Aggregation of Electricity Supply Plans Fiscal Year 2018

November 2018

Organization for Cross-regional Coordination of Transmission Operators, JAPAN

＜INTRODUCTION＞

The Organization for Cross-regional Coordination of Transmission Operators, JAPAN (hereafter, the Organization) has aggregated the electricity supply plans for fiscal year (FY) 2018 according to Article 28 of the Operational Rules of the Organization and Article 29 of the Electricity Business Act, which require the plans to be submitted to the Ministry of Economy, Trade and Industry (METI) by electric power companies (EPCOs) under the same article of the Act.

The electricity supply plans are submitted by the EPCOs according to the Network Code of the Organization, aggregated by the Organization, and sent to METI annually by the end of March.

In total, 1,125 electricity supply plans for FY 2018 were aggregated, including 1,124 plans submitted by companies that became EPCOs by the end of December 2017 and one plan submitted by a company that became an EPCO by the end of March 2018.

Number of Electric Power Companies Subject to the Aggregation in FY 2018

Business License	Number
Generation Companies	642
Retail Companies	448
Specified Transmission, Distribution and Retail Companies	19
Specified Transmission and Distribution Companies	4
Transmission Companies	2
General Transmission and Distribution Companies	10
Total	1,125

CONTENTS

1. Electricity Demand Forecast

(1) Actual and Preliminary Data for FY 2017 and Forecast for FY 2018 (Short-term)

a. Peak Demand (average value of the three highest daily loads[1]) in August

Table 1-1 shows the actual data for the aggregated peak demand for each regional service area[2] submitted by the 10 general transmission and distribution (GT&D) companies for FY 2017 and the forecast[3] value for FY 2018.

Peak demand (average value of the three highest daily loads) in August 2018 was forecast at 157,870 MW, which represents a 0.5% increase over 157,080 MW in August 2017. In addition, the actual data for FY 2017 were temperature adjusted[4] to 157,020 MW, and the forecast value for FY 2018 is an increase of 0.5% over the temperature-adjusted value for FY 2017.

Table 1-1 Peak Demand (average value of the three highest daily loads) in August
(Nationwide, 10^4 kW at the sending end)

FY 2017 Actual	FY 2018 Forecast
15,708 (15,702)	15,787 +0.5% (+0.5%)*

Value in parentheses is temperature adjusted.
* % change compared with actual data for the previous year

b. Forecast for FY 2018

Table 1-2 shows the monthly average value of the three highest daily loads in FY 2018 from the aggregated peak demand for each regional service area submitted by the 10 GT&D companies. The monthly average value of the three highest daily loads in summer (August) is greater than that in winter (January) by about 10 GW; therefore, nationwide peak demand occurs in summer.

Table 1-2 Monthly Peak Demand (average value of the three highest daily loads) in FY 2018
(Nationwide, 10^4 kW at the sending end)

	Apr.	May	Jun.	Jul.	Aug.	Sep.
Peak Demand	11,767	11,484	12,696	15,745	15,787	13,901
	Oct.	Nov.	Dec.	Jan.	Feb.	Mar.
Peak Demand	11,881	12,587	14,048	14,798	14,778	13,479

1 Peak demand (average value of the three highest daily loads) corresponds to the average value of the three highest daily loads (hourly average) in each month.
2 Peak demand in the regional service areas refers to the average value of the three highest daily loads in public demand supplied by retail companies and GT&D companies through the transmission and distribution network of the GT&D companies. The Organization publishes these average values according to the provisions of paragraph 5, Article 23 of the Operational Rules.
3 Demand forecast beyond FY 2018 is based on normal weather. Thus, weather conditions for forecast assumption may vary in contrast to the actual data or estimated value in FY 2017.
4 Temperature adjustment is implemented to capture the current demand based on normal weather, which excludes demand fluctuations triggered by air-conditioner operation.

c. Annual Electric Energy Requirements

Table 1-3 shows the preliminary data[5] for FY 2017 and the forecast value for FY 2018 from the aggregated electric energy requirements of each regional service area submitted by the 10 GT&D companies. The electric energy requirements for FY 2018 are forecast at 888.9 TWh, a 0.4% decrease over 892.6 TWh in the preliminary data for FY 2017. In addition, the preliminary data for FY 2017 were temperature adjusted to 885.4 TWh, and the forecast value for FY 2018 is a 0.4% increase over the temperature-adjusted value in FY 2017.

Table 1-3 Annual Electric Energy Requirements
(Nationwide, TWh at the sending end)

FY 2017 Preliminary	FY 2018 Forecast
892.6 (885.4)	888.9 ▲0.4% (+0.4%)*

Value in parenthesis is temperature adjusted.
* % changes over the preliminary value for the previous year.

[5] Preliminary data for annual electric energy requirements are an aggregation of the actual data from April to November 2017 with the preliminary data from December 2017 to March 2018.

(2) 10-Year Demand Forecast (Long-term)

Table 1-4 shows the major economic indicators developed and published on November 27, 2017 by the Organization, which are assumptions for the GT&D companies to forecast the peak demand in their regional service areas.

The real gross domestic product (GDP)[6] is estimated at ¥ 537.7 trillion in FY 2018 and ¥581.4 trillion in FY 2027 with annual average growth rates of 0.9%. The index of industrial production (IIP)[7] is projected at 105.3 in FY 2018 and 108.2 in FY 2027 with annual average growth rates (AAGR) of 0.3%.

Table 1-4 Major Economic Indicators Assumed for Demand Forecast

	FY 2018	FY 2027
Gross Domestic Product(GDP)	¥ 537.7 trillion	¥ 581.4 trillion [0.9%]*
Index of Industrial Product(IIP)	105.3	108.2 [0.3%]*

* Average annual growth rate for the forecast value of FY 2018

a. Peak Demand (average value of the three highest daily loads) in August

Table 1-5 shows the peak demand forecast for FY 2018, FY 2022, and FY 2027 as the aggregation of peak demand for each regional service area submitted by the 10 GT&D companies. In addition, Figure 1-1 shows the actual data and the forecast of peak demand from FY 2005 to 2027. The peak demand nationwide is forecast at 157,860 MW in FY 2022 and 157,390 MW in FY 2027, with AAGR of -0.0% from FY 2018 to FY 2027.

The peak demand forecast over 10 years shows a slightly decreasing trend, which is largely due to negative factors, such as efforts to reduce electricity use, wider utilization of energy-saving electric appliances, a shrinking population, and load-leveling measures, and despite positive factors such as the expansion of economic scale and greater dissemination of electric appliances.

In addition, the AAGR forecast is lower than that of the previous year, mainly due to a declining level of economic activity and a decreasing trend in actual electricity demand because of progress in energy conservation.

Table 1-5 Peak Demand Forecast (average value of the three highest daily loads) for August (Nationwide, 10^4 kW at the sending end)

FY 2018 [aforementioned]	FY 2022	FY 2027
15,787	15,786 [-0.0%]*	15,739 [-0.0%]*

* Average Annual Growth Rate for the forecast value of FY 2018

6 GDP expressed as the chained price for CY 2011.
7 Index value in CY 2010 = 100

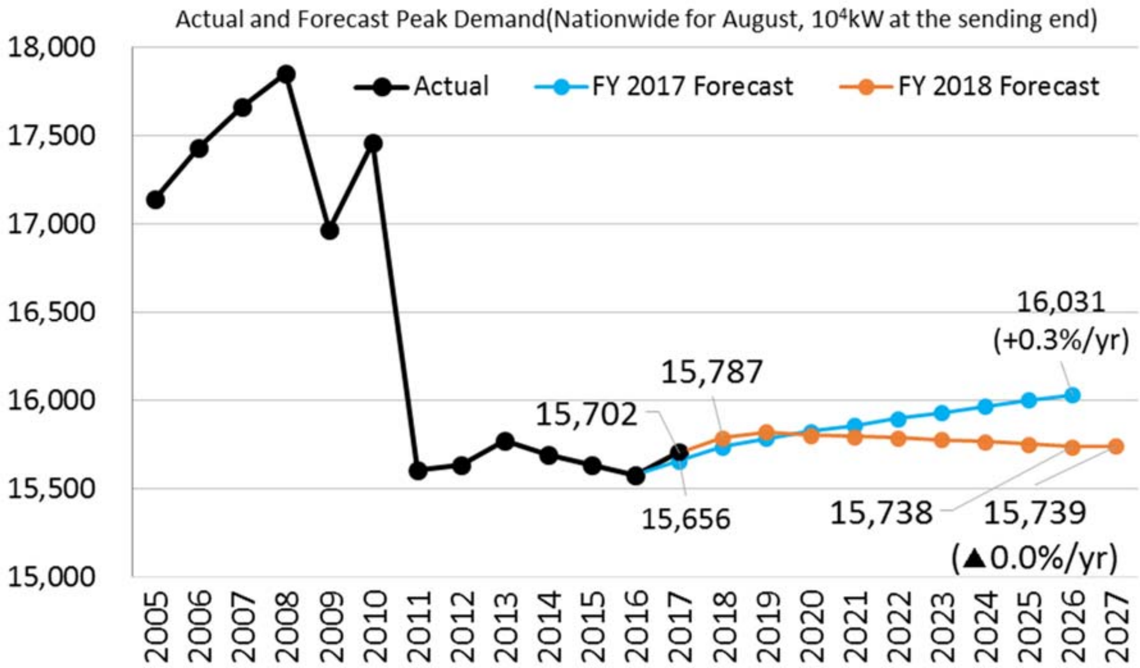


Figure 1-1 Actual and Forecast Peak Demand (Nationwide for August, 10^4 kW at the sending end)

b. Annual Electric Energy Requirement

Table 1-6 shows the forecast for annual electric energy requirements in FY 2018, FY 2022, and FY 2027 as the aggregation of the electric energy requirements for each regional service area submitted by the 10 GT&D companies. The nationwide annual electric energy requirement is forecast at 889.7 TWh in FY 2022 and 888.2 TWh in FY 2027, with an AAGR of 0.0% from FY 2018 to FY 2027.

The annual electric energy requirement forecast over 10 years shows a slightly decreasing trend, which is largely due to negative factors, such as efforts to reduce electricity use, wider utilization of energy-saving electric appliances, and a shrinking population, and despite positive factors such as expansion of economic scale and greater dissemination of electric appliances.

Table 1-6 Annual Electric Energy Requirement Forecast
(Nationwide, TWh at the sending end)

FY 2018 [aforementioned]	FY 2022	FY 2027
8,889	8,897 [+0.0%]*	8,882 [-0.0%]*

* Average annual growth rate for the forecast value of FY 2018.

2. Electricity Supply and Demand

(1) Supply–Demand Balance Evaluation Method

The Organization will evaluate the supply–demand balance for each regional service area as well as nationwide using the supply capacity[8] and peak demand data for the regional service areas. Based on the discussion at the 26th meeting of the Study Committee on Regulating and Marginal Supply Capability and Long-Term Supply–Demand Balance Evaluation (March 22, 2018), the Organization will implement its evaluation using the criterion of whether the reserve margin (%)[9] for each regional service area is secured over 8% or not, and when the least reserve margin emerges at the time other than the average value of the three highest daily loads, the least reserve margin also is secured over 8%.

In the Okinawa EPCO, the criterion is to secure power supply capacity over peak demand against an interruption of its largest generating unit and balancing capacity with frequency control function in its regional service area.

Figure 2-1 summarizes the supply–demand balance evaluation. Supply capacity includes the generating capacity requirements secured by retail and GT&D companies for their regional service areas and the production of surplus power[10] of generation companies. The supply capacity currently secured by retail companies includes power procured from other regional service areas through cross-regional interconnection lines. Thus, the surplus power of generation companies or reserve capacity of retail companies might provide supply capacity for other regional service areas in the future.

Under the circumstances in which the operation of a nuclear power plant has become uncertain, the supply capacity of the corresponding unit or plant is recorded as zero where the corresponding supply capacity is reported as “uncertain” according to Procedures for Electricity Supply Plans of FY 2018 (published in December 2017 by the Agency for Natural Resources and Energy). In the electricity supply plans for FY 2018, supply capacity was reported as “uncertain” by all nuclear power plants except for those that had resumed operation by the time of the submittal of the electricity supply plans (March 1, 2018).

---

[8] Supply capacity is the maximum power that can be generated steadily during the peak demand period (average value of the three highest daily loads).

[9] Reserve margin (%) describes the difference between supply capacity and peak demand (average value of the three highest daily loads) divided by peak demand (average value of the three highest daily loads).

[10] Surplus power is the surplus power generation capacity of generation companies in a regional service area without sales destination.

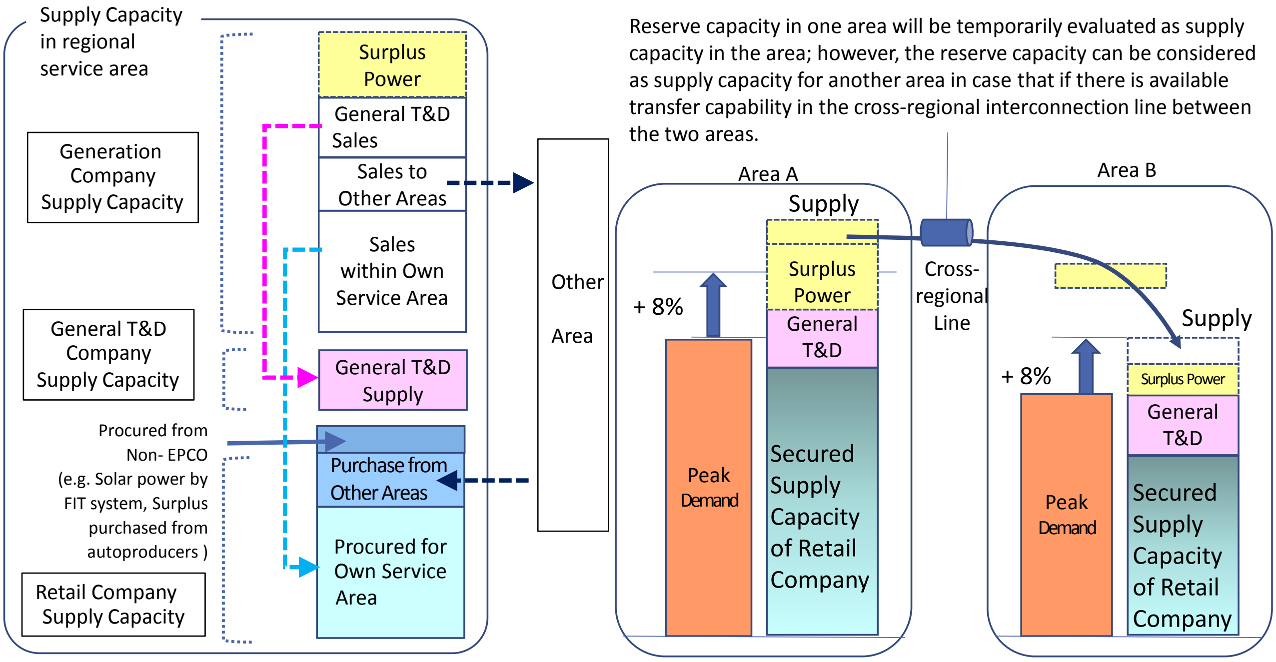


Figure 2-1 Summary of Supply–Demand Balance Evaluation

(2) Actual Data for FY 2017 and Projection for FY 2018 (Short-term)

a. Actual Data for FY 2017

Table 2-1 shows the actual supply–demand balance in August 2017 based on the nationwide supply capacity and peak demand data.

Table 2-1 Actual Supply–demand Balance in August 2017
(Nationwide, 10^4 kW at the sending end)

Peak Demand (temperature adjusted) [aforementioned]	Supply Capacity	Reserve Capacity	Reserve Margin
15,702	18,520	2,818	17.9%

A reserve margin of 8%, which is the criterion for stable supply, was secured in all regional service areas supplied by GT&D companies.

b. Projection of Supply–Demand Balance in FY 2018

Table 2-2 and Figure 2-2 show the projection of a monthly supply–demand balance (at the time of the least reserve margin) for FY 2018. A reserve margin of 8% is secured for each month nationwide.

Table 2-2 Projection of the Monthly Supply–demand Balance for FY 2018
(At the time of the least reserve margin; nationwide, 10^4 kW at the sending end)

	Apr.	May	Jun.	Jul.	Aug.	Sep.
Peak Demand	11,767	11,430	12,580	15,541	15,574	13,791
Supply Capacity	14,317	14,216	15,093	17,153	17,086	16,312
Reserve Margin	21.7%	24.4%	20.0%	10.4%	9.7%	18.3%
	Oct.	Nov.	Dec.	Jan.	Feb.	Mar.
Peak Demand	11,859	12,578	14,049	14,798	14,778	13,480
Supply Capacity	14,540	15,000	16,214	16,820	16,777	16,081
Reserve Margin	22.6%	19.3%	15.4%	13.7%	13.5%	19.3%

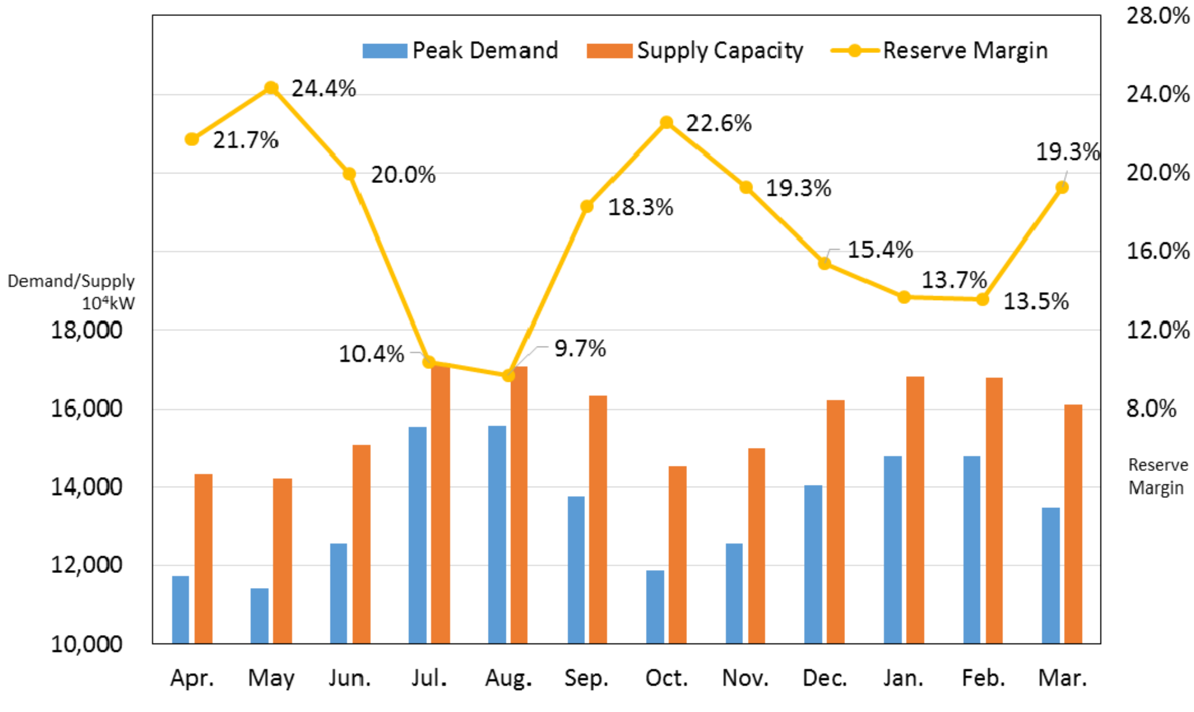


Figure 2-2 Projection of the Monthly Supply–demand Balance for FY 2018
(At the time of the least reserve margin; nationwide, at the sending end)

Table 2-3 shows the monthly projection of the least reserve margin for each regional service area. In addition, Table 2-4 shows the monthly projection of the least reserve margin[11] for each regional service area recalculated using power exchanges to areas below the 8% reserve margin from areas of over 8% reserve margin based on the available transfer capability (ATC)[12].

The least reserve margin for each regional service area almost secures the criterion of a stable supply, with a reserve margin of 8%, except for some areas and months. However, a nationwide reserve margin of 8% (the criterion of stable supply) is secured by using cross-regional interconnection lines to share power from other areas with sufficient supply capacity.

Table 2-3 Monthly Projection of the Least Reserve Margins Nationwide and for Each Regional Service Area
(Resources within own service area only, at the sending end)

	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.	Jan.	Feb.	Mar.
Hokkaido	23.8%	34.7%	35.5%	23.5%	25.2%	26.5%	28.6%	28.8%	20.1%	19.3%	19.1%	32.2%
Tohoku	9.8%	19.6%	18.0%	13.4%	12.6%	14.4%	12.3%	6.2%	5.8%	10.1%	6.4%	5.7%
Tokyo	20.7%	29.5%	20.0%	6.8%	6.5%	16.6%	25.6%	17.8%	12.8%	11.3%	10.4%	17.1%
50Hz areas Total	18.8%	28.0%	20.6%	9.0%	8.7%	16.9%	23.1%	16.3%	11.9%	11.7%	10.2%	15.9%
Chubu	19.1%	15.7%	14.0%	8.1%	8.1%	17.6%	11.8%	13.4%	10.2%	9.8%	12.3%	17.9%
Hokuriku	12.7%	31.1%	11.8%	14.8%	12.2%	10.3%	16.6%	11.0%	13.1%	12.8%	13.0%	10.8%
Kansai	34.6%	33.8%	28.9%	14.9%	12.2%	20.2%	33.4%	33.4%	31.2%	23.5%	24.4%	32.3%
Chugoku	28.7%	19.6%	31.2%	19.3%	19.8%	36.6%	27.5%	20.7%	25.2%	20.2%	19.2%	25.9%
Shikoku	11.7%	15.5%	16.4%	7.1%	9.5%	10.5%	19.3%	14.1%	12.6%	14.5%	14.9%	8.2%
Kyushu	15.6%	7.3%	5.4%	3.4%	2.4%	13.7%	18.9%	20.5%	6.9%	5.2%	4.8%	15.2%
60Hz areas Total	23.5%	21.1%	19.1%	11.1%	10.1%	19.0%	21.8%	21.3%	17.8%	14.7%	15.6%	21.6%
Interconnected	21.4%	24.2%	19.8%	10.1%	9.5%	18.1%	22.4%	19.0%	15.1%	13.4%	13.1%	19.0%
Okinawa	56.4%	43.1%	35.9%	37.0%	36.3%	39.4%	42.5%	48.6%	52.6%	58.1%	68.0%	60.8%
Nationwide	21.7%	24.4%	20.0%	10.4%	9.7%	18.3%	22.6%	19.3%	15.4%	13.7%	13.5%	19.3%

Below 8% Criteria

Table 2-4 Monthly Projection of the Least Reserve Margins Nationwide and for Each Regional Service Area
(With power exchanges through cross-regional interconnection lines, at the sending end)

	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.	Jan.	Feb.	Mar.
Hokkaido	**19.3%**	**26.3%**	**31.5%**	**20.0%**	**21.8%**	**23.1%**	**22.4%**	**19.3%**	**12.5%**	**12.1%**	**10.7%**	**23.2%**
Tohoku	**19.3%**	**26.3%**	**19.5%**	**8.6%**	**8.2%**	**16.8%**	**22.4%**	**16.2%**	**12.5%**	**12.1%**	**10.7%**	**16.0%**
Tokyo	**19.3%**	**26.3%**	**19.5%**	**8.6%**	**8.2%**	**16.8%**	**22.4%**	**16.2%**	**12.5%**	**12.1%**	**10.7%**	**16.0%**
Chubu	**23.1%**	**22.5%**	**19.5%**	**10.9%**	**9.8%**	**18.8%**	**22.4%**	**21.2%**	**17.3%**	**14.4%**	**15.2%**	**21.1%**
Hokuriku	**23.1%**	**22.5%**	**19.5%**	**10.9%**	**9.8%**	**18.8%**	**22.4%**	**21.2%**	**17.3%**	**14.4%**	**15.2%**	**21.1%**
Kansai	**23.1%**	**22.5%**	**19.5%**	**10.9%**	**9.8%**	**18.8%**	**22.4%**	**21.2%**	**17.3%**	**14.4%**	**15.2%**	**21.1%**
Chugoku	**23.1%**	**22.5%**	**19.5%**	**10.9%**	**9.8%**	**18.8%**	**22.4%**	**21.2%**	**17.3%**	**14.4%**	**15.2%**	**21.1%**
Shikoku	**23.1%**	**22.5%**	**19.5%**	**10.9%**	**9.8%**	**18.8%**	**22.4%**	**21.2%**	**17.3%**	**14.4%**	**15.2%**	**21.1%**
Kyushu	**23.1%**	**22.5%**	**19.5%**	**10.9%**	**9.8%**	**18.8%**	**22.4%**	**21.2%**	**17.3%**	**14.4%**	**15.2%**	**21.1%**
Interconnected	**21.4%**	**24.2%**	**19.8%**	**10.1%**	**9.5%**	**18.1%**	**22.4%**	**19.0%**	**15.1%**	**13.4%**	**13.1%**	**19.0%**
Okinawa	**56.4%**	**43.1%**	**35.9%**	**37.0%**	**36.3%**	**39.4%**	**42.5%**	**48.6%**	**52.6%**	**58.1%**	**68.0%**	**60.8%**
Nationwide	**21.7%**	**24.4%**	**20.0%**	**10.4%**	**9.7%**	**18.3%**	**22.6%**	**19.3%**	**15.4%**	**13.7%**	**13.5%**	**19.3%**

Improved to over 8%

[11] This evaluation is implemented based on the following. The evaluation of timing of utilization of interconnection lines varies in the regional service areas; power exchange availability is calculated based on the least reserve margin, and the calculated results are less than those based on the reserve margin of a given time. Therefore, this evaluation covers a more severe condition, which is better for a stable supply.

[12] The projection of the reserve margin is based on the ATC of transactions among areas indicated in the electricity supply plan.

In the Okinawa EPCO regional service area,[13] which is a small and isolated island system unable to receive power through interconnection lines, the criterion of stable supply is to secure supply capacity over peak demand by deducting the capacity of the largest generating unit and balancing this capacity with frequency control ('Generator I', total of 301 MW), without applying the criteria of other interconnected areas. Table 2-5 shows the monthly reserve margin against the deduction of the capacity of Generator I, which indicates the stable supply secured in each month.

Table 2-5 Monthly Reserve Margin against the Deduction of the Capacity of Generator I (At the sending end)

	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.	Jan.	Feb.	Mar.
Okinawa	27.8%	18.5%	14.1%	16.3%	15.7%	18.1%	18.5%	20.9%	22.5%	28.8%	38.8%	30.1%

[13] In the Okinawa EPCO regional service area, the evaluation includes the reserve margins of several isolated islands.

(3) Projection of Supply–Demand Balance for 10 years (Long-term)

a. Supply–Demand Balance

Table 2-6 and Figure 2-3 show the annual supply–demand balance projection for a 10-year period. A reserve margin of 8% is secured each year nationwide.

Table 2-6 Annual Supply–Demand Balance Projection from FY 2018 to 2027
(Nationwide at 17:00 in August, 10^4 kW at the sending end)

	2018 [Aforementioned]	2019	2020	2021	2022
Peak Demand	15,460	15,490	15,473	15,466	15,458
Supply Capacity	17,048	16,925	17,215	16,725	16,844
Reserve Margin	10.3%	9.3%	11.3%	8.1%	9.0%
	2023	2024	2025	2026	2027
Peak Demand	15,448	15,436	15,424	15,411	15,412
Supply Capacity	17,165	17,377	17,307	17,332	17,348
Reserve Margin	11.1%	12.6%	12.2%	12.5%	12.6%

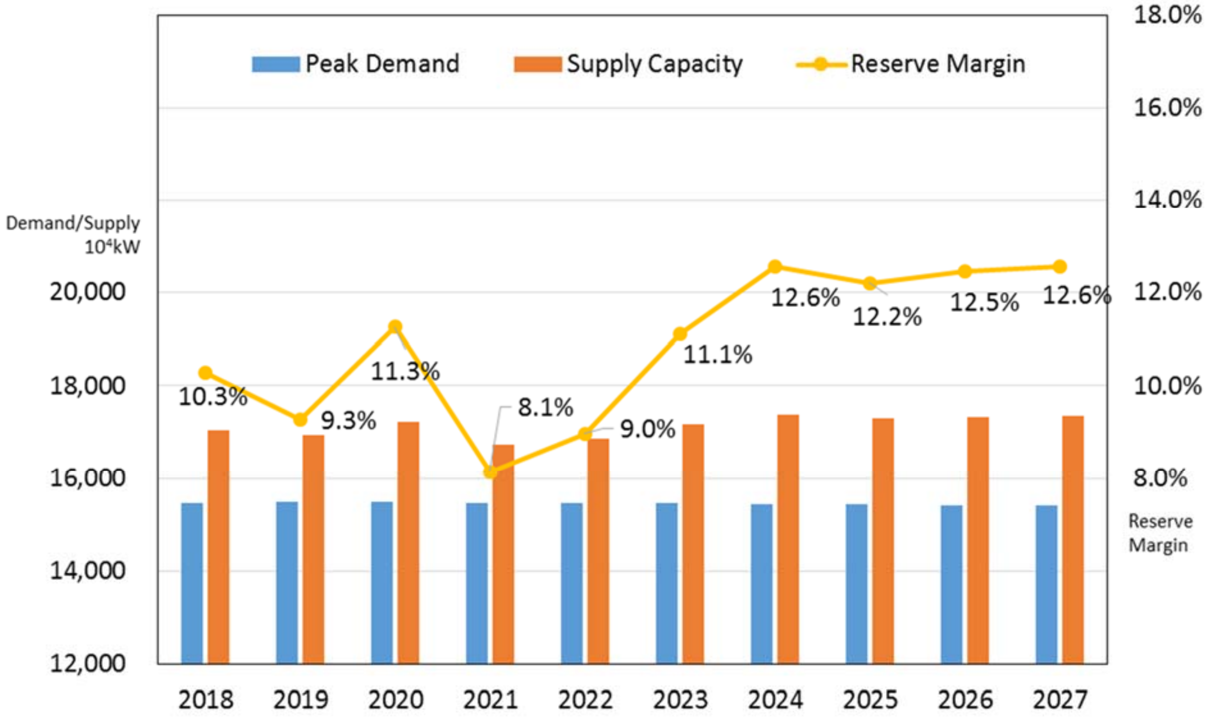


Figure 2-3 Mid-to-long-term Annual Supply–Demand Balance Projection
(Nationwide at 17:00 in August, at the sending end)

The hours with the least reserve margins vary; for example, 15:00 in the areas of Tokyo, Hokuriku, and Shikoku, 17:00 in the areas of Hokkaido, Tohoku, Chubu, Kansai, and Chugoku, 19:00 in the Kyushu area, and 20:00 in Okinawa. Among those, the reserve margins at 15:00, 19:00, and 20:00 include some areas and months that cannot achieve the criterion of a stable supply, i.e., a reserve margin of 8%. However, the criterion of a stable supply is projected to be secured in all areas and years by sharing power from other areas with sufficient supply capacity through cross-regional interconnection lines (see 7. Findings and Current Challenges (4)).

Table 2-7 shows the annual projection of reserve margins at 17:00 in August judged as the most severe supply–demand balance for each regional service area from FY 2018 to 2027. Table 2-8 shows these projections recalculated by adding power exchanges for the year and areas of below 8% reserve margin even with additional generated surplus from areas of over 8% reserve margin based on ATC.

The evaluation shows that the reserve margin will fall below 8% as follows: in the Tokyo EPCO regional service area in FY 2018–2022 (except in 2020); in the Chubu EPCO area in FY 2019–2021 and 2023–2027; in the Kansai EPCO area in FY 2021, 2022, and 2025–2027; in the Shikoku area in FY 2019, 2021, and 2022; and in the Kyushu area in FY 2018–2021. However, all areas will be projected to secure more than 8% reserve margin required for a stable supply by sharing power from other areas with sufficient supply capacity through cross-regional interconnection lines during the projected period except FY 2021.

Table 2-7 Annual Projection of Reserve Margins for Each Regional Service Area
(At 17:00 in August; resources within own service area only, at the sending end)

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Hokkaido	25.2%	21.6%	39.0%	37.5%	39.2%	39.4%	39.3%	39.5%	39.2%	50.1%
Tohoku	12.6%	10.3%	15.6%	12.9%	13.5%	14.1%	14.6%	15.4%	15.5%	18.2%
Tokyo	6.7%	7.0%	9.1%	5.9%	5.0%	9.6%	15.0%	15.2%	15.1%	14.1%
50Hz areas Total	8.9%	8.5%	12.1%	9.1%	8.7%	12.3%	16.4%	16.7%	16.7%	17.1%
Chubu	8.1%	7.4%	5.3%	5.0%	8.4%	5.9%	2.9%	3.2%	3.6%	3.8%
Hokuriku	14.7%	15.7%	13.9%	13.2%	13.0%	12.9%	12.8%	11.5%	11.4%	11.3%
Kansai	11.9%	11.6%	11.6%	4.3%	7.0%	9.8%	9.2%	6.2%	7.4%	7.5%
Chugoku	19.8%	9.1%	17.9%	13.9%	14.6%	17.8%	17.7%	17.7%	17.8%	17.3%
Shikoku	9.5%	6.7%	12.8%	2.5%	-0.3%	9.3%	9.3%	9.3%	9.6%	9.7%
Kyushu	6.8%	8.0%	7.2%	7.9%	9.1%	9.4%	10.4%	10.6%	10.7%	10.6%
60Hz areas Total	10.9%	9.4%	10.0%	6.7%	8.6%	9.7%	8.9%	8.0%	8.5%	8.6%
Interconnected	10.0%	9.0%	10.9%	7.8%	8.6%	10.9%	12.3%	11.9%	12.2%	12.4%
Okinawa	38.6%	36.8%	44.6%	43.7%	42.8%	34.1%	41.1%	40.1%	38.9%	30.5%
Nationwide	10.3%	9.3%	11.3%	8.1%	9.0%	11.1%	12.6%	12.2%	12.5%	12.6%

Below 8% Criteria

Note: The reserve margin in the Kyushu EPCO area in FY 2019 is lower than 8.0% and was rounded up to 8.0%.

Table 2-8 Annual Projection of Reserve Margins for Each Regional Service Area [At 17:00 in August]
(With additional surplus power and power exchanges through cross-regional interconnection lines, at the sending end)

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Hokkaido	21.8%	10.9%	28.3%	28.1%	28.8%	29.0%	28.9%	29.2%	28.9%	39.8%
Tohoku	8.4%	8.5%	10.4%	7.2%	8.1%	10.4%	12.8%	13.0%	13.0%	12.9%
Tokyo	8.4%	8.5%	10.4%	7.2%	8.1%	10.4%	12.8%	13.0%	13.0%	12.9%
Chubu	10.6%	9.3%	10.4%	7.2%	8.1%	10.4%	11.1%	10.2%	10.7%	10.6%
Hokuriku	10.6%	9.3%	10.4%	7.2%	8.1%	10.4%	11.1%	10.2%	10.7%	10.6%
Kansai	10.6%	9.3%	10.4%	7.2%	8.1%	10.4%	11.1%	10.2%	10.7%	10.6%
Chugoku	10.6%	9.3%	10.4%	7.2%	8.1%	10.4%	11.1%	10.2%	10.7%	10.6%
Shikoku	10.6%	9.3%	10.4%	7.2%	8.1%	10.4%	11.1%	10.2%	10.7%	10.6%
Kyushu	10.6%	9.3%	10.4%	7.2%	8.1%	10.4%	11.1%	10.2%	10.7%	10.6%
Interconnected	10.0%	9.0%	10.9%	7.8%	8.6%	10.9%	12.3%	11.9%	12.2%	12.4%
Okinawa	38.6%	36.8%	44.6%	43.7%	42.8%	34.1%	41.1%	40.1%	38.9%	30.5%
Nationwide	10.3%	9.3%	11.3%	8.1%	9.0%	11.1%	12.6%	12.2%	12.5%	12.6%

Below 8% Criteria   Improved above Criteria

For FY 2021, the stable supply criterion of 8% reserve margin cannot be achieved for the major part of the country at 7.2% even utilizing the ATC of the interconnection lines and sufficient capacity of other areas. However, the Organization did not count newly developing facilities at EPCOs that are not obliged to submit development plans or at EPCOs that are obliged to submit plans, but have not reported such plans. Therefore, the Organization has investigated generating facilities that are not included in the electricity supply plans, although they were already applied to generator connection to GT&D companies and submitted construction plans according to the provisions of Article 48 of the Electricity Business Act in cooperation with the Government.

As a result, there are 1,050 MW of such generating facilities nationwide; thus, the Organization includes those facilities to supply capacity and recalculates reserve margins as outlined in Table 2-9. However, even with this procedure, the reserve margins below 8% only rise to 7.9%, i.e., slightly below the criterion of stable supply.

Table 2-9 Annual Projection of Reserve Margins for Each Regional Service Area [At 17:00 in August]
(With additional surplus power, power exchanges through cross-regional interconnection lines and generating facilities not included in the electricity supply plans, at the sending end)

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Hokkaido	21.8%	10.9%	30.7%	30.4%	31.1%	31.4%	31.3%	31.6%	31.3%	42.1%
Tohoku	8.4%	8.5%	10.4%	7.9%	8.7%	11.0%	14.2%	14.5%	14.5%	14.4%
Tokyo	8.4%	8.5%	10.4%	7.9%	8.7%	11.0%	14.2%	14.5%	14.5%	14.4%
Chubu	10.6%	9.3%	10.4%	7.9%	8.7%	11.0%	11.1%	10.2%	10.7%	10.6%
Hokuriku	10.6%	9.3%	10.4%	7.9%	8.7%	11.0%	11.1%	10.2%	10.7%	10.6%
Kansai	10.6%	9.3%	10.4%	7.9%	8.7%	11.0%	11.1%	10.2%	10.7%	10.6%
Chugoku	10.6%	9.3%	10.4%	7.9%	8.7%	11.0%	11.1%	10.2%	10.7%	10.6%
Shikoku	10.6%	9.3%	10.4%	7.9%	8.7%	11.0%	11.1%	10.2%	10.7%	10.6%
Kyushu	10.6%	9.3%	10.4%	7.9%	8.7%	11.0%	11.1%	10.2%	10.7%	10.6%
Interconnected	10.0%	9.0%	11.0%	8.5%	9.3%	11.6%	12.9%	12.6%	12.9%	13.1%
Okinawa	38.6%	36.8%	44.6%	43.7%	42.8%	34.1%	41.1%	40.1%	38.9%	30.5%
Nationwide	10.3%	9.3%	11.3%	8.8%	9.6%	11.8%	13.2%	12.9%	13.1%	13.2%

Below 8% Criteria

[Referential Review]

Adding Supply Capacity of Generating Facilities Not Included in the Electricity Supply Plans

As noted, the reserve margins in FY 2021 could not achieve the 8% criterion of stable supply. The Organization has implemented hearings with the EPCOs and recognized that there are some generating facilities that were planned to be shut down, but which would be capable of generation in FY 2021 and which are not included in the electricity supply plans (hereafter referred to as "rapid power-generatable facilities"[14]). Figure 2-4 shows projections of discontinuance or retirement of thermal power plants in the mid-to-long term.

The current plan indicates that such generating facilities total about 3,300 MW. Therefore, the Organization reevaluates the reserve margins with such additional supply capacity of 100 MW each in both 50 Hz and 60 Hz areas (200 MW nationwide). The result is shown in Table 2-10, and indicates that reserve margins in FY 2021 exceed 8% nationally.

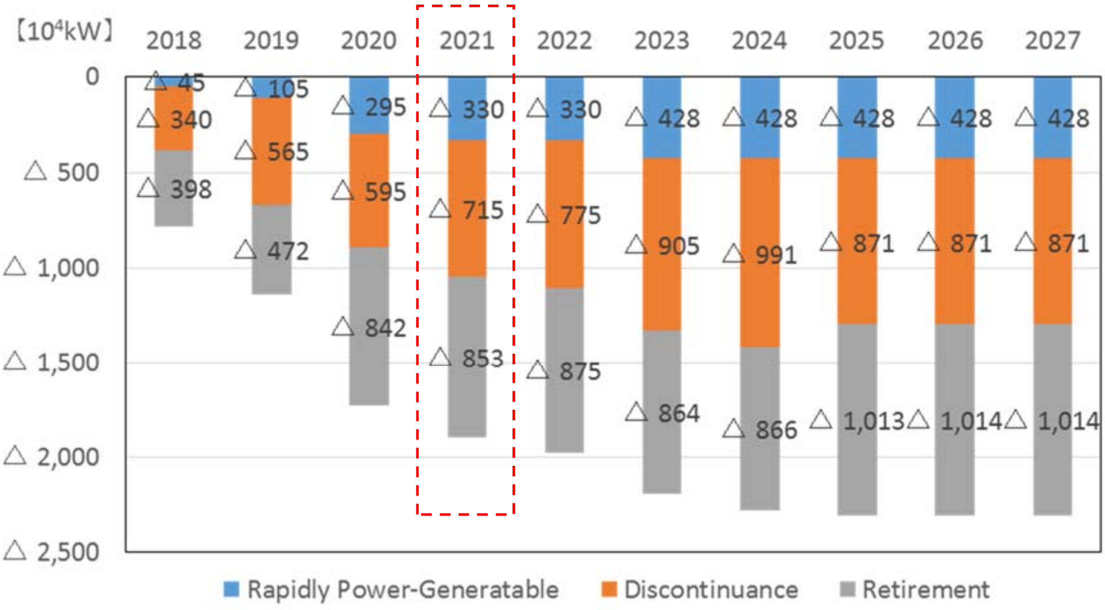


Figure 2-4 Mid-to-long-term Projections of Discontinuance or Retirement of Thermal Power Plants

[14] A generating facility that is planned to be shut down, but which resumes its generation within about 6 months in case of necessity.

Table 2-10 Annual Projection of Reserve Margins for Each Regional Service Area [At 17:00 in August]
(With additional surplus power, power exchanges through cross-regional interconnection lines, and generating facilities not included in the electricity supply plans, and rapid power-generatable facilities at the sending end)

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Hokkaido	21.8%	10.9%	30.7%	30.4%	31.1%	31.4%	31.3%	31.6%	31.3%	42.1%
Tohoku	8.4%	8.5%	10.4%	8.0%	8.7%	11.0%	14.2%	14.5%	14.5%	14.4%
Tokyo	8.4%	8.5%	10.4%	8.0%	8.7%	11.0%	14.2%	14.5%	14.5%	14.4%
Chubu	10.6%	9.3%	10.4%	8.0%	8.7%	11.0%	11.1%	10.2%	10.7%	10.6%
Hokuriku	10.6%	9.3%	10.4%	8.0%	8.7%	11.0%	11.1%	10.2%	10.7%	10.6%
Kansai	10.6%	9.3%	10.4%	8.0%	8.7%	11.0%	11.1%	10.2%	10.7%	10.6%
Chugoku	10.6%	9.3%	10.4%	8.0%	8.7%	11.0%	11.1%	10.2%	10.7%	10.6%
Shikoku	10.6%	9.3%	10.4%	8.0%	8.7%	11.0%	11.1%	10.2%	10.7%	10.6%
Kyushu	10.6%	9.3%	10.4%	8.0%	8.7%	11.0%	11.1%	10.2%	10.7%	10.6%
Interconnected	10.0%	9.0%	11.0%	8.6%	9.3%	11.6%	12.9%	12.6%	12.9%	13.1%
Okinawa	38.6%	36.8%	44.6%	43.7%	42.8%	34.1%	41.1%	40.1%	38.9%	30.5%
Nationwide	10.3%	9.3%	11.3%	9.0%	9.6%	11.8%	13.2%	12.9%	13.1%	13.2%

Table 2-11 shows the annual projection of reserve margins with the capacity equivalent to Generator I in the Okinawa EPCO area deducted, which indicates a stable supply is secured throughout the period.

Table 2-11 Annual Projection of a Reserve Margin with the Capacity Equivalent to Generator I in Okinawa Deducted
(At 20:00 in August, at the sending end)

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Okinawa	15.7%	13.9%	21.5%	20.7%	19.7%	11.1%	18.0%	17.2%	16.2%	7.9%

Table 2-12 shows the annual projection of reserve margins in January for winter peak demands in the Hokkaido and Tohoku EPCO areas. In the Tohoku area in FY 2021–2023, the reserve margins are below 8%. Table 2-13 shows the reserve margins recalculated with the additional supply capacity through interconnection lines. The result indicates a stable supply is secured throughout the period.

Table 2-12 Annual Projection of Reserve Margins for Winter Peak Demand in the Hokkaido and Tohoku Areas
(At 18:00 in January, at the sending end)

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Hokkaido	19.3%	19.3%	15.8%	16.0%	17.1%	17.1%	17.1%	17.0%	26.9%	26.6%
Tohoku	10.1%	9.3%	9.1%	6.6%	7.1%	7.6%	8.0%	8.5%	8.4%	10.6%

Table 2-13 Annual Projection of Reserve Margins for Winter Peak Demand in the Hokkaido and Tohoku Areas
(At 18:00 in January, With additional surplus power, power exchanges through cross-regional interconnection lines, at the sending-end)

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Hokkaido	12.1%	12.0%	10.9%	9.1%	9.8%	10.2%	11.7%	11.8%	13.4%	15.0%
Tohoku	12.1%	12.0%	10.9%	9.1%	9.8%	10.2%	11.7%	11.8%	13.4%	15.0%

b. Conclusion of Supply–Demand Balance Evaluation

Supply–demand Balance Evaluation for FY 2018 (short term): The criterion of stable supply (i.e., 8% of reserve margin) is secured throughout the areas and for the short-term period.

Supply–demand Balance Evaluation for FY 2019–2027 (mid-to-long term): As noted, the criterion of stable supply cannot be secured in many regional service areas at 17:00 in August in 2021. Under the circumstances in which the reserve margin follows a downward trend, the Organization has practical concerns that the reserve margins will fall sharply below the 8% level and lead to power shortages before FY 2024, when the launch of the capacity market is planned to secure supply capacity.

However, the majority of nuclear power plants are reported with supply capacity as zero, including four units projected to resume their operation during the first half of 2018. When the mid-to-long-term supply–demand balances are evaluated, the resumption of operation of nuclear power plants needs to be considered.

Moreover, it is recognized that there are some generating facilities that are planned to be shut down but which are capable of generation in a relatively short period ("rapid power-generatable facilities")

Thus, the Organization continuously and carefully evaluates the mid-to-long-term supply–demand balance; the new plan to restart some nuclear power plants will change the situation, and the accompanying supply–demand balance. The Organization will review safeguard measures for generation procurement in case of necessity.

c. Supply Capacity Secured by Retail Companies According to Their Demand

Table 2-14 and Figure 2-5 show the supply capacity secured by retail companies according to their demand for the 10-year period FY 2018–2027. Particularly in the mid-to-long term, retail companies have planned their supply capacity as “unspecified procurement[15]”.

Table 2-14 Supply Capacity Secured by Retail Companies According to Their Demand for the 10-year Period FY 2018–2027 (At 15:00 in August; 10^4 kW at the sending end)

	FY 2018	FY 2019	FY 2020	FY 2021	FY 2022
Peak Demand Nationwide	15,787	15,819	15,801	15,794	15,786
Secured Supply Capacity	15,620	15,552	15,466	14,715	14,680
Ratio*	98.9%	98.3%	97.9%	93.2%	93.0%
	FY 2023	**FY 2024**	**FY 2025**	**FY 2026**	**FY 2027**
Peak Demand Nationwide	15,776	15,764	15,751	15,738	15,739
Secured Supply Capacity	14,586	14,242	14,207	12,236	12,179
Ratio*	92.5%	90.3%	90.2%	77.8%	77.4%

Note: * denotes the ratio of peak demand nationwide to the secured supply capacity.

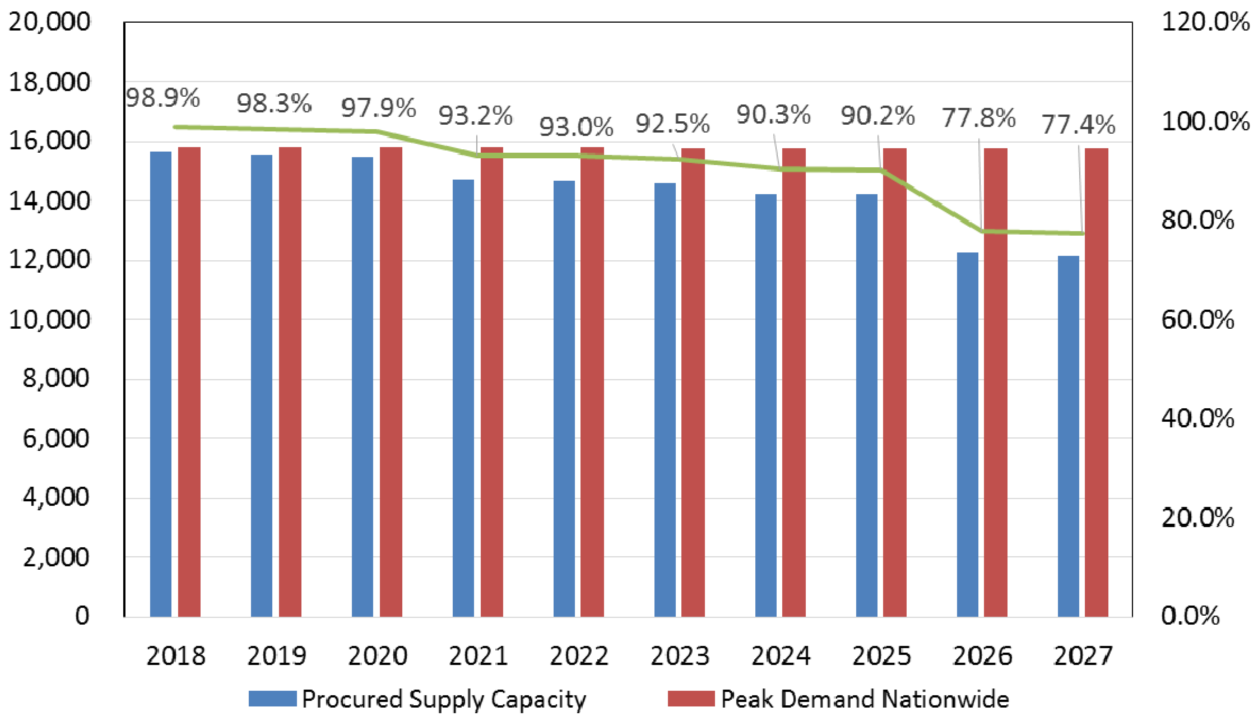


Figure 2-5 Supply Capacity Procured by Retail Companies According to Their Demand for the 10-year Period FY 2018–2027 (At 15:00 in August; at the sending end)

[15] “Unspecified procurement” means that retail companies plan to procure their future supply capacity by means of various procurement choices, including procurement from the market, as described in the format of the electricity supply plan.

d. Supply Capacity Secured by General Transmission and Distribution Companies

GT&D companies secure their supply capacity for the demand of isolated island areas throughout the projected period, and also secure a balancing capacity equivalent to 7%[16] over their peak demand in their regional service areas for FY 2018 by public solicitation. Table 2-15 shows the secured balancing capacity procured by GT&D companies.

Table 2-15 Secured Balancing Capacity[17] Procured by GT&D Companies

	Hokkaido	Tohoku	Tokyo	Chubu	Hokuriku	Kansai	Chugoku	Shikoku	Kyushu	Okinawa
Balancing Capacity	7.2%	6.8%	7.5%	6.9%	7.0%	6.9%	7.1%	7.2%	7.0%	20.5%

[16] Public solicitation of balancing capacity is implemented so as to secure a balancing capacity equivalent to 7% over their peak demand in their regional service areas, and its procurement is based on the peak demand of the second projected year of the previous electric supply plan. Therefore, the procured balancing capacity may be lower than the capacity equivalent to 7% over their peak demand of the current year.

[17] The capacity is the ratio of the balancing capacity to the peak demand in the regional service areas of GT&D companies. The ratios for the Hokkaido and Tohoku EPCO areas are in January, and in August for the other areas.

3. Analysis of the Transition of Power Generation Sources

(1) Transition of Power Generation Sources (Capacity)

The installed power generation capacity is the aggregation of the capacity of electric power plants owned by EPCOs and those owned by companies other than EPCOs that are registered as the procured supply capacity of retail and GT&D companies.

Table 3-1 and Figure 3-1 show the transition of installed power generation capacity by power generation sources. Figure 3-2 shows the composition of the transition of installed power generation capacities.

Solar power will notably increase its capacity. Coal- and LNG-fired capacities are also projected to increase, although they may temporarily decrease through replacement according to future power development plans for thermal generation. Oil-fired capacity is projected to decrease through retirement.

Table 3-1 Composition of the Transition of Installed Power Generation Capacities by Power Generation Sources[18]
(Nationwide, 10^4 kW)

Power Generation Sources		FY 2017 (Actual)	FY 2018	FY 2022	FY 2027
Hydro		4,915 [16.3%]	4,915 [16.0%]	4,919 [14.9%]	4,922 [14.5%]
	Conventional	2,168 [7.2%]	2,168 [7.1%]	2,172 [6.6%]	2,175 [6.4%]
	Pumped Storage	2,747 [9.1%]	2,747 [8.9%]	2,747 [8.3%]	2,747 [8.1%]
Thermal		16,323 [54.0%]	16,304 [53.1%]	16,705 [50.7%]	17,216 [50.7%]
	Coal	4,365 [14.4%]	4,376 [14.3%]	5,097 [15.5%]	5,262 [15.5%]
	LNG	8,196 [27.1%]	8,397 [27.3%]	8,141 [24.7%]	8,489 [25.0%]
	Oil and others[19]	3,763 [12.4%]	3,531 [11.5%]	3,466 [10.5%]	3,465 [10.2%]
Nuclear		3,665 [12.1%]	3,555 [11.6%]	3,500 [10.6%]	3,032 [8.9%]
Renewables		5,335 [17.6%]	5,925 [19.3%]	7,849 [23.8%]	8,781 [25.9%]
	Wind	361 [1.2%]	379 [1.2%]	702 [2.1%]	924 [2.7%]
	Solar	4,597 [15.2%]	5,169 [16.8%]	6,718 [20.4%]	7,435 [21.9%]
	Geothermal	48 [0.2%]	48 [0.2%]	47 [0.1%]	47 [0.1%]
	Biomass	234 [0.8%]	241 [0.8%]	315 [1.0%]	310 [0.9%]
	Waste	95 [0.3%]	88 [0.3%]	66 [0.2%]	64 [0.2%]
Miscellaneous		7 [0.0%]	7 [0.0%]	7 [0.0%]	7 [0.0%]
Total		30,246 [100%]	30,707 [100%]	32,979 [100%]	33,957 [100%]

[18] The installed power generation capacity is the sum of the values submitted by EPCOs.
[19] The category 'Oil and others' includes the total installed capacities from oil, LPG, and other gas and bituminous mixture fired capacities.

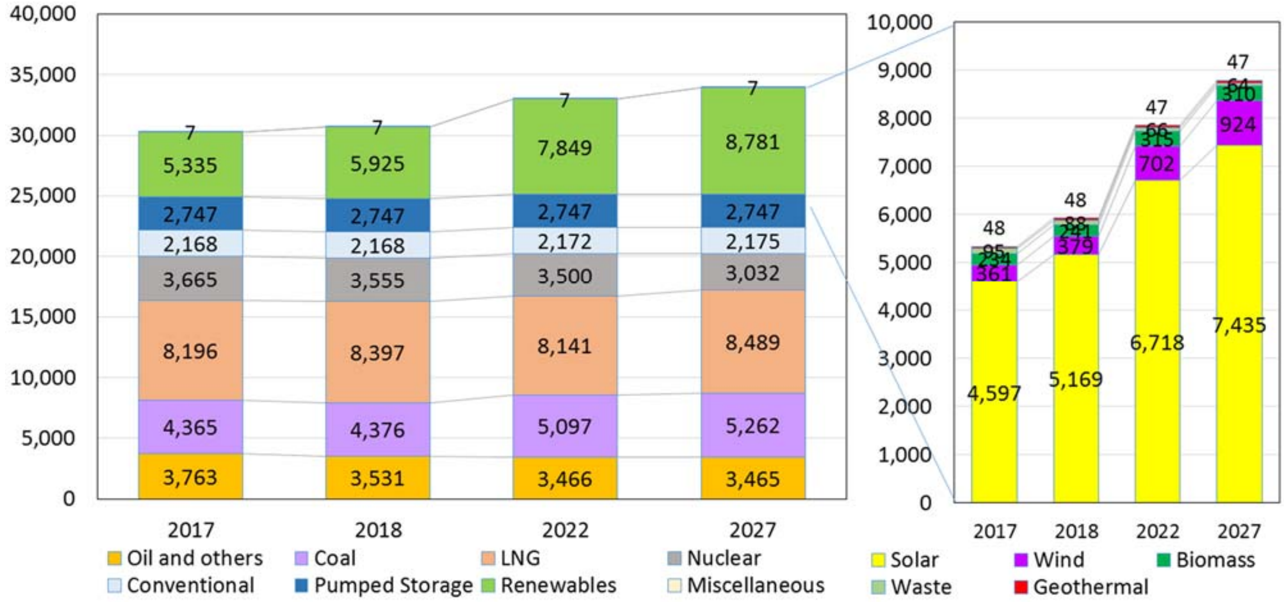


Figure 3-1 Transition of Installed Power Generation Capacities by Power Generation Sources (Nationwide)

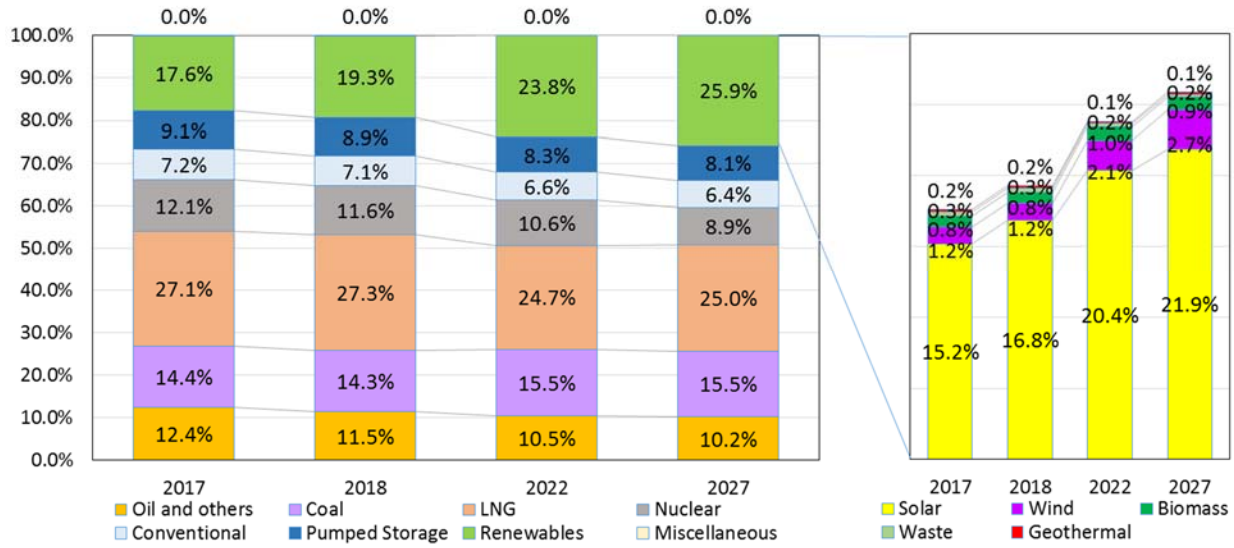


Figure 3-2 Composition of the Transition of Installed Power Generation Capacities by Power Generation Sources (Nationwide)

(2) Transition of Gross Electric Energy Generation

Table 3-2 and Figure 3-3 show the transition of gross electric energy generation by power generation sources aggregated with the reported values submitted by generation companies and those procured by retail and GT&D companies from companies other than EPCOs. Figure 3-4 shows the composition of the transition of gross electric energy generation.

For nuclear power plants, energy generation is calculated as zero for their capacity reported as "uncertain;" however, changes to the composition of gross electric energy generation may alter according to the operating conditions of nuclear power plants.

Electricity generated by renewable energy such as solar power will notably increase. Electricity generated by coal is projected to remain at a certain level according to future power development plans for thermal generation. Electricity generated by LNG is projected to decrease sharply.

Table 3-2 Composition of the Transition of Gross Electric Energy Generation by Power Generation Sources (Nationwide, 10^8 kWh at the generating end)

Power Generation Sources		FY 2017	FY 2018	FY 2022	FY 2027
Hydro		838 [9.0%]	815 [8.8%]	855 [9.2%]	880 [9.7%]
	Conventional	782 [8.4%]	780 [8.4%]	804 [8.7%]	810 [8.9%]
	Pumped Storage	57 [0.6%]	35 [0.4%]	51 [0.6%]	70 [0.8%]
Thermal		7,388 [79.2%]	7,391 [79.8%]	6,904 [74.5%]	6,801 [74.6%]
	Coal	2,973 [31.9%]	2,861 [30.9%]	3,156 [34.1%]	3,226 [35.4%]
	LNG	3,973 [42.6%]	3,944 [42.6%]	3,345 [36.1%]	3,199 [35.1%]
	Oil and others[19]	442 [4.7%]	586 [6.3%]	403 [4.4%]	377 [4.1%]
Nuclear		326 [3.5%]	214 [2.3%]	238 [2.6%]	0 [0.0%]
Renewables		732 [7.8%]	817 [8.8%]	1,159 [12.5%]	1,302 [14.3%]
	Wind	65 [0.7%]	69 [0.7%]	115 [1.2%]	165 [1.8%]
	Solar	496 [5.3%]	557 [6.0%]	777 [8.4%]	865 [9.5%]
	Geothermal	24 [0.3%]	26 [0.3%]	26 [0.3%]	26 [0.3%]
	Biomass	122 [1.3%]	141 [1.5%]	219 [2.4%]	226 [2.5%]
	Waste	24 [0.3%]	23 [0.2%]	21 [0.2%]	20 [0.2%]
Miscellaneous		40 [0.4%]	29 [0.3%]	106 [1.1%]	132 [1.4%]
Unspecified[20]		0 [0.0%]	0 [0.0%]	0 [0.0%]	0 [0.0%]
Total		9,324 [100%]	9,266 [100%]	9,262 [100%]	9,115 [100%]

[20] Unspecified means shortage that is calculated from the balance between the electric energy generated converting the peak demand of a regional service area (nationwide, at the sending end) and the addition of electric energy generated by the type of power generation source.

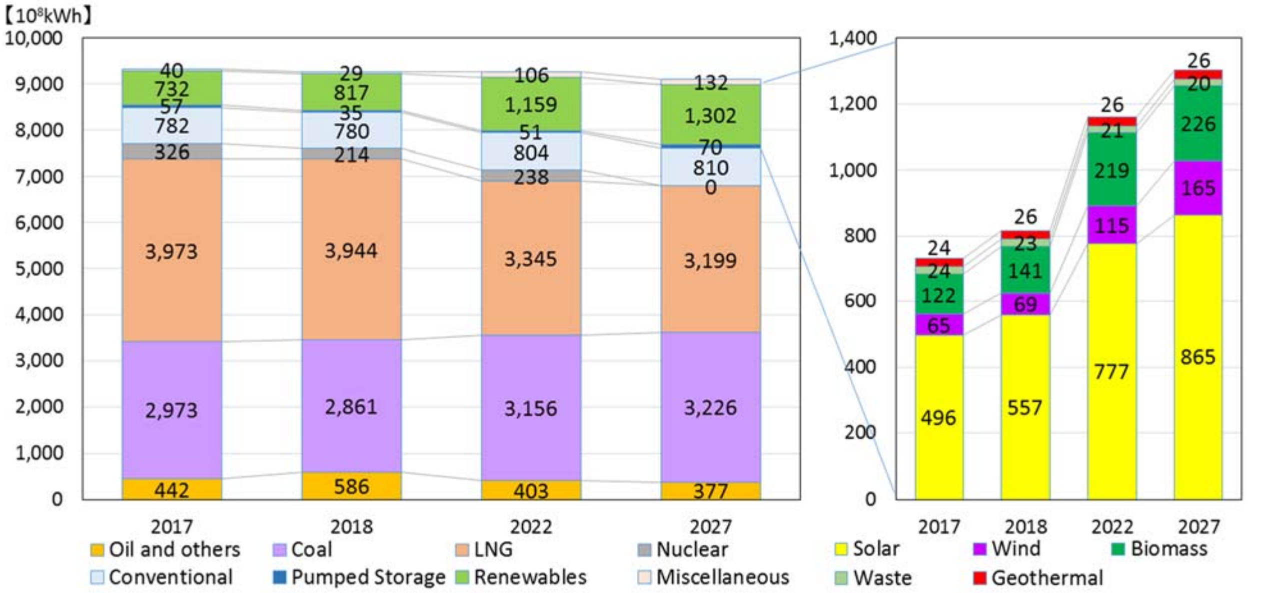


Figure 3-3 Transition of Electric Energy Generation by Power Generation Sources (Nationwide)

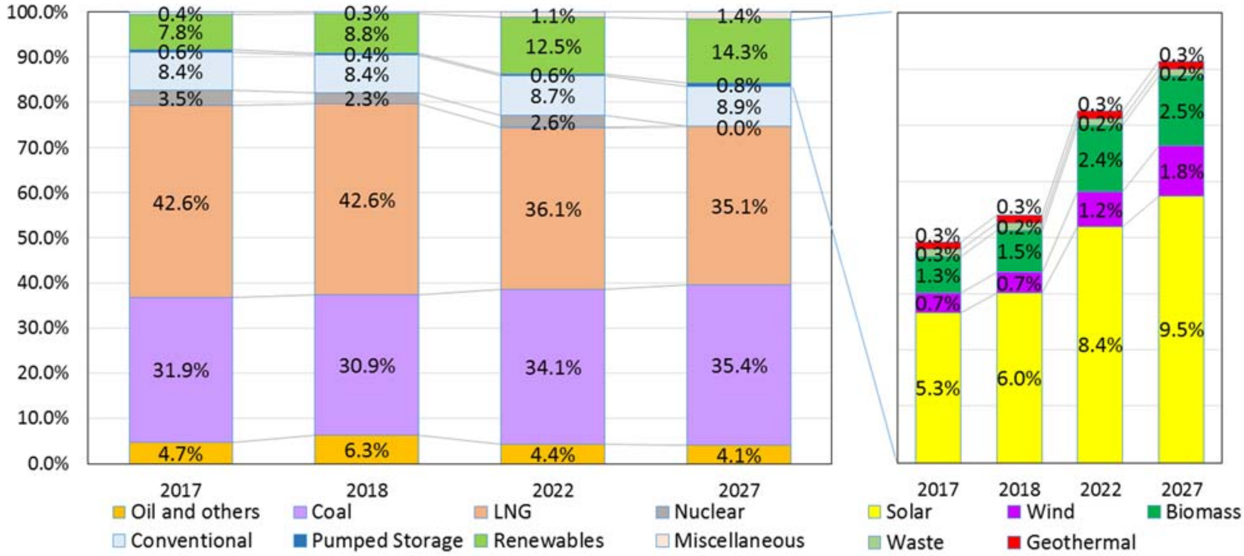


Figure 3-4 Transition of Electric Energy Generation Composition by Power Generation Sources (Nationwide)

(3) Transition of Capacity Factor by Power Generation Sources

Table 3-3 and Figure 3-5 show the capacity factor by power generation sources. The projection of the capacity factor is calculated using the aforementioned power generation sources and gross electric energy generation data provided by the Organization.

According to future power development plans, the installed power generation capacity for thermal generation is projected to increase. However, this does not mean an increase in thermal generation, as the power supply from renewable energy is projected to increase; therefore, the capacity factor of thermal power plants is projected to decrease gradually.

For nuclear power generation, the installed power generation capacity contains that which is specified as uncertain and the capacity factor appears lower; therefore, this projection does not necessarily indicate the real capacity factor for nuclear power plants actually in operation.

Table 3-3 Capacity Factors by Power Generation Sources (Nationwide)[21]

Power Generation Sources		FY 2017	FY 2018	FY 2022	FY 2027
Hydro		19.5%	18.9%	19.8%	20.4%
	Conventional	41.2%	41.1%	42.2%	42.5%
	Pumped Storage	2.4%	1.5%	2.1%	2.9%
Thermal		51.7%	51.7%	47.2%	45.1%
	Coal	77.8%	74.6%	70.7%	70.0%
	LNG	55.3%	53.6%	46.9%	43.0%
	Oil and others[19]	13.4%	18.9%	13.3%	12.4%
Nuclear		10.2%	6.9%	7.8%	0.0%
Renewables		15.7%	15.7%	16.9%	16.9%
	Wind[22]	20.6%	20.9%	18.8%	20.4%
	Solar[22]	12.3%	12.3%	13.2%	13.3%
	Geothermal	56.0%	61.0%	63.6%	63.6%
	Biomass	59.6%	66.8%	79.3%	83.1%
	Waste	29.4%	29.9%	36.6%	35.5%
Miscellaneous		-	-	-	-

[21] The capacity factor of nuclear power appears lower due to the calculation using the supply capacity reported as "uncertain" and does not indicate the real capacity factor for nuclear power plants.

[22] The capacity factors of wind and solar do not consider the decrease due to output shedding.

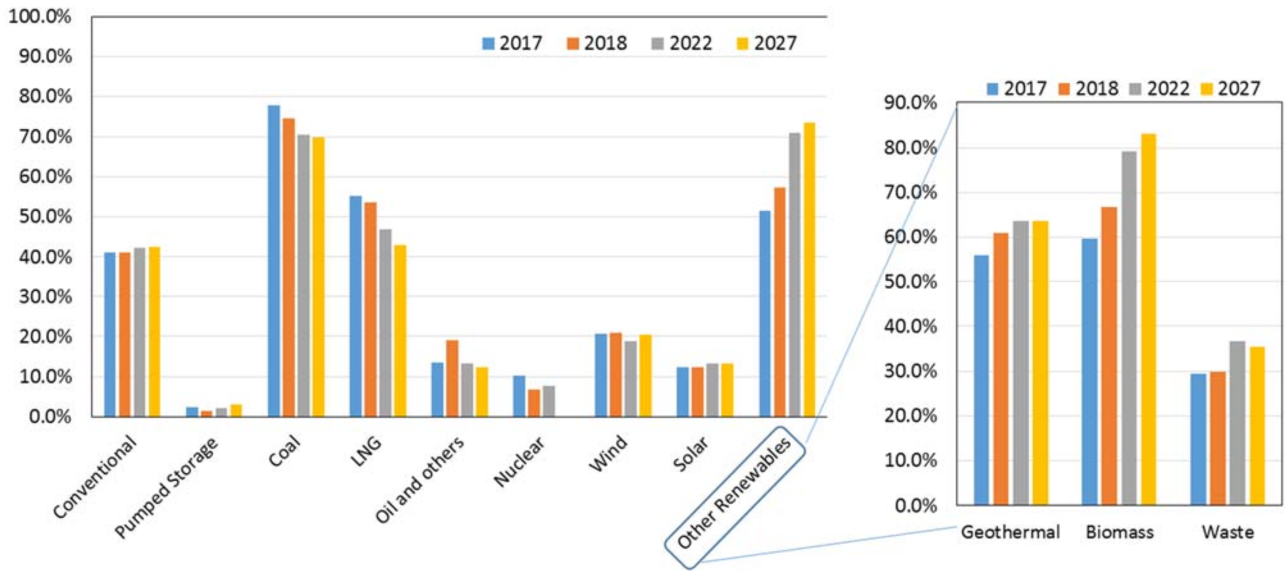


Figure 3-5 Capacity Factor by Power Generation Sources (Nationwide)[21]

(4) Installed Power Generation Capacity and Gross Electric Energy Generation for Each Regional Service Area

Figure 3-6 shows the installed power generation capacity for each regional service area at the end of FY 2017. Figure 3-7 shows the gross electric energy generation for each regional service area at the end of FY 2017.

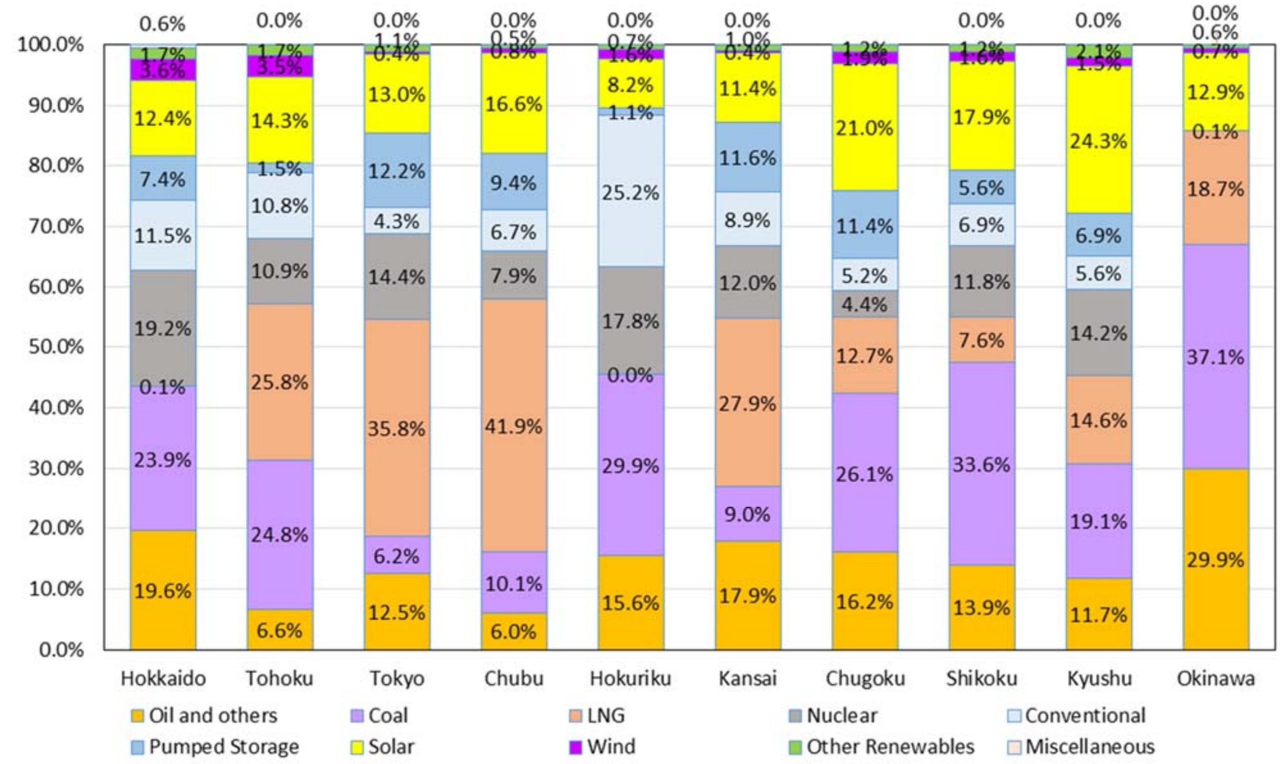


Figure 3-6 Composition of Installed Power Generation Capacity for Each Regional Service Area

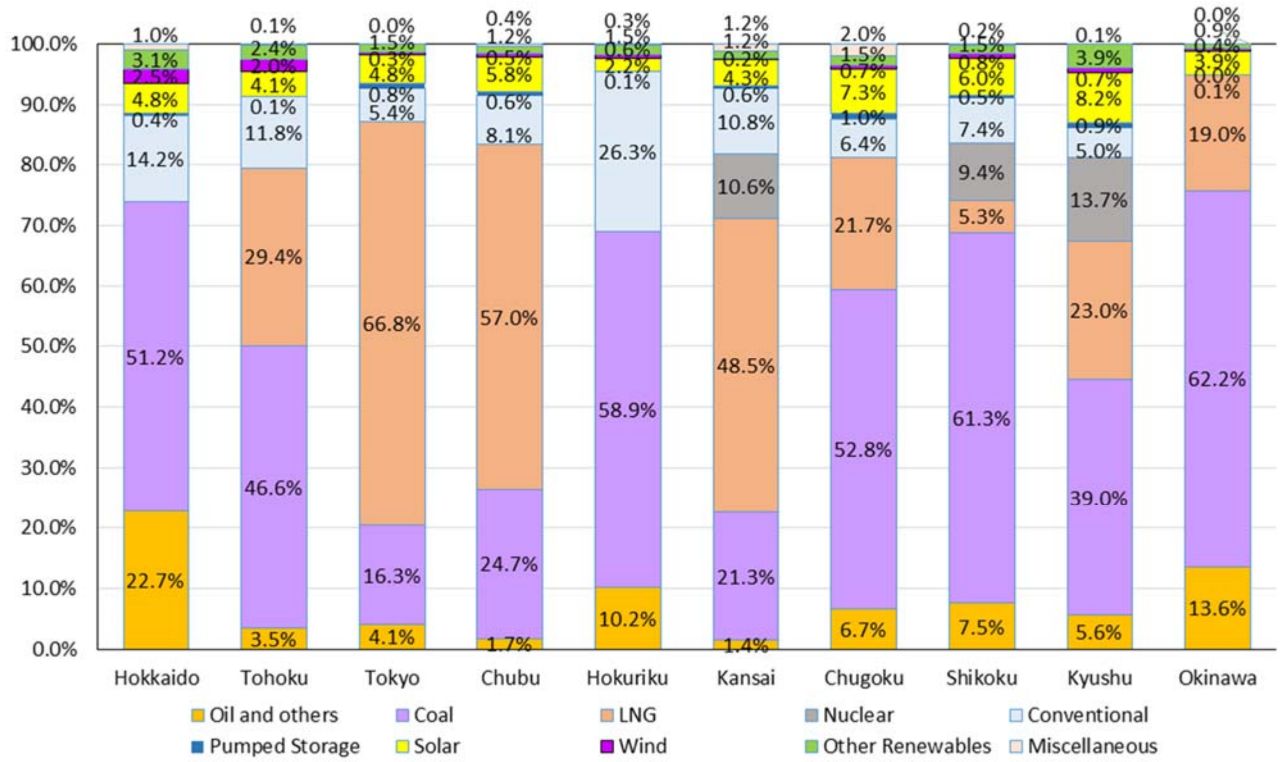


Figure 3-7 Composition of Gross Electric Energy Generation for Each Regional Service Area

(5) Development Plans by Power Generation Sources

Table 3-4 shows the development plans[23] up to FY 2027 submitted by generation companies, according to their new developments, uprating or derating installed facilities, and planned retirement of facilities in the projected period.

Table 3-4 Generation Development Plans up to FY 2027 by Stages (Nationwide, 10^4 kW)

Power Generation Sources		New Installation		Uprating/Derating		Retirement	
		Capacity	Sites	Capacity	Sites	Capacity	Sites
Hydro		**27.9**	**32**	**3.6**	**42**	**▲ 17.2**	**13**
	Conventional	27.9	32	3.6	42	▲ 17.2	13
	Pumped Storage	-	-	-	-	-	-
Thermal		**1,741.8**	**47**	**▲ 11.5**	**7**	**▲ 880.7**	**46**
	Coal	809.0	14	-	-	▲ 75.6	3
	LNG	896.6	17	13.4	5	▲ 587.6	12
	Oil	6.2	13	▲ 25.0	2	▲ 207.4	29
	LPG	-	-	-	-	-	-
	Bituminous	10.6	1	-	-	-	-
	Other Gas	19.4	2	-	-	▲ 10.1	2
Nuclear		**1,018.0**	**7**	**15.2**	**1**	**▲ 235.0**	**2**
Renewables		**580.6**	**410**	**0.2**	**1**	**▲ 27.9**	**33**
	Wind	152.7	51	-	-	▲ 13.9	24
	Solar	363.8	331	-	-	-	-
	Geothermal	-	-	0.2	1	-	-
	Biomass	58.0	23	-	-	▲ 6.3	4
	Waste	6.1	5	-	-	▲ 7.7	5
Total		3,368.4	496	7.5	51	▲ 1,160.8	94

[23] Aggregated using facilities for which the date of commercial operation is “uncertain”.

4. Development Plans for Transmission and Distribution Facilities

The Organization has aggregated the development plans[24] for cross-regional transmission lines and substations (transformers and AC/DC converters) up to FY 2027 submitted by GT&D and transmission companies. Table 4-1 shows the development plans for cross-regional transmission lines and substations. Figure 4-1 shows the outlook for electric systems nationwide. (1), (2), and (3) below list the development plans according to cross-regional transmission lines, major substations, and summaries, respectively.

Table 4-1 Development Plans for Cross-regional Transmission Lines and Substations

Increased Length of Transmission Lines*[25]*[26]		601 km
	Overhead Lines*	572 km
	Underground Lines	30 km
Uprated Capacities of Transformers		18,020 MVA
Uprated Capacities of AC/DC Converters[27]		2,100 MW
Decreased Length of Transmission Lines (Retirement)		▲ 50 km
Derated Capacities of Transformers (Retirement)		▲ 1,600 MVA

Enhancement plans for cross-regional transmission lines are summarized below.

Interconnection Facility Enhancement Plan between Hokkaido and Tohoku
(In-service: March 2019)

AC/DC Converter Stations	・Hokuto Converter Station: 300 MW ・Imabetsu Converter Station: 300 MW
DC Bulk Line 275kV Transmission Lines	・Hokuto-Imabetsu DC Bulk Line: 122 km ・Customer Line AC/DC Converter Station Dπ lead-in:2 km

[24] Development plans for transmission lines and substations are required to be submitted for voltages of more than 250kV, or within two classes of the highest voltage available in the regional service areas. (For the Okinawa EPCO, only 132kV or more is required.) The totals are not necessarily equal due to independent rounding.
[25] Development plans corresponding to changes in line category or circuit numbers that were not included in measuring the increased length of transmission lines were treated as no change in the length of transmission lines.
[26] Increased length does not include the item with * because of an undefined in-service date.
[27] Installed capacity for the converter station on one side is included in the DC transmission system.

Interconnection Facility Enhancement Plan between Tohoku and Tokyo
(In-service: November 2027)

500kV Transmission Lines	・Cross-regional North Bulk Line(prov.): 81 km ・Cross-regional South Bulk Line(prov.): 62 km ・Soma-Futaba Bulk Line/ Connecting Point Change: 15 km ・Shinchi Thermal Power Line/ Cross-regional Switching Station(prov.) lead-in: 1 km ・Joban Bulk Line/ Cross-regional Switching Station(prov.) Dπ lead-in: 1 km
Switching Stations	500kV Switching Station(prov.): 10 circuits

Interconnection Facility Enhancement Plan between Tokyo and Chubu
(120MW→210MW; In-service: FY 2020)

AC/DC Converter Stations	・Shin Shinano AC/DC Converter Station： 900 MW ・Hida AC/DC Converter Station： 900 MW
DC Bulk Line 275kV Transmission Lines	・Hida-Shinano DC Bulk Line: 89 km ・Hida Branch Line: 1 km

Interconnection Facility Enhancement Plan between Tokyo and Chubu
(210MW→300MW; In-service: FY 2027)

Frequency Converter Stations	・Shin Sakuma FC station(prov.): 300 MW ・Higashi Shimizu FC station: 300 MW→900 MW
275 kV Transmission Lines	・Higashi Shimizu Line (prov.): 20 km ・Sakuma Higashi Bulk Line/ Shin Sakuma FC Branch Line (prov.): 1 km ・Sakuma Nishi Bulk Line/ Shin Sakuma FC Branch Line (prov.): 1 km ・Shin Toyone-Toei Line: 1 km ・Sakuma Nishi Bulk Line/ Toei Branch Line (prov.): 2km ・Sakuma Higashi Bulk Line: 125 km ・Sakuma Nishi Bulk Line: 11 km
500 kV Transformers	・Shin Fuji Substation: 1,500MVA×1 ・Shizuoka Substation: 1,000MVA×1 ・Toei Substation: 800MVA×1 →1,500MVA×2

Interconnection Facility Enhancement Plan between Chubu and Kansai
(In-service: Undetermined)

500 kV Transmission Lines	・Sekigahara Kita Oomi Line: 2 km ・Sangi Bulk Line/ Sekigahara Switching Station π lead-in: 1 km ・Kita Oomi Line/ Kita Oomi Switching Station π lead-in: 1 km
Switching Stations	・Sekigahara Switching Station: 6 circuits ・Kita Oomi Switching Station: 6 circuits

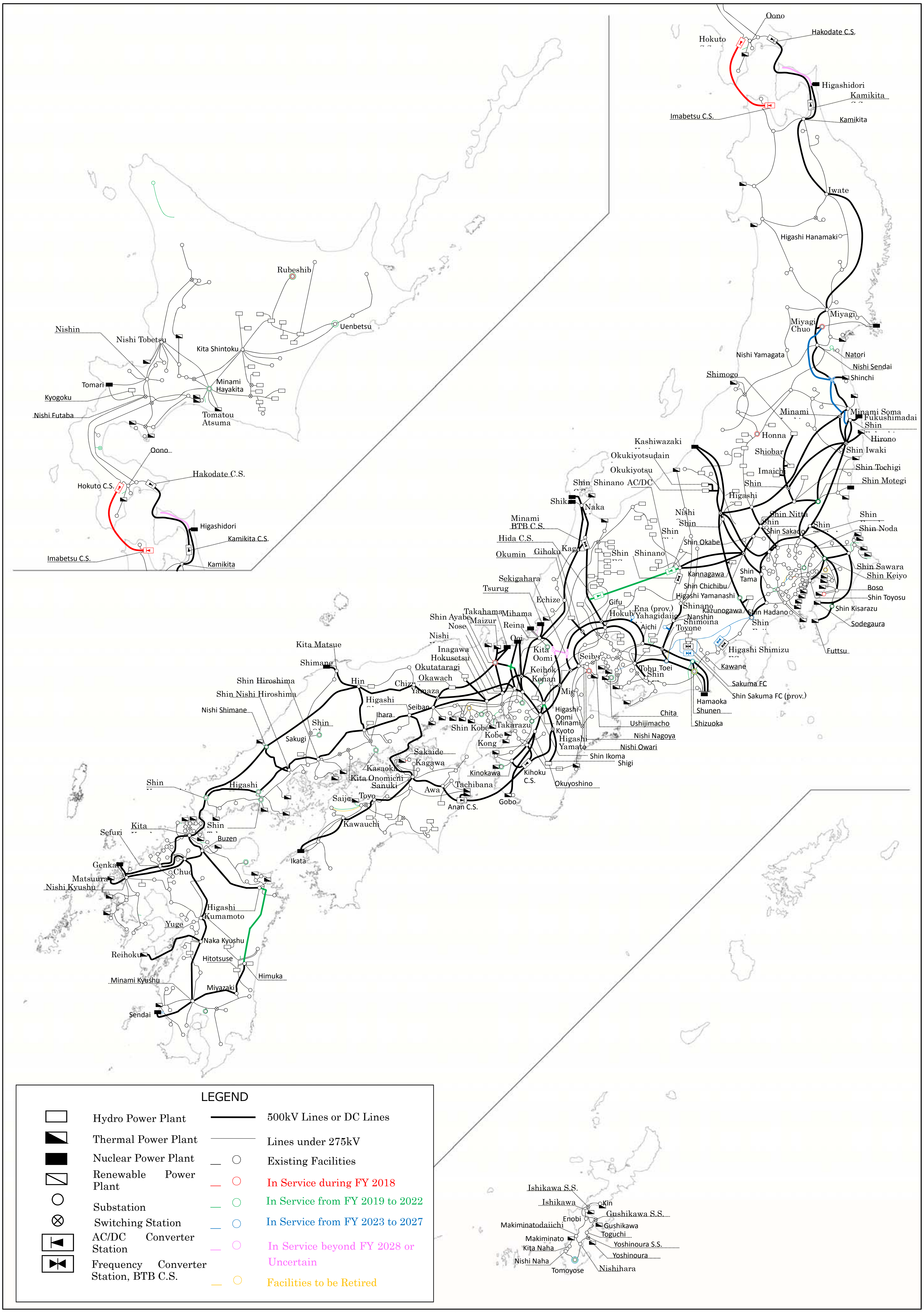


Figure 4 Power Grid Configuration in Japan

(1) Development Plans for Major Transmission Lines

Table 4-2　Development Plans under Construction

Company	Line	Voltage	Length[28,29]	Circuit	In-construction	In-service	Purpose[30]
Hokkaido EPCO	Hokuto-Imabetsu DC Bulk Line	DC250kV DC250kV	97.7km 24.4km*1	SP 1	Apr.2014	Mar. 2019	Reliability upgrade*3
Tohoku EPCO	Customer Line/ AC/DC CS Dπ lead-in	275kV	2.2km	2	Aug.2016	Jun. 2018	Reliability upgrade*3
	1408G02 Branch Line	500kV	3km	2	Sep.2017	Jul. 2019	Generator connection
TEPCO Power Grid	G3060006 access line (prov.)	275kV	6km	2	Jan. 2017	Apr. 2019	Generator connection
	Shinano-Hida DC Bulk Line	DC± 200kV	89km	BP 1	Jul. 2017	FY 2020	Reliability upgrade*3
	Shinjuku-Jonan Line replacement	275kV	16.4km *1,*2	3	Nov. 2017	Jul. 2018(No.1) Apr. 2019(No.2) Apr. 2020(No.3)	Aging management
Chubu EPCO	Shizuoka Higashi Branch Line	275kV	2km	2	Jul.2001	Jun. 2019	Aging management Economic upgrade
	Shizuoka Nishi Branch Line	275kV	3km	2	Jul.2001	Jun. 2019	Aging management Economic upgrade
Kansai EPCO	Kobe Ironworks/ Thermal Power access line(prov.)	275kV	4.4km*1	3	Apr. 2017	Feb. 2021 (No.1) Feb. 2022(No.2&3)	Generator connection
Kyushu EPCO	Hyuga Bulk Line	500kV	124km	2	Nov. 2014	Jun. 2022	Reliability upgrade Economic upgrade
	Customer line	220kV	4km*1*2	1	Oct. 2017	May 2019	Aging management
Electric Power Develop-ment Company (EPDC)	Ooma Bulk Line	500kV	61.2km	2	May 2006	Uncertain	Generator connection

Table 4-3　Development Plans on Planning Stages

Company	Line	Voltage	Length	Circuit	In-construction	In-service	Purpose
Hokkaido EPCO	SB Energy/ Yakumo PV(prov.) access line	187kV	0.2km	1	Apr. 2018	Nov.2019	Generator connection
	SB Energy/ Yakumo PV(prov.) access 187kV Switching Station	187kV	-	2	Jun. 2018	Oct. 2019	Generator connection
	Tomakomai Biomass (prov.) access line	187kV	0.2km	1	Apr. 2019	Oct. 2020	Generator connection
	Kaminokuni daini Wind Power (prov.) access line	187kV	0.1km	1	Apr. 2019	Mar. 2021	Generator connection

---

28 Length with *1 denotes "Underground," otherwise "Overhead."
29 Length with *2 denotes the change of line category or circuit numbers, not included in Table 4.
30 Purpose is stated below: *3 indicates the enforcement relating to cross-regional interconnection lines.

Demand coverage	Relating to increase/decrease of demand
Generator connection	Relating to generator connection
Aging management	Relating to aging management of facilities (including proper update of facilities with evaluation of obsolesce)
Reliability upgrade	Relating to improvement of reliability or security of stable supply
Economic upgrade	Relating to improvement of economies, such as reducing transmission loss, facility downsizing or upgrading stability of the system

Company	Line	Voltage	Length[22,23]	Circuit	In-construction	In-service	Purpose[24]
Tohoku EPCO	Customer Line/ Natori Substation Dπ lead-in	275kV	0.4km	2	May 2018	Jun. 2019	Demand coverage
	Cross-regional North Bulk Line(prov.)	500kV	81km	2	Sep. 2022	Nov. 2027	Generator connection Reliability upgrade*3
	Cross-regional South Bulk Line(prov.)	500kV	62km	2	Sep. 2024	Nov. 2027	Generator connection Reliability upgrade*3
	Soma-Futaba Bulk Line/connecting point change	500kV	15km	2	Apr. 2022	Nov. 2025	Generator connection Reliability upgrade*3
	Shinchi Thermal Power access line / Cross-regional Switching Station (prov.) lead-in	500kV	1km	2	Jul. 2024	Jun. 2026	Generator connection Reliability upgrade*3
	Joban Bulk Line/Cross-regional Switching Station(prov.) Dπ lead-in	500kV	1km	2	May 2025	Jul. 2026	Generator connection Reliability upgrade*3
	Cross-regional Switching Station(prov.)	500kV	-	10	May 2023	Nov. 2027 (Jun. 2026)	Generator connection Reliability upgrade*3
TEPCO Power Grid	G7060005 access line(prov.)	275kV	1km*1	1	May 2018	Aug. 2021	Generator connection
	Keihin Line No.1&2 /connecting point change	275kV	22.7→ 23.1km*2	2	Jul. 2021	Apr. 2022	Generator connection
	Higashi Shimizu Line (prov.)	275kV	13km 7km	2	FY 2021	FY 2026	Reliability upgrade*3
	Nishi Gunma Bulk Line /Higashi Yamanashi Substation T lead-in	500kV	0.2km	2→3	Nov. 2022	Oct. 2023	Demand coverage
	Generator access line (prov.)	275kV	0.1km	2	Dec. 2018	Jun. 2019	Generator connection
	Shinjuku Line replacement	275kV	22.1→ 21.1km (No.1) *1, *2 19.9→ 21.1km (No.2,3) *1, *2	3	Feb. 2019	Aug. 2028(No.1) Nov. 2025(No.2) Nov. 2032(No.3)	Aging management
	Higashi Shinjuku Line replacement	275kV	23.4→ 5.0km (No.2) *1, *2 23.4→ 5.3km (No. 3) *1, *2	2	Feb. 2019	Nov. 2025(No.2) Nov. 2032(No.3)	Aging management
Chubu EPCO	Hida Branch Line	500kV	0.4km	2	Apr. 2018	FY 2020	Reliability upgrade*3
	Yahagi daiichi Branch Line	275kV	5km	1	Jul. 2019	Feb.2021	Aging management Economic upgrade
	Ena Branch Line(prov.)	500kV	1km	2	Sep. 2021	Oct. 2024	Demand coverage
	Shimo Ina Branch Line(prov.)	500kV	1km	2	Sep. 2021	Oct. 2024	Demand coverage
	Higashi Nagoya -Tobu Line	275kV	8km*2	2	Apr. 2019	Jun. 2026	Aging management Economic upgrade
	Sekigahara-Kita Oomi Line	500kV	2km	2	Uncertain	Uncertain	Generator connection *3
	Sekigahara Switching Station	500kV	—	6	Uncertain	Uncertain	Generator connection *3
	Sangi Bulk Line/ Sekigahara Switching Station π lead-in	500kV	1km	2	Uncertain	Uncertain	Generator connection *3

Company	Line	Voltage	Length[22,23]	Circuit	In-construction	In-service	Purpose[24]
Kansai EPCO	Tsuruga Line/ North side improvement	275kV	9.8km→ 9.3km*2	2	Beyond FY 2020	Beyond FY 2023	Aging management
	Ooi Bulk Line/ Shin Ayabe Line route change	500kV	1.9km	2	Mar. 2019	Jan. 2020	Economic upgrade
	Kita Yamato Line/ Minami Kyoto Substation Lead-in change	500kV	0.1km	2	Jun. 2021	Dec. 2021	Economic upgrade
	Kita Oomi Switching Station	500kV	—	6	Uncertain	Uncertain	Generator connection *3
	Kita Oomi Line/ Kita Oomi Switching Station πlead-in	500kV	0.5km	2	Uncertain	Uncertain	Generator connection *3
	Shin Kobe Line/ reinforcement	275kV	20.2→ 21.5km*2	2	Mar. 2019	Jul. 2020	Generator connection Aging management
Shikoku EPCO	Customer line	187kV	0.7km*1*2	1	May 2018	Aug. 2018	Aging management
	Matsuyama Higashi Line	187kV	47.8km*2	1→2	Aug. 2018	Nov. 2019	Aging management Economic upgrade
	Saijo Thermal Power access line	187kV	6.5km*2	2	Jul. 2020	May 2021	Generator connection
Kyushu EPCO	Power access line	220kV	0.3km	1	Nov. 2018	Jul. 2019	Generator connection
	Customer line	220kV	1km	2	Jul. 2019	Apr. 2021	Demand coverage
	Power access line	220kV	4km	2	Jul. 2020	Jul.2022	Generator connection
	Shin Kagoshima Line/ Sendai Nuclear Power π lead-in	220kV	2→5km*2	1→2	Aug. 2020	Jul. 2023	Economic upgrade
EPDC	Sakuma Higashi Bulk Line/ Shin Sakuma FC Branch Line(prov.)	275kV	1km	2	FY 2022	FY 2026	Reliability upgrade*3
	Sakuma Nishi Bulk Line/ Shin Sakuma FC Branch Line (prov.)	275kV	1km	2	FY 2022	FY 2026	Reliability upgrade*3
	Shin Toyone-Toei Line	275kV	1km	1	FY 2022	FY 2026	Reliability upgrade*3
	Sakuma Nishi Bulk Line/Toei Branch Line(prov.)	275kV	2km	2	FY 2022	FY 2026	Reliability upgrade*3
	Sakuma Higashi Bulk Line	275kV	124.8→ 125km*2	2	FY 2022	FY 2027	Reliability upgrade*3
	Sakuma Nishi Bulk Line	275kV	10.6→ 11km*2	2	FY 2022	FY 2027	Reliability upgrade*3
Northern Hokkaido Wind Energy Trans-mission Company (NHWETC)	NHWETC Toyotomi-Nakagawa Bulk Line (prov.)	187kV	51km	2	Oct. 2018	Sep. 2022	Generator connection

Table 4-4 Retirement Plans

Company	Line	Voltage	Length	Circuit	Retirement	Purpose[24]
Shikoku EPCO	Kita Matsuyama Line	187kV	⊿47.5km	1	Nov. 2019	Aging management Economic upgrade
EPDC	Shin Toyone-Toei Line	275kV	⊿2.6km	1	FY 2026	Reliability upgrade*3

(2) Development Plans for Major Substations

Table 4-5 Development Plans under Construction

Company	Substation[31]	Voltage	Capacity	Number	In-construction	In-service	Purpose[24]
Hokkaido EPCO	Rubeshibe	187/66kV	60MVA→ 100MVA	1→1	Jun.2017	Jul. 2018	Aging management
	Hokuto Converter Station*4	—	300MW	—	Mar. 2015	Mar. 2019	Reliability upgrade*3
	Imabetsu Converter Station*4	—	300MW	—	Mar. 2016	Mar. 2019	Reliability upgrade*3
Tohoku EPCO	Miyagi Chuo	500/275kV	1,000MVA	1	Feb. 2016	Nov. 2018	Economic upgrade
	Natori*4	275/154kV	450MVA×2	2	Feb. 2017	Jun. 2019	Demand coverage
	Honna	275/154kV	120MVA→ 150MVA	1→1	Aug. 2017	Sep. 2018	Aging management
TEPCO Power Grid	Shin Shinano AC/DC Converter Station*4	—	900MW	-	Mar. 2016	FY 2020	Reliability upgrade*3
Chubu EPCO	Nishi Nagoya	275/154kV	450MVA	1	Apr. 2011	May 2018	Economic upgrade
	Shizuoka*4	500/275kV	1,000MVA	1	Aug.2001	Jun.2019	Aging management Economic upgrade
	Hida Converter Station*4	—	900MW	—	Jul. 2017	FY 2020	Reliability upgrade*3
Chugoku EPCO	Higashi Yamaguchi	500/220kV	1,000MVA	1	May 2017	Apr. 2019	Demand coverage Generator connection
Okinawa EPCO	Tomoyose	132/66kV	125MVA×2→ 200MVA×2	2→2	Oct. 2017	Jun. 2020 Oct. 2023	Aging management

Table 4-6 Development Plans in Planning Stages

Company	Substation[25]	Voltage	Capacity	Number	In-construction	In-service	Purpose[24]
Hokkaido EPCO	Minami Hayakita	187/66kV	200MVA	1	Aug. 2018	Sep.2019	Generator connection
	Uenbetsu	187/66kV	75MVA→ 100MVA	1→1	Mar. 2019	Nov. 2019	Aging management
	Rubeshibe	187/66kV	60MVA×2→ 100MVA	2→1	Mar. 2021	Oct. 2021	Aging management
TEPCO Power Grid	Shin Fuji	500/275kV	1500MVA	1	FY 2023	FY 2026	Reliability upgrade*3
	Higashi Yamanashi	500/154kV	750MVA	1	Apr. 2019	Dec. 2022	Demand coverage
	Shin Motegi	500/275kV	1500MVA	1	Sep.2018	Mar. 2021	Generator connection
	Anegasaki Chuo	275/66kV	150MVA×1→ 300MVA×1	1→1	Apr. 2018	Dec. 2018	Generator connection
	Shin Kisarazu	275/154kV	450MVA×2	2	Jun. 2020	Apr. 2022	Generator connection
	Shin Keiyo	275/154kV	300MVA×2→ 450MVA×2	2→2	Jul. 2018	Nov. 2019(5B) Apr. 2021(6B)	Aging management
	Ueno	275/66kV	300MVA	1	Dec. 2018	Dec. 2019	Economic upgrade
Chubu EPCO	Shunen	275/154kV	450MVA×1→ 300MVA×1	1→1	Jan. 2019	Jun. 2020	Aging management
	Chita Thermal Power	275/154kV	300MVA×1→ 450MVA×1	1→1	Dec. 2018	Mar. 2021	Aging management
	Chita Thermal Power	275/154kV	450MVA×2	2	Dec. 2018	Oct. 2020(1B) Aug. 2021(2B)	Generator connection
	Ena(prov.)*4	500/154kV	200MVA×2	2	Oct. 2020	Oct. 2024	Demand coverage
	Shimo Ina(prov.)*4	500/154kV	300MVA×2	2	Oct. 2020	Oct. 2024	Demand coverage

[31] Substation with *4 denotes a substation or converter station installed new, including an uprated electric facility.

Company	Substation[25]	Voltage	Capacity	Number	In-construction	In-service	Purpose [24]
Chubu EPCO	Toei	500/275kV	800MVA×1→ 1,500MVA×2	1→2	FY 2020	FY 2026	Reliability upgrade*3
	Shizuoka	500/275kV	1,000MVA	1	FY 2024	FY 2026	Reliability upgrade*3
	Higashi Shimizu	—	300MW→ 900MW	—	FY 2020	FY 2027	Reliability upgrade*3
Kansai EPCO	Shin Ayabe	275/77kV	200MVA×1→ 300MVA×1	1→1	May 2018	Mar. 2019	Aging management
	Konan	275/77kV	300MVA×1→ 200MVA×1	1→1	Aug. 2018	Oct. 2019	Aging management
	Higashi Osaka	275/77kV	300MVA×1→ 200MVA×1	1→1	Sep. 2019	Jun. 2020	Aging management
	Nishi Kobe	275/77kV	200MVA×2→ 300MVA×1	2→1	Nov. 2020	Jun. 2021	Aging management
	Koto	275/77kV	200MVA×1→ 300MVA×1	1→1	Apr. 2020	Jun. 2021	Aging management
	Yodogawa	275/77kV	300MVA×2→ 300MVA×1	2→1	Nov. 2020	Oct. 2021	Aging management
	Kainannko	275/77kV	300MVA×1, 200MVA×2→ 300MVA×2	3→2	Jun. 2020	Jan. 2023	Aging management
Chugoku EPCO	Shin Tokuyama	220/110kV	150MVA×1→ 300MVA×1	1→1	Jun. 2018	Apr. 2019	Aging management Generator connection
	Sakugi	220/110kV	200MVA	1	Jun. 2019	Apr. 2020	Generator connection
	Shin Yamaguchi	220/110kV	400MVA×2	2	Apr. 2019	Jun. 2021	Economic upgrade
	Kasaoka	220/110kV	250MVA→ 300MVA	1→1	Aug. 2020	Jun. 2021	Aging management
	Nishi Shimane	500/220kV	1,000MVA	1	Apr. 2020	Mar. 2022	Generator connection
Kyushu EPCO	Hayami	220/66kV	250MVA	1	Apr. 2019	Jun. 2020	Generator connection
	Kirishima	220/66kV	300MVA	1	Nov. 2019	Sep. 2021	Generator connection
EPDC	Shin Sakuma FC (prov.)	—	300MW	—	FY 2021	FY 2027	Reliability upgrade*3
NHWETC	Kita Toyotomi(prov.)	187/66kV	165MVA×3	3	Oct. 2018	Sep. 2022	Generator connection

Table 4-7 Retirement Plans

Company	Substation	Voltage	Capacity	Number	Retirement	Purpose
TEPCO Power Grid	Hanamigawa	275/66kV	△300 MVA	△1	Mar. 2021	Demand coverage
Chubu EPCO	Shunen	500/275kV	△1,000 MVA	△1	Jun. 2019	Aging management
Kansai EPCO	Shin Kakogawa	275/77kV	△300 MVA	△1	Dec. 2018	Aging management

Other development plans (not subject to submission by the electric supply plan)

The development plan stated below is not required to be included in the electricity supply plan, but will be implemented as a functional improvement by Chubu EPCO and Hokuriku EPCO.

◇Minami Fukumitsu Interconnection Facility・Substation 500kV AC Connecting Bus Line Addition (In service: September 2019).

(3) Summary of Development Plans for Transmission Lines and Substations

Tables 4-8 to 4-11 show the summarized development or extension plans of major transmission lines and substations (transformers and converter stations) up to FY 2027 submitted by GT&D and transmission companies.

Table 4-8 Development Plans for Major Transmission Lines

Category	Voltage	Lines	Length[32]	Extended Length[33]	Total Length	Total Extended Length
Newly Installed or Extended	500kV	Overhead	291 km*[34]	583 km*	291 km*	583 km*
		Underground	0 km	0 km		
	275kV	Overhead	37 km	67 km	42 km	82 km
		Underground	5 km	14 km		
	220kV	Overhead	5 km	10 km	5 km	10 km
		Underground	0 km	0 km		
	187kV	Overhead	52 km	103 km	52 km	103 km
		Underground	0 km	0 km		
	132kV	Overhead	0 km	0 km	0 km	0 km
		Underground	0 km	0 km		
	DC	Overhead	187 km	187 km	211 km	211 km
		Underground	24 km	24 km		
	Total	Overhead	572 km	950 km	601 km	988 km
		Underground	30 km	39 km		
To be Retired	275kV	Overhead	△3km	△3km	△3km	△3km
		Underground	0km	0km		
	220kV	Overhead	△ 48 km	△ 48 km	△ 48 km	△ 48 km
		Underground	0 km	0 km		
	Total	Overhead	△50 km	△50 km	△ 50 km	△ 50 km
		Underground	0 km	0 km		

Table 4-9 Revised Plans for Line Category and the Numbers of Circuits[35]

Voltage	Length Extended	Total Extended Length
500kV	0 km	1 km
275kV	288 km	486 km
220kV	9 km	14 km
187kV	55 km	109 km
132kV	0 km	0 km
DC	0 km	0 km
Total	352 km	610 km

32 Length denotes both the increased length due to newly installed or extended plans, and the decreased length due to retirement. Development plans corresponding to the change of line category or the number of circuits were not included in the increased length of transmission lines shown in Table 4-8 and are treated as no change in the length. The total lengths are not necessarily equal due to independent rounding.
In addition, the total length is not necessarily equal due to independent rounding.

33 Total length denotes the aggregation of length multiplied by the number of circuits. Development plans corresponding to the change of line category or the number of circuits were not included in the increased length of transmission lines in Table 4-8 and are treated as no change in the length.

34 See footnote 26.

35 Table 4-9 aggregates the extended and total extended lengths corresponding to the revised plans for the line category and the number of circuits.

Table 4-10 Development Plans for Major Substations

Category[36]	Voltage[37]	Increased Numbers	Increased Capacity
Newly Installed or Extended	500kV	13 [5]	11,950 MVA [2,000MVA]
	275kV	5 [2]	3,430 MVA [900MVA]
	220kV	5 [0]	1,750 MVA [0MVA]
	187kV	3 [3]	740 MVA [495MVA]
	132kV	0 [0]	150 MVA [0MVA]
	Total	26 [10]	18,020 MVA [3,395MVA]
To be Retired	500kV	△ 1	△ 1,000 MVA
	275kV	△ 2	△ 600 MVA
	220kV	0	0 MVA
	187kV	0	0 MVA
	132kV	0	0 MVA
	Total	△ 3	△ 1,600 MVA

[ ] : The aforementioned increase in the number of transformers resulted from new substation installations.

Table 4-11 Development Plans for AC/DC Converter Stations

Category	Company and Number of Sites		Capacity[38]
Newly Installed or Extended	Hokkaido EPCO	2	300MW each
	TEPCO Power Grid	1	900MW
	Chubu EPCO	2	900MW 600MW
	Electric Power Development Company	1	300MW

36 Retirement plans with transformer installations are included in Newly Installed or Extended, and negative values are included in the increased numbers or the increased capacity.
37 Voltage class by upstream voltage.
38 Installed capacity of the converter stations on both sides of the DC lines is included.

5. Cross-regional Operation

Retail companies will procure the supply capacity for their customers in their regional service areas. The scheduled procurement from the external service areas at 15:00 in August 2018 is illustrated in four figures. Figures 5-1 and 5-2 show the ratio of the supply capacity and the supply capacity, respectively at 15:00 in August. Figures 5-3 and 5-4 show the ratio of the energy supply and the energy supply, respectively in FY 2018.

Higher ratios for procurement from the external regional service areas are observed in Chugoku, Shikoku and Kansai EPCO areas, and capacity and energy are transmitted to other areas from Tohoku, Shikoku, and Kyushu EPCO areas.

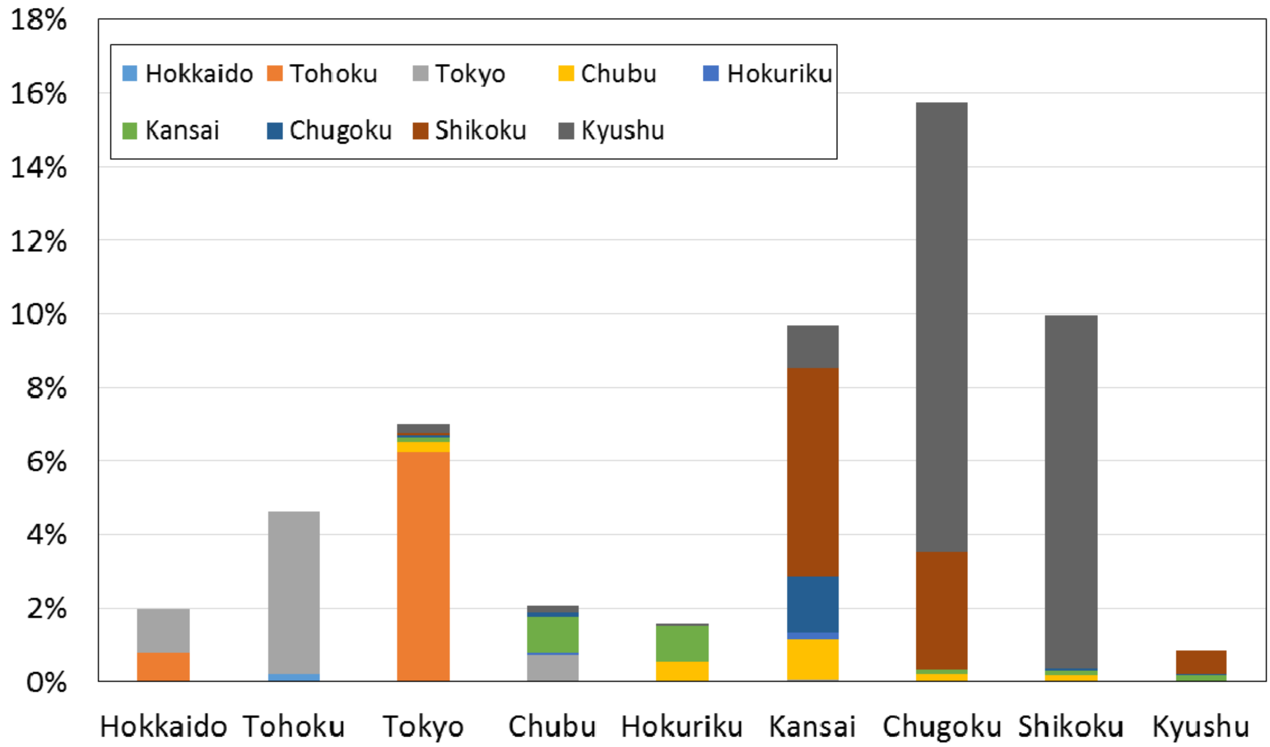


Figure 5-1 Ratio of Scheduled Procurement of Supply Capacity from External Regional Service Areas

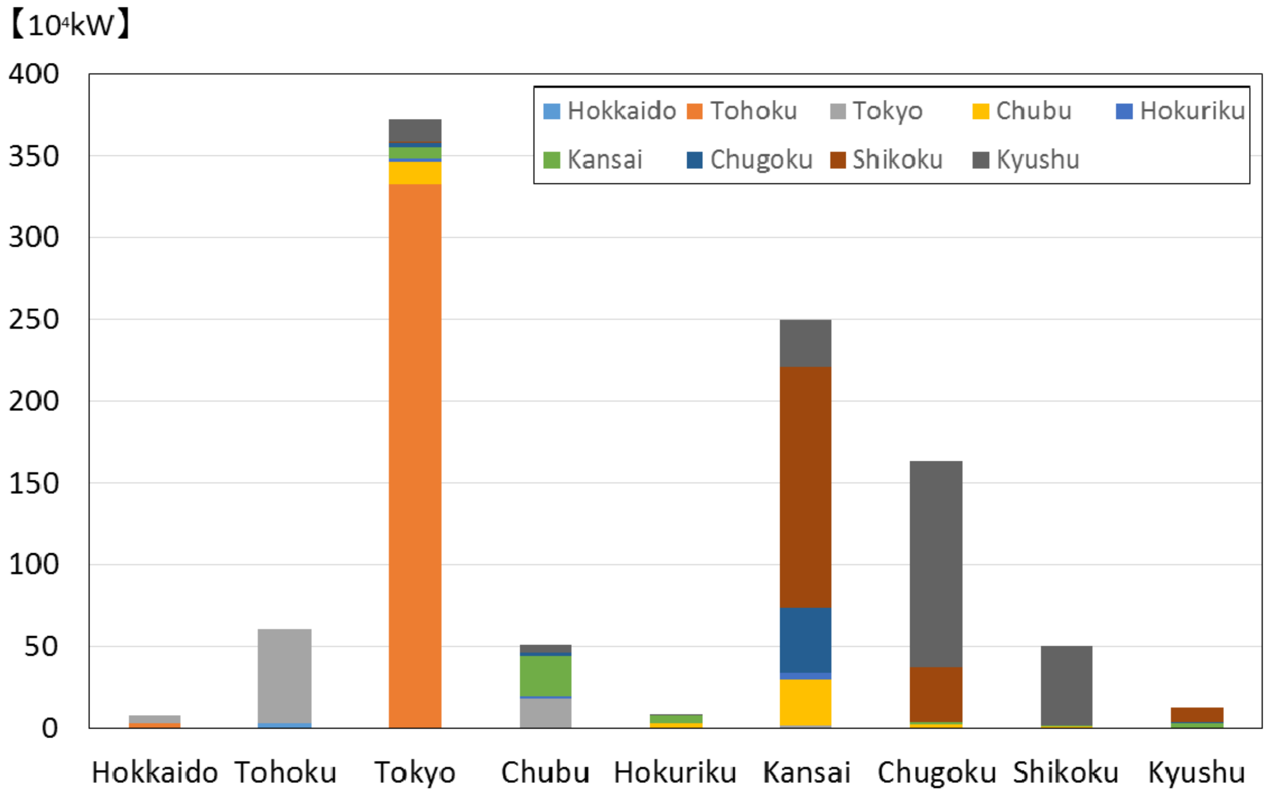


Figure 5-2 Scheduled Procurement of Supply Capacity from External Regional Service Areas

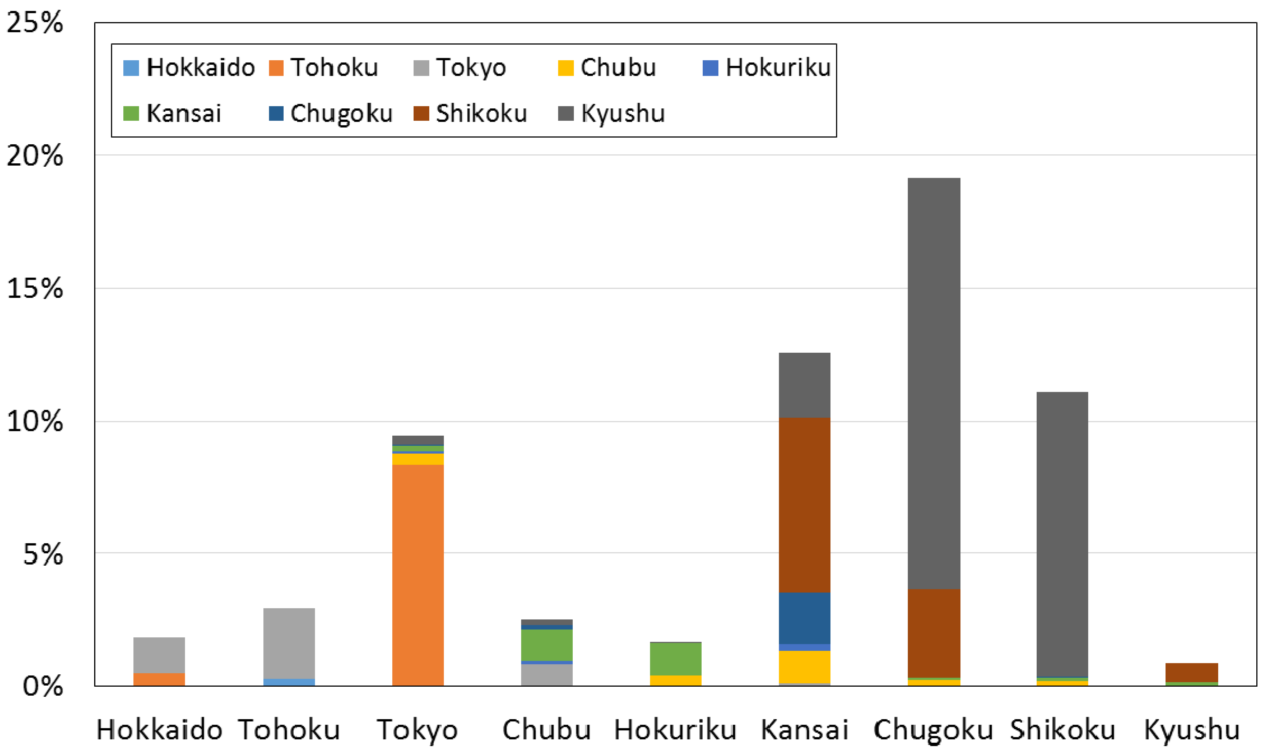


Figure 5-3 Ratio of Scheduled Procurement of Energy Supply from External Regional Service Areas

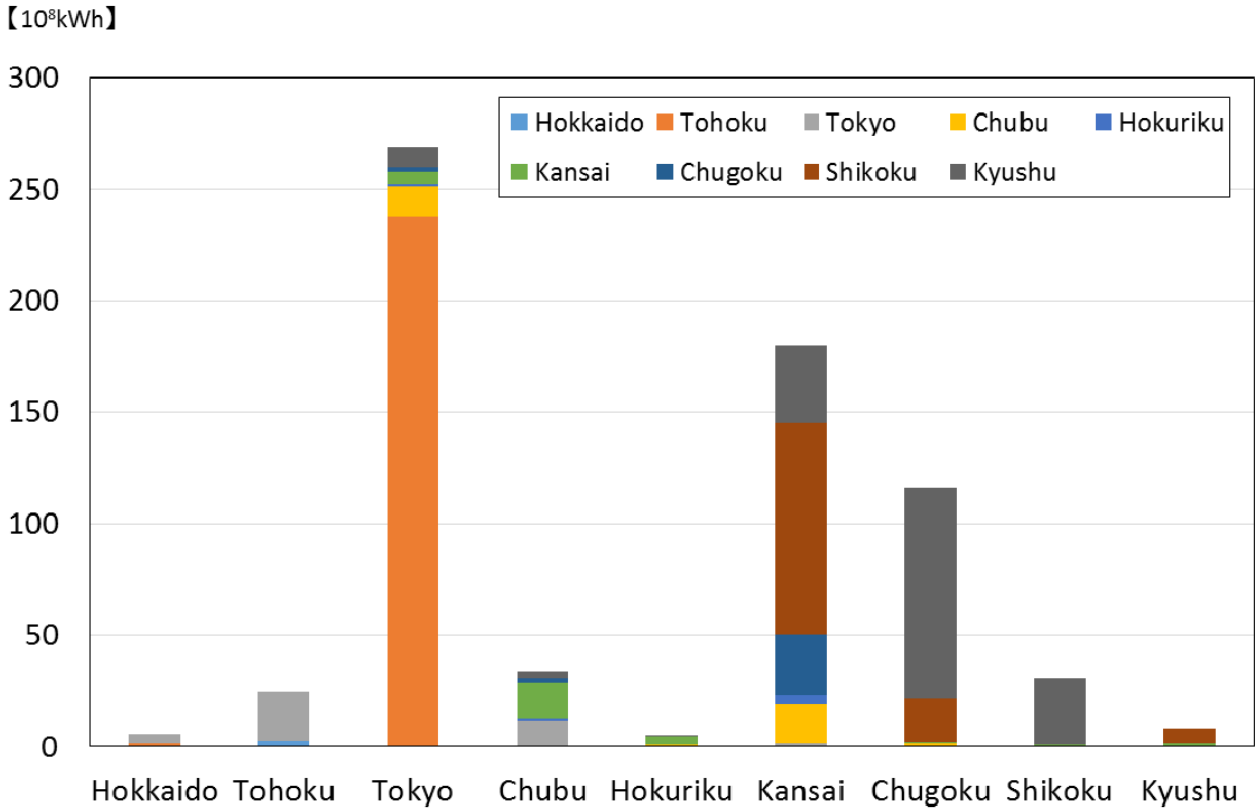


Figure 5-4 Scheduled Procurement of Energy Supply from External Regional Service Areas

6. Analysis of Characteristics of Retail Companies

(1) Distribution of Retail Companies by Business Scale (Retail Demand)

In total, 448 retail companies submitted their electricity supply plans, which have been classified by the business scale of the retail demand forecast by the corresponding companies. Figure 6-1 and 6-2 show the distributions of the business scale of retail demand and the accumulated retail demand forecast by the corresponding companies, respectively. Notably, smaller retail companies plan to expand business.

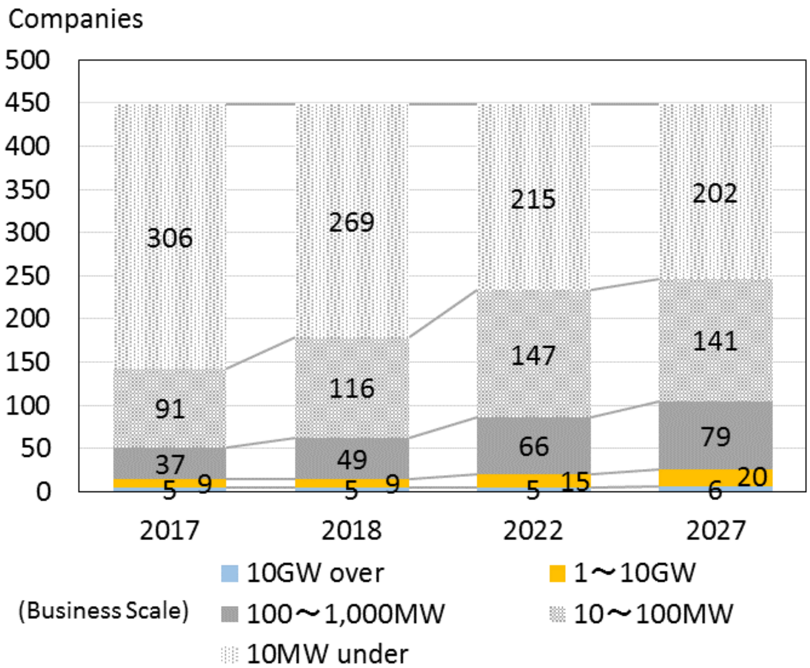


Figure 6-1 Distribution by Business Scale of the Retail Demand by Retail Companies

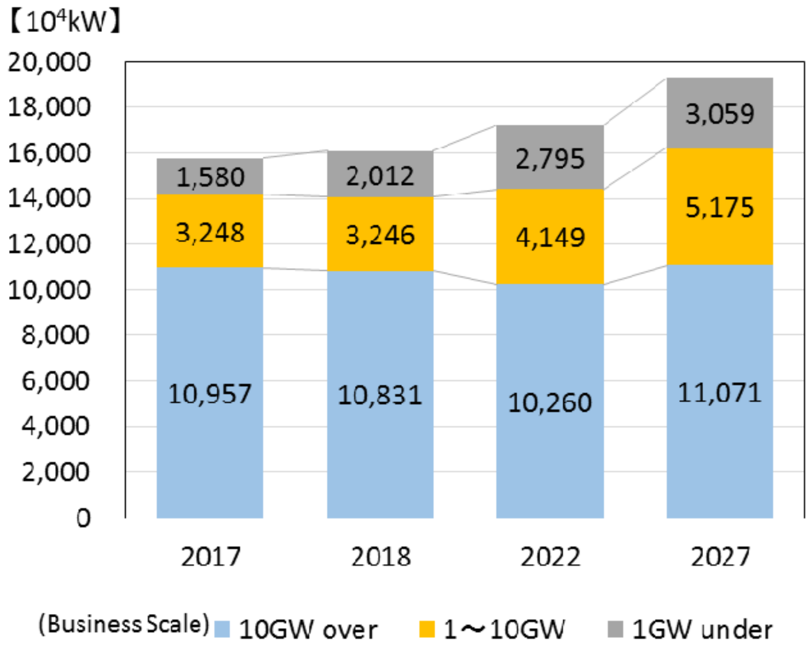


Figure 6-2 Distribution by Accumulated Retail Demand by Retail Companies

Similarly, retail companies are classified by the business scale of the retail energy sales forecast by the corresponding companies. Figure 6-3 and 6-4 show the distributions of the business scale of retail companies' energy sales and their accumulated energy sales forecast, respectively.

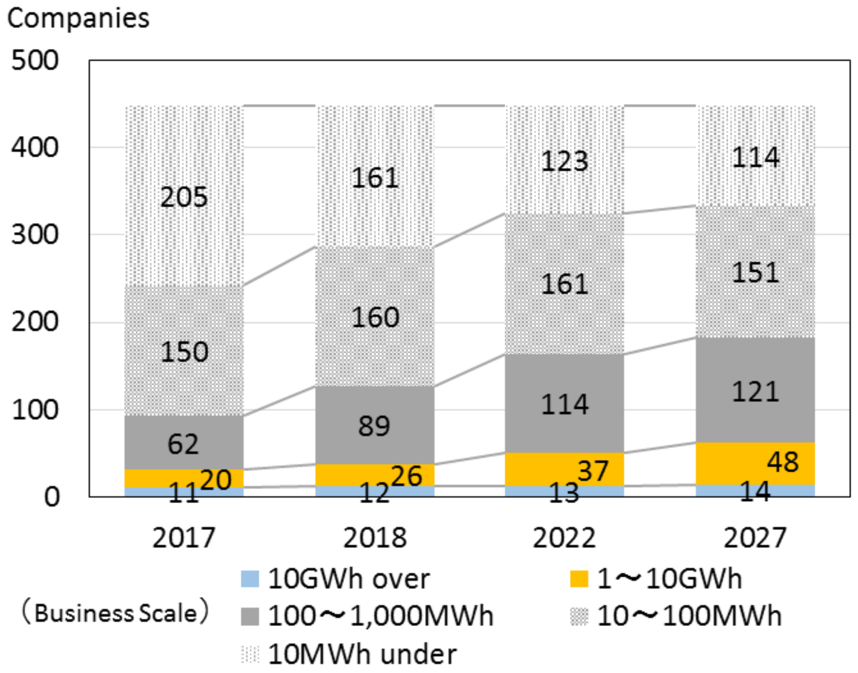


Figure 6-3 Distribution by Business Scale of Retail Companies' Energy Sales

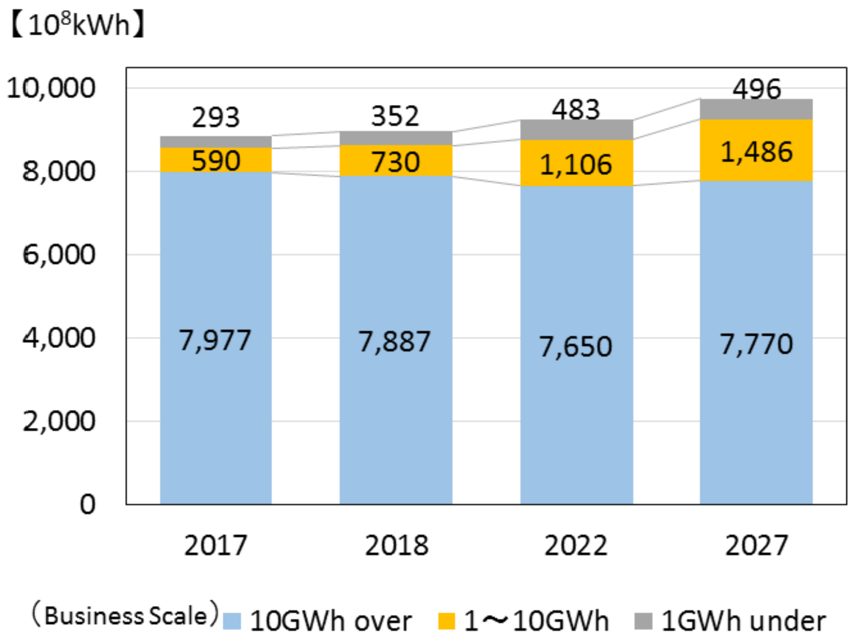


Figure 6-4 Distribution by Retail Companies' Accumulated Energy Sales

(2) Retail Companies' Business Areas

Figure 6-5 shows the ratio of retail companies by the number of areas where they plan to conduct their business. Figure 6-6 shows the number of retail companies by their business planning areas in FY 2018. The figures exclude 39 retail companies that had not yet developed their retail business plans. Half of the retail companies plan their business in a single area.

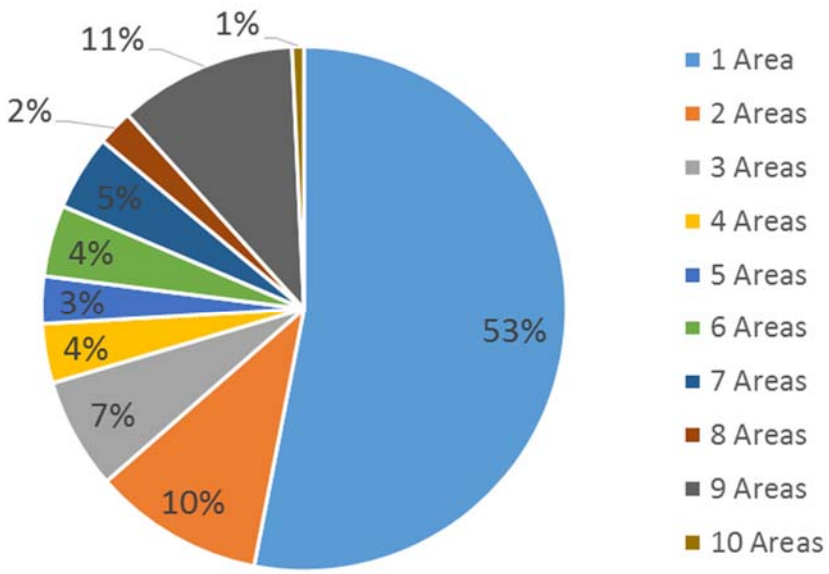


Figure 6-5 Ratio of Retail Companies by the Number of Planned Business Areas in FY 2018

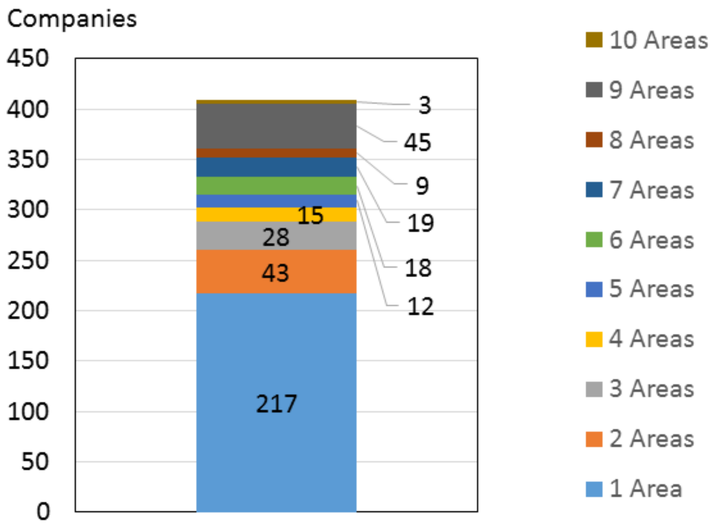


Figure 6-6 Number of Retail Companies by their Business Planning Areas in FY 2018

Figure 6-7 shows the number and the retail demand of retail companies in each regional service areas for GT&D companies in FY 2018. In general, the number of companies is comparable with the scale of retail demand in the regional service area.

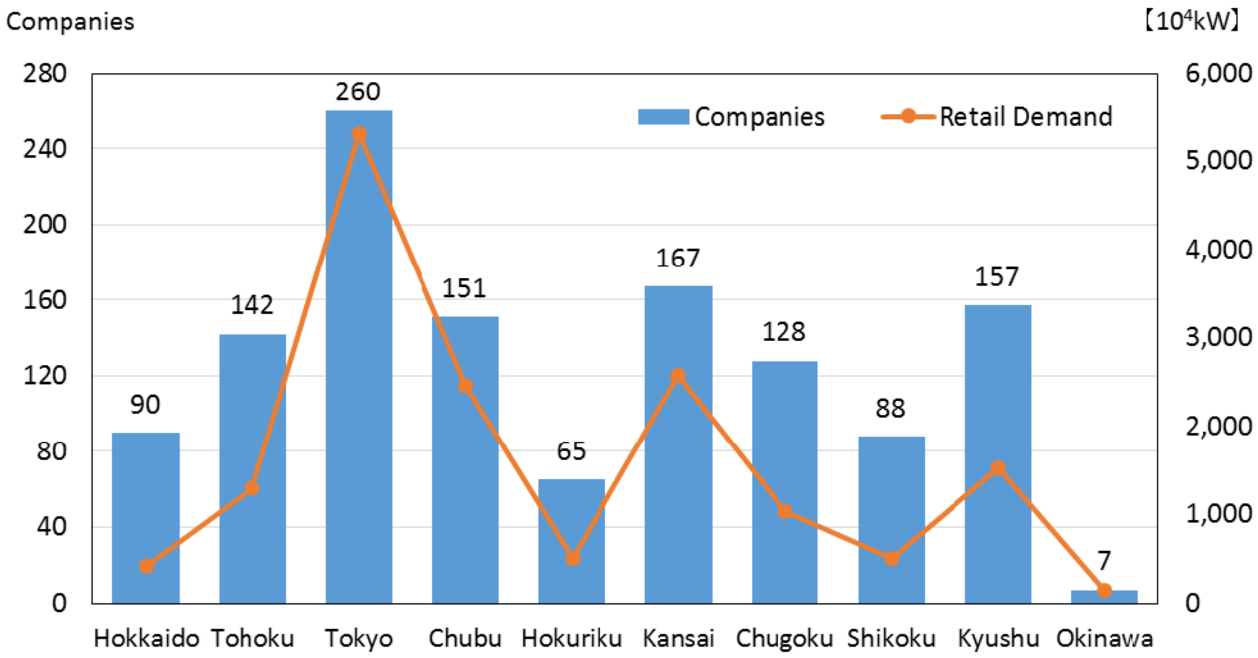


Figure 6-7 Number and Retail Demand of Retail Companies in Each Regional Service Area

(3) Supply Capacity Procurement by Retail Companies

Figures 6-8 and 6-9 show the volume and ratios of the contractually procured supply capacity to the forecast retail demand by the business scale of retail companies, respectively.

Both figures indicate that small and medium-sized retail companies plan their mid-to-long-term supply capacity as "undetermined," which leads to a downward trend in supply capacity procurement.

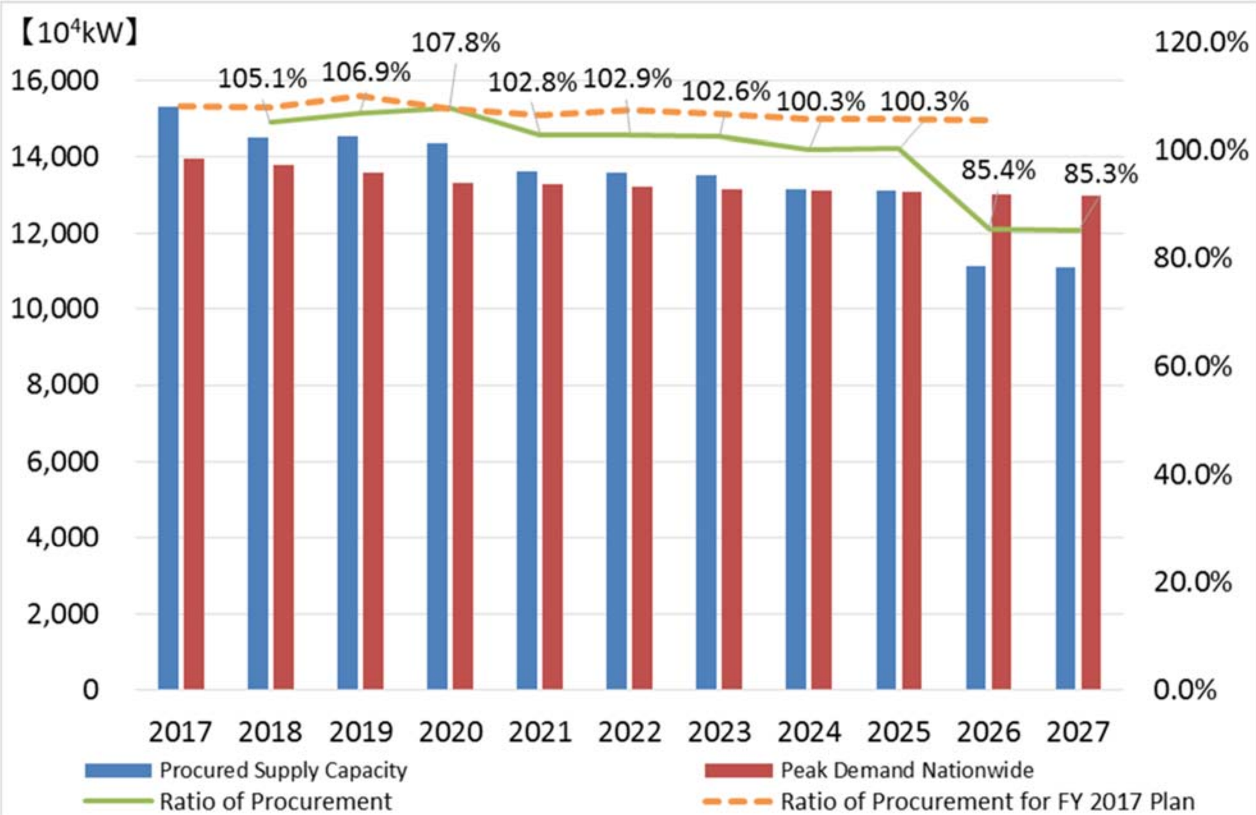


Figure 6-8 Ratio of Contractually Procured Supply Capacity to Forecast Retail Demand (Companies for Retail peak demand over 2GW)

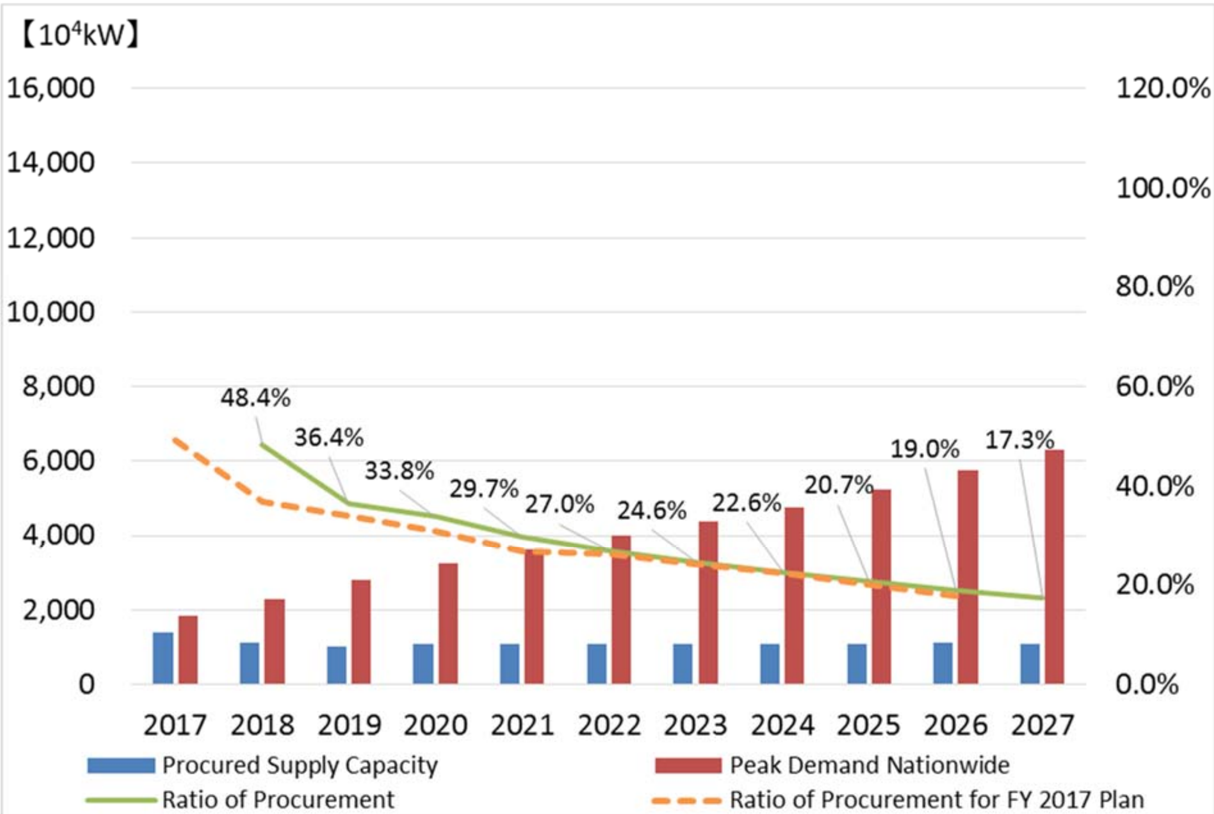


Figure 6-9 Ratio of Contractually Procured Supply Capacity to Forecast Retail Demand (Companies for Retail peak demand under 2GW)

(4) Distribution of Generation Companies by Business Scale (Installed Capacity)

In total, 642 generation companies submitted their electricity supply plans, which have been classified by the business scale of the installed capacity operated by the corresponding companies. Figure 6-10 shows the distribution by business scale and Figure 6-11 shows the installed capacity operated by the corresponding companies.

Generation companies with an installed capacity of under 100 MW are planning to enlarge the scale of their business.

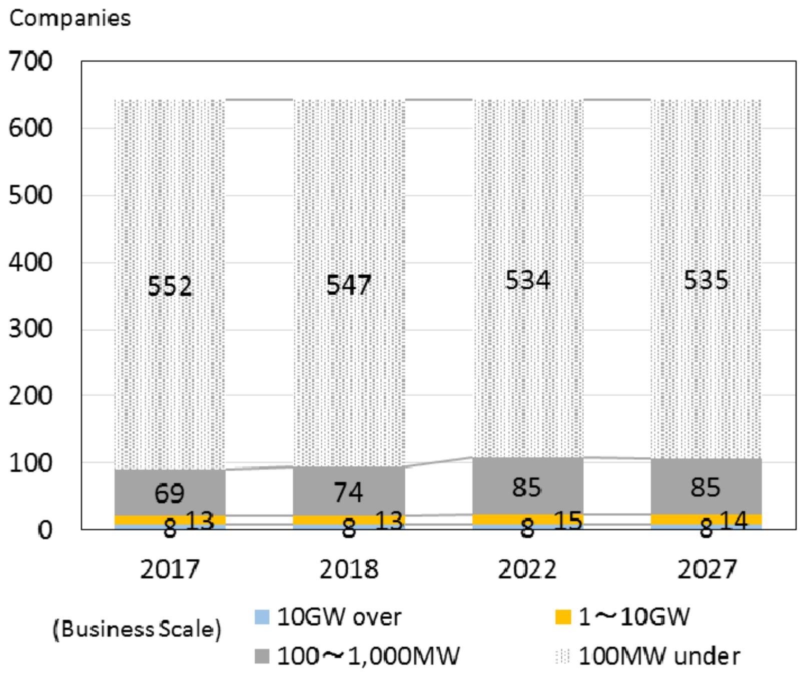


Figure 6-10 Distribution by Business Scale of Generation Companies' Installed Capacity

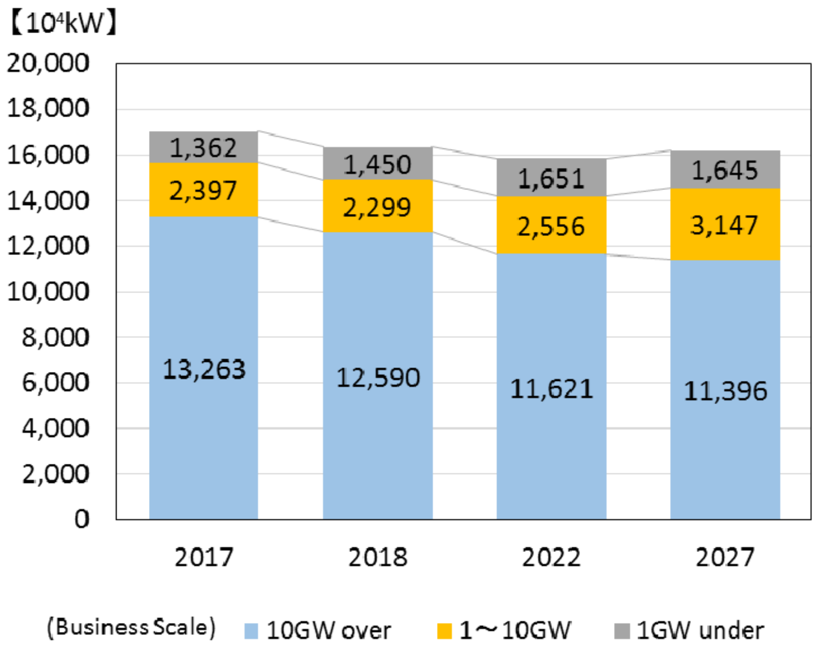


Figure 6-11 Distribution by Generation Companies' Accumulated Installed Capacity

Similarly, generation companies are classified by the business scale of the corresponding companies' energy supply forecast. Figure 6-12 shows the distribution by the business scale of the energy supply and Figure 6-13 shows the distribution by the corresponding companies' accumulated energy supply forecast.

Generation companies with an energy supply of under 1 TWh are planning to enlarge their business scale.

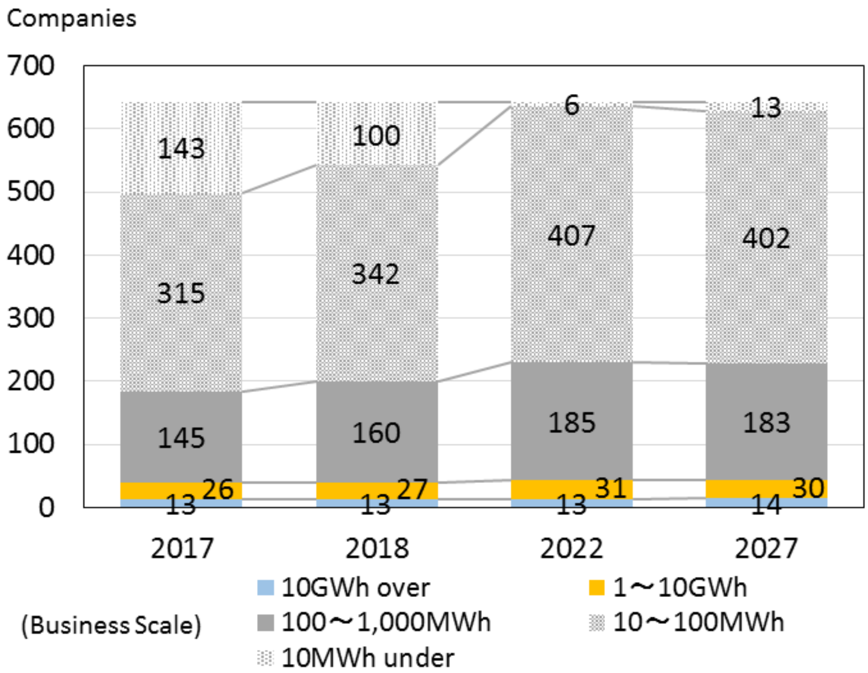


Figure 6-12 Distribution by Business Scale of Generation Companies' Energy Supply

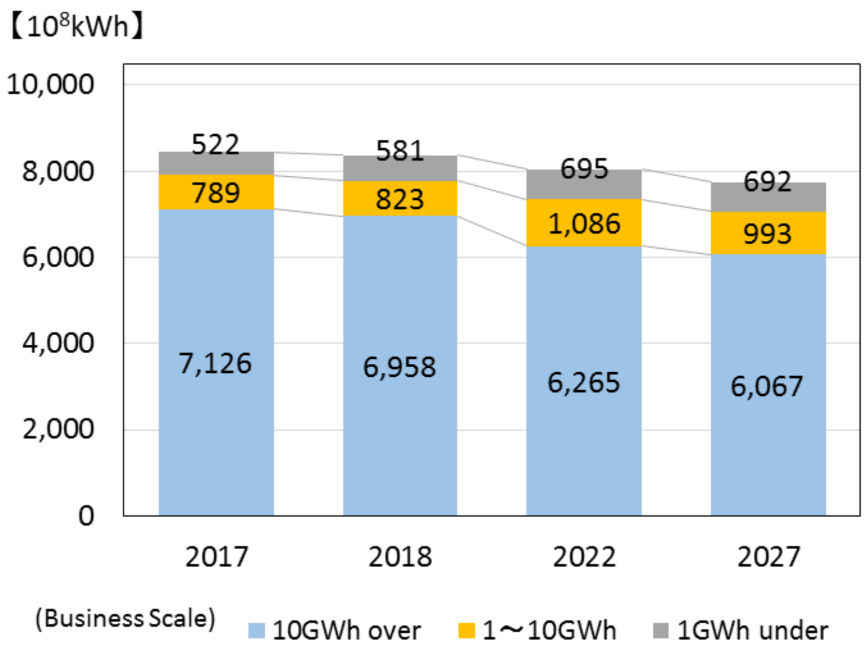


Figure 6-13 Distribution by Generation Companies' Accumulated Energy Supply

(5) Generation Companies' Business Areas

Figure 6-14 shows the ratio of generation companies to the number of areas where they plan to conduct their business. Figure 6-15 shows the number of generation companies by their business planning areas in FY 2018. The figures exclude 106 generation companies that do not own their generation plants. Approximately 75% of all generation companies plan their business in a single area.

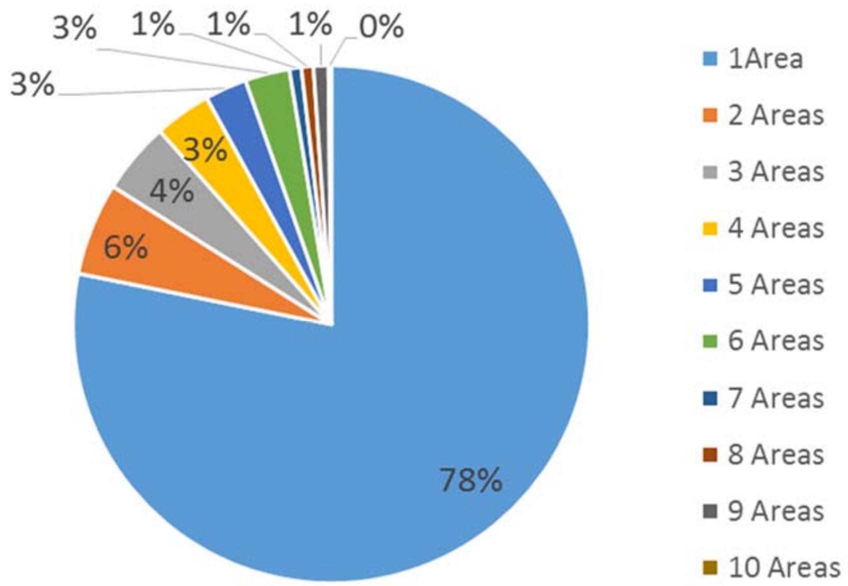


Figure 6-14 Ratio of Generation Companies by the Number of Planned Business Areas in FY 2018

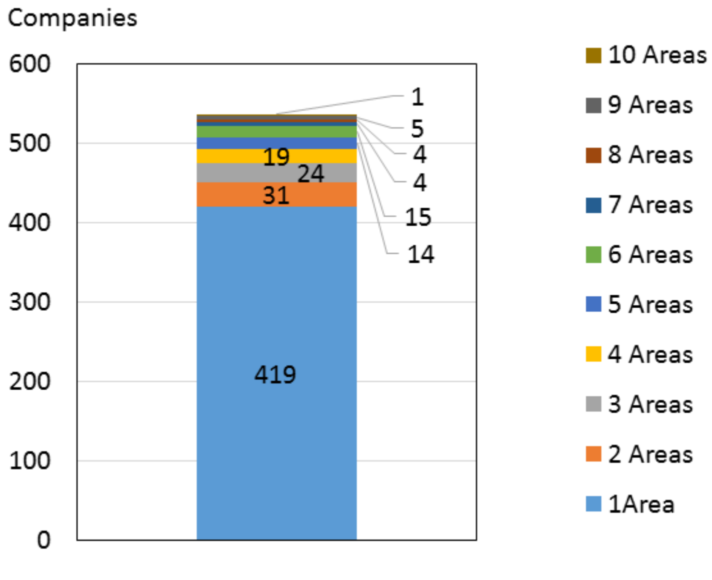


Figure 6-15 Number of Generation Companies by Their Business Planning Areas in FY 2018

Figure 6-16 shows the number and installed capacity of generation companies in each regional service area for GT&D companies in August 2018. In the Hokkaido, Tohoku, Chugoku, Shikoku, and Kyushu regional service areas, the scale of generation companies is rather small and their supply capacity is comparatively small despite the number of generation companies in these regional service areas.

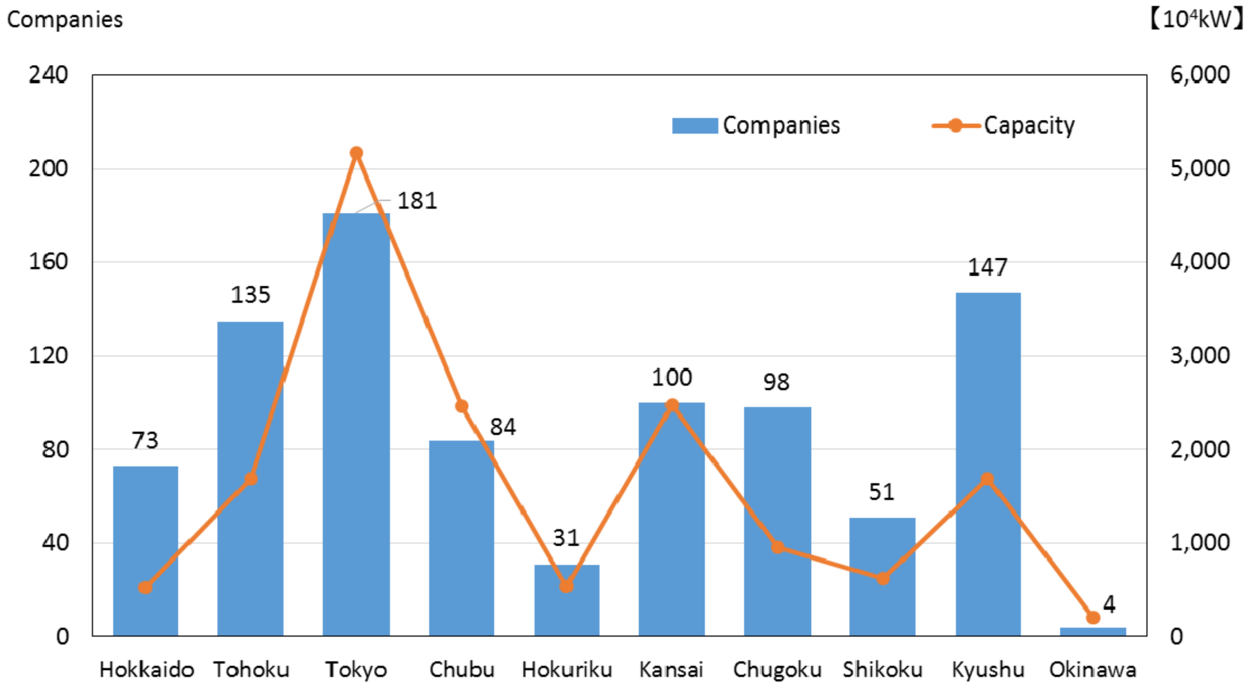


Figure 6-16 Number and Installed Capacity of Generation Companies in Each Regional Service Area

7. Findings and Current Challenges

(1) Electricity Supply Plan Aggregation Findings

After aggregating the electricity supply plans, the Organization identified the following items for the electricity supply plan and the evaluation of supply–demand balances during the aggregation of electricity supply plans under the circumstances that lead to transition of electric power supply: the greater integration of renewable energy, the enlargement of the market with the participation of new players, and the results of some changes to the system.

a. Appropriate State between Aggregation of Electricity Supply Plan and Supply–Demand Evaluation at Electricity Supply–Demand Verification, and Principle of Electricity Supply Plan beyond Capacity Market Introduction

・Since the East Japan Earthquake, electricity supply–demand verification studies have been conducted to assess supply–demand conditions for the upcoming summer and winter assuming severe weather conditions in addition to the aggregation of electricity supply plans.

・The supply–demand evaluation at Electricity Supply–Demand Verification has been overlapped for purpose and role with electricity supply plans that evaluates supply–demand balance and recognize supply capacity according to demand based on the Electricity Business Act. To improve business efficiency, the Organization will review the purpose and the role of both effort, and assign proper roles to each of them.

・Further, the introduction of the capacity market has been reviewed as an effective scheme for procuring supply capacity in a secure manner. After its introduction, it is likely that the contents of the electricity supply plan or matters to be reviewed will differ among retail, generation, and GT&D companies. Therefore, the principle of the electricity supply plan will be changed to become a more efficient and effective procedure.

b. Need for the Comprehension of Unreported Supply Capacity

The supply capacity of the EPCOs that are not obliged to submit their supply plans is unknown. Accordingly, the Organization has investigated the submission of construction plans of such unreported power plants and included them in the supply capacity aggregation (see p. 12). Henceforth, improvement of the scheme for supply plans will be reviewed in cooperation with the Government so as to continuously report such unreported supply capacity in the aggregation of the supply plans.

c. Method of Calculating Supply Capacity of Pumped-Storage Hydro Power Plant and Energy Storage Batteries

・The supply capacity of pumped-storage hydro power plants must be properly calculated according to the energy supply expected to pump up water and the water capacity of upper reservoir ponds. The calculation method differs somewhat between GT&D companies. In future, the calculation methods of the supply capacity of pumped-storage hydro power plants must be clarified and unified due to the increasing importance of the function of pumped-storage hydro power plants and the trading of the supply capacity of pumped-storage hydro power plants in the capacity market given greater integration of renewable energy.

・Similarly, it is likely that more large-scale energy storage batteries will be integrated into the grid to secure balancing capacity apace with the integration of renewable energy. The calculation method of the supply capacity of energy storage batteries must be established in accordance with the possibility of utilizing energy storage batteries as supply capacity.

(2) Current Challenges in the Aggregation of Electricity Supply Plans

a. Need to Secure Stable Supply at the Introduction of a Capacity Market and Beyond

・At the previous aggregation of supply plans, the Organization recognized that the reserve margin of the Tokyo, Chubu, and the Kansai EPCO regional service areas (the three major areas) will fall below the 8% criterion in some projected years. The Organization has analyzed that the decreasing reserve margins are attributable to: (1) the former general electric power companies (retail and generation sectors of the current 10 GT&D companies) have decreased their supply capacity according to the shrinking demand of their area, and (2) in the meanwhile, small and medium-sized retail companies have grown their share of energy sales remaining their supply capacity as "unspecified procurement"

・At this year's aggregation, the Organization recognized that the other areas (particularly, Tohoku, Shikoku, and Kyushu) as well as the three major areas share the same tendency of decreasing reserve margins. This will lead to a fall in the reserve margin under 8% in several areas, even though the leveling of the reserve margin for supply–demand balance is implemented through interconnection lines.

・In addition, the Organization has implemented hearings with the former general electric power companies (retail and generation sector of the GT&D companies), and gathered relevant information to analyze the factors that decrease the supply capacity, such as discontinued operation or retirement of aged thermal power plants.

- ✔ The retail sector of the former general electric power companies (deemed retail companies) is projecting that if the demand that is supplied by another retail company (i.e. renounced demand) grows at the present pace, renounced demand will achieve 22% equivalent of the regional service area demand nationwide (25% for the three major areas) in FY 2027.
- ✔Based on the above projection, five deemed retail companies (including the three major areas) have submitted supply plans that indicate that the procured reserve capacity is 1–3% equivalent of the area demand for their supply capacity in the long term. Moreover, they consider that further supply capacity will be procured from their surplus power of the generation company (i.e., the generation sector of the company).
- ✔A Generator regarded as surplus power is a less competitive aged thermal power plant. The relatively low turnover market price of such power plants will decrease further given greater integration of renewable energy. The generation sector of the company projects that such a

generator cannot be maintained if the generation necessary for maintaining surplus power is put on the market at marginal cost.

· On the assumption that these trend rapidly progress, the Organization has practical concerns that the above-stated conditions will lead to power shortages before FY 2024, when the capacity market will be introduced to secure supply capacity. Therefore, the Organization will pay greater attention to future trends of supply capacity and will implement the evaluation of supply–demand balance. In addition, the Organization will proceed with a review of practical measures including institutional measures in cooperation with the Government to ensure a secure supply capacity before the introduction of the capacity market.

· As part of the review process noted above, the Organization will also address the following issues: (1) retail companies should procure long-term supply capacity of 1–3% equivalent to their projected peak demand; (2) once deemed retail companies have proposed their reserve margin as 5% equivalent to their projected peak demand at the review process, and whether it has integrity with (1); and (3) the principle of supply capacity in the projecting period that the deemed retail companies must essentially procure. If necessary, the Organization will implement countermeasures for these matters.

· In addition, the Organization has stated the need for the introduction of the capacity market at the FY 2017 aggregation of supply plans. Recent circumstances emphasize the need for the capacity market as a scheme to ensure a secure supply capacity in the future. The Organization will proceed with the practical design of the capacity market in continued cooperation with the Government.

b. Need for Supply–demand Balance Evaluation at Maximum Residual Peak Demand Including Winter

· At present, summer peak demand is only assessed for long-term supply–demand balance for the areas that have annual peak demand in the summer (all areas except Hokkaido and Tohoku). In contrast, the 2017 winter was the most severe that Japan has experienced for several decades. The summer peak areas have recorded sharp increases in winter peak demand; Tokyo in particular suffered power shortages and was supplied electricity from other areas.

· The background of power shortages will be analyzed in detail; preliminary analysis has examined the relationship between demand growth and estimation of securing supply capacity and indicates the following factors.

- ✔ The supply capacity of solar power is likely to exceed the conservatively estimated value (L5)[39] in summer; however in winter, its supply capacity is likely to be lower due to snowfall, snow cover, or cloudy weather. Forecast error will arise from the derated supply capacity of solar power and the demand growth due to the cold, which will result in the worsening condition of supply–demand.

[39] Average of the five lowest actual supply capacities (hourly average) during a given period.

- ✔Generally, daily demand in the winter increases day by day, which leads to greater daily energy consumption. In turn, this consumes a larger balancing capacity supplied by pumped-storage hydro power plants. The consumed water volume in upper reservoir ponds cannot be restored within a day, meaning that the supply–demand balance for the next day cannot be secured.
- ✔To exacerbate matters, there is the scheduled maintenance of thermal power plants and the forced outage of generators. Further compromised supply–demand balance occurs from the combination of these conditions.

・To focus on the recent severe winter demand, deducting the portion of demand supplied by solar and wind power (i.e., residual peak demand) from the projected peak demand, all areas other than Kansai and Okinawa have a larger demand in winter than summer. In the winter of 2016, although somewhat milder than last winter, six areas recorded higher actual residual peak demand in winter than in the previous summer. Further, for the recent aggregation of supply plans, projected residual peak demand will be higher in winter than in summer for the areas other than Tokyo, Kansai, and Okinawa (see reference 1).

・Thus, the occurrence of annual peak demand is likely to change from summer to winter for comparison of projected residual peak demand. The Organization will consider reflecting the forecast error[40] of solar power supply capacity in the winter supply–demand balance evaluation, and the evaluation method of supply capacity of pumped-storage hydro power plants in the review process of mid-to-long-term supply and balancing capacity and coordination of scheduled maintenance work in the short term.

・Further, in the case of possible power shortages as occurred this past winter, the Organization will accurately inform members who are generation companies or retail companies of the conditions with respect to temporary measures in advance of requesting countermeasures such as energy conservation to the public or large customers. The Organization will also review schemes to encourage the adoption of proper countermeasures and the principles of countermeasures against power shortages in cooperation with the Government.

[40] The improvement in forecast error of solar power supply capacity shall be continuously reviewed by all EPCOs concerned.

<Reference 1> Actual and Projected Residual Peak Demand Comparison between Summer and Winter

(10^4kW)

		Hokkaido		Tohoku		Tokyo		Chubu		Hokuriku		Kansai		Chugoku		Shikoku		Kyushu		Okinawa	
		S	W	S	W	S	W	S	W	S	W	S	W	S	W	S	W	S	W	S	W
FY 2016 (Actual)	Peak Demand	422	519	1,272	1,410	5,106	4,901	2,433	2,317	487	507	2,649	2,456	1,047	1,020	520	466	1,540	1,439	145	100
	Winter/Summer Ratio	122.9%		110.9%		96.0%		95.2%		104.2%		92.7%		97.4%		89.6%		93.5%		69.3%	
	Residual Peak Demand	410	507	1,189	1,330	4,832	4,891	2,219	2,246	464	496	2,523	2,437	948	987	468	455	1,451	1,429	142	100
	Winter/Summer Ratio	123.7%		111.9%		101.2%		101.2%		106.8%		96.6%		104.1%		97.1%		98.4%		70.6%	
FY 2017 (Actual)	Peak Demand	422	515	1,293	1,443	5,235	5,167	2,429	2,355	496	539	2,626	2,543	1,067	1,093	519	506	1,568	1,560	150	108
	Winter/Summer Ratio	121.9%		111.6%		98.7%		97.0%		108.6%		96.8%		102.4%		97.4%		99.5%		71.6%	
	Residual Peak Demand	418	512	1,240	1,435	4,951	5,149	2,216	2,346	478	538	2,557	2,539	957	1,083	488	505	1,285	1,559	146	107
	Winter/Summer Ratio	122.3%		115.8%		104.0%		105.9%		112.4%		99.3%		113.1%		103.5%		121.4%		73.5%	
FY 2018 (Forecast)	Peak Demand	419	498	1,294	1,371	5,316	4,788	2,463	2,268	500	491	2,578	2,376	1,035	986	503	461	1,532	1,457	147	103
	Winter/Summer Ratio	118.9%		106.0%		90.1%		92.1%		98.1%		92.2%		95.3%		91.7%		95.1%		70.1%	
	Residual Peak Demand	408	496	1,208	1,363	5,075	4,785	2,222	2,241	479	489	2,441	2,376	908	968	433	460	1,184	1,456	138	103
	Winter/Summer Ratio	121.6%		112.8%		94.3%		100.9%		102.1%		97.3%		106.6%		106.2%		123.0%		74.7%	

Note:

1. Actual average value of the three highest daily loads are processed data from Open Access Same-time Information System of the Organization. (Summer: July to September, Winter: December to February)

2. The projected average values of the three highest daily loads are data submitted from the supply plans (Summer: August, Winter: January).

3. Residual Peak Demand = Average Value of the Three Highest Daily Loads – Supply Capacity of Solar Power – Supply Capacity of Wind Power.

The supply capacity of solar and wind power is calculated as actual data for FY 2016, and projected supply capacity as L5[39] for FY 2017 and 2018.

c. Securing Mid-to-long-term Balancing Capacity

・The Organization has intensively conducted hearings with GT&D companies on supply– demand balance evaluation during off-peak periods other than traditional supply–demand balance evaluation at the occurrence of peak demand in the aggregation of the FY 2017 supply plans. As a result, there is a possible need in several areas for output shedding of thermal power generation or renewable energy according to the priority dispatch rule of generation with greater integration of renewable energy or lower demand occurrence at off-peak evaluation in FY 2018.

・Moreover, the Organization has recognized the following factors as being characteristic of supply–demand balance during off-peak periods.

- ✔ Surplus supply capacity in daytime hours is expected to be absorbed by pumping of pumped-storage hydro power plants, which are unevenly installed across regional service areas.
- ✔There is increasing need for balancing capacity with a higher ramp speed that can cope with the steep decrease of solar power supply capacity in the evening time on the condition that fewer thermal power plants are integrated for the purpose of balancing. (See Reference 2.)
- ✔There is an increasing need for balancing capacity as reserve capacity for times when the balancing capacity is activated against severe weather (i.e., Generator I'[41]; demand reduction)

[41] Additionally procured supply capacity with Generator I (i.e., firmly procured generators or contracts that GT&D companies exclusively procure) against severe weather.

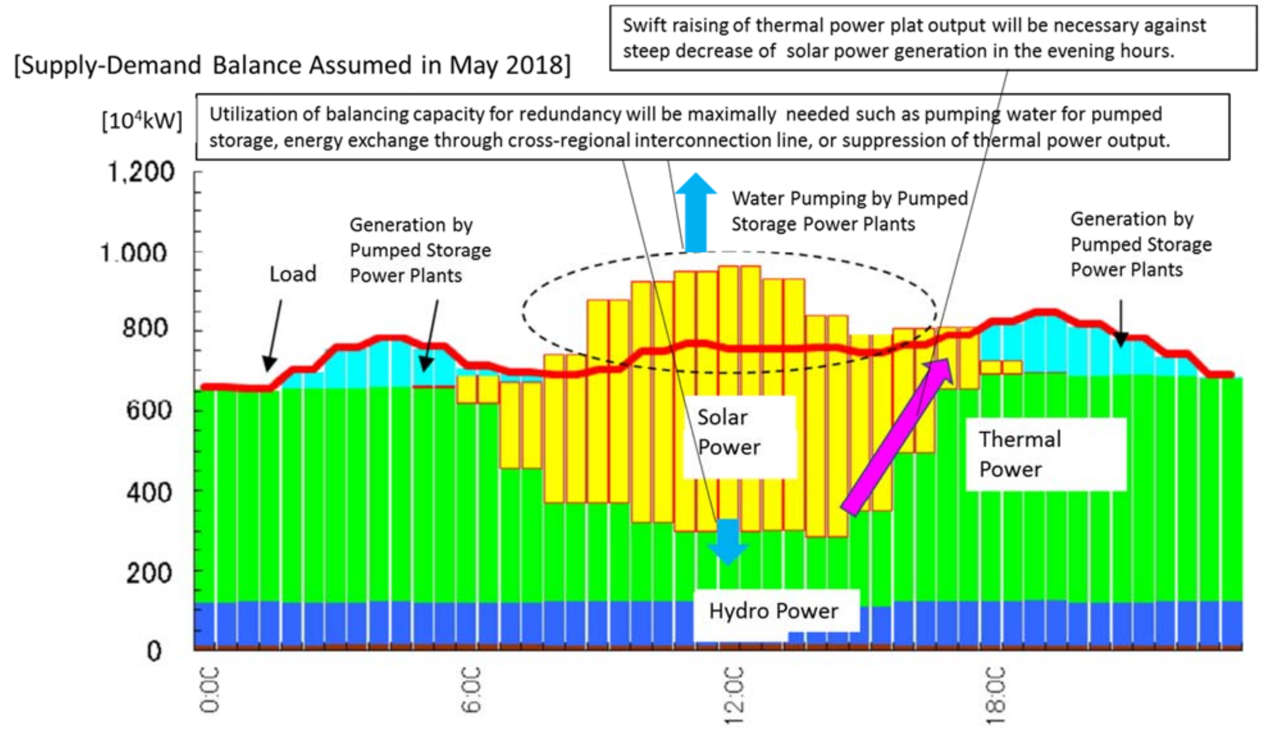
other than in peak periods due to the larger forecast error of solar power generation. (See Reference 3.)

・In view of these varying conditions during off-peak periods due to greater integration of renewable energy and reflecting the forecast error of solar power generation during winter peak period, the Organization has recognized anew the validity in the present procurement of the balancing capacity of Generator I (7% equivalent to peak demand), which has been uniformly set in regional service areas based upon the assumption that the surplus balancing capacity of Generator II[42] can be abundantly expected.

・In addition, it is important that both the required mid-to-long-term balancing capacity generator and the scheme for procuring balancing capacity with timing, volume, and necessary specification will be secured to utilize renewable energy at most and rationally achieve the security of stable supply and supply–demand balance under the national long-term projections of energy supply and demand. Therefore, the Organization will structure the detailed design of the balancing capacity market as a scheme that can broadly and economically ensure the necessary procurement of balancing capacity in cooperation with the Government and GT&D companies.

[42] Generators or contracts that share capacity between the supply capacity of retail companies and the balancing capacity of GT&D companies, which are procured as the supply capacity of retail companies; however, any surplus after gate closure is utilized as balancing capacity for any deficiencies or redundancy of GT&D companies.

<Reference 2>Supply-Demand Image during Off-peak Period



<Reference 3>Utilization of Generator I'

Utilization of Generator I'　　2

Utilization of Generator I' for the first half of FY 2017 in Kyushu area is summarized as below.

【Summary of Utilization of Generator I'】

- ○ Period　September 7(Thursday), 2017 from 10:30 to 17:00*
- ○ Service Area　Kyushu Electric Power Company
- ○ Utilized Capacity　148,000 kW (including 70,000 kW of Demand Response)
- ○ Background　Possibility of supply capacity shortage due to downward forecast of solar power output compared to the forecast at 4:00 on that day (about 600 kW)

* Generator/11:30 to 17:00(78,000 kW), Demand Response/10:30 to 14:30(60,000 kW), 13:00 to 17:00(10,000 kW).

【Supply-Demand Condition(Forecast)】

September 7(Thursday), 2017 between 13:00 and 14:00

Forecast	Time	Demand (10^4kW)	Supply (10^4kW)	Reserve Margin
At 16:00 on the two days before	14:00	1,200	1,451	20.9%
At 10:00 on the previous day	14:00	1,170	1,408	20.3%
At 16:00 on the previous day	14:00	1,150	1,301	13.1%
At 4:00 on that day	14:00	1,210	1,359	12.3%
Around 9:00 on that day	14:00	1,240	1,262	1.7%

Source: Reference document 4 of Agenda 2-1 for the 22nd meeting of the Study Committee on Regulating and Marginal Supply Capability and Long-Term Supply-Demand Balance Evaluation (Oct. 12, 2017)

(3) Evaluation of the Supply–Demand Balance at the Occurrence of Peak Demand in the Short Term

Monthly evaluations of the supply–demand balance at the occurrence of peak demand for FY 2018 are presented below as reference.

<Reference 4> Monthly Reserve Margin (at the time peak demand occurred, without additional supply capacity support, at the sending end)

	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.	Jan.	Feb.	Mar.
Hokkaido	23.8%	34.7%	37.5%	25.3%	26.9%	26.5%	28.6%	28.8%	20.1%	19.3%	19.1%	32.2%
Tohoku	9.8%	20.7%	19.6%	15.7%	14.9%	15.5%	12.3%	6.2%	5.8%	10.1%	6.4%	5.7%
Tokyo	20.7%	29.5%	20.0%	6.8%	6.5%	16.6%	25.6%	17.8%	12.8%	11.3%	10.4%	17.1%
50Hz areas Total	18.8%	28.2%	21.1%	9.5%	9.3%	17.1%	23.1%	16.3%	11.9%	11.7%	10.2%	15.9%
Chubu	19.1%	15.7%	14.0%	8.2%	8.3%	17.6%	11.8%	13.4%	10.2%	9.8%	12.3%	17.9%
Hokuriku	12.7%	31.1%	12.2%	14.8%	12.2%	12.3%	20.8%	14.4%	13.1%	12.8%	13.0%	10.8%
Kansai	34.6%	33.8%	29.5%	18.1%	14.5%	20.9%	33.7%	33.4%	31.2%	23.5%	21.1%	32.3%
Chugoku	28.7%	19.6%	31.2%	21.3%	21.9%	37.6%	27.5%	20.7%	25.2%	20.2%	19.2%	25.9%
Shikoku	11.7%	15.5%	16.4%	7.1%	9.5%	10.5%	19.3%	14.1%	12.6%	14.5%	14.9%	8.2%
Kyushu	15.6%	7.5%	5.8%	15.5%	15.4%	14.1%	18.9%	20.5%	6.9%	5.2%	4.8%	15.2%
60Hz areas Total	23.5%	21.1%	19.3%	14.3%	13.3%	19.6%	22.1%	21.5%	17.8%	14.7%	14.6%	21.6%
Interconnected	21.4%	24.2%	20.1%	12.2%	11.5%	18.4%	22.5%	19.1%	15.1%	13.4%	12.6%	19.0%
Okinawa	56.4%	44.1%	39.6%	40.7%	41.6%	44.2%	43.0%	48.4%	52.9%	58.1%	68.4%	61.3%
Nationwide	21.7%	24.4%	20.3%	12.4%	11.8%	18.7%	22.8%	19.4%	15.4%	13.7%	13.0%	19.3%

Below 8% Criteria

<Reference 5> Monthly Reserve Margin (at the time peak demand occurred, with additional supply capacity support, at the sending end)

	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.	Jan.	Feb.	Mar.
Hokkaido	19.3%	26.5%	33.6%	21.8%	23.5%	23.1%	22.5%	19.3%	12.5%	12.1%	10.7%	23.2%
Tohoku	19.3%	26.5%	19.7%	9.0%	8.7%	17.0%	22.5%	16.2%	12.5%	12.1%	10.7%	16.0%
Tokyo	19.3%	26.5%	19.7%	9.0%	8.7%	17.0%	22.5%	16.2%	12.5%	12.1%	10.7%	16.0%
Chubu	23.1%	22.4%	19.7%	14.1%	13.0%	19.3%	22.5%	21.4%	17.3%	14.4%	14.2%	21.1%
Hokuriku	23.1%	22.4%	19.7%	14.1%	13.0%	19.3%	22.5%	21.4%	17.3%	14.4%	14.2%	21.1%
Kansai	23.1%	22.4%	19.7%	14.1%	13.0%	19.3%	22.5%	21.4%	17.3%	14.4%	14.2%	21.1%
Chugoku	23.1%	22.4%	19.7%	14.1%	13.0%	19.3%	22.5%	21.4%	17.3%	14.4%	14.2%	21.1%
Shikoku	23.1%	22.4%	19.7%	14.1%	13.0%	19.3%	22.5%	21.4%	17.3%	14.4%	14.2%	21.1%
Kyushu	23.1%	22.4%	19.7%	14.1%	13.6%	19.3%	22.5%	21.4%	17.3%	14.4%	14.2%	21.1%
Interconnected	21.4%	24.2%	20.1%	12.2%	11.5%	18.4%	22.5%	19.1%	15.1%	13.4%	12.6%	19.0%
Okinawa	56.4%	44.1%	39.6%	40.7%	41.6%	44.2%	43.0%	48.4%	52.9%	58.1%	68.4%	61.3%
Nationwide	21.7%	24.4%	20.3%	12.4%	11.8%	18.7%	22.8%	19.4%	15.4%	13.7%	13.0%	19.3%

Improved to over 8%

(4) Evaluation of the Mid-to-long-term Supply–Demand Balance at Times Other Than 17:00 in August

Annual evaluations of the supply–demand balance at 15:00 and 19:00 for the 10-year period FY 2018–2027 are presented below.

<Reference 6> Annual Reserve Margin Calculated at 15:00 in August (without additional supply capacity support, at the sending end)

Without Additional Supply Capacity

Reserve Margin at 15:00 in August (Reserve Capacity / Peak Demand)

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Hokkaido	26.9%	23.5%	41.3%	40.0%	41.6%	41.8%	41.7%	42.0%	41.6%	52.5%
Tohoku	14.9%	13.3%	19.0%	16.8%	17.7%	18.7%	19.6%	20.7%	21.2%	24.3%
Tokyo	6.5%	6.8%	8.8%	5.7%	4.8%	9.3%	14.6%	14.7%	14.7%	13.6%
50Hz areas Total	9.3%	9.0%	12.6%	9.8%	9.4%	13.0%	17.1%	17.4%	17.5%	17.9%
Chubu	8.3%	8.1%	6.3%	6.2%	9.7%	7.3%	4.4%	4.7%	5.1%	5.3%
Hokuriku	12.2%	14.0%	12.5%	12.2%	12.3%	12.3%	12.4%	11.4%	11.5%	11.6%
Kansai	14.5%	14.5%	14.9%	7.7%	10.4%	13.3%	12.8%	9.9%	11.2%	11.4%
Chugoku	21.9%	10.5%	18.2%	16.7%	18.5%	22.0%	22.1%	22.3%	22.5%	22.1%
Shikoku	9.5%	6.7%	13.3%	3.6%	1.1%	10.8%	11.1%	11.3%	11.8%	12.1%
Kyushu	15.4%	19.9%	15.6%	16.6%	18.3%	18.8%	20.1%	20.3%	20.5%	20.5%
60Hz areas Total	13.3%	12.7%	12.7%	10.0%	12.2%	13.4%	12.7%	12.0%	12.6%	12.7%
Interconnected	11.5%	11.0%	12.7%	9.9%	10.9%	13.2%	14.7%	14.4%	14.8%	15.0%
Okinawa	41.6%	40.2%	48.1%	47.5%	46.8%	38.4%	45.5%	44.5%	43.3%	34.9%
Nationwide	11.8%	11.3%	13.0%	10.3%	11.3%	13.5%	15.0%	14.7%	15.1%	15.2%

Below 8% Criteria

<Reference 7> Annual Reserve Margin Calculated at 15:00 in August (with additional supply capacity support, at the sending end)

With Additional Supply Capacity

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Hokkaido	23.5%	12.8%	30.7%	30.5%	31.2%	31.4%	31.3%	31.6%	31.3%	42.2%
Tohoku	8.7%	8.9%	11.8%	9.0%	9.3%	12.5%	14.1%	13.7%	14.1%	14.0%
Tokyo	8.7%	8.9%	11.8%	9.0%	9.3%	12.5%	14.1%	13.7%	14.1%	14.0%
Chubu	13.0%	11.1%	12.5%	9.0%	10.5%	12.5%	14.1%	13.7%	14.1%	14.0%
Hokuriku	13.0%	11.1%	12.5%	9.0%	10.5%	12.5%	14.1%	13.7%	14.1%	14.0%
Kansai	13.0%	11.1%	12.5%	9.0%	10.5%	12.5%	14.1%	13.7%	14.1%	14.0%
Chugoku	13.0%	11.1%	12.5%	9.0%	10.5%	12.5%	14.1%	13.7%	14.1%	14.0%
Shikoku	13.0%	11.1%	12.5%	9.0%	10.5%	12.5%	14.1%	13.7%	14.1%	14.0%
Kyushu	13.6%	19.2%	12.5%	12.5%	14.2%	14.7%	16.0%	16.3%	16.4%	16.4%
Interconnected	11.5%	11.0%	12.7%	9.9%	10.9%	13.2%	14.7%	14.4%	14.8%	15.0%
Okinawa	41.6%	40.2%	48.1%	47.5%	46.8%	38.4%	45.5%	44.5%	43.3%	34.9%
Nationwide	11.8%	11.3%	13.0%	10.3%	11.3%	13.5%	15.0%	14.7%	15.1%	15.2%

Improved to over 8%

<Reference 8> Annual Reserve Margin Calculated at 19:00 in August (without additional supply capacity support, at the sending end)

Without Additional Supply Capacity

Reserve Margin at 19:00 in August (Reserve Capacity / Peak Demand)

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Hokkaido	27.0%	23.2%	40.7%	39.2%	40.9%	41.1%	41.0%	41.3%	40.9%	52.0%
Tohoku	19.2%	16.3%	21.7%	18.6%	19.0%	19.5%	19.9%	20.5%	20.4%	23.1%
Tokyo	7.1%	7.4%	9.6%	6.2%	5.3%	10.2%	15.8%	16.0%	16.0%	14.8%
50Hz areas Total	10.5%	10.0%	13.7%	10.5%	10.0%	13.8%	18.2%	18.4%	18.4%	18.7%
Chubu	9.3%	9.2%	7.1%	7.0%	10.9%	8.2%	5.0%	5.3%	5.7%	6.0%
Hokuriku	28.6%	33.6%	27.1%	26.1%	25.9%	25.7%	25.4%	24.0%	23.8%	23.6%
Kansai	16.3%	15.7%	15.6%	7.9%	10.6%	13.5%	12.9%	9.7%	10.9%	10.9%
Chugoku	22.2%	10.8%	18.3%	15.4%	15.8%	19.1%	18.9%	18.7%	18.7%	18.1%
Shikoku	9.5%	6.7%	13.3%	3.6%	0.3%	10.5%	10.3%	10.2%	10.5%	10.5%
Kyushu	2.4%	2.7%	1.0%	1.1%	1.4%	1.2%	1.9%	1.8%	1.7%	1.5%
60Hz areas Total	12.8%	11.4%	11.4%	8.1%	9.9%	10.9%	10.0%	8.9%	9.4%	9.4%
Interconnected	11.8%	10.8%	12.5%	9.2%	9.9%	12.2%	13.7%	13.2%	13.4%	13.6%
Okinawa	41.8%	39.8%	47.7%	46.7%	45.5%	36.4%	43.5%	42.5%	41.3%	32.5%
Nationwide	12.1%	11.0%	12.8%	9.5%	10.3%	12.5%	14.0%	13.5%	13.7%	13.8%

Below 8% Criteria

<Reference 9> Annual Reserve Margin Calculated at 19:00 in August (with additional supply capacity support, at the sending end)

With Additional Supply Capacity

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Hokkaido	23.5%	12.2%	29.9%	29.5%	30.3%	30.6%	30.5%	30.7%	30.4%	41.5%
Tohoku	10.0%	10.0%	11.9%	8.6%	9.3%	11.7%	14.3%	14.5%	14.5%	14.3%
Tokyo	10.0%	10.0%	11.9%	8.6%	9.3%	11.7%	14.3%	14.5%	14.5%	14.3%
Chubu	12.6%	11.3%	11.9%	8.6%	9.3%	11.7%	12.3%	11.3%	11.7%	11.5%
Hokuriku	12.6%	11.3%	11.9%	8.6%	9.3%	11.7%	12.3%	11.3%	11.7%	11.5%
Kansai	12.6%	11.3%	11.9%	8.6%	9.3%	11.7%	12.3%	11.3%	11.7%	11.5%
Chugoku	12.6%	11.3%	11.9%	8.6%	9.3%	11.7%	12.3%	11.3%	11.7%	11.5%
Shikoku	12.6%	11.3%	11.9%	8.6%	9.3%	11.7%	12.3%	11.3%	11.7%	11.5%
Kyushu	12.6%	11.3%	11.9%	8.6%	9.3%	11.7%	12.3%	11.3%	11.7%	11.5%
Interconnected	11.8%	10.8%	12.5%	9.2%	9.9%	12.2%	13.7%	13.2%	13.4%	13.6%
Okinawa	41.8%	39.8%	47.7%	46.7%	45.5%	36.4%	43.5%	42.5%	41.3%	32.5%
Nationwide	12.1%	11.0%	12.8%	9.5%	10.3%	12.5%	14.0%	13.5%	13.7%	13.8%

Improved to over 8%

Attached are the Appendices on the aggregation of the electricity supply plans.

APPENDIX 1 Supply–Demand Balance for FY 2018

Tables A1-1 to A1-4 show the monthly peak demand, monthly supply capacity, monthly reserve capacity, and reserve margin for each regional service area in FY 2018, respectively. Table A1-5 shows the monthly projection of the reserve margin for each regional service area recalculated with power exchanges to areas below the 8% reserve margin from areas with over 8% reserve margin.

Table A1-1 Monthly Peak Demand Forecast for Each Regional Service Area

【10^4kW】

	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.	Jan.	Feb.	Mar.
Hokkaido	399	366	362	404	419	419	415	455	498	498	498	455
Tohoku	1,059	974	1,047	1,255	1,272	1,152	1,067	1,187	1,302	1,371	1,356	1,257
Tokyo	3,904	3,687	4,126	5,316	5,316	4,560	3,725	4,089	4,491	4,788	4,788	4,385
50Hz areas Total	5,362	5,027	5,535	6,975	7,007	6,131	5,207	5,731	6,291	6,657	6,642	6,097
Chubu	1,831	1,882	2,040	2,387	2,387	2,188	1,997	1,964	2,182	2,268	2,268	2,127
Hokuriku	393	367	401	500	500	454	369	410	468	491	491	468
Kansai	1,916	1,892	2,085	2,572	2,553	2,294	1,871	1,989	2,209	2,376	2,376	2,124
Chugoku	743	748	824	1,011	1,011	862	760	818	925	986	986	883
Shikoku	354	354	404	503	503	437	363	375	461	461	461	411
Kyushu	1,063	1,038	1,153	1,448	1,467	1,284	1,167	1,183	1,413	1,457	1,452	1,272
60Hz areas Total	6,300	6,281	6,907	8,421	8,421	7,519	6,527	6,739	7,658	8,039	8,034	7,285
Interconnected	11,662	11,308	12,442	15,396	15,428	13,650	11,734	12,470	13,949	14,696	14,676	13,382
Okinawa	105	123	138	145	146	141	126	108	100	103	103	98
Nationwide	11,767	11,430	12,580	15,541	15,574	13,791	11,859	12,578	14,049	14,798	14,778	13,480

Table A1-2 Monthly Projection of Supply Capacity for Each Regional Service Area

【10^4kW】

	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.	Jan.	Feb.	Mar.
Hokkaido	494	493	490	499	525	530	534	586	598	594	593	601
Tohoku	1,163	1,164	1,235	1,424	1,433	1,318	1,198	1,260	1,378	1,509	1,443	1,328
Tokyo	4,713	4,775	4,952	5,678	5,662	5,317	4,677	4,816	5,065	5,331	5,284	5,135
50Hz areas Total	6,370	6,432	6,677	7,600	7,619	7,165	6,409	6,662	7,041	7,434	7,320	7,065
Chubu	2,181	2,178	2,326	2,581	2,580	2,573	2,232	2,228	2,405	2,491	2,548	2,508
Hokuriku	442	481	448	574	561	501	430	455	529	553	554	518
Kansai	2,578	2,532	2,687	2,956	2,863	2,757	2,495	2,653	2,899	2,934	2,955	2,810
Chugoku	956	895	1,081	1,206	1,211	1,177	969	988	1,158	1,185	1,176	1,111
Shikoku	396	409	470	539	551	483	433	428	519	528	530	445
Kyushu	1,229	1,114	1,216	1,497	1,502	1,460	1,388	1,425	1,511	1,532	1,521	1,465
60Hz areas Total	7,783	7,609	8,228	9,354	9,268	8,950	7,948	8,176	9,020	9,223	9,284	8,858
Interconnected	14,153	14,040	14,906	16,954	16,887	16,116	14,357	14,839	16,061	16,657	16,604	15,923
Okinawa	165	175	188	199	199	196	179	161	153	163	173	158
Nationwide	14,317	14,216	15,093	17,153	17,086	16,312	14,536	15,000	16,214	16,820	16,777	16,081

Table A1-3 Monthly Projection of Reserve Capacity for Each Regional Service Area

【10^4kW】

	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.	Jan.	Feb.	Mar.
Hokkaido	95	127	128	95	106	111	119	131	100	96	95	146
Tohoku	104	190	188	169	161	166	131	73	76	138	87	71
Tokyo	809	1,088	826	362	346	757	952	727	574	543	496	750
50Hz areas Total	1,008	1,405	1,142	626	612	1,034	1,202	931	750	777	678	968
Chubu	350	296	286	194	193	385	235	264	223	223	280	381
Hokuriku	50	114	47	74	61	47	61	45	61	63	64	51
Kansai	662	640	602	384	310	463	625	664	690	558	579	686
Chugoku	213	147	257	195	200	315	209	170	233	199	190	228
Shikoku	42	55	66	36	48	46	70	53	58	67	69	34
Kyushu	166	76	62	49	35	176	221	242	98	75	69	193
60Hz areas Total	1,483	1,328	1,321	933	847	1,432	1,421	1,437	1,362	1,185	1,251	1,574
Interconnected	2,491	2,733	2,464	1,559	1,459	2,466	2,623	2,369	2,113	1,962	1,929	2,542
Okinawa	59	53	50	54	53	55	53	53	53	60	70	60
Nationwide	2,550	2,786	2,513	1,612	1,512	2,521	2,676	2,422	2,165	2,022	1,999	2,602

Table A1-4 Monthly Projection of Reserve Margin for Each Regional Service Area
(Resources within own service area only, at the sending end)[Aforementioned Table 2-3]

	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.	Jan.	Feb.	Mar.
Hokkaido	23.8%	34.7%	35.5%	23.5%	25.2%	26.5%	28.6%	28.8%	20.1%	19.3%	19.1%	32.2%
Tohoku	9.8%	19.6%	18.0%	13.4%	12.6%	14.4%	12.3%	6.2%	5.8%	10.1%	6.4%	5.7%
Tokyo	20.7%	29.5%	20.0%	6.8%	6.5%	16.6%	25.6%	17.8%	12.8%	11.3%	10.4%	17.1%
50Hz areas Total	18.8%	28.0%	20.6%	9.0%	8.7%	16.9%	23.1%	16.3%	11.9%	11.7%	10.2%	15.9%
Chubu	19.1%	15.7%	14.0%	8.1%	8.1%	17.6%	11.8%	13.4%	10.2%	9.8%	12.3%	17.9%
Hokuriku	12.7%	31.1%	11.8%	14.8%	12.2%	10.3%	16.6%	11.0%	13.1%	12.8%	13.0%	10.8%
Kansai	34.6%	33.8%	28.9%	14.9%	12.2%	20.2%	33.4%	33.4%	31.2%	23.5%	24.4%	32.3%
Chugoku	28.7%	19.6%	31.2%	19.3%	19.8%	36.6%	27.5%	20.7%	25.2%	20.2%	19.2%	25.9%
Shikoku	11.7%	15.5%	16.4%	7.1%	9.5%	10.5%	19.3%	14.1%	12.6%	14.5%	14.9%	8.2%
Kyushu	15.6%	7.3%	5.4%	3.4%	2.4%	13.7%	18.9%	20.5%	6.9%	5.2%	4.8%	15.2%
60Hz areas Total	23.5%	21.1%	19.1%	11.1%	10.1%	19.0%	21.8%	21.3%	17.8%	14.7%	15.6%	21.6%
Interconnected	21.4%	24.2%	19.8%	10.1%	9.5%	18.1%	22.4%	19.0%	15.1%	13.4%	13.1%	19.0%
Okinawa	56.4%	43.1%	35.9%	37.0%	36.3%	39.4%	42.5%	48.6%	52.6%	58.1%	68.0%	60.8%
Nationwide	21.7%	24.4%	20.0%	10.4%	9.7%	18.3%	22.6%	19.3%	15.4%	13.7%	13.5%	19.3%

Below Criteria of 8%

Table A1-5 Monthly Projection of Reserve Margin for Each Regional Service Area
(With power exchange through cross-regional interconnection lines, at the sending end)[Aforementioned Table 2-4]

	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.	Jan.	Feb.	Mar.
Hokkaido	**19.3%**	**26.3%**	**31.5%**	**20.0%**	**21.8%**	**23.1%**	**22.4%**	**19.3%**	**12.5%**	**12.1%**	**10.7%**	**23.2%**
Tohoku	**19.3%**	**26.3%**	**19.5%**	**8.6%**	**8.2%**	**16.8%**	**22.4%**	**16.2%**	**12.5%**	**12.1%**	**10.7%**	**16.0%**
Tokyo	**19.3%**	**26.3%**	**19.5%**	**8.6%**	**8.2%**	**16.8%**	**22.4%**	**16.2%**	**12.5%**	**12.1%**	**10.7%**	**16.0%**
Chubu	**23.1%**	**22.5%**	**19.5%**	**10.9%**	**9.8%**	**18.8%**	**22.4%**	**21.2%**	**17.3%**	**14.4%**	**15.2%**	**21.1%**
Hokuriku	**23.1%**	**22.5%**	**19.5%**	**10.9%**	**9.8%**	**18.8%**	**22.4%**	**21.2%**	**17.3%**	**14.4%**	**15.2%**	**21.1%**
Kansai	**23.1%**	**22.5%**	**19.5%**	**10.9%**	**9.8%**	**18.8%**	**22.4%**	**21.2%**	**17.3%**	**14.4%**	**15.2%**	**21.1%**
Chugoku	**23.1%**	**22.5%**	**19.5%**	**10.9%**	**9.8%**	**18.8%**	**22.4%**	**21.2%**	**17.3%**	**14.4%**	**15.2%**	**21.1%**
Shikoku	**23.1%**	**22.5%**	**19.5%**	**10.9%**	**9.8%**	**18.8%**	**22.4%**	**21.2%**	**17.3%**	**14.4%**	**15.2%**	**21.1%**
Kyushu	**23.1%**	**22.5%**	**19.5%**	**10.9%**	**9.8%**	**18.8%**	**22.4%**	**21.2%**	**17.3%**	**14.4%**	**15.2%**	**21.1%**
Interconnected	**21.4%**	**24.2%**	**19.8%**	**10.1%**	**9.5%**	**18.1%**	**22.4%**	**19.0%**	**15.1%**	**13.4%**	**13.1%**	**19.0%**
Okinawa	**56.4%**	**43.1%**	**35.9%**	**37.0%**	**36.3%**	**39.4%**	**42.5%**	**48.6%**	**52.6%**	**58.1%**	**68.0%**	**60.8%**
Nationwide	**21.7%**	**24.4%**	**20.0%**	**10.4%**	**9.7%**	**18.3%**	**22.6%**	**19.3%**	**15.4%**	**13.7%**	**13.5%**	**19.3%**

Improved to over 8%

APPENDIX 2 Long-term Supply–Demand Balance for the 10-year Period FY 2018–2027

Tables A2-1 to A2-4 show a 10-year projection of the annual peak demand, annual supply capacity, annual reserve capacity, and reserve margin for each regional service area from FY 2018 to FY 2027, respectively. Table A2-5 shows the annual projection of the reserve margin for each regional service area recalculated with power exchanges from areas with over 8% reserve margin to areas below the 8% reserve margin. Tables A2-6 to A2-10 show a 10-year projection of the annual peak demand, annual supply capacity, annual reserve capacity, and reserve margin for winter peak areas of Hokkaido and Tohoku, respectively.

Table A2-1 Annual Peak Demand Forecast for Each Regional Service Area (at 17:00 in August)

【10^4kW】

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Hokkaido	419	420	420	421	422	423	424	424	425	426
Tohoku	1,272	1,273	1,273	1,269	1,265	1,261	1,257	1,252	1,247	1,243
Tokyo	5,154	5,175	5,165	5,167	5,168	5,169	5,168	5,168	5,166	5,178
50Hz areas Total	6,845	6,868	6,858	6,857	6,855	6,853	6,849	6,844	6,838	6,847
Chubu	2,387	2,395	2,390	2,385	2,380	2,375	2,370	2,366	2,361	2,356
Hokuriku	489	489	490	492	492	492	492	492	492	492
Kansai	2,558	2,552	2,543	2,537	2,533	2,527	2,522	2,516	2,511	2,505
Chugoku	1,011	1,013	1,017	1,018	1,018	1,019	1,020	1,021	1,021	1,022
Shikoku	496	496	496	495	494	493	492	491	490	490
Kyushu	1,528	1,530	1,531	1,533	1,536	1,538	1,540	1,542	1,544	1,546
60Hz areas Total	8,469	8,475	8,468	8,460	8,453	8,444	8,435	8,427	8,419	8,411
Interconnected	15,314	15,343	15,325	15,317	15,308	15,297	15,285	15,271	15,257	15,257
Okinawa	146	147	147	148	150	151	152	153	154	155
Nationwide	15,460	15,490	15,473	15,466	15,458	15,448	15,436	15,424	15,411	15,412

Table A2-2 Annual Projection of Supply Capacity for Each Regional Service Area (at 17:00 in August)

【10^4kW】

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Hokkaido	525	511	584	579	587	590	591	592	592	639
Tohoku	1,433	1,404	1,471	1,432	1,435	1,439	1,441	1,445	1,440	1,468
Tokyo	5,500	5,536	5,634	5,471	5,426	5,667	5,944	5,951	5,948	5,907
50Hz areas Total	7,457	7,452	7,689	7,482	7,448	7,696	7,975	7,987	7,980	8,014
Chubu	2,580	2,573	2,517	2,505	2,581	2,516	2,440	2,441	2,445	2,445
Hokuriku	560	567	558	557	556	556	555	549	548	548
Kansai	2,863	2,847	2,840	2,648	2,709	2,774	2,754	2,672	2,696	2,692
Chugoku	1,211	1,105	1,199	1,159	1,167	1,200	1,201	1,202	1,203	1,199
Shikoku	543	529	559	508	493	539	538	537	537	538
Kyushu	1,631	1,651	1,640	1,653	1,676	1,682	1,700	1,705	1,708	1,710
60Hz areas Total	9,389	9,273	9,313	9,029	9,182	9,267	9,188	9,105	9,138	9,131
Interconnected	16,846	16,724	17,002	16,511	16,631	16,963	17,163	17,093	17,118	17,146
Okinawa	202	201	213	213	214	202	214	214	214	202
Nationwide	17,048	16,925	17,215	16,725	16,844	17,165	17,377	17,307	17,332	17,348

Table A2-3 Annual Projection of Reserve Capacity for Each Regional Service Area (at 17:00 in August)

【10^4kW】

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Hokkaido	106	91	164	158	165	167	167	168	167	213
Tohoku	161	131	198	163	170	178	184	192	193	226
Tokyo	346	361	469	304	258	498	776	783	782	729
50Hz areas Total	612	584	831	625	593	843	1,126	1,143	1,142	1,168
Chubu	193	178	127	120	201	141	70	75	84	89
Hokuriku	72	77	68	65	64	63	63	57	56	55
Kansai	305	295	296	110	177	247	232	156	185	188
Chugoku	200	92	182	141	149	181	181	181	182	177
Shikoku	47	33	63	13	-1	46	46	46	47	48
Kyushu	103	122	110	121	140	145	161	163	165	164
60Hz areas Total	920	797	846	569	730	823	752	678	719	721
Interconnected	1,532	1,381	1,677	1,194	1,323	1,666	1,878	1,821	1,861	1,889
Okinawa	56	54	66	64.9	64	51	62	61	60	47
Nationwide	1,588	1,435	1,742	1,259	1,387	1,717	1,941	1,882	1,921	1,936

Table A2-4 Annual Projection of Reserve Margin for Each Regional Service Area
(Resource within own service area only, at 17:00 in August, at the sending end)[Aforementioned Table 2-7]

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Hokkaido	25.2%	21.6%	39.0%	37.5%	39.2%	39.4%	39.3%	39.5%	39.2%	50.1%
Tohoku	12.6%	10.3%	15.6%	12.9%	13.5%	14.1%	14.6%	15.4%	15.5%	18.2%
Tokyo	6.7%	7.0%	9.1%	5.9%	5.0%	9.6%	15.0%	15.2%	15.1%	14.1%
50Hz areas Total	8.9%	8.5%	12.1%	9.1%	8.7%	12.3%	16.4%	16.7%	16.7%	17.1%
Chubu	8.1%	7.4%	5.3%	5.0%	8.4%	5.9%	2.9%	3.2%	3.6%	3.8%
Hokuriku	14.7%	15.7%	13.9%	13.2%	13.0%	12.9%	12.8%	11.5%	11.4%	11.3%
Kansai	11.9%	11.6%	11.6%	4.3%	7.0%	9.8%	9.2%	6.2%	7.4%	7.5%
Chugoku	19.8%	9.1%	17.9%	13.9%	14.6%	17.8%	17.7%	17.7%	17.8%	17.3%
Shikoku	9.5%	6.7%	12.8%	2.5%	-0.3%	9.3%	9.3%	9.3%	9.6%	9.7%
Kyushu	6.8%	8.0%	7.2%	7.9%	9.1%	9.4%	10.4%	10.6%	10.7%	10.6%
60Hz areas Total	10.9%	9.4%	10.0%	6.7%	8.6%	9.7%	8.9%	8.0%	8.5%	8.6%
Interconnected	10.0%	9.0%	10.9%	7.8%	8.6%	10.9%	12.3%	11.9%	12.2%	12.4%
Okinawa	38.6%	36.8%	44.6%	43.7%	42.8%	34.1%	41.1%	40.1%	38.9%	30.5%
Nationwide	10.3%	9.3%	11.3%	8.1%	9.0%	11.1%	12.6%	12.2%	12.5%	12.6%

Below Criteria of 8%

Note: The reserve margin in the Kyushu EPCO regional service area in FY 2019 was rounded up to 8.0%.

Table A2-5 Annual Projection of Reserve Margin for Each Regional Service Area
(With power exchanges through cross-regional interconnection lines, at the sending end)[Aforementioned Table 2-8]

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Hokkaido	**21.8%**	**10.9%**	**30.7%**	**30.4%**	**31.1%**	**31.4%**	**31.3%**	**31.6%**	**31.3%**	**42.1%**
Tohoku	**8.4%**	**8.5%**	**10.4%**	**7.9%**	**8.7%**	**11.0%**	**14.2%**	**14.5%**	**14.5%**	**14.4%**
Tokyo	**8.4%**	**8.5%**	**10.4%**	**7.9%**	**8.7%**	**11.0%**	**14.2%**	**14.5%**	**14.5%**	**14.4%**
Chubu	**10.6%**	**9.3%**	**10.4%**	**7.9%**	**8.7%**	**11.0%**	**11.1%**	**10.2%**	**10.7%**	**10.6%**
Hokuriku	**10.6%**	**9.3%**	**10.4%**	**7.9%**	**8.7%**	**11.0%**	**11.1%**	**10.2%**	**10.7%**	**10.6%**
Kansai	**10.6%**	**9.3%**	**10.4%**	**7.9%**	**8.7%**	**11.0%**	**11.1%**	**10.2%**	**10.7%**	**10.6%**
Chugoku	**10.6%**	**9.3%**	**10.4%**	**7.9%**	**8.7%**	**11.0%**	**11.1%**	**10.2%**	**10.7%**	**10.6%**
Shikoku	**10.6%**	**9.3%**	**10.4%**	**7.9%**	**8.7%**	**11.0%**	**11.1%**	**10.2%**	**10.7%**	**10.6%**
Kyushu	**10.6%**	**9.3%**	**10.4%**	**7.9%**	**8.7%**	**11.0%**	**11.1%**	**10.2%**	**10.7%**	**10.6%**
Interconnected	**10.0%**	**9.0%**	**11.0%**	**8.5%**	**9.3%**	**11.6%**	**12.9%**	**12.6%**	**12.9%**	**13.1%**
Okinawa	**38.6%**	**36.8%**	**44.6%**	**43.7%**	**42.8%**	**34.1%**	**41.1%**	**40.1%**	**38.9%**	**30.5%**
Nationwide	**10.3%**	**9.3%**	**11.3%**	**8.8%**	**9.6%**	**11.8%**	**13.2%**	**12.9%**	**13.1%**	**13.2%**

Table A2-6 Annual Peak Demand Forecast for Winter Peak Areas of Hokkaido and Tohoku (at 18:00 in January)

【10^4kW】

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Hokkaido	498	500	500	501	502	503	504	505	506	507
Tohoku	1,371	1,375	1,375	1,372	1,369	1,366	1,363	1,360	1,357	1,354

Table A2-7 Annual Projection of Supply Capacity for Winter Peak Areas of Hokkaido and Tohoku (at 18:00 in January)

【10^4kW】

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Hokkaido	594	597	579	581	588	589	590	591	642	642
Tohoku	1,509	1,503	1,501	1,463	1,467	1,470	1,472	1,475	1,471	1,498

Table A2-8 Annual Projection of Reserve Capacity for Winter Peak areas of Hokkaido and Tohoku (at 18:00 in January)

【10^4kW】

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Hokkaido	96	97	79	80	86	86	86	86	136	135
Tohoku	138	128	126	91	98	104	109	115	114	144

Table A2-9 Annual Projection of Reserve Margin for Winter Peak Areas of Hokkaido and Tohoku (at 18:00 in January)
[Aforementioned Table 2-10]

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Hokkaido	19.3%	19.3%	15.8%	16.0%	17.1%	17.1%	17.1%	17.0%	26.9%	26.6%
Tohoku	10.1%	9.3%	9.1%	6.6%	7.1%	7.6%	8.0%	8.5%	8.4%	10.6%

Table A2-10 Annual projection of Reserve Margin for Winter Peak Areas of Hokkaido and Tohoku (at 18:00 in January, With power exchanges through cross-regional interconnection lines, at the sending end) [Aforementioned Table 2-10]

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Hokkaido	12.1%	12.0%	10.9%	9.1%	9.8%	10.2%	11.7%	11.8%	13.4%	15.0%
Tohoku	12.1%	12.0%	10.9%	9.1%	9.8%	10.2%	11.7%	11.8%	13.4%	15.0%

March 30, 2018

Organization for Cross-regional Coordination of Transmission Operators, Japan

Opinions for the Minister of Economy, Trade and Industry on the Aggregation of the Electricity Supply Plan

On the aggregation of the electricity supply plan, the Organization sent the results and opinions stated below to the Minister of Economy, Trade and Industry according to the provision of paragraph 2 of Article 29 of the Electricity Business Act .

1. Need to Secure Stable Supply at the Introduction of a Capacity Market and Beyond

At the previous aggregation of supply plans, the Organization recognized that the reserve margin of the Tokyo, Chubu, and the Kansai EPCO regional service areas (the three major areas) will fall below the 8% criterion in some projected years. The Organization has analyzed that the decreasing reserve margins are attributable to: (1) the former general electric power companies (retail and generation sectors of the current 10 GT&D companies) have decreased their supply capacity according to the shrinking demand of their area, and (2) in the meanwhile, small and medium-sized retail companies have grown their share of energy sales remaining their supply capacity as "unspecified procurement"

At this year's aggregation, the Organization recognized that the other areas (particularly, Tohoku, Shikoku, and Kyushu) as well as the three major areas share the same tendency of decreasing reserve margins. This will lead to a fall in the reserve margin under 8% in several areas, even though the leveling of the reserve margin for supply–demand balance is implemented through interconnection lines.

In addition, the Organization has implemented hearings with the former general electric power companies (retail and generation sector of the GT&D companies), and gathered relevant information to analyze the factors that decrease the supply capacity, such as discontinued operation or retirement of aged thermal power plants.

- ✔ The retail sector of the former general electric power companies (deemed retail companies) is projecting that if the demand that is supplied by another retail company (i.e. renounced demand) grows at the present pace, renounced demand will achieve 22% equivalent of the regional service area demand nationwide (25% for the three major areas) in FY 2027.
- ✔ Based on the above projection, five deemed retail companies (including the three major areas) have submitted supply plans that indicate that the procured reserve capacity is 1–3% equivalent of the area demand for their supply capacity in the long term. Moreover, they consider that further supply capacity will be procured from their surplus power of the generation company (i.e., the generation sector of the company).
- ✔ A Generator regarded as surplus power is a less competitive aged thermal power plant. The relatively low turnover market price of such power plants will decrease further given greater

integration of renewable energy. The generation sector of the company projects that such a generator cannot be maintained if the generation necessary for maintaining surplus power is put on the market at marginal cost.

On the assumption that these trend rapidly progress, the Organization has practical concerns that the above-stated conditions will lead to power shortages before FY 2024, when the capacity market will be introduced to secure supply capacity. Therefore, the Organization will pay greater attention to future trends of supply capacity and will implement the evaluation of supply–demand balance. In addition, the Organization will proceed with a review of practical measures including institutional measures in cooperation with the Government to ensure a secure supply capacity before the introduction of the capacity market.

As part of the review process noted above, the Organization will also address the following issues: (1) retail companies should procure long-term supply capacity of 1–3% equivalent to their projected peak demand; (2) once deemed retail companies have proposed their reserve margin as 5% equivalent to their projected peak demand at the review process, and whether it has integrity with (1); and (3) the principle of supply capacity in the projecting period that the deemed retail companies must essentially procure. If necessary, the Organization will implement countermeasures for these matters.

In addition, the Organization has stated the need for the introduction of the capacity market at the FY 2017 aggregation of supply plans. Recent circumstances emphasize the need for the capacity market as a scheme to ensure a secure supply capacity in the future. The Organization will proceed with the practical design of the capacity market in continued cooperation with the Government.

2. Need for Supply–Demand Balance Evaluation at Maximum Residual Peak Demand Including Winter

At present, summer peak demand is only assessed for long-term supply–demand balance for the areas that have annual peak demand in the summer (all areas except Hokkaido and Tohoku). In contrast, the 2017 winter was the most severe that Japan has experienced for several decades. The summer peak areas have recorded sharp increases in winter peak demand; Tokyo in particular suffered power shortages and was supplied electricity from other areas.

The background of power shortages will be analyzed in detail; preliminary analysis has examined the relationship between demand growth and estimation of securing supply capacity and indicates the following factors.

- ✔ The supply capacity of solar power is likely to exceed the conservatively estimated value (L5) in summer; however in winter, its supply capacity is likely to be lower due to snowfall, snow cover, or cloudy weather. Forecast error will arise from the derated supply capacity of solar power and the demand growth due to the cold, which will result in the worsening condition of supply–demand.
- ✔ Generally, daily demand in the winter increases day by day, which leads to greater daily energy consumption. In turn, this consumes a larger balancing capacity supplied by pumped-

storage hydro power plants. The consumed water volume in upper reservoir ponds cannot be restored within a day, meaning that the supply–demand balance for the next day cannot be secured.

✔ To exacerbate matters, there is the scheduled maintenance of thermal power plants and the forced outage of generators. Further compromised supply–demand balance occurs from the combination of these conditions.

To focus on the recent severe winter demand, deducting the portion of demand supplied by solar and wind power (i.e., residual peak demand) from the projected peak demand, all areas other than Kansai and Okinawa have a larger demand in winter than summer. In the winter of 2016, although somewhat milder than last winter, six areas recorded higher actual residual peak demand in winter than in the previous summer. Further, for the recent aggregation of supply plans, projected residual peak demand will be higher in winter than in summer for the areas other than Tokyo, Kansai, and Okinawa.

Thus, the occurrence of annual peak demand is likely to change from summer to winter for comparison of projected residual peak demand. The Organization will consider reflecting the forecast error* of solar power supply capacity in the winter supply–demand balance evaluation, and the evaluation method of supply capacity of pumped-storage hydro power plants in the review process of mid-to-long-term supply and balancing capacity and coordination of scheduled maintenance work in the short term.

Further, in the case of possible power shortages as occurred this past winter, the Organization will accurately inform members who are generation companies or retail companies of the conditions with respect to temporary measures in advance of requesting countermeasures such as energy conservation to the public or large customers. The Organization will also review schemes to encourage the adoption of proper countermeasures and the principles of countermeasures against power shortages in cooperation with the Government.

*Improvement of forecast error of solar power supply capacity shall be continuously reviewed by the all EPCOs concerned.

<u>3. Securing Mid-to-long-term Balancing Capacity</u>

The Organization has intensively conducted hearings with GT&D companies on supply– demand balance evaluation during off-peak periods other than traditional supply–demand balance evaluation at the occurrence of peak demand in the aggregation of the FY 2017 supply plans. As a result, there is a possible need in several areas for output shedding of thermal power generation or renewable energy according to the priority dispatch rule of generation with greater integration of renewable energy or lower demand occurrence at off-peak evaluation in FY 2018.

Moreover, the Organization has recognized the following factors as being characteristic of supply–demand balance during off-peak periods.

✔ Surplus supply capacity in daytime hours is expected to be absorbed by pumping of pumped-storage hydro power plants, which are unevenly installed across regional service areas.

- ✔ There is an increasing need for balancing capacity with a higher ramp speed that can cope with the steep decrease of solar power supply capacity in the evening time on the condition that fewer thermal power plants are integrated for the purpose of balancing
- ✔ There is an increasing need for balancing capacity as reserve capacity for times when the balancing capacity is activated against severe weather (i.e., Generator I' ; demand reduction) other than in peak periods due to the larger forecast error of solar power generation.

In view of these varying conditions during off-peak periods due to greater integration of renewable energy and reflecting the forecast error of solar power generation during winter peak period, the Organization has recognized anew the validity in the present procurement of the balancing capacity of Generator I (7% equivalent to peak demand), which has been uniformly set in regional service areas based upon the assumption that the surplus balancing capacity of Generator II can be abundantly expected.

In addition, it is important that both the required mid-to-long-term balancing capacity generator and the scheme for procuring balancing capacity with timing, volume, and necessary specification will be secured to utilize renewable energy at most and rationally achieve the security of stable supply and supply–demand balance under the national long-term projections of energy supply and demand. Therefore, the Organization will structure the detailed design of the balancing capacity market as a scheme that can broadly and economically ensure the necessary procurement of balancing capacity in cooperation with the Government and GT&D companies.