Paper

CO_2 Emission Reduction and Primary Energy Conservation Effects of Cogeneration System in Commercial and Residential Sectors Considering Long-Term Power Generation Mix in Japan

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This paper proposes a comprehensive model to examine future CO_2 emission reduction and primary energy conservation through the installation of a cogeneration system (CGS) in commercial and residential sectors of Japan considering its long-term power generation mix. With the development of a CGS model and a long-term generation mix model on cost minimizing basis, Japan's prospective power generation structure is figured out and the potential of CO_2 emission reduction and primary energy conservation by a CGS is evaluated. With considerable uncertainty remaining concerning various assumptions made for the model analysis, following results are identified. (1) In all fuel price scenarios in power plants, the installation of CGS in commercial and residential sectors accomplishes the reduction of primary energy consumption. (2) In a standard fuel price scenario, the installation of CGS in commercial and residential sectors achieves the reduction of CO_2 emission. In a low fuel price scenario which is the case current fuel prices continue for the future, however, CO_2 reduction effect becomes decreasing compared to the standard fuel price scenario because of the dominant generation share of a LNG fired plant and a LNG combined cycle in future generation mix and these less carbon intensive plants replaced by CGS. In the case where nuclear power plant becomes competitive and increases its share in future generation mix, CO_2 emission from energy system conversely increases by installing CGS in comparison with before installing, because electric power generation of CGS gradually replaces a nuclear power plant. These results suggest that the CO_2 reduction potential by CGS introduction is cautiously evaluated taking into consideration the future power plant construction program in Japan.

Keywords: cogeneration system, long-term power generation mix model, primary energy conservation, CO_2 emission

1. Introduction

Final energy consumption on commercial and residential sectors in Japan had increased steadily over 1996∼2000 at the rate of 1.1% per year on average and CO_2 emission in these sectors also increased averagely at the rate of 1.3% per year [1]. This final energy consumption and associated CO_2 emission increasing tendency is likely to continue for the future due to the more extension of commercial buildings, which situation stems from the recent change of industrial structure and pursuing of convenient lifestyle in household sector. An important point is thus how to accomplish both primary energy conservation and CO_2 emission abatement in these sectors for the future.

In this paper, we adopt a cogeneration system (CGS) as a prospective key option for end-use energy conservation and CO_2 mitigation [2]. CGS, used as on-site power and heat generating devices, is expected to be installed increasingly into commercial and residential sectors in Japan, due to its high potential of energy conservation characteristics, resultant high economic performance and CO_2 emission reduction effect by its recent research and development. Since CGS, with increasing installed capacity in commercial and residential sectors, is on-site power generation facility, it is likely to replace utilities' power generation plants such as coal-fired, oil-fired and LNG-fired power plants in the future because end-use installation of CGS reduces electric power purchase by CGS equipped customers. CGS introduction consequently has an influence on the optimal planning of power generation mix in utility, which eventually changes both CO_2 emission and primary energy consumption in a power sector.

Against these backgrounds, the purpose of this paper is to develop a comprehensive model including both a long-term optimal power generation mix module and an end-use CGS module in order to evaluate the future trajectory of CO_2 emission and primary energy consumption through the installation of CGS in commercial and

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residential sectors of Japan. In a following section, the long-term generation mix model and the end-use CGS model are first described. Second, several simulation conditions and the evaluation method adopted here are presented. Finally, the evaluation method yields numerical results about primary energy consumption and CO_2 emission through CGS installation in commercial and residential sectors of Japan.

2. Model Structure

In order to evaluate CGS installation potential, we develop both a long-term power generation mix model and an end-use CGS model, the specifications of which are described as follows.

2.1 Long-Term Power Generation Mix Model

If end-use CGS installation increases in the future, utilities could escape constructing new capacity to satisfy electric power demand. Since CGS installation influences future utilities' power plant construction planning, it is, therefore, necessary to consider the future expansion program of power generating capacity in utilities. The fundamental purpose of this model is to determine how electric power industry will change its mix of generating capacity and electric power generation over forecast horizon.

This model uses linear programming (LP) formulation to identify planning decisions, capacity additions and retirements that are required to satisfy future growing demand and power plants' operational requirements [3]. It, concretely to say, simulates the least-cost planning of power plant construction and operation by selecting strategies for meeting expected future demand and complying with various technological constraints that minimize the discounted, present value of facility and operational costs. Planning horizon, the length of which usually influences the optimal result of LP model, is from 1990 to 2050 (number of year per one planning term is 5 years, planning terms are 13). In this model, planning decision is determined for each of nine electricity supply regions in Japan and interchanged electric power flows among nine regions are explicitly considered on the basis of inter-regional transmission constraints. Capacity additions and scheduled retirements of existing units that have been officially announced by utilities are also taken into consideration. In this model, it should be noted that lead-time for power plant construction is not explicitly considered. Decision making for power plant construction, hence, largely depends on its generation cost on the basis of cost minimizing optimization. In addition, the utilities assumed here do not include IPP (independent power producer) and PPS (power producer and supplier), the type of which utilities eventually denote general electric utilities in this paper.

The mathematical formulation of this model is represented in following Eqs. (1)~(16). The explanation of endogenous and exogenous variables is shown in Table 1 and input data shown in Table 2.

Table 1. Variables for a power generation best mix model

Dimensions:	
hr	: Time in a day (1~24)
m	: Total number of power plants (=7)
n_T	: Total number of planning terms (=13)
plt	: Power plant type
ptn	: Seasonal segmentation (summer peak, summer, winter, mid season, summer holiday, winter holiday ,mid season holiday)
r	: Electricity supply regions (Hokkaido, Tohoku, Tokyo, Chubu, Hokuriku, Kansai, Chugoku, Shikoku, Kyushu)
R	: Total number of electricity supply regions (=9)
t	: Year in planning horizon
TL_{plt}	: Lifetime of power plant plt
Endogenous variables:	
$EX_{t,r,ptn,hr}$	: Interchanged power in year t, region r, season ptn, time hr[kW]
$ST_{t,r,ptn,hr}$	: Storage power in year t, region r, season ptn, time hr [kW]
$X_{t,r,plt,ptn,hr}$	: Power generation in year t, plant plt, season ptn, time hr [kW]
$YN_{r,plt,t}$	: Newly-built capacity of power plant plt in year t [kW]
$YSUM_{t,r,plt}$	: Cumulative capacity of power plant plt in year t, region r [kW]
Exogenous variables:	
a_{plt}	: Construction cost of power plant plt [yen/kW]
$b_{plt,t}$	: Fuel unit cost of power plant plt in year t [yen/kWh]
$days_{ptn}$	: Number of days in seasonal segmentation ptn
$disc$	: Discount rate (=5%)
$D_{t,r,ptn,hr}$	: Transmission-end power demand in year t, region r, seasonal segmentation ptn, time hr [kWh]
$EU_{t,r,ptn,hr}$	: Import-export limit of interchanged power in year t, region r, seasonal segmentation ptn, time hr [kW]
$fdown_{plt}$	: Lower limit of load following factor of power plant plt
fup_{plt}	: Upper limit of load following factor of power plant plt
$FAC_{plt,ptn}$	: Utilization factor of power plant plt in seasonal segmentation ptn
$INEX_r$	: Identification of import or export of interchanged power flow in region r (import region = 1, export region = -1)
$LNGMAX_t$	: Upper limit of LNG consumption in year t [t]
$NUCUP$	: Nuclear construction upper limit (=70GW)
$YPLAN_{t,r,plt,t}$	: Planning capacity of power plant plt in year t, officially announced by utilities [kW]
α_{plt}	: Internal power consumption rate in power plant plt
$\beta_{LNG,LNGCC}$	: LNG consumption per power generation of LNG,LNGCC [t/kWh]
δ	: Spinning reserve margin (=5%)
γ_{plt}	: Annual expenditure rate of power plant plt
η_{pump}	: Storage efficiency
τ	: Number of years per one planning term (=5 years)

Objective function:

- Discounted system total cost:

$$TC=\sum_{t=1}^{n_T}\sigma_t\sum_{r=1}^{R}\sum_{plt=1}^{m}(Fix_{t,r,plt}+Fuel_{t,r,plt})\cdots\cdots(1)$$

$$\sigma_t=\left(\frac{1}{1+disc}\right)^{\tau(t-1)}\cdot\sum_{n=0}^{\tau-1}\left(\frac{1}{1+disc}\right)^{n}$$

- Fixed cost:

$$Fix_{t,r,plt}=a_{plt}\sum_{r=1}^{R}\sum_{\tau=1}^{t}\gamma_{plt}\cdot YSUM_{r,plt,\tau}\cdots\cdots(2)$$

Table 2. Input data for electric power plants [3] [4]

	Nuclear	Coal	IGCC	LNG	LNGCC	Oil	Pump
Construction cost [10^3yen/kW]	310	300	330	200	232	190	196
Fuel cost [yen/kWh]	1.7	5	5	18.9	18.9	10.6	-
Lifetime[year]	40	40	40	40	40	60	60
Thermal efficiency	-	37.80%	48.00%	38.60%	46.50%	39.00%	-
CO_2 emission intensity	-	0.618 kg-C/kg	0.618 kg-c/kg	0.746 kg-C/kg	0.742 kg-C/kg	0.788 kg-C/l	-

- Fuel cost:

$$Fuel_{t,r,plt} = b_{plt,t} \sum_{ptn=1}^{7} days_{ptn} \sum_{r=1}^{R} \sum_{hr=1}^{24} X_{t,r,plt,ptn,hr} \cdots\cdots (3)$$

Description of constraints:

- Hourly power supply-demand balance:

$$\sum_{plt \neq pump} X_{t,r,plt,ptn,hr} - X_{t,r,pump,ptn,hr} + INEX_r \cdot EX_{t,r,ptn,hr} = D_{t,r,ptn,hr} \cdots\cdots (4)$$

- Newly-construction and retirement concerning power plant capacity:

$$YSUM_{t,r,plt} = YSUM_{t-1,r,plt} + YN_{r,plt,t} + YPLAN_{r,plt,t} - YN_{r,plt,t-TL_{plt}} \cdots\cdots (5)$$

- Spinning reserve margin requirement:

$$\sum_{r=1}^{R} \sum_{plt=1}^{m} FAC_{plt,ptn} \cdot (1-\alpha_{plt}) \cdot YSUM_{t,r,plt} \geq (1+\delta) \sum_{r=1}^{R} D_{t,r,ptn,hr} \cdots\cdots (6)$$

- Power generation limit:

$$X_{t,r,plt,ptn,hr} \leq FAC_{plt,ptn} \cdot (1-\alpha_{plt}) \cdot YSUM_{t,r,plt} \cdots\cdots (7)$$

- Load following constraints:

$$X_{t,r,plt,ptn,hr+1} \leq (1+fup_{plt}) X_{t,r,plt,ptn,hr} \cdots\cdots (8)$$

$$X_{t,r,plt,ptn,hr+1} \geq (1-fdown_{plt}) X_{t,r,plt,ptn,hr} \cdots (9)$$

- Annual LNG consumption upper limit:

$$\sum_{ptn=1}^{7} days_{ptn} \sum_{r=1}^{R} \sum_{hr=1}^{24} (\beta_{LNG} \cdot X_{t,r,\ln g,ptn,hr} + \beta_{LNGCC} \cdot X_{t,r,gcc,ptn,hr}) \leq LNGMAX_t \cdots (10)$$

- Electric power availability for pumped storage:

$$ST_{t,r,ptn,hr} \leq \sum_{plt \neq pump} X_{t,r,plt,ptn,hr} \cdots\cdots (11)$$

- Input-output balance for pumped storage:

$$\sum_{hr} X_{t,r,pump,ptn,hr} = \eta_{pump} \sum_{hr} ST_{t,r,ptn,hr} \cdots (12)$$

- Interchanged electric power flow constraint:

$$\sum_{r=1}^{R} INEX_r \cdot EX_{t,r,ptn,hr} = 0 \cdots\cdots (13)$$

- Upper limit of interchanged electric power flow:

$$EX_{t,r,ptn,hr} \leq EU_{r,ptm} \cdots\cdots (14)$$

- Construction upper limit for oil-fired power plant:

$$\sum_{r=1}^{R} YSUM_{t,r,'Oil'} \leq \sum_{r=1}^{R} YSUM_{'1990',r,'Oil'} \cdots (15)$$

- Construction upper limit for nuclear power plant:

$$\sum_{r=1}^{R} YSUM_{t,r,'Nuc'} \leq NUCUP \cdots\cdots (16)$$

2.2 End-Use CGS Model Future supply planning decisions by CGS installed customers are determined with an end-use CGS module. Cogenerators considered in this paper consist of office, shop, hotel and hospital in a commercial sector, detached house and apartment in a residential sector. The planning decisions by cogenerators are mathematically formulated as linear programming which determines appropriate mix of various electricity and heat supply options and minimizes the objective function of the discounted, present value of fixed and variable cost satisfying expected future energy demand and energy supply balance requirements [5]. Planning horizon is from 1990 to 2050 (number of year per one planning term is 5 years, planning terms are 13) and we calculate CGS capacity in each of 46 administrative divisions of Japan. Mathematical expression is described in Eqs. (17)~(29). It is assumed that capacity installation by cogenerators is implemented when commercial associated building, detached house and apartment are refurnished or newly constructed.

Figure 1 and Fig. 2 show schematic diagrams of CGS investigated in this paper. CGS in a commercial sector is composed of gas engine, absorption refrigerator, heat

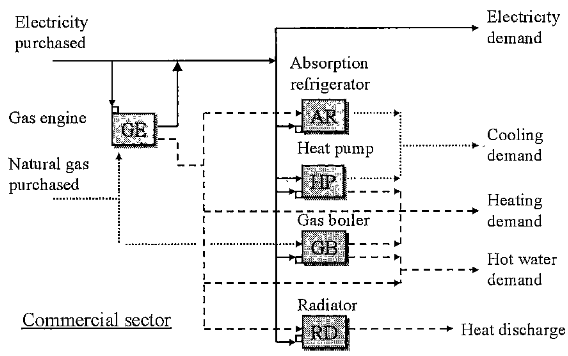

Fig. 1. Configuration of gas engine cogeneration system for a commercial sector

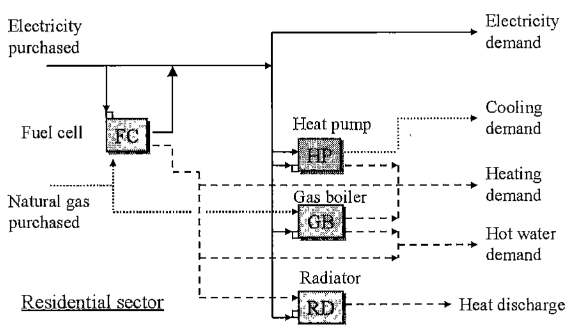

Fig. 2. Configuration of fuel cell cogeneration system for a residential sector

pump and gas boiler, and one in a residential sector consists of Polymer Electrolyte Fuel Cell (PEFC), gas boiler and heat pump.

Electricity is supplied to customers by operating gas engine or fuel cell unit and purchasing electricity from an electric power company. It also enables peripheral facilities (heat pump etc.) to drive. Exhaust heat generated from gas engine and fuel cell unit is assumed to be recovered in the form of hot water, supplying thermal energy in a cascade way. Cooling demand is supplied with absorption refrigerator and heat pump in a commercial sector, and only heat pump in a residential sector. Hot water demand is satisfied with recovered exhaust heat and gas-fired boiler. Radiator discharges surplus exhaust heat. In addition, we only take into consideration a natural gas CGS on the assumption that natural gas becomes more prospective primary fuel for the future.

Table 4 summarizes representative values of performance characteristics and the unit capital costs of pieces of equipment. Electric generation efficiency and heat recover efficiency are assumed to be constant with respect to the utilization factor of each facility. Concerning the data of fuel cell performance, which system is under development and has not actually and widely spread, we refer to the report published by IBEC (6). Energy purchase is according to the rate of Tokyo electric power company in electricity and that of Tokyo gas in city gas.

Objective function:

- Discounted system total cost:

$$TC = \sum_{t=1}^{n_T} \sigma_t \sum_{r=1}^{R} \sum_{c=1}^{SE} (CSM_{t,r,c} + CSE_{t,r,c}) \cdots (17)$$

$$\sigma_t = \left(\frac{1}{1+disc}\right)^{\tau(t-1)} \cdot \sum_{n=0}^{\tau-1} \left(\frac{1}{1+disc}\right)^{n}$$

- Fixed cost:

$$CSM_{t,r,c} = \sum_{m=1}^{M} MUP_m \cdot EXP_m \cdot YCSUM_{t,r,c,m} \cdots\cdots\cdots\cdots\cdots\cdots (18)$$

- Operational cost:

$$CSE_{t,r,c} = \sum_{ptn=1}^{7} \sum_{hr=1}^{24} \sum_{e=1}^{2} days_{ptn} \cdot EUP_{ptn,hr,e} \times PQ_{t,r,c,ptn,hr,e} + \sum_{ptn=1}^{7} \sum_{e=1}^{2} MONTHS_{ptn} \times \{FBS_{ptn,e} + BS_{ptn,e} \cdot Z_{t,r,c,e}\} \cdot (19)$$

Description of constraints:

- Energy generation constraint:

$$YCSUM_{t,r,c,m} \geq XC_{t,r,c,ptn,hr,m,out} \cdots\cdots\cdots (20)$$

- Newly-construction and retirement about energy-related facility:

$$YCSUM_{t,r,plt} = YCSUM_{t-1,r,plt} + YCN_{r,plt,t} - YCN_{r,plt,t-TL_m} \cdots\cdots\cdots (21)$$

Table 3. Variables for an end-use CGS model

Dimensions:

c	: Cogenerators (office, shop, hotel, hospital, residence)
d	: Each kind of demand (electricity, heating, cooling, hot water)
e	: Each kind of energy (1:electricity, 2:gas)
hr	: Time in a day (1～24)
io	: Energy input-output state (*in*, *out*)
m	: Energy supply facility (cgs [cgst:heat, cgse:electricity], boiler, heat pump, absorption refrigerator)
n_T	: Total number of planning horizon (=13)
p	: Energy flow (purchased elec., purchased gas, elec. demand, heating demand, cooling demand, hot water demand, CGS[elec.], CGS[heat], boiler, heat pump, absorption refrigerator, heat discharge)
ptn	: Seasonal segmentation (summer peak, summer, winter, mid season, summer holiday, winter holiday ,mid season holiday)
r	: Electricity supply region (each of 46 administrative divisions)
R	: Total number of electricity supply region (=46)
SE	: Number of kinds of cogenerators (=4)
t	: Year in planning horizon
TL_m	: Lifetime of CGS facility m

Endogenous variables:

$PQ_{t,r,c,ptn,hr,e}$	: Energy purchase quantity in year t, region r, cogenerator c, seasonal segmentation ptn, time hr, energy e [kWh,Mcal]
$SP_{t,r,c,ptn,hr}$	: Exhaust heat from CGS in year t, region r, cogenerator c, seasonal segmentation ptn, time hr [Mcal]
$XC_{t,r,c,ptn,hr,m,io}$	: Input or output energy in year t ,region r, cogenerator c, seasonal segmentation ptn, time hr, facilitiy m, state io [kWh,Mcal]
$YCN_{t,r,c,m}$	: Newly constructed capacity of facility m in year t, region r, cogenerator c [kW,Mcal/h]
$YCSUM_{t,r,c,m}$	: Cumulative capacity of facility m in year t, region r ,cogenerator c [kW,Mcal/h]
$Z_{t,r,c,e}$	: Energy contract quantity in year t, region r, cogenerator c, energy e [kW,Mcal/h]

Exogenous variables:

$BS_{ptn,e}$	:Energy demand charge in seasonal segmentation ptn, energy e [yen/kW/month, yen/Mcal/month]
$CF_{p,p',io}$	:Linkage coefficient between p and p'(connected:1,unconnected:0)
$days_{ptn}$	: Number of days in seasonal segmentation ptn
$disc$	: Discount rate (=5%)
EF_m	: Energy conversion efficiency of facility m
$EUP_{ptn,hr,e}$	: Energy charges in seasonal segmentation ptn, time hr, energy e [yen/kWh,yen/Mcal]
EXP_m	: Annual expenditure rate of facility m
$FBS_{ptn,e}$	: Energy customer charge in seasonal segmentation ptn, energy e [yen/month]
$MONTHS_{ptn}$	: Number of month in seasonal segmentation m
MUP_m	: Unit capital cost of facility m [yen/kW,yen/(Mcal/h)]
$PIPE_{t,r,c,ptn,hr,p,p'}$	: Enegy flow from p to p' in year t, region r, cogenerator c, seasonal segmentation ptn, time hr [kWh,Mcal]
$TFS_{t,r,c}$	: Flooring space in year t, region r, cogenerator c [m^2]
TR_m	: Conversion factor of facility m [kWh/Mcal,Mcal/kWh]
$UDM_{t,r,c,ptn,hr,d}$	: Energy demand per flooring space in year t, region r, cogenerator c, seasonal segmentation ptn, time hr, demand d [kWh/m^2,Mcal/m^2]

Table 4. Performance characteristics and unit capital cost of pieces of equipment

Facility	Performance characteristics	Unit capital cost
Gas engine	Electric generation efficiency 32%, Heat recover efficiency 43%, depreciation period 15years	250×10^3 yen/kW
Fuel cell	Electric generation efficiency 35%, Heat recover efficiency 45%,depreciation period 15years	500×10^3 yen/kW
Heat pump	Coefficient of performance(COP): 4 0 (heating), 3.0 (cooling), depreciation period 15years	61×10^3 yen/(Mcal/h)
Gas-fired boiler	Thermal efficiency 0.88, depreciation period 15years	10×10^3 yen/(Mcal/h)
Single-stage absorption refrigeraotr	Coefficient of performance(COP) 0 73、depreciation period 15years	16×10^3 yen/(Mcal/h)
Radiator	depreciation period 15years	10×10^3 yen/(Mcal/h)

- Energy contract constraint:

$$Z_{t,r,c,e} \geq PQ_{t,r,c,ptn,hr,e} \cdots\cdots\cdots\cdots\cdots\cdots (22)$$

- Input-output balance of CGS facility:

$$XC_{t,r,c,ptn,hr,m,out} = TR_m \cdot EF_m \cdot XC_{t,r,c,ptn,hr,m,in} \cdots\cdots\cdots\cdots\cdots\cdots (23)$$

- Energy purchase balance:

$$PQ_{t,r,c,ptn,hr,e} = \sum_{p'} CF_{e,p',out} \cdot PIPE_{t,r,c,ptn,hr,e,p'} \cdots\cdots\cdots\cdots\cdots\cdots (24)$$

- Input-output relationship of facility with internal energy flow:

$$XC_{t,r,c,ptn,hr,m,in} = \sum_{p} CF_{p,m,in} \cdot PIPE_{t,r,c,ptn,hr,p,m} \cdots (25)$$

$$XC_{t,r,c,ptn,hr,m,out} = \sum_{p'} CF_{m,p',out} \cdot PIPE_{t,r,c,ptn,hr,m,p'} \cdots\cdots\cdots\cdots\cdots\cdots (26)$$

- Hourly energy supply-demand balance:

$$UDM_{t,r,c,ptn,hr,d} \cdot TFS_{t,r,c} = \sum_{p} CF_{p,d,in} \cdot PIPE_{t,r,c,ptn,hr,p,d} \cdots\cdots (27)$$

- Exhaust heat balance:

$$SP_{t,r,c,ptn,hr} = \sum_{p} CF_{p,sp,in} \cdot PIPE_{t,r,c,ptnhr,p,sp} \cdots\cdots\cdots\cdots\cdots\cdots (28)$$

- CGS constraint:

$$PIPE_{t,r,c,ptn,hr,p,cgst} = PIPE_{t,r,c,ptn,hr,p,cgse} \cdots\cdots\cdots\cdots\cdots\cdots (29)$$

2.3 The Method of Evaluation In this model, both utilities and cogenerators do not compete directly in energy supply planning, which situation suggests they independently develop their optimal energy supply strategies. In the first procedure on the evaluation method, cogenerators identify the electricity which they purchase from utilities by the end-use CGS module. The difference of purchased electricity between the CGS model and the traditional energy supply model which is without gas engine or fuel cell as shown in Fig. 1 or Fig. 2 corresponds to the end-use reduction of electricity purchase from utilities. Electric load curves of utilities, therefore, need to be corrected with considering the change of purchased electricity. Utilities are, as a result, able to specify the optimal electric generation strategies through the long-term best mix model taking into consideration that electricity sales reduction, which means calculating the best mix model by replacing Eq. (4) with Eq. (30) as follows.

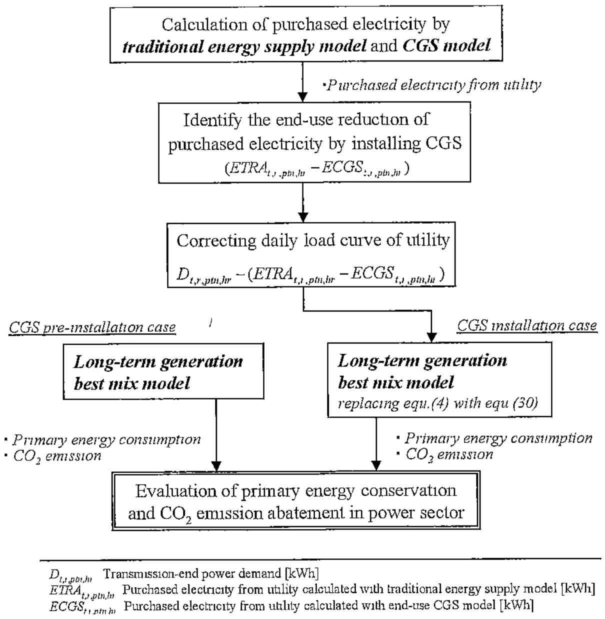

Fig. 3. Evaluation flow of primary energy consumption and CO_2 emission in a power sector

$$\sum_{plt \neq pump} X_{t,r,plt,ptn,hr} - X_{t,r,pump,ptn,hr} + INEX_r \cdot EX_{t,r,ptn,hr} = D_{t,r,ptn,hr} - (ETRA_{t,r,ptn,hr} - ECGS_{t,r,ptn,hr}) \cdots\cdots\cdots\cdots\cdots\cdots (30)$$

$ETRA_{t,r,ptn,hr}$: Purchased electricity from utility in year t, region r, seasonal segmentation ptn, time hr [kWh], calculated with a traditional energy supply model

$ECGS_{t,r,ptn,hr}$: Purchased electricity from utility in year t, region r, seasonal segmentation ptn, time hr [kWh], calculated with an end-use CGS model

Finally, total CO_2 reduction and primary energy conservation by CGS installation can be identified by comparing CO_2 emission and primary energy consumption between a CGS installation case and a pre-installation case. A series of evaluation flow is presented in Fig. 3. In this simulation, however, electricity and city gas rates are assumed not to change in conjunction with generation cost stemmed from future generation mix strategies' variation, which situation does not eventually influence the growing rate and load curve of electricity demand in planning horizon. And we also assume that electricity and city gas rates do not become rising by the deterioration of utilities' electricity demand load factor caused by end-use CGS introduction.

3. Simulation Conditions and Assumptions

3.1 Long-Term Power Generation Mix Model

Electric load curves of utilities in each of nine regional disaggregations according to power service areas are assumed to be increasing at the rate of 1.6% per year until

Table 5. Fuel price scenarios for electric power plants [7]

	Standard price scenario	Low price scenario
Nuclear [yen/kWh]	1.7	1 7
Coal [yen/kg]	5 0→6.1 (2010)	5
Oil [yen/l]	10 6→17.4 (2010)	10.6 → 12.1 (2010)
LNG [yen/kg]	18.9→29.5 (2010)	18.9

2010 and 0.5% per year after 2010 on the basis of future electric power demand outlook developed by CRIEPI (Central Research Institute of Electric Power Industry).

Alternative fuel price scenarios: Evaluation of CGS installation is implemented in the following three fuel price scenarios in a power sector, though it should be noted that these price projections actually remain quite uncertain.

- *Standard price scenario*
- *Low price scenario*
- *Standard price scenario (without upper limit of nuclear)*

This standard price scenario corresponds to the standard fuel price scenario developed by IEA (International Energy Agency) [7]. A low price scenario is defined as current fuel prices continuing for the future. The third case assumes that optimal planning decision is implemented without upper limit of nuclear power plant construction after 2005, concretely means implementing the long-term optimal best mix model without involving Eq. (16) after a year 2005. In the former two cases, the upper limit (70 GW) of nuclear power plant construction is imposed. According to the future generating plant capacity authorized by ACNRE (Advisory Committee for Natural Resources and Energy) Long-term Energy Supply-Demand Outlook [8], nuclear capacity of 66~70 GW is constructed until a fiscal year 2010. Thus we determine 70 GW as the upper limit of nuclear power plant construction. Table 5 describes numerical data of standard and low fuel price scenarios for power plants.

3.2 End-Use CGS Model As to cogenerator, its energy demand mainly depends on the scale of its floor space and as a result end-use demand is assumed to be linear with respect to its floor scale. Standard energy load profile (unit is W/m^2 or $kcal/m^2$) multiplied by floor space of each customer (the unit is m^2) eventually becomes end-use energy demand. app.Fig. 1 and app.Fig. 2 in Appendix represent typical daily load curves indicating seasonal variations of hourly energy demand in office and residence. Customers' hourly energy loads change periodically relying on typical seasonal segmentation (summer, winter and fall/spring [or mid season]). We adopt these demand profiles including shop, hotel and hospital, authorized by SHASE (The Society of Heating, Air-conditioning and Sanitary Engineers of Japan) [9], which energy profiles are assumed to be increasing at 0.5% per year after a year 2010.

CGS installation target scenarios: Analyzing customer's floor space, it ranges from the owner of large floor space to that of small floor space. In order to consider a CGS installation target dependent on customer's floor scale, we define following two cases in evaluating both primary energy conservation and CO_2 emission reduction effects.

- *CGS installation to customers the flooring scale of which is more than 700 m^2 in a commercial sector and is more than 100 m^2 in a residential sector.*
- *CGS installation to customers the flooring scale of which is more than 5000 m^2 in a commercial sector and is more than 120 m^2 in a residential sector.*

Speculation of future floor space: Prospective floor space of cogenerator until a year 2050 is speculated by considering the past annual flows of newly constructed building space in commercial and residential sectors [10]. In this speculation, we made following assumptions.

- The annual increasing rate of floor space stock of a commercial sector is 1.5%~2.5%, that of a residential sector is 0.37%
- The annual building retirement rate is 0.37% in a commercial sector and 2.7% in a residential sector.
- After a year 2010, the stock of flooring space continues to be constant until the end of planning horizon.

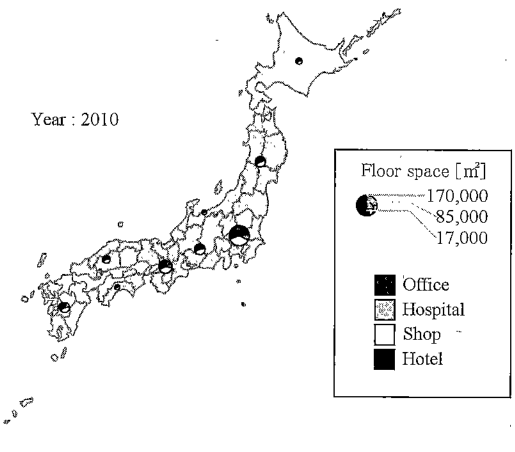

Fig. 4. Prospective floor space of a commercial sector in a year 2010, constituted by newly constructed and refurnished buildings. Customer scale is more than 700 m^2

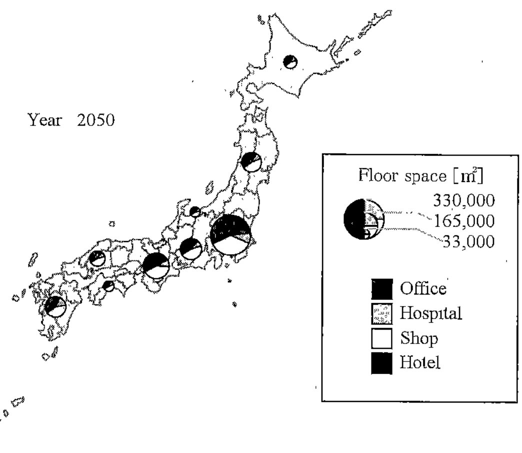

Fig. 5. Prospective floor space of a commercial sector in a year 2050, constituted by newly constructed and refurnished buildings. Customer scale is more than 700 m^2

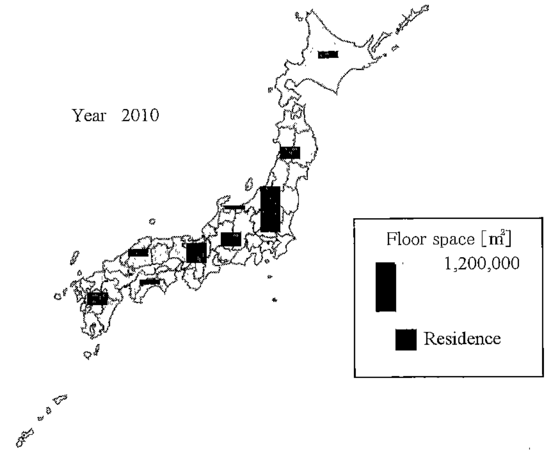

Fig. 6. Prospective floor space of a residential sector in a year 2010, constituted by newly constructed and refurnished buildings. Customer scale is more than $100\,\mathrm{m}^2$

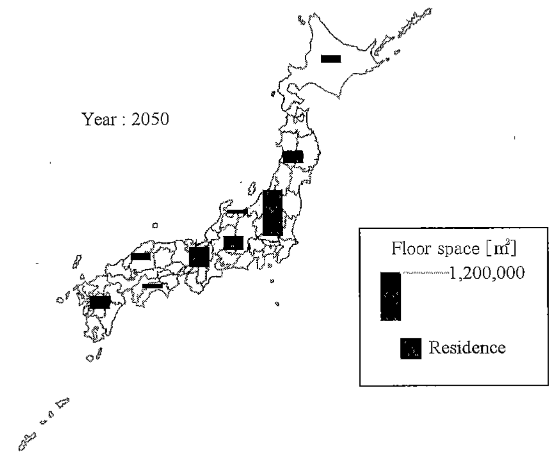

Fig. 7. Prospective floor space of a residential sector in a year 2050, constituted by newly constructed and refurnished buildings. Customer scale is more than $100\,\mathrm{m}^2$

- Building in these sectors is assumed to be refurnished 20 years after newly-constructed

Figure 4 and Fig. 5 show future floor space with customers' floor scales more than $700\,\mathrm{m}^2$ of a commercial sector in a year 2010, 2050 respectively. We develop floor space outlook in each of the 46 administrative divisions of Japan, aggregated and illustrated on nine power service regions. This floor space is composed of newly constructed and refurnished buildings.

Figure 6 and Fig. 7 show future floor space with customer's floor space more than $100\,\mathrm{m}^2$ of a residential sector in a year 2010 and 2050 respectively.

Regional characteristics of heating and cooling demand: Concerning customers' heating and cooling demand in each region, we calculate corrective coefficients to reflect the regional characteristics of final energy demand on the basis of Extended Degree Day (EDD) method authorized by IBEC (Institute for Building Environment and Energy Conservation), roughly described by Eqs. (31), (32). The EDD method yields

Table 6. Variables for annual load calculation by an EDD method

Q_H	: Annual heating load [MJ/year·zone]
Q_C	: Annual cooling load [MJ/year·zone]
k_H	: Regional adjustment coefficient (heating)
k_C	: Regional adjustment coefficient (cooling)
$U_T(a)$	: Coefficient of heat transmission (sunny part)[W/K]
$U_T(a)$	: Coefficient of heat transmission (shade part)[W/K]
EHD	: Extended heating degree day[K·DAY]
ECD	: Extended cooling degree day[K·DAY]
D_{OH}	: Extended heating degree day (shade part) [K·DAY]
D_{OC}	: Extended cooling degree day (shade part) [K·DAY]

Table 7. Corrective coefficients of heating load in each power service areas

Hokkaido	Tohoku	Tokyo	Chubu	Hokuriku	Kansai	Chugoku	Shikoku	Kyushyu
3.8	2.4	1.0	1.3	1.8	1.2	1.3	1.2	0.8

Table 8. Corrective coefficients of cooling load in each power service areas

Hokkaido	Tohoku	Tokyo	Chubu	Hokuriku	Kansai	Chugoku	Shikoku	Kyushyu
0.2	0.5	1.0	1.0	0.8	1.2	1.0	1.2	1.3

regional annual heating and cooling demand loads of specific building reflecting district climate conditions. Extended heating and cooling degree days of this method have regional dependence. We apply EDD method to standard office building (floor space: $9600\,\mathrm{m}^2$) on each region, following which we obtain normalized coefficients through dividing regional heating and cooling loads by those of Tokyo area as numerical results presented in Table 7 and Table 8. We are thus able to adjust regional heating and cooling demand by multiplying together these coefficients and the standard heating and cooling demand such as shown in app.Fig. 1 or app.Fig. 2. Daily electricity and hot water demand of standard load profile are assumed to be commonly applied into all administrative regions.

$$Q_H = 0.0864K_H\{U_T(a)\cdot EHD + U_T(b)\cdot D_{OH}\} \quad \cdots\cdots (31)$$

$$Q_C = 0.0864k_C\{U_T(a)\cdot ECD + U_T(b)\cdot D_{OC}\} \quad \cdots\cdots (32)$$

4. Simulation Results

4.1 Simulation Results of Long-Term Best Mix Model Figures 8∼10 show annual electric power generation trajectories of general electric utilities in Japan at three fuel price scenarios respectively. In the standard fuel price scenario, the generation from nuclear, IGCC, LNG combined cycle (LNGCC) become dominant in the latter of planning horizon. Meanwhile, LNGCC increases and nuclear declines its share in low fuel price scenario, implying that nuclear has no competitive edge on the condition of current fuel prices continuing for the future. When simulated in the third fuel price scenario, a nuclear clearly becomes competitive on the assumption of current fuel price transition.

Figures 11∼13 illustrate annual CO_2 emission trajectories in a power sector. In the case of the standard

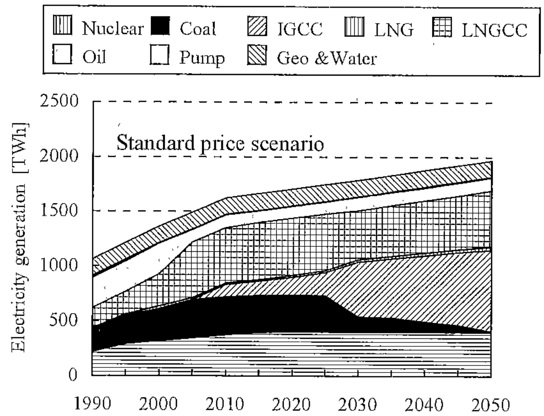

Fig. 8. An electric power generation trajectory of general electric utilities in Japan at a standard fuel price scenario

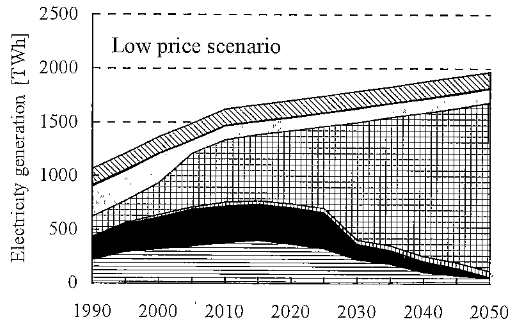

Fig. 9. An electric power generation trajectory of general electric utilities in Japan at a low fuel price scenario

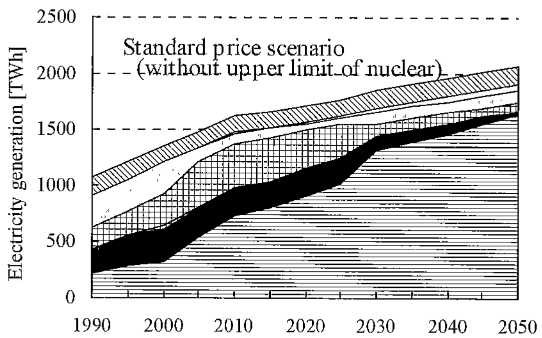

Fig. 10. An electric power generation trajectory of general electric utilities in Japan at a standard fuel price scenario without upper limit of nuclear construction

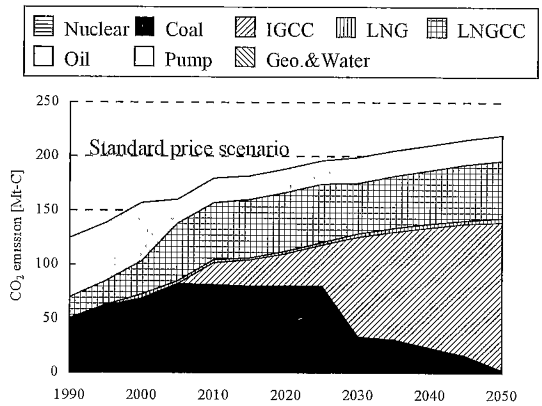

Fig. 11. A CO_2 emission trajectory of utilities in Japan at a standard fuel price scenario

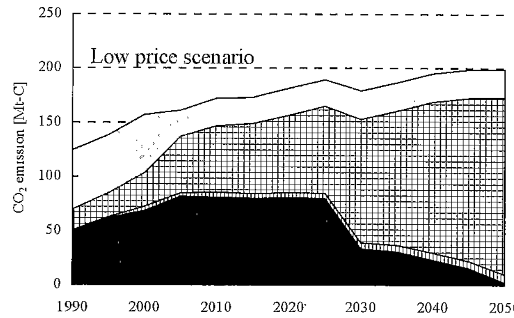

Fig. 12. A CO_2 emission trajectory of utilities in Japan at a low fuel price scenario

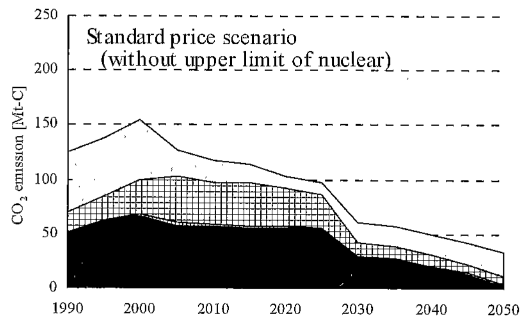

Fig. 13. A CO_2 emission trajectory of utilities in Japan at a standard fuel price scenario without upper limit of nuclear construction

and the low fuel price scenario, large parts of electricity supply relying on fossil fuel combustion result in steady increase of CO_2 emission through the simulated horizon. In spite that the power generation of a LNGCC has large share in the low fuel price scenario, total CO_2 emission in each year is not substantially different from that of the standard fuel price scenario due to the decreasing of power generation from a nuclear compared to the standard price scenario. As to the standard price case without upper limit of nuclear, CO_2 emission declines as a nuclear increases its share. In a year 2050, the CO_2 emission of the third cases is around a quarter as much as that of the other two cases.

4.2 Simulation Results of End-Use CGS Model

Figures 14 and Fig. 15 show CGS installation capacity in newly constructed and refurnished buildings dependent on customer's floor scale in commercial and residential sectors respectively. CGS in a commercial sector corresponds to gas engine cogeneration system and one in a residential sector equivalent to fuel cell cogeneration system.

Total gas engine or fuel cell capacity in the case of more than 700 m^2 in a commercial and 100 m^2 in a residential sector amounts to around 49.8 GW in a commercial and 47.6 GW in a residential sector at the year of 2050. The share of CGS capacity against all power generators (CGS + General electric utilities' power plants) in a year 2050 becomes around 23%. In the case of more than 5000 m^2 in commercial and 120 m^2 in residential sector, gas engine capacity is about 27.7 GW and fuel

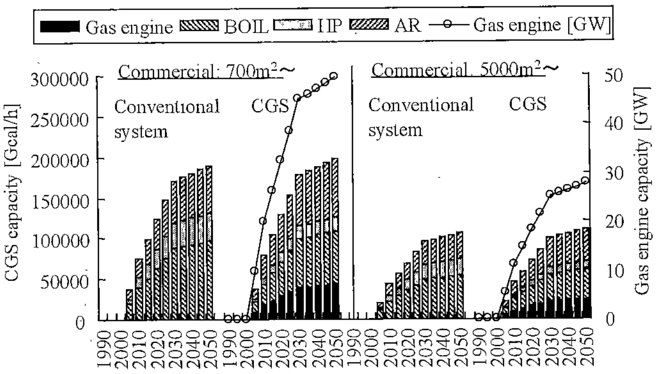

Fig. 14. CGS capacity of refurnished and newly constructed buildings in a commercial sector

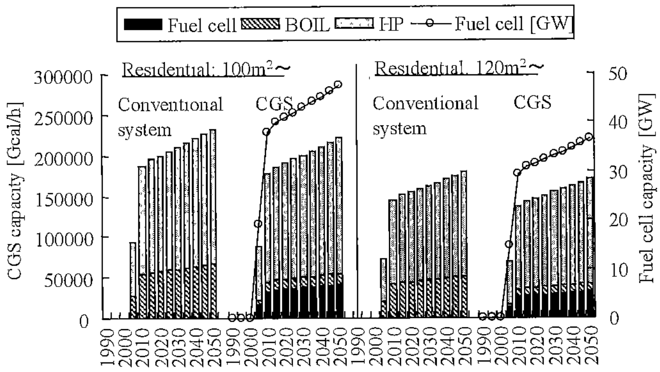

Fig. 15. CGS capacity of refurnished and newly constructed buildings in a residential sector

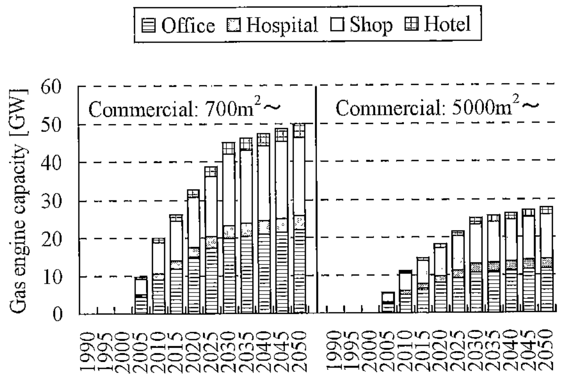

Fig. 16. Breakdown of gas engine capacity in a commercial sector

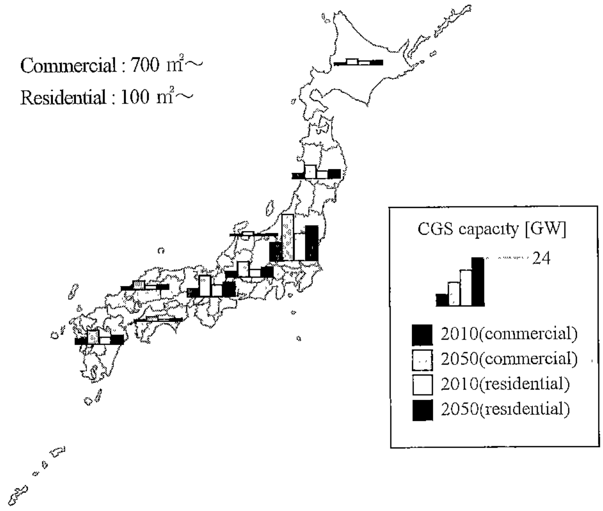

Fig. 17. Regional gas engine or fuel cell installation capacity in newly constructed and refurnished buildings. An installation target is more than 700 m^2 in a commercial sector and more than 100 m^2 in a residential sector

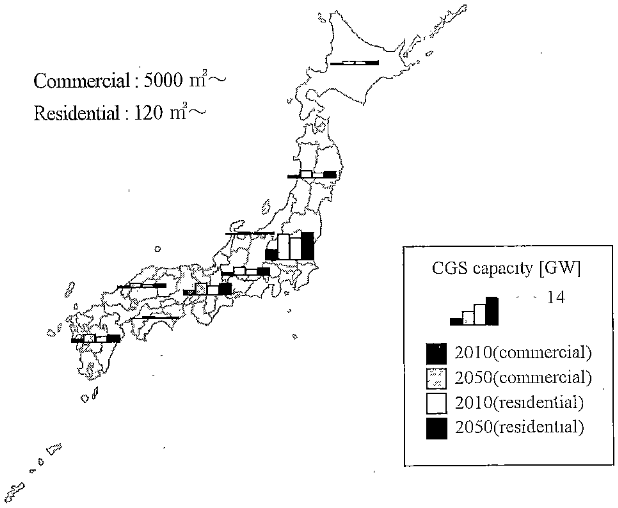

Fig. 18. Regional gas engine or fuel cell installation capacity in newly constructed and refurnished buildings. An installation target is more than 5000 m^2 in a commercial sector and more than 120 m^2 in a residential sector

cell is about 36.6 GW in a year 2050, which CGS share amounts to about 15% of total generators at 2050.

Figure 16 shows the breakdown of gas engine capacity in a commercial sector, implying that the capacitiy in office and shop are larger compared with those of hospital and hotel. In order to investigate the ratio of CGS contribution over each cogenerators' energy demand, we show the dependency on CGS for satisfying electricity and heating demand [11]. CGS electricity generation divided by electricity demand in 2020 is as follows: 0.62 (office), 0.76 (hospital), 0.60 (shop), 0.80 (hotel), 0.49 (residence). The recovery heating divided by heating demand is as follows: 0.64 (office), 0.65 (hospital), 0.68 (shop), 0.73 (hotel), 0.43 (residence).

Figure 17 and Fig. 18 show regional gas engine and fuel cell introduction potential in each case of CGS installation targets. Calculation result in each of the 46 prefectures of Japan is aggregated and displayed on nine power service areas. In both cases, Tokyo, Kinki and Chubu area have large CGS introduction potential.

4.3 Evaluation of Primary Energy Conservation and CO_2 Reduction by CGS Introduction

Figure 19 and Fig. 20 show the eventual change of utilities' power plant capacity and its electricity generation by end-use installation of CGS in the case of more than 700 m^2 in a commercial and 100 m^2 in a residential sector of both newly-built and refurnished, which figures suggest that CGS mainly replaces the power plant and its generation of IGCC and LNGCC in the standard price scenario, LNGCC in the low price scenario and nuclear in the standard price scenario without upper limit

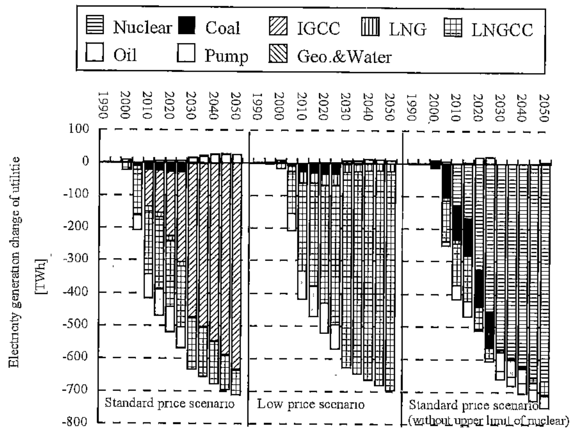

Fig. 19. The change of utilities' electricity generation through demand-side CGS installation in respective fuel price scenario

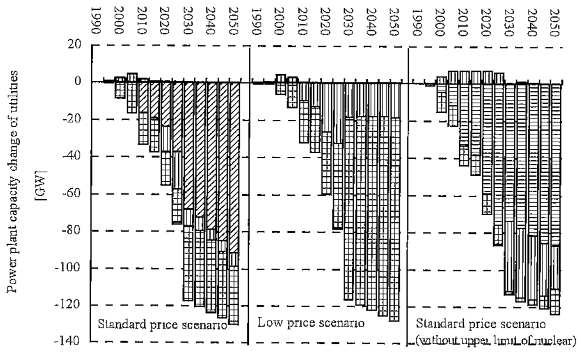

Fig. 20. The change of utilities' power plant capacity through demand-side CGS installation in respective fuel price scenario

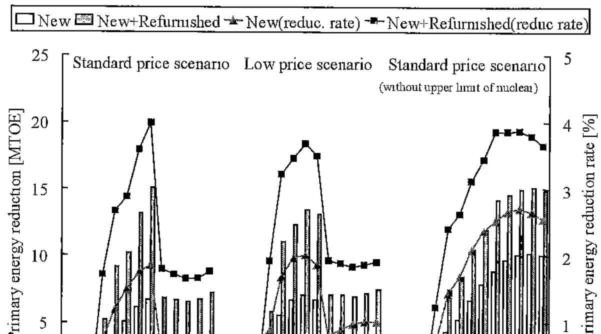

Fig. 21. Primary energy reduction effect by end-use CGS installation. The CGS installation target of a commercial sector is more than $700\,m^2$ and that of a residential sector is more than $100\,m^2$

constraint of nuclear construction.

CGS introduction, thereby, substitutes the power plant and its electricity generation with a high CO_2 emission unit in the standard price scenario, that with a low CO_2 emission unit in both the low and the standard fuel price scenario without nuclear constraint. Consequently CGS has larger impact of CO_2 abatement in the standard scenario and smaller impact in the other

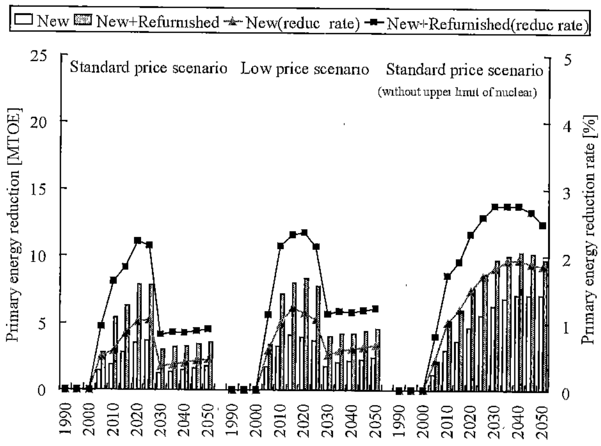

Fig. 22. Primary energy reduction effect by end-use CGS installation. The CGS installation target of a commercial sector is more than $5000\,m^2$ and that of a residential sector is more than $120\,m^2$

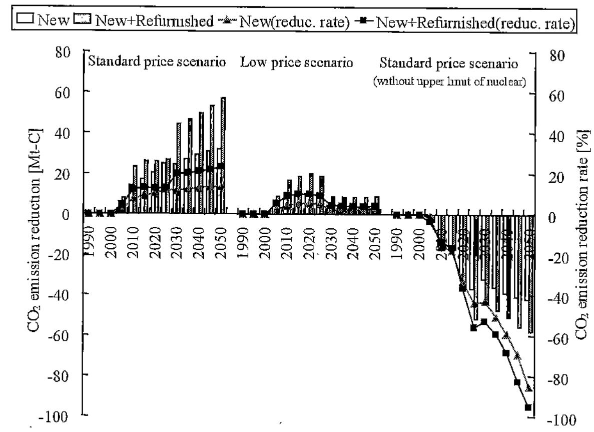

Fig. 23. CO_2 emission reduction effect by end-use CGS installation. The CGS installation target of a commercial sector is more than $700\,m^2$ and that of a residential sector is more than $100\,m^2$

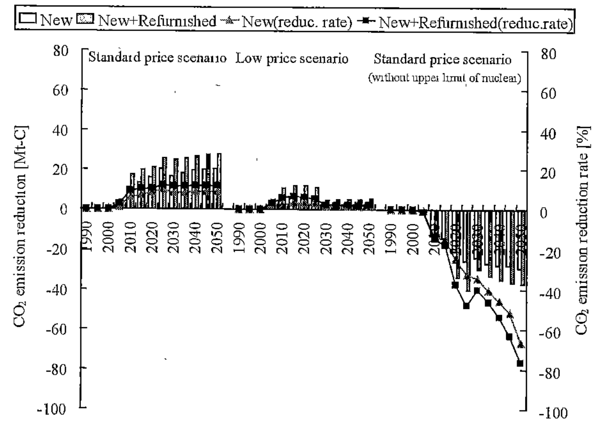

Fig. 24. CO_2 emission reduction effect by end-use CGS installation. The CGS installation target of a commercial sector is more than $5000\,m^2$ and that of a residential sector is more than $120\,m^2$

two cases compared to the standard case.

Figure 21 and Fig. 22 show primary energy reduction effect by end-use CGS installation in each case of CGS introduction targets. In all fuel price scenarios, CGS

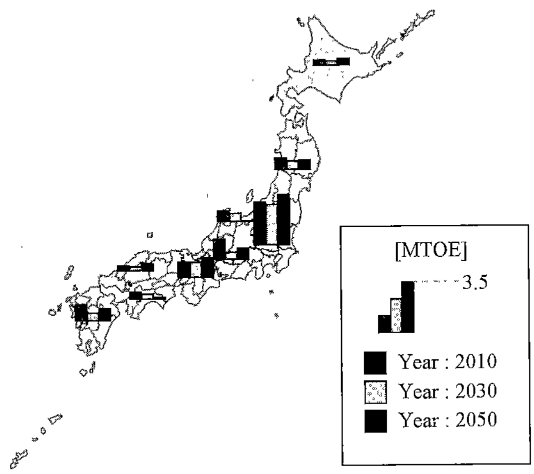

Fig. 25. Regional primary energy conservation effect in Japan. The CGS installation target of a commercial sector is more than 700 m^2 and that of a residential sector is more than 100 m^2 over newly-constructed and refurnished buildings

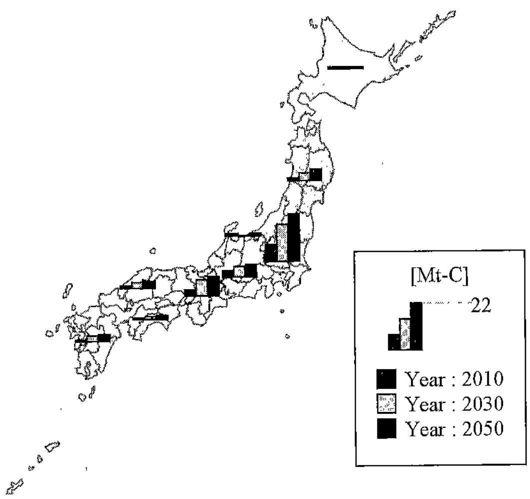

Fig. 26. Regional CO_2 emmision reduction effect in Japan. The CGS installation target of a commercial sector is more than 700 m^2 and that of a residential sector is more than 100 m^2 over newly-constructed and refurnished buildings

introduction accomplishes primary energy conservation in a power sector.

Figure 23 and Fig. 24 show CO_2 emission abatement effect by end-use CGS installation in each case of CGS introduction targets. In the standard fuel price scenario, the installation of CGS in commercial and residential sectors achieves CO_2 emission mitigation. In the low fuel price scenario which is the case current fuel prices continue for the future, however, CO_2 reduction effect becomes decreasing compared to the standard fuel price scenario because of the dominant generation share of a LNG fired plant and a LNGCC in future generation mix and the replacement of these less carbon intensive plants by CGS installation. In the case where a nuclear power plant becomes competitive and increases its share in future generation mix, CO_2 emission from an energy system conversely increases by installing CGS in comparison with before installing, because the electric power generation of CGS gradually replaces a nuclear power plant as shown in Fig. 19 and Fig. 20.

In order to understand the gist of both primary energy conservation and CO_2 mitigation potential of each power service regions in Japan, Fig. 25 and Fig. 26 respectively show regional primary energy saving and CO_2 abatement effects on commercial and residential sectors in the standard fuel price scenario. The CGS installation target of a commercial sector is more than 700 m^2 and that of a residential sector is more than 100 m^{2}over newly constructed and refurnished buildings. Kanto, Kansai, Chubu area have large potential of both primary energy saving and CO_2 mitigation by CGS installation.

5. Conclusion

In this paper, we evaluate the reduction effects of primary energy consumption and CO_2 emission in a power sector by CGS installation.

With considerable uncertainty remaining concerning various assumptions made for a model analysis such as consideration of the reliability of electric power grid by end-use CGS installation or the penetration rate of city gas into customers, following results are identified. Concerning primary energy consumption in all fuel price scenarios of a power sector, CGS introduction contributes to its reduction. Concerning CO_2 emission, in a standard fuel price scenario, the installation of CGS in commercial and residential sectors accomplishes the reduction of CO_2 emission. In a low fuel price scenario which is the case current fuel prices continue for the future, however, CO_2 reduction effect becomes decreasing compared to the standard fuel price scenario because of the dominant generation share of a LNG fired plant and a LNG combined cycle in future generation mix and these less carbon intensive power plants replaced by CGS introduction. In the case where a nuclear power plant remains competitive and increases its share in future generation mix, CO_2 emission from an energy system conversely increases by installing CGS in comparison with before installing, because electric power of CGS gradually replaces a nuclear. These results suggest that the effect of CO_2 reduction potential by the introduction of CGS is cautiously evaluated taking into account the future power plant construction program in Japan and the power plants which might be replaced by CGS installation.

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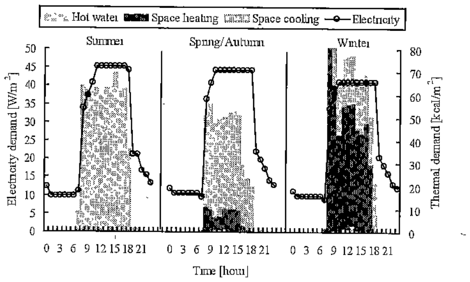
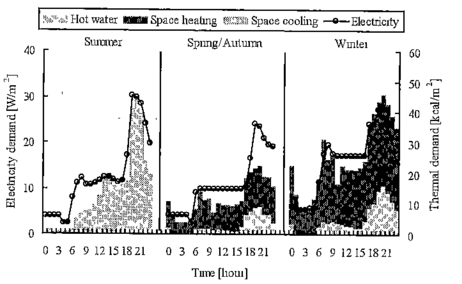
Appendix

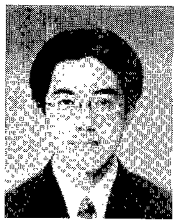
app.Fig. 1 and app.Fig. 2 show daily energy load curves in a office and residential sector with seasonal load segmentation [9].



app. Fig. 1. Daily energy load (hot water, space heating, space cooling, electricity) curve of an office building in respective seasonal load segmentation



app. Fig. 2. Daily energy load (hot water, space heating, space cooling, electricity) curve of a residential sector in respective seasonal load segmentation



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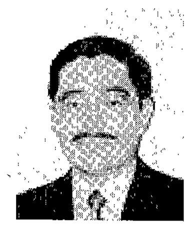

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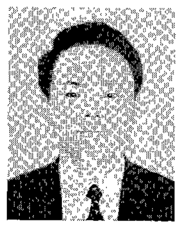

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