Aggregation of Electricity Supply Plans for Fiscal Year 2022

September 2022

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) 2022. This aggregation was conducted according to the provisions of Article 28 of the Operational Rules of the Organization and Article 29 of the Electricity Business Act(hereafter, the Act), which require the electric power companies (EPCOs) to submit their plans and publish the results.

The EPCOs submit the electricity supply plans according to the Network Code of the Organization; they are aggregated by the Organization, and sent to the Ministry of Economy, Trade and Industry (METI) annually by the end of March.
In total, 1,768 electricity supply plans for FY 2022 were aggregated, including 1,767 submissions from companies that became EPCOs by the end of November 2021 and one submission from a company that became EPCOs by March 1, 2022.

Number of Electric Power Companies Subject to the Aggregation in FY 2022

Business License	Number
Generation Companies	1,007
Retail Companies	712
Specified Transmission, Distribution and Retail Companies	30
Specified Transmission and Distribution Companies	6
Transmission Companies	3
General Transmission and Distribution Companies	10
Total	1,768

[Reference] Electricity supply plan
The EPCOs shall develop a comprehensive plan for electricity supply, and development of a generation or transmission facility for 10 years according to the provisions of Article 29 of the Act.

The METI shall recommend to EPCOs any alterations to the supply plan if the plan is recognized as inadequate for the security of a stable supply by cross-regional operation or for other development of the electricity business comprehensively and rationally.

Due Date of Submission of Supply Plans	
(1)Electric Power Company (EPCO) except General Transmission and Distribution Company submission to the Organization	March 1 (draft: Feb. 10)
(2)General Transmission and Distribution Company submission to the Organization	March 25 (draft: Mar. 10)
(3)The Organization submission to the METI	the End of March

[Reference] Items to be aggregated in the electricity supply plan
Items aggregated in the electricity supply plan are described in the covering letter of the aggregation of electricity supply plans according to the provisions of the Ordinance of the METI. The Organization has aggregated the plans according to this description

Items to be reported in the Aggregation (determined by the Ordinance of the METI)	Contents
I. Electricity Demand Forecast	
1. Actual and Preliminary Data for FY 2020, and Forecast for FY 2021 and 2022 (Short-Term)	Actual peak demand for the previous year, and forecast peak demand for the 1st and 2nd years of the projected period in both each regional area and nationwide
2. 10-Year Demand Forecast (Long-Term)	Forecast peak demand from the 3rd to 10th years of the projected period in both each regional area and nationwide
II. Electricity Supply and Demand	
1. Actual Data for FY 2020, and Projection for FY 2021 and 2022 (Short-Term)	Actual supply-demand for the previous year, and projected supply-demand for the 1st and 2nd years of the projected period in both each regional area and nationwide
2. Projection of Supply–Demand Balance for 10 years (Long-Term)	Projected supply-demand from the 3rd to 10th years of the projected period in both each regional area and nationwide
III. Analysis of the Transition of Power Generation Sources	Development and retirement plans of power generation sources which express the transition of power generation in nationwide
IV. Development Plans for Transmission and Distribution Facilities	Aggregated reinforcement plans of inter- and intra-regional transmission and distribution facilities
V. Cross-Regional Operation	Aggregated transaction plans between each area
VI. Analysis of Characteristics of Electric Power Companies	Aggregated situation for electric power companies by each business licenses
VII. Findings and Current Challenges	Opinion to the Minister of Economics, Trade & Industry

CONTENTS

I. Electricity Demand Forecast

1. Actual and Preliminary Data for FY 2021 and Forecast for FY 2022 and 2023 (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 10 general transmission and distribution (GT&D) companies for FY 2021 and the forecast[3] value for FY 2022 and 2023.

The peak demand (average value of the three highest daily loads) for FY 2022 was forecast at 159,030 MW, representing a 0.1% decrease over 159,160 MW; i.e., the temperature-adjusted[4] value for FY 2021.

Peak demand for FY 2022 was forecast at 159,530 MW, representing a 0.2% increase over the temperature-adjusted[4] value for FY 2020.

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

FY 2021 Actual (temperature adjusted)	FY 2022 Forecast	FY 2023 Forecast
16,230	16,051 (-1.1%*)	16,028 (-1.2%*)

*% change compared with actual data for FY 2021 (temperature adjusted)

b. Forecast for FY 2022 and 2023

Tables 1-2 and 1-3 show the monthly peak demand in FY 2022 and 2023, respectively, from the aggregated peak demand for each regional service area submitted by 10 GT&D companies. The monthly peak demand in summer (August) is greater than that in winter (January) by about 10 GW; therefore, nationwide peak demand occurs in summer.

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[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 2022 is based on normal weather. Thus, weather conditions for forecast assumption may vary in contrast to the actual data or estimated value in FY 2021.

[4] Temperature adjustment is implemented to capture the current demand based on normal weather, which excludes demand fluctuations triggered by air-conditioner operation.

Table 1-2 Monthly Peak Demand (average value of the three highest daily loads) in FY 2022
(Nationwide, 10^4 kW at the sending end)

	Apr.	May	Jun.	Jul.	Aug.	Sep.
Peak Demand	11,631	11,379	12,759	16,001	16,051	14,101
	Oct.	Nov.	Dec.	Jan.	Feb.	Mar.
Peak Demand	11,967	12,425	14,307	15,068	15,041	13,347

Table 1-3 Monthly Peak Demand (average value of the three highest daily loads) in FY 2023
(Nationwide, 10^4 kW at the sending end)

	Apr.	May	Jun.	Jul.	Aug.	Sep.
Peak Demand	11,612	11,361	12,741	15,978	16,028	14,079
	Oct.	Nov.	Dec.	Jan.	Feb.	Mar.
Peak Demand	11,950	12,408	14,286	15,045	15,018	13,318

c. Annual Electric Energy Requirements

Table 1-4 shows the preliminary data[5] for FY 2021 and the forecast value for FY 2022 from the aggregated electric energy requirements of each regional service area submitted by the 10 GT&D companies.

The electric energy requirements for FY 2022 are forecast at 877.5 TWh, a 0.9% increase over the 869.3 TWh in the preliminary data for FY 2021.

Table 1-4 Annual Electric Energy Requirements
(Nationwide, TWh at the sending end)

FY 2021 Preliminary (temperature- and leap-year-adjusted)	FY 2022 Forecast
869.3	877.5(+0.9%*)

* % 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 2020 with the preliminary data from December 2020 to March 2021.

2. 10-Year Demand Forecast (Long Term)

Table 1-5 shows the significant economic indicators developed and published on November 25, 2021 by the Organization, which are assumptions to be used by the GT&D companies to forecast the peak demand in their regional service areas.

The real gross domestic product (GDP)[6] is estimated at 541.4 trillion Japanese Yen (JPY) in FY 2021 and 596.1 trillion JPY in FY 2031, with an annual average growth rate (AAGR) of 1.0%. The index of industrial production (IIP)[7] is projected at 96.4 in FY 2021 and 104.2 in FY 2031, with an AAGR of 0.8%. In contrast, the population is estimated at 125.74 M. in FY 2021 and 119.23 M. in FY 2031, with an AAGR of −0.5%.

Table 1-5 Major Economic Indicators Assumed for Demand Forecast

	FY 2021	FY 2031
Gross Domestic Product(GDP)	541.4 trillion JPY	596.1 trillion JPY [+1.0%]*
Index of Industrial Product(IIP)	96.4	104.2 [+0.8%]*
Population	125.74 M	119.23 M [-0.5%]*

* Average annual growth rate for the forecast value of FY 2021.

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

Table 1-6 shows the peak demand forecast for FY 2022, FY 2026, and FY 2031 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 forecast from FY 2010 to 2031. The peak demand nationwide is forecast at 159,260 MW in FY 2026 and 157,460 MW in FY 2031, with an AAGR of −0.3% from FY 2021 to FY 2031.

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

Table 1-6 Peak Demand Forecast (average value of the three highest daily loads) for August
(Nationwide, 10^4 kW at the sending end)

FY 2022 [aforementioned]	FY 2026	FY 2031
16,051	15,926 [-0.4%]*	15,746 [-0.3%]*

* Average Annual Growth Rate for the forecast value of FY 2021.

6 GDP expressed as the chained price for calendar year (CY) 2015.
7 Index value in CY 2015 = 100.

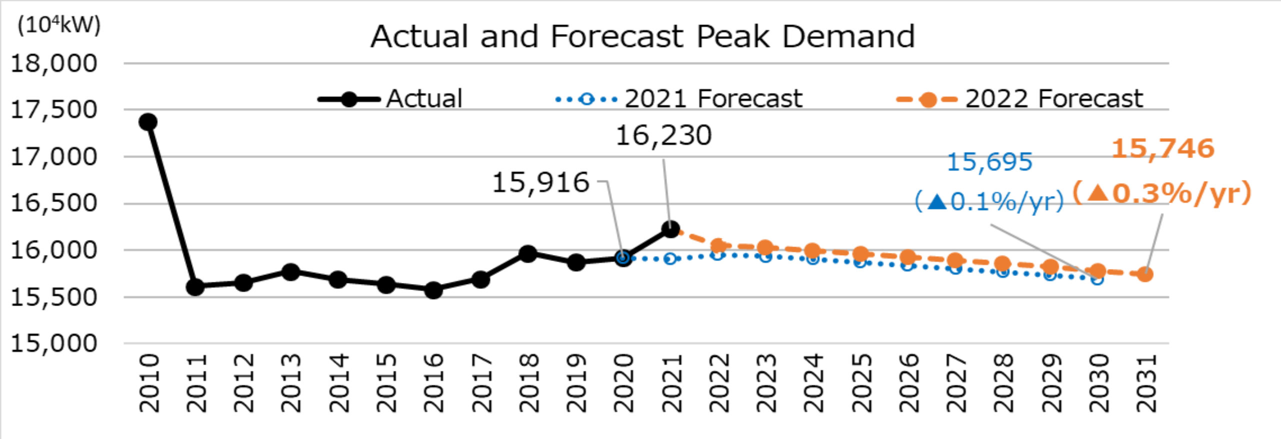

Figure 1-1 Actual and Forecast Peak Demand (August for Nationwide, 10^4 kW at the sending end)

b. Annual Electric Energy Requirement

Table 1-7 shows the forecast for annual electric energy requirements in FY 2022, FY 2026, and FY 2031 as the aggregation of the electric energy requirements for each regional service area submitted by 10 GT&D companies.

The nationwide annual electric energy requirement is forecast at 870.7 TWh in FY 2026 and 863.4 TWh in FY 2031, with an AAGR of −0.1% decrease from FY 2021 to FY 2031.

The annual electric energy requirement forecast over 10 years shows a slightly decreasing trend, which is attributable to negative factors, such as efforts to reduce electricity use, and a shrinking population offsetting the positive factors such as the expansion of economic scale and greater dissemination of electric appliances, in the projected period.

Table 1-7 Annual Electric Energy Requirement Forecast
(Nationwide, TWh at the sending end)

FY 2022 [aforementioned]	FY 2026	FY 2031
877.5	870.7 [+0.0%]*	863.4 [-0.1%]*

* AAGR for the forecast value of FY 2021.

II. Electricity Supply and Demand

1. Supply Reliability Criteria

As a new reliability criterion, the Organization has applied expected unserved energy (EUE) to the electricity supply plan based on the discussions of the Study Committee on Regulating and Marginal Supply Capability and Long-Term Supply–Demand Balance Evaluation.[8] From FY 2021, annual EUE values of 0.048kWh/kW-year nationwide and 0.498kWh/kW-year for the Okinawa area, are the newly applied reliability criteria for the electricity supply plan.

The supply reliability criteria for the electricity supply plan now apply annual EUE criteria to confirm supply reliability; however, it is crucial that supply capacity must be balanced for each month according to the consideration of area characteristics, such as winter in the Hokkaido area or severe weather. Therefore, the Organization evaluates whether the supply capacity in the short term(the first and second year of the projected period) is satisfied by the annual EUE criteria, and simultaneously confirms the reserve margin of each area and month.

(Reference) Characteristics of Annual EUE

Figure 2-1 shows characteristics of annual EUE. For evaluation by annual EUE criteria, the stable supply is secured through the year at the usual level if the annual EUE value is less than 0.048 kWh/kW-year.

Still, as it is difficult to understand the lowering reserve margin in a specific area and month solely by the annual EUE evaluation, because of an imbalance in the supply capacity caused by the scheduled maintenance of the generating facilities and other factors. The Organization evaluates the reserve capacity for each month by a conventional approach.

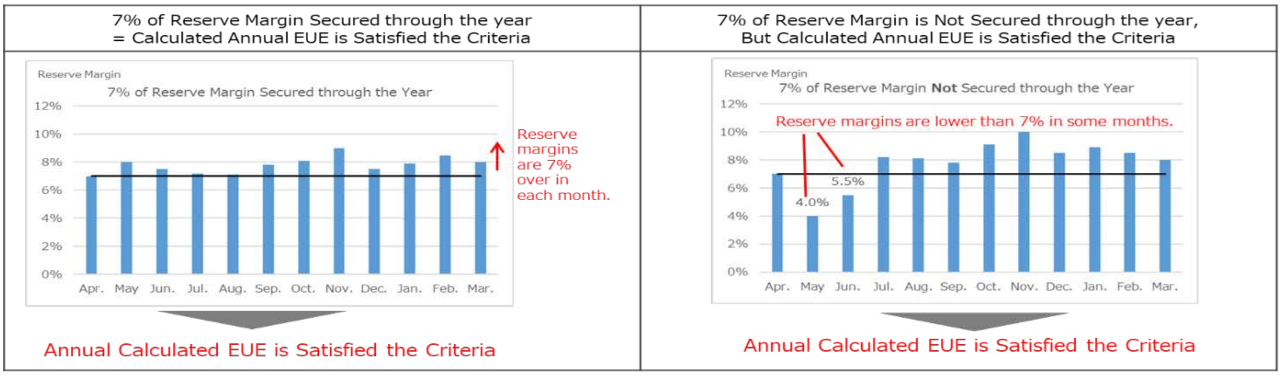

Figure 2-1 Characteristic of Annual EUE

[8] [Source]Material 2, 58th meeting of the Study Committee on Regulating and Marginal Supply Capability and Long-Term Supply–Demand Balance Evaluation (March 3, 2021)
https://www.occto.or.jp/iinkai/chouseiryoku/2020/files/chousei_58_02.pdf

2. Evaluation of Supply Capacity by EUE Approach in the Projected Period (FY 2022 Through 2031)

Table 2-1 shows the calculated result of supply capacity by annual EUE. In the short term (the first and second year of the projected period), the entire area and year fall within the criteria of secure supply (0.048kWh/kW-year nationwide, 0.498kWh/kW-year in Okinawa). The maximum value in the projected period is 0.038kWh/kW-year for the Tokyo area in FY 2022.

In the long term, the calculated result for the Kyushu area from FY 2024 to FY 2029 exceeds the criteria, because of uncertainty in the commercial operation of some large generating facilities in the area. Furthermore, the result for the Okinawa area from FY 2025 to FY 2027 and FY 2029 exceeds its criteria, reflecting scheduled maintenance of generating facilities for the period.

Currently, some areas and years do not satisfy the criteria of reliability; the Organization continues evaluation work for future supply plans keeping watch for development plans of generating facilities in the mid-to-long term.

Table 2-1 Calculated Result of Supply Capacity by Annual EUE

(kWh/kW-year)

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Hokkaido	0.000	0.007	0.000	0.001	0.001	0.001	0.000	0.000	0.000	0.000
Tohoku	0.007	0.001	0.005	0.002	0.001	0.001	0.001	0.001	0.000	0.000
Tokyo	0.038	0.011	0.042	0.008	0.003	0.002	0.001	0.001	0.000	0.000
Chubu	0.003	0.001	0.000	0.002	0.001	0.000	0.000	0.000	0.000	0.001
Hokuriku	0.000	0.000	0.000	0.001	0.000	0.000	0.000	0.000	0.000	0.000
Kansai	0.000	0.000	0.000	0.001	0.000	0.000	0.000	0.000	0.000	0.000
Chugoku	0.000	0.000	0.000	0.001	0.000	0.000	0.000	0.000	0.000	0.000
Shikoku	0.000	0.000	0.000	0.001	0.000	0.000	0.000	0.000	0.000	0.000
Kyushu	0.001	0.001	0.210	0.130	0.119	0.113	0.107	0.096	0.031	0.027
Interconnected	0.014	0.004	0.035	0.016	0.013	0.011	0.010	0.009	0.003	0.003
Okinawa	0.027	0.021	0.354	0.793	0.662	0.860	0.282	0.917	0.311	0.304

3. Evaluation of Supply Capacity by Conventional Approach in the Short Term

The Organization evaluates the supply–demand balance for each regional service area and nationwide using the supply capacity[9] and peak demand data for the regional service areas.

The Organization implements its evaluation using the criterion of whether or not the reserve margin (%)[10] for each regional service area is secured over 8%. In the Okinawa EPCO regional service area, the criterion is to secure the 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. The evaluation is implemented at the time of the least reserve margin.

Figure 2-2 summarizes the supply–demand balance evaluation. The supply capacity includes the generating capacity requirements secured by retail and GT&D companies for their regional service areas and the generation companies' surplus power production.[11] The supply capacity currently secured by retail companies includes power procured[12] from other regional service areas through cross-regional interconnection lines. Thus, the generation companies' surplus power or the reserve capacity of retail companies might provide future supply capacity for other regional service areas.

When the operation of a nuclear power plant becomes uncertain, the corresponding unit or plant's supply capacity is recorded as zero; the corresponding supply capacity is reported as "uncertain" according to Procedures for Electricity Supply Plans of FY 2022, published in December 2021 by the Agency for Natural Resources and Energy. In the electricity supply plans for FY 2022, the supply capacity was reported as "uncertain" for all nuclear power plants except those that had resumed operation by the time of the plans were submitted.

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

[10] 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).

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

[12] In case of congestion in cross-regional interconnection lines, the rebated figure for each area calculated by the Organization is added.

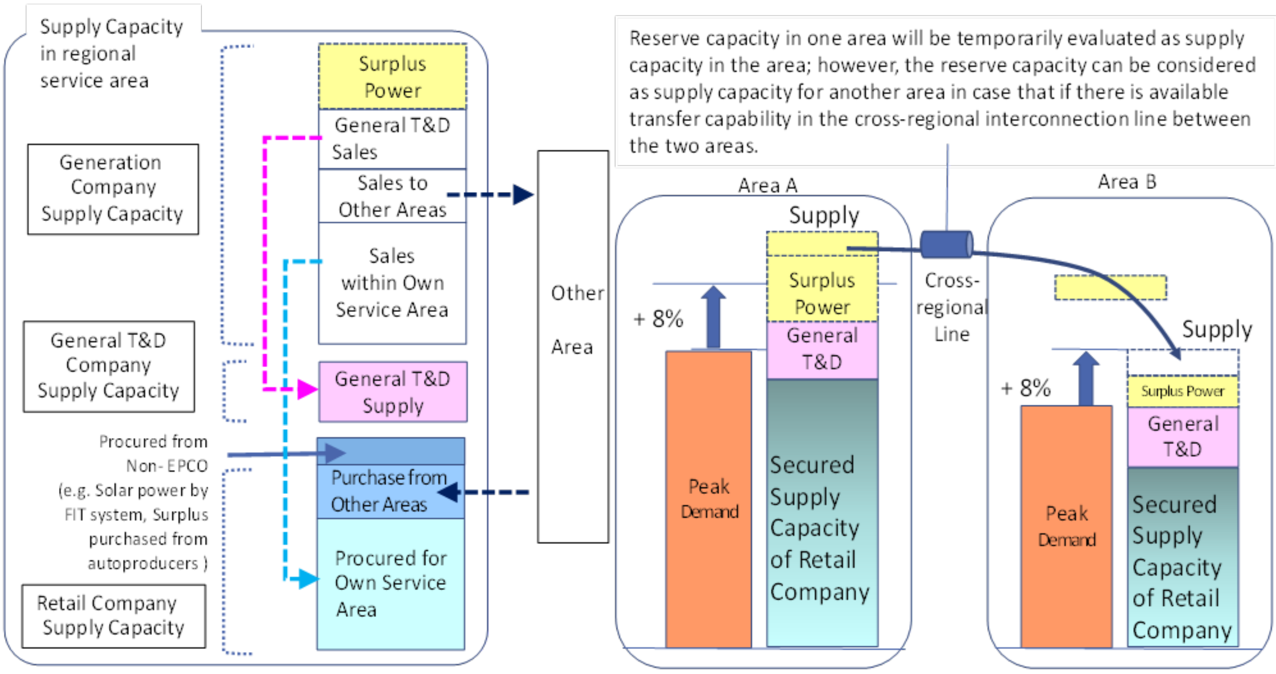


Figure 2-2 Summary of Supply–Demand Balance Evaluation

[Reference] Calculation Method of Supply Capacity

The calculation method for supply capacity or surplus power is based on the description in the "Guideline for the Calculation of Demand and Supply Capacity"[13](Agency for Natural Resources and Energy: December 2021) and "Procedures for Electricity Supply Plans of FY 2022"[14](Agency for Natural Resources and Energy: December 2021).

[13] Guideline for the Calculation of Demand and Supply Capacity (only in Japanese)
https://www.enecho.meti.go.jp/category/electricity_and_gas/electricity_measures/001/pdf/guideline.pdf

[14] Procedures for Electricity Supply Plans of FY 2021 (only in Japanese)
https://www.enecho.meti.go.jp/category/electricity_and_gas/electricity_measures/001/pdf/kisai-youryo.pdf

[Reference] Calculation Method of Available Transfer Capability(ATC)

The calculation method of available transfer capability of cross-regional interconnection lines is stated below.

ATC = Transfer Capability (1) –Transfer Margin (2) –Schedule Power Flow of cross-regional interconnection line at 15:00 h in August (3).

Short term

(1): Based on "Transfer Capability of Cross-regional Interconnection Lines FY 2022-2031" [annual and long-term plans] (February 10, 2022: The Organization)[15]

(2): Based on "Transfer Margin of Cross-regional Interconnection Lines FY 2022 and 2023" [annual plan] (February 10, 2022: The Organization)[16], and the calculated figures considering expected contribution from external areas (equivalent to 3% of transfer capability of the interconnection lines)

(3): Based on monthly scheduled power flows reported in the "Plan for Transaction of Electricity (Table 36)" of the electricity supply plan for FY 2022

Mid-to-Long term

(1): For FY 2022 and 2023, the August value was calculated from (1) in the short term above; the value for FY 2024-2031 was based on "Transfer Capability of Cross-regional Interconnection Lines FY 2022-2031" [annual and long-term plans] (February 10, 2022: The Organization)[15]

(2): For FY 2022 and 2023, the August value was calculated from (2) in the short term above; the value for FY 2024-2031 was based on "Transfer Margin of Cross-regional Interconnection Lines FY 2022-2031" [long-term plans] (February 10, 2022: The Organization), [16], and the calculated figures considering expected contribution from external areas (equivalent to 3% of transfer capability of the interconnection lines).

(3): Based on 15:00 in August scheduled power flows of the period reported in the "Plan for Transaction of Electricity (Table 32-8)" of the electricity supply plan for FY 2022

[15] Reference: material from the "4th Meeting of the Working Group on Cross-regional Transfer Capability" (only in Japanese)
http://www.occto.or.jp/iinkai/unyouyouryou/2021/unyouyouryou_2021_4_haifu.html

[16] Reference: material from the "3rd Meeting of the Working Group on Transmission Margin" (only in Japanese)
http://www.occto.or.jp/iinkai/margin/2021/margin_kentoukai_2021_3.html

a. Projection of Supply–Demand Balance in FY 2022 and 2023

To present the cross-regional reserve margin, the Organization recalculates the monthly projection of the least reserve margin for each regional service area to the level around neighboring areas. This recalculation is done by using power exchanges to transfer electricity from areas of over the 8% reserve margin to areas of below the 8% reserve margin based on the available transfer capability of each interconnection line.[17]

In addition, additional supply capacity has been applied to the interconnected areas (except Okinawa) in July and August, which is based on the correlation between solar power generation and electric demand.[18]

Furthermore, information on the environmental assessment of thermal power plants[19] probably includes some generating facilities, in which EPCOs confirm their business judgment and proceed to their construction. Therefore, the Organization has investigated generating facilities that are not included in the electricity supply plans; however, they have already applied for generator connection to GT&D companies and submitted construction plans according to the provisions of Article 48 of the Act in cooperation with the government.

(i) Projection for FY 2022

Table 2-2 shows the projected reserve margin in each regional service area for FY 2022. The reserve margin in every area and month is over 8% criteria.

Table 2-2 Monthly Projection of the Cross-regional Reserve Margins Nationwide and for Each Regional Service Area

(Power exchanges through cross-regional interconnection lines and generating facilities are not included at the sending end at the sending end of the electricity supply plans,)

	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.	Jan.	Feb.	Mar.
Hokkaido	29.6%	48.7%	55.5%	41.5%	27.6%	31.9%	34.2%	21.1%	16.1%	15.4%	15.6%	20.2%
Tohoku	18.3%	20.3%	13.3%	15.3%	20.1%	16.8%	23.1%	14.6%	11.9%	15.4%	15.6%	19.9%
Tokyo	14.7%	20.3%	13.3%	10.3%	10.2%	16.8%	17.0%	8.1%	11.9%	10.7%	10.6%	18.4%
Chubu	14.7%	20.3%	20.2%	10.3%	10.5%	16.8%	17.0%	11.3%	11.9%	10.7%	10.6%	18.4%
Hokuriku	18.0%	20.3%	20.2%	11.3%	10.5%	16.8%	17.0%	11.3%	11.9%	10.7%	10.6%	18.4%
Kansai	18.0%	20.3%	20.2%	11.3%	10.5%	16.8%	17.0%	11.3%	11.9%	10.7%	10.6%	18.4%
Chugoku	18.0%	20.3%	20.2%	11.3%	10.5%	16.8%	17.0%	11.3%	11.9%	10.7%	10.6%	18.4%
Shikoku	18.0%	20.3%	21.9%	11.3%	10.5%	16.8%	24.2%	11.9%	11.9%	10.7%	10.6%	18.4%
Kyushu	18.0%	20.3%	20.2%	11.3%	10.5%	16.8%	27.1%	23.1%	11.9%	10.7%	10.6%	18.4%
Okinawa	62.5%	35.8%	28.0%	35.0%	40.1%	30.8%	53.3%	60.3%	73.5%	57.1%	60.5%	86.2%

* Cross-regional reserve margins becoming the same value are shown in the same background colors after utilization of cross-regional interconnection line.

[17] This evaluation is implemented based on the following. The evaluation of the 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 lower than those based on the reserve margin at a given time. Therefore, this evaluation covers a more severe condition, which is better for a stable supply.

[18] Reference: 69th meeting of the Study Committee on Regulating and Marginal Supply Capability and Long-Term Supply–Demand Balance Evaluation
https://www.occto.or.jp/iinkai/chouseiryoku/2021/files/chousei_69_01.pdf

[19] Reference: Information on the environmental assessment of thermal power plants (METI website, only in Japanese)
http://www.meti.go.jp/policy/safety_security/industrial_safety/sangyo/electric/detail/thermal.html

The Okinawa EPCO regional service area[20] is a small and isolated island system unable to receive power through interconnection lines. In this area, the criterion of stable supply is to secure supply capacity over peak demand by deducting the capacity of the largest generating unit and the balancing capacity with frequency control ("Generator I-a", 301 MW in total), without applying the criteria of other interconnected areas.[21]

Table 2-3 shows the monthly reserve margin against the deduction of the capacity of Generator I-a, which indicating that the stable supply was secured in each month.

Table 2-3 Monthly Reserve Margin against the Deduction of the Capacity of Generator I-a (at the sending end)

	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.	Jan.	Feb.	Mar.
Okinawa	33.3%	11.2%	7.4%	14.5%	19.6%	11.0%	30.5%	33.9%	43.0%	27.6%	30.6%	54.2%

(ii) Projection for FY 2023

Table 2-4 shows a result of the similar calculation result for FY 2023, indicating that the reserve margins are over the criteria of 8% in every month and area.

Table 2-4 Monthly Projection of the Cross-regional Reserve Margins Nationwide and for Each Regional Service Area

(Power exchanges through cross-regional interconnection lines and generating facilities are not included at the sending end at the sending end of the electricity supply plans,)

	4月	5月	6月	7月	8月	9月	10月	11月	12月	1月	2月	3月
Hokkaido	30.0%	45.3%	47.6%	29.2%	30.9%	29.7%	26.1%	20.6%	23.7%	18.1%	20.8%	25.1%
Tohoku	30.0%	29.9%	21.1%	19.7%	22.0%	29.7%	26.1%	20.6%	16.5%	15.4%	16.4%	25.1%
Tokyo	11.4%	22.1%	21.1%	13.6%	14.1%	15.8%	18.0%	10.4%	15.1%	14.6%	15.7%	19.6%
Chubu	28.9%	22.1%	22.5%	13.6%	14.1%	15.8%	18.0%	10.6%	15.1%	14.6%	15.0%	19.6%
Hokuriku	28.9%	35.4%	34.4%	20.9%	20.0%	24.4%	18.0%	10.6%	15.1%	14.6%	15.0%	20.0%
Kansai	28.9%	35.4%	34.4%	20.9%	20.0%	24.4%	30.3%	28.6%	15.6%	14.6%	15.0%	20.0%
Chugoku	28.9%	35.4%	34.4%	20.9%	20.0%	24.4%	30.3%	28.6%	15.6%	14.6%	15.0%	20.0%
Shikoku	28.9%	35.4%	34.4%	20.9%	30.9%	25.2%	33.7%	28.6%	15.6%	22.0%	21.3%	41.5%
Kyushu	28.9%	35.4%	34.4%	20.9%	20.0%	24.4%	31.0%	28.6%	15.6%	14.6%	15.0%	20.0%
Okinawa	65.1%	59.2%	39.7%	38.7%	36.8%	31.4%	36.6%	52.6%	63.7%	63.2%	68.4%	78.5%

* Reserve margins becoming the same value are shown in the same background colors after utilization of cross-regional interconnection line.

The Okinawa EPCO regional service area,[22] which is a small and isolated island system unable to receive power through interconnection lines. In this area, the criterion of stable supply is to secure the supply capacity over peak demand by deducting the capacity of the largest generating unit and the balancing capacity with frequency control ('Generator I-a,' 301 MW in total), without applying the criteria of other interconnected areas.[23]

Table 2-5 shows the monthly reserve margin against the deduction of the capacity of Generator I-a, indicating that the stable supply was secured in each month.

[20] In the Okinawa EPCO regional service area, the evaluation excludes the reserve margins of several isolated islands.
[21] The evaluation is implemented at the time of the least reserve margin instead of the peak demand occurrence.
[22] See footnote 19.
[23] See footnote 20.

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

	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.	Jan.	Feb.	Mar.
Okinawa	36.3%	34.9%	19.6%	18.5%	16.7%	11.8%	14.1%	26.5%	33.6%	34.1%	39.0%	46.9%

b. Difference Between Scheduled Maintenance of Generating Facility for FY 2022 Evaluated by the Conventional Approach

Figure 2-3 shows the monthly scheduled maintenance planned for FY 2022 in the 2022 Supply Plan. Figure 2-4 shows the difference in scheduled maintenance for FY 2022 between the supply plans of FY 2022(the 1st year) and FY 2021 (the 2nd year).

The Organization has requested that all EPCOs avoid the period of tight supply and demand balance for their generating facilities' scheduled maintenance; as a result, the schedule maintenance decreased compared with the 2021 Supply Plan.

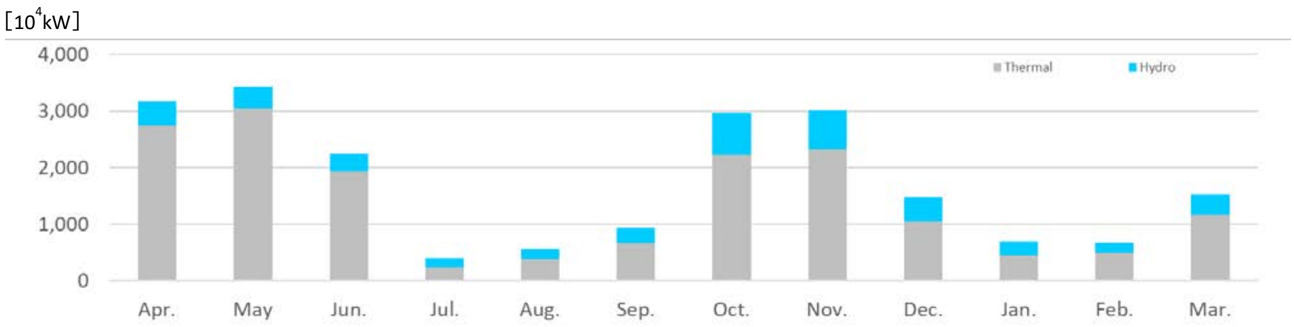


Figure 2-3 Monthly Scheduled Maintenance Planned for FY 2022 in 2022 Supply Plan

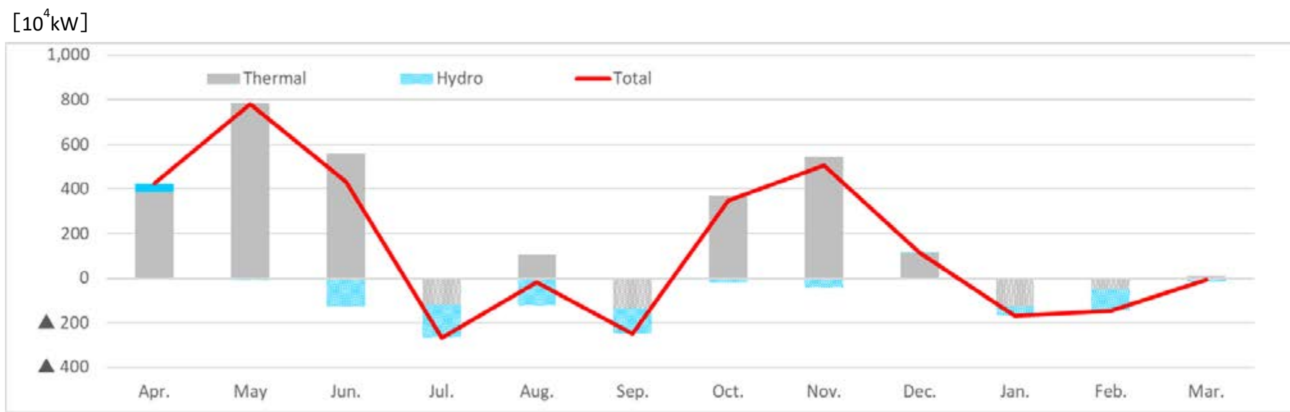


Figure 2-4 Difference in Scheduled Maintenance for FY 2022 between FY 2021 (the 2nd year) and FY 2022 (the 1st year) Supply Plan

c. Suspension and Decommissioning of Generating Facilities in 2022 Supply Plan

Table 2-6 shows the suspension and decommissioning of generating facilities in the 2022 Supply Plan. The plan adds an additional capacity of 140 MW to the suspension and decommissioning plan.

Furthermore, 4,070 MW of generating facilities has already been included in the suspension and decommissioning plan untill FY 2021. In total, a 4,210 MW capacity is planned for the suspension and decommissioning in FY 2022.

Table 2-6 Suspension and Decommissioning of Generating Facilities in 2022 Supply Plan (10^4 kW)

Fuel	Newly Added	Already Included	Total Capacity to be Decommissioned
LNG	–	311	311
Oil	–	60	60
Coal	14	36	50
Total	14	407	421

d. Capacity Secured and Surplus Power Evaluated by the Conventional Approach

Figure 2-5 compares the supply capacity to be procured[24] by a retail company for their forecasted peak demand and the surplus power of generation companies. The supply capacity to be procured exceeds the surplus power in August 2022.

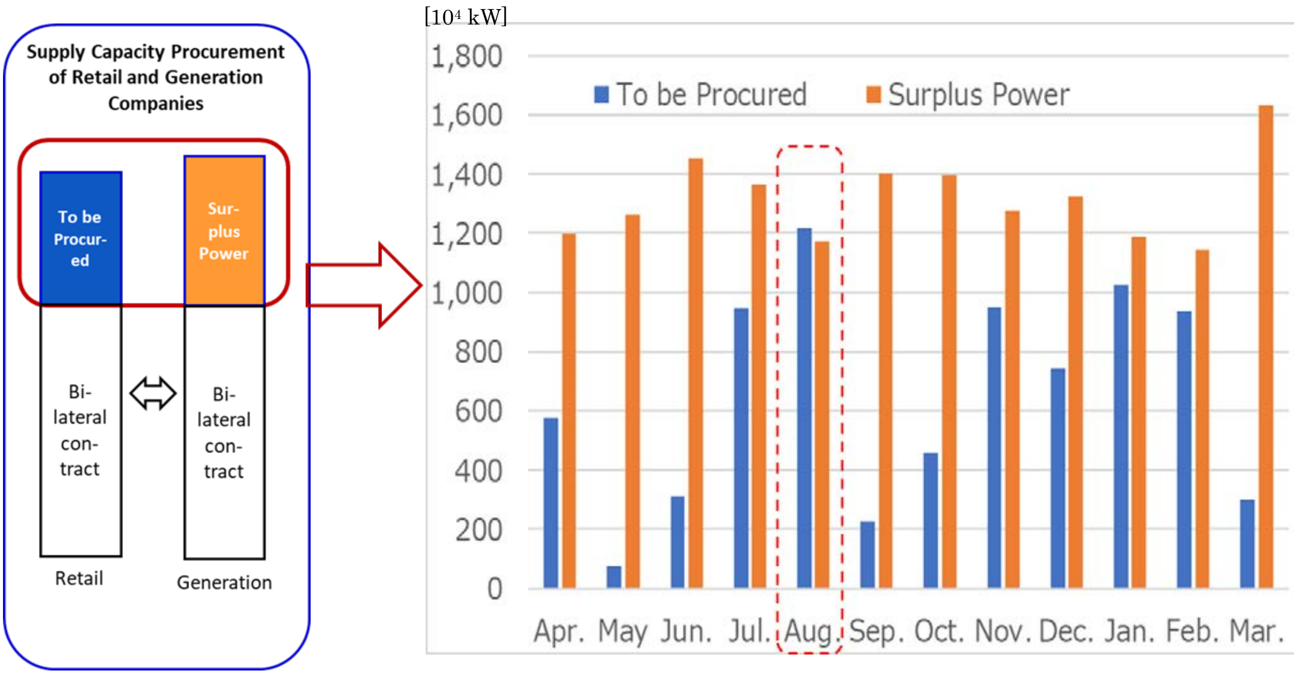


Figure 2-5 Comparison Between Supply Capacity to Be Procured by a Retail Company for Their Forecasted Peak Demand and Surplus Power of Generation Companies

4. Evaluation of Energy Supply

To evaluate the energy supply (kWh), the Organization plans to implement a semi-annual evaluation, known as an "Electricity Supply–demand Verification," in spring and autumn. In these times, information for demand forecast, such as weather forecast is obtained, and additional generation fuel can be available. In addition to the above evaluation, the Organization plans to monitor the

[24] Supply capacity to be procured: Σ(forecasted peak demand of retail companies – procured supply capacity of retail companies).

energy supply twice a month and publish the results.

The Organization does not implement the evaluation of energy supply balance in the aggregation of the supply plans; however, it confirms the annual energy supply balance at this point and publishes information that will lead to a response from the EPCOs.

a. Projection of Energy Supply

Figure 2-6 shows the monthly energy supply balance for a total of nine interconnected areas in FY 2022(the 1st year of the projected period of FY 2022 plans). Table 2-7 shows the forecasted energy requirement of the FY 2022 plan, and volumes and shortage rates from the forecast. It seems that the energy supply[25]* will be 0.2–2.4 TWh/month less than the forecasted energy requirement (equivalent to 0.3 to 3.2% against the forecast energy requirement) throughout the year.

The Organization expects retail companies to premeditatedly procure supply capacity, and generation companies to procure generation fuel to increase energy generation for actual demand and supply timing based on the projection. Additionally, the Organization shall confirm the projection of securing energy supply by implementing kWh monitoring for the high demand period.

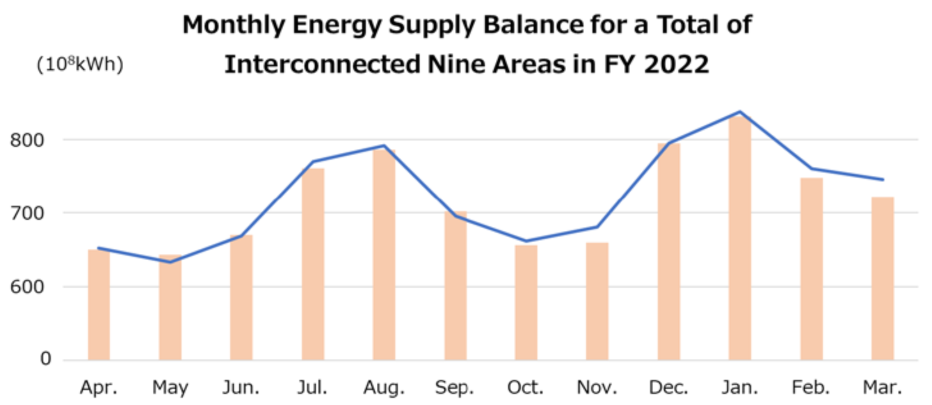


Figure 2-6 Monthly Energy Supply Balance for a Nine Interconnected Areas in FY 2022

Table 2-7 Forecasted Energy Requirement of FY 2022 Plan, Volumes, and Rates of Shortage from the Forecast

(10^8kWh)

	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.	Jan.	Feb.	Mar.	Annual total
Forecasted Energy Requirement	652	633	669	770	792	696	662	681	795	838	761	746	8,695
Projected Energy Supply Shortage	-2	10	1	-9	-6	6	-6	-21	0	-7	-13	-24	-71
Projected Shortage Rate	-0.3%	1.6%	0.1%	-1.2%	-0.8%	0.9%	-0.9%	-3.1%	0.0%	-0.8%	-1.7%	-3.2%	-0.8%

b. Evaluation of Energy Supply (Energy to Be Procured and Surplus Energy)

Figure 2-7 shows the comparison of energy supply, which retail companies plan to procure from the energy market and surplus energy that the generation companies are expected to provide. Surplus energy exceeds the procurement by retail companies throughout the year due to the retail companies' planned procurement and the surplus energy provided by generation companies. The Organization monitors the condition to succeed.

[25] Projected energy supply is an addition of energy supply with bilateral contract to retail companies which includes generation of nonelectric power companies, and generation surplus.

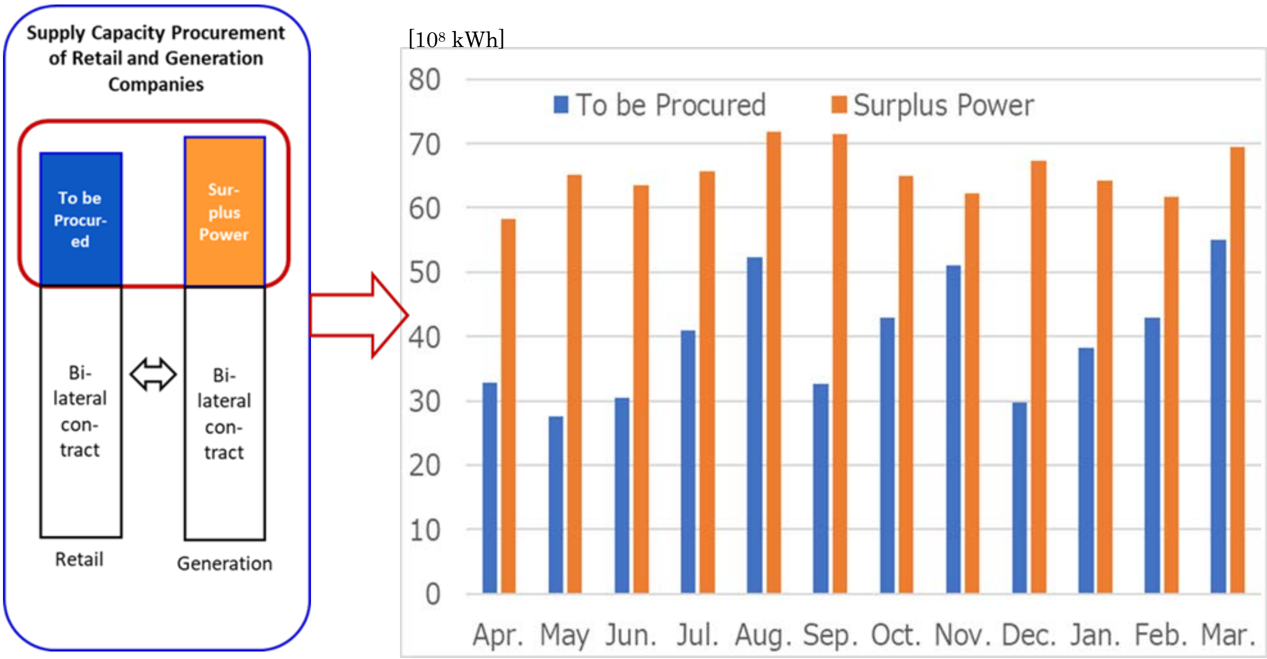


Figure 2-7 Comparison of Retail Companies' Energy Supply Procurement and Surplus Energy Provision

5. Evaluation of Supply-Demand for Supply Capacity and Energy Supply

・ Evaluation of Supply Capacity by the EUE Approach

For the short term of the projected period (FY 2022 and 2023), the EUE indices are satisfied in all areas and years. In contrast, for the mid-to-long term, the EUE indices exceed the criteria for the Kyushu area from FY 2024 to FY 2029, and the Okinawa area from FY 2025 to FY 2027, and FY 2029.

・ Evaluation of Supply Capacity by the Conventional Approach

The 8% resereve margin is secured in FY 2022 and 2023 in every area and for all months.

・ Evaluation of Energy Supply

The energy supply in FY 2022 is expected to be 0.2 to 2.4 TWh/month of volume less than the forecasted energy requirement (equivalent to 0.3 to 3.2% against the forecast energy requirement) throughout the year.

In the short term, all areas or periods satisfy EUE, and none fall below the 8% criteria. The Organization proceeds to review supply measures based on the analytical result of supply–demand variance risk which premises severe climate conditions (heatwave and severe cold) emerge once in 10 years.

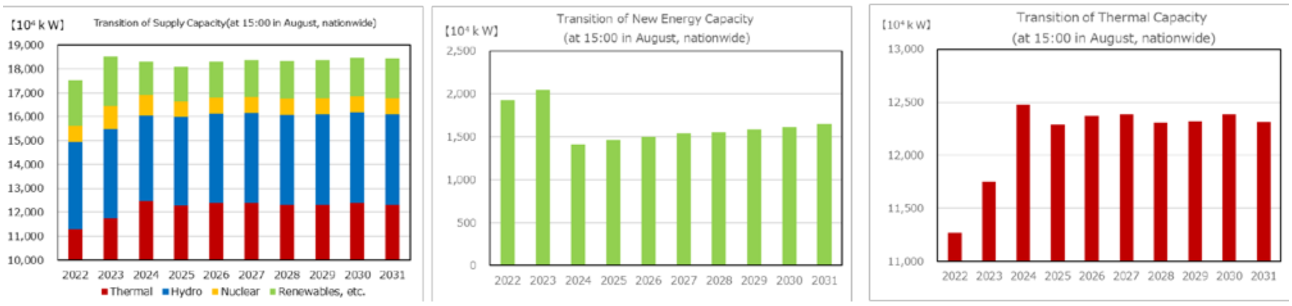
For the mid-to-long term, after FY 2024, considering the area and period of not achieving EUE, the Organization shall carefully examine supply capacity in future supply plans based on the continuous watch on generation facility development

[Reference] Detailed Analysis of the Aggregation

a. Transition of Supply Capacity by Generation Sources

Figure 2-8 shows the power generation sources' supply capacity (nationwide in August, at 15:00) in the projected period.

The supply capacity of new energy, etc. is projected to decrease temporarily in FY 2024 due to the calculation using an annual adjustment factor after the year; however, it is projected to increase afterward. Thermal power is projected to increase till FY 2023 by new and added installations, and stay at almost the same level afterward. As a whole, supply capacity is projected to increase untill FY 2023 and stay almost the same after that.



Aggregated value submitted by each electric power company

New Energy, etc: Wind, Solar, Geothermal, Biomass and Waste, classified by "Guideline for the Calculation of Demand and Supply Capacity" (Agency for Natural Resources and Energy: Dec. 2011)

Renewable Energy : New Energy and Hydro

Figure 2-8 Transition of Supply Capacity by Generation Sources

b. Transition of Suspended Thermal Power Plants

Figure 2-9 shows mid-to-long-term projections of suspended thermal power plants (8-12 GW), which are not counted as part of the supply capacity due to long-term planned outages. They will temporarily decrease in FY 2024 due to resuming operation of the some plants and will keep their capacity at about 10 GW in total.

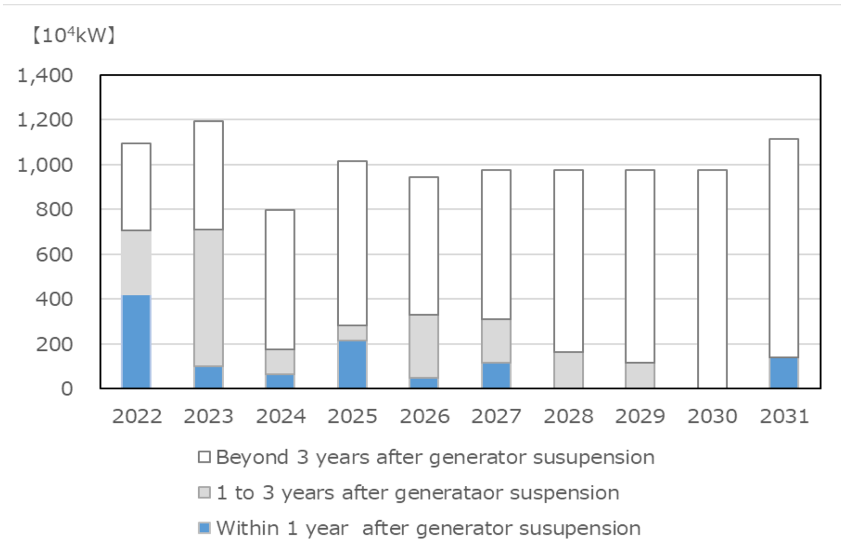


Figure 2-9 Projections of Suspended Thermal Power Plants

III. Analysis of the Transition of Power Generation Sources

This chapter's analysis is based on the automatic aggregation of values submitted by EPCOs. These values will not necessarily be realized in the future due to operating conditions of the power plants or actions due to political measures.

1. Transition of Power Generation Sources (Capacity)

The installed power generation capacity is the automatic aggregation of the capacity of an electric power plant's capacity owned by EPCOs and feed-in-tariff (FIT) generators owned by companies (other than EPCOs) registered as procurers of supply capacity of retail and GT&D companies in the projected period. For EPCOs' development plans, only generating facilities with a given probability of development are included in the calculation; however, not all development plans will necessarily be realized; inefficient facilities will proceed toward decomissioning due to political measures in the future.

The installed generation capacity by a power generation source submitted from the EPCOs is calculated from the concepts below.

*1 Hydro and Thermal[26]

For existing facilities, the generation company aggregates the generating facility that it owns. For a newly installed facility, a generating facility such as one proceeding with its environmental assessment or publishing its commercial operation, is included in the aggregation.

*2 Nuclear

The generation company aggregates its generating facilities with actual operation experience, in addition to 33 units for which the date for resuming operation is uncertain, and excludes any facility that terminated operation.

*3 Solar and Wind

The GT&D company aggregates the projected value of the generation facility integration according to preliminary consultation and the available connecting capacity of its transmission lines or the actual growth trend of integration.

Table 3-1 and Figure 3-1 show the transition of installed power generation capacity by a power generation source, which are automatically aggregates the EPCOs submission values based on the concepts above.

[26] The same concept is applied to geothermal, biomass, and waste power generation sources.

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

Power Generation Sources		2021	2022	2026	2031
Thermal*1		15,529	15,549	15,353	15,408
	Coal	4,836	5,079	5,234	5,233
	LNG	7,804	7,814	8,244	8,301
	Oil and others[27]	2,888	2,657	1,875	1,874
Nuclear*2		3,308	3,308	3,308	3,308
Hydro and Renewables		12,552	13,109	14,907	16,533
	Conventional Hydro	2,175	2,184	2,191	2,199
	Pumped Storage	2,747	2,747	2,747	2,747
	Wind*3	469	531	1,026	1,575
	Solar*3	6,541	6,940	8,165	9,238
	Geothermal*1	54	49	54	55
	Biomass*1	480	575	656	650
	Waste*1	85	82	68	69
Miscellaneous		79	97	98	98
Total		31,469	32,063	33,666	35,348

Note) The totals are not necessarily equal due to independent rounding.

*1 The Organization automatically aggregates the value of the generation company's genererating facility; however, not all development plans will necessarily be realized; inefficient facilities will be retired resulting from actions due to political measures in the future. For newly installed facilities, generating facilities such as those proceeding with environmental assessments or publishing commercial operations, are included in the aggregation.

*2 Facilities with actual operation experience are included, along with 33 units for which the date for resuming operation is uncertain; operation-terminated facilities are excluded.

*3 The GT&D company aggregates the projected value of integrating the generation facility according to the application of preliminary consultation and the available connecting capacity of its transmission lines or the actual growth trend of integration.

[27] The category 'Oil and others' includes the total installed capacities from oil, LPG, and other gas and bituminous mixture fired capacities.

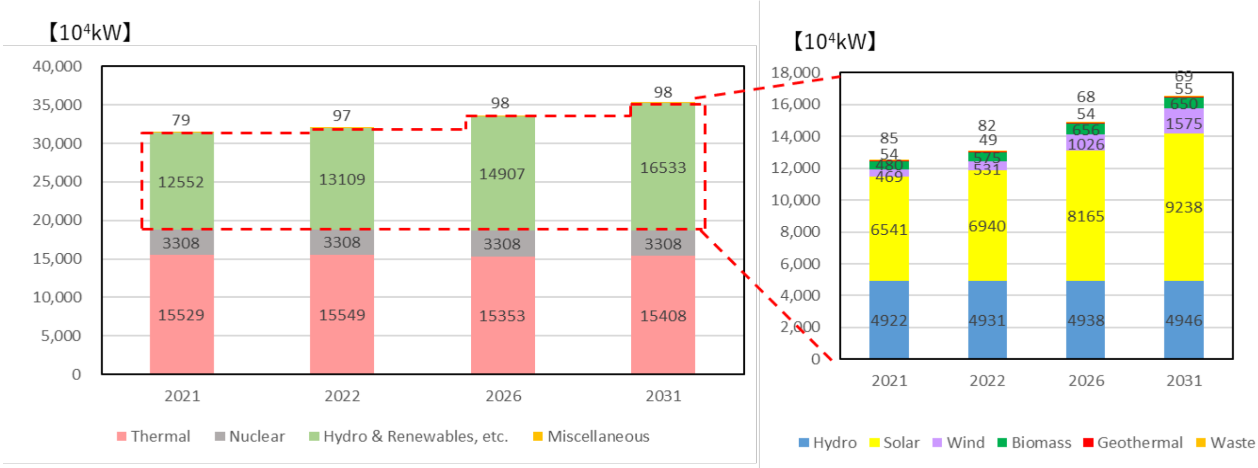


Figure 3-1 Transition of Installed Power Generation Capacities by Power Generation Sources (Nationwide)

* The sum of each power generation source's installed power generation capacity is the aggregation of the values submitted by EPCOs.

2. Installed Power Generation Capacity for Each Regional Service Area

Figure 3-2 shows the installed power generation capacity for each regional service area at the end of FY 2021.

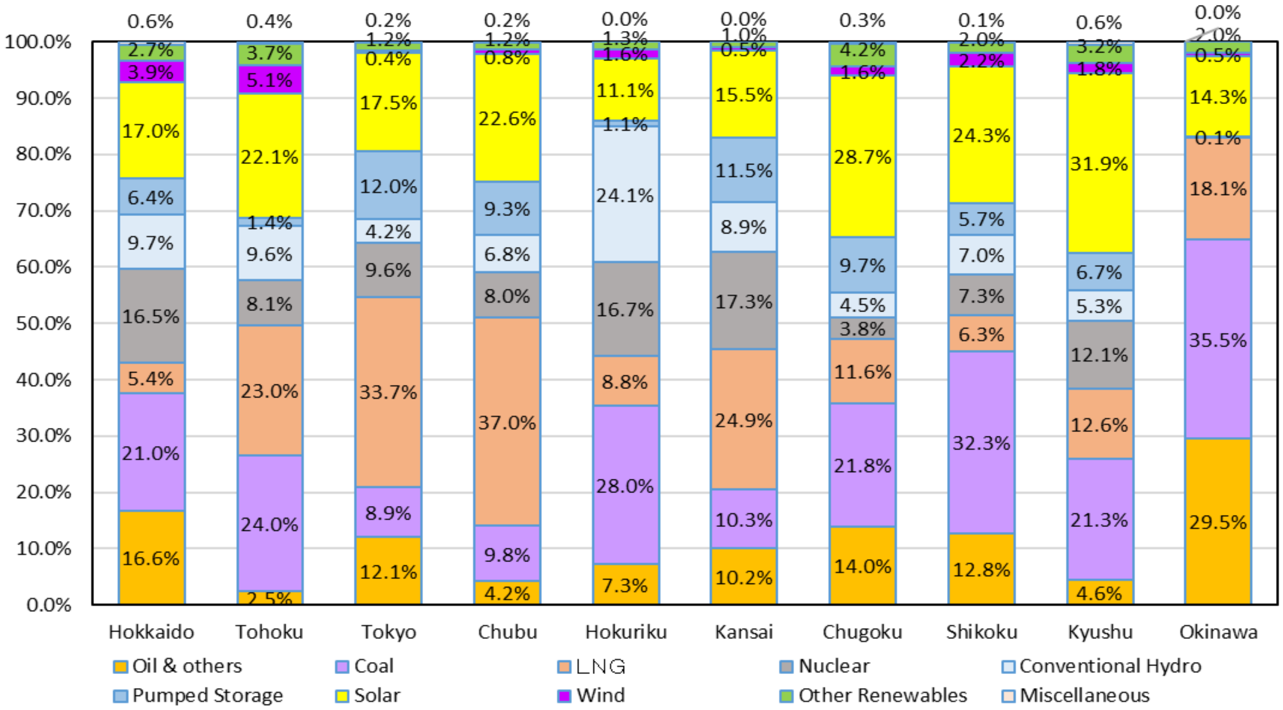


Figure 3-2 Composition of Installed Power Generation Capacity (kW) for Each Regional Service Area

* The ratio of the installed power generation capacity by each power generation source is calculated from the automatic aggregation of the values.

3. Transition of Solar and Wind Generation Capacities

Figure 3-3 shows the projection of integrated solar and wind generation capacities for each regional service area (at the end of the indicated fiscal year).[28]

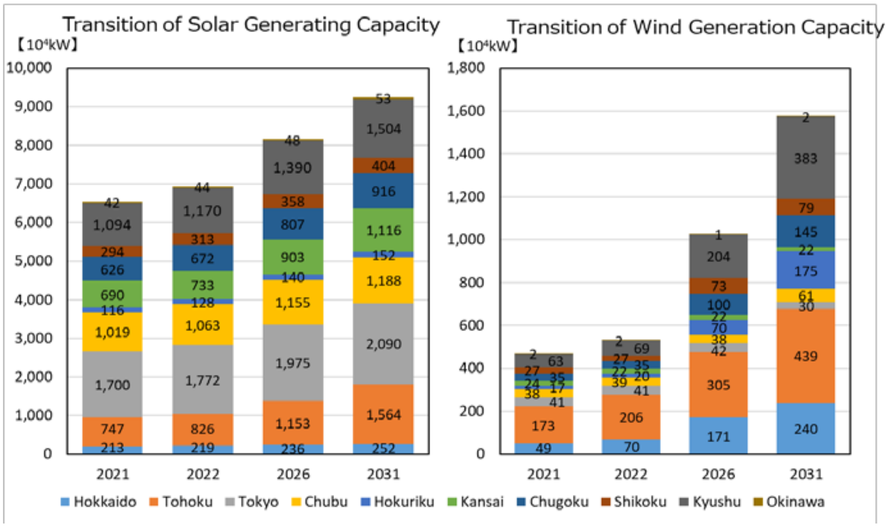


Figure 3-3 Transition of Solar and Wind Generating Capacity for Each Regional Service Area

[28] The GT&D company of each regional area aggregates the projected value of generation facility integration according to the application of preliminary consultation for generator interconnection, and the available connecting capacity of its transmission lines or the actual growth trend of integration.

4. Development Plans by the Power Generation Source

Table 3-2 shows the generation companies' development plans[29] up to FY 2031, according to each company's new developments, uprated or derated installed facilities, and planned decommissioning of facilities in the projected period.

Table 3-2 Generation Development Plans up to FY 2031 by Stages (Nationwide, 10^4 kW)

Power Generation Sources		New Installation		Uprating/Derating		Decommissioning	
		Capacity	Sites	Capacity	Sites	Capacity	Sites
Hydro		**44.6**	**68**	**6.0**	**43**	**△19.3**	**35**
	Conventional	44.6	68	6.0	43	△19.3	35
	Pumped Storage	—	—	—	—	—	—
Thermal		**1,199.5**	**28**	**0.7**	**1**	**△1,172.9**	**37**
	Coal	482.0	7	—	—	△28.8	2
	LNG	714.9	15	0.7	1	△216.8	6
	Oil	2.6	6	—	—	△927.3	29
	LPG	—	—	—	—	—	—
	Bituminous	—	—	—	—	—	—
	Other Gas	—	—	—	—	—	—
Nuclear		**1,018.0**	**7**	**15.2**	**1**	**0.0**	**0**
Renewables		**1,045.7**	**376**	**△0.6**	**2**	**△81.3**	**64**
	Wind	363.6	89	—	—	△65.0	52
	Solar	510.2	241	—	—	△0.2	1
	Geothermal	7.5	5	—	—	△5.0	1
	Biomass	158.3	37	—	—	△4.8	3
	Waste	6.2	4	△0.6	2	△6.3	7
Total		**3,307.8**	**479**	**21.3**	**47**	**△1,273.4**	**136**

Note) The totals are not necessarily equal due to independent rounding to two decimal places.

[29] These are aggregated including facilities for which the commercial operation date is "uncertain."

[Reference] Net Electric Energy Generation (at the Sending End)

The net electric energy generation (at the sending end) for the projected period is an estimation[30] of values calculated by the power generation source in a given premise for each generation or GT&D company. This is not necessarily the same as the actual net electric energy generation.

Each generation company submits the value of electric energy generation, which is the sum of the energy generation of available generation facilities in the projected period. This is automatically summed in merit order of operational cost. Furthermore, the value is based on future energy sales led by actual sales and future sales contracts, without considering the effect of regulating measures.

This estimation of net electric energy generation may change according to the operating conditions of nuclear power plants, change in generation sources (specified as "miscellaneous" in future trends), and energy output shedding of inefficient coal-fired thermal power generation according to the regulating measures of generation efficiency under the Energy Conservation Act. Thus, the estimation is not necessarily the same as the electric energy generation in the future, and is likely to approximate the target value of the country's energy mix.

The calculation method and the result of net electric energy generation by power generation source are stated below.

(1) Renewables (Table 3-3)

For solar and wind power, the GT&D company calculates their energy generation based on the aggregation of the projected value of generation facility integration, according to the preliminary consultation and the available connecting capacity of its transmission lines or the actual growth trend of the integration. For geothermal, biomass and waste power generation sources, the generation company calculates its energy generation based on the company's development plans.

Table 3-3 Composition of the Transition of Electric Energy Generated by Renewable Generation Sources (Nationwide, at the sending end; 10^8 kWh)

Generation Source		2021	2022	2026	2031
Renewables		1,159	1,268	1,516	1,727
	Wind	83	95	179	274
	Solar	782	829	967	1,082
	Geothermal	25	26	28	29
	Biomass	242	293	317	316
	Waste	27	26	25	25

[30] This estimation includes the electric energy generated from generation facilities owned by generation companies and generation facilities such as FIT generators, which retail companies or GT&D companies procure from sources other than generation companies.

(2) Hydro and Thermal (Table 3-4)

The generation company calculates its energy generation based on the company's development plan. For thermal power generation, the energy generated from coal-fired thermal power, which has a relatively low operation cost, has a large share due to its merit-order ranking (by operation cost) without considering the effect of regulating measures.

Table 3-4 Composition of the Transition of Electric Energy Generated by Hydro and Thermal Generation Sources

(Nationwide, at the sending end; 10^8 kWh)

Generation Source		2021	2022	2026	2031
Hydro		857	829	850	871
	Conventional	774	764	790	801
	Pumped Storage	83	65	60	69
Thermal		6,229	6,226	6,104	5,869
	Coal	2,715	2,974	3,004	2,897
	LNG	3,212	3,026	2,894	2,772
	Oil and others [277]	302	226	206	200

(3) Nuclear (Table 3-5)

The generation company calculates its energy generation based on the plan that the company develops for units resuming operation at the end of February 2022. Units with over 40 years of actual operation require permission from the Nuclear Regulation Authority to resume operation; the energy generation of such units is calculated as zero. In addition, projections concerning the resumption of operation are excluded from the estimation.

Table 3-5 Composition of the Electric Energy Transition Generated by Nuclear Generation Sources

(Nationwide, at the sending end; 10^8 kWh)

Generation Source	2021	2022	2026	2031
Nuclear	675	599	551	552

Table 3-6 sums items (1), (2), and (3) above, with the energy generation categorized as "miscellaneous."

Table 3-6 Composition of the Electric Energy Transition Generated by All Generation Sources

(Nationwide, at the sending end; 10^8 kWh)

	2021	2022	2026	2031
Total	9,038	8,978	9,072	9,065

[Reference] Net Electric Energy Generation for Each Regional Service Area

Figure 3-4 shows each regional service area's net electric energy generation in FY 2021.

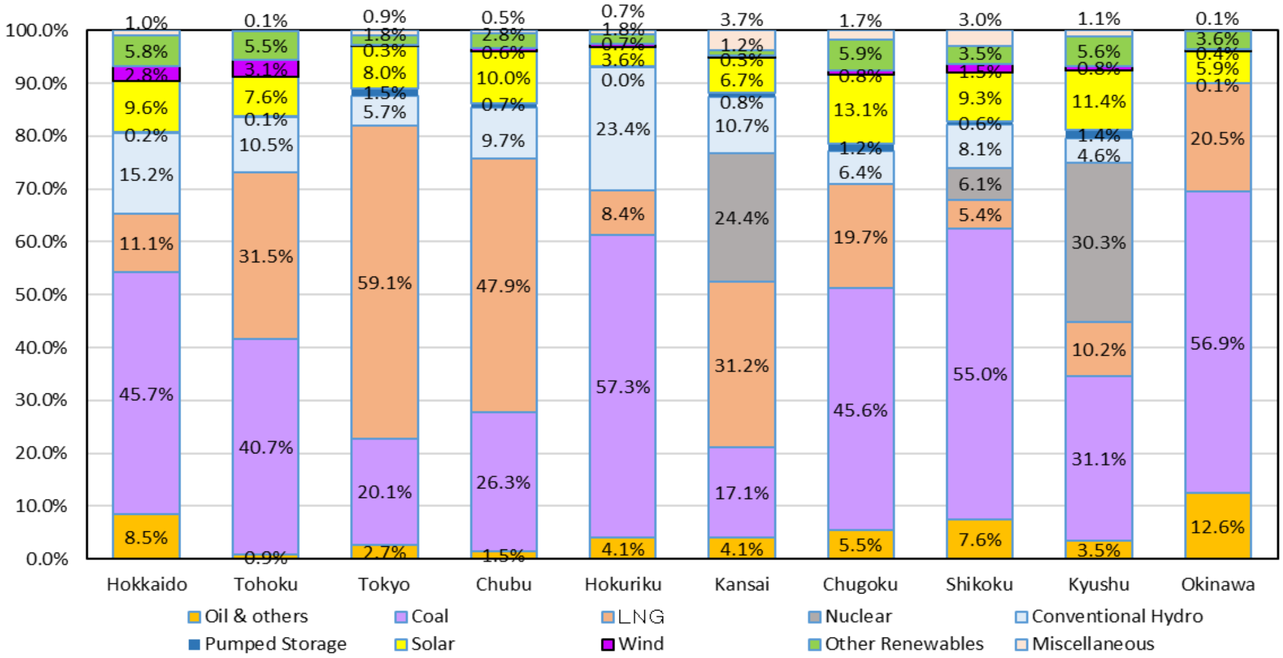


Figure 3-4 Composition of the Net Electric Energy Generation (kWh) for Each Regional Service Area

[Reference] Transition of Capacity Factors by Power Generation Source

Table 3-7 and Figure 3-5 show the capacity factors by the power generation source. Projection of the capacity factors is automatically calculated using the aforementioned power generation sources and the net electric energy generation data provided to the Organization.

As noted, these values are calculated from a given projection; the capacity factors in this chapter differ from those in actual operation.

Table 3-7 Capacity Factors by Power Generation Source (Nationwide)

Power Generation Sources		2021	2022	2026	2031
Hydro		19.9%	19.2%	19.6%	20.0%
	Conventional	40.6%	39.9%	41.1%	41.5%
	Pumped Storage	3.5%	2.7%	2.5%	2.9%
Thermal		45.8%	45.7%	45.4%	43.4%
	Coal	64.1%	66.8%	65.5%	63.0%
	LNG	47.0%	44.2%	40.1%	38.0%
	Oil and others [27]	11.9%	9.7%	12.6%	12.1%
Nuclear		23.3%	20.7%	19.0%	19.0%
Renewables		17.3%	17.7%	17.4%	17.0%
	Wind [31]	20.1%	20.3%	19.9%	19.8%
	Solar [31]	13.6%	13.6%	13.5%	13.3%
	Geothermal	52.3%	59.6%	59.2%	59.9%
	Biomass	57.5%	58.2%	55.1%	55.3%
	Waste	36.6%	36.4%	41.8%	41.3%

* These values are calculated from a given projection; note that the capacity factors in this chapter differ from those in actual operation.

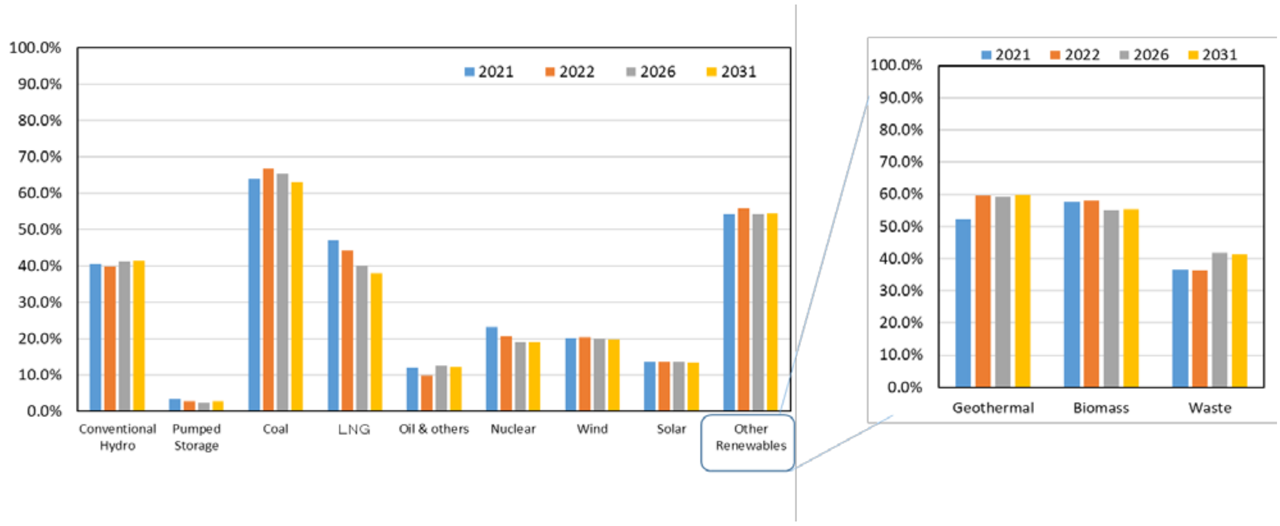


Figure 3-5 Capacity Factors by Power Generation Source (Nationwide)

[31] There is no consideration for low capacity factors of solar and wind power generation due to output shedding.

IV. Development Plans for Transmission and Distribution Facilities

The Organization aggregates the development plans[32] for cross-regional transmission lines and substations (transformers and AC/DC converters) up to FY 2031, as submitted by GT&D and transmission companies. Table 4-1 shows the development plans for cross-regional transmission lines and substations, and Figure 4-1 shows the outlook for electric systems nationwide. Items (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[33]

Increased Length of Transmission Lines [34]*[35]		672 km (635 km)
	Overhead Lines*	616 km (597 km)
	Underground Lines	56 km (39 km)
Uprated Capacities of Transformers		28,578 MVA (29,235 MVA)
Uprated Capacities of AC/DC Converters [36]		1,200 MW (900 MW)
Decreased Length of Transmission Lines (Decommissioning)		△101 km (△61 km)
Derated Capacities of Transformers (Decommissioning)		△4,550 MVA (△4,300 MVA)

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

Interconnection Facility Enhancement Plan between Hokkaido and Honshu
(900 MW→1,200 MW; in-service: March 2028)

AC/DC Converter Stations	・Hokuto Converter Station: 300 MW→600 MW ・Imabetsu Converter Station: 300 MW→600 MW
275 kV DC Lines	・Hokuto Imabetsu DC Interconnection Line: 122 km ・Imabetsu Bulk Line extension: 50 km

32 Development plans for transmission lines and substations must be submitted for voltages higher than 250 kV, or within two classes of the highest voltage available in the regional service areas. (For the Okinawa EPCO, the requirement applies only for 132 kV or more.) The totals are not necessarily equal due to independent rounding.
33 The figures in parentheses are those from the previous year.
34 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.’
35 Increased length does not include the item with * because of an undetermined in-service date.
36 The DC transmission system includes installed capacity for the converter station on one side.

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

500kV Transmission Lines	・(prov.)Cross-regional North Bulk Line: 79 km ・(prov.)Cross-regional South Bulk Line: 64 km ・Soma-Futaba Bulk Line/ Connecting Point Change: 16 km ・(prov.)Shinchi Access Line/ Cross-regional Switching Station lead-in: 1km ・(prov.)Joban Bulk Line/ Cross-regional Switching Station Dπ lead-in: 1 km ・ Fukushima Bulk Line/Mountain Line connecting point change: 1 km
Switching Stations	(prov.)Cross-regional Switching Station: 10 circuits

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

Frequency Converter Stations	・Shin Sakuma FC station: 300 MW ・Higashi Shimizu FC station: 300 MW→900 MW
275 kV Transmission Lines	・Higashi Shimizu Line: 19 km ・Sakuma Higashi Bulk Line/ Shin Sakuma FC Branch Line: 3 km ・Sakuma Nishi Bulk Line/ Shin Sakuma FC Branch Line: 1 km ・Shin Toyone-Toei Line: 1 km ・Sakuma-Toei Line: 11km, 2km ・Sakuma Higashi Bulk Line: 123 km
500 kV Transformers	・Shin Fuji Substation: 750MVA×1 ・Shizuoka Substation: 1,000MVA×1 ・Toei Substation: 800MVA×1 →1,500MVA×2
275 kV Transformers	・Shin Fuji Substation: 200MVA×1→0MVA

Interconnection Facility Enhancement Plan between Chubu and Kansai
(In-service: undetermined)*under review in the master plan [37]

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: 0.5 km
Switching Stations	・Sekigahara Switching Station: 6 circuits ・Kita Oomi Switching Station: 6 circuits

Interconnection Facility Enhancement Plan between Chubu and Hokuriku
(In-service: undetermined)*under review as part of reinforcement in the master plan

BTB Converter Stations	Minami Fukumitsu Converter Station: 300 MW→0 MW (to be decommissioned)

[37] The master plan is the policy of facility formation targeting the long-term future electricity system.

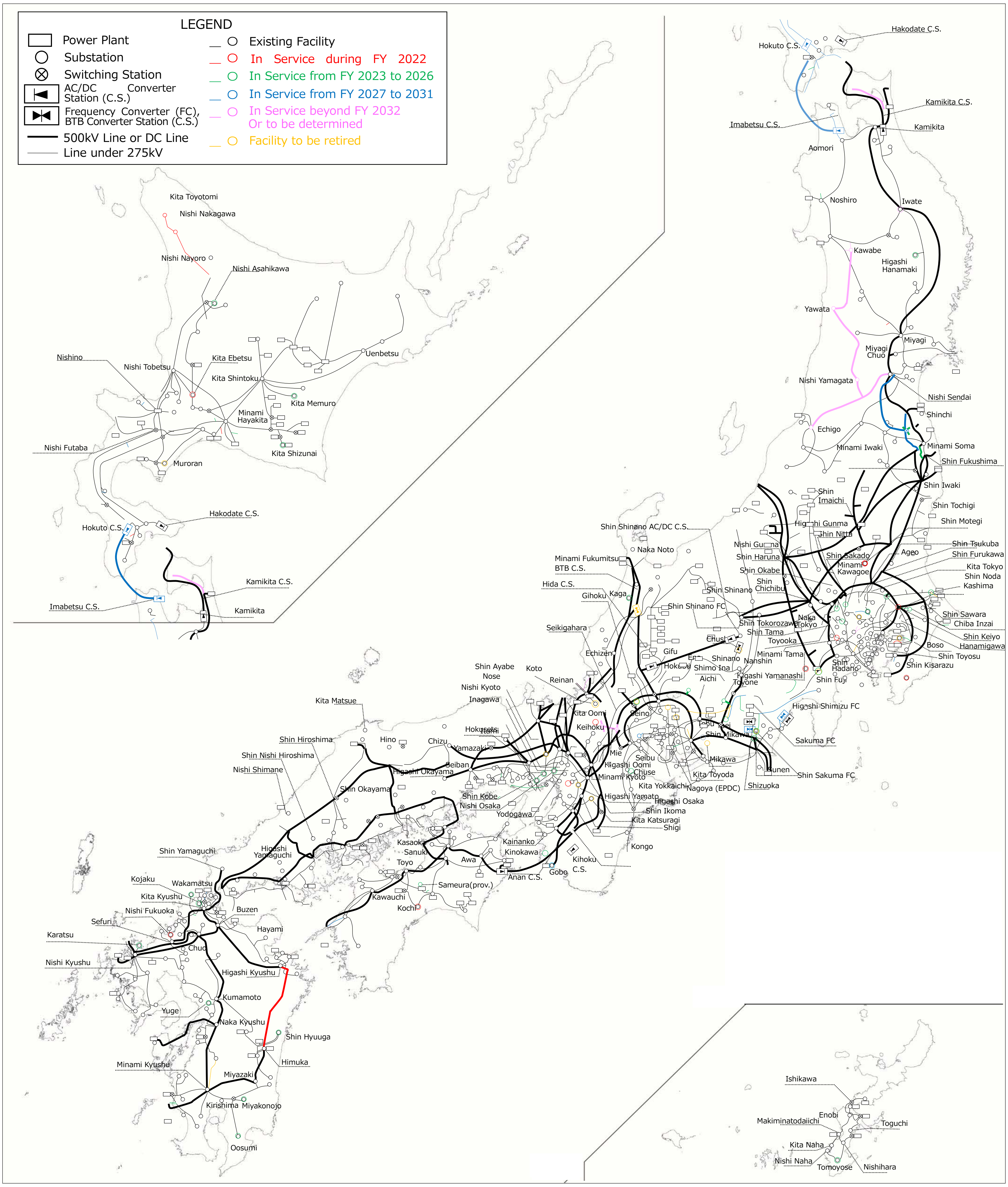


Figure 4-1 Power Grid Configuration in Japan

1. Development Plans for Major Transmission Lines

Table 4-2 Development Plans under Construction

Company	Line38	Voltage	Length39,40	Circuit	Under construction	In service	Purpose41
Hokkaido Electric Power Network, Inc.	Tsuruoka branch Line	187kV	0.1km	1	Sep. 2020	Aug. 2022	Generator connection
Tohoku Electric Power Network Co., Inc.	Kita Horonobe Line	100kV→187kV	69km	2	May 2021	Jul. 2022	Generator connection
	Branch Line B *1	187kV	0.1km	1	May 2021	Aug. 2022	Generator connection
TEPCO Power Grid, Inc.	Plant A Access Line*1	275kV	3km	1	Apr. 2021	Dec. 2022	Generator connection
	Soma-Futaba Bulk Line/connecting point change	500kV	16km	2	Mar. 2022	Nov. 2025	Generator connection, Reliability upgrade*4
	Shinjuku Line replacement	275kV	22.1km→ 21.2km (No.1)*2*3 19.9km→ 21.2km (No.2)*2*3 19.8km→ 21.2km (No.3)*2*3	3	Aug. 2019	Aug. 2028(No.1) Nov. 2032(No.2) Nov. 2025(No.3)	Aging management
	Chiba Inzai Substation lead-in	275kV	10.5km	2	Apr. 2020	Apr. 2024	Demand coverage
	Anegasaki Access Line*1	275kV	0.5km	2	Jun. 2021	May 2022(No.1) Jun. 2022(No.2)	Generator connection
	Johoku Line	275kV	20.9km*2	3	Dec. 2021	Feb. 2030	Economic upgrade
Chubu Electric Power Grid Co., Inc.	Shimo Ina Branch Line	500kV	0.3km	2	Dec. 2021	Oct. 2024	Demand coverage
	Ena Branch Line	500kV	1km	2	Jun. 2020	Oct. 2025	Demand coverage
	Higashi Nagoya -Tobu Line	275kV	8km*3	2	Apr. 2019	Nov. 2025	Aging management, Economic upgrade
Kansai Transmission and Distribution, Inc.	(prov.) Himeji Access Line*1	275kV	0.9km*2	2	Mar. 2021	Jan. 2025	Generator connection
	(prov.) Himeji Access West Branch Line*1	275kV	1.2km*3	2	Sep. 2021	Feb. 2024	Aging management
	Shin Kakogawa Line	275kV	25.3km*3	2	Jul. 2021	Jun. 2025	Generator connection, Aging management

[38] Line with *1 denotes the line renamed not to be identified the fuel of the connecting power plant.
[39] Length with *2 denotes "underground," otherwise "overhead."
[40] Length with *3 denotes that the change in line category or circuit numbers is not included in Table 4-1.
[41] The purpose is stated below: *4 indicates enforcement related to cross-regional interconnection lines.
*5 indicates that the case is under review in the master plan of the cross-regional development.

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

Company	Line	Voltage	Length,	Circuit	Under construction	In service	Purpose
Kyushu Electric Power Transmission & Distribution Co., Inc.	Hyuga Bulk Line	500kV	124km	2	Nov. 2014	Jun. 2022	Reliability upgrade, Economic upgrade
	Shin Kagoshima Line/ Sendai Plant π lead-in*1	220kV	2km→ 4km*3	1→2	Aug. 2020	Dec. 2023	Economic upgrade
	Shin Kokura Line	220kV	15km→ 15km*2*3	3→2	Apr. 2021	Oct. 2029	Aging management
J-POWER Transmission Network Co.,Ltd.	Ooma Bulk Line	500kV	61.2km	2	May 2006	TBD	Generator connection
Northern Hokkaido Wind Energy Transmission Company (NHWETC)	NHWETC Toyotomi-Nakagawa Bulk Line	187kV	51km	2	Sep. 2018	Sep. 2022	Generator connection
Fukushima Souden	Abukumananbu Line	154kV	22km*2	1	Jul. 2020	May 2024	Generator connection

Table 4-3 Development Plans in Planning Stages

Company	Line	Voltage	Length,	Circuit	Under construction	In service	Purpose
Hokkaido Electric Power Network, Inc.	Plant C Access Line*1	275kV	0.1km	1	May 2024	Nov. 2025	Generator connection
	Plant D Access Line*1	275kV	0.1km	1	Jun. 2023	Feb. 2025	Generator connection
	Branch Line E *1	187kV	2.4km	2	May 2024	Aug. 2028	Demand coverage
	Branch Line F *1	275kV	7.9km	2	May 2024	Aug. 2028	Demand coverage
	Branch Line G *1	187kV	5.8km	2	May 2024	Aug. 2028	Demand coverage
	Hokuto-Imabetsu DC Interconnection Line	DC-250kV	98km*3 24km*2,3	1→2	Mar. 2024	Mar. 2028	Reliability upgrade
Tohoku Electric Power Network Co., Inc.	Plant B Access Line*1	275kV	0.2km	1	Apr. 2023	May 2024	Generator connection
	Northern Akita Prefecture HS Line	275kV	0.3km	2	May 2023	Dec. 2024	Generator connection
	(prov.)Cross-regional North Bulk Line	500kV	79km	2	Aug. 2022	Nov. 2027	Generator connection, Reliability upgrade*4
	(prov.)Cross-regional South Bulk Line	500kV	64km	2	Aug. 2024	Nov. 2027	Generator connection, Reliability upgrade*4
	(prov.)Shinchi Access Line/ Cross-regional Switching Station lead-in*1	500kV	1km	2	Feb. 2024	Jun. 2026	Generator connection, Reliability upgrade*4
	(prov.)Joban Bulk Line/ Cross-regional Switching Station Dπ lead-in	500kV	1km	2	May 2024	Jul. 2026	Generator connection, Reliability upgrade*4
	(prov.)Cross-regional Switching Station	500kV	-	10	Sep. 2022	Nov. 2027 (Jun. 2026)	Generator connection, Reliability Upgrade*4
	Imabetsu Bulk Line extension	275kV	50km*3	2	Apr. 2023	FY 2027	Generator connection, Reliability upgrade, Aging Management*4
	Akita Bulk Line/ Kawabe Substation DT lead-in	275kV	5km	2	Beyond FY 2023	Beyond FY 2029	Generator connection

Company	Line [33]	Voltage	Length [34,35]	Circuit	Under construction	In service	Purpose [36]
Tohoku Electric Power Network Co., Inc.	Akimori Bulk Line/ Kawabe Substation DT lead-in	275kV	0.3km	2	Beyond FY 2025	Beyond FY 2029	Generator connection
	Asahi Bulk Line uprating	275kV→500kV	139km→138km	2	Beyond FY 2027	Beyond FY 2030	Generator connection
	Minami Yamagata Bulk Line uprating	275kV→500kV	23km→23km	2	Beyond FY 2030	Beyond FY 2030	Generator connection
	Dewa Bulk Line	500kV	96km	2	Apr. 2022	Beyond FY 2031	Generator connection
	Yamagata Bulk Line uprating/ extension	275kV→500kV	53km→103km	2	Beyond FY 2026	Beyond FY 2031	Generator connection
TEPCO Power Grid, Inc.	Higashi Shinjuku Line replacement	275kV	23.4km→5.0km (No.2)*2*3 23.4km→5.3km (No.3)*2*3	2	FY 2024	Nov. 2032 (No.2) Nov. 2025 (No.3)	Aging management
	MS18GHZ051500 Access Line (prov.)	275kV	0.1km	2	Jun. 2024	Jan. 2025	Generator connection
	Higashi Shimizu Line	275kV	12.4km 6.4km (diversion)	2	Dec. 2022	Jan. 2027	Reliability upgrade*4
	Nishi Gunma Bulk Line /Higashi Yamanashi Substation T lead-in	500kV	0.1km(No.2)*3 0.1km(No.2)*3	2→3	May 2022	Nov. 2022	Demand coverage
	Goi Access Line*1	275kV	11.1km	2	Apr. 2022	Oct. 2023	Generator connection
	Shin Sodegaura Line	500kV	0.1km	2	May 2026	Mar. 2027 (No.1) Feb. 2028 (No.2)	Generator connection, Reliability upgrade*4
	Fukushima Bulk Line/Mountain Line connecting point change	500kV	1.1km	2	May 2024	Jan. 2025 (No.1) Apr. 2025 (No.2)	Generator connection, Reliability upgrade*4
	Kashima Keihin Line /connecting point change	275kV	0.4km*3	2	Jul. 2023	Apr. 2025 (No.1) Nov. 2024 (No.2)	Economic upgrade
Chubu Electric Power Grid Co., Inc.	Kita Yokkaichi Branch Line	275kV	3km*2 0.2km	2	Dec. 2024	Nov. 2028	Demand coverage, Economic upgrade
	Sekigahara-Kita Oomi Line	500kV	2km	2	TBD	TBD	Generator connection*4, *5
	Sekigahara Switching Station	500kV	—	6	TBD	TBD	Generator connection*4, *5
	Sangi Bulk Line/ Sekigahara Switching Station π lead-in	500kV	1km	2	TBD	TBD	Generator connection*4, *5
Kansai Transmission and Distribution, Inc.	Kita Oomi Switching Station	500kV	—	6	TBD	TBD	Generator connection*4, *5
	Kita Oomi Line/ Kita Oomi Switching Station πlead-in	500kV	0.5km	2	TBD	TBD	Generator connection*4, *5
	Tsuruga Line/ North side improvement	275kV	9.8km→ 9.3km*3	2	TBD	TBD	Aging management
Shikoku Electrc Power Transmission and Distribution, Inc.	Ikata North Bulk Line	187kV	19km*3	2	Feb. 2024	Sep. 2028	Aging management
Kyushu Electric Power Transmission and Distribution, Inc.	Hibiki Access Line*1	220kV	4km	2	Mar. 2023	Jul. 2025	Generator connection

Company	Line [33]	Voltage	Length [34,35]	Circuit	Under construction	In service	Purpose [36]
J-POWER Transmission Network Co.,Ltd.	Sakuma Higashi Bulk Line/FC Branch Line	275kV	3km	2	FY 2023	FY 2026	Reliability upgrade*4
	Sakuma-Toei Line/ FC Branch Line	275kV	1km	2	FY 2023	FY 2026	Reliability upgrade*4
	Shin Toyone-Toei Line	275kV	1km	1	FY 2023	FY 2026	Reliability upgrade*4
	Sakuma-Toei Line	275kV	11km→ 11km*3	2	FY 2023	FY 2027	Reliability upgrade*4
	Sakuma Higashi Bulk Line	275kV	123.7km→ 123km*3	2	May 2022	FY 2027	Reliability upgrade*4
	Nabari Bulk Line/Reihoku-Kunimisan Branch Line	187kV	0.1km	1	FY 2025	FY 2026	Generator connection

Table 4-4 Decommissioning Plans

Company	Line	Voltage	Length	Circuit	Retirement	Purpose [36]
TEPCO Power Grid, Inc.	Kashima Thermal Power Line No.1, No.2	275kV	△5.0km	2	May 2025	Economic upgrade
Kyushu Electric Power Transmission and Distribution, Inc.	Kagoshima Bulk Line	220kV	△35km	2	Jun. 2022	Aging management
J-POWER Transmission Network Co.,Ltd.	Shin Toyone-Toei Line	275kV	△3km	1	FY 2026	Reliability upgrade*4
	Sakuma Nishi Bulk Line	275kV	△58km	2	FY 2026	Economic upgrade

2. Development Plans for Major Substations

Table 4-5 Development Plans under Construction

Company	Substation [33,42]	Voltage	Capacity	Unit	Under construction	In service	Purpose [36]
Hokkaido Electric Power Network, Inc.	Nishi Nakagawa*6	187/100kV	100MVA×2	2	Apr. 2020	Jul. 2022	Generator connection
	Kita Ebetsu	187/66kV	100MVA→ 150MVA	1→1	Aug. 2021	Jul. 2022	Aging management
TEPCO Power Grid, Inc.	Higashi Yamanashi	500/154kV	750MVA	1	Nov. 2019	Dec. 2022	Demand coverage
	Shin Kisarazu	275/154kV	450MVA×2	2	Aug. 2020	May 2022 (8B) Jun. 2022 (5B)	Generator connection
	Minami Tama	275/66kV	200MVA→ 300MVA	1→1	Jun. 2021	Jun. 2022	Demand coverage
	Shin Tochigi	500/154kV	750MVA	1	May 2021	Nov. 2022	Generator connection
	Chiba Inzai*6	275/66kV	300MVA×2	2	Mar. 2022	Apr. 2024	Demand coverage
Chubu Electric Power Grid Co., Inc.	Shimo Ina*6	500/154kV	300MVA×2	2	Jun. 2021	Oct. 2024	Demand coverage
	Higashi Shimizu	—	600MW	—	Dec. 2020	Mar. 2028	Reliability upgrade*4
Hokuriku Electric Power Transmission & Distribution Co.	Kaga	275/154kV	400MVA	1	Sep. 2021	Dec. 2023	Reliability upgrade
Kansai Transmission and Distribution, Inc.	Yodogawa	275/77kV	300MVA×2→ 300MVA	2→1	Jan. 2021	Sep. 2022	Aging management
	Koto	275/77kV	200MVA→ 300MVA	1→1	Feb. 2022	Oct. 2022	Aging management
Shikoku Electric Power Transmission & Distribution Co., Inc.	Kochi	187/66kV	200MVA→ 300MVA	1→1	Sep. 2021	Jul. 2022	Aging management, Demand coverage
Kyushu Electric Power Transmission & Distribution Co., Inc.	Shin Hyuga	220/110/66kV	250/150 /200MVA	1	Jun. 2021	Apr. 2023	Generator connection
	Miyakonojo	220/110kV	150MVA	1	Sep. 2021	Mar. 2024	Generator connection
	Oosumi	110/66kV → 220/110 /66kV	60MVA → 250/100 /200MVA	1→1	Mar. 2022	Feb. 2025	Generator connection
	Nishi Fukuoka	220/66kV	180MVA×2→ 300MVA	2→1	Sep. 2020	Apr. 2022	Aging management
	Kojaku	220/66kV	150MVA→ 200MVA	1→1	Jun. 2021	Jun. 2023	Aging management
The Okinawa Electric Power Co., Inc.	Tomoyose	132/66kV	125MVA×2→ 200MVA×2	2→2	Oct. 2017	Mar. 2025	Aging management
NHWETC	Kita Toyotomi*6	187/66kV	165MVA×3	3	Apr. 2019	Sep. 2022	Generator connection

[42] Substation with *6 denotes a newly installed substation or a converter station, including an uprated electric facility.

Table 4-6 Development Plans in Planning Stages

Company	Substation [33,37]	Voltage	Capacity	Unit	Under construction	In service	Purpose [36]
Hokkaido Electric Power Network, Inc.	Kita Memuro	187/66kV	60MVA→ 150MVA	1→1	May 2023	Nov. 2024	Aging management
	Nishi Asahikawa	187/66kV	60MVA→ 100MVA	1→1	May 2023	Nov. 2024	Aging management
	Kita Shizunai	187/66/11kV	45MVA→ 60MVA	1→1	Dec. 2024	Feb. 2026	Aging management
	Hokuto C.S.	—	300MW	—	Mar. 2023	Mar. 2028	Reliability upgrade*4
	Imabetsu C.S.	—	300MW	—	Aug. 2023	Mar. 2028	Reliability upgrade*4
Tohoku Electric Power Network Co., Inc.	Higashi Hanamaki	275/154kV	300MVA	1	Jan. 2023	Oct. 2025	Demand coverage
	Iwate	500/275kV	1,000MVA	1	Beyond FY 2024	Beyond FY 2028	Generator connection
	Echigo*6	500/275kV	1500MVA×3	3	Beyond FY 2024	Beyond FY 2030	Generator connection
	Yawata*6	500/154kV	750MVA	1	Beyond FY 2026	Beyond FY 2031	Generator connection
	Kawabe*6	500/275kV	1500MVA×3	3	Beyond FY 2024	Beyond FY 2031 (Beyond FY 2029)	Generator connection
	Nishi Yamagata*6	275/154kV →500/154kV	300MVA×2 →450MVA×2	2→2	Beyond FY 2024	Beyond FY 2031 (Beyond FY 2030)	Generator connection
	Higashi Hanamaki	275/154kV	300MVA	1	May 2023	Feb. 2027	Demand coverage
TEPCO Power Grid, Inc.	Shin Fuji	500/154kV	750MVA	1	May 2024	Feb. 2027	Reliability upgrade*4
	Kita Tokyo	275/66kV	300MVA	1	Jul. 2022	Feb. 2024	Economic upgrade
	Shin Keiyo	275/154kV	450MVA	1	Apr. 2022	Mar. 2023	Demand coverage
	Kashima	275/66kV	300MVA	1	Apr. 2023	Jun. 2024	Generator connection
	Shin Noda	275/154kV	220MVA→ 300MVA	1→1	Jan. 2023	Oct. 2023	Aging management
	Toyooka	275/154kV	450MVA	1	Sep. 2024	Jun. 2026	Demand coverage
	Naka Tokyo	275/154kV	200MVA→ 300MVA	2→2	Aug. 2023	Jan. 2025 (1B) Jun. 2025 (2B)	Aging management
Chubu Electric Power Grid Co., Inc.	Nakase	275/77kV	150MVA×1→ 250MVA×1	1→1	Sep. 2024	Apr. 2025	Aging management
	Seino	275/154kV	300MVA×2 →450MVA	2→1	Dec. 2024	Jun. 2025	Aging management
	Ena*6	500/154kV	200MVA×2	2	Jun. 2022	Oct. 2025	Demand coverage
	Sunen	275/77kV	150MVA×2→ 250MVA×1	2→1	Nov. 2025	Oct. 2026	Aging management
	Toei	500/275kV	800MVA×1→ 1,500MVA×2	1→2	Apr. 2022	Oct. 2024 (N 2B) Mar. 2027 (1B)	Reliability upgrade*4
	Shizuoka	500/275kV	1,000MVA	1	Dec. 2024	Mar. 2027	Reliability upgrade*4
	Kita Yokkaichi*6	275/154kV	450MVA×3	3	Dec. 2025	Mar. 2027	Demand coverage, Economic upgrade
	Shin Mikawa	500/275kV	1,500MVA	1	Jul. 2027	Aug. 2030	Generator connection
Kansai Transmission and Distribution, Inc.	Gobo	500/154kV	750MVA×2	2	Aug. 2024	Nov. 2027	Generator connection
	Kainanko	275/77kV	300MVA×1、200MVA×2→ 300MVA×2	3→2	Dec. 2022	Jun. 2024	Aging management
	Nishi Osaka	275/77kV	300MVA	1	May 2022	Jun. 2023	Demand coverage
	Shin Kobe	275/77kV	300MVA×1、200MVA×1→ 200MVA×1	2→1	Feb. 2023	Feb. 2024	Aging management

Company	Substation [33,37]	Voltage	Capacity	Unit	Under construction	In service	Purpose [36]
	Itami	275/154kV	300MVA	1	Feb. 2023	Jun. 2024	Aging management
Kyushu Electric Power Transmission & Distribution Co., Inc.	Wakamatsu	220/66kV	250MVA	1	Nov. 2022	Oct. 2024	Generator connection
	Yuge	220/110/66kV	300/100/250MVA	1	Mar. 2024	Jun. 2025	Demand coverage
	Karatsu	220/66kV	150MVA→ 250 MVA	1→1	Jul. 2022	Nov. 2023	Aging management
J-POWER Transmission Network Co.,Ltd.	Shin Satkuma FC*6	—	300MW	—	FY 2024	FY 2027	Reliability upgrade*4
	Minami Kawagoe	275/154kV	264MVA×3, 300MVA→ 300MVA×2, 450MVA×1	4→3	FY 2023	FY 2023 (6B) FY 2024 (2B) FY 2025 (1B)	Aging management
	Sameura (prov.)*6	187/13kV	25MVA	1	FY 2024	FY 2025	Demand coverage
Fukushima souden	Abukumaminami*6	154/66/33kV	170MVA	1	Oct. 2022	Jun. 2024	Generator connection

Table 4-7 Decommissioning Plans

Company	Substation	Voltage	Capacity	Unit	Retirement	Purpose
Hokkaido Electric Power Network, Inc.	Muroran	187/66kV	100MVA	1	Apr. 2023	Aging management
TEPCO Power Grid, Inc.	Hanamigawa	275/66kV	300MVA	1	Mar. 2027	Demand coverage
	Ageo	275/66kV	300MVA	1	Jun. 2024	Economic upgrade
	Shin Fuji	275/154kV	200MVA	1	Apr. 2025	Economic upgrade*4
Chubu Electric Power Grid Co., Inc.	Kita Toyoda	275/154kV	450MVA	1	Dec. 2023	Aging management
	Mikawa	275/154kV	450MVA	1	Apr. 2025	Aging management
	Chushin	275/154kV	300MVA	1	Oct. 2026	Aging management
	Minami Fukumitsu	—	300MW	—	FY 2026	Aging management*4
Kansai Transmission and Distribution, Inc.	Higashi Osaka	275/154kV	300MVA	1	May 2023	Aging management
	Koto	275/77kV	100MVA×2	2	Oct. 2023	Aging management
	Kita Katsuragi	275/77kV	200MVA×2	2	May 2022 (3B) May 2023 (4B)	Aging management
	Inagawa	500/154kV	750MVA	1	Apr. 2025	Aging management
J-POWER Transmission Network Co.,Ltd.	Nagoya	275/154kV	300MVA×3	3	FY 2024	Economic upgrade

3. Summary of Development Plans for Transmission Lines and Substations

Tables 4-8 to 4-11 summarize the development or extension plans of major transmission lines and substations (transformers and converter stations) up to FY 2031 submitted by GT&D and transmission companies.

Table 4-8 Development Plans for Major Transmission Lines

Category	Voltage	Lines	Length [43]	Extended Length [44]	Total Length	Total Extended Length
Newly Installed or Extended	500kV	Overhead	648 km*	1,295 km*	648 km*	1,296 km*
		Underground	1 km	1 km		
	275kV	Overhead	△164 km	△333 km	△131 km	△235 km
		Underground	33 km	97 km		
	220kV	Overhead	4 km	8 km	4 km	8 km
		Underground	0 km	0 km		
	187kV	Overhead	129 km	257 km	129 km	257 km
		Underground	0 km	0 km		
	154kV	Overhead	0 km	0 km	22 km	22 km
		Underground	22 km	22 km		
	Total	Overhead	616 km	1,227 km	672 km	1,348 km
		Underground	56 km	121 km		
To be Decommissioned	275kV	Overhead	△61 km	△119 km	△61 km	△119 km
		Underground	0 km	0 km		
	220kV	Overhead	△35 km	△70 km	△35 km	△70 km
		Underground	0 km	0 km		
	Total	Overhead	△101 km	△199 km	△101 km	△199 km
		Underground	0 km	0 km		

Table 4-9 Revised Plans for Line Category and the Numbers of Circuits[45]

Voltage	Length Extended	Total Extended Length
500kV	0 km	1 km
275kV	245 km*	511 km*
220kV	19 km	23 km
187kV	19 km	38 km
DC 250kV	122 km	244 km
Total	414 km	835 km

[43] Length denotes the increased length due to newly installed or extended plans and the decreased length due to decommissioning. 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 and the overall total lengths are not necessarily equal due to independent rounding.

[44] The total length denotes the aggregation of length multiplied by the number of circuits. Development plans corresponding to changes in 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."

[45] 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 [46]	Voltage [47]	Increased Numbers	Increased Capacity
Newly Installed or Extended	500kV	22 [11]	21,100MVA [10,750MVA]
	275kV	8 [3]	4,988MVA [1,350MVA]
	220kV	4 [0]	1,290MVA [0MVA]
	187kV	6 [6]	1,015MVA [720MVA]
	154kV	1 [1]	170MVA [170MVA]
	132kV	0 [0]	75MVA [0MVA]
	110kV	△1 [0]	△60 MVA [0 MVA]
	Total	40 [21]	28,578MVA [12,990MVA]
To be Decommissioned	500kV	△1	△750 MVA
	275kV	△14	△3,700 MVA
	187kV	△1	△100 MVA
	Total	△16	△4,550 MVA

The figures in [ ] indicate the increase in the number of transformers resulting from new substation installations.

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

Category	Company and Number of Sites		Capacity[48]
Newly Installed or Extended	Hokkaido Electric Power Network, Inc.	2	300 MW×2
	Chubu Electric Power Grid Co.,Inc.	1	600 MW
	J-POWER Transmission Network Co., Ltd.	1	300 MW
To be Decommissioned	Chubu Electric Power Grid Co.,Inc.	1	△300 MW

4. Aging Management of Existing Transmission and Distribution Facility

Existing transmission and distribution facilities installed after the economic expansion (from the 1960s to the 1970s) will reach their replacement time. Facilities to be replaced are increasing trend, and significant facilities will remain unreplaced in place of the recent replacement work. Proper decisions for the replacement schedule are evitable to secure a stable electricity supply in the future. Figures 4-2–4-5 show the actual installation years of existing transmission and distribution facilities.

46 Decommission plans with transformer installations are included in "Newly Installed" or "Extended," and negative values are included in the increased numbers or the increased capacity.
47 Voltage class by upstream voltage.
48 For DC transmission, the capacities of both converter stations are included.

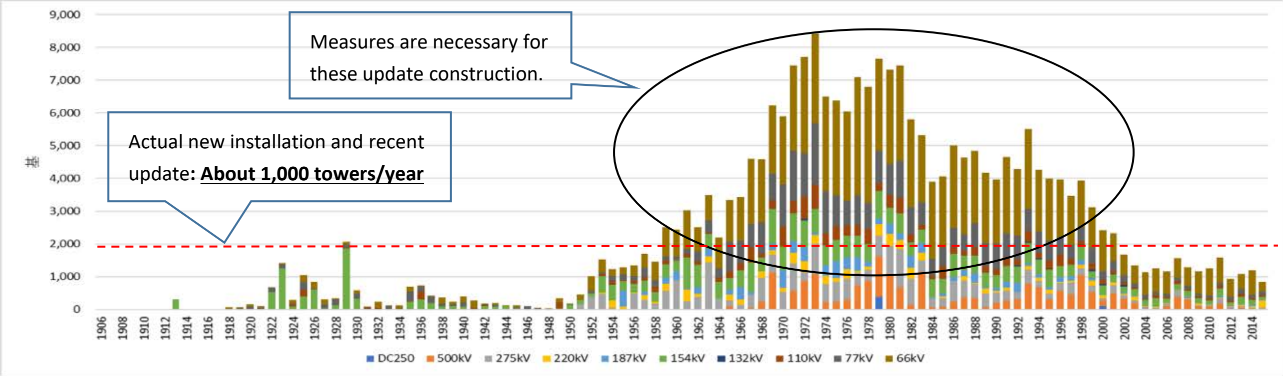


Figure 4-2 Actual Installation Year of Existing Transmission Towers (66kV-500kV)

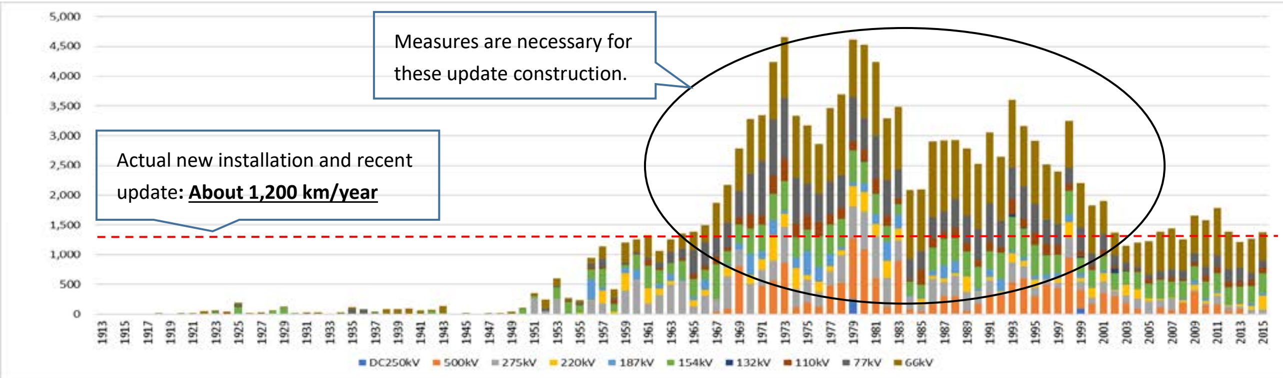


Figure 4-3 Actual Installation Year of Existing Overhead Lines (66kV-500kV)

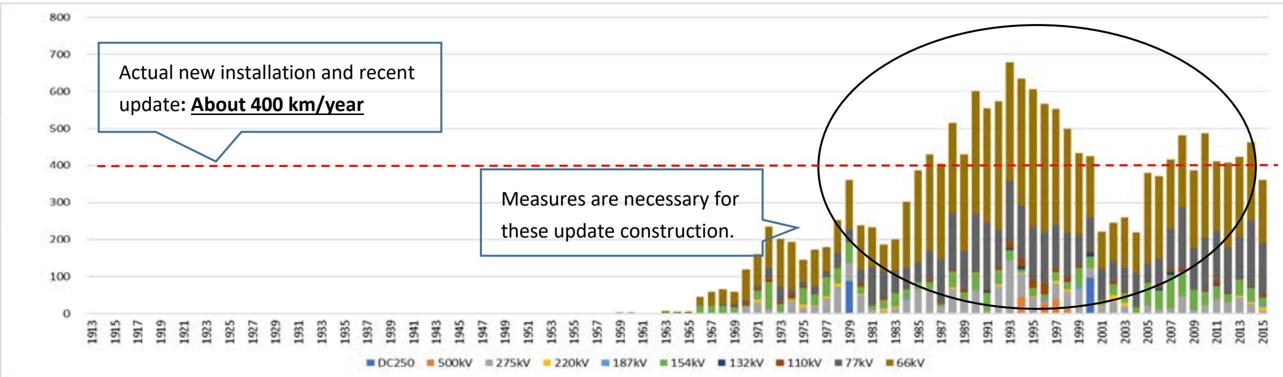


Figure 4-4 Actual Installation Year of Existing Underground Cables (66kV-500kV)

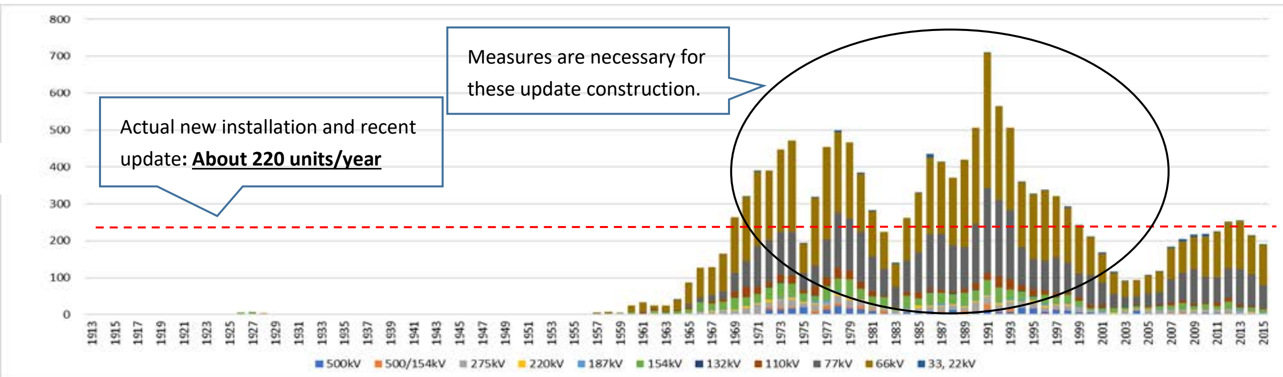


Figure 4-5 Actual Installation Year of Existing Transformers (66kV-500kV; one those of 22kV is partly included)

Furthermore, in recent years the number of working linesmen tends to decrease, and a workforce with skills and ability is in short supply. Figure 4-6 shows the transition in numbers of tower-climbing linesmen working on the transmission construction.[49]

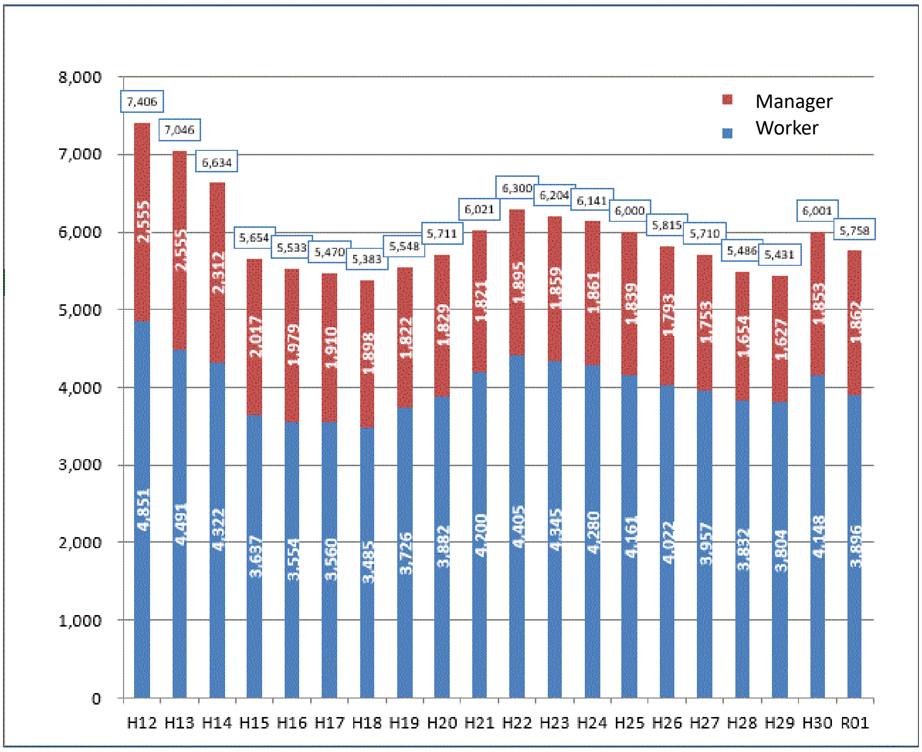


Figure 4-6 Transition of the Number of Tower-climbing Linesmen

49 Source: Transmission Line Construction Engineering Society of Japan. http://www.sou-ken.or.jp/01souken/souken_toukei.php (only in Japanese)

V. Cross-regional Operation

Retail companies procure the supply capacity for their customers in their regional service areas. Four figures illustrate the scheduled procurement from external service areas at 15:00 during August 2022. Figures 5-1 and 5-2 show the supply capacity and the ratio of the supply capacity, respectively, at 15:00 during August. Figures 5-3 and 5-4 show the energy supply and the ratio of the energy supply, respectively, in FY 2022.

Higher ratios for procurement from external regional service areas are observed in the Tokyo, Kansai, and Chugoku EPCO areas; in contrast, higher transmission to external regional service areas are observed in the Tohoku, Chubu, Shikoku, and Kyushu EPCO areas.

The analysis result shows the same tendency as in previous years because there were no changes in major bilateral contracts of transmission line use.

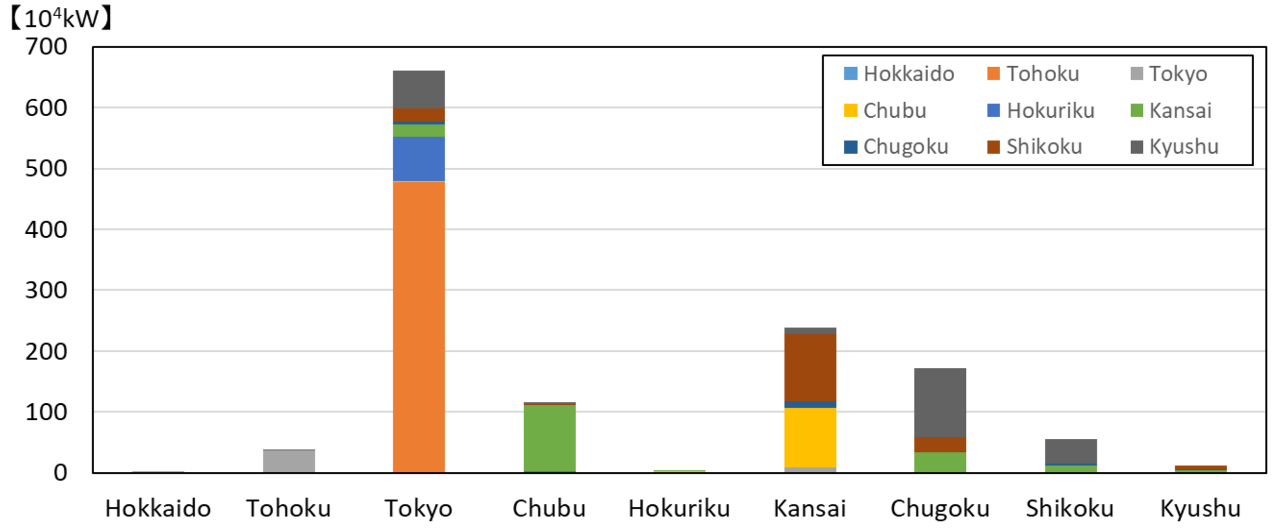


Figure 5-1 Scheduled Procurement of Supply Capacity from External Regional Service Areas

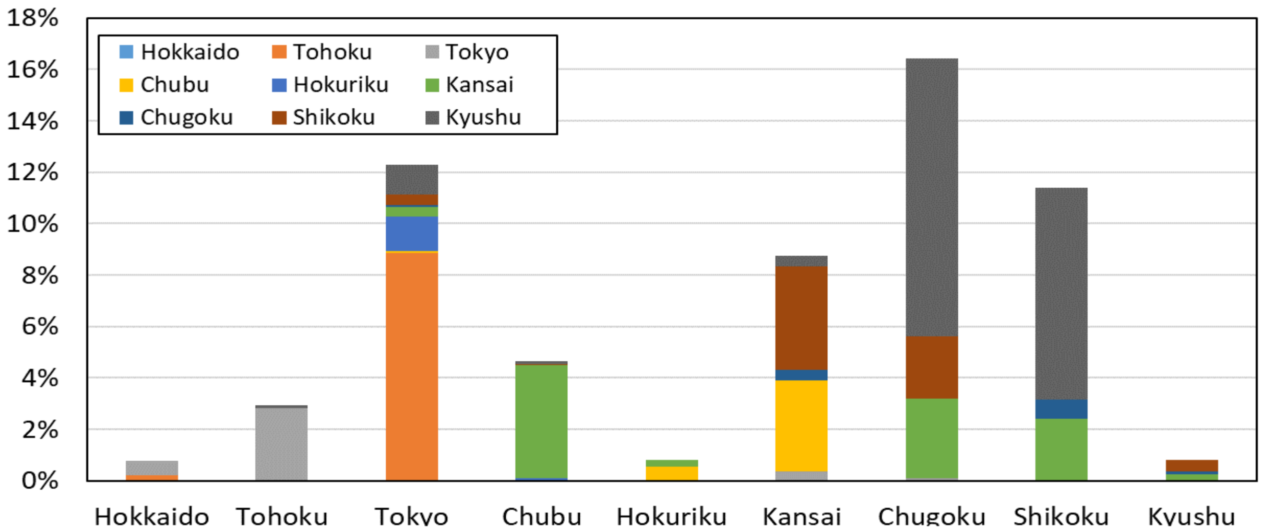


Figure 5-2 Ratio of Scheduled Procurement of Supply Capacity from External Regional Service Areas

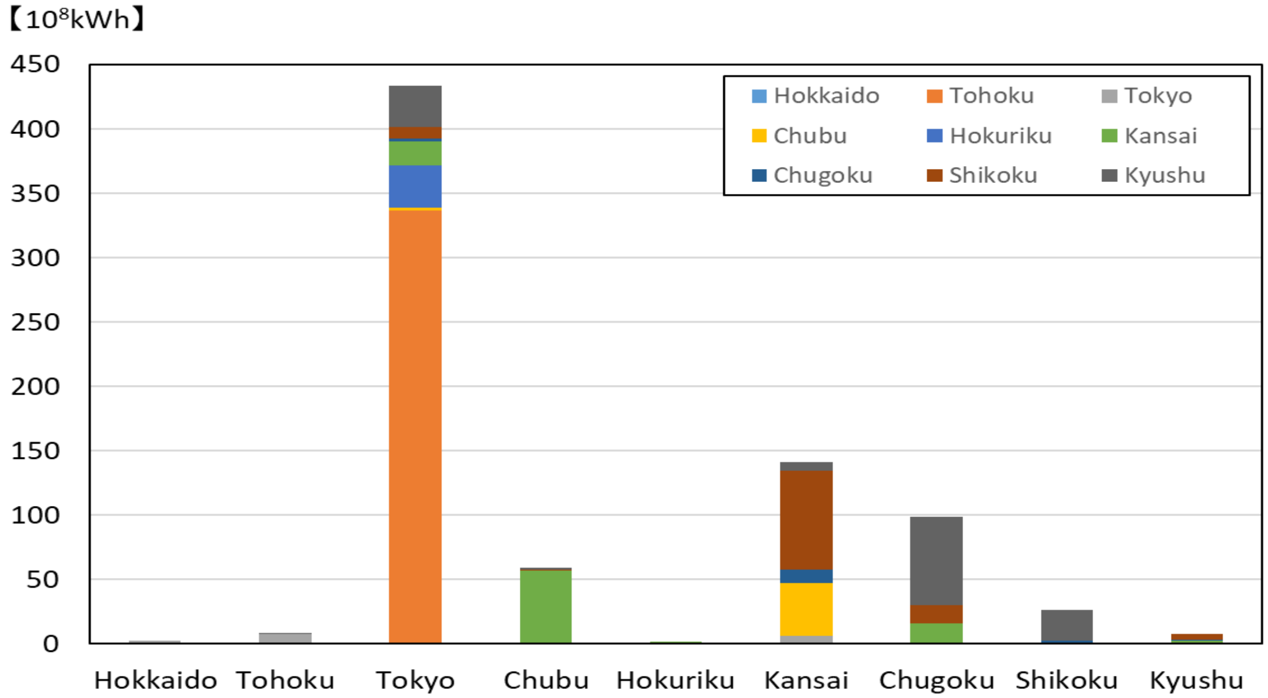


Figure 5-3 Scheduled Procurement of Energy Supply from External Regional Service Areas

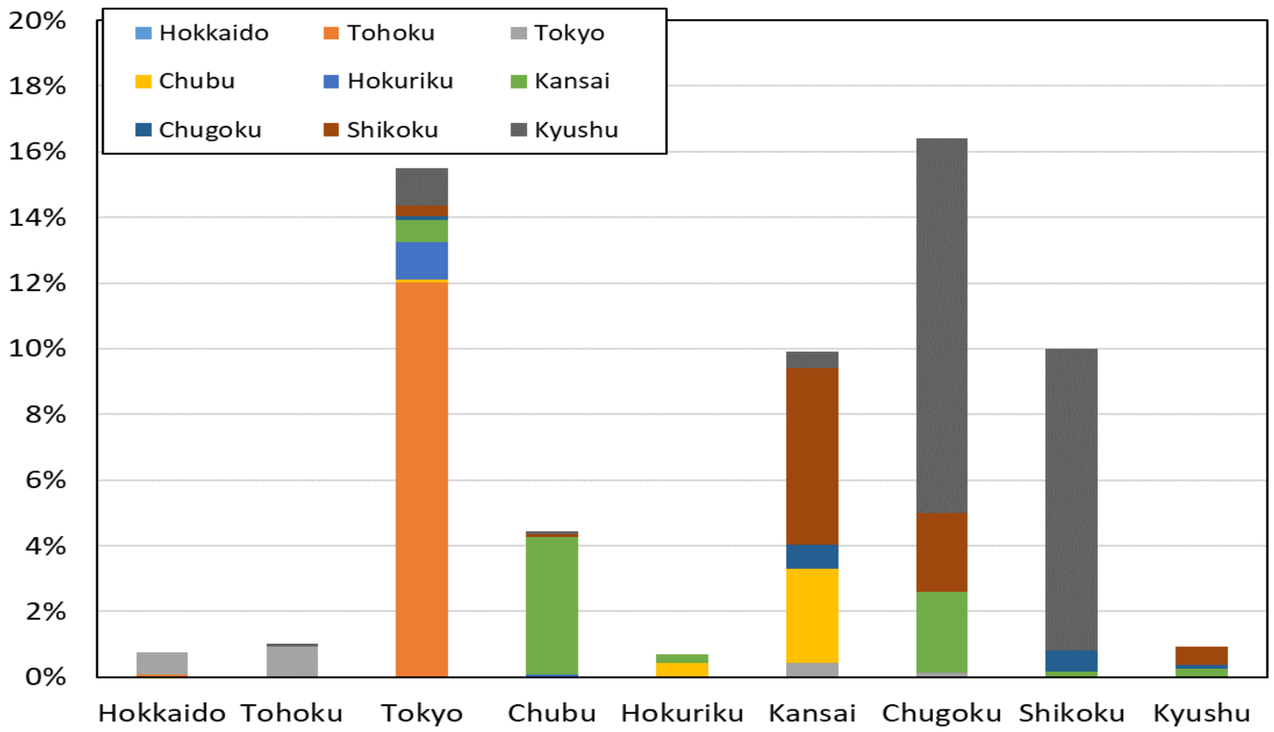


Figure 5-4 Ratio of Scheduled Procurement of Energy Supply from External Regional Service Areas

VI. Analysis of Characteristics of EPCOs

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

In total, 712 retail companies submitted their electricity supply plans, which are classified by the corresponding companies' business scale of the retail demand forecast. Figures 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, small and medium-sized retail companies (business scale of under 1 GW) plan to expand their businesses.

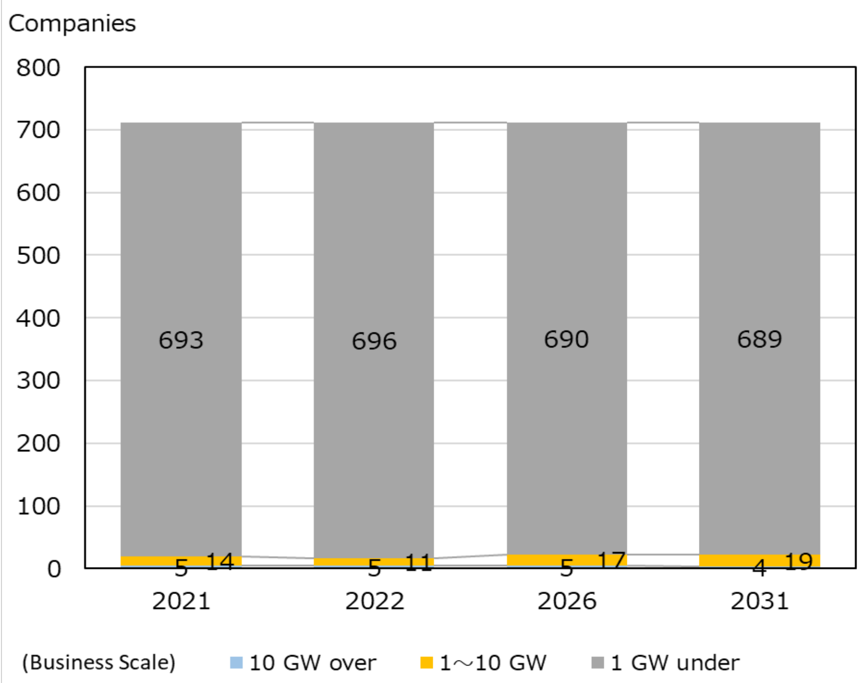


Figure 6-1 Distribution of the Retail Demand by Retail Companies by Business Scale

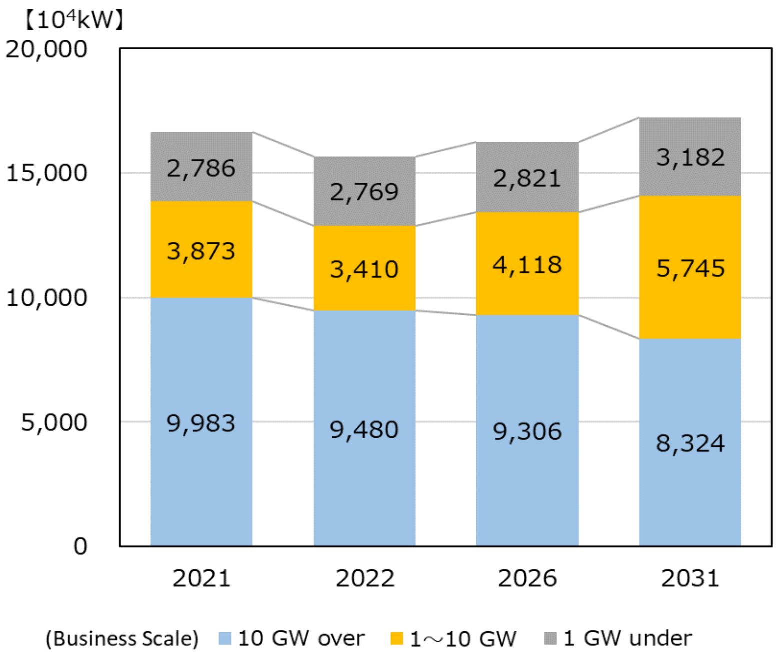


Figure 6-2 Distribution by Accumulated Retail Demand by Retail Companies

Again, retail companies are classified by the corresponding companies' business scale of the retail energy sales forecast. Figures 6-3 and 6-4 show the distributions of the business scale of retail company energy sales and their accumulated energy sales forecast, respectively. Similarly, small and medium-sized retail companies (business scale of under 1 GW) plan to expand their businesses.

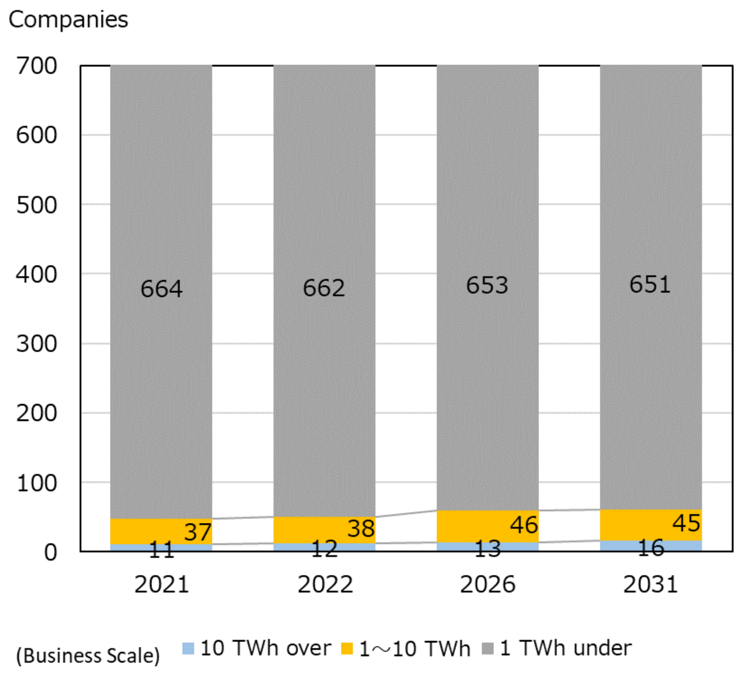


Figure 6-3 Distribution of Retail Company Energy Sales by Business Scale

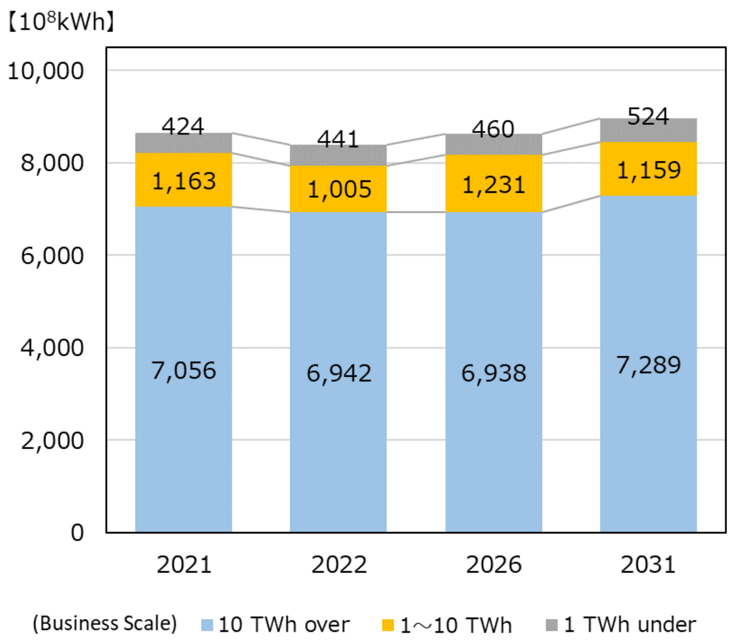


Figure 6-4 Distribution by Retail Company of Accumulated Energy Sales

2. Retail Company Business Areas

Figure 6-5 shows the ratio of retail companies by the number of areas where they plan to conduct business. Figure 6-6 shows the number of retail companies by their business planning areas in FY 2022. The figures exclude 103 retail companies that had not yet developed their business plans. Half of the retail companies plan their business in a single area.

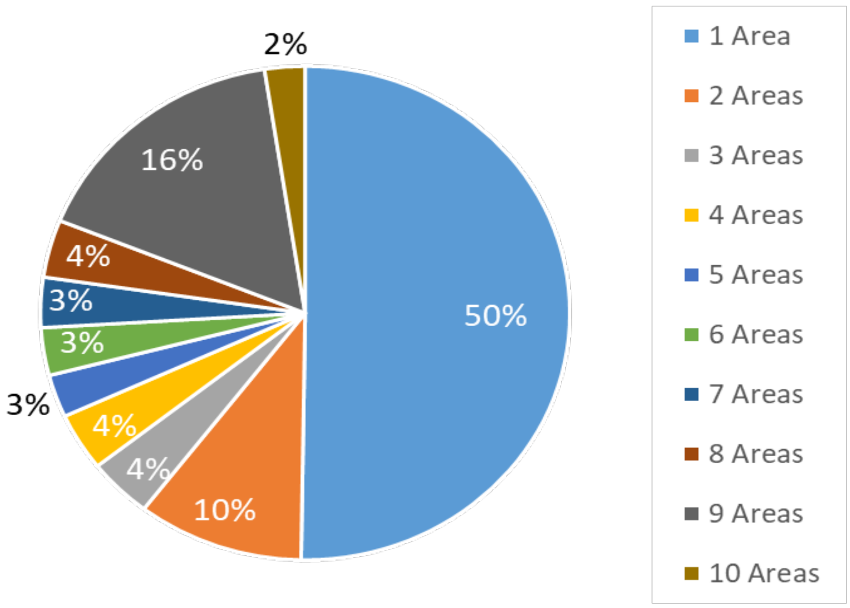


Figure 6-5 Ratio of Retail Companies by the Number of Planned Business Areas in FY 2022

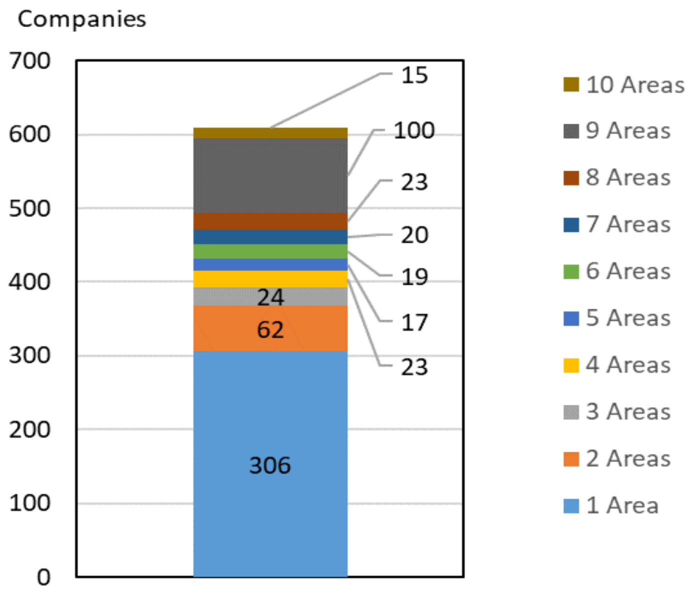
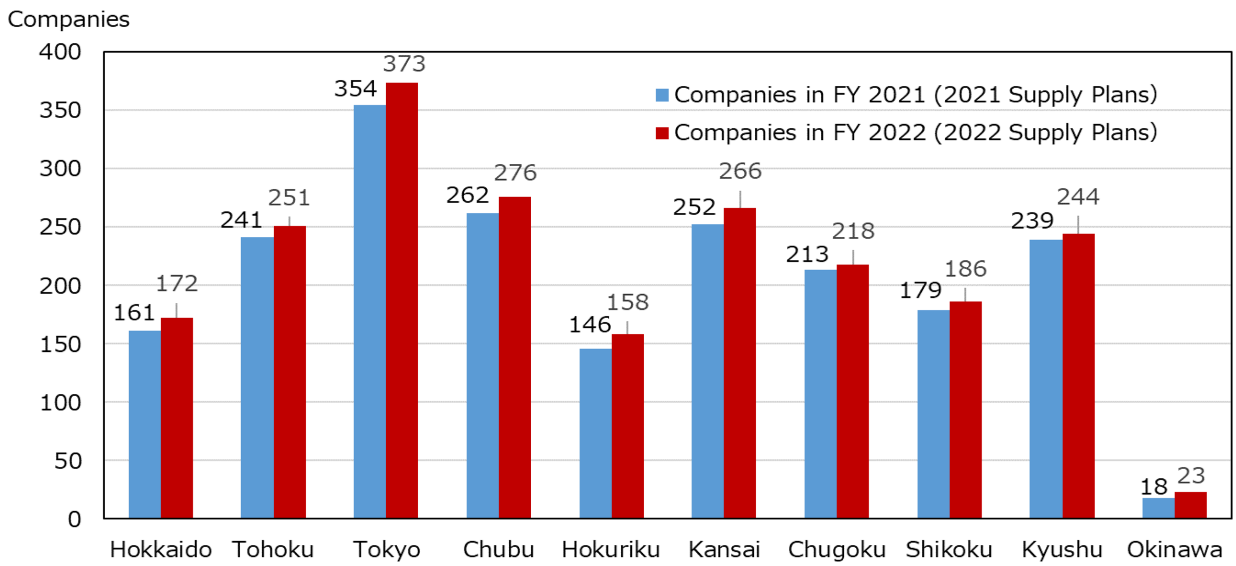


Figure 6-6 Number of Retail Companies by their Business Planning Areas in FY 2022

Figure 6-7 shows the number and the retail demand of retail companies in each regional service area for GT&D companies in FY 2022. As retail companies increase their numbers in every regional service area, the choice of retail companies for electricity customers is expanding.



Projected Peak Demand for FY 2022 (10^4 kW)	Hokkaido	Tohoku	Tokyo	Chubu	Hokuriku	Kansai	Chugoku	Shikoku	Kyushu	Okinawa
	417	1,306	5,379	2,485	495	2,739	1,047	494	1,535	154

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

3. Supply Capacity Procurement by Retail Companies

Figure 6-8 shows the transition of retail demand forecast in the regional service area by the retail department of the former general electric utilities and their procured supply capacity for the demand. The retail and generation departments of the former general electric utilities secure a sufficient supply capacity procured toward the retail demand of their own area.

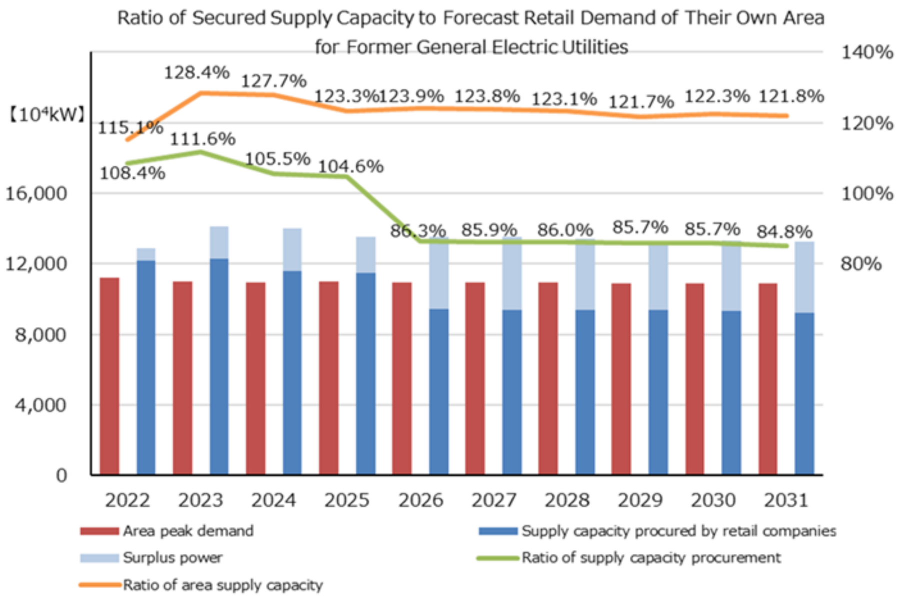


Figure 6-8 Ratio of Secured Supply Capacity to Forecast Retail Demand of Their Own Area for Former General Electric Utilities[50] (at 15:00 in August, at the sending end)

The competition among retail departments of former general electric utilities becomes fierce; there is a declining trend in the supply capacity procured for the retail demand of external areas that such companies forecast and the forecasted retail demand that power producers and suppliers (PPSs) (Figure 6-9).

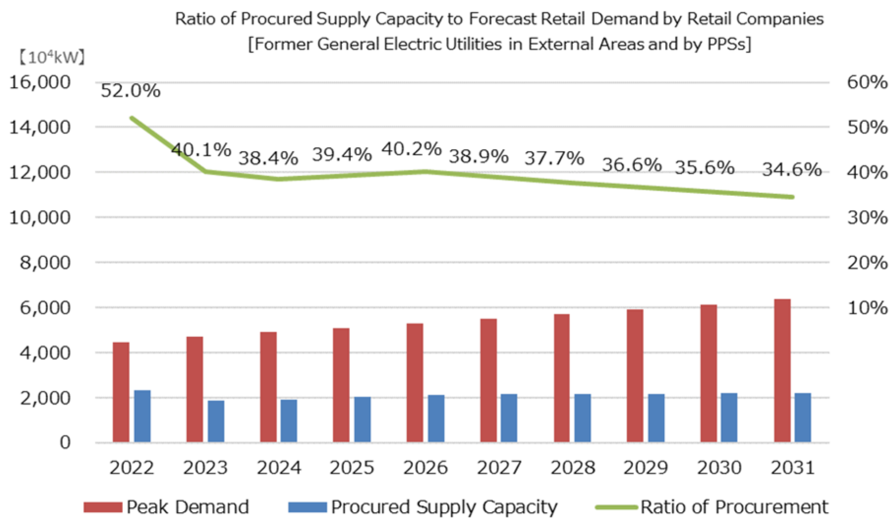


Figure 6-9 Ratio of Retail Companies' Procured Supply Capacity to Forecast Retail Demand [Former General Electric Utilities in External Areas and by PPSs] (at 15:00 in August, at the sending end)

[50] Including the surplus power of a group of companies deducting the balancing capacity to the retail companies' secured supply capacity.

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

In total, 1,007 generation companies submitted their electricity supply plans, which are classified by corresponding companies' the business scale of the installed capacity. 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 10 GW are planning to enlarge the scale of their business.

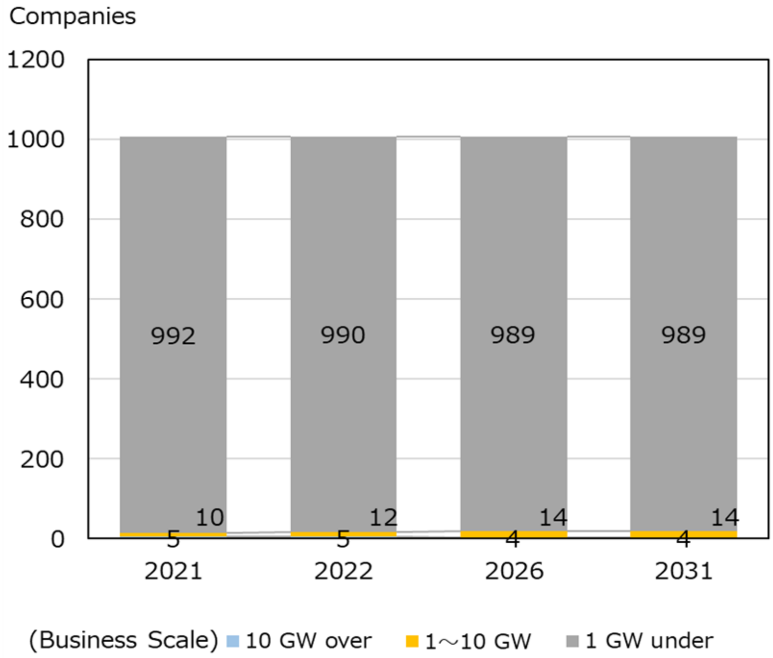


Figure 6-10 Distribution by Business Scale of a Generation Company's Installed Capacity

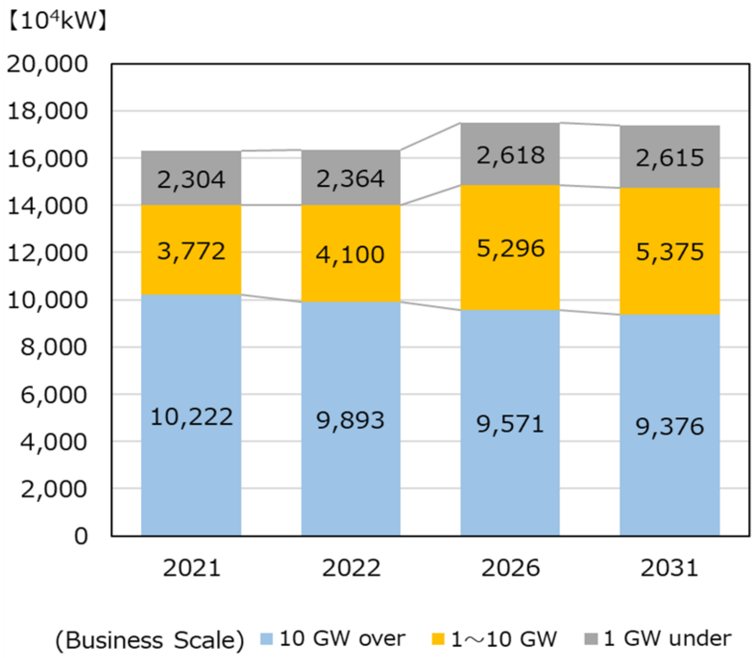


Figure 6-11 Distribution by a Generation Company's Accumulated Installed Capacity

Similarly, generation companies are classified by the business scale of the corresponding company's 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 company's accumulated energy supply forecast.

Generation companies with an energy supply of under 10 TWh are planning to decrease their energy generation.

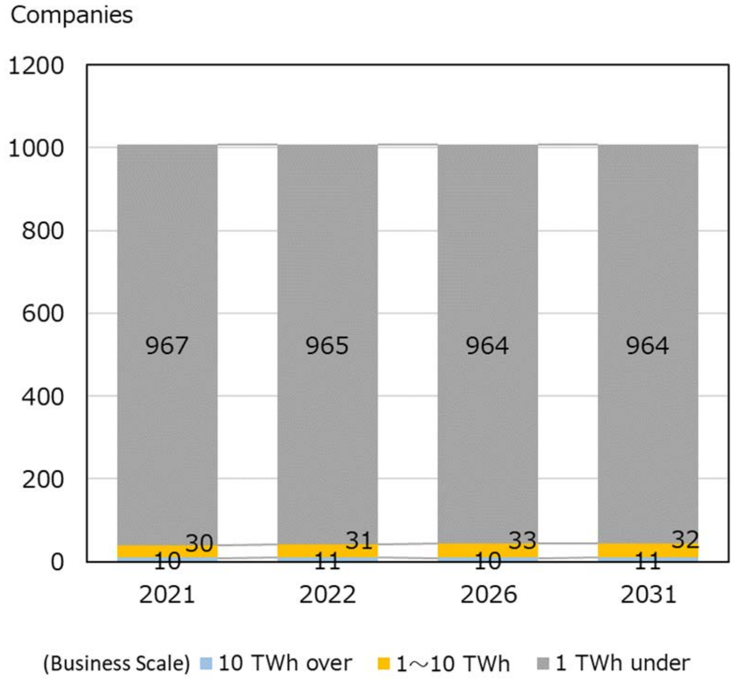


Figure 6-12 Generation Companies' Distribution of Energy Supply by Business Scale

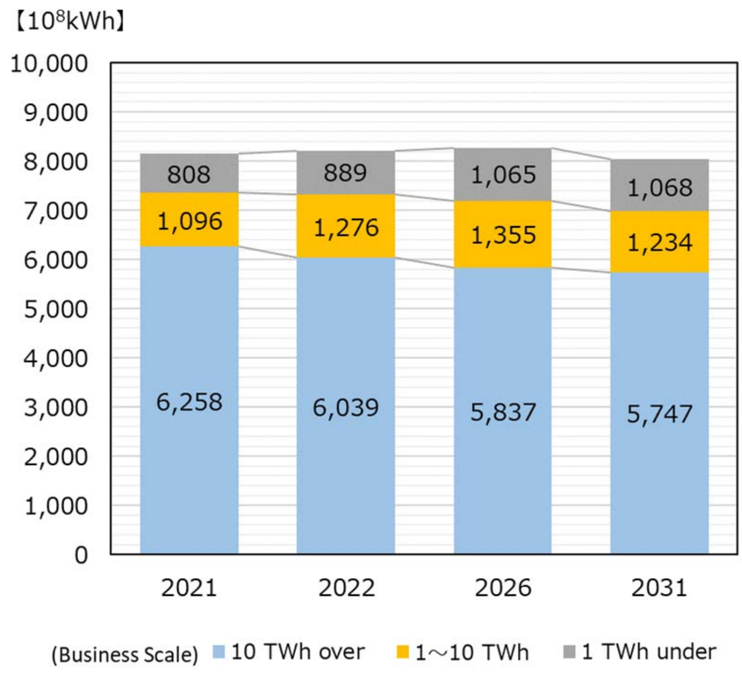


Figure 6-13 Generation Companies' Distribution by Accumulated Energy Supply

Figure 6-14 shows the number of generation companies at the end of FY 2021 by the power generation sources of their generators. The figures exclude 103 generation companies that do not own their generation plants. Approximately half of all generation companies solely own renewable energy generation facilities.

It is prominent that the generation companies with renewable energy (particularly solar power) are increasing, and new generation companies are leading a stronger introduction of renewable energy.

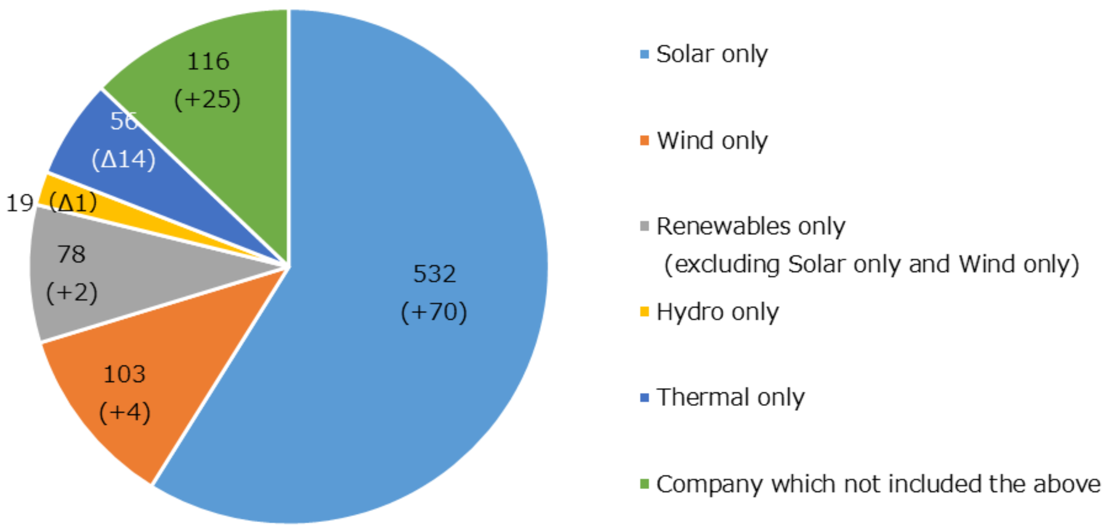


Figure 6-14 Number of Generation Companies by Power Generation Sources

5. Generation Company Business Areas

Figure 6-15 shows the ratio of generation companies to the number of areas where they plan to conduct business. Figure 6-16 shows the number of generation companies by their business planning areas in FY 2022. The figures exclude 136 generation companies that do not own their generation plants.

Eighty percent of all generation companies plan their business in a single area.

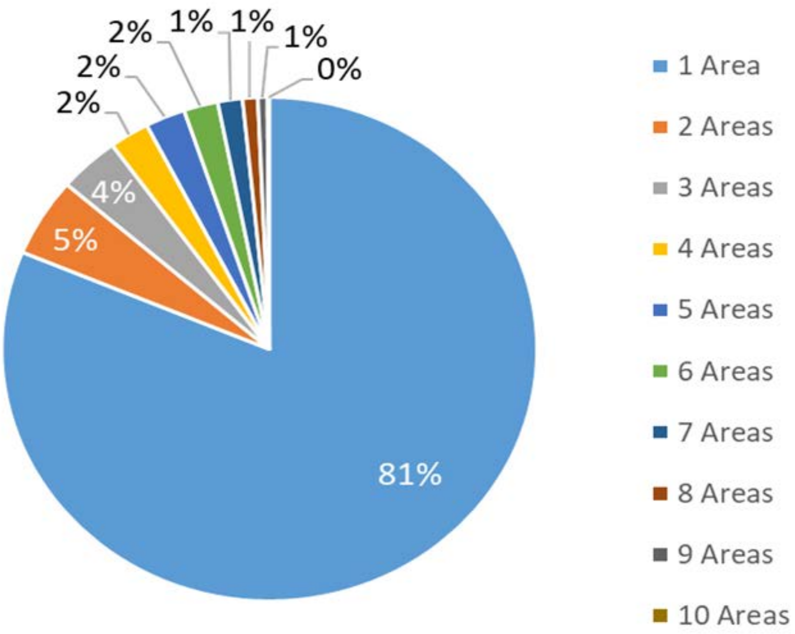


Figure 6-15 Ratio of Generation Companies by the Number of Planned Business Areas in FY 2022

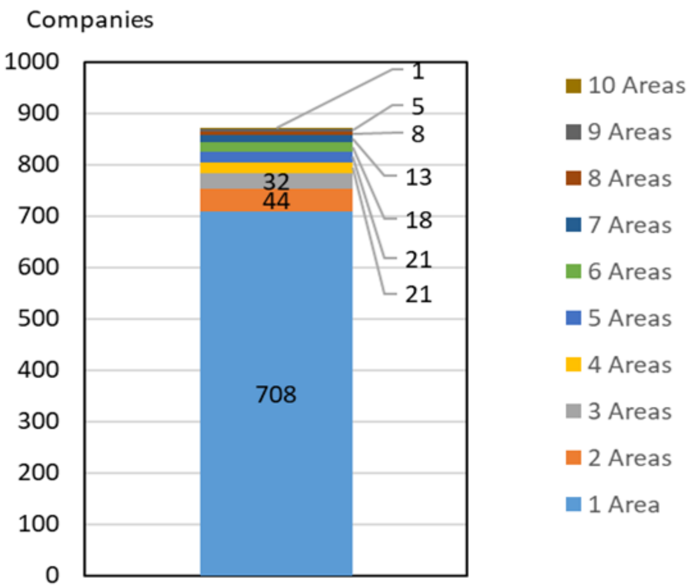
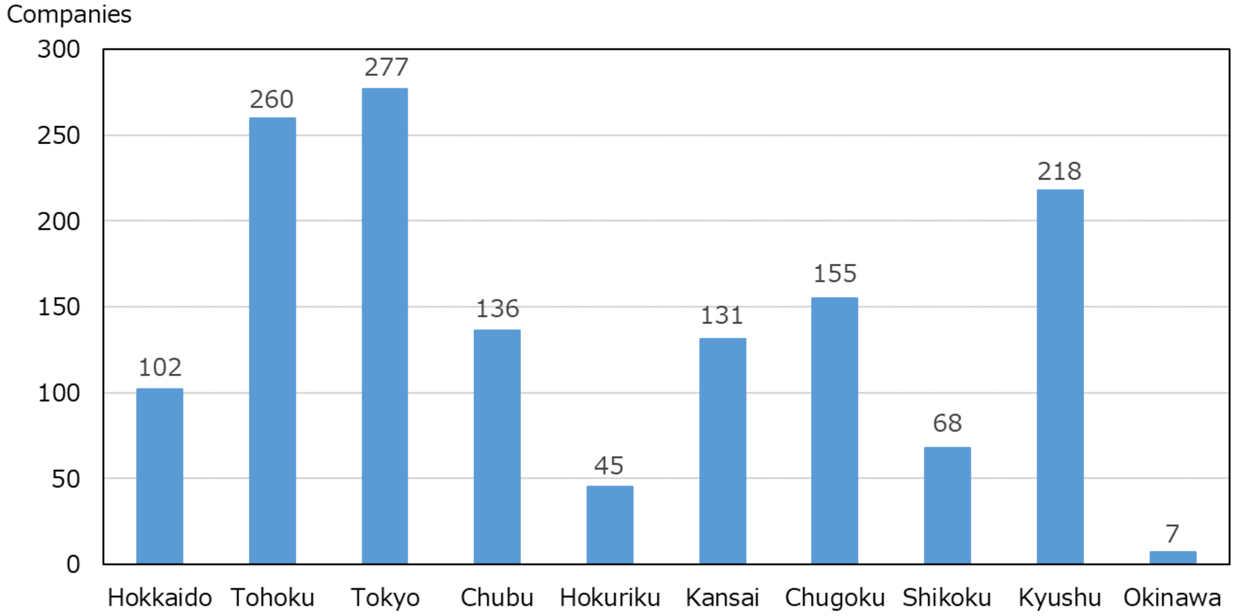


Figure 6-16 Number of Generation Companies by Their Business Planning Areas in FY 2022

Figure 6-17 shows the number and the installed capacity of generation companies in each regional service area for GT&D companies in August 2022. In the Hokkaido, Tohoku, Chugoku, and Kyushu regional service areas, the scale of generation companies is relatively small and their supply capacity is comparatively small despite the number of generation companies in these regional service areas.



Projected Supply Capacity in FY 2022 (10^4 kW)

Projected Supply Capacity for FY 2022 (10^4 kW)	Hokkaido	Tohoku	Tokyo	Chubu	Hokuriku	Kansai	Chugoku	Shikoku	Kyushu	Okinawa
	539	1,853	4,904	2,348	559	2,393	990	707	1,804	213

Figure 6-17 Number and Installed Capacity of Generation Companies in Each Regional Service Area

VII. Findings and Current Challenges

The current challenges relating to the aggregation of electricity supply plans are as follows.

1. Action for the structural challenge of the managing electricity supply-demand

For the management of electricity supply–demand, the Organization confirms the necessary supply capacity procurement by the "Aggregation of Electricity Supply Plans" for a 10-year period and "Electricity Supply–demand Verification" implemented before the coming high demand period, which considers demand increase by severe climate condition. Based on the tight power supply condition occurred in the winter of 2020/2021, there is possibly a structural challenge behind the tight power supply caused by decreasing supply capacity in recent years and demand increase by severe climate conditions.

The Organization recognizes that managing electricity supply–demand shall be more accurately implemented and makes every effort to evaluate and manage the supply–demand condition following the government or EPCOs for the review, including the necessity of revising the evaluation method.

In addition, the tight power supply on March 22 and 23, 2022 triggered by the 2022 Fukushima earthquake, raised concerns about blackouts and the burden of saving electricity. The Organization pays special attention to this incident as the responsible entity for securing the electricity supply.

Cooperating with the government, the Organization shall review, in good time, whether the security of supply capacity and balancing capacity and the supply–demand operation management scheme is adequate given this tight power supply, with the ongoing process of the transmission system reinforcement plan that contributes to the improving the transmission system's resilience.

2. Concerns for supply capacity shortage in recent years

In the aggregation of the supply plans in the previous year, some areas were in the severe condition of lower adequate reserve margins for their monthly demand–supply balance in the short term of the projected period. Before this year's aggregation, the Organization published the condition to widely call related EPCOs for coordinating the scheduled maintenance of generation facilities or transmission and substation facilities, and made every effort to improve supply–demand balance; however, it is not sound to maintain such coordination in the future.

For the aggregation of this year, evaluation in the short term (FY 2022 and FY 2023) , a certain reserve margin is secured against the average three highest loads. But to secure a stable supply for various EPCOs to manage and operate their generation or transmission facilities efficiently, the Organization has a new understanding of the importance that the facilities' scheduled maintenance is implemented for the short-term period at the proper time.

From FY 2022, the actual delivery year of FY 2024 becomes a period of scheduled maintenance coordination in the capacity market. Thus, the Organization shall cope with the market for cooperation and coordination with related EPCOs to effectively execute these actions.

Based on the experience of tight power supply during the winter of 2020/21, the Organization has monitored the condition of supply capacity (kW) and energy (kWh), including fuel procurement of generation companies, during winter of 2021/22—and published the result. Monitoring supply capacity and energy become more critical indicators for capacity procurement decisions or countermeasures for securing stable supply in unforeseen circumstances, such as Ukuranian situation. The Organization continuously implements the monitoring for FY 2022. For fuel procurement, such as liquefied natural gas, generation companies procure their fuel for a long-term contract; however, some of the procurement depends on the spot market. In case of increasing geopolitical risk, it is anticipated that individual generation companies cannot procure generation fuel for their endeavors; thus, the electricity industry expects the government to respond according to the condition.

Furthermore, as for supply–demand projection in FY 2022, the Organization shall make every effort to review supply capacity measures in cooperation with the government and related EPCOs. That is attributable to the difficulty of predicting consequences to the supply capacity triggered by the Fukushima earthquake on March 16, 2022, and the necessity for close watch on supply–demand balance at the highest winter peak demand (i.e., the condition which lowers the 3% of the minimum reserve margin for operation) after reviewing of the highest demand in severe climate condition.

3. Challenges regarding to securing supply capacity in the long term

For the trend of supply capacity in the mid-to-long term in the FY 2022 aggregation, the installation of new facilities, replacement of existed facilities, and resuming operation of nuclear power plant operations are increasing; however, there is a simultaneous increasing trend of suspension and decommissioning of aging thermal power plants.

In these circumstances, generation companies generally plan their power development according to the contract result of the capacity market and the contracted price level. There is a tendency to change suspension or decommissioning plans due to a single-year auction result, and some changes are observed at the auction for delivery in FY 2025.

Thus, the Organization shall analyze new and added installation of the generation facility in the mid-to-long term. These analyses are based on the auction result for the capacity market, transition of suspensions and decommissions, and industrial trends at the aggregation of supply plans. In addition, the Organization shall cooperate with the government to review necessary measures.

Throughout the cooperation, the Organization expects the government to adequately monitor and supervise contracted generators in the capacity market, and implement institutional treatment or action for securing the necessary supply capacity. This supervision includes measures like promoting new installations or replacing existing facilities to move toward decarbonization.

4. Challenges regarding to securing balancing capacity in the long term

The balancing market has started the trade of replacement reserve for FIT in FY 2021, replacement reserve in April 2022, and plans to add additional items. Furthermore, trade in the balancing market and solicitation of balancing capacity (Generator I and II) have been partially implemented. The solicitation process ends in FY 2024; after that, balancing capacity shall be procured in the balancing market.

It means that the necessary supply capacity for a national basis shall be procured in the capacity market in the future, and the supply capacity containing balancing function also shall also be traded in the capacity market. This is critical to the security of stable supply, and both markets shall be coordinated as needed. In the future of promoting integration for renewable energy, it is predicted that the importance of synchronization and inertia shall be increased as new balancing capacity, and necessary to continue reviewing the method for their procurement.

Based on this recognition, existing facilities, such as thermal and pumped storage hydro power plants, function as the balancing capacity. From FY 2024, the solicitation process of the balancing capacity shall be terminated; generation companies must earn their revenue from the kW value in the capacity market and, in a limited way, Δ(delta) kW in the balancing market. Some generation companies are anxious about not maintaining their generators under such conditions.

This anxiety is premature because generation companies cannot predict future incidents with objective evidence. The Organization shall diligently respond with GT&D companies, which are operators of the balancing market, and other related EPCOs to maintain supply capacity with the necessary balancing capacity be procured in the capacity market. Together, they can realize procurement of necessary balancing capacity in the balancing market based on both market coordination.

The Organization expects the government to preemtively review the function and economic value of generators with balancing capacity, such as the function of mitigating output shedding of renewable energy in the light load period, for their market design in political aspect.

VIII. Conclusions

1. Electricity Demand Forecast

The AAGR of peak demand nationwide in the mid-to-long term is forecast to decrease by 0.3%. AAGR is forecasted to be negative, and is attributable to several major decreasing factors, such as a shrinking population, and efforts to reduce electricity use, notwithstanding increasing factors like economic growth and broader use of electric appliances.

2. Electricity Supply and Demand

The Organization applied EUE as a new reliability criterion to the electric supply plan based on the review of the existing reliability criteria. In the short term (the first and second year of the projected period), all the areas and years fall within the criteria of secure supply (0.048 kWh/kW-year nationwide, 0.498 kWh/kW-year in Okinawa). In the long term, the calculated result for the Kyushu area from FY 2024 to FY 2029 exceeds the criteria due to the uncertain supply capacity of some sizable generating units. The result for the Okinawa area also exceeds its EUE from FY 2025 to FY 2027, and FY 2029 due to scheduled maintenance of the generating facilities. The supply–demand balance evaluation by the conventional approach shows that the 8% reserve margin will be achieved in the short term in FY 2022 and 2023.

For energy-supply requirement evaluation, it seems that energy supply will be 0.2 to 2.4 TWh/month of volume below the forecasted energy requirement (equivalent to 0.3 to 3.2% against the forecast energy requirement) throughout FY 2022.

In the short term, all areas and periods satisfy EUE, and none fall below the 8% criteria. The Organization proceeds to review for supply measures based on the analytical result of supply–demand variance risk, which premises severe climate conditions (heatwave and severe cold) emerge once in 10 years.

3. Analysis of the Transition of Power Generation Sources Nationwide

Renewable energy, such as solar and wind power, is projected to increase regarding the transition of installed power generation capacity and net electricity generation. Conversely, thermal is projected to decrease. Nuclear power plants' energy generation is calculated as zero, given that their capacity is reported as "uncertain."

4. Development Plans for Transmission and Distribution Facilities

Regarding the development plans for major transmission lines and substations, significant generator access lines are planned, as are development plans for cross-regional interconnection lines, including facilities necessary for cross-regional operation.

5. Cross-regional Operation

The aggregated results for procuring supply capacity or energy from external service areas, are almost the same as in the previous year, with higher procurement from external services and higher transmission to external areas.

6. Analysis of Characteristics of EPCOs

Distributions are calculated for retail and generation companies according to business scale and business areas, and are aggregated to the projection for a 10-year period. In addition, the ratios of the secured supply capacity are reviewed. Particularly, small and medium-sized retail companies have planned their supply capacity as “unspecified procurement,” as in the previous year’s plan; therefore, the ratios of the secured supply capacity indicate a declining tendency.

7. Findings and Challenges

The Organization has communicated to METI its opinions concerning four significant challenges concerning the aggregation of electricity supply plans for FY 2022.

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

APPENDIX 1 Supply–Demand Balance for FY 2022 and 2023 (Short-term)

i) Projection for FY 2022

Tables A1-1 to A1-4 show the monthly supply–demand balance, such as peak demand, monthly supply capacity, monthly reserve capacity, and reserve margin for each regional service area in FY 2022. 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, with additional supply capacity according to provision of Article 48 of the Act. Furthermore, Table A1-6 shows the monthly peak demand, monthly supply capacity, monthly reserve capacity, and reserve margin at the designated time.

Table A1-1 Monthly Peak Demand Forecast for Each Regional Service Area in FY 2022 (10^4kW at the sending end)

[10^4kW]

	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.	Jan.	Feb.	Mar.
Hokkaido	395	359	357	406	417	391	393	450	484	499	495	452
Tohoku	1,057	982	1,063	1,271	1,306	1,175	1,040	1,166	1,306	1,369	1,347	1,224
Tokyo	3,858	3,681	4,204	5,379	5,379	4,569	3,857	4,016	4,436	4,765	4,765	4,340
50Hz areas Total	5,310	5,022	5,624	7,056	7,102	6,135	5,290	5,632	6,226	6,633	6,607	6,016
Chubu	1,850	1,869	2,045	2,485	2,485	2,342	1,984	1,946	2,207	2,342	2,342	2,074
Hokuriku	390	364	402	495	495	441	378	414	473	511	511	457
Kansai	1,838	1,856	2,126	2,739	2,739	2,341	1,911	1,942	2,366	2,515	2,515	2,150
Chugoku	759	750	823	1,047	1,047	935	783	856	1,029	1,040	1,040	914
Shikoku	344	343	392	494	494	432	362	370	461	461	461	404
Kyushu	1,037	1,053	1,199	1,535	1,535	1,324	1,128	1,152	1,446	1,464	1,464	1,239
60Hz areas Total	6,218	6,235	6,987	8,795	8,795	7,815	6,545	6,679	7,982	8,333	8,333	7,238
Interconnected	11,528	11,257	12,611	15,851	15,897	13,950	11,835	12,311	14,208	14,966	14,940	13,254
Okinawa	103	122	146	147	147	152	132	114	99	102	101	94
Nationwide	11,631	11,379	12,757	15,998	16,044	14,101	11,967	12,425	14,307	15,068	15,041	13,347

Table A1-2 Monthly Projection of Supply Capacity for Each Regional Service Area in FY 2022 (10^4kW at the sending end)

[10^4kW]

	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.	Jan.	Feb.	Mar.
Hokkaido	575	595	576	596	562	549	581	611	633	627	626	609
Tohoku	1,247	1,159	1,175	1,505	1,549	1,379	1,250	1,270	1,429	1,528	1,503	1,468
Tokyo	4,371	4,467	4,773	5,920	5,914	5,549	4,594	4,302	5,094	5,419	5,473	5,248
50Hz areas Total	6,192	6,221	6,524	8,021	8,025	7,477	6,425	6,184	7,156	7,574	7,602	7,325
Chubu	2,040	2,123	2,442	2,597	2,706	2,541	2,293	2,105	2,358	2,438	2,441	2,308
Hokuriku	487	460	475	571	579	526	533	509	523	511	515	526
Kansai	2,061	2,095	2,403	2,806	2,730	2,403	1,805	1,973	2,496	2,644	2,755	2,561
Chugoku	894	936	1,040	1,334	1,309	1,175	1,004	1,016	1,183	1,234	1,214	1,139
Shikoku	541	575	630	695	703	655	604	566	590	594	504	520
Kyushu	1,244	1,231	1,418	1,713	1,690	1,570	1,456	1,441	1,616	1,657	1,587	1,338
60Hz areas Total	7,267	7,421	8,408	9,716	9,717	8,869	7,697	7,610	8,766	9,078	9,016	8,390
Interconnected	13,459	13,641	14,932	17,738	17,742	16,346	14,122	13,793	15,921	16,652	16,619	15,715
Okinawa	168	166	187	198	206	198	203	183	171	160	162	175
Nationwide	13,626	13,807	15,119	17,936	17,948	16,545	14,325	13,976	16,093	16,813	16,780	15,890

Table A1-3 Monthly Projection of Reserve Capacity for Each Regional Service Area in FY 2022 (10^4kW at the sending end)

[10^4kW]

	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.	Jan.	Feb.	Mar.
Hokkaido	180	236	219	190	145	158	188	161	149	128	131	157
Tohoku	190	177	112	234	243	204	210	104	123	159	156	244
Tokyo	513	786	569	541	535	980	737	286	658	654	708	908
50Hz areas Total	882	1,199	900	965	923	1,342	1,135	552	930	941	995	1,309
Chubu	190	254	397	112	221	199	309	159	151	96	99	234
Hokuriku	97	97	74	76	84	85	156	96	50	-0	4	69
Kansai	223	239	277	67	-9	62	-105	31	130	129	240	411
Chugoku	135	186	217	287	262	240	221	160	154	194	174	225
Shikoku	197	232	238	201	209	223	242	196	129	133	43	116
Kyushu	207	178	219	178	155	246	328	289	170	193	123	99
60Hz areas Total	1,049	1,186	1,421	921	922	1,055	1,152	931	783	745	683	1,152
Interconnected	1,931	2,384	2,321	1,887	1,845	2,397	2,287	1,482	1,713	1,686	1,679	2,462
Okinawa	65	44	41	51	59	47	70	69	73	58	61	81
Nationwide	1,996	2,428	2,362	1,938	1,904	2,443	2,358	1,551	1,786	1,745	1,740	2,543

Table A1-4 Monthly Projection of Reserve Margin for Each Regional Service Area in FY 2022

	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.	Jan.	Feb.	Mar.
Hokkaido	45.5%	65.6%	61.3%	46.9%	34.9%	40.5%	47.9%	35.8%	30.7%	25.6%	26.5%	34.7%
Tohoku	17.9%	18.0%	10.6%	18.4%	18.6%	17.4%	20.2%	8.9%	9.4%	11.6%	11.6%	19.9%
Tokyo	13.3%	21.4%	13.5%	10.1%	9.9%	21.4%	19.1%	**7.1%**	14.8%	13.7%	14.9%	20.9%
50Hz areas Total	16.6%	23.9%	16.0%	13.7%	13.0%	21.9%	21.5%	9.8%	14.9%	14.2%	15.1%	21.8%
Chubu	10.3%	13.6%	19.4%	**4.5%**	8.9%	8.5%	15.6%	8.1%	**6.8%**	**4.1%**	**4.2%**	11.3%
Hokuriku	25.0%	26.7%	18.4%	15.3%	17.0%	19.2%	41.3%	23.1%	10.6%	**0.0%**	**0.8%**	15.1%
Kansai	12.1%	12.9%	13.0%	**2.5%**	**-0.3%**	**2.7%**	**-5.5%**	**1.6%**	**5.5%**	**5.1%**	9.5%	19.1%
Chugoku	17.7%	24.7%	26.3%	27.4%	25.0%	25.6%	28.3%	18.7%	14.9%	18.7%	16.7%	24.6%
Shikoku	57.2%	67.8%	60.6%	40.6%	42.3%	51.7%	67.0%	52.9%	27.9%	28.9%	9.4%	28.6%
Kyushu	20.0%	16.9%	18.3%	11.6%	10.1%	18.6%	29.1%	25.1%	11.8%	13.2%	8.4%	**8.0%**
60Hz areas Total	16.9%	19.0%	20.3%	10.5%	10.5%	13.5%	17.6%	13.9%	9.8%	8.9%	8.2%	15.9%
Interconnected	16.8%	21.2%	18.4%	11.9%	11.6%	17.2%	19.3%	12.0%	12.1%	11.3%	11.2%	18.6%
Okinawa	62.5%	35.8%	28.0%	38.6%	43.5%	38.0%	53.3%	60.3%	73.5%	57.1%	60.5%	86.2%
Nationwide	17.2%	21.3%	18.5%	12.2%	11.9%	17.4%	19.7%	12.5%	12.5%	11.6%	11.6%	19.1%

Below 8% criteria

Table A1-5 Monthly Projection of Cross-regional Reserve Margin for Each Regional Service Area in FY 2022

(Power exchanges through cross-regional interconnection lines and generating facilities are not included at the sending end at the sending end of the electricity supply plans,)

	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.	Jan.	Feb.	Mar.
Hokkaido	29.6%	48.7%	55.5%	41.5%	27.6%	31.9%	34.2%	21.1%	16.1%	15.4%	15.6%	20.2%
Tohoku	18.3%	20.3%	13.3%	15.3%	20.1%	16.8%	23.1%	14.6%	11.9%	15.4%	15.6%	19.9%
Tokyo	14.7%	20.3%	13.3%	10.3%	10.2%	16.8%	17.0%	8.1%	11.9%	10.7%	10.6%	18.4%
Chubu	14.7%	20.3%	20.2%	10.3%	10.5%	16.8%	17.0%	11.3%	11.9%	10.7%	10.6%	18.4%
Hokuriku	18.0%	20.3%	20.2%	11.3%	10.5%	16.8%	17.0%	11.3%	11.9%	10.7%	10.6%	18.4%
Kansai	18.0%	20.3%	20.2%	11.3%	10.5%	16.8%	17.0%	11.3%	11.9%	10.7%	10.6%	18.4%
Chugoku	18.0%	20.3%	20.2%	11.3%	10.5%	16.8%	17.0%	11.3%	11.9%	10.7%	10.6%	18.4%
Shikoku	18.0%	20.3%	21.9%	11.3%	10.5%	16.8%	24.2%	11.9%	11.9%	10.7%	10.6%	18.4%
Kyushu	18.0%	20.3%	20.2%	11.3%	10.5%	16.8%	27.1%	23.1%	11.9%	10.7%	10.6%	18.4%
Okinawa	62.5%	35.8%	28.0%	35.0%	40.1%	30.8%	53.3%	60.3%	73.5%	57.1%	60.5%	86.2%

Improved over 8%

* Reserve margins with the same value are shown in the same background color after utilization of cross-regional interconnection line.

Table A1-6 Monthly Projection of Supply–Demand Balance in Okinawa in FY 2022 (10^4kW at the sending end)

[10^4kW]

	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.	Jan.	Feb.	Mar.
Peak Demand	103	122	148	150	154	152	132	114	99	102	101	94
Supply Capacity	168	166	190	208	220	209	203	183	171	160	162	175
Reserve Capacity	65	44	42	58	67	58	70	69	73	58	61	81
Reserve Margin	62.5%	35.8%	28.0%	38.6%	43.5%	38.0%	53.3%	60.3%	73.5%	57.1%	60.5%	86.2%

ii) Projection for FY 2023

Tables A1-7 to A1-10 show the monthly supply–demand balance, such as peak demand, monthly supply capacity, monthly reserve capacity, and reserve margin for each regional service area in FY 2023. Table A1-11 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 with additional supply capacity according to the provision of Article 48 of the Act. Furthermore, Table A1-12 shows the monthly peak demand, monthly supply capacity, monthly reserve capacity, and reserve margin at the designated time.

Table A1-7 Monthly Peak Demand Forecast for Each Regional Service Area in FY 2023 (10^4kW at the sending end)

[10^4kW]

	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.	Jan.	Feb.	Mar.
Hokkaido	395	359	357	406	417	391	393	450	484	499	495	452
Tohoku	1,054	980	1,061	1,268	1,303	1,173	1,037	1,163	1,302	1,365	1,343	1,220
Tokyo	3,846	3,669	4,192	5,364	5,364	4,555	3,846	4,004	4,423	4,751	4,751	4,318
50Hz areas Total	5,295	5,008	5,610	7,038	7,084	6,119	5,276	5,617	6,209	6,615	6,589	5,990
Chubu	1,849	1,868	2,045	2,484	2,484	2,341	1,983	1,945	2,206	2,341	2,341	2,074
Hokuriku	390	364	402	495	495	441	379	415	475	513	513	459
Kansai	1,835	1,854	2,123	2,735	2,735	2,337	1,908	1,938	2,363	2,511	2,511	2,147
Chugoku	758	749	822	1,046	1,046	934	782	856	1,028	1,039	1,039	913
Shikoku	343	341	389	492	492	429	360	368	458	458	458	401
Kyushu	1,038	1,054	1,200	1,536	1,536	1,324	1,129	1,153	1,447	1,465	1,465	1,240
60Hz areas Total	6,213	6,229	6,980	8,788	8,788	7,806	6,541	6,675	7,977	8,327	8,327	7,233
Interconnected	11,508	11,237	12,590	15,826	15,872	13,925	11,817	12,292	14,186	14,942	14,916	13,223
Okinawa	105	124	150	149	149	154	134	116	100	103	102	95
Nationwide	11,612	11,361	12,741	15,975	16,021	14,079	11,950	12,408	14,286	15,045	15,018	13,318

Table A1-8 Monthly Projection of Supply Capacity for Each Regional Service Area in FY 2023 (10^4kW at the sending end)

[10^4kW]

	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.	Jan.	Feb.	Mar.
Hokkaido	557	581	538	555	566	511	514	572	669	661	669	602
Tohoku	1,326	1,363	1,368	1,637	1,693	1,536	1,288	1,373	1,528	1,596	1,624	1,515
Tokyo	4,284	4,331	4,979	5,850	5,868	5,476	4,558	4,407	5,121	5,535	5,640	5,273
50Hz areas Total	6,167	6,275	6,886	8,042	8,128	7,523	6,360	6,353	7,318	7,791	7,934	7,390
Chubu	2,290	2,192	2,438	2,688	2,670	2,445	2,232	2,097	2,399	2,487	2,451	2,310
Hokuriku	467	470	492	554	532	489	515	496	480	506	513	512
Kansai	2,411	2,471	2,795	3,047	3,125	2,950	2,421	2,588	2,868	2,866	2,827	2,601
Chugoku	1,048	1,090	1,205	1,398	1,339	1,131	1,004	952	1,195	1,281	1,214	1,014
Shikoku	479	622	669	763	735	649	584	545	580	664	668	675
Kyushu	1,315	1,338	1,538	1,787	1,748	1,631	1,479	1,495	1,574	1,592	1,659	1,510
60Hz areas Total	8,010	8,183	9,138	10,237	10,150	9,295	8,234	8,172	9,097	9,396	9,331	8,624
Interconnected	14,177	14,458	16,024	18,279	18,277	16,818	14,595	14,525	16,414	17,186	17,265	16,014
Okinawa	173	197	210	207	204	202	183	177	164	169	172	170
Nationwide	14,350	14,655	16,234	18,486	18,482	17,020	14,778	14,701	16,578	17,355	17,437	16,183

Table A1-9 Monthly Projection of Reserve Capacity for Each Regional Service Area in FY 2023 (10^4kW at the sending end)

[10^4kW]

	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.	Jan.	Feb.	Mar.
Hokkaido	162	222	181	149	149	120	121	122	185	162	174	150
Tohoku	272	383	307	369	390	363	251	210	226	231	281	295
Tokyo	438	662	787	486	504	921	712	403	698	784	889	955
50Hz areas Total	872	1,267	1,276	1,004	1,044	1,404	1,084	736	1,109	1,176	1,345	1,400
Chubu	441	324	393	204	186	104	249	152	193	146	110	236
Hokuriku	77	107	91	59	37	48	136	81	5	-7	-0	54
Kansai	576	618	672	312	390	613	513	649	505	355	316	455
Chugoku	290	341	383	352	293	197	222	96	167	242	175	101
Shikoku	136	281	280	271	243	220	224	177	122	206	210	274
Kyushu	277	284	338	251	212	307	350	342	127	127	194	270
60Hz areas Total	1,797	1,954	2,158	1,449	1,362	1,489	1,694	1,497	1,120	1,069	1,004	1,390
Interconnected	2,669	3,221	3,434	2,453	2,405	2,893	2,778	2,233	2,229	2,244	2,349	2,790
Okinawa	68	73	60	58	55	48	49	61	64	65	70	75
Nationwide	2,737	3,294	3,493	2,511	2,460	2,941	2,827	2,293	2,292	2,310	2,419	2,865

Table A1-10 Monthly Projection of Reserve Margin for Each Regional Service Area in FY 2023

	4月	5月	6月	7月	8月	9月	10月	11月	12月	1月	2月	3月
Hokkaido	41.0%	61.7%	50.8%	36.7%	35.8%	30.8%	30.9%	27.2%	38.2%	32.4%	35.2%	33.2%
Tohoku	25.8%	39.1%	29.0%	29.1%	30.0%	30.9%	24.2%	18.1%	17.3%	16.9%	21.0%	24.2%
Tokyo	11.4%	18.0%	18.8%	9.1%	9.4%	20.2%	18.5%	10.1%	15.8%	16.5%	18.7%	22.1%
50Hz areas Total	16.5%	25.3%	22.7%	14.3%	14.7%	23.0%	20.6%	13.1%	17.9%	17.8%	20.4%	23.4%
Chubu	23.8%	17.3%	19.2%	8.2%	**7.5%**	**4.5%**	12.6%	**7.8%**	8.8%	**6.3%**	**4.7%**	11.4%
Hokuriku	19.8%	29.3%	22.6%	11.9%	**7.5%**	10.9%	35.8%	19.4%	**1.1%**	**-1.4%**	**0.0%**	11.7%
Kansai	31.4%	33.3%	31.7%	11.4%	14.3%	26.2%	26.9%	33.5%	21.4%	14.1%	12.6%	21.2%
Chugoku	38.3%	45.6%	46.6%	33.6%	28.0%	21.0%	28.4%	11.2%	16.3%	23.3%	16.8%	11.1%
Shikoku	39.6%	82.3%	72.0%	55.2%	49.5%	51.3%	62.3%	48.2%	26.6%	44.9%	45.8%	68.3%
Kyushu	26.7%	26.9%	28.2%	16.3%	13.8%	23.2%	31.0%	29.7%	8.8%	8.7%	13.3%	21.8%
60Hz areas Total	28.9%	31.4%	30.9%	16.5%	15.5%	19.1%	25.9%	22.4%	14.0%	12.8%	12.1%	19.2%
Interconnected	23.2%	28.7%	27.3%	15.5%	15.2%	20.8%	23.5%	18.2%	15.7%	15.0%	15.7%	21.1%
Okinawa	65.1%	59.2%	39.7%	42.3%	40.5%	38.7%	36.6%	52.6%	63.7%	63.2%	68.4%	78.5%
Nationwide	23.6%	29.0%	27.4%	15.8%	15.4%	21.0%	23.7%	18.5%	16.0%	15.4%	16.1%	21.5%

Below 8% criteria

Table A1-11 Monthly Projection of Reserve Margin for Each Regional Service Area in FY 2023

(Power exchanges through cross-regional interconnection lines and generating facilities are not included at the sending end at the sending end of the electricity supply plans,)

	4月	5月	6月	7月	8月	9月	10月	11月	12月	1月	2月	3月
Hokkaido	30.0%	45.3%	47.6%	29.2%	30.9%	29.7%	26.1%	20.6%	23.7%	18.1%	20.8%	25.1%
Tohoku	30.0%	29.9%	21.1%	19.7%	22.0%	29.7%	26.1%	20.6%	16.5%	15.4%	16.4%	25.1%
Tokyo	11.4%	22.1%	21.1%	13.6%	14.1%	15.8%	18.0%	10.4%	15.1%	14.6%	15.7%	19.6%
Chubu	28.9%	22.1%	22.5%	13.6%	14.1%	15.8%	18.0%	10.6%	15.1%	14.6%	15.0%	19.6%
Hokuriku	28.9%	35.4%	34.4%	20.9%	20.0%	24.4%	18.0%	10.6%	15.1%	14.6%	15.0%	20.0%
Kansai	28.9%	35.4%	34.4%	20.9%	20.0%	24.4%	30.3%	28.6%	15.6%	14.6%	15.0%	20.0%
Chugoku	28.9%	35.4%	34.4%	20.9%	20.0%	24.4%	30.3%	28.6%	15.6%	14.6%	15.0%	20.0%
Shikoku	28.9%	35.4%	34.4%	20.9%	30.9%	25.2%	33.7%	28.6%	15.6%	22.0%	21.3%	41.5%
Kyushu	28.9%	35.4%	34.4%	20.9%	20.0%	24.4%	31.0%	28.6%	15.6%	14.6%	15.0%	20.0%
Okinawa	65.1%	59.2%	39.7%	38.7%	36.8%	31.4%	36.6%	52.6%	63.7%	63.2%	68.4%	78.5%

Improved over 8%

* Reserve margins with the same value are shown in the same background color after utilization of cross-regional interconnection line.

Table A1-12 Monthly Projection of Supply–Demand Balance in Okinawa in FY 2023 (10^4kW at the sending end)

[10^4kW]

	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.	Jan.	Feb.	Mar.
Peak Demand	105	124	150	152	156	154	134	116	100	103	102	95
Supply Capacity	173	197	210	216	219	213	183	177	164	169	172	170
Reserve Capacity	68	73	60	64	63	59	49	61	64	65	70	75
Reserve Margin	65.1%	59.2%	39.7%	42.3%	40.5%	38.7%	36.6%	52.6%	63.7%	63.2%	68.4%	78.5%

APPENDIX 2 Long-Term Supply–Demand Balance for a 10-year Period FY 2022–2031

Tables A2-1 and A2-2 show a 10-year projection of the annual peak demand and supply capacity for each regional service area from FY 2022 to 2031. Tables A2-3 and A2-4 show a 10-year projection of the annual peak demand and annual supply capacity for winter peak areas of Hokkaido, Tohoku, and Hokuriku, respectively. Further, Table A2-5 shows the annual projection of supply–demand balance in Okinawa

Table A2-1 Annual Peak Demand Forecast for Each Regional Service Area
(At 15:00 in August, 10^4kW at the sending end)

[10^4kW]

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Hokkaido	417	417	417	417	416	416	416	415	415	416
Tohoku	1,306	1,303	1,298	1,293	1,288	1,284	1,279	1,273	1,268	1,263
Tokyo	5,379	5,364	5,362	5,359	5,356	5,351	5,347	5,342	5,337	5,331
50Hz areas Total	7,102	7,084	7,077	7,069	7,060	7,051	7,042	7,030	7,020	7,010
Chubu	2,485	2,484	2,475	2,466	2,457	2,448	2,439	2,430	2,421	2,412
Hokuriku	495	495	494	492	491	490	489	487	486	485
Kansai	2,739	2,735	2,726	2,720	2,709	2,700	2,692	2,683	2,675	2,666
Chugoku	1,047	1,046	1,045	1,043	1,042	1,040	1,039	1,037	1,036	1,034
Shikoku	494	492	489	486	483	481	478	475	473	470
Kyushu	1,535	1,536	1,533	1,529	1,526	1,522	1,518	1,514	1,510	1,506
60Hz areas Total	8,795	8,788	8,762	8,736	8,708	8,681	8,655	8,626	8,601	8,573
Interconnected	15,897	15,872	15,839	15,805	15,768	15,732	15,697	15,656	15,621	15,583
Okinawa	147	149	156	157	158	159	160	161	162	163
Nationwide	16,044	16,021	15,995	15,962	15,926	15,891	15,857	15,817	15,782	15,746

Table A2-2 Annual Projection of Supply Capacity for Each Regional Service Area
(At 15:00 in August, 10^4kW at the sending end)

[10^4kW]

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Hokkaido	562	566	641	652	650	654	659	663	663	715
Tohoku	1,549	1,693	1,637	1,594	1,587	1,603	1,623	1,638	1,650	1,666
Tokyo	5,914	5,868	5,823	6,022	6,124	6,138	6,118	6,136	6,154	6,168
50Hz areas Total	8,025	8,128	8,101	8,268	8,361	8,395	8,400	8,436	8,467	8,550
Chubu	2,706	2,670	2,832	2,699	2,710	2,711	2,665	2,663	2,661	2,527
Hokuriku	579	532	561	580	555	565	545	549	547	548
Kansai	2,730	3,125	3,075	2,824	2,953	2,958	2,997	3,004	3,010	3,018
Chugoku	1,309	1,339	1,291	1,246	1,250	1,249	1,245	1,247	1,249	1,255
Shikoku	703	735	660	678	689	690	682	683	687	687
Kyushu	1,690	1,748	1,571	1,589	1,584	1,588	1,570	1,573	1,623	1,630
60Hz areas Total	9,717	10,150	9,990	9,616	9,740	9,761	9,703	9,720	9,777	9,664
Interconnected	17,742	18,277	18,091	17,884	18,101	18,155	18,104	18,156	18,244	18,214
Okinawa	206	204	215	208	210	208	220	209	220	221
Nationwide	17,948	18,482	18,306	18,092	18,311	18,363	18,324	18,364	18,464	18,435

* Supply capacity for Okinawa in FY 2022 and 2023 indicates that the supply capacity falls to the least reserve margin.

Table A2-3 Annual Peak Demand Forecast for Winter Peak Areas of Hokkaido, Tohoku, and Hokuriku (At 18:00 in January, 10^4kW at the sending end)

[10^4kW]

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Hokkaido	499	499	498	498	498	498	497	497	497	498
Tohoku	1,369	1,365	1,361	1,356	1,350	1,345	1,340	1,334	1,329	1,324
Hokuriku	511	513	512	512	512	511	511	511	511	510

Table A2-4 Annual Projection of Supply Capacity for Winter Peak Areas of Hokkaido, Tohoku, and Hokuriku (At 18:00 in January, 10^4kW at the sending end)

[10^4kW]

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Hokkaido	627	661	692	671	669	673	679	681	731	728
Tohoku	1,544	1,596	1,684	1,641	1,635	1,649	1,670	1,685	1,695	1,712
Hokuriku	511	506	584	590	570	580	561	564	563	564

Table A2-5 Annual Projection of Supply–Demand Balance in Okinawa (10^4kW at the sending end)

[10^4 kW]

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Peak Demand	150	152	154	155	156	157	157	158	159	160
Supply Capacity	206	226	229	234	217	229	229	229	230	230
Reserve Capacity	56	74	75	79	61	72	72	71	71	70
Resreve Margin	37.5%	48.6%	49.0%	50.8%	39.2%	46.2%	45.7%	45.2%	44.6%	44.0%