RIETI Discussion Paper Series 17-E-063

Assessing the Impact of Renewable Energy Sources: Simulation analysis of the Japanese electricity market

YOSHIHARA Keisuke
University of Tokyo

OHASHI Hiroshi
RIETI

Research Institute of Economy, Trade & Industry, IAA
The Research Institute of Economy, Trade and Industry
http://www.rieti.go.jp/en/

RIETI Discussion Paper Series 17-E-063
April 2017

Assessing the Impact of Renewable Energy Sources: Simulation analysis of the Japanese electricity market[1]

YOSHIHARA Keisuke
The University of Tokyo

OHASHI Hiroshi
The University of Tokyo and RIETI

Abstract

This paper evaluates the impact of renewable energy (RE) sources on market outcomes in Japan. We develop a simulation model to compute the kWh-market equilibrium, and conduct simulation exercises for 2015 and 2030. Using scenarios proposed by the government, we find that the diffusion of RE sources would lower the kWh-market prices and greenhouse gases by reducing fossil fuel consumption in 2030. It would also mothball many of the thermal power plants, which were active and profitable in 2015.

Keywords: Simulation model, Energy policy, Renewable energy, Mothballing, Missing money problem
JEL classifications: C63, L94

[1] This study is conducted as a part of the "Basic Research for a New Industrial Policy" project undertaken at the Research Institute of Economy, Trade and Industry (RIETI). The authors are grateful for helpful comments and suggestions by Discussion Paper seminar participants at RIETI.

1 Introduction

The Great East Japan Earthquake on March 11, 2011 revealed many challenges of Japanese electricity system. The Strategic Energy Plan [29] approved by the Cabinet in April 2014 states that the goals of Japan's energy policy is to first ensure stable supply (*Energy Security*), realize lower energy costs by enhancing the efficiency (*Economic Efficiency*), and pursue environment suitability (*Environment*) on the premise of *Safety*, referred to as "*3E+S*". All of these four goals are important, and examining them from various perspectives is considered to be crucial for developing the nation's energy policy. In order to achieve these goals, the Strategic Energy Plan [29] also provides the fundamental direction of energy policy such as lowering dependency on nuclear power generation to the extent possible through energy conservation and introducing renewable energy (RE) sources as well as improving the efficiency of thermal power plants. Among them, introducing RE sources is primarily of importance in terms of improving energy self-sufficiency ratio and reducing the volume of CO_2 emissions.

In the paper, we evaluate the impact of further installation of RE sources, by developing a simulation model to compute the kWh-market equilibrium and conduct simulations in the years of 2015 and 2030 on the basis of the publicly available data. We choose the year of 2030 based on the Long-term Energy Supply and Demand Outlook [15] which is approved in July 2015. Using our simulation model, we can compute the equilibrium kWh-price and each power plant's output, revenue, variable cost and inframarginal rent on an hourly basis.

We find that further installation of RE sources lowers average system price by 2.14 JPY/kWh and reduces annual fuel cost and volume of CO_2 emissions by 40.9% and 37.1%, respectively, from 2015 to 2030. However, it decreases average utilization rate of the thermal power plants by 27.2 percentage points from 2015 to 2030, resulting in undermining the profitability of the thermal power plants. In particular, only 34.5% of coal-fired thermal power plants that are base-load electricity sources can recover their fixed cost in 2030 while all of them could recover their fixed cost in 2015. This finding indicates a need for new revenue mechanism such as capacity market that enables power plants to earn revenue from the generation capacity (kW) along with the conventional market mechanism where they earn revenue based on the volume of electricity output (kWh).

The paper is organized as follows. Section 2 briefly explains the background of Japanese electricity market. Section 3 explains the related literature. Section 4 and 5 describe our simulation model and the data. Section 6 presents the simulation results. Section 7 concludes.

2 Japanese Electricity Market

Japanese electricity system in the postwar period has achieved an adequate and stable electricity supply under the system of regional monopoly by ten vertically integrated electric power companies. On the other hand, a series of electricity system reform with the main purpose of filling the gap between the domestic and foreign electricity prices has been implemented from the year of 1995, and the discussion of the electricity market liberalization has been advanced. The outcomes of past electricity system reforms include the liberalization in the electricity generation market (1995), the partial liberalization in the electricity retail market (2000~), and the establishment of Japan Electric Power Exchange (JEPX) (2003). While the electricity retail market has been partially liberalized in a phased manner and the customers in a liberalized sector could procure the electricity from outside their own area after the amendment of the Electricity Business Act in 1999, the inter-area transmission lines were not actively utilized, and basically, the electricity system has been operated by electric power companies in an area-by-area basis, almost no competition across areas. This is mainly due to the insufficient capacity of inter-area transmission lines relative to the electricity demand in each area as in Figure 1.

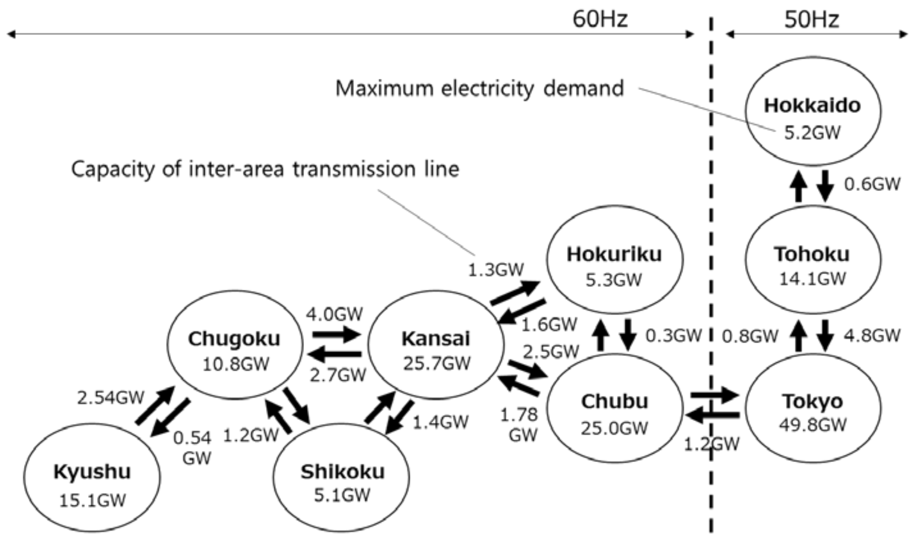

Figure 1. Japanese electricity market in 2015

On March 11, 2011, the Great East Japan Earthquake struck the northeastern area of Japan, unleashing a savage tsunami. Many electric power facilities in Tohoku and Tokyo area were devastated and the capacity of electricity supply significantly decreased. Immediately after the earthquake, the rolling blackouts were carried out to avoid a massive power outage. This terrible disaster had considerable impacts on people’s lives and revealed many challenges of Japanese electricity system; the concerns about the safety of nuclear power plants, the risk arising from the dependence on large-scale and centralized power sources (importance of further installation of RE sources), the lack of system to transmit electricity beyond areas (need for the efficient utilization or consolidation of inter-area transmission network).

In February 2012, the Expert Committee on Electricity System Reform was organized and the discussion of the fifth electricity system reform started. In April 2013, the Cabinet approved the Policy on Electricity System Reform [28] to realize the following three objectives in Japanese electricity market, (1) securing a stable electricity supply by facilitating the electric power interchange between areas, (2) suppressing electricity charges to the maximum extent possible, and (3) expanding choices for consumers and business opportunities. Under that policy, the fifth electricity system reform consists of three steps. In April 2015, the Organization for Cross-regional Coordination of Transmission Operators (OCCTO) was established as a first step. In April 2016, the electricity retail market was fully liberalized as a second step. Finally, the legal unbundling of transmission/distribution sectors is scheduled in 2020 as a third step. In addition, the Long-term Energy Supply and Demand Outlook [15] was approved in July 2015. It discusses the ideal situation of Japanese electricity market in light of the Strategic Energy Plan [29] and proposes the optimal power source mix in the fiscal year of 2030: 22-24% for RE sources, 20-22% for nuclear, 27% for LNG-fired, 26% for coal-fired, and 3% for oil-fired.

3 Related Literature

Our simulation model can be positioned as part of optimal power generation mix model. The optimal power generation mix model enables us to simulate each power plant's operation that minimizes the total variable cost under several constraints such as demand-supply balances and transmission constraints. Closely related literature that investigates Japanese electricity market using the optimal power generation mix model includes Kainou(2016) [34] and Komiyama and Fujii(2017) [35].

Komiyama and Fujii(2017) [35] develops an optimal power generation mix model and simulates the model assuming a year 2030 to assess the post-Fukushima renewable energy policy in Japan's nation-wide power grid. The highlight of their model consists in detailed geographical and temporal resolution. Their model is characterized by considering the power grid topology composed of 135 nodes and 166 high-voltage power transmission lines in Japan with 10-min resolution. As one of their simulation results, they show that the integration of massive variable renewable such as photovoltaics (PV) and wind decreases the capacity factor of thermal power plant and possibly affects that profitability.

The most closely related literature is Kainou(2016) [34]. He also develops an optimal power generation mix model and simulates the model assuming the fiscal year 2025, and conducts the policy impact assessments for (i) interim electricity tariff regulation, (ii) nuclear reactor safety regulation for old reactors and (iii) "Feed-in-tariff" systems for solar PV cell origin electricity. From the policy impact assessment for (iii), he shows that expansion of the installed capacity of PV decreases average utilization rate of the thermal power plants by 0.77 percentage points. He also shows that expansion of the installed capacity of PV decreases inframarginal rent especially for the combined cycle LNG-fired thermal power plants and makes new entry of them more difficult.

Although it is difficult to compare our simulation result with that from above literature since Komiyama and Fujii(2017) [35] does not quantitatively assess the impact of RE sources on thermal power plants' profitability, and Kainou(2016) [34] only investigates the impact of PV, both papers obtain the results which indicate the negative impact of RE sources on the thermal power plants and our simulation result is consistent with them.

Our simulation model refers to the model by Kainou(2016) [34]. However, his model has a drawback that unreasonable solution may occur due to the looped structure of inter-area transmission network. In other words, the looped structure such as the transmission network among Kansai, Chugoku and Shikoku area may cause "circulating power flow", resulting in redundant power flow or redundant iterations in the process of equilibrium computation. In order to avoid the computational difficulty resulting from the looped structure of inter-area transmission network, he eliminates Kansai-Shikoku and Chubu-Hokuriku transmission lines from the equilibrium computation in advance assuming that the electricity is transmitted up to the maximum capacity at all times from Shikoku to Kansai area and from Hokuriku to Chubu area, respectively. Although our simulation model also has such computational difficulty, we overcome this problem in a similar way as Kainou(2016) [34] which is shown in Figure 4. In addition, Kainou(2016) [34] first segment the nationwide market into six markets (Market 1: Hokkaido area, Market 2: Tohoku and Tokyo area, Market 3: Chubu area, Market 4: Hokuriku, Kansai, Chugoku and Kyushu area, Market 5: Shikoku area, Market 6: Okinawa area) based on the simulated disjuncture rate [2] and fix the segmentation of markets throughout his simulation. It implies that the same kWh-price is realized for areas in a market at any given point in time (hour). On the other hand, we perform a market segmentation process[3] at each point in time (hour), which is thought of as more similar way to the actual equilibrium computation in JEPX. However, all models described here, including our model, have advantages and disadvantages, and it is not easy to judge which model is the best one. Our model should be considered as a counterpart to their models.

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2 Disjuncture rate is defined as the number of hours at which hypothetical power flow is greater than or equal to the capacity of inter-area transmission line divided by 8,760 hours. In terms of hypothetical power flow, see Section 4.2.

3 Market segmentation process is briefly explained in Section 4.2.

4 Simulation Model

4.1 Overview

We develop a simulation model that computes the competitive kWh-market equilibrium following Kainou(2016) [34]. The model consists of nine areas except for Okinawa area (Hokkaido, Tohoku, Tokyo, Chubu, Hokurisku, Kansai, Chugoku, Shikoku and Kyushu area) and each area is connected via capacity constrained inter-area transmission line as shown in Figure 1. Under a sufficiently competitive environment, the equilibrium kWh-price is determined by marginal generation cost. In electricity market, the marginal generation cost can be approximated by average variable cost. We assume that supply is constructed in terms of merit order of variable cost per kWh and that demand is vertical as in Figure 2. Thus, the equilibrium kWh-price is the variable cost per kWh of marginal power plant and it achieves the optimal market outcomes that minimize the total variable cost. Using the data on hourly electricity demand by area, generation capacity and variable cost per kWh of the power plants, and capacity of inter-area transmission lines as input data, we can compute equilibrium kWh-price and each power plant's output, revenue, variable cost and inframarginal rent on an hourly basis as in Figure 2.

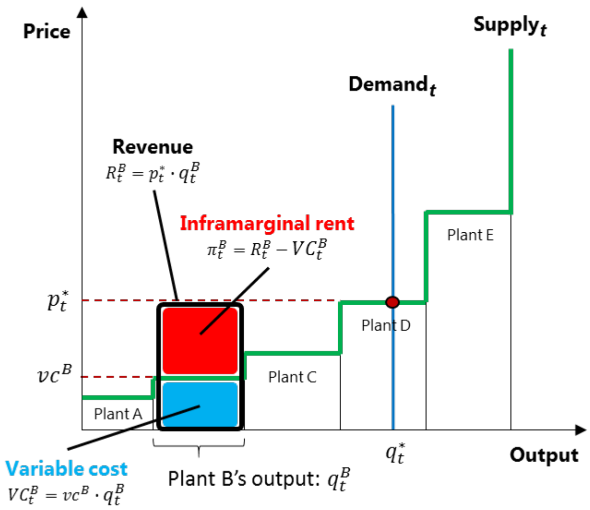


Figure 2. Demand, supply and market equilibrium in kWh-market

4.2 Computational Algorithm

In this section, we explain the computational algorithm of our model using a simple example in Figure 3. For simplification, we consider two areas connected by capacity constrained inter-area transmission line (Its capacity is assumed to be 1GW) at a given point in time (hour). Detailed algorithm is described in Figure 4.

In our algorithm, we perform a market segmentation process which is actually performed in JEPX. We first compute an equilibrium system price[4] and compute each power plant's output under the equilibrium. After that, we aggregate each power plant's output by area and compute the demand-output gap in each of two areas. Then, we compute hypothetical power flow from excess supply to excess demand area ignoring the capacity constraint of transmission line so that two areas' demand-output gaps become zero. If the hypothetical power flow is less than the capacity of transmission line, we can set a uniform price for two areas and the equilibrium area price[5] in each area is set to the equilibrium system price computed above. Otherwise, the demand-output gap in the excess demand area cannot be filled even if we transmit electricity from excess supply to excess demand area up to the maximum capacity of transmission line. In other words, under the equilibrium computed above, we cannot set a uniform price for two areas due to the capacity constraint of transmission line. Therefore, we segment the market and consider area 1 as market 1 and area2 as market 2. After transmitting electricity from excess supply to excess demand area up to the maximum capacity of transmission line, we compute the equilibrium area price by market at the intersection of each market's supply and residual demand.

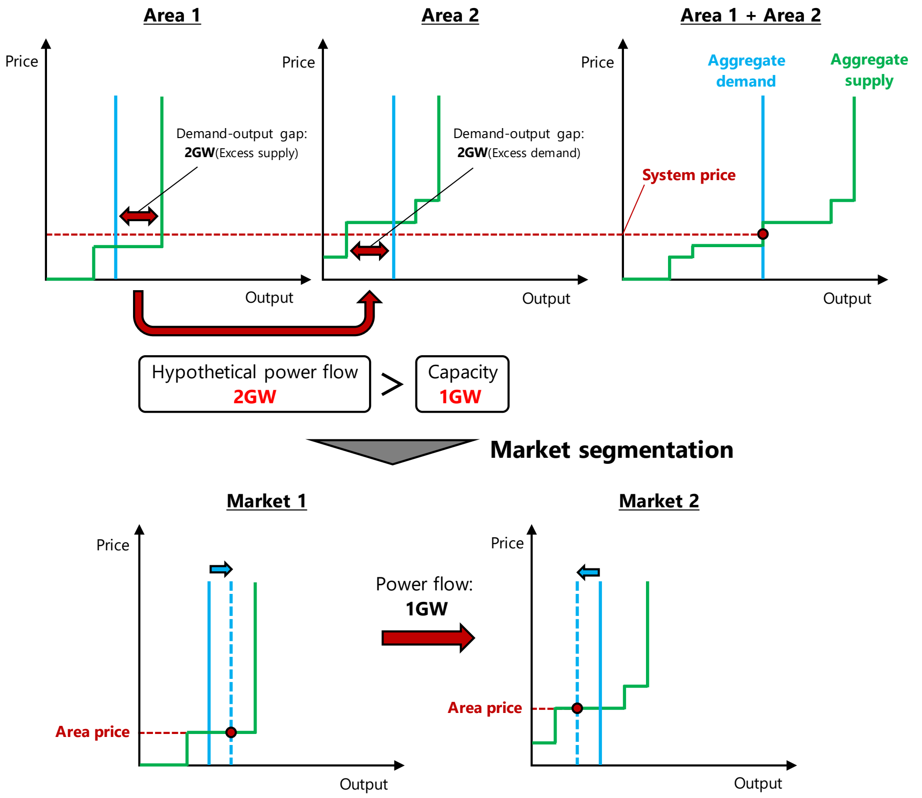


Figure 3. Two-area example of equilibrium computation

4 System price is defined as the equilibrium kWh-price which is determined at the intersection of aggregate demand and supply regarding all areas as one nationwide market.
5 Area price is defined as the equilibrium kWh-price by area which is computed after the market segmentation process.

Step.0: Set $t=1$ ($t=1,\ldots,8{,}760$).

Step.1:
Compute an equilibrium system price.

– If demand exceeds supply, the equilibrium system price is assumed to be the minimum value of price cap among nine areas.

Step.2:
Under the equilibrium in Step.1, compute each power plant's output and aggregate them by area.
After that, compute demand-output gap in each of nine areas.

Step.3:
Compute hypothetical power flow in each transmission line ignoring capacity constraints so that all areas' demand-output gap in Step.2 become zero.

Step.3-1
Pick up any excess demand area, and compute the distance from that area to all excess supply areas.

Step.3-2
Pick up one excess supply area that has the shortest distance from the excess demand area, and compute power flow from the excess supply to excess demand area through the shortest path b/w two areas.

– If the amount of excess demand is greater than that of excess supply, set the power flow to the amount of excess supply. Otherwise, set the power flow to the amount of excess demand.

Step.3-3
If all areas' demand-output gaps are zero, go to Step.4. Otherwise, go to Step.3-1.

Step.4:
For each transmission line, if the hypothetical power flow in Step.3 is greater than or equal to its capacity, regard such transmission line as "*disjunct*" and segment the nationwide market in Japan into some markets.

– For example, if only Hokkaido-Tohoku transmission line is regarded as disjunct transmission line, consider Hokkaido area as Market 1 and other areas as Market 2.
– If any two markets are connected via more than one disjunct transmission lines, we regard a transmission line with the largest excess amount of hypothetical power flow as disjunct transmission line.

Step.5:
For each market determined in Step.4, compute an equilibrium area price, and identify the variable cost per kWh of *next supply plant**.

* *Next supply plant* is defined as a power plant that has the minimum variable cost per kWh among power plants that have larger variable cost per kWh than the equilibrium area price. Let the variable cost of next supply plant be *next supply price*.

– We assume that if demand exceeds supply in a market, the equilibrium area price is set to the minimum value of price cap among areas in the market.

Step.6:
For each market i, pick up one other market j that is connected with market i via transmission line and that the difference b/w market i and j's equilibrium area price is the largest.
Compute inter-area power flow with capacity constraint b/w market i and j.

– If both equilibrium area price and next supply price in market i (j) is less than the equilibrium area price in market j (i), set the inter-area power flow from market i (j) to j (i) to the generation capacity of next supply plant in market i (j).

Step.7:
Compute residual demand in each market by adding (subtracting) the inter-area power flow in Step.6.
Under the residual demand, perform the same process in Step. 5.

Step.8:
If the inter-area power flow does not reach the capacity for all transmission lines and change in the inter-area power flow from the previous iteration is greater than the threshold, go to Step.6.
Otherwise, if $t < 8{,}760$, let $t = t + 1$ and go to Step.1, otherwise, finish the algorithm.

Figure 4. Computational algorithm of the model

5 Data

5.1 Electricity Demand

We use hourly electricity demand by area in 2015, the data which is disclosed by nine electric power companies [1]. Since there are some missing values especially for holidays, we estimate the electricity demand function and complement the missing values with the predicted values from estimated demand function. After that, we add the self-consumption of residential PV and obtain the electricity demand data for our simulation. Details of the electricity demand function estimation is described in Appendix. We assume that the level of electricity demand in 2030 is the same as in 2015. In figure 5, we show a duration curve for aggregate electricity demand in 2015.

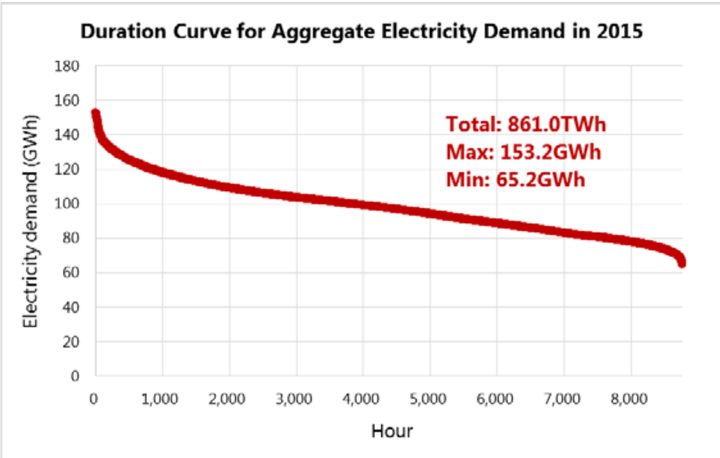


Figure 5. Electricity demand in 2015

5.2 Electric Power Plants

5.2.1 Thermal, Hydro and Nuclear Power Plants

The thermal power plants are divided into Oil-, LNG- and Coal-fired with steam turbine, the light oil- and LNG-fired with gas turbine, and the combined cycle thermal power plants that concurrently use steam and gas turbine. The hydro power plants are divided into run-of-river and reservoir type (General hydro power plants), and pumped storage power plants.

For the simulation in 2015, we collect the data on thermal, hydro and nuclear power plants at the end of 2015 based on the publicly available materials [6] [7].[6] We reflect new construction, abolition and the change in generation capacity of those plants on a day-to-day basis in 2015 based on Survey of electric power statistics [8]. We assume that the capacity factor of reservoir type and pumped storage power plants is 52.6% and 2.00%, respectively

[6] We include thermal and hydro power plants whose generation capacity is greater than or equal to 0.03GW in our simulation.

so that their annual output is consistent with the actual output in 2015 [8].[7] We also adjust the capacity factor of the thermal power plants so that the capacity factor of the thermal power plants in our simulation result is consistent with the actual capacity factor of the thermal power plants in the fiscal year 2014 [9]. The run-of-river type hydro and nuclear power plants are assumed to be in operation at the rated power at all times.[8]

For the simulation in 2030, in addition to the existing power plants, we reflect new construction, abolition and the change in generation capacity of thermal and hydro power plants up to 2030 as much as possible based on the electric supply plan disclosed by nine electric power companies and wholesale electricity utilities [10]. For the nuclear power plants, we adjust the number of plants so that the annual output of nuclear power plants is consistent with the official target in Long-term Energy Supply and Demand Outlook [15]. Since average capacity factor of nuclear power plants in five years before the Great East Japan Earthquake is 64.7% [13], we assume its capacity factor to be 64.7%. The capacity factor of reservoir type hydro, pumped storage and thermal power plants are assumed to be the same as in the simulation in 2015. In Table 1, we show the number of thermal, hydro and nuclear power plants by area in 2015 and 2030, and in Table 2, we show the generation capacity of them by area in 2015 and 2030.

Table 1. Number of power plants by power source and area

(Units)

2015		Hokkaido	Tohoku	Tokyo	Chubu	Hokuriku	Kansai	Chugoku	Shikoku	Kyushu	Total
Hydro	Pumped storage	4	2	13	7	1	6	3	2	3	41
	General hydro	11	29	22	26	19	45	3	8	12	175
Thermal	Oil-fired	9	5	37	8	4	21	17	5	11	117
	LNG-fired	0	14	40	20	0	20	4	2	8	108
	Coal-fired	9	10	10	7	5	7	9	9	11	77
Nuclear		0	0	0	0	0	0	0	0	2	2
Total		33	60	122	68	29	99	36	26	47	520

(Units)

2030		Hokkaido	Tohoku	Tokyo	Chubu	Hokuriku	Kansai	Chugoku	Shikoku	Kyushu	Total
Hydro	Pumped storage	5	2	14	7	1	6	3	2	3	43
	General hydro	11	29	22	27	19	45	3	8	12	176
Thermal	Oil-fired	9	4	37	8	4	19	17	5	8	111
	LNG-fired	3	13	40	21	2	21	4	3	9	116
	Coal-fired	9	11	10	8	5	9	11	9	12	84
Nuclear		3	4	12	3	2	10	1	2	5	42
Total		40	63	135	74	33	110	39	29	49	572

7 We don't take the constraints in terms of pumped storage power plants' operations such as the capacity of upper and lower reservoirs, and the amount of electricity consumed by them into account in our simulation.
8 We don't take power plant's minimum output, maintenance status, forced outages and minimum outage time into account in our simulation.

Table 2. Generation capacity by power source and area

(GW)

2015		Hokkaido	Tohoku	Tokyo	Chubu	Hokuriku	Kansai	Chugoku	Shikoku	Kyushu	Total
Hydro	Pumped storage	0.8	1.5	10.2	4.5	0.2	5.3	2.1	0.6	2.3	27.5
	General hydro	0.5	2.5	1.3	1.7	1.5	3.2	0.1	0.4	0.9	12.0
Thermal	Oil-fired	2.1	1.7	14.0	3.2	1.5	8.7	4.6	1.7	4.0	41.6
	LNG-fired	0.0	7.3	29.8	17.2	0.0	8.5	2.2	0.6	4.7	70.2
	Coal-fired	2.4	6.2	11.1	4.4	2.7	5.4	3.5	1.9	6.1	43.5
Nuclear		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.8	1.8
Total		5.8	19.1	66.4	30.9	5.8	31.1	12.5	5.2	19.8	196.7

(GW)

2030		Hokkaido	Tohoku	Tokyo	Chubu	Hokuriku	Kansai	Chugoku	Shikoku	Kyushu	Total
Hydro	Pumped storage	1.0	1.5	13.7	4.4	0.2	5.3	2.1	0.6	2.3	31.2
	General hydro	0.5	2.5	1.3	1.8	1.5	3.2	0.1	0.4	0.9	12.2
Thermal	Oil-fired	2.1	1.6	14.0	3.2	1.5	7.5	4.6	1.7	2.8	39.1
	LNG-fired	1.7	8.0	31.9	19.7	0.8	12.2	2.2	0.9	5.2	82.5
	Coal-fired	2.4	6.7	11.1	5.4	2.7	6.6	5.1	2.4	7.1	49.5
Nuclear		2.1	3.3	13.7	3.6	1.7	10.1	0.8	1.5	4.7	41.5
Total		10	24	86	38	8	45	15	7	23	256.0

5.2.2 RE Sources

RE sources are divided into residential and non-residential PV, wind, medium-small sized hydro, geothermal and biomass power plants. For the simulation in 2015, we use the actual installed capacity of RE sources by area at the end of June 2015 [11] and for the simulation in 2030, we **a**ssume that the expected capacity of RE sources in 2030 disclosed by Long-term Energy Supply and Demand Outlook [15] is installed. We allocate the expected capacity in 2030 to each area in proportion to the installed capacity at the end of April 2016 [11] [15]. We show the installed capacity of RE sources by area in 2015 in Table 3 and the expected capacity of RE sources by area in 2030 in Table 4. For residential PV, non-residential PV and wind power plants, we compute hourly output by area and fix them exogenously throughout our simulation following Saito et al.(2014) [36], Saito and Ohashi(2015) [37]. In terms of PV, we compute hourly output per kW by prefecture using the data (PV300 Data) on the amount of insolation at 321 spots in Japan from January 2011 to June 2013 which is collected by the demonstration project by Ministry of Economy, Trade and Industry (METI).[9] Multiplying hourly output per kW by installed capacity of PV, we obtain hourly output of PV by area. In terms of wind power plants, we use hourly capacity factor by area in the fiscal year 2011 and 2012, the data which is collected by Japan Wind Power Association. Multiplying hourly capacity factor by installed capacity of wind power plants, we obtain hourly output of wind power plants by area. In Figure 6, we show hourly total output from PV and wind in 2015. Electricity from PV is generated between 5 a.m. and 7 p.m.. The same is true in 2030. The annual total output from PV is 30.09TWh and that from wind is 6.17TWh

[9] The project is referred to as "Bunsan-gata Shin Energy Tairyo Dounyu Sokushin Keito Antei Taisaku Jigyo".

in 2015. In 2030, the annual total output from PV and wind increase to 74.54TWh and 22.89TWh, respectively.

Table 3. Installed capacity of RE sources by area in 2015

(GW)

2015	Residential PV	Non-residential PV	Wind	Medium-small sized hydro	Geothermal	Biomass
Hokkaido	0.12	0.53	0.32	0.05	0.03	0.04
Tohoku	0.55	1.22	0.87	0.10	0.26	0.10
Tokyo	2.25	4.38	0.23	0.04	0.00	0.44
Chubu	1.46	2.70	0.25	0.05	0.00	0.21
Hokuriku	0.12	0.33	0.15	0.03	0.00	0.03
Kansai	1.08	2.01	0.16	0.00	0.00	0.20
Chugoku	0.68	1.39	0.30	0.02	0.00	0.16
Shikoku	0.34	1.08	0.14	0.01	0.00	0.06
Kyushu	1.31	3.97	0.47	0.01	0.22	0.19
Total	7.93	17.60	2.89	0.31	0.51	1.45

Table 4. Expected capacity of RE sources in 2030

	Expected capacity in 2030 (GW)
Residential PV	9.0
Non-residential PV	55.0
Wind	10
Medium-small sized hydro	1.30～2.01
Geothermal	1.40～1.55
Biomass	6.02～7.28

(By Long-term Energy Supply and Demand Outlook)

(GW)

2030	Residential PV	Non-residential PV	Wind	Medium-small sized hydro	Geothermal	Biomass
Hokkaido	0.15	1.76	2.29	0.18	0.07	0.31
Tohoku	0.63	9.56	4.56	0.44	0.79	0.89
Tokyo	2.53	13.48	0.41	0.15	0.01	1.62
Chubu	1.64	6.67	0.41	0.39	0.01	1.04
Hokuriku	0.13	0.80	0.18	0.15	0.00	0.09
Kansai	1.21	4.44	0.31	0.08	0.00	0.77
Chugoku	0.74	4.28	0.57	0.09	0.00	0.45
Shikoku	0.38	1.97	0.41	0.08	0.00	0.38
Kyushu	1.49	11.66	0.84	0.10	0.59	1.08
Total	8.91	54.61	9.98	1.65	1.48	6.62

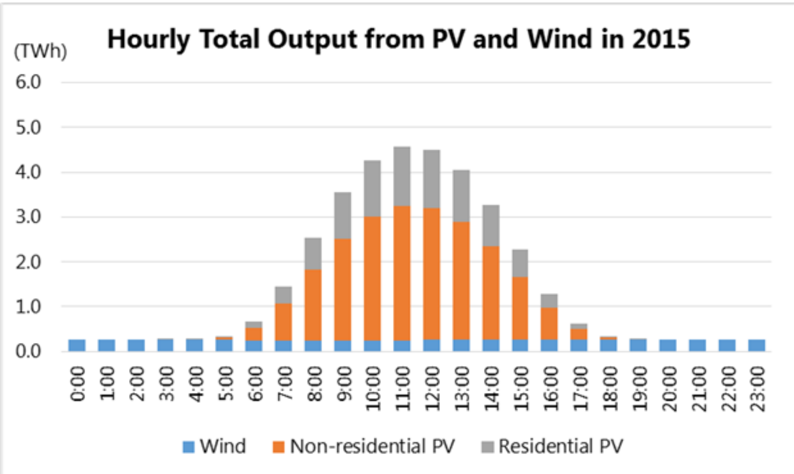


Figure 6. Hourly total output from PV and wind in 2015

5.2.3 Variable Cost and Volume of CO_2 Emissions

We consider fuel cost as variable cost. For the simulation in 2015, we assume that the fuel cost per kWh of hydro power plants, RE sources other than biomass are zero. For the nuclear power plants, we consider nuclear fuel cycle cost (front- and back-end) and set 1.54 JPY/kWh [21]. For the biomass power plants, the fuel cost of model plant (Generation capacity: 0.0057GW, Capacity factor: 87%, Years in operation: 40 years) is 21.0 JPY/kWh according to the publicly available material [21]. Based on this data, we compute the fuel cost per kWh of each biomass power plant in our simulation in proportion as its generation capacity. For the thermal power plants, we first compute the fossil fuel price per unit for oil, LNG and coal using the actual fossil fuel price in 2015 [18] [19], miscellaneous fuel expense [21] and petroleum and coal tax [22]. After that, using the data on heating value of each fuel type [23] and generating efficiency of each thermal power plant [12], we compute the fuel cost per kWh by fuel type and generating efficiency following Saito and Ohashi(2015) [37]. Since the ratio of crude oil and Bunker C consumption for electric power generation is 4 : 6 in the fiscal year 2014 [7], we use the average fossil fuel price weighted by that ratio for the power plants that consume crude and heavy oil for electric power generation. In addition, we collect the data on the volume of CO_2 emissions per kWh by power source based on Imamura et al.(2016) [33] and compute the volume of CO_2 emissions per kWh of thermal power plants in our simulation by fuel type and generating efficiency. We assume that the volume of CO_2 emissions per kWh of other power sources are zero.

For the simulation in 2030, we compute expected fossil fuel prices for oil, LNG and coal in 2030 based on the International Energy Agency (IEA)'s predictions for 2030 as provided in "*World Energy Outlook 2015*" [17]. It provides the expected dollar-based fossil fuel prices in 2030 in addition to the dollar-based fossil fuel prices in 2014. First, we compute (I) yen-based fossil fuel prices in 2030 evaluated by the exchange rate in 2014 by multiplying yen-based fossil fuel prices in 2014 by the ratio of dollar-based fossil fuel prices in 2030 to that in 2014. Second, we compute (II) yen-based fossil fuel prices in 2030 evaluated by the exchange rate in 2015 by multiplying (I) by the ratio of average exchange rate in 2015 to that in 2014 [20]. Finally, we obtain the expected fossil fuel prices in 2030 for our simulation by adding miscellaneous fuel expense [21] and petroleum and coal tax [22] to (II) computed above. Based on this price, we compute the fuel cost per kWh of thermal power plants in 2030 in the same way as the simulation in 2015. The fuel cost per kWh of other power plants is assumed to be the same as in the simulation in 2015. We also assume that the volume of CO_2 emissions per kWh of thermal power plants is the same as in the simulation in 2015. We show the fuel cost and the volume of CO_2 emissions per kWh for the thermal power plants by fuel type and generating efficiency in Table 5.

In Figure 7, we show supply curves in 2015 and 2030 using the data on each power plant's generation capacity and fuel cost per kWh described above. RE in Figure 7 includes PV, wind, geothermal, biomass and hydro power plants. The total generation capacity increases from 227.4GW in 2015 to 339.3GW in 2030, and the installed capacity of RE sources increases from 30.7GW in 2015 to 83.3GW in 2030. Broadly speaking, the fuel cost per kWh of oil-fired thermal power plants is the highest, following LNG-fired and coal-fired thermal power plants, nuclear power plants and RE sources both in 2015 and 2030.

Table 5. Fuel cost and volume of CO_2 emissions for the thermal power plants

Fuel type (unit)	Heating value (MJ/unit)	Category of thermal power plant (Year of operation start or fuel conversion)	Generating efficiency (%)	Output (kWh/unit)	Volume of CO_2 emissions (g-CO_2/kWh)	2015		2030	
						Fuel price (JPY/unit)	Fuel cost (JPY/kWh)	Expected fuel price (JPY/unit)	Fuel cost (JPY/kWh)
Light oil (kl)	38,040	Gas turbine(~1978)	27.0	2853.0	695.0	103,725	36.36	169,740	59.50
		Gas turbine: Emergent power source(2011~)	31.0	3275.7	695.0		31.67		51.82
Crude and heavy oil (kl)	40,380	Oil-fired(~1973)	37.0	4150.2	696.2	51,390	12.38	98,951	23.84
		Oil-fired(1974~1980)	38.0	4262.3	696.2		12.06		23.22
		Oil-fired(1981~1986)	39.0	4374.5	696.2		11.75		22.62
		Oil-fired(1987~)	40.0	4486.7	696.2		11.45		22.05
LNG (ton)	55,010	Gas turbine: Emergent power source	31.0	4737.0	476.0	66,697	14.08	84,319	17.80
		Combined cycle(~1990)	43.0	6570.6	406.0		10.15		12.83
		Combined cycle(1991～1997)	50.0	7640.3	406.0		8.73		11.04
		Combined cycle(1998～2010)	52.0	7945.9	362.0		8.39		10.61
		Combined cycle(2011～2017)	54.0	8251.5	341.0		8.08		10.22
		Combined cycle(2018~)	56.0	8557.1	341.0		7.79		9.85
		Steam turbine(~1988)	38.0	5806.6	476.0		11.49		14.52
		Steam turbine(1989~)	41.0	6265.0	476.0		10.65		13.46
Coal (ton)	25,970	Coal-fired(~1980)	36.0	2597.0	886.0	11,620	4.47	17,564	6.76
		Coal-fired(1981~1991)	38.0	2741.3	886.0		4.24		6.41
		Coal-fired(1992~)	41.0	2957.7	810.0		3.93		5.94

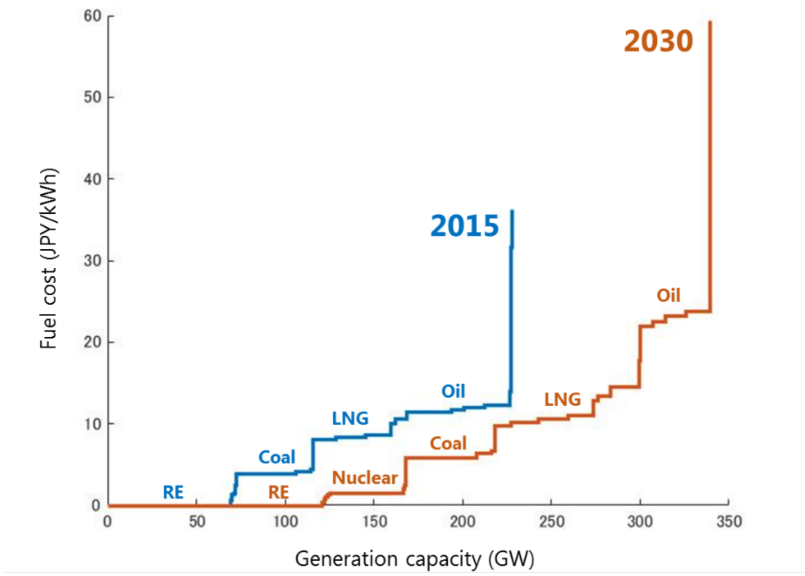


Figure 7. Supply curve

5.2.4 Fixed Cost

We assume that the fixed cost consists of capital cost, and operating and maintenance (O&M) cost. We collect the data on capital and O&M cost of model plant by power source based on the publicly available material [21]. In terms of O&M cost, we compute the annual O&M cost per kW by power source by dividing model plant's annual O&M cost by its generation capacity. In terms of capital cost, following Saito et al.(2014) [36], we compute the present value of total capital cost in the years in operation by power source assuming that the power plants incur the construction cost at the time of construction, the property tax in the years in operation, the decommissioning cost at the end of operation. We use average interest rate of 40-year government bonds in 2015 [24] as discount factor for the present value calculation. Dividing the present value of total capital cost in the years in operation by the number of years in operation and generation capacity, we obtain the annual capital cost per kW by power source. Based on this data, we compute the annual fixed cost of each power plant in our simulation in proportion as its generation capacity. We use the same value of fixed cost both in 2015 and 2030. We show the annual fixed cost per kW for model plants by power source in Table 6. In Figure 8, we show the scatter plot in terms of fuel cost per kWh and annual fixed cost for each power plants in 2015. The power plants with lower fuel cost tend to have higher fixed cost in 2015. We find almost the same tendency in 2030.

Table 6. Annual fixed cost per kW for model plants by power source

Power source	Generation capacity (kW)	Years in operation (Year)	Annual capital cost (JPY/kW)	Annual O&M cost (JPY/kW)	Annual fixed cost (JPY/kW)
Nuclear	1,200,000	40	10,736	19,144	29,880
Coal-fired thermal	800,000	40	6,844	9,944	16,788
LNG-fired thermal	1,400,000	40	3,285	3,651	6,936
Oil-fired thermal	400,000	40	5,475	6,421	11,896
Hydro	12,000	40	19,089	9,140	28,229
Wind	20,000	20	15,758	6,000	21,758
Geothermal	30,000	40	21,626	33,000	54,626
Residential PV	4	20	18,600	3,600	22,200
Non-residential PV	2,000	20	16,148	3,700	19,848
Medium-small sized hydro	200	40	25,378	70,680	96,058
Biomass	5,700	40	10,895	27,000	37,895

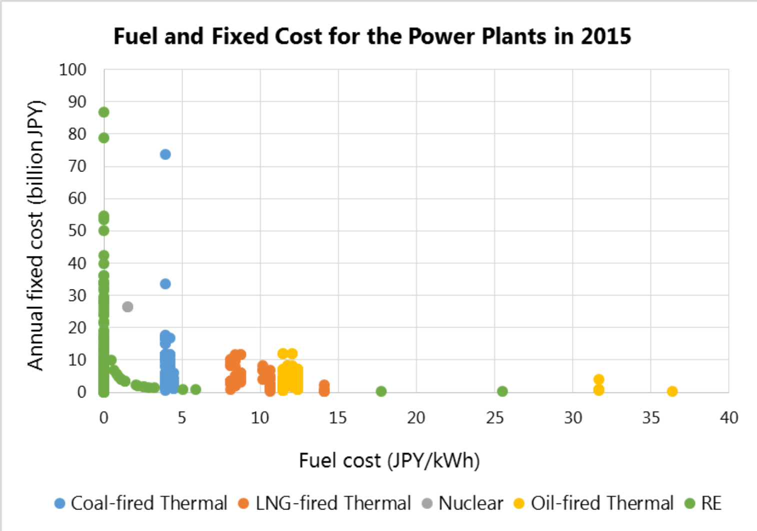


Figure 8. Fuel and fixed cost for the power plants in 2015

5.3 Capacity of Inter-area Transmission Lines

For the simulation in 2015, we use the actual operating capacity in the daytime on weekdays in August, 2015. For the simulation in 2030, we use the operating capacity in 2025 planed by OCCTO [25], and in addition, we reflect the consolidation of Tokyo-Chubu and Tohoku-Tokyo transmission line up to 3.0GW and 11.2GW, respectively. We assume that all inter-area transmission lines are being operated in an economically efficient manner.[10] We show the capacity of each inter-area transmission line in 2015 and 2030 in Table 7.

Table 7. Capacity of inter-area transmission lines

(GW)

Inter-area transmission line		2015	2030
Hokkaido⇔Tohoku	Hokkaido→Tohoku	0.60	0.90
	Tohoku→Hokkaido	0.60	0.90
Tohoku⇔Tokyo	Tohoku→Tokyo	4.80	11.20
	Tokyo→Tohoku	0.80	0.66
Tokyo⇔Chubu	Tokyo→Chubu	1.20	3.00
	Chubu→Tokyo	1.20	3.00
Hokuriku⇔Chubu	Hokuriku→Chubu	0.30	0.30
	Chubu→Hokuriku	0.30	0.30
Chubu⇔Kansai	Chubu→Kansai	1.78	1.92
	Kansai→Chubu	2.50	2.50
Hokuriku⇔Kansai	Hokuriku→Kansai	1.60	1.62
	Kansai→Hokuriku	1.30	1.30
Kansai⇔Chugoku	Kansai→Chugoku	2.70	2.78
	Chugoku→Kansai	4.00	4.05
Kansai⇔Shikoku	Kansai→Shikoku	1.40	1.40
	Shikoku→Kansai	1.40	1.40
Chugoku⇔Shikoku	Chugoku→Shikoku	1.20	1.20
	Shikoku→Chugoku	1.20	1.20
Chugoku⇔Kyushu	Chugoku→Kyushu	0.54	0.54
	Kyushu→Chugoku	2.54	2.78

10 We don’t take transmission loss into account in our simulation.

5.4 Price Cap

Since the level of imbalance energy price is the de facto price cap in Japanese kWh-market, we use it as the level of price cap. We collect data on the imbalance energy price disclosed by nine electric power companies [26]. We assume the same level of price cap in the simulation in 2030 as in 2015. We show the level of price cap by area, season, day- and night-time in Table 8.

Table 8. Level of price cap by area, season, day- and night-time

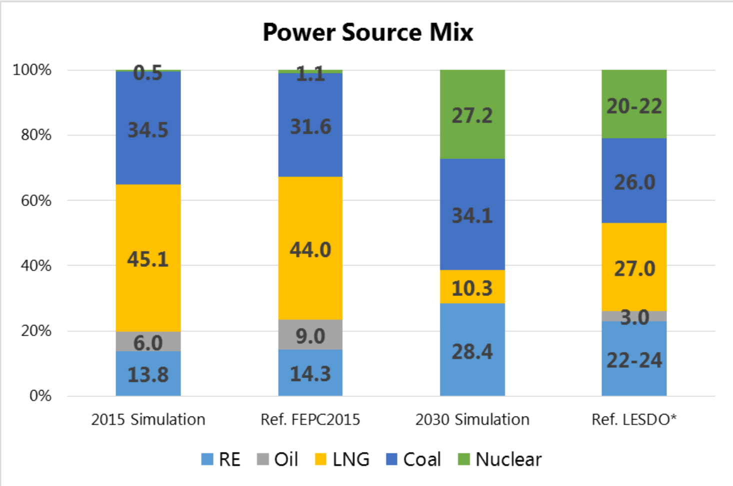
(JPY/kWh)

Area	Summer		Other seasons	
	Daytime	Night-time	Daytime	Night-time
Hokkaido	51.60	30.69	51.60	30.69
Tohoku	42.95	24.00	41.03	24.00
Tokyo	53.21	28.84	47.03	28.84
Chubu	52.30	28.47	45.26	28.47
Hokuriku	38.03	17.34	29.61	17.34
Kansai	56.58	28.33	39.57 (~May, 2015) 45.37 (June, 2015~)	24.46(~May, 2015 28.33 (June, 2015~)
Chugoku	40.78	20.37	32.34	20.37
Shikoku	48.57	22.84	36.99	22.84
Kyushu	49.01	21.51	36.22	21.51

6 Simulation Results

6.1 Power Source Mix, Annual Fuel Cost and Volume of CO_2 Emissions

In Figure 9, we show the composition of energy sources for electric power generation from our simulation results in 2015 and 2030 ("2015 Simulation" and "2030 Simulation" in Figure 9). For comparison, we also show the actual power source mix in the fiscal year 2015 which is disclosed by The Federation of Electric Power Companies of Japan [30] ("FEPC2015" in Figure 9) and the official target in 2030 [15] ("LESDO" in Figure 9). Comparing "2015 Simulation" with "FEPC2015", we verify that our simulation model can almost replicate the actual power source mix. From our simulation results, we find that the share of power sources with zero CO_2 emissions (RE and nuclear) increases from 14.3% in 2015 to 55.6% in 2030, achieving the official target of 44% in 2030 [15]. Accordingly, the annual fuel cost reduces by 40.9% and the annual volume of CO_2 emissions by 37.1% from 2015 to 2030 as in Table 9. The amount of reduction is 2.15 trillion JPY (2.49 JPY/kWh) and 159.9 million tons, respectively. The latter corresponds to 12.1% of Japan's total volume of greenhouse gas emissions in the fiscal year 2015 (1.32 billion tons) and 0.58 trillion JPY (0.67 JPY/kWh) if we convert the volume of CO_2 emissions to monetary value by 3,631 JPY/ton from EU Current Policies Scenario in 2030 [17]. We find that the reduction rate of CO_2 emissions also achieves the official target in 2030 (32% below the fiscal year 2014 levels) [15].



(*LESDO=Long-term Energy Supply and Demand Outlook)

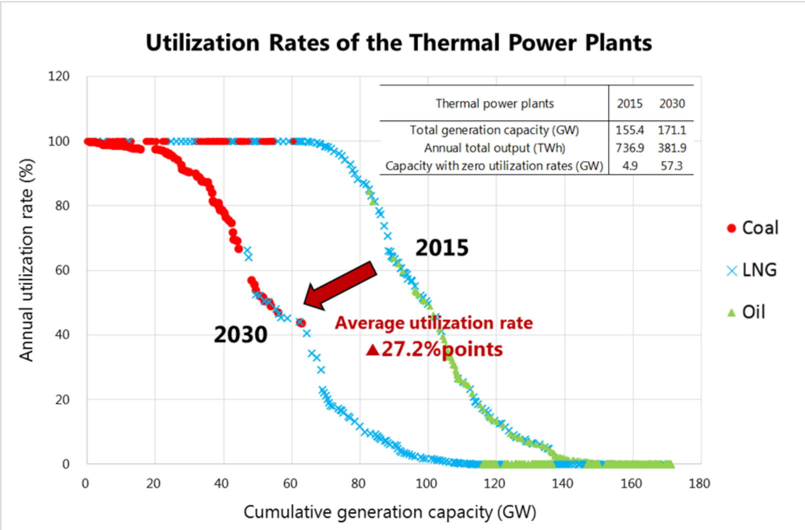
Figure 9. Power source mix

Table 9. Annual fuel cost and volume of CO_2 emissions

	Annual fuel cost (trillion JPY)	Annual volume of CO_2 emissions (million ton)
2015 Simulation	5.2520	431
2030 Simulation	3.1061	271
%Change	-40.9	-37.1

6.2 Mothballing

Increase in the share of power sources with zero CO_2 emissions from 2015 to 2030 significantly decreases utilization rates of the thermal power plants. In Figure 10, we show the relationship between cumulative generation capacity and annual utilization rates of the thermal power plants in 2015 and 2030. We find that although total capacity of the thermal power plants increase by 15.7GW from 2015 to 2030, average utilization rate of the thermal power plants significantly decreases by 27.2 percentage points. In particular, that of LNG-fired thermal power plants significantly decreases by 50.2 percentage points. Decrease in the utilization rates reduce annual total output of the thermal power plants by 355.0TWh, and the capacity of the thermal power plants with zero utilization rates increase by 52.4GW. RE sources such as PV and wind have the features of variability and intermittency. Therefore, a certain portion of load-following thermal power plants must be kept running at minimum output as a backup power source (*Mothballing*). While such operations of the thermal power plants are indispensable to cope with the fluctuation of the output from variable and intermittent RE sources, it significantly decreases utilization rates of the thermal power plants.



Fuel type	Average utilization rate (%)	
	2015	2030
Coal	99.99	83.30
LNG	59.80	9.59
Oil	16.43	0.00
All	53.25	26.08

Figure 10. Utilization rates of the thermal power plants

6.3 System Price

In Figure 11, we show the distribution of equilibrium system price from our simulation results in 2015 and 2030 ("2015 Simulation" and "2030 Simulation (Demand = Same as 2015)" in Figure 11). For comparison, we also show the distribution of actual system price in JEPX in 2015 [31]. Moreover, in terms of the simulation in 2030, we also show the simulation result for an additional scenario in 2030 ("2030 Simulation (Demand = LESDO)" in Figure 11) which assumes that annual total electricity demand in 2030 is 973.2TWh which is the official target in 2030 by Long-term Energy Supply and Demand Outlook [15].

In 2015, average system price from our simulation is 10.69 JPY/kWh which is close to the actual average system price 10.97 JPY/kWh in 2015. Comparing "2015 Simulation" with "2030 Simulation (Demand = Same as 2015)", we find that average system price decreases by 2.14 JPY/kWh from 2015 to 2030. The system price ranges from 8.39 to 12.38 JPY/kWh in "2015 Simulation" and from 1.54 to 14.52 JPY/kWh in "2030 Simulation (Demand = Same as 2015)". Although the fuel cost per kWh of the thermal power plants is higher in the simulation in 2030 than that in 2015 as shown in Table 5, the equilibrium system price is lower in 2030 because further installation of RE sources and the operation of nuclear power plants significantly shift the supply curve rightward as shown in Figure 7. In terms of an additional scenario "2030 Simulation (Demand = LESDO)", average system price decreases by 0.69 JPY/kWh from "2015 Simulation" to "2030 Simulation (Demand = LESDO)". If we assume this additional scenario in 2030, the demand curve also shift rightward along with the supply curve and the amount of reduction in average system price from 2015 to 2030 decreases from 2.14 to 0.69 JPY/kWh.

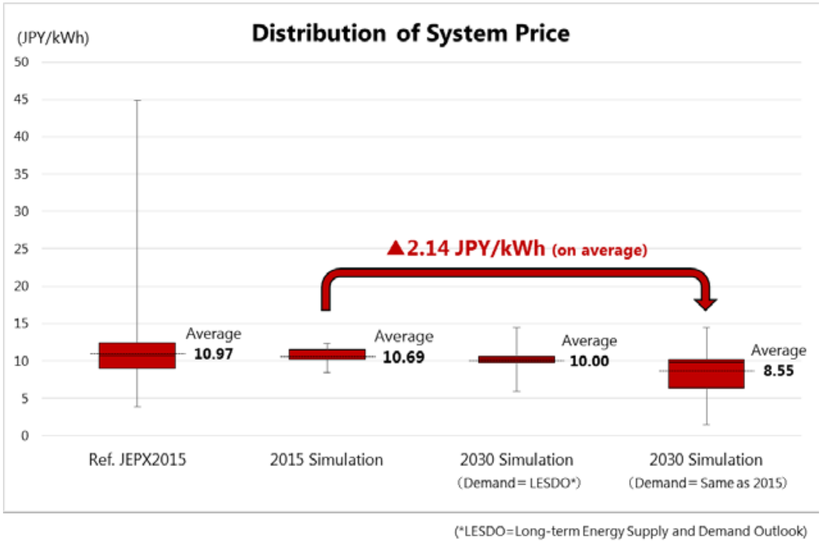


Figure 11. System price

6.4 Missing Money Problem

Decrease in utilization rates of the thermal power plants and equilibrium kWh-price results in undermining the profitability of the thermal power plants. In Figure 12, we show the relationship between fuel cost and fixed cost recovery rate for the thermal power plants in 2015 and 2030. We compute the fixed cost recovery rate for each thermal power plant as annual inframarginal rent divided by annual fixed cost. We find that the thermal power plants with lower fuel cost tend to have higher fixed cost recovery rate, or higher profitability and that the percentage of the thermal power plants with fixed cost recovery rate over 100% decreases by 32.1 percentage points from 2015 to 2030. By fuel type, we find that (i) none of the oil-fired thermal power plants can recover their fixed cost both in 2015 and 2030, (ii) none of the LNG-fired thermal power plants can recover their fixed cost in 2030, and (iii) even for the coal-fired thermal power plants that are base-load electricity sources, only 34.5% of them can recover their fixed cost in 2030. This finding indicates that the rise of variable and intermittent RE sources results in undermining the profitability of the thermal power plants under the conventional market mechanism where power plants earn revenue only from the kWh-market (*Missing money problem*). In addition, since further installation of RE sources with lower marginal generation cost lowers the equilibrium kWh-price as we describe in Section 6.3, it decreases the revenue even for the thermal power plants in operation. If it is hard for power plants to sufficiently recover their fixed cost, they might exit from the market and new investments on power plants might be also discouraged. It might result in Japan being unable to maintain sufficient capacity of electricity supply in the future.

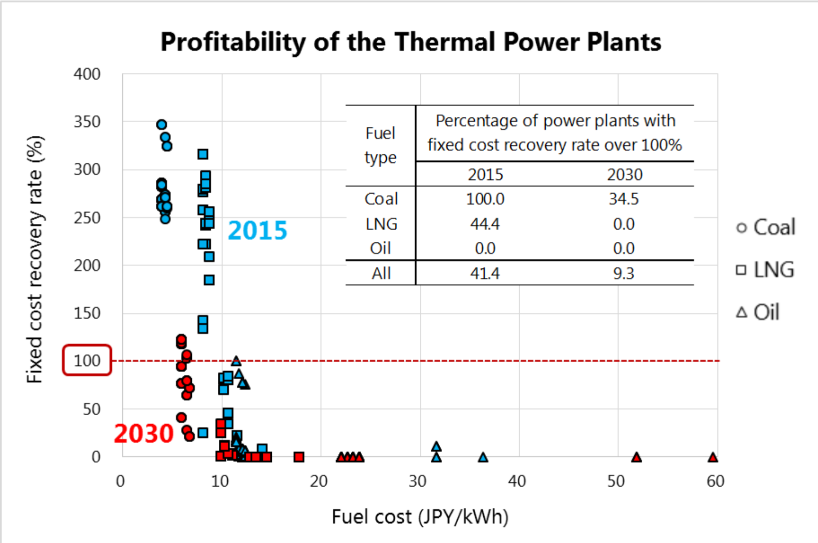


Figure 12. Profitability of the thermal power plants

7 Conclusion

We develop a simulation model to compute the competitive kWh-market equilibrium. The model enables us to simulate the equilibrium kWh-price and each power plant's output, revenue, variable cost and inframarginal rent on an hourly basis. Using the model, we conduct simulations in the years of 2015 and 2030 on the basis of the publicly available data in order to evaluate the impact of further installation of RE sources.

We find that on the basis of the scenario in 2030 proposed by the government, further installation of RE sources lowers kWh-price and reduces the fuel cost and the volume of CO_2 emissions. However, it significantly decrease utilization rates of the thermal power plants, resulting in undermining the profitability of them.

Our finding indicates a need for new revenue mechanism such as capacity market that enables power plants to earn revenue from their generation capacity (kW) along with the conventional market mechanism where they earn revenue based on the volume of electricity output (kWh). Capacity market is a type of capacity mechanism [11] which is already introduced or under consideration in major Western countries. While Japan lays out the direction for introducing the capacity market in the future, it is indispensable for a careful consideration since introducing the capacity mechanism is still under a trial and error process even in the countries that already introduced the capacity mechanism.

[11] Capacity mechanism can be divided into some types such as capacity market (centralized or decentralized), strategic reserve and capacity payment.

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Appendix: Estimation of electricity demand function

Estimation of electricity demand function is based on the method by Saito et al.(2014) [36] and Saito and Ohashi(2015) [37]. Dependent variable is the logarithmic hourly electricity demand by area from 2008 to 2015 which disclosed by nine electric power companies [1] [2]. Number of samples is 434,010. As the explanatory variables, we first consider the regional difference adjusted monthly electricity charges to capture the effect of electricity charges on electricity demand. The monthly consumer price index (electricity charges) on the basis of 2010 and the regional difference price index in the capital of each prefecture are disclosed by Statistics Bureau, Ministry of Internal Affairs and Communications [3] [4]. We collect data on the regional difference price index in 2010 in each of nine city (Sapporo city, Sendai city, Tokyo metropolitan area, Nagoya city, Toyama city, Osaka city, Hiroshima city, Takamatsu city and Fukuoka city) in which the head offices of nine electric power companies are. We obtain regional difference adjusted monthly electricity charges by multiplying this index by monthly consumer price index (electricity charges) in each city. We also consider hourly temperature (up to the quartic term) and the dummy variable in terms of the daily rainfall amount by each city above as the additional explanatory variables [5]. Since the effect of these weather variables is expected to be different by area, we estimate the coefficients of weather variables by area. We also include the fixed effect of area, quarterly period, year, month, day, day of the week, hour and hour of the public holiday. In addition, in order to capture the effect of Great East Japan Earthquake, we also include dummy variables in terms of hours after 3 p.m. on the day of the earthquake, announcement of the law of electricity usage restrictions in Tohoku and Tokyo area and rolling blackouts in Tokyo area. Using above dependent and explanatory variables, we estimate the electricity demand function and obtain adjusted R^2 of 0.9964. The coefficient on electricity charges is -0.00187 which implies that the electricity demand decrease by 0.187% if the electricity charges increase by 1%. Using the predicted values from estimated demand function, we complement the missing values.

After estimating the demand function and complementing the missing values, we add the self-consumption of residential PV. Residential PV is under the Excess Electricity Purchasing Scheme, and the self-consumption and electricity saving cannot be distinguished from the view point of the electric power companies. Since the rate of excess output sold of residential PV is 70% based on the publicly available material [14], we assume that if the capacity factor of residential PV is greater than or equal to 8%, the excess output more than 8% is sold, and otherwise, the output is self-consumed so that the annual selling output is consistent with 70% of the annual total output. By adding the self-consumption of residential PV to the complemented demand data, we obtain the electricity demand data which is used in our simulation.