An Evaluation of CO2 Emission Reduction by EV and FCV Introduction Considering Stable and Economical Power System Operation

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Abstract:

To reduce CO_2 emissions in transport sector, it is a hopeful way to replace gasoline vehicles (GV) by electric vehicles (EV) and fuel cell vehicles (FCV). However, the reduction is largely affected by CO_2 emission intensity of power system and the way to make hydrogen. Authors simulate a power system in 2030 where a large amount of PV is implemented and 16% of PV generated energy must be curtailed. The annual cost is minimized by optimizing the hourly output of coal fired and LNGCC plants, when the 16% of passenger GV mileage is replaced by EV charged at midnight and/or daytime. In FCV case, the capacity of water electrolysis and hydrogen tank, and the hourly electrolysis output as well as thermal power output are optimized. Results show CO_2 emissions decrease particularly when EVs are charged at daytime using a part of surplus PV energy and the charging power is controlled to contribute frequency stability. The electrolysis demand decreases the PV energy curtailment but increases the CO_2 emission because of the lower energy converting efficiency and higher facility cost. Constraint conditions of the minimum ratio of non-synchronous generation and frequency control ability affect the results too.

Keywords:

CO_2 emission, Economic evaluation, Electric vehicle, Fuel cell vehicle, Operation optimization.

1. Introduction

Out of Japan's total CO_2 emissions in FY2017, emissions from automobiles were 176 million tons, 15.4%. A Japan's government committee targets to achieve 80% reduction of greenhouse gas emissions per km of travel by 2050 (90% for passenger cars) by increasing the ratio of "electrified vehicles" including electric vehicles (EV), plug-in hybrid vehicles (PHV), hybrid vehicles (HV), and fuel cell vehicles (FCV), up to 100% of existing passenger cars. And a government's report on long-term plan for energy supply and demand assumes ratios of HV, EV+PHV, and FCV, to reach 29%, 16%, 1% of existing cars in 2030 respectively.

Reducing CO_2 emissions in power generation and in hydrogen production is as important as replacing conventional cars with EVs, PHVs, and FCVs. So, raising the ratio of non-fossil power sources and boosting CO_2-free hydrogen production must be promoted.

Currently, the capacity of photovoltaic power generation (PV) has been greatly increased particularly in Kyusyu area in Japan because of feed-in tariff (FIT). The PV output curtailment has been common in Kyusyu on days when the electric power demand is small and the weather is fine, in order to avoid excess power generation and shortage of frequency adjustment power. This curtailed PV and wind energy ratio will increase significantly in the future. The CO_2 emission and fuel consumption in thermal power can be reduced by using this surplus energy for EV/PHV charging and hydrogen production for FCV by water electrolysis. If the amount of power for charging and water electrolysis is controlled quickly so as to compensate for short-period fluctuations in PV and wind power, the operation of thermal power and pumped hydro for load frequency control (LFC) can be reduced, and costs and CO_2 emissions can be cut back further.

This paper sets a situation where a large amount of PV is introduced to Kyushu in 2030 and 16% of PV generated energy get curtailed. In such a situation, 16% of the annual mileage of passenger gasoline vehicles (GV) in Kyushu will be replaced by EVs and PHVs. In addition to charging at midnight, CO_2 reduction in the case of charging a commuter car at office or a non-commuter car at home in the daytime is quantitatively evaluated. In addition, in a scenario in which a certain number of FCVs is introduced, the total capacity and the operation pattern of water electrolysis to secure the required amount of hydrogen are optimized, and then the volume of CO_2 emission is evaluated. By fixing the amount of service, annual automobile mileage, and economically optimizing the "energy chain" from the service to the fuel (gasoline, coal and liquified natural gas (LNG)), the total CO_2 emissions from vehicles and power generation plants are evaluated.

Szinaia et al. [1] showed "smart" PHV charging lowered grid costs and renewable energy curtailment relative to unmanaged charging. Nishimura et al. [2] calculated CO_2 emissions for each introduction scenario of passenger EVs in Japan by 2050. Osawa et al. [3] evaluated the PV self-consumption ratio at houses with EVs and the reduction amount of CO_2 emission by "Vehicle to Home" (V2H). In these studies, the CO_2 emission intensity of the power system is set to a constant value for a year, but Komiyama et al. [4] calculated CO_2 emissions repeatedly by linking the power generation mix optimization model and the EV penetration model, and showed that when the share of EVs and PHVs reaches 10%, CO_2 emissions can be reduced by about 15 million tons in Japan. In this study, the effect of output change in power generation types corresponding to the power demand change including the EV/PHV charging is considered, but the charging time is limited to midnight.

On the other hand, many papers [5-10] evaluated hydrogen costs produced via electrolysis using surplus renewable energy, particularly wind power and/or off-peak power. Shibata [11-12] found that even if the surplus of renewable energy could be procured free of charge, the capacity factor of the electrolysis system would be low and the cost would be high, so that it is a practical way in the short term to use also stable grid power, and to manage electrolysis output in order to participate in the frequency regulation market. In the long term, significant cost reduction and large-scale introduction of renewable energy will generate a large amount of inexpensive surplus electricity, allowing renewable energy providers and hydrogen producers to coexist. Yamamoto et al. [13] estimated the cost of transporting hydrogen to a metropolitan area 1000 km or 100 km away from a wind farm by pipeline, and showed that the cost is high. Papers [14-15] evaluated the conditions under which the co-firing of hydrogen produced by the surplus renewable power with LNG becomes economical. Those conditions are the strict CO_2 emission upper limit, the cost reduction of hydrogen production/storage system, and a large amount of renewable energy curtailment. It is fairly difficult to realize an economical hydrogen system, because energy is lost at each stage of production, transportation, storage and utilization.

Authors have evaluated the economics and environmental performance of the "energy chain" including the fuel, conversion and transportation with loss, while fixing the final demand or service every hour. The evaluation [16] of the case where PV and storage battery are installed at customer side, shows that the self-consumption rates of PV generated energy increase and most of curtailment can be prevented, so that the CO_2 emission can be reduced. However, it is also found that by levelling the load, the capacity factor of coal-fired generation units with lower fuel unit cost is increased, and the capacity factor of the LNG combined cycle (LNGCC) units is reduced, thereby offsetting a part of the CO_2 reduction. In addition, we [17] evaluate the effect of introducing a CO_2 reduction surcharge that is paid in proportion to CO_2 emissions instead of a FIT surcharge in proportion to the used amount of grid power energy. As a result, when battery energy storage systems are used together with a CO_2 reduction surcharge of about 10,000 yen/ton-CO_2 or more, that is almost equivalent to the FIT surcharge (3 yen/kWh now), a significant amount of CO_2 can be reduced, because the variable cost with this surcharge of LNGCC is lower than that of coal-fired generation and storage battery can raise the utilization rate of surplus renewable energy.

In this paper, instead of stationary storage batteries, EVs consume surplus PV generated power. But the EVs must be parked at places where they can be charged when the surplus may occur. Therefore, in addition to the case of midnight charging at home, we also evaluate the case where a half of the charging is demanded at workplaces or homes in the daytime. For daytime charging, LFC operation case that compensates for short-period fluctuations in renewable energy output is also studied. It is expected that the discharge of EV storage batteries (vehicle to home or building (V2H, V2B) will partially cover the power demand of houses or reduce the maximum power of buildings and factories as well as the kW charge. Since it is necessary to consider the extra costs for inverters and so on, and individual customer usage patterns of vehicles and power demands, the V2H and V2B are excluded from this study, and the EV connection with the power system is made only during charging.

We evaluate the case of using surplus renewable energy also for hydrogen production fueling FCVs. As CO_2-free hydrogen, there is a method of importing hydrogen produced by coal and CO_2 capture and storage overseas, and a method of producing it by water electrolysis with domestic renewable power generation output. The former requires the construction of large-scale infrastructure, and the cost and specifications are not clear. So only the latter, domestic production by electrolysis, is considered this time. When the water electrolysis system uses only the surplus electric energy of PV and wind power, the low capacity factor becomes a problem. There is also a method of producing hydrogen in wind farms that are not connected to the grid, but there is another cost issue to construct a network to distribute hydrogen to many fueling stations for FCVs. Therefore, we assume that hydrogen is produced at the fueling stations using the grid electric energy as a practical way. Then, the economical surplus renewable energy is expected to be used preferentially because calculated hourly electric energy costs are used for optimizing the hydrogen production schedule.

The setting on the power system side is based on one of the power generation mix that can be assumed in Kyushu area. Power generation outputs of coal-fired generation and LNGCC are optimized by linear programming every hour for one year, and changes in CO_2 emissions are analyzed. In spite of the simplified method, the starting cost, partial load efficiency, frequency adjustment ability in thermal power and pumped hydro power units, and PV and wind power output curtailment, etc. are also considered. Using the same method as the multi-mode generation mix optimization model [18] developed by the CRIEPI, the model WOPTIGEN [16] developed by Waseda University is used.

The purpose of this paper is to quantify the CO_2 reduction effect considering stable and economical power system operation when a certain amount of EV or FCV is introduced to the area with large PV generated energy surplus. The feature is that changes in gasoline, coal, and LNG consumption are analyzed with the energy chain, taking into account the hourly renewable energy curtailment and the optimized power generation configuration for a year.

2. Simulation method and condition setting

2.1. Objective function and power system setting

The objective function *OBJ* (yen/year) Eq. (1), the sum of annual cost equivalent to the facility cost of thermal power and water electrolysis system and fuel cost in Kyushu area, is minimized. The fixed costs of EV/FCV, charging equipment, and hydrogen fuelling stations other than water electrolysis system and hydrogen tanks, as well as the cost of power supply equipment other than thermal power, are not included in the objective function.

(Endogenous variables are shown as upper-case, and exogenous variables lower-case.)

$$OBJ = \sum_f \{fixc(f) \cdot CAP(f) + p(f) \sum_{t=1}^{8760} F\,(f,t)\} + fixc(e) \cdot CAP(e) + fixc(t) \cdot CAP(t) \quad (1)$$

where $F(f,t)$ fuel consumption (kWh) of fuel f between time *t*-1 to *t* :

$$F(f,t) = \sum_{mode} \frac{X(mode,f,t)}{\eta_{mode,f}} + \sum_{smode} u_{smode,f} \cdot X(smode,f,t) \tag{2}$$

f	Fuel type; Coal, LNG
$fixc(f)$	Annual fixed unit cost for thermal power, yen/MW
$fixc(e)$	Annual fixed unit cost for electrolysis system, yen/MW
$fixc(t)$	Annual fixed unit cost for hydrogen tank, yen/kg-H_2
$CAP(f)$, $CAP(e)$	Capacity of thermal power and electrolysis system, MW
$CAP(t)$	Capacity of hydrogen tank, kg-H_2
$p(f)$	Unit price of fuel *f*, yen/MWh
mode	Operation modes (load levels to rated power) of thermal power; 100%, 90%, 75%, 60%, 50%(LNGCC only), 45%(Coal only), 30%(Coal only)
smode	Start modes; cold-start, warm-start (LNGCC only), banking (LNGCC only)
$X(mode,f,t)$	Sending point generation output for each mode between time *t*-1 to *t*, MWh
$\eta_{mode,f}$	Partial load efficiency for each operation mode
$u_{smode,f}$	Fuel consumption for each start mode, MWh/MW
$X(smode,f,t)$	Capacity of each start mode between time *t*-1 to *t*, MW

Total capacity of LNGCC and that of water electrolysis system is optimized, and the installed capacity of other power sources is fixed as shown in Table 1. Assuming that coal-fired generation units will not be replaced and LNG-fired generation units without gas turbines can be replaced by LNGCC up to the optimum capacity, the lower limit of LNGCC capacity is decided by the capacity whose operation years are 40 years or less. Nuclear power is assumed to be abolished 40 years after the start of operation, and under the same conditions, the capacity of oil-fired generation units which will almost disappear in 2030 is set to zero. Transmission lines connecting other areas and Kyusyu area are not considered in order to keep secure power system operation. (There is only one route tie-line and too much power flow through this tie-line has a risk of frequency instability.)

Table 1. Total capacity setting of each generation type, MW.

Type	Nuclear	Coal	LNGCC	PV	Wind	Hydro	By-product gas
MW	2,360	4,349	2,825 or more	13,220	1,800	2,030	716

Type	Biomass	Fixed speed pumped hydro	Variable speed pumped hydro
MW	1,060	1,100	1,200

The capacity of renewable energy is set considering the capacity of already connected and applied or approved capacity to connect to the Kyusyu power grid, and set as total capacity in Japan matches to the target in FY2030. The hourly demand is based on the actual data in Kyushu area in FY2016, which is assumed to remain unchanged in FY2030. The hourly renewable power output pattern is set by proportional enlargement of actual output in FY2016 considering the difference between capacity in Table 1 and actual capacity in 2016.

There are many constraints including the matching of power demand and supply at every hour, operating reserve of 3% of the demand, hourly mode change pattern of thermal generation considering the output change speed (60%/hour to the rated power for coal-fired) and the minimum continuous stop hours (4 hours for LNGCC, 8 hours for coal-fired), monthly upper limit of hourly operating rate (thermal power: average 85% and 75 to 95% for each month, pumped hydro: one unit unavailable) considering periodic inspections and unplanned outages. As for the supply ability for operating reserve, the following are counted, the capacity of thermal power during operation, available capacity of pumped hydro, 30% of PV output, 0% of wind power, and output from other power sources at that time.

Another constraint is to secure LFC supply ability at every hour indicated in Eq. (3).

$$LFCSUPPLY \geq \sqrt{(\Delta PV)^2 + (\Delta Wind)^2 + (\Delta Load)^2 - (\Delta Allowance)^2} \quad (3)$$

We assume the "short-period fluctuation" ($\Delta PV, \Delta Wind, and\ \Delta Load$) whose frequency elements include several minutes to 20 minutes, is set to 10% of the hourly output of PV, 10% of the rated output of wind power, and 1.5% of load respectively. ΔPV and $\Delta Wind$ are decreased proportional to the curtailment rate. And $\Delta Allowance$ is set to 2.4% of the load. As for supply side, "$LFCSUPPLY$" is the sum of LFC ability of thermal and pumped hydro power units. The ability is decided by the operating capacity multiplied by the adjustment range shown at Table 2.

Table 2. Adjustment range for frequency control at each operation mode.

Type	Coal-fired			LNGCC		
Operation mode	100% load	90, 75, 60, 45%	30%	100%	90, 75, 60%	50%
Control range	±0%	±5%	±0%	±0%	±5%	±0%

Type	Fixed speed pumped hydro				Variable speed pumped hydro		
Operation mode	*Generation*			*Pump*	*Generation and Pump*		
(load level)	100%	80%	60%	100%	100%	80%	60%
Control range	±0%	±15%	±35%	±0%	±0%	±15%	±35%

The constraint Eq. (3) is not linear, but we adopt a linear approximation using 8 planes to apply linear programming. The sum of each operation mode is equal to the total capacity of each generation type. And mode shifts are limited such as a banking mode of LNGCC can shift only to warm-start mode or stop mode at next hour, and 30% load mode of coal-fired cannot shift to 100% load mode at next hour because of output change speed limit. In these manners, we avoid the mixed integer programming to solve the large unit commitment problem, and adopt linear programming using optimization tools, GAMS and CPLEX as a solver, to calculate it within a few minutes to one hour. (Refer to the report [18] in detail.)

In addition, another constraint is set so that the ratio of the inverter power supply to the total power output (SNSP: System Non-Synchronous Penetration) must be 50% or less. This adopts the same condition introduced in Ireland to avoid the large and quick frequency drop due to lack of inertia force after a severe accident.

2.2. Setting of vehicles

Table 3. Fuel efficiency and annual mileage settings.

Vehicle type	Fuel efficiency 2016 actual	Fuel efficiency 2030 estimate	Annual mileage, billion km Case 1	Case 2	Case 3
DE	4.55km/ℓ	(13.4% up) 5.15km/ℓ	14.3	14.3	14.3
GV	11.8 km/ℓ	(30% up) 15.5 km/ℓ	89.5	77.6	77.6
EV	-	4.97km/kWh	0	11.9	0
FCV	-	93.9km/kg-H_2	0	0	11.9

Table 3 shows the settings of fuel efficiency and total annual mileage in Kyusyu area. The annual mileage in FY2030 is assumed to be the same as in FY2016 shown at statistical report by the Government. The average fuel efficiency improvement rate is set according to the target made by the Government committees. In Japan, because diesel engine vehicles (DE) are mainly used as trucks, the fuel efficiency is low. The electric mileage is set to 0.8 times the WLTC mode value from the catalogue value of the "Nissan Leaf e+" considering air conditioner usage and the future technical improvement. The fuel efficiency of FCV is similarly set from the data of "Toyota MIRAI".

Table 4 shows simulation cases.

Table 4. Simulation cases

Case	Conditions	
Case1	GV and DE only, no EV, no FCV,	
Case2M	Midnight charge 100%	(13.3% of GV mileage is replaced by EVs)
Case2D	Midnight 50%, daytime charge 50%	(13.3% mileage by EVs)
Case2L	Midnight 50%, daytime charge 50% with LFC operation	(13.3% mileage by EVs)
Case3	Optimized H_2 production schedule with LFC operation	(13.3% mileage by FCVs)

The number of vehicles using liquified propane gas and compressed natural gas as fuel is considered to be zero because the number is small, and only GV and DE are used in Case 1, which is the case where electrified vehicles without HVs are not introduced.

According to the Government target, the penetration rate of EV and PHV is set to 16% of existing passenger cars in 2030. The electric mileage of the PHV varies greatly depending on the driving pattern, but in consideration of the maximum electric driving range, 68.2 km for the recent Prius PHV, which is sufficient for the average daily mileage, PHV is not distinguished from EV in this paper. In Case 2, 11.9 billion km equivalent to 16% of the annual total mileage of private passenger GVs in Kyusyu (13.3% of GVs including freight and commercial use) is replaced by EVs.

EVs are often recharged using timers during midnight at homes where time-of-use electric rate system is applied. Case 2M is a case where the electric energy required for daily driving is charged at flat level of power from 23 to 7 o'clock. The actual amount of charge for each vehicle varies widely, but the total amount is assumed to be the same every day.

Case2D considers that some rate of EVs used for commuting are charged at workplaces in the daytime, and non-commuting EVs are charged at homes with roof-top PV systems in the daytime. Energy of daytime charge is set to a half of daily required energy, which is charged flat from 23 to 7 o'clock and from 9 to 15 o'clock.

Case2L performs LFC operation for the daytime charge of Case2D. At this time, the average charging power for one hour should be 50% or less of the rated value, and high-speed power control within 90% of the average power is possible according to the command value from the transmission and distribution company. The hourly charging power is optimized as total thermal power cost is minimized under the condition that charging for one day travel is performed.

2.3. Setting of hydrogen production

The introduction target for FCV is not so big number in 2030, that makes the effect difficult to see. In Case 3, for the purpose of comparing the impact of the EV and FCV introduction, EV is set to zero and FCV is set to replace 16% of the mileage of private passenger GVs. The annual hydrogen production is set to 127,000 tons/year, capable of driving 11.9 billion km.

Table 5. Annual costs of hydrogen production system.

Equipment	PEM electrolyser	O&M	Hydrogen tank
(Initial cost)	(65,000 yen/kW)		(70,000 yen/kg-H_2)
Annual cost	7,620 yen/kW/year	1,311 yen/kW/year	150 yen/kWh/year

As the water electrolysis device, PEM type is adopted, whose output change speed is high, and suitable for LFC operation. Based on the target value [13] for 2030, annual costs are calculated on conditions of discount rate 3% and lifetime 10 years and shown in Table 5.

The electric energy consumption is set as shown in Table 6, based on the data in a previous demonstration project in Japan. In this project as well as this paper, hydrogen is produced by electrolysis using grid power at FCV fuelling stations, compressed to 70MPa, and cooled to avoid dangerous overheating when it is fuelled to FCV. At fuelling stations, it is assumed that there is a demand for the same amount of hydrogen filling every day and hour from 8 to 20 o'clock, and that tanks have a stock of half a day's demand at least. At 0 am on the first and end day of a year, tanks have a stock of half day demand. The tank capacity is optimized subject to this constraint.

Regarding the LFC operation of the water electrolysis device, when the power change width is ± ΔP (MW) and the average power for an hour P (MW), the constraints are Eq. (4).

$$\Delta P \leq 0.9\,(CAP\,(e) - P) \quad \text{and} \quad \Delta P \leq 0.9P \tag{4}$$

Table 6. Electric energy consumption for hydrogen production system. (kWh/kg/H_2)

Process	Electrolysis	Compression	Pre-cool	Total
Electric energy demand	50.4	3.12	1.02	54.54

3. Simulation results and discussion

3.1. CO_2 reduction by EV introduction

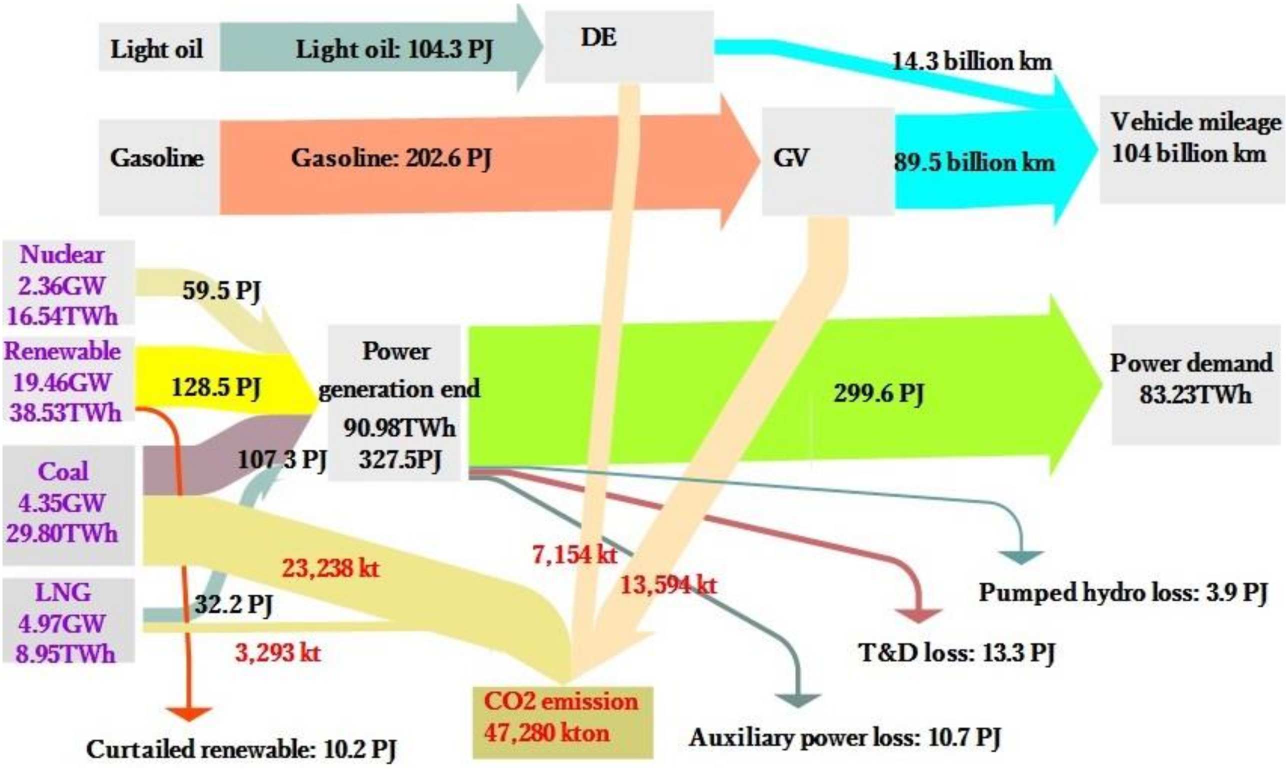


Fig. 1. Energy chain diagram for Case1 (No EV or FCV in 2030 in Kyusyu).

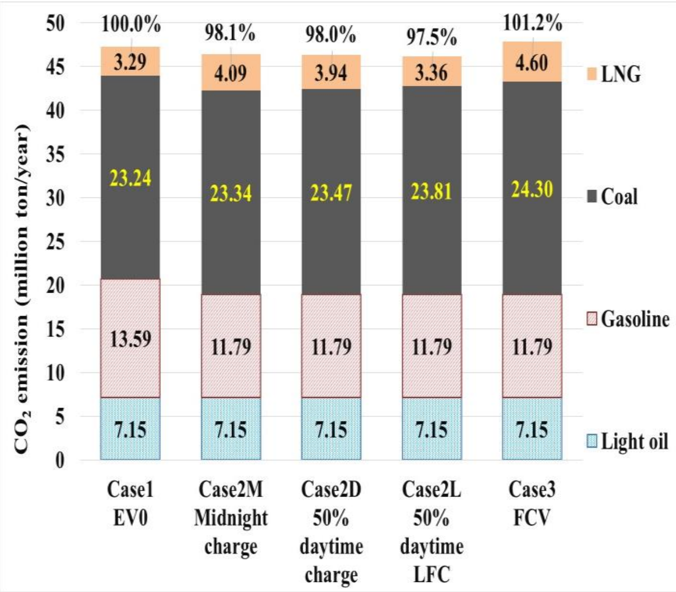
Fig. 1 shows the energy chain for the area of automobile and electricity in Kyushu in Case 1. For the sake of simplicity, thermal losses at generation plants and vehicles are not displayed, and the left end is the secondary energy. The amounts of secondary energy for vehicles and for electric power demand shown in PJ are roughly the same, and CO_2 emissions shown in kilo ton (kt) are also almost the same.

DEs include many large vehicles like trucks, so the mileage is about 1/7 of the whole car, but it accounts for 1/3 of CO_2 emission.

Looking at the power supply configuration, the 2.14 GW capacity of LNGCC must be added to the least capacity condition to secure the regulating power for the fluctuation made by a large amount of

13.22 GW PV, though the capacity factor of LNGCC is as low as 21%. Coal-fired generation is used as a base power source at 78% capacity factor, but the percentage of full power operation time is 62% for a year, and operated also at partial load in the daytime.

Fig. 2 shows the amounts of CO_2 emission by fuel types for each case and the relative amounts of total emission when the Case1 is the base. In Case1 shown in Fig. 3, the curtailed rate of PV generated energy is 16.1% and that of wind power is 3.1%.



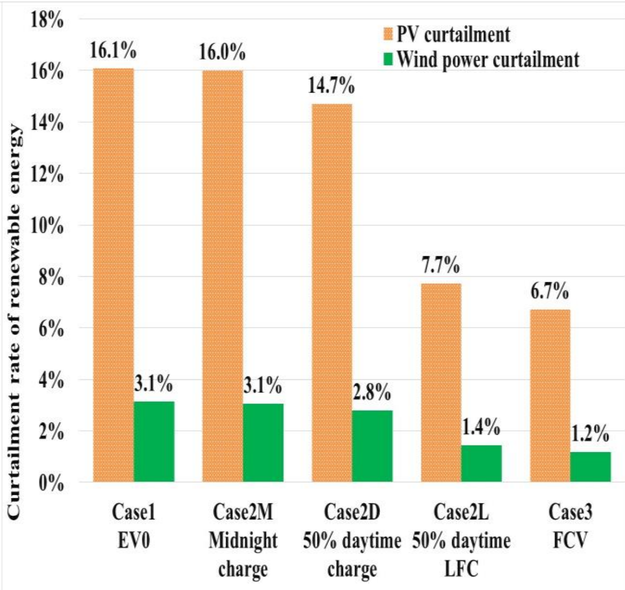
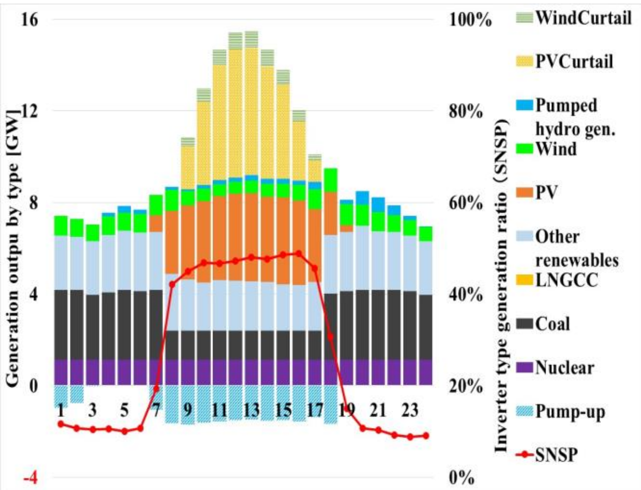


Fig. 2. CO_2 emissions by fuel types from vehicles and electric power demand.

Fig. 3. Curtailment rate of renewable energy.

In Case2, the emission from gasoline is reduced by 1.8 million tons, more than the increased emissions from coal and LNG which covers EV charging, so the total emission is reduced. In Case2D, the amount of PV and wind energy during the daytime charge seems to reduce the curtailment and CO_2 emission. However, the actual calculated curtailment rate shown in Fig.3 is nearly the same (about 10% reduction) as Case2M. It is because PV and wind power must be curtailed anyway in order to secure frequency adjustment power. In Case2L, by LFC operation during daytime charging, frequency adjustment power is secured, and the curtailment rate is about half that of Case1. As shown in Fig. 2, the emission from LNG is reduced, but the emission from coal is increased and partially offsets the total reduction of emissions.



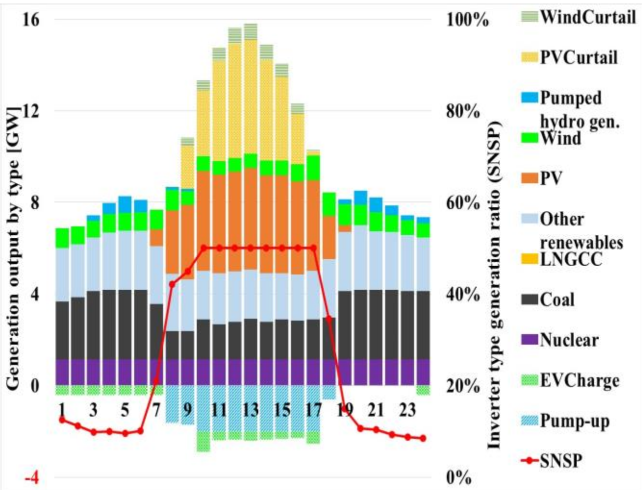


Fig. 4. Generation output on May 4(Case1).

Fig. 5. Generation output on May 4 (Case2L).

Figs. 4 to 5 show the power generation outputs by power sources in Case1 and 2L on May 4th, when it is a fine holiday with less power demand. On this day, LNGCC units are shut down all day, and coal-fired and pumped hydro generation units secure the regulating power. While PV power increases, in Case1, the coal-fired generation output is reduced to 45% of the rated output set to the minimum output that allows LFC operation. In Case2L, while a part of LFC is supplied by EV charging, the coal-fired output is increased a little bit, but about half power of PV is still curtailed. In Fig. 4, the inverter power supply ratio (SNSP) is 48.9% at maximum, but in Fig. 5, the upper limit of 50% is reached from 9 to 17 o'clock and so the PV output cannot be increased any more.

In other words, daytime EV charging with LFC operation can reduce CO_2 emissions as well as PV output curtailment to some extent, but for further reductions, some measures are required to increase the economics of LNG use instead of coal, and also to increase the LFC ability and inertia force which secure frequency stability. The former measures include the introduction of carbon pricing such as CO_2 reduction surcharge or tax and the latter include the increase of daytime power demand like EV charging, demand response and storage battery use with price incentives to increase the operating units of thermal power, or introduction of inverters with virtual synchronous generator function.

Fig. 6 shows the energy chain diagram of Case2L. Compared to Fig. 1, the small EV charge of 8.6PJ, compared to 26.9PJ for gasoline, indicates that EV efficiency is high. Approximately 9 PJ including loss to this EV charge, is covered by 5.7 PJ of increased renewable energy due to reduced output curtailment and increased generation of 2.8 PJ by coal and 0.5 PJ by LNG. As for CO_2 emissions, as shown in Fig. 2, part of the decrease from gasoline is offset by the increase from coal and LNG.

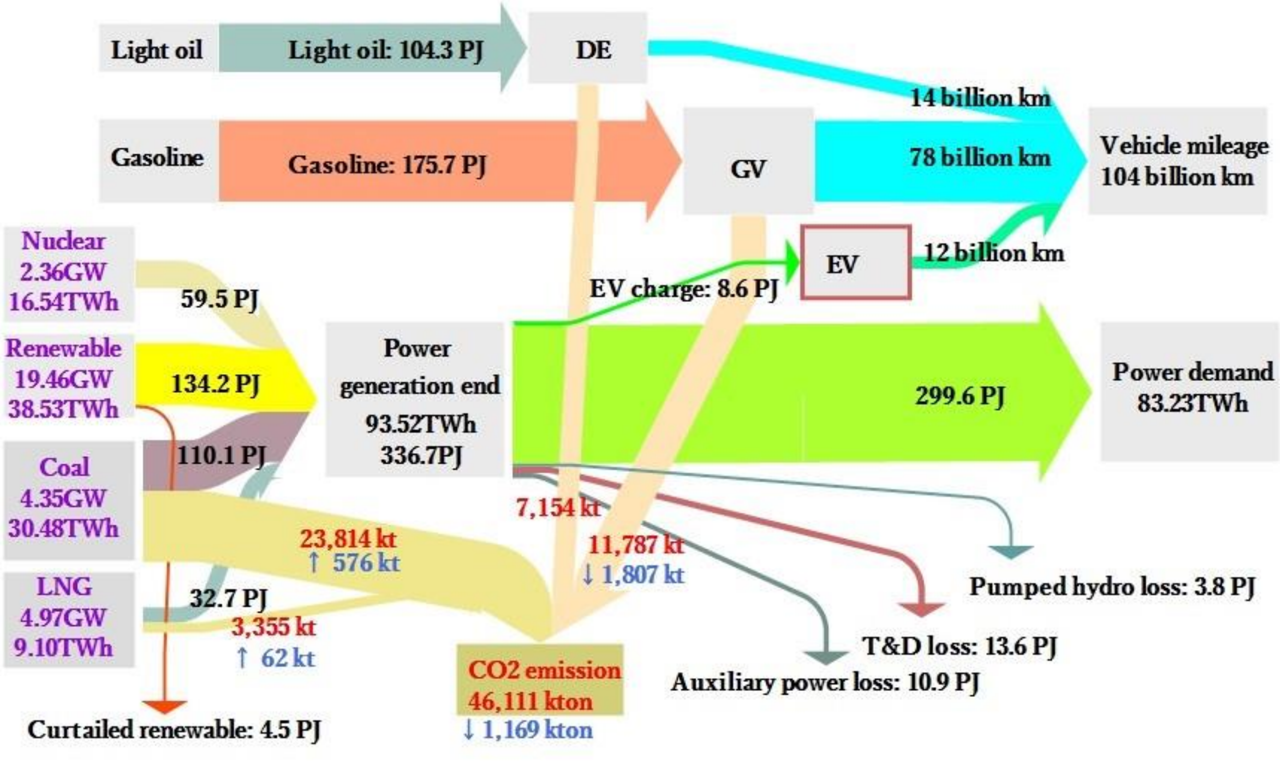


Fig. 6. Energy chain diagram for Case2L (50% daytime EV charge with LFC operation).

Table 7 shows the relative annual costs to the cost in Case2M, which is the optimized value of objective function Eq. (1), and LNGCC capacity. In Case2D, the LNGCC capacity has increased in response to the charging load from 9 to 15 o'clock. In Case2L, the additional facility investment is avoided by optimizing the hourly amount of charge, and also the fuel cost is reduced by increasing the use of surplus renewable energy. However, since the charging equipment cost is not included in Case2L, there is actually an increase in the cost for providing the LFC function. Case3 includes the cost of the water electrolysis system and hydrogen tank, but other costs, including labour costs and land costs for the hydrogen station, are likely to be more expensive than the charging equipment cost in Case2, so the cost of Case3 remains higher than Case2.

Table 7. Relative annual cost and LNGCC capacity (GW)

Case	Case2D	Case2M	Case2L	Case3
Annual cost	(base) 100%	99.9%	94.8%	111.1%
LNGCC capacity	4.966GW	5.536GW	4.966GW	4.966GW

3.2 CO_2 reduction by FCV introduction

As shown in Fig. 2, in Case3, FCVs run the same distance as the EVs in Case 2, the CO_2 emission slightly increases compared to Case1. The fuel consumption of the FCV in Table 2 divided by the total electric energy used for the water electrolysis system in Table 4 is 1.72 kWh/km, which is about three times the energy consumption of EV. In Case3, although the PV curtailment rate (Fig. 3) is reduced more than Case2L, emissions (Fig. 2) from coal and LNG increase because of the increase of total electric energy.

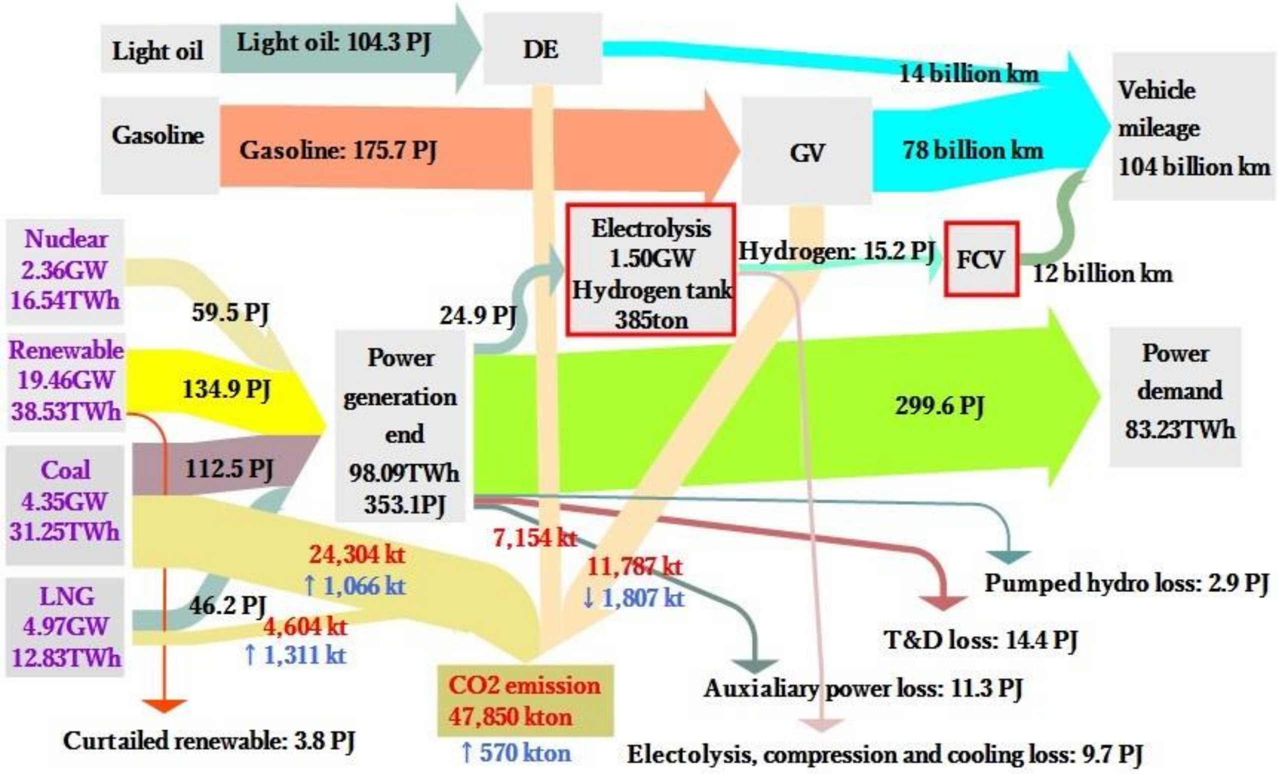


Fig. 7. Energy chain diagram for Case3 (FCV introduction instead of EV).

Fig. 7 shows the energy chain diagram for Case3. Compared to Fig. 1, the power demand for water electrolysis of 24.9 PJ plus transmission and distribution loss, etc., increases by 25.6 PJ. This is covered by 6.4 PJ renewable energy due to the avoided curtailment and the increased generation by coal 5.2 PJ and LNG 14.0 PJ.

The capacity of the water electrolysis system and hydrogen tank is the optimized result. The daily hydrogen demand is 347 tons, and the tank capacity is 385 tons, about 1.1 times the daily demand.

Though it is said that hydrogen is more suitable for long-term energy storage than storage batteries, results show that producing hydrogen every day by relatively small capacity system is more economical than increasing investment in hydrogen tanks and water electrolysis system to increase the use of surplus power.

The total curtailed PV energy is reduced to 1,029 MWh (3.8 PJ), which is smaller than the demand for water electrolysis of 7,219 MWh. (Both are values at sending end.) In Case3 as well as in Case2, restraints of LFC and SNSP play major role in the renewable energy curtailment, and for many hours in a year it is difficult to further reduce the curtailment. Therefore, the increased investment in hydrogen system to use surplus renewable energy is not economical.

4. Conclusions

When the power system is most economically operated when EVs or FCVs are penetrated in the area where 16% of the PV generated energy must be curtailed, the total CO_2 emission from automobiles and thermal power plants are quantitatively evaluated. Results show the following.

- The introduction of EVs and PHVs will reduce CO_2 emissions, but even if half of the charge is performed during the day, PV output must be curtailed to ensure frequency stability, and results are almost the same as midnight charge.
- By performing LFC operation to compensate the frequency fluctuation during daytime EV charging, PV output curtailment as well as CO_2 emissions are reduced. However, the curtailment is necessary to some extent for the stable power system operation, and increased thermal power output partially offsets the reduction of CO_2 emission.
- When FCVs using hydrogen by water electrolysis are introduced instead of EVs, CO_2 emission slightly increases compared to the case without FCVs. This is because energy conversion efficiency is low, inertia and LFC are limited, and equipment costs of water electrolysis and hydrogen tanks are high, and then the utilization rate of surplus renewable energy does not increase so much.

These results imply that it is important to introduce incentive policy, such as discounted electricity bill, to increase daytime EV charging with LFC operation. And to further decrease the CO_2 emission by introducing EVs, it is effective to increase the ratio of non-coal power generation by carbon pricing, etc. It is important not only to increase the amount of renewable energy and electric mileage, but also to take measures on the grid side, to secure the frequency stability.

Future tasks include the evaluation of the impact of V2H and V2B, the customer side economics, and evaluation at the national or global level. The introduction of large amounts of wind power may give a different evaluation from PV.

With this paper's setting, FCVs cannot be expected to reduce CO_2, but considering the complete reduction of CO_2 emissions in 2050, hydrogen use will also be necessary. Future issues include the usage of FCVs on long-distance trucks and other vehicles that are not suitable for EVs in terms of weight and cruising distance, and the evaluation of hydrogen production overseas.

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