility cost 4075$/kW Assumed with reference to cost report by NEA and Power Generation Cost WG
			O&M cost			O&M cost	
			Capacity factor	Upper limit 85%		Capacity factor	Upper limit 85%
	Upper limit	**10%**	Upper limit	Assuming 60-year operation of some existing furnaces	**20%**	Upper limit	Assuming that new expansion and replacement will be realized by restoring public confidence, etc.
Hydrogen	**Price**	**Power generation: About ¥16-27/kWh** **Hydrogen: About ¥25-45/Nm3**	Capital, O&M cost	Facility cost 1160$/kW (Assuming 60$/kW is added as high-efficiency gas CC facility cost + NOx countermeasure cost)	**Power generation: about ¥13-21/kWh** **Hydrogen: about ¥20-35 /Nm3**	Capital, O&M cost	Same as Standard Case
			Fuel cost	Calculated in the model		Fuel cost	Further reduction of manufacturing costs overseas and realization of very low-cost freight technology
			Capacity factor	Calculated in the model with upper limit 85%		Capacity factor	Calculated in the model with upper limit 85%
	Upper limit	**None**	Upper limit	No upper limit on import volume	**None**	Upper limit	No upper limit on import volume
Fossil + CCS	**Price**	**Power generation** Coal-fired: About ¥13 /kWh Gas-fired: About ¥16 /kWh **CCS** Coal-fired: About ¥7400/tCO_2 Gas-fired: About ¥10,000/tCO_2 Note: Assuming cost curve for CO_2 storage cost that depends on how much CCS is conducted	Capital, O&M and fuel cost	Facility cost 1100-1700$/kW (High-efficiency coal power generation: 1700$/kW, high-efficiency gas CC power generation: 1100$/kW, when including CO_2 recovery facility cost (actually, the recovery facility capacity (installation ratio) is calculated in the model), about 2100 $/kW and about 1450$/kW, respectively) (With reference to NEA report and Power Generation Cost WG)	**Power generation** Coal-fired: About ¥13 /kWh Gas-fired: About ¥16 /kWh **CCS** Coal-fired: About ¥7400/tCO_2 Gas-fired: About ¥10,000/tCO_2 Note: Assuming cost curve for CO_2 storage cost that depends on how much CCS is conducted	Capital, O&M and fuel cost	Same as Standard Case
			CCS price	Based on various documents		CCS price	Based on various documents
			Capacity factor	Calculated in the model with upper limit 85%		Capacity factor	Calculated in the model with upper limit 85%
	Upper limit	**Domestic: 90 million tCO_2/year** **Overseas: 230 million tCO_2/year**	Upper limit	Assuming storage potential based on GIS data in Japan, considering rig restrictions, etc., and assuming restrictions on the procurement amount of transport vessels overseas	**Domestic: 270 million tCO_2/year** **Overseas: 280 million tCO_2/year**	Upper limit	Assuming that the amount of storage will increase domestically by overcoming the restrictions on drilling rigs.

4. Results of Scenario Analysis

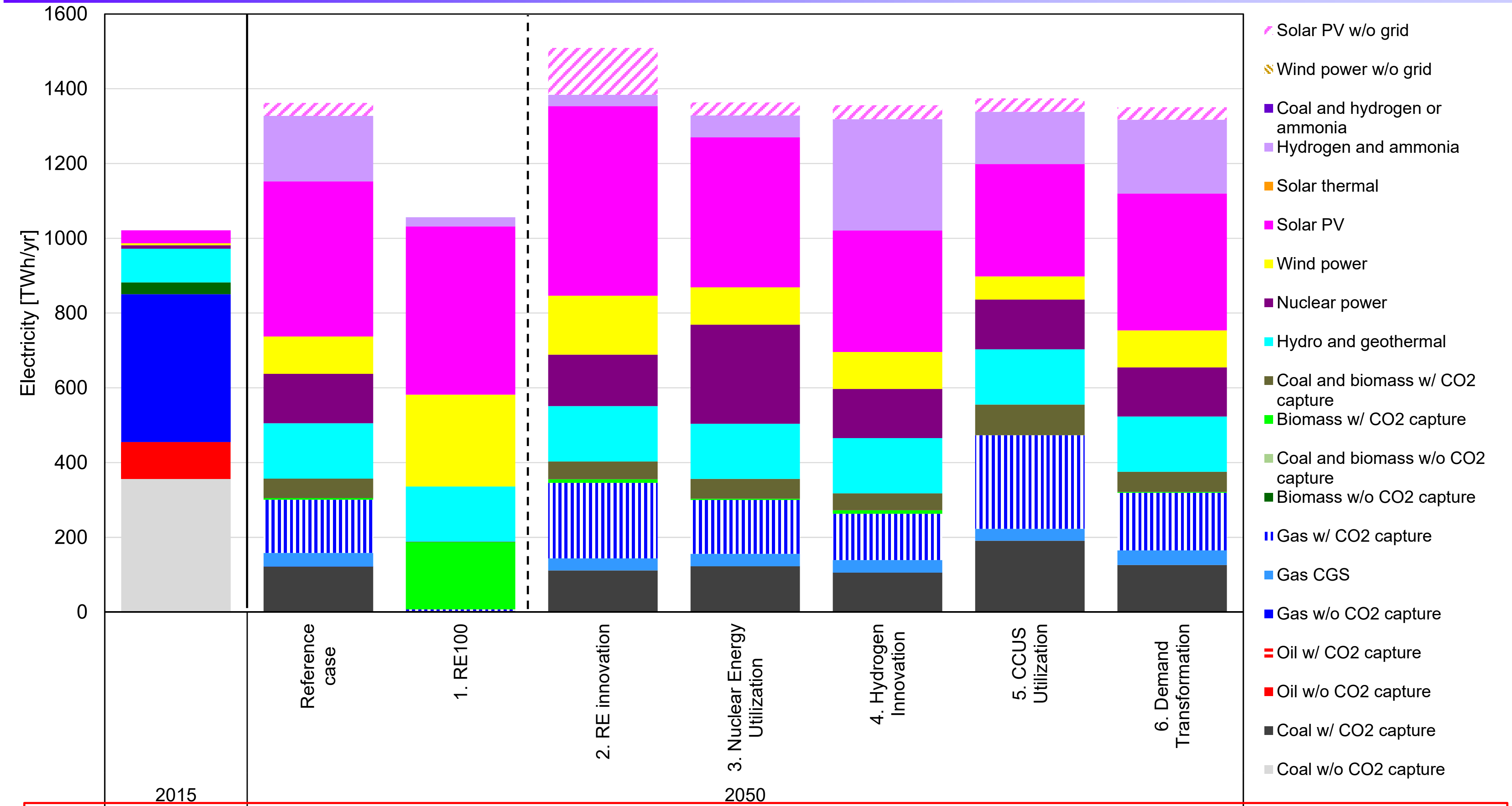
Total Primary Energy Supply in Japan in 2050



Note 1) Conversion rates of primary energies correspond to IEA statistics.
Renewable energies except biomass : 1 TWh = 0.086 Mtoe, nuclear : 1TWh = 0.086 / 0.33 Mtoe
Note 2) Fossil fuels without CCS are offset with NETs, thus serving as carbon-neutral fossil fuels.

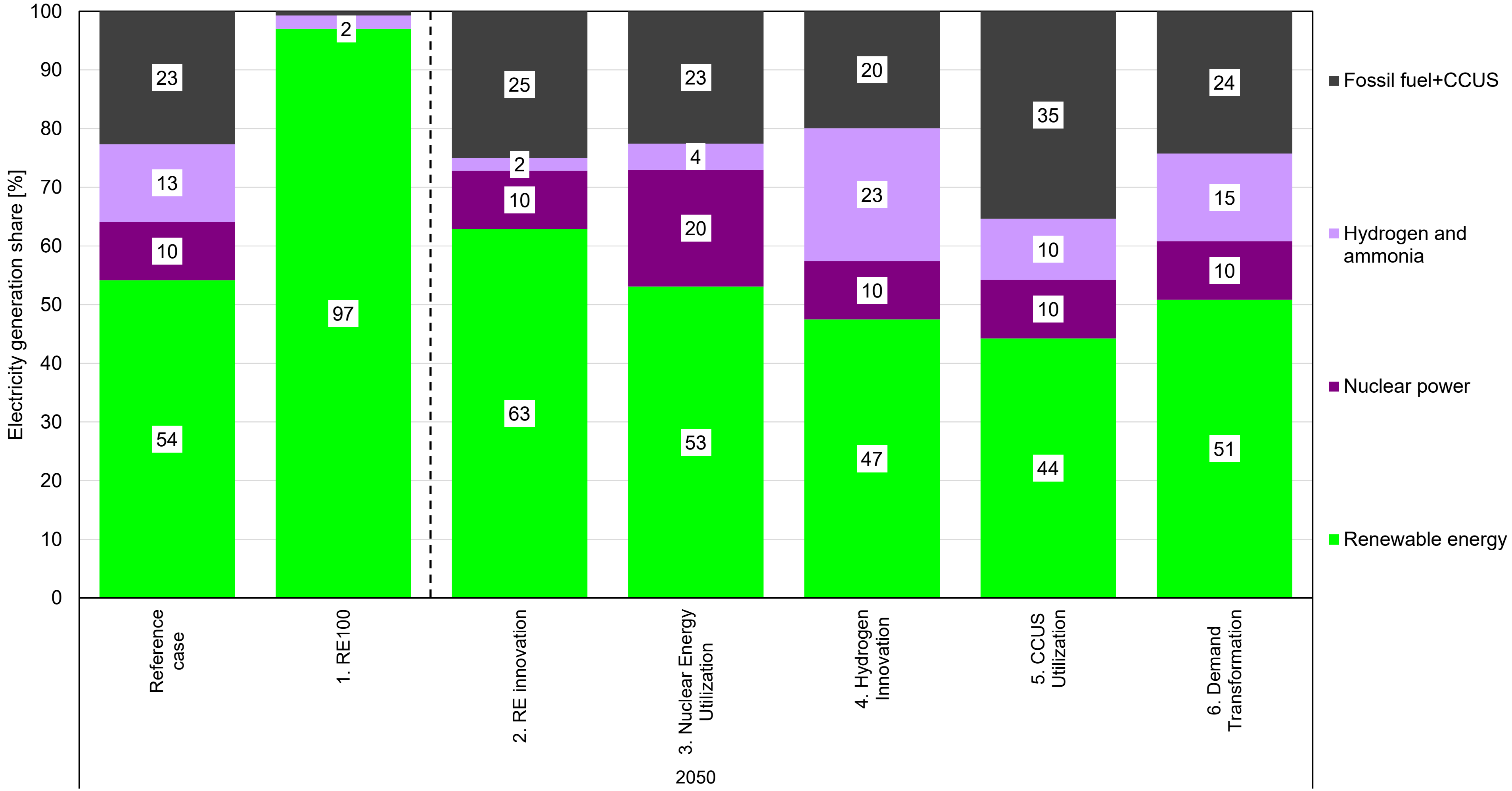
✓ **Substantial amount of imports of hydrogen, ammonia and synthetic fuels are observed in all of ▲100% scenarios.**

Electricity Supply in Japan in 2050



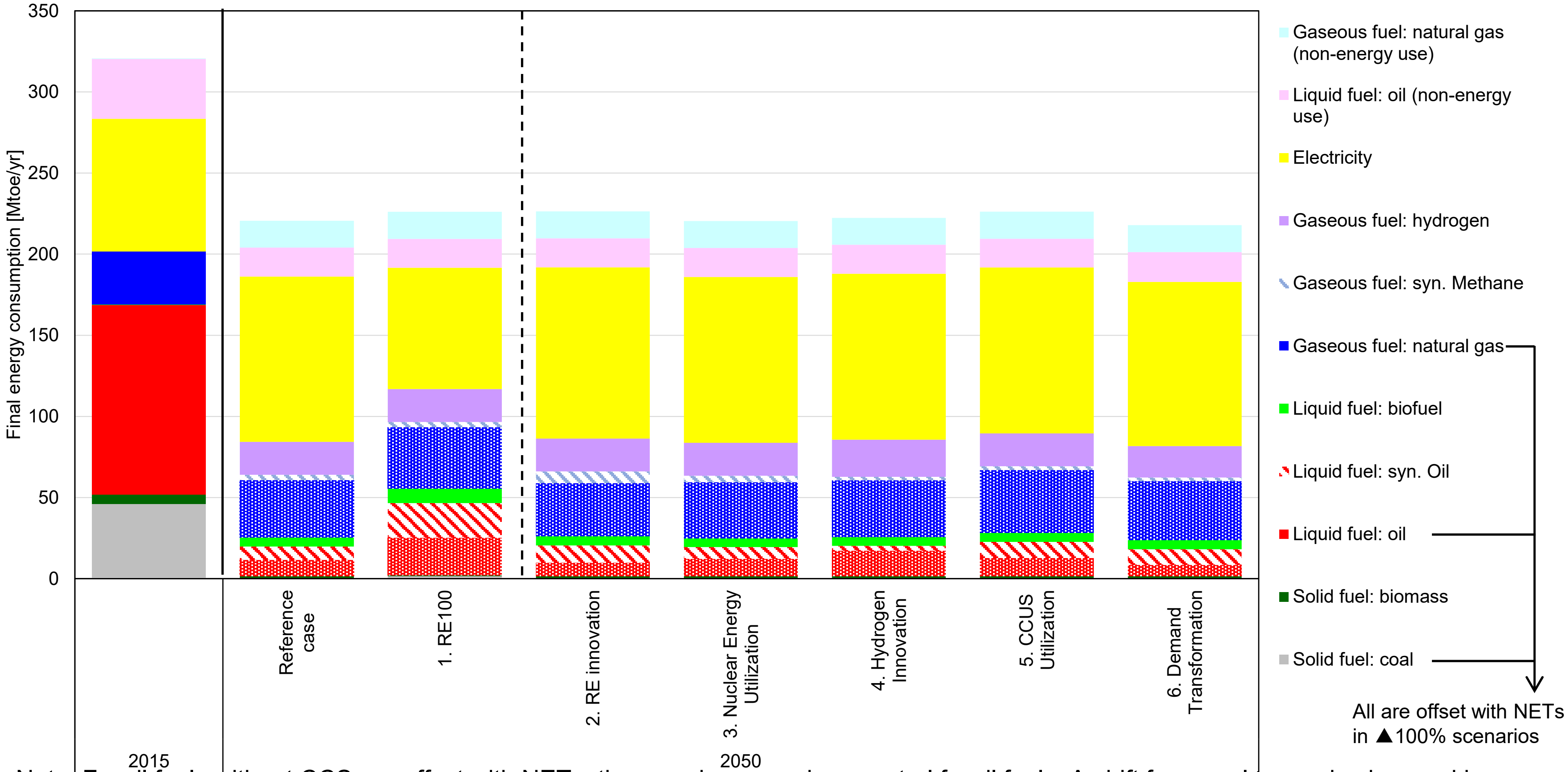
- ✓ **Increases in integration costs are observed in the case where renewable energy share is higher than that in the Reference case. Especially for the RE100 case, a surge in integration costs significantly raises marginal cost of electricity supply, causing considerable decrease in electricity demand. An increase in BECCS instead of fossil fuel + CCS is observed for supply-demand balance.**

【ref.】 Electricity Generation Share in 2050



✓ **Modifying assumption of power generation by each scenario and consequent changes in electricity generation share from the Reference case would cause a decrease in share of expensive power generation. Under assumption of this analysis, hydrogen generation is likely to decline, and assuming further cost reduction of hydrogen or a higher cost for other electricity would cause a decrease in other power generation.**

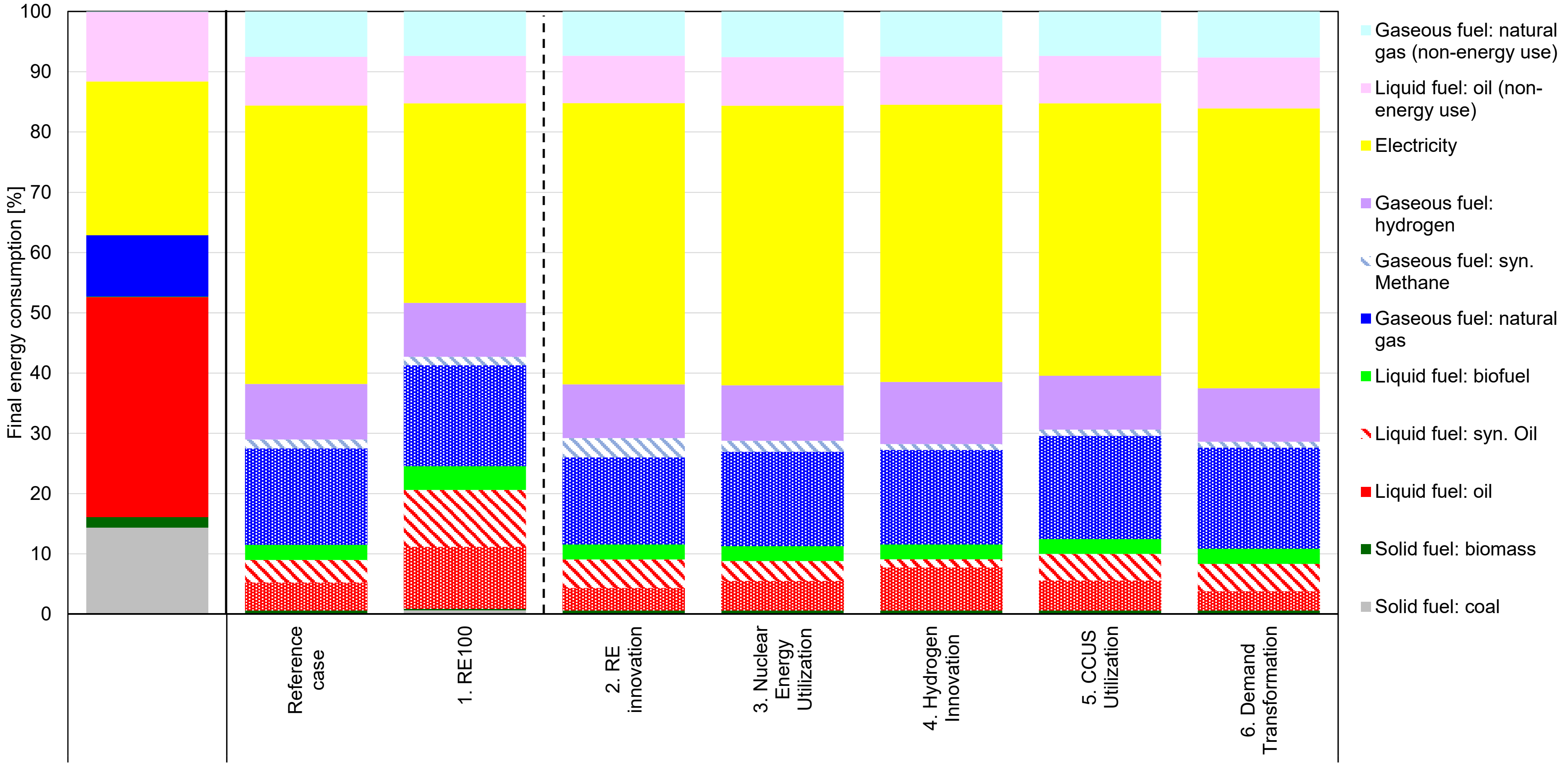
Final Energy Consumption in 2050



Note: Fossil fuels without CCS are offset with NETs, thus serving as carbon-neutral fossil fuels. A shift from coal to gas is observed in sectors such as industry, and gas is likely to remain used in sectors where electrification is difficult.

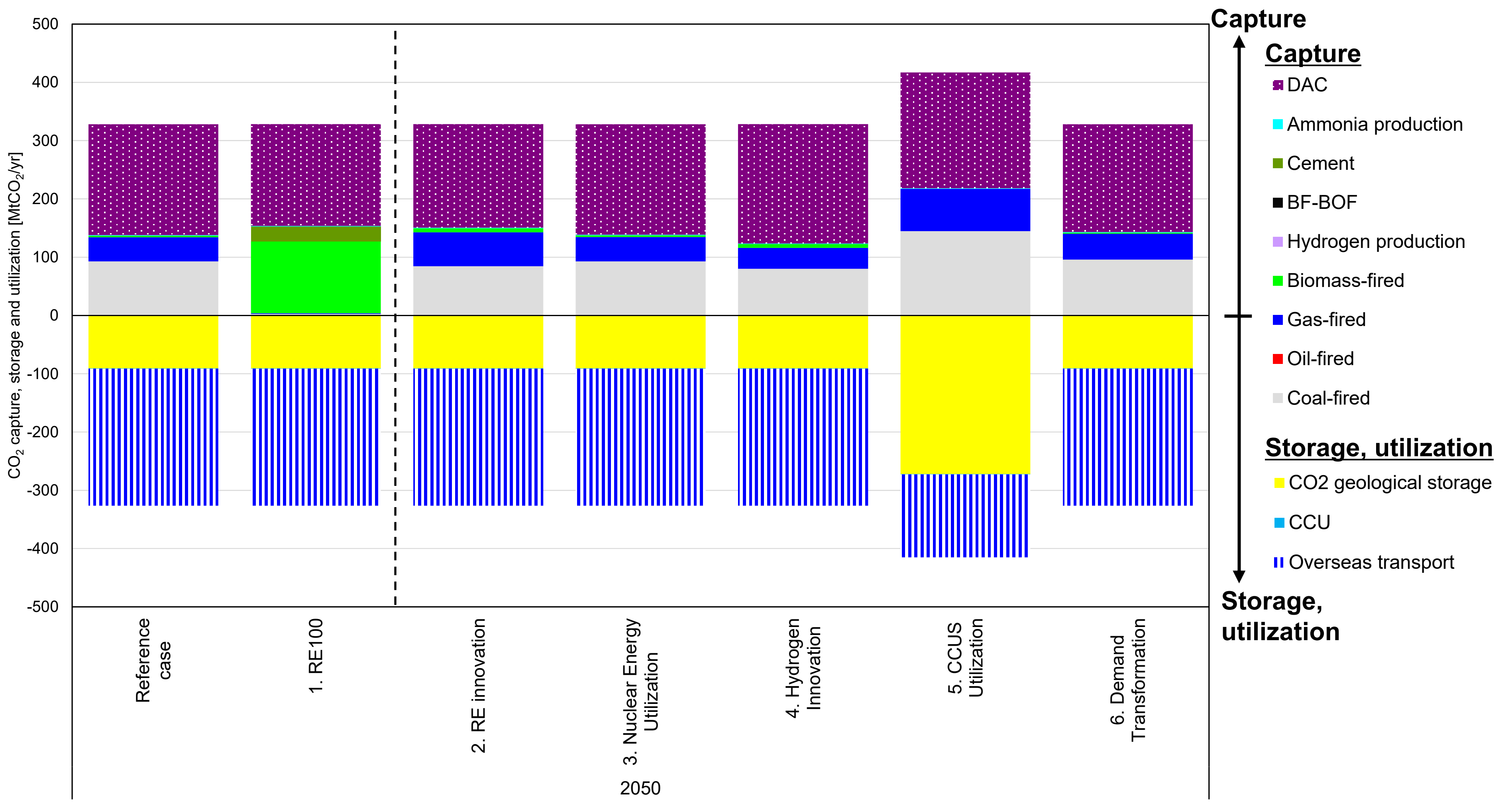
- ✓ **Significant reduction of energy consumption is seen in 2050 for every scenario of ▲100%.**
- ✓ **Increases in integration costs are observed in the case where renewable energy share is higher than that in the Reference case. Especially for the RE100 case, a surge in integration costs significantly raises marginal cost of electricity supply, causing considerable decrease in electricity demand. Electrification is slow in sectors such as Residential and Commercial, and thus oil demand is higher compared to the Reference case.**

【ref.】 Final Energy Consumption Share in 2050



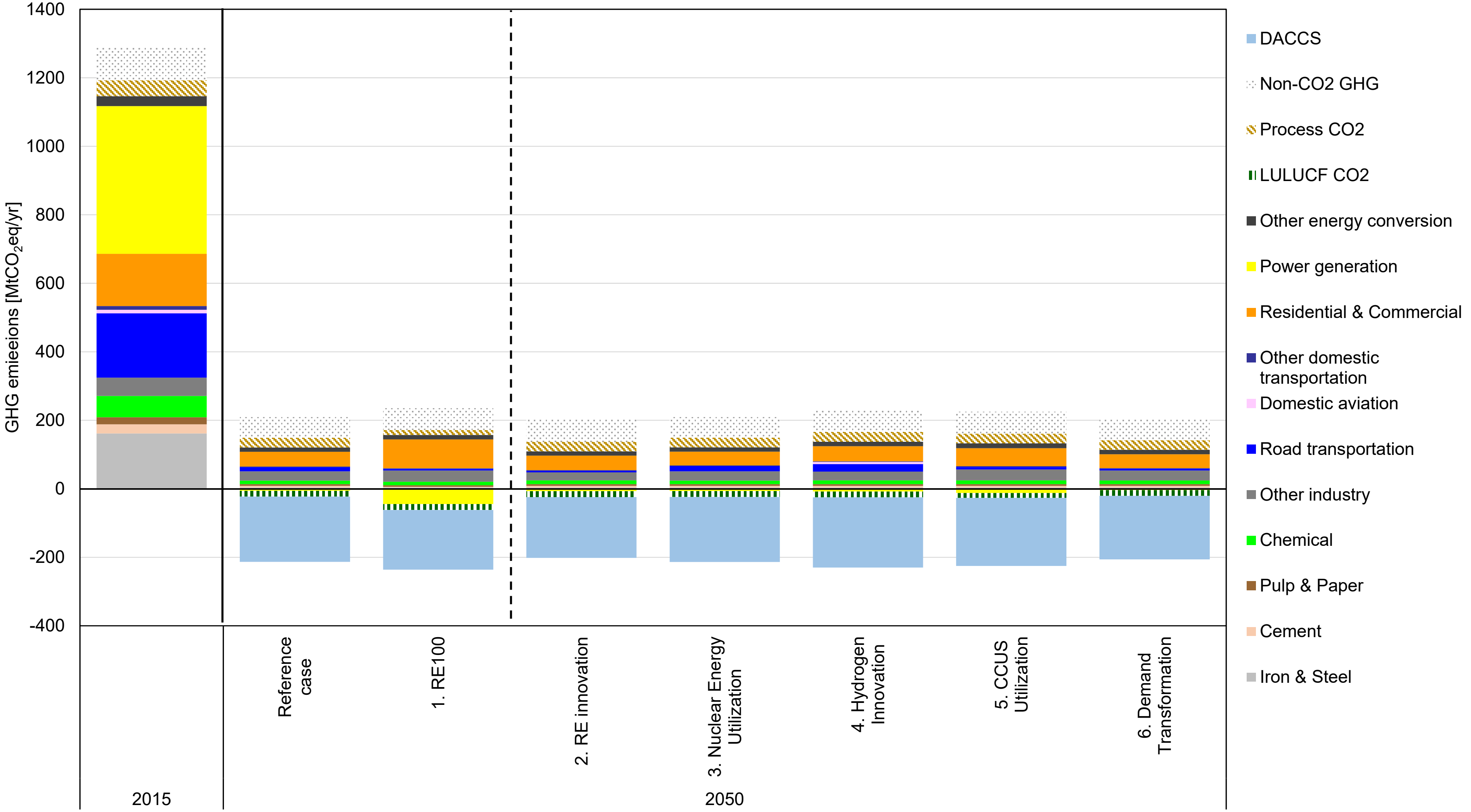
- ✓ **Electrification rate increases significantly to about 40% in all scenarios except RE100, from current level of about 20%.**
- ✓ **Fossil fuels with using existing assets and DACCS, or fuels from captured carbon such as synthetic oil or synthetic methane are utilized.**

CO2 Balances in Japan in 2050

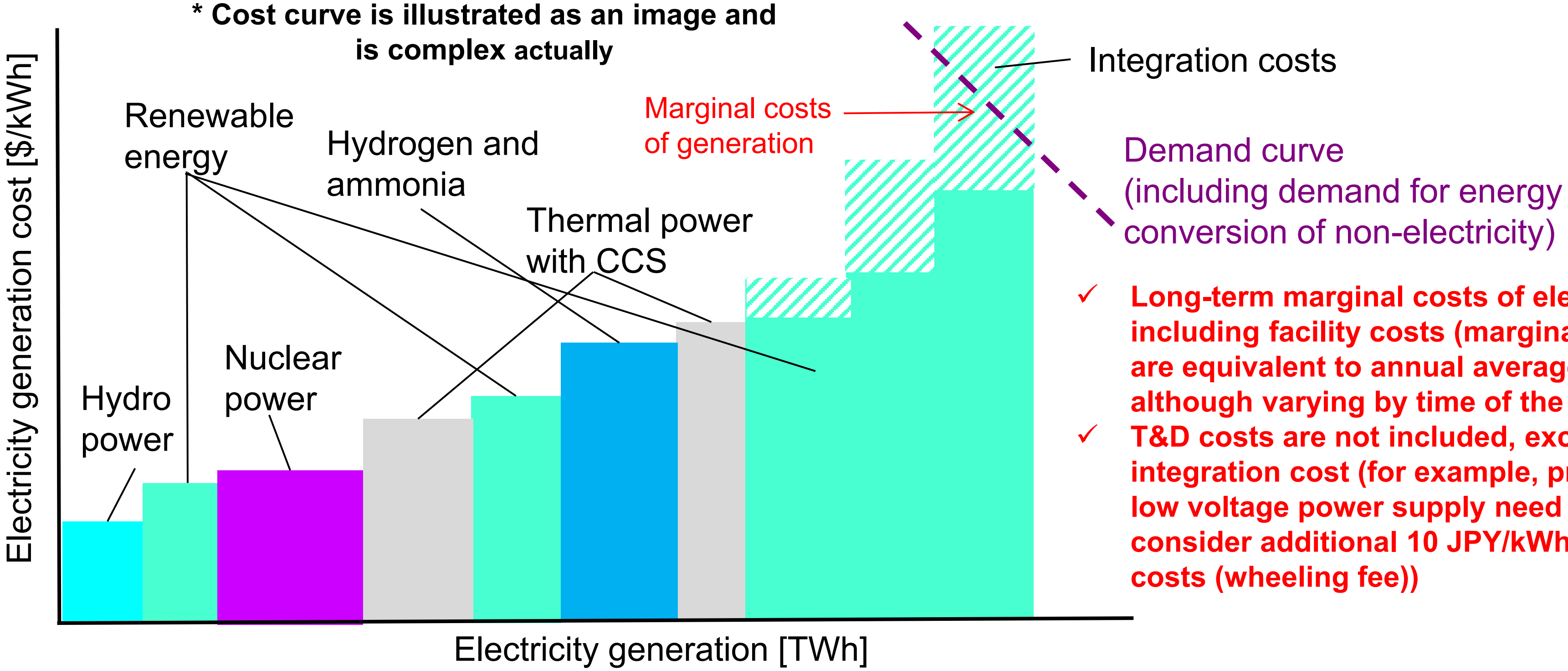


✓ **In the RE100 case, fossil fuels + CCS is excluded and BECCS is utilized instead.**

GHG Emissions by Sector in Japan in 2050



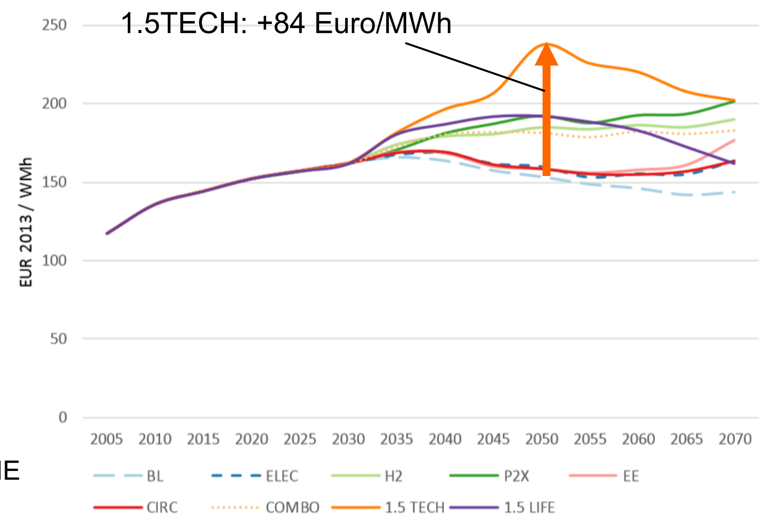
【ref.】 Marginal Costs of Electricity



- ✓ **Long-term marginal costs of electricity including facility costs (marginal costs are equivalent to annual average costs, although varying by time of the day)**
- ✓ **T&D costs are not included, except for integration cost (for example, prices for low voltage power supply need to consider additional 10 JPY/kWh as T&D costs (wheeling fee))**

* Hydropower, nuclear power and CCS are constrained by their quantity before reaching their marginal costs

【ref.】Differences in retail prices of electricity in EU scenarios
(increases in price evidently shown)



Source) IN-DEPTH ANALYSIS IN SUPPORT OF THE COMMISSION COMMUNICATION COM (2018)

Summary (preliminary)

- It is noted that scenario assumptions for this analysis such as introduction amount or costs of technology options do not take into account natural or societal constraints in Japan in detail, as well as that costs are assumed on the basis of cost projections by international organizations and the like. Future landscape that aligns more with realities can be drawn with further analysis considering these constraints precisely.
- Therefore, it is crucial to constantly consider various constraints not evident in figures below, instead of utilizing only appearances of those figures for future policymaking.
- Moreover, marginal cost of electricity, namely electricity cost (electricity costs at output, and additional wheeling fee of about 10 JPY/kWh required for retail prices. Hereafter referred to as “electricity cost”) , is approximately twice as high as calculated price for the year 2020 (approx. 13 JPY/kWh), even for the Reference case. Reduction of those costs would be essential towards carbon neutrality by 2050, from the perspective of industrial competitiveness.
- For the assumed required amount of hydrogen and ammonia outside the power sector and CCUS in the Reference case, realization of significant amount of hydrogen and ammonia supply or CO_2 storage both domestically and abroad is mechanically assumed for drawing a vision of reference value, on the basis that barriers such as assuring appropriate sites or infrastructure development are to be overcome.
- All cases in this analysis, including the Reference case, utilization of carbon removal technologies such as H_2-based direct reduced iron in non-power sector or DACCS is assumed (CO_2 storage capacity of CCUS in this analysis considers CO_2 also from non-power sector).

	Total electricity generation	Power generation mix				Implications of analysis results, Challenges to achieve results
		Renewable energies	Nuclear power	Hydrogen, Ammonia	CCUS-Thermal	
Reference case * Case with assumptions for realizing a vision of reference value towards carbon neutrality in 2050 indicated at the committee	1,350 TWh	54% (730)	10% (140)	13% (180)	23% (310)	➢ All power generations are required to overcome all of technical, natural or societal, and economic challenges. This scenario is constructed under the assumption that these various challenges are to be overcome. Hard-to-achieve level for each power generation. ➢ Assumed level of generation costs per kWh for inputs are ¥10 - 17 for solar PV, ¥11 - 20 for wind, ¥13 for nuclear, ¥16 - 27 for hydrogen and ammonia, and ¥13 - 16 for CCUS-thermal. Electricity cost (marginal costs of electricity) is ¥24.9 per kWh, which does not consider natural and societal constraints in detail. Assumed potentials for CO_2 storage are 91 $MtCO_2$/yr for Japan and 230 $MtCO_2$/yr for export.
Renewable Energy 100% 1	1,050 TWh	Approx. 100%	0%	0%	0%	➢ A scenario where renewable energy share is exogenously assumed as 100%. Electricity costs for inputs are assumed as same with the Reference case. ➢ Electricity cost is ¥53.4/kWh due to an increase in system integration costs. As a result of unavailability of other low cost power options, electricity consumption would be reduced. ➢ Moreover, significant level of challenges such as natural and societal constraints are required to be overcome for realizing such amount of renewable energy introduction which might not be realistic.

Summary (preliminary)

Cases with modified assumption of the Reference case due to technological innovation assumption ↓	Total electricity generation	Power generation mix: Renewable energies	Nuclear power	Hydrogen, ammonia	CCUS-thermal	Implications of analysis results, Challenges to achieve results
Renewable Energy Innovation 2	1,500 TWh	63% (950)	10% (150)	2% (30)	25% (380)	➢ More innovation is realized in renewable energy compared with the Reference case, such as development and commercialization of new solar PV or wind turbine with higher generation efficiency, which induce significant reduction in assumed generation costs; ¥6 – 10/kWh for PV and ¥8 - 15/kWh for wind. ➢ More introduction is required compared with the Reference case, with natural and societal constraints overcome. ➢ Renewable energy cost is lower than hydrogen, therefore are introduced in prior to hydrogen in this scenario. Electricity cost in this scenario is ¥22.4/kWh.
Nuclear Power Utilization 3	1,350 TWh	53% (720)	20% (270)	4% (50)	23% (310)	➢ A scenario with the assumption that nuclear power would consists of power generation mix with upper limit of 20%, assuming that replacement or new construction of nuclear power plant are realized based on advanced public understanding for nuclear power compared with the Reference case. ➢ Electricity cost in this scenario is ¥24.1/kWh. ➢ Electricity cost with hypothetically setting upper limit for nuclear power at 50% is ¥19.5/kWh.
Hydrogen innovation 4	1,350 TWh	47% (630)	10% (140)	23% (310)	20% (270)	➢ Assumed generation cost of hydrogen is ¥13 – 21/kWh, based on significant hydrogen cost reduction is realized through technological innovation relating to hydrogen production (facility costs of water electrolysis or hydrogen liquefaction) as well as market expansion with increased private investment, compared to the Reference case. Electricity cost in this case is ¥23.5/kWh. ➢ Additional hydrogen supply infrastructure is required in a similar scale assumed in the Reference case.
CCUS Utilization 5	1,350 TWh	44% (590)	10% (140)	10% (140)	35% (470)	➢ Storage potential for CO_2 is assumed to expand significantly (270 $MtCO_2$ for Japan and 280 $MtCO_2$ for export) compared to the Reference case, with further technological innovation. Electricity cost in this case is ¥22.7/kWh. ➢ Required storage potential of CO_2 in Japan would almost triple of that in the Reference case.
Demand transformation 6	1,350 TWh	51% (690)	10% (140)	15% (200)	24% (320)	➢ Realization and diffusion of fully autonomous vehicles, and substantial diffusion of car sharing and ride sharing are assumed. ➢ Other assumptions are same as those in the Reference case. Electricity cost in this case is ¥24.6/kWh.

*Regarding demand side transformation, further scenario analysis considering factors other than car sharing would be conducted.

Implications of Scenario Analysis Results

- The scenario analysis provides implications below.

  - For non-power sectors, technologies for removal or recycle of carbon such as H_2-based direct reduced iron or DACCS are imperative. Without implementing these technologies, an achievement of carbon neutral society is extremely difficult.

  - In light of technological difficulties in decarbonizing non-power sectors, decarbonization of the power sector, which already has established decarbonizing technologies, is prerequisite for achieving carbon neutrality by 2050. While each power generation has various challenges and constraints, preconditions to overcome these challenges and constraints for realizing the reference value are considered and assumed for the Reference case. In addition to substantial difficulties in overcoming these challenges and constraints, electricity cost is projected to be twice as high as current one, and all of these challenges are required to be overcome.

  - For a model analysis, it is possible to exogenously assume further increased level of introduction of <u>renewable energy which would cause increases in generation costs or system integration costs as they are introduced</u>, but in reality, <u>increasing dependence on such power generation to an extremely high level is difficult due to natural condition or societal constraints</u>. Moreover, assuming renewable energy 100%, <u>significant increase in cost</u> is evidently shown in the case 1. Those results suggest that renewable energy 100% scenario might not be a realistic one.

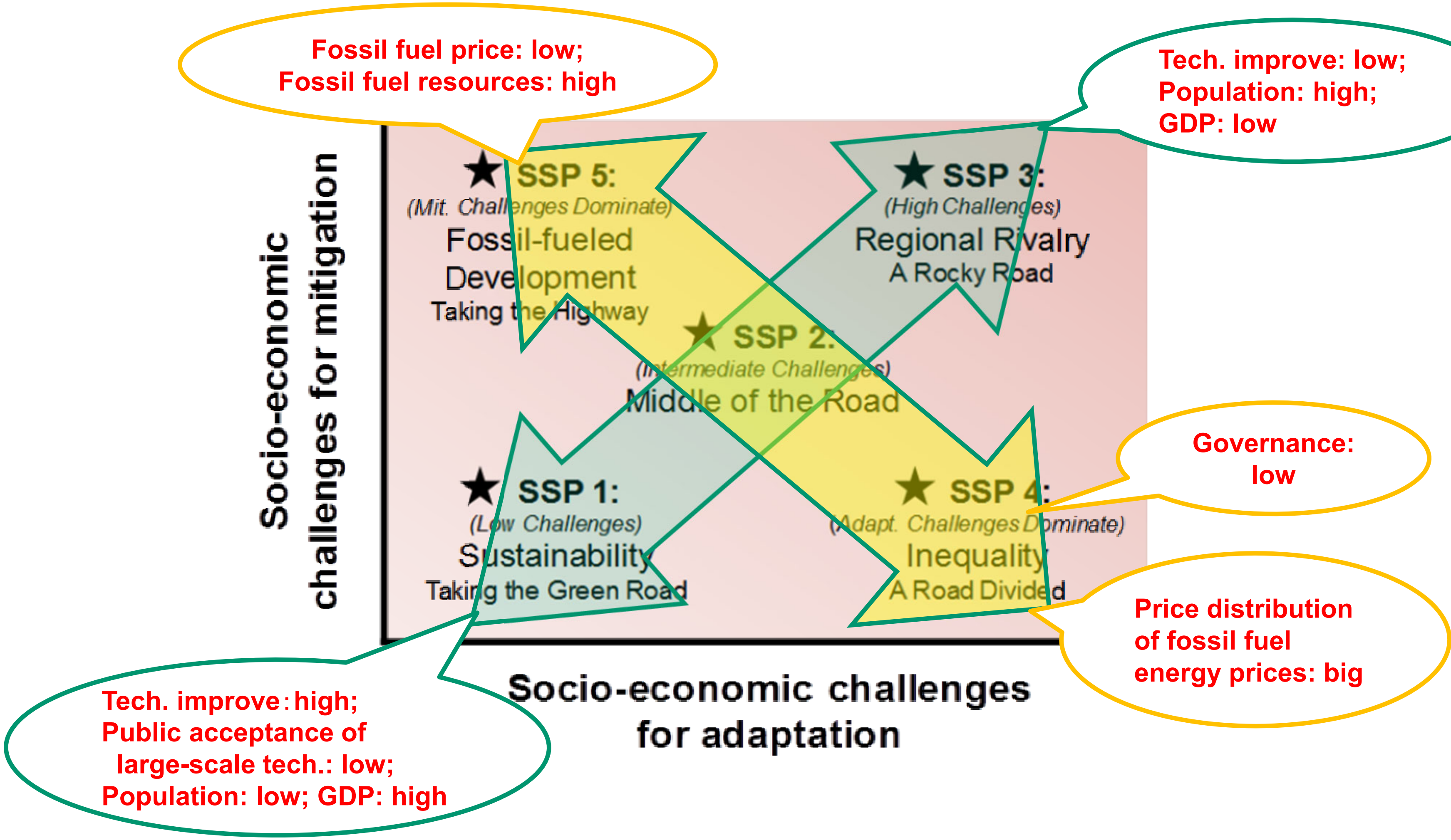
  - By comparing results for 4 cases (cases 2 to 5) where advanced technology innovation is assumed, <u>several pathways toward carbon neutrality by 2050 are shown to be drawn, indicating higher feasibility of carbon neutrality</u>, <u>if challenges of each decarbonized power are to be overcome with technology innovation, cost reduction, enhanced public understandings, and alleviation of deployment constraints,</u> as well as <u>their deployment is further expanded</u>. However, overcoming these challenges bear a lot of uncertainty yet.

=> Based on these implications, realization of various technology innovation is essential to ensure carbon neutrality into the future. Considering uncertainty in innovation, it is important for sectors, such as the power sector where robust decarbonization is required, to utilize established decarbonizing technologies including renewable energy and nuclear power. Furthermore, broader policy responses are required for securing continuous availability of these decarbonizing technologies, without narrowing policy options.

=> Considering difficulties in foreseeing categories where innovation is realized, policy responses toward practical realization of innovation in every category including hydrogen, ammonia and CCUS are required, without leaning to specific ones.

Appendix

Overview of Shared Socioeconomic Pathways (SSPs)



- In response to a call from IPCC, the international research community on climate issues developed SSPs (Shared Socioeconomic Pathways) for consistent analysis and evaluation on mitigation, impacts and adaptation of climate change considering social and economic uncertainties, as well as for aggregation of scientific knowledge, based on which quantitative analyses with Integrated Assessment Models are being conducted.
- RITE has been conducting evaluation on energy and climate policies under several SSPs with using the Integrated Assessment Model DNE21+. For this study, only SSP2 scenario is analyzed due to time constraints.

Assumed Socioeconomic Scenarios

Shared Socioeconomic Pathways, SSP1 to 5, are developed in response to a call from IPCC. Among the quantitative scenarios developed by RITE in line with these SSPs storylines, this study assumes SSP2 "middle of the road" scenario to deliver the analyses.

【World】

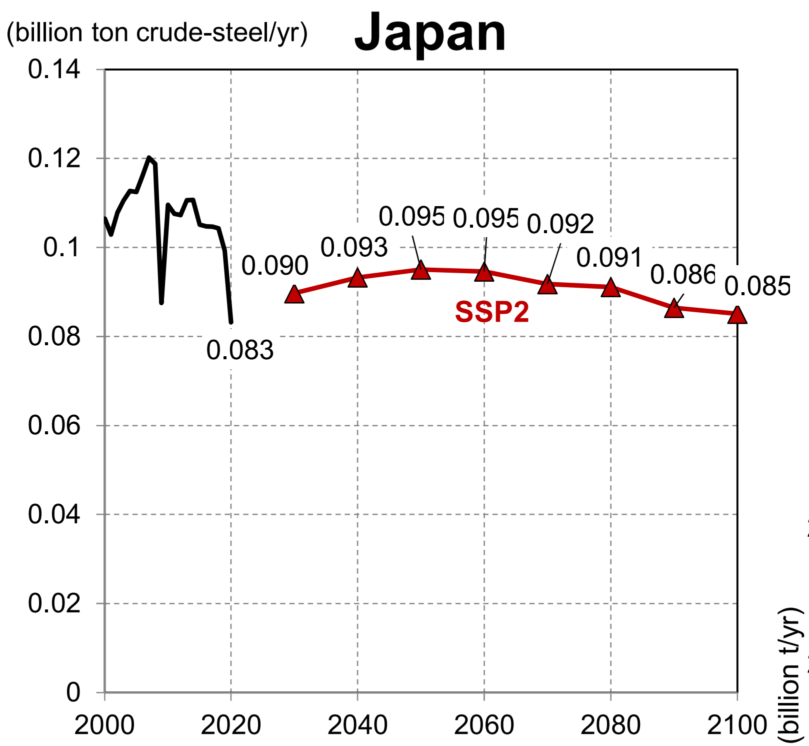
	2030	2050	2100
Population (billion people)	**8.36** (8.14-8.59)	**9.21** (8.61-10.05)	**9.31** (7.00-12.73)
GDP (%/year)	**2.7** (2.4-3.1) [2010-]	**2.2** (1.3-2.8) [2030-]	**1.4** (0.6-2.2) [2050-]
Crude steel production (billion ton)	**1.96** (1.88-2.00)	**2.13** (1.93-2.27)	**2.29** (1.47-2.65)
Cement production (billion ton)	**4.16** (3.90-4.30)	**4.40** (3.85-4.66)	**4.47** (2.94-5.91)
Passenger transport demand in Road sector (trillion p-km)	**30.2** (31.2-37.3)	**60.0** (56.8-74.2)	**83.3** (66.8-88.8)

【Japan】

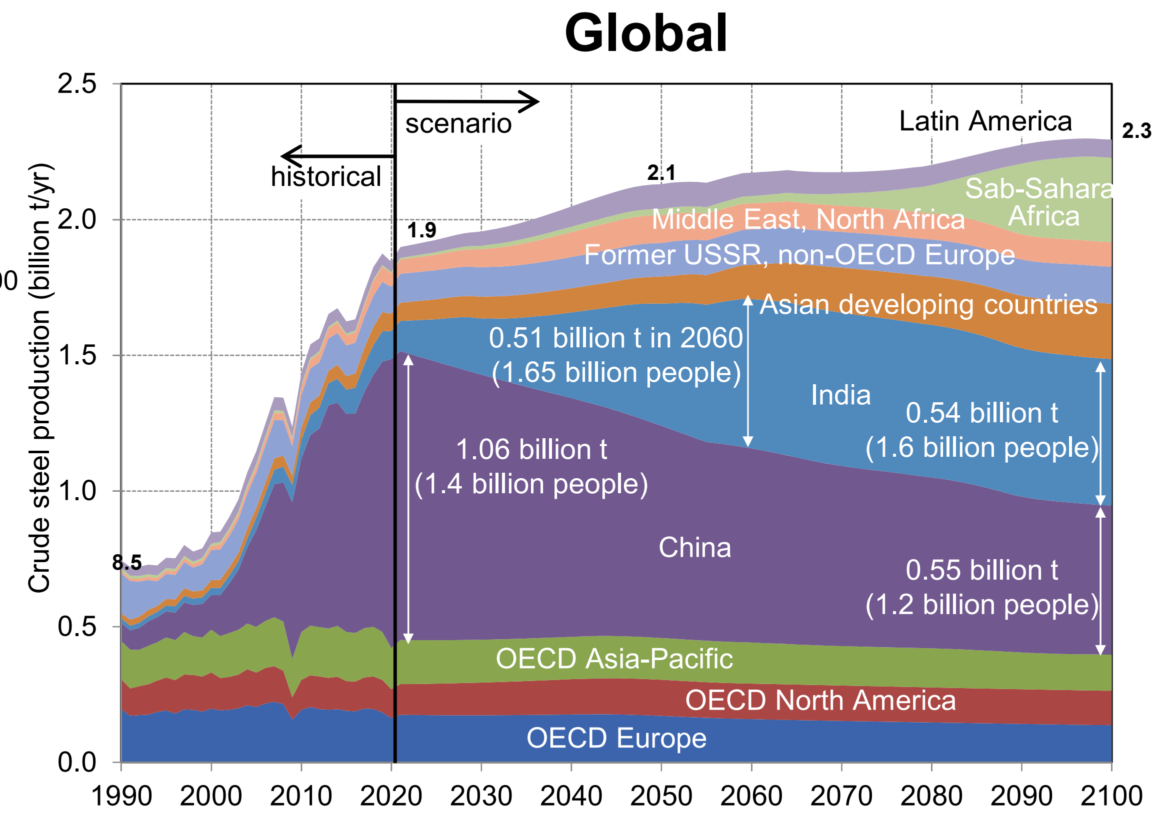
	2030	2050	2100
Population (billion people)	**0.118** (0.116-0.126)	**0.102** (0.096-0.122)	**0.084** (0.047-0.105)
GDP (%/year)	**1.6** (1.3-1.9) [2010-]	**0.4** (-0.1-1.2) [2030-]	**0.4** (-0.9-1.5) [2050-]
Crude steel production (billion ton)	**0.09** (0.081-0.097)	**0.095** (0.073-0.111)	**0.085** (0.045-0.090)
Cement production (billion ton)	**0.054** (0.050-0.068)	**0.044** (0.031-0.075)	**0.040** (0.023-0.065)
Passenger transport demand in Road sector (trillion p-km)	**0.77** (0.69-0.85)	**0.64** (0.61-0.82)	**0.61** (0.51-0.70)

Note: The values in parentheses show the scenario ranges among SSP1-SSP5. Energy demands and electricity generation are endogenously calculated in the model.

Crude Steel Production Scenario for Global and Japan

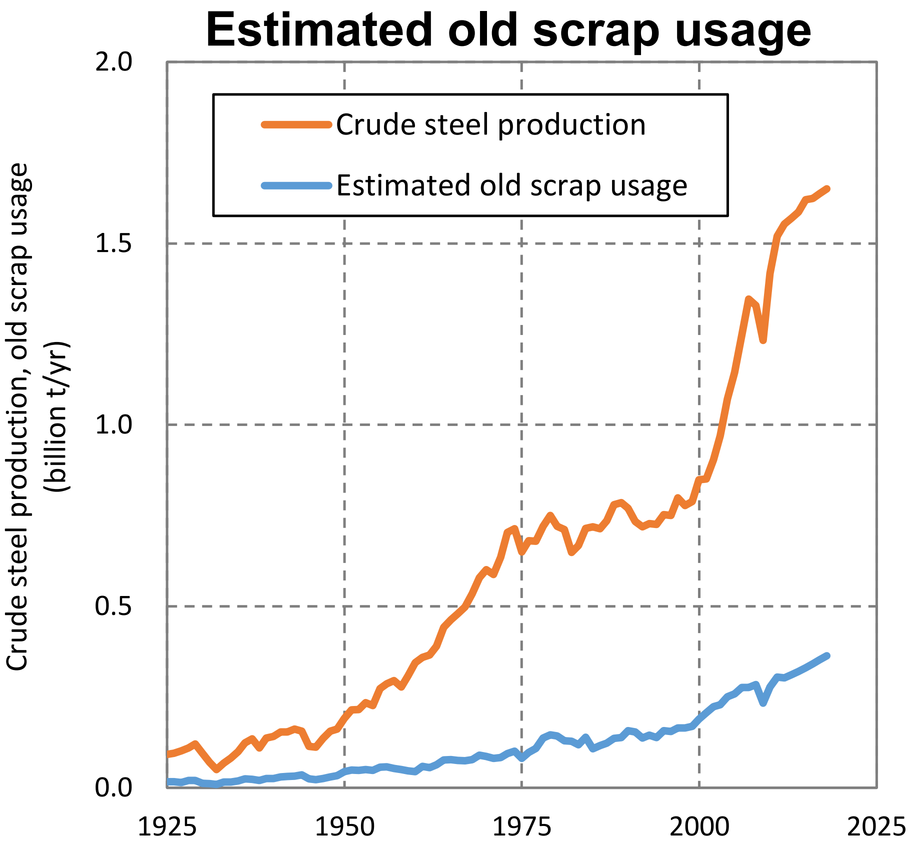


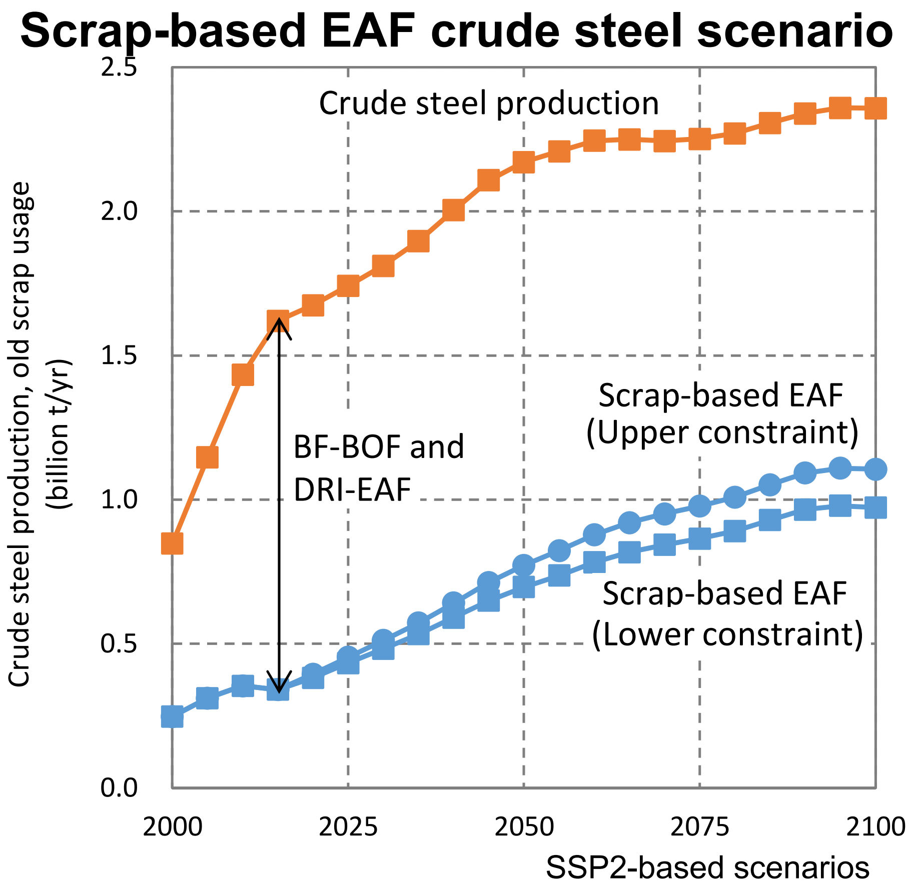
SSP2-based scenario



Global EAF Crude Steel Scenario

EAF: Electric arc furnace

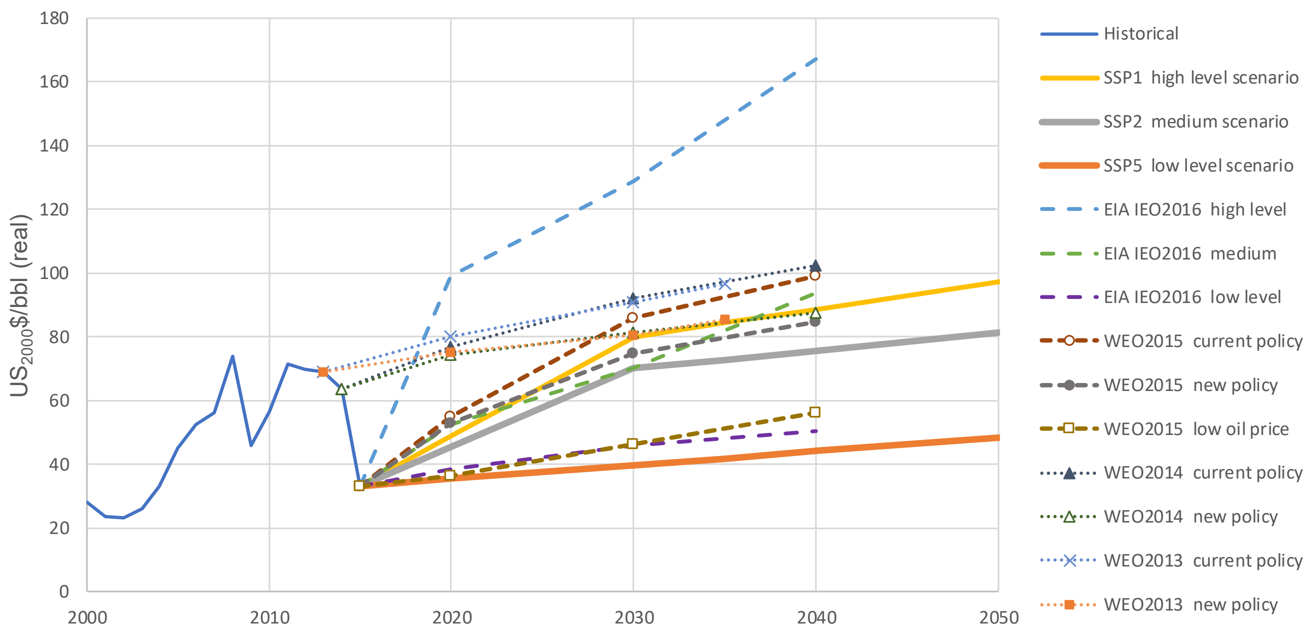




Supplementary remarks: Usage of old scrap, which is the main source of iron for scrap-based EAF, has risen slowly in the past. In the future, the amount of old scrap usage is expected to rise gradually due to the increase in the steel stock. We assumed upper and lower bounds on future production of scrap-based EAF steel.

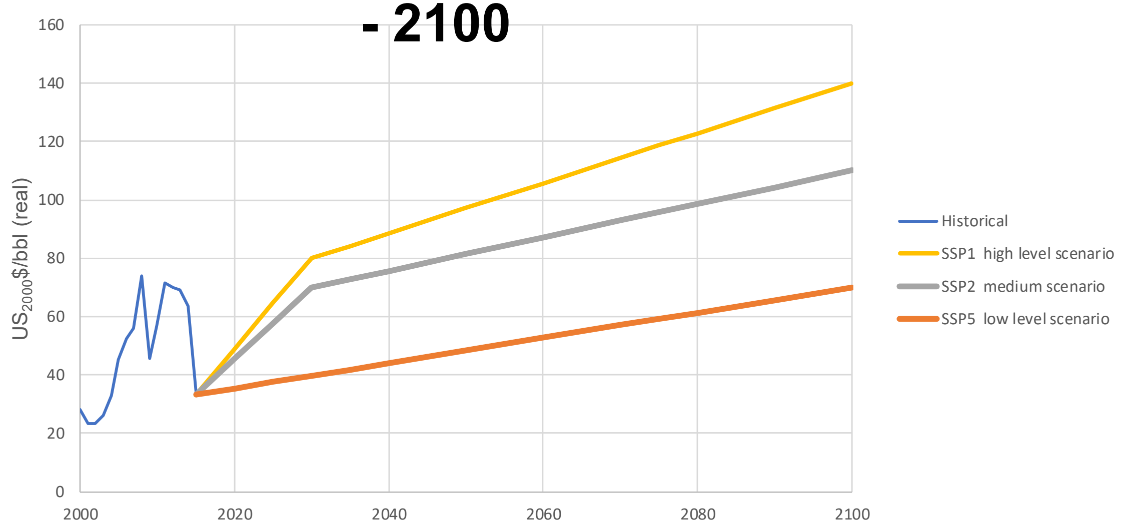
Note: It is noted that expanded usage of EAF, one of the measures for low-carbon or decarbonization, has a large constraint in an amount of old scrap available as well its quality. New technologies such as H_2-based direct reduced iron (DRI) is required for decarbonizing crude steel.

Fossil Fuel Price Scenario (Oil)

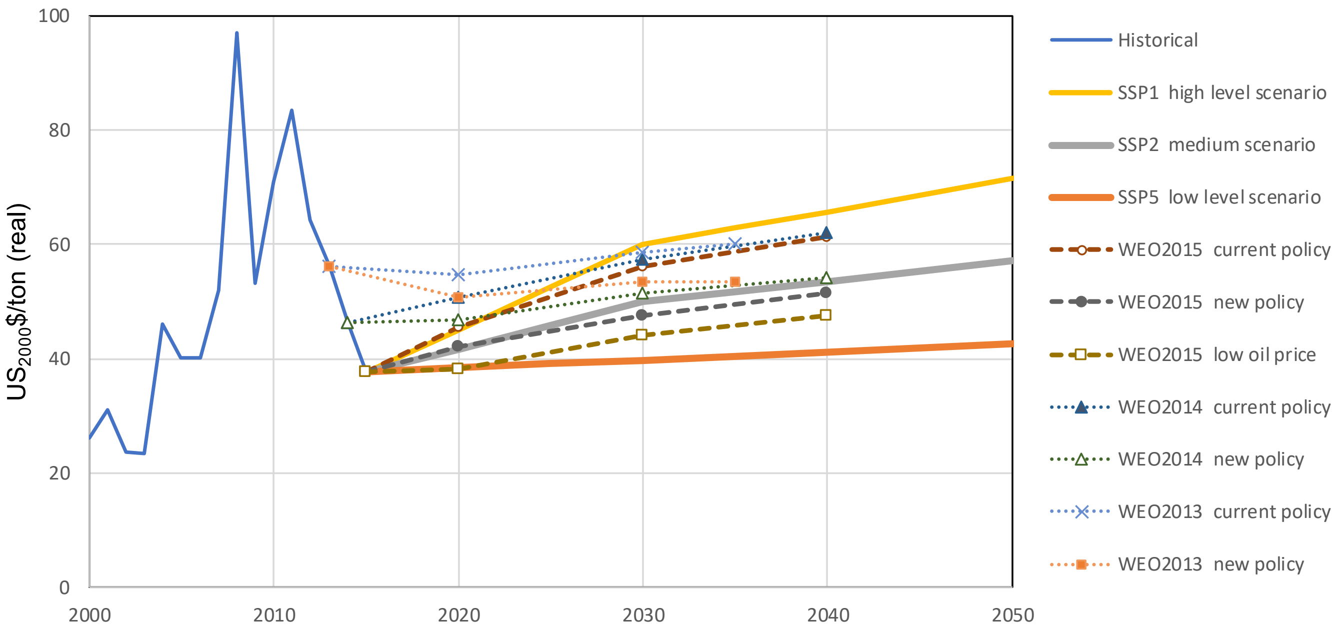


- 2050 Comparison with other literature

- 2100

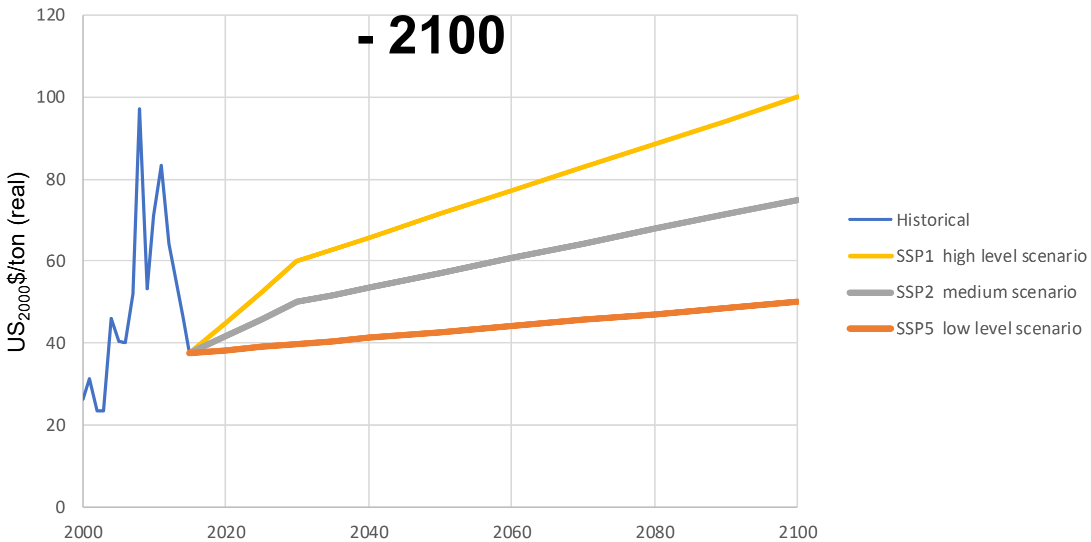


Fossil Fuel Price Scenario (Coal)



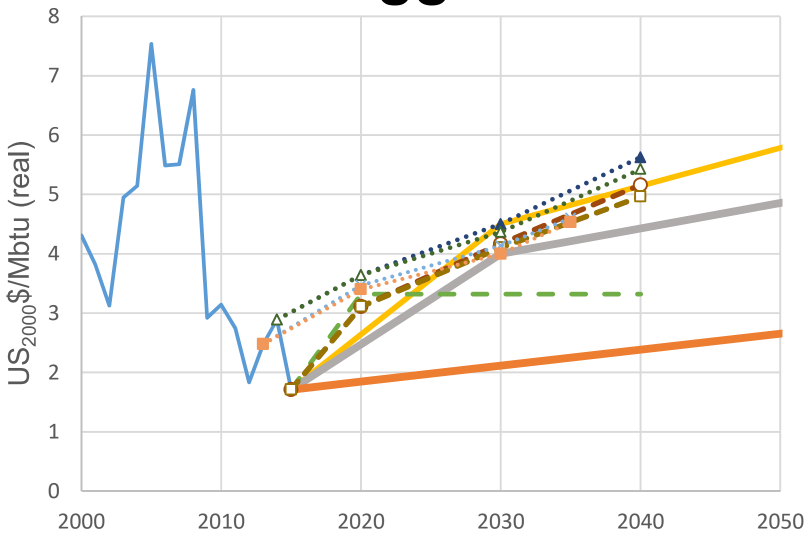
- 2050
Comparison with other literature

- 2100

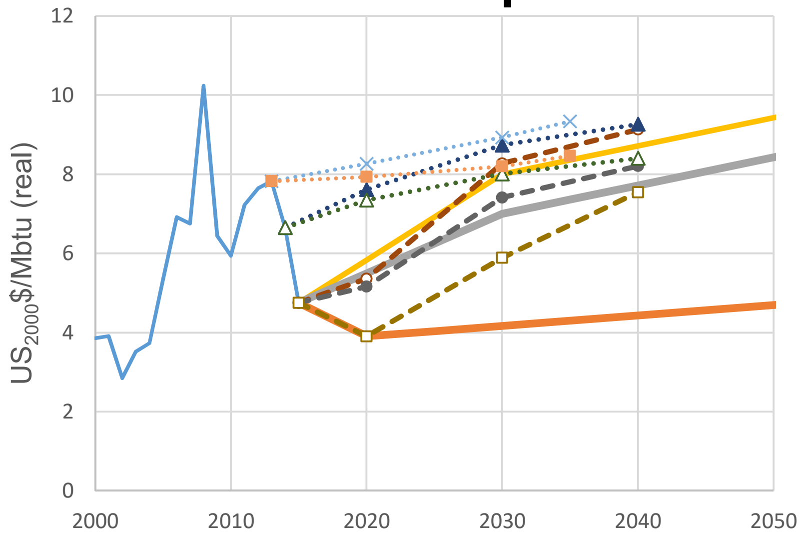


Fossil Fuel Price Scenario (Gas)

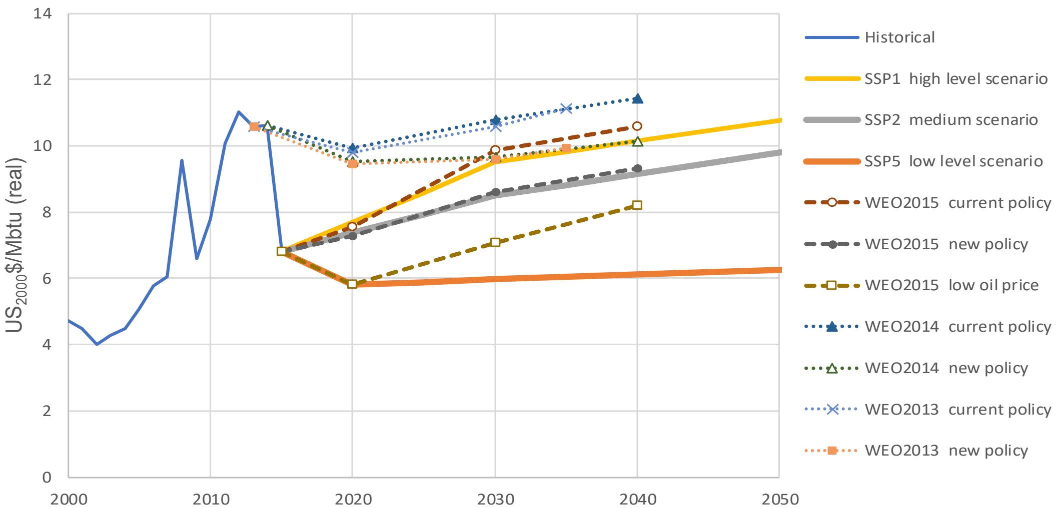
US



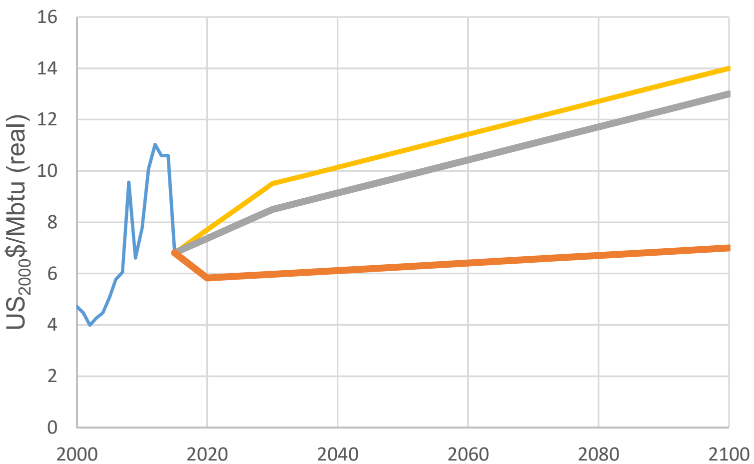
Europe



Asia (incl. Japan)



Asia (incl. Japan); - 2100



Cost Modeling

【 Types of Accumulated Technology Cost】

［Facility Cost］／［Payback Period］＋［Operation · Maintenance Cost］＋［Annual Fuel Cost］

Note1）･ [Annual Expense Ratio] ≡ 1 / [Payback Period] + [Ratio of Ops. ･ Maint. Cost for Facility Cost]

* Assumption: [Annual Expense Ratio] is per technology; [Ratio of Ops. ･ Maint. Cost] is a coefficient against Facility Cost (Approx. 1-8% per yr depending on the facility)

･[Payback Period] = 1 / ([Implicit Discount Rate] / (1- (1 + [Implicit Discount Rate]) ^ [Useful Life of Equip.]))

Note 2) Fuel costs are endogenously determined within the model.

【Cost of Top-Down Modeling Part (loss of utility consumption)】

For other energy consumption that is not subject to technology accumulation, the relationship between the final energy price and the amount of energy saved is expressed by the long-term price elasticity value (electric power: -0.3, non-electric power: -0.4). The integral value can be defined as the loss of utility consumption, and it is regarded as the emission reduction cost other than the accumulated technology.

Assumption of Power Generation Facility Cost

Note 1) For the DNE21 + model, the price of standard year 2000, is used. The 2018 price shown is converted using the US GDP deflator.
Note 2) Facility costs are assumed to decrease over time within the range shown in the table.
Note 3) This figure is an assumed value for the United States, and is multiplied by the location factor depending on the country / region, and there is a slight difference (up to + 3% in Japan). Renewable energy is assumed separately (p.24-28)

			Capital costs in 2000 [US$/kW]	Capital costs in 2018 [US$/kW]
Coal power	Low efficiency (e.g., Conventional (sub-critical), currently used in developing countries)		1000	1458
	Middle efficiency (e.g., mainly used in developed countries (super-critical) – Combined power generation including Integrated Coal Gasification (IGCC) in the future)		1500	2187
	High efficiency (e.g., mainly used in developed countries (super-critical) – Combined power generation including IGCC and Integrated Coal Gasification Fuel cell Combined Cycle (IGFC) in the future)		1700	2479
Co-firing of Coal / Biomass	(Additional cost to medium and high efficiency coal power generation)	Co-firing rate -5%	+85	+124
		Co-firing rate -30%	+680	+992
Co-firing of Coal / ammonia	(Additional cost to medium and high efficiency coal power generation)	Co-firing rate -20%	+264-+132	+385-+193
		Co-firing rate -60%	+271-+135	+395-+197
Oil power	Low efficiency (e.g., diesel)		250	365
	Middle efficiency (sub-critical)		650	948
	High efficiency (super-critical)		1100	1604
	CHP		700	1021
Gas power	Low efficiency (steam turbine)		300	437
	Middle efficiency (combined cycle)		650	948
	High efficiency (combined cycle with high temperature)		1100	1604
	CHP		700	1021
Co-firing of Natural gas / hydrogen	(Additional cost to medium and high efficiency natural gas power generation)	Co-firing rate -20%	+55	+80
Biomass power	Low efficiency (steam turbine)		2720–2400	3967–3500
	High efficiency (combined cycle)		3740–3030	5454–4419
Nuclear power			2743	4000
IGCC/IGFC with CO_2 Capture			2800–2050	4083–2989
Natural gas oxy-fuel power			1900–1400	2771–2042
Hydrogen power（FC/GT）			1160	1692
Ammonia power generation (single fuel firing)			3040-1444	4433-2106
Electricity storage (e.g., pumping-up)			1000	1458

Assumption on Technology Advancement of Power Generating Efficiency for Thermal Power

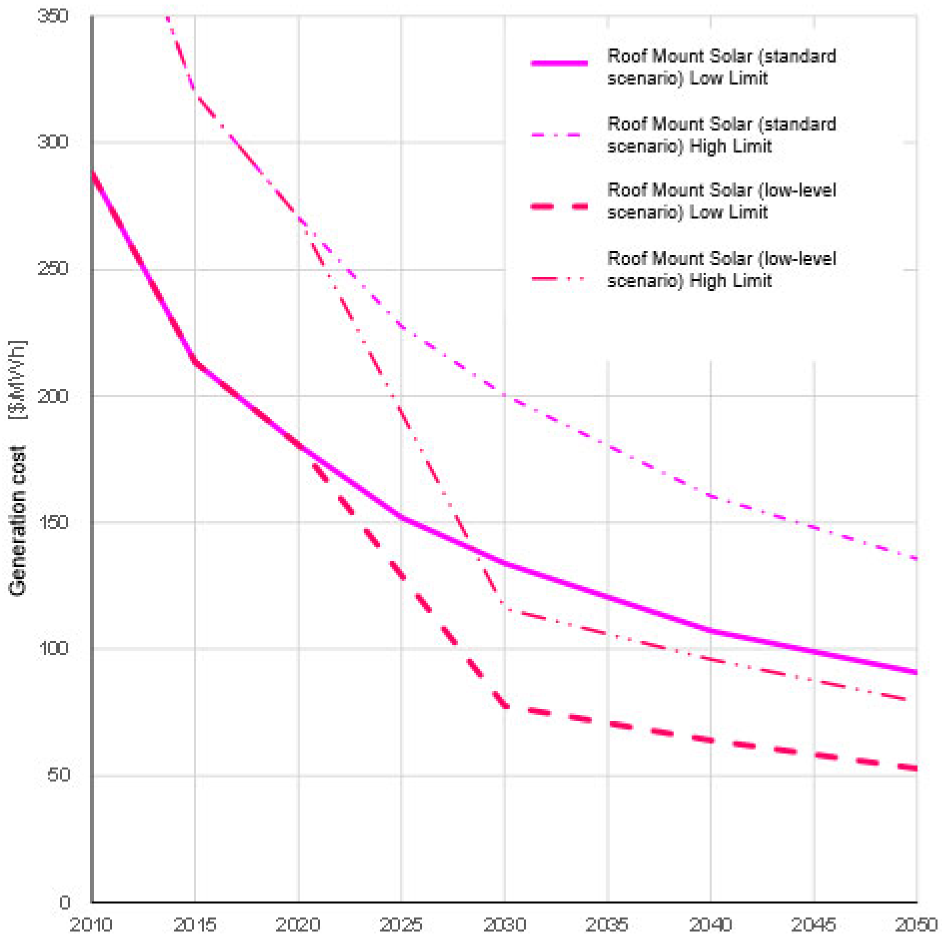
Generating efficiency (%LHV)

		2010	2020	2030	2050
Coal power	Low efficiency (e.g., Conventional (sub-critical), currently used in developing countries)	23.0	24.0	25.0	27.0
	Middle efficiency (e.g., mainly used in developed countries (super-critical) – Combined power generation including Integrated Coal Gasification (IGCC) in the future)	37.8	39.6	41.4	45.0
	High efficiency (e.g., mainly used in developed countries (super-critical) – Combined power generation including IGCC and Integrated Coal Gasification Fuel cell Combined Cycle (IGFC) in the future)	44.0	46.0	48.0	58.0
	IGCC/IGFC with CO_2 Capture	34.0	35.5	38.5	50.3
Oil power	Low efficiency (e.g., diesel)	23.0	24.0	25.0	27.0
	Middle efficiency (sub-critical)	38.6	40.2	41.8	45.0
	High efficiency (super-critical)	52.0	54.0	56.0	60.0
	CHP*1	39.0	41.0	43.0	47.0
Gas power	Low efficiency (steam turbine)	27.2	28.4	29.6	32.0
	Middle efficiency (combined cycle)	39.8	41.6	43.4	47.0
	High efficiency (combined cycle with high temperature)	54.0	56.0	58.0	62.0
	CHP*1	40.0	42.0	44.0	48.0
	Natural gas oxy-fuel power	40.7	41.7	43.7	48.7
Biomass power	Low efficiency (steam turbine)	22.0	22.5	23.5	25.5
	High efficiency (combined cycle)	38.0	40.0	42.0	46.0
Hydrogen power (GT/FC)		54.0	56.0	58.0	62.0

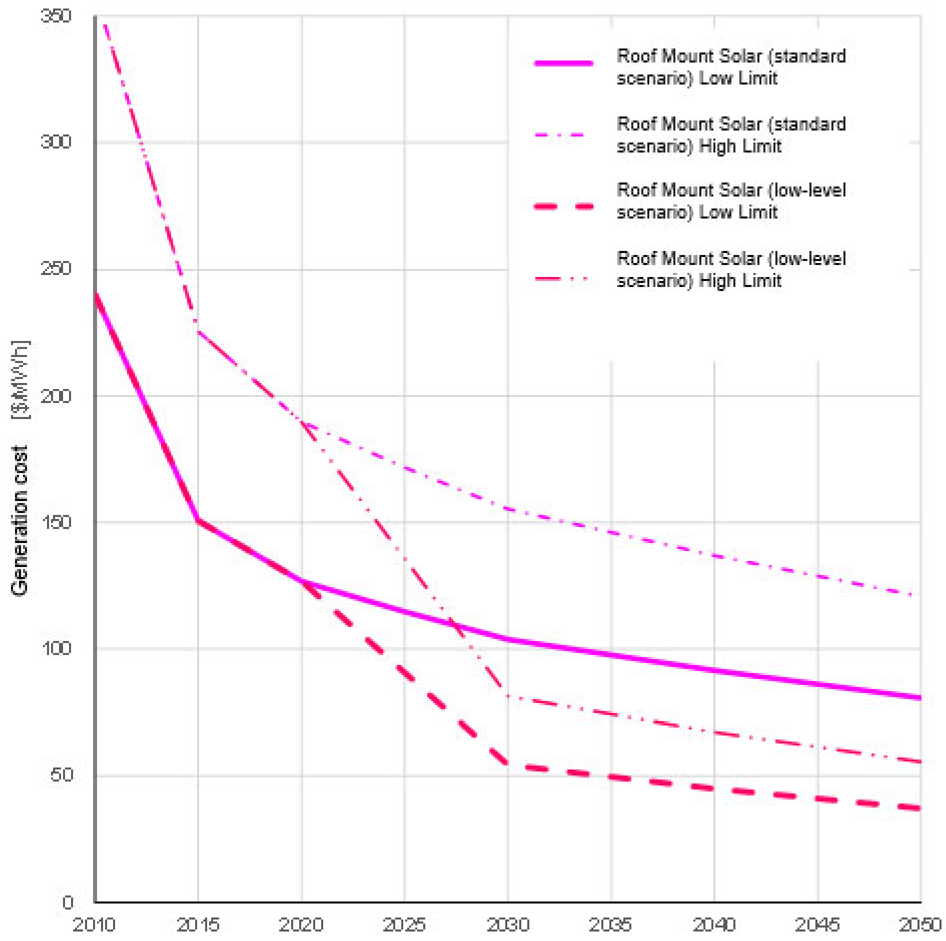
*1 Exhaust heat recovery efficiency is assumed to be 5 to 20% that varies by region, considering supply and demand balance.

Assumption for Rooftop Solar PV Power Generation Cost in Japan: Time Series

Stock

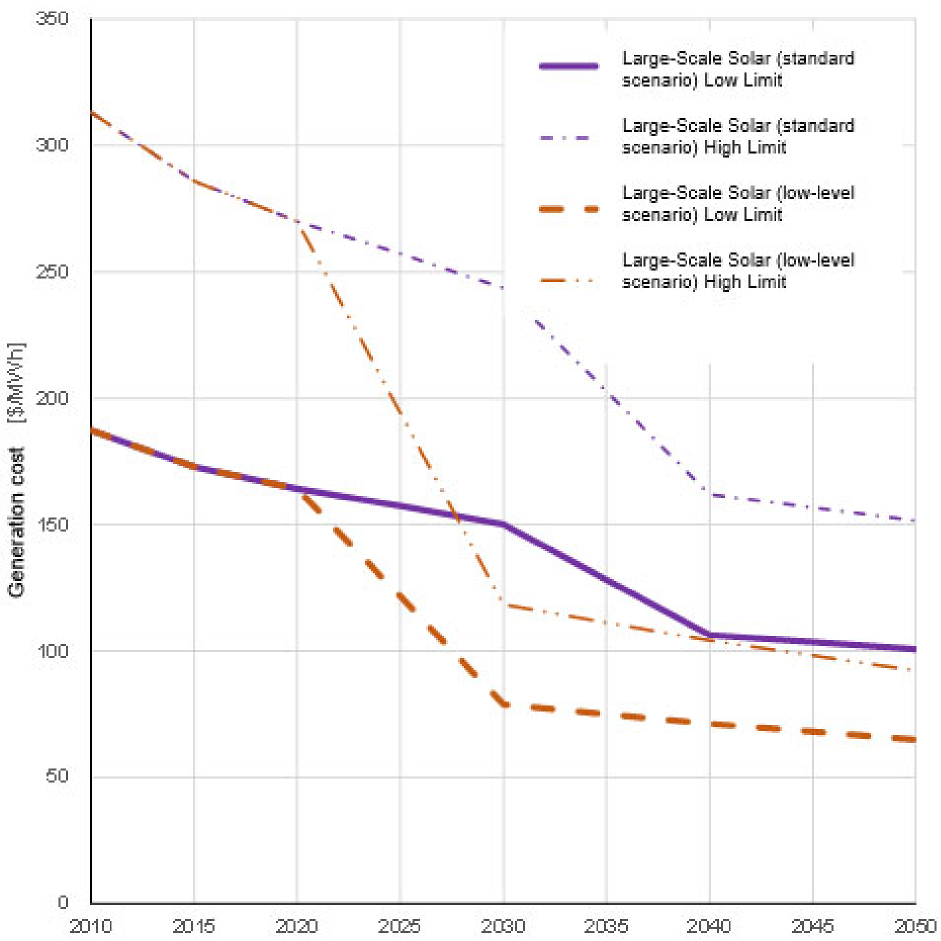


Flow



Assumption for Large-Scale Solar PV Power Generation Cost in Japan: Time Series

Stock



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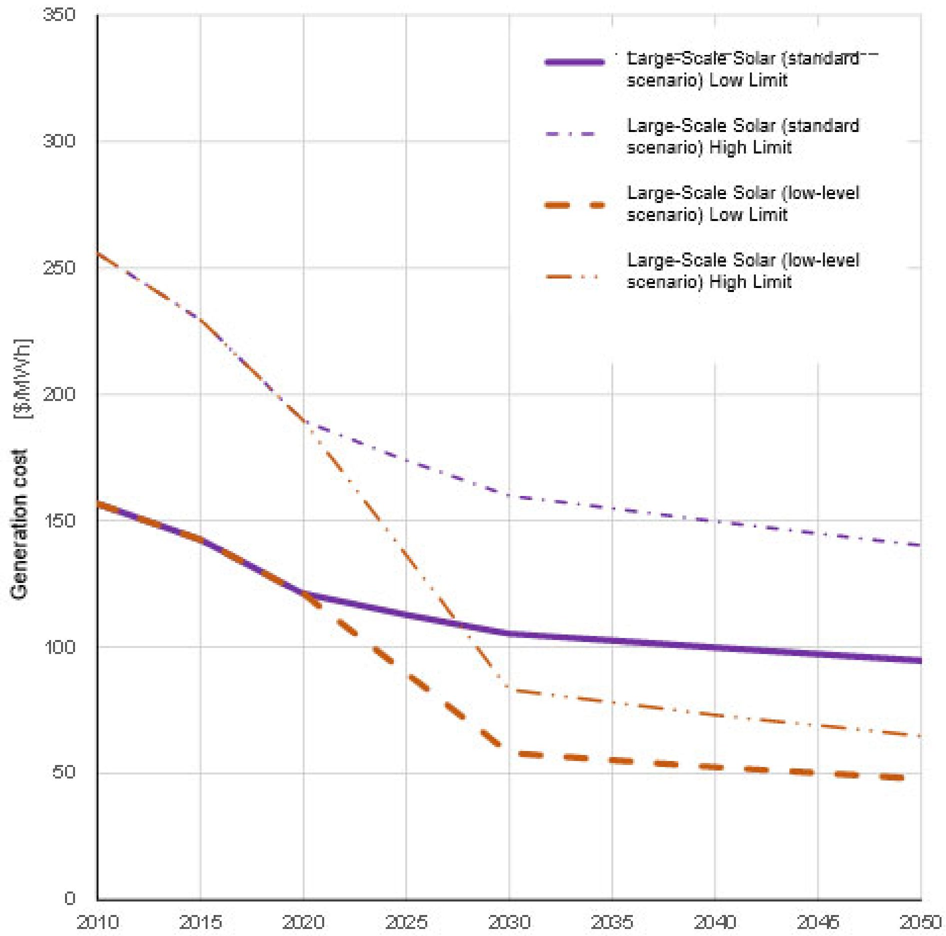
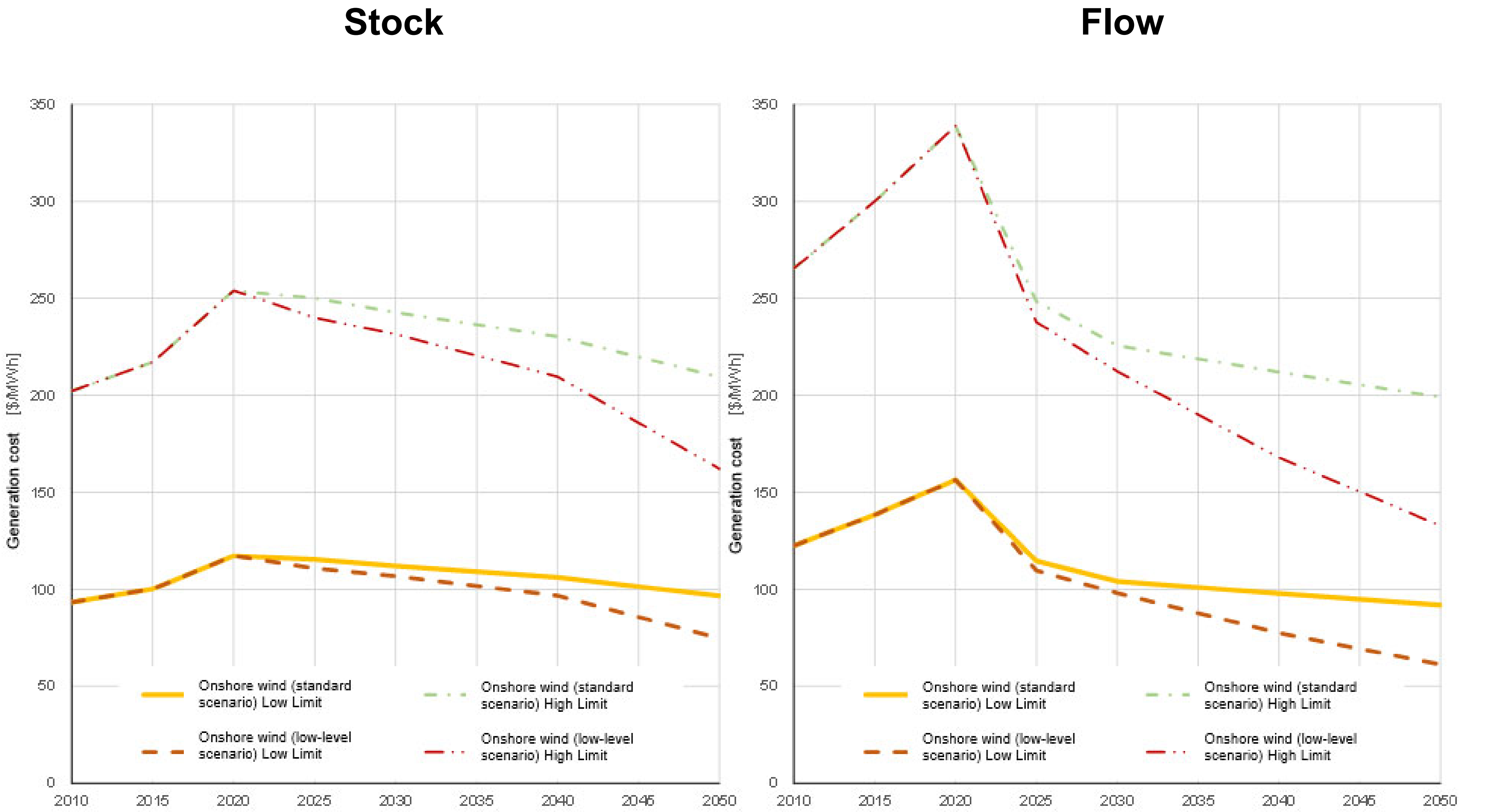
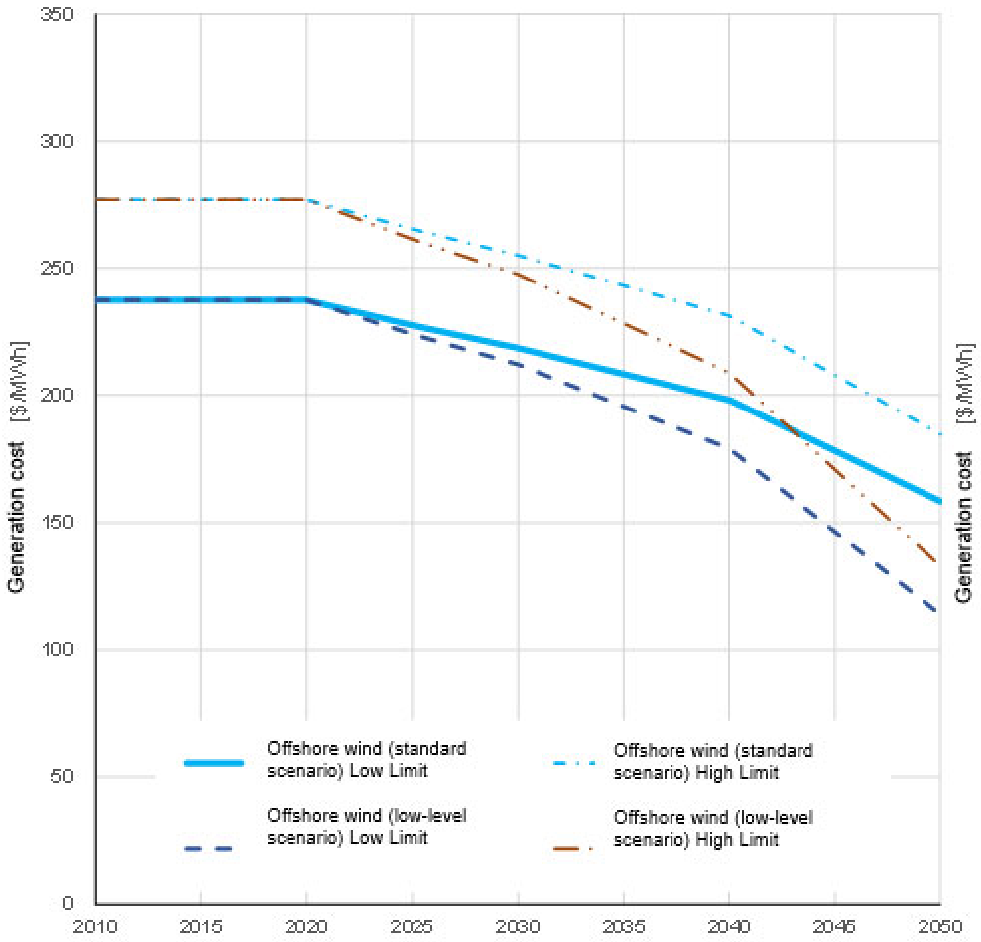


Assumption for Onshore Wind Power Generation Cost in Japan: Time Series



Assumption for Offshore Wind Power Generation Cost in Japan: Time Series

Stock



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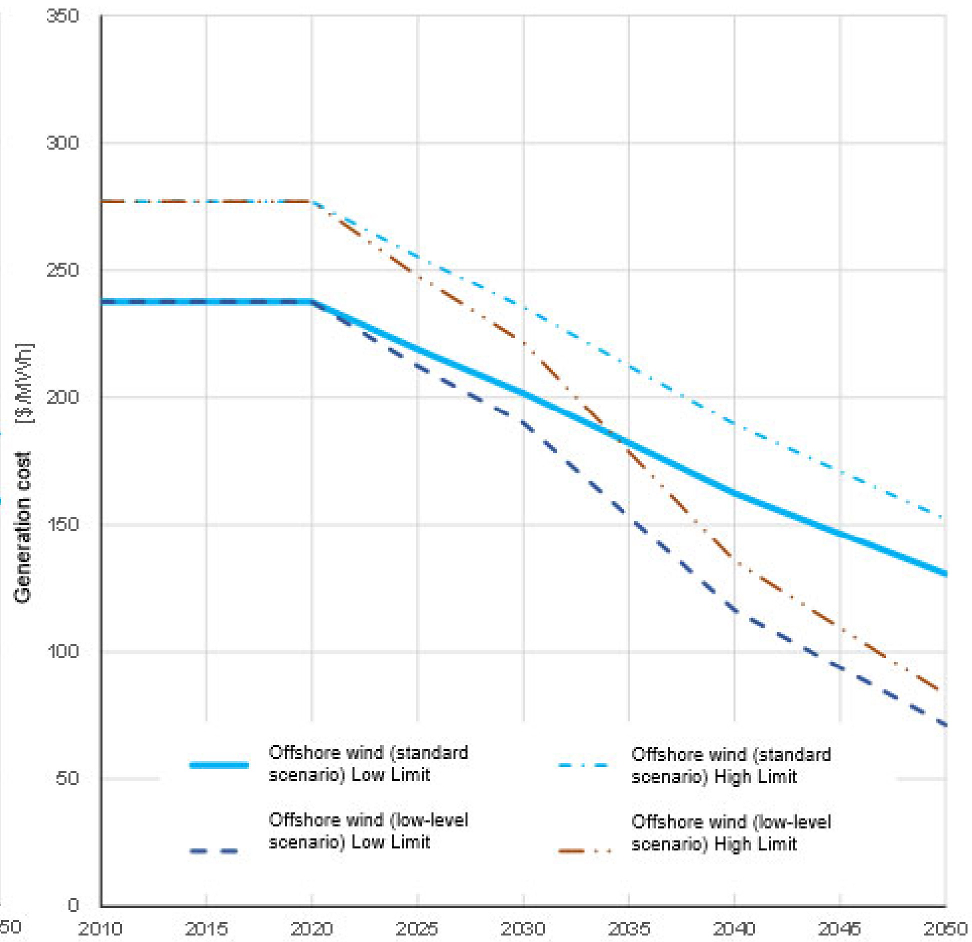
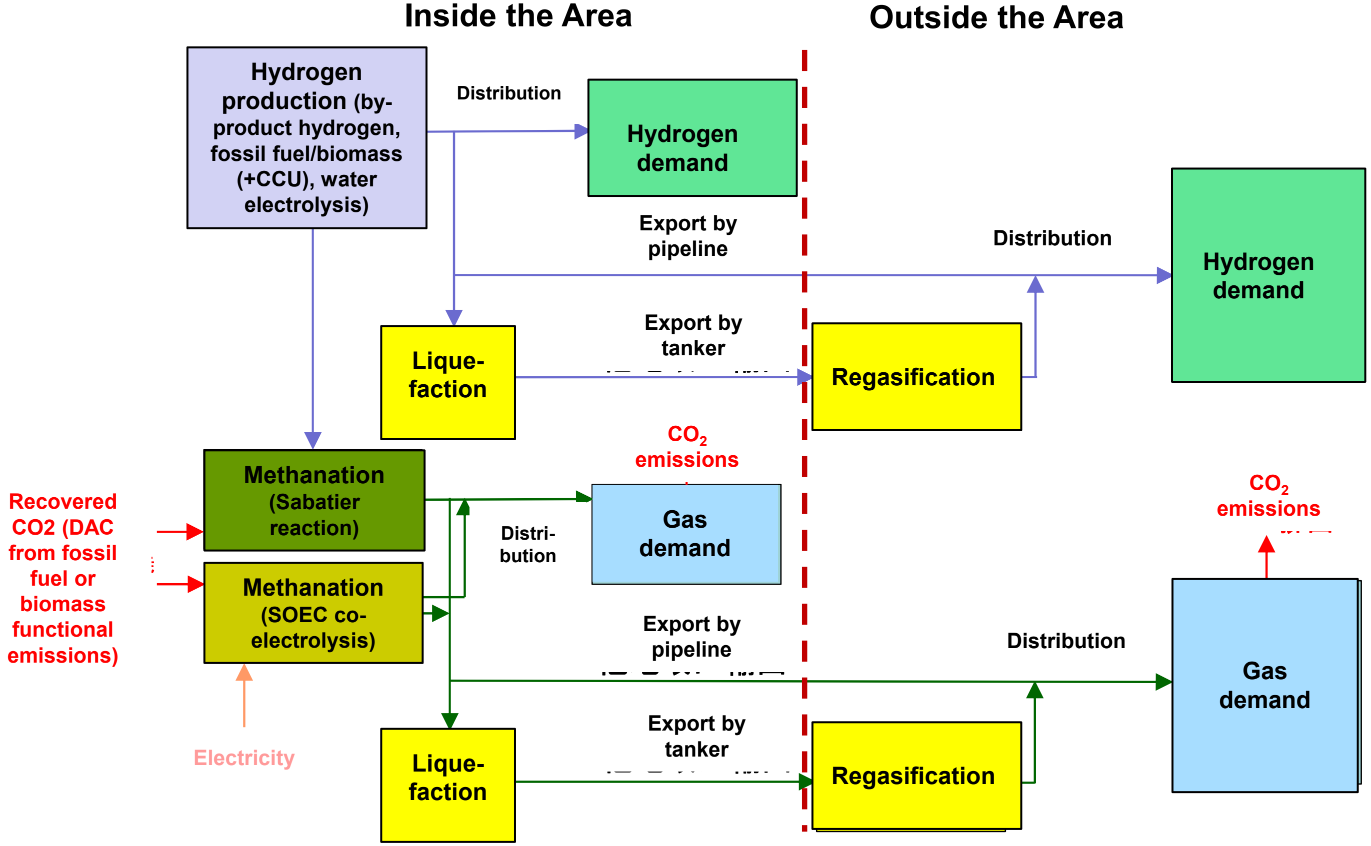


Modeling of Synthetic Methane (Methanation)



- ✓ **Hydrogen is not limited to renewable energy hydrogen (e-gas). The most economical one is selected according the assumed scenarios.**
- ✓ **Recovery CO2 can be obtained from fossil fuel or biomass combustion emission, or by DAC. The most economical one is selected according the assumed scenarios.**

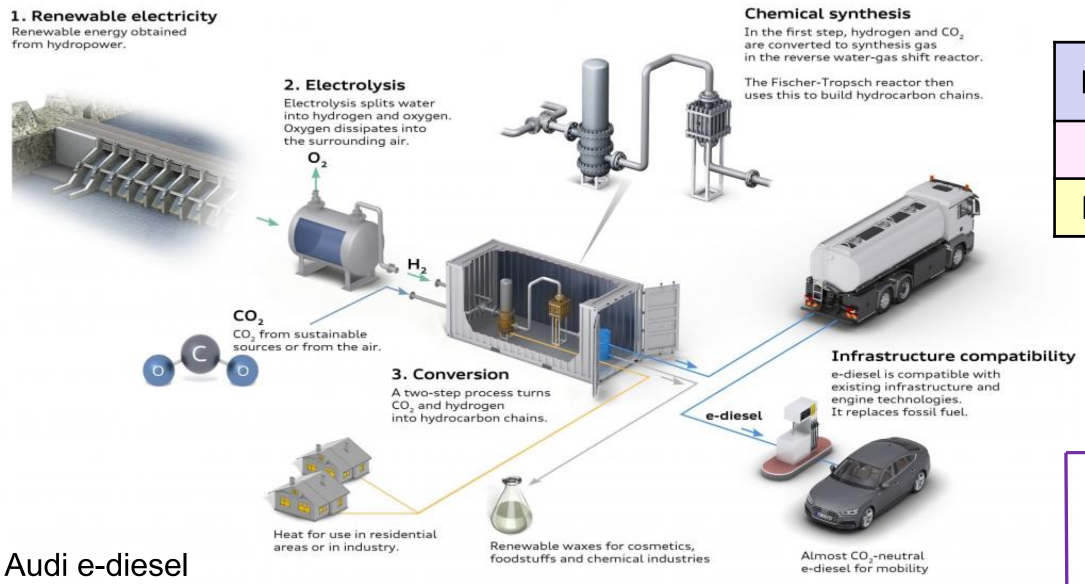
Note) In this analysis in order to provide incentives to use of synthetic fuels for the countries that use the fuels, CO2 emissions are not recorded in the countries that use them, but in the countries that produce them.

Balance in Methanation（Assumption in 2050）

Sabatier reaction	Hydrogen	1.22 toe	⇒	**Methane**	1 toe
	CO_2	2.33 tCO2			
SOEC co-electrolysis	Electricity	15.7 MWh (=1.35 toe)	⇒		
	CO_2	2.33 tCO2			

Modeling of Synthetic Oil

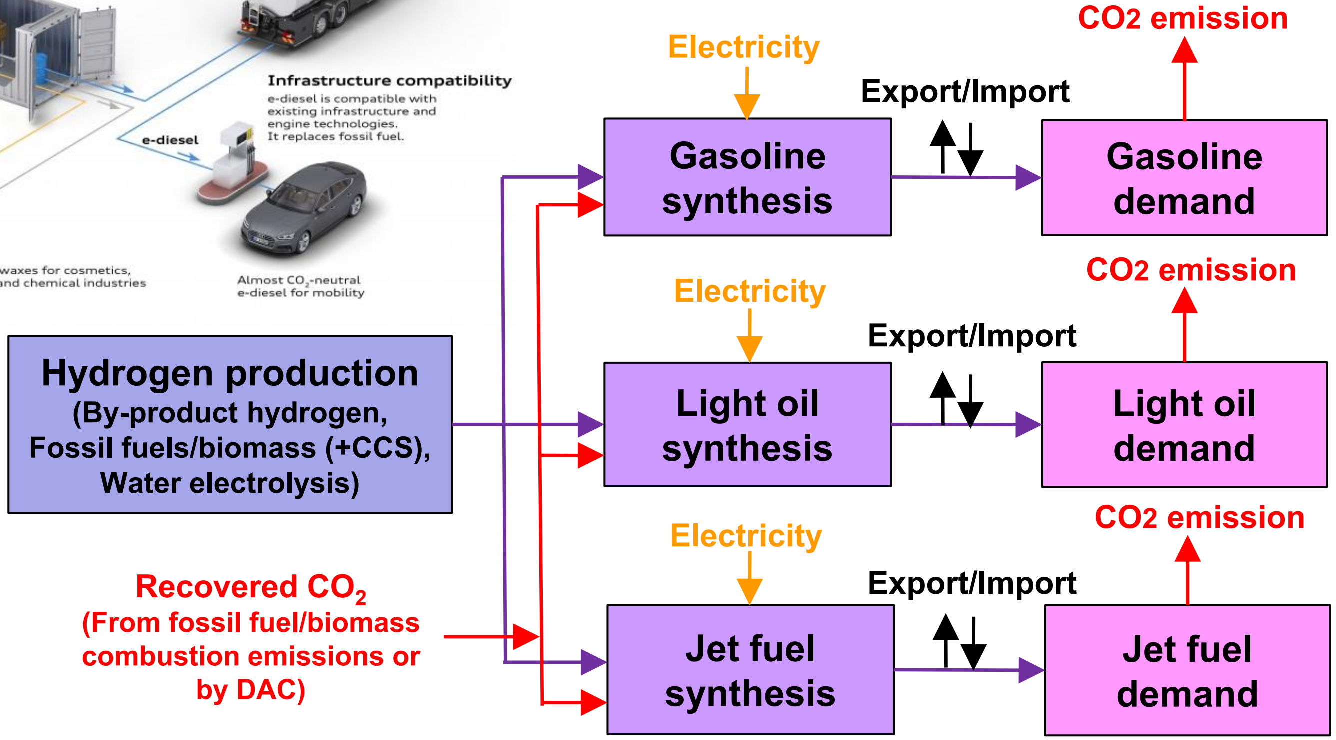
- ✓ **Hydrogen is not limited to renewable energy hydrogen (e-liquid). The most economical one is selected according to the assumed scenarios.**
- ✓ **Recovered CO_2 can be obtained from fossil fuel / biomass combustion emissions or by DAC. The most economical one is selected according the assumed scenarios.**



Audi e-diesel

Balance in synthetic oil generation in 2050

Hydrogen	1.25 toe	⇒	Synthetic oil	1 toe (Available energy: 0.71 toe)
CO_2	3.02 tCO2			
Electricity	0.02 toe			

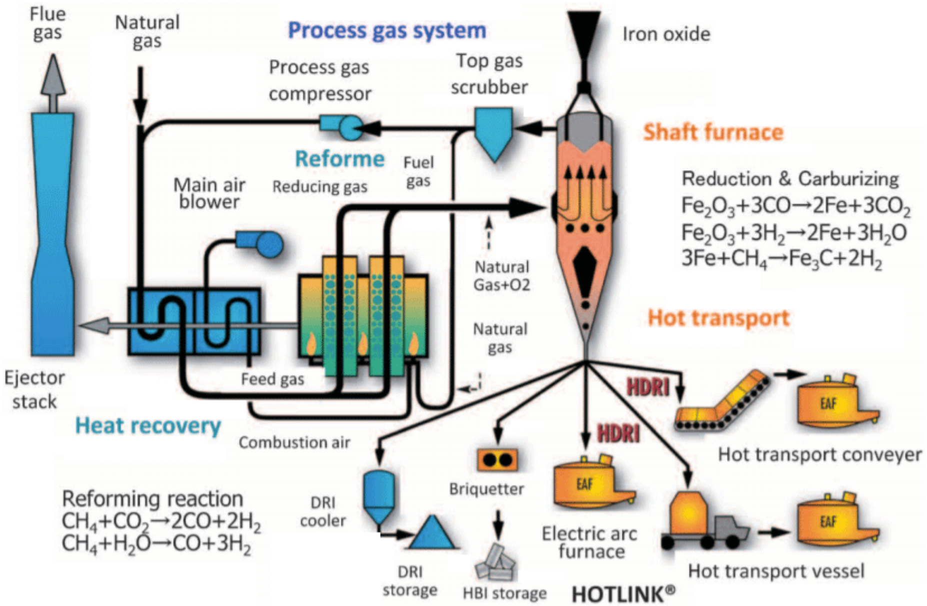


Note) In this analysis in order to provide incentives to use of synthetic fuels for the countries that use the fuels, CO2 emissions are not recorded in the countries that use them, but in the countries that produce them.

Modeling and Assumption of H2-based DRI process

- ✓ **The fuel used for existing direct reduced iron (DRI) production is natural gas, etc. (see left Fig).**
- ✓ **H_2-based DRI is a process that replaces fuel with hydrogen (see right Fig).**
- ✓ **DNE21+ assumes a set of integrated processes up to EAF and hot rolling in addition to the H_2-based DRI process [capital cost: 438.1$/(t-cs/yr), H_2 consumption: 12.1GJ/t-cs, power consumption: 695kWh/t-cs]**
- ✓ **In the H_2-based DRI acceleration scenario, it is assumed that new construction will be possible from 2031 (after 2040).**

Example of gas-based DRI making process



J. Kopfle et al. Millenium Steel 2007, p.19

Demonstration plant for H_2-based DRI

https://www.midrex.com/
https://www.kobelco.co.jp/releases/1201993_15541.html

Co-Generation System (CGS) Assumption

Facility Cost ($/kW, Price in 2000)

	2015	2030	2050
Industry (equivalent to 5 MW)	1250		
Business 1 (1-2 MW)	1875		
Business 2（0.5MW）	2500		
Household（PEFC/SOFC）	15167	3575	3575

Note) The listed price is the price in 2000. The US consumer price index is 1.46 in 2015 if year 2000 is 1.

Efficiency Assumption (LHV%)

		2015	2030	2050
Industry (equivalent to 5 MW)	PGE	49.0	51.0	54.5
	HRE	36.2	34.8	31.2
Business 1 (1-2 MW)	PGE	42.3	47.5	50.7
	HRE	36.2	31.0	27.8
Business 2（0.5MW）	PGE	41.0	44.0	47.0
	HRE	34.0	31.0	28.0
Household（PEFC/SOFC）	PGE	39.7	47.8	55.0
	HRE	55.3	45.0	37.8

Note) PGE = Power Generation Efficiency, HRE=Heat Recovery Efficiency

Vehicle and Fuel Costs Assumptions: Compact Cars (Example)

Vehicle Cost

	2015	2020	2030	2050
Conventional internal combustion engine	170	170	180	185
Hybrid (gasoline)	210	209	202	201
Plug-in hybrid (gasoline)	270	248	219	210
Pure electric (EV)	311	305	265	225
Fuel cell (FCV)	598	514	388	244

*1-million JPY per vehicle

Fuel Cost（Equivalent to catalog value）

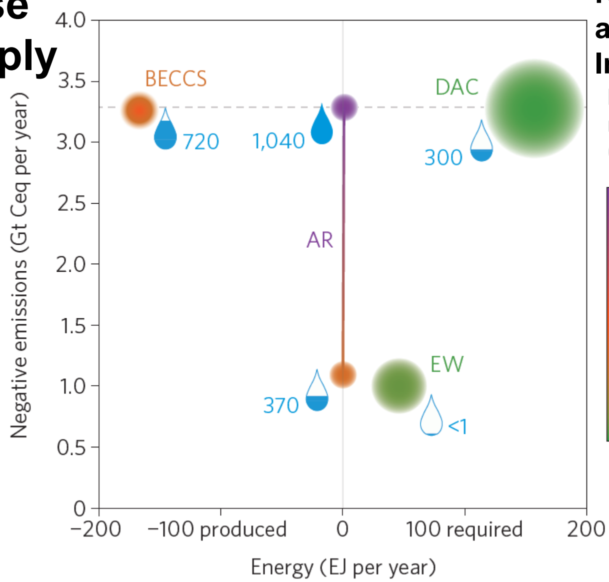
	2015	2020	2030	2050
Conventional internal combustion engine	12.7	13.0	13.5	14.1
Hybrid (gasoline)	31.0	32.2	34.9	36.3
Plug-in hybrid (gasoline)	57.9	59.0	61.3	62.2
Pure electric (EV)	80.1	88.5	101.7	106.6
Fuel cell (FCV)	41.3	43.9	49.6	55.0

*km per liter

Assumption for Direct Air Capture (DAC)

- DAC is a technology to capture atmospheric CO_2 at low level of about 400ppm, requiring more amounts of energy than capturing exhaust gas emissions from fossil fuels combustion.
- On the other hand, DACCS (up to storage) can achieve negative emissions.
- It is economical to deploy in area close to CO_2 storage and where energy supply is available at low cost such as low cost PV.

Climeworks



Required energy (horizontal axis), Land areas (color), Investments (circle size) etc.

EW: Enhanced weathering
AR: Afforestation and reforestation

Smith et al. (2015)

Assumed energy consumption and facility costs of DAC in 2020 based on M. Fasihi et al., (2019):

This analyses adopt "Conservative" among 2 scenarios, "Base" and "Conservative", by Fasihi et al.

		Energy consumption（/tCO2）		Facility costs（Euro/(tCO2/yr)）	
		2020	2050	2020	2050
High temperature (electrification) system (HT DAC)	Elec. (kWh)	1535	1316	815	222
Low temperature systems （LT DAC）: use of hydrogen or gas for heat	Heat (GJ)	6.3 (=1750 kWh)	4.0	730	199
	Elec. (kWh)	250	182		

Assumption of Implicit Discount Rate in Investment

Assumption of implicit discount rate in technology selection

		Medium scenario (SSP2)
Power generation		**8%** ～ 20%
Other energy transition		**15%** ～ 25%
Energy intensive industry		**15%** ～ 25%
Transportation	Automobile	**30%** ～ 45%
	(Environmental purchasing layer)	**10%**
	Trucks, buses, etc.	**20%** ～ 35%
Consumer (business / home)	Cogeneration	**15%** ～ 25%
	Hot water supply, air conditioning, etc.	**20%** ～ 35%
	Refrigerator, lighting, etc.	**25%** ～ 40%

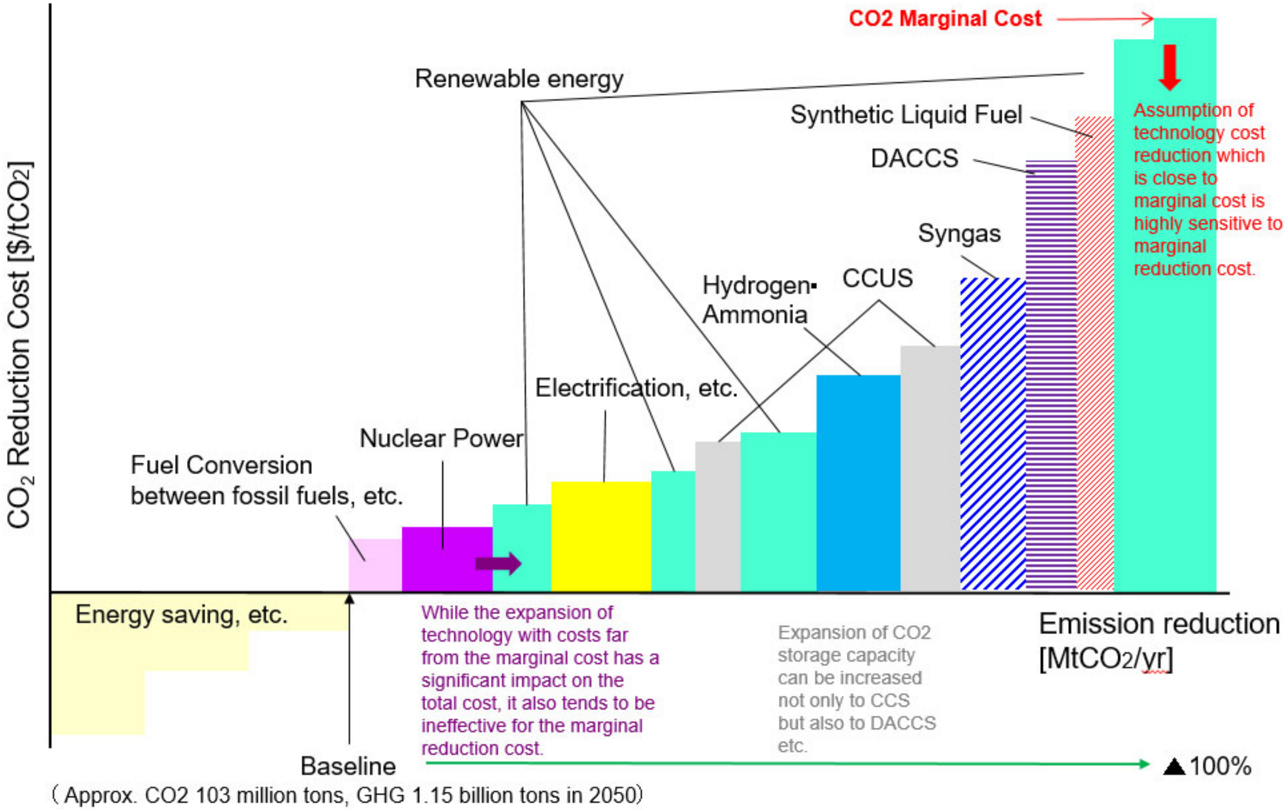
Note 1) Assumed within the range described by region and time point according to GDP per capita. Japan has a lower limit (deficit) regardless of the time point

Note 2) Countries with high investment risk (with low GDP per capita) tend to have high investment discount rates and because energy and basic materials are universal products, equipment depletion rate is low, resulting in low investment discount rate. On the other hand, the implicit discount rate for purchasing products tends to be high in the transportation and residential & commercial sectors which has the rapid changes in products due to the high depletion rate of equipment.

Note 3) e.g., in power generation, 8.2% / yr is used as WACC in the Net CONE calculation of the capacity market in the US PJM. In the UK National Grid, 7.8% / yr is used and it is consistent level with the 8%/yr of Japan, US, Europe, etc. of the power generation sector.

【ref.】Marginal Abatement Cost & Total Energy System Cost

※ The cost curve is illustrated as an image (in reality, it is complicated due to the correlation between technologies)



[Area cost]：
[▲100%Total Energy System Cost]－[Baseline Total Energy System Cost]

	Energy System Cost*1 (billion US$/yr)	
Reference case	1179	—
1.Renewable Energy 100%	1284	(+106)
2.Renewable Energy Innovation	1142	(-37)
3.Nuclear Power Utilization*2	1166～1133	(-13～-45)
4.Hydrogen Innovation	1160	(-19)
5.CCUS Utilization	1150	(-29)
6.Case where demand decreases due to car sharing	909	(-270)

*1：Numbers in parentheses are fluctuations from the reference
*2：Nuclear utilization scenarios represent results from 20% and 50% nuclear ratios

CO_2 Marginal Abatement Cost in Japan

	CO_2 Marginal Abatement Cost in 2050 [US$/t$CO_2$]
Reference Case	525
1. RE100	545
2. RE Innovation	469
3. Nuclear Energy Utilization*	523～503
4. Hydrogen Innovation	466
5. CCUS Utilization	405
6. Demand Transformation	509

* Nuclear power utilization scenarios show results under a nuclear power ratio of 20% to 50%

Marginal Cost of Electricity in Japan

	Marginal Cost of Electricity in 2050 [US$/MWh]
Reference Case	221
1. RE100	485
2. RE Innovation	198
3. Nuclear Energy Utilization*	215～177
4. Hydrogen Innovation	213
5. CCUS Utilization	207
6. Demand Transformation	221

* Nuclear power utilization scenarios show results under a nuclear power ratio of 20% to 50%

Note) The electricity marginal cost of model estimation in 2020 is 123 US$/ MWh.

World CO_2 Marginal Abatement Cost in 2050：Comparison with Japan

	Reference Case	RE Innovation Case
Japan	525	469
US	167	138
UK	181	141
EU	211	169
Others	162	138

[US$/t$CO_2$]

Note: CO_2 marginal abatement costs are not the marginal costs of electricity but are those of whole energy systems, and they are determined by the industrial structure, potential economic outlook, the potential availabilities of decarbonization technologies such as renewables, CCS and nuclear power.

✓ **Japan has a high CO_2 marginal abatement cost due to its low-cost renewable energy potential and low CCS potential.**

World Marginal Cost of Electricity in 2050: Comparison with Japan

	Model Estimated Value in 2020	Reference Case	RE Innovation Case
Japan	123	221	198
US	57	99	87
UK	99	201	176
France	110	160	147
Germany	115	188	164
Northern Europe	79	127	111

[US$/MWh]

Note 1: The costs exclude power transmission and distribution costs but include grid integration costs of VRE.
Note 2: The analyses consider the grid integration costs of VRE for Japan based on the estimations of the IEEJ model, while those for other countries are assumed by the original simple assumptions of DNE21+ model. Therefore the cost comparisons between Japan and other countries will not be appropriate, and rather it will be better to compare with the costs in 2020 within each country.

- ✓ **The marginal cost of electricity is increasing in each country to realize carbon neutrality. However, the increase in Japan tends to be larger than in other western countries.**