Aggregation of Electricity Supply Plans
Fiscal Year 2021

September 2021

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) 2021 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 plans to be submitted by electric power companies (EPCOs), and their results be published.

The electricity supply plans are submitted by the EPCOs according to the Network Code of the Organization, are aggregated by the Organization, and sent to the Ministry of Economy, Trade and Industry (METI) annually by the end of March.
In total, 1,642 electricity supply plans for FY 2021 were aggregated, including 1,636 plans submitted by companies that became EPCOs by the end of November 2020 and six plans submitted by companies that became EPCOs by March 1, 2021.

Number of Electric Power Companies Subject to the Aggregation in FY 2021

Business License	Number
Generation Companies	935
Retail Companies	660
Specified Transmission, Distribution and Retail Companies	31
Specified Transmission and Distribution Companies	3
Transmission Companies	3
General Transmission and Distribution Companies	10
Total	1,642

[Reference] Electricity supply plan

The EPCOs shall develop a comprehensive plan for electricity supply, and development of a generation or transmission facility for a 10-year period 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 being inadequate for the security of a stable supply by cross-regional operation or for other development of electricity business in a comprehensive and rational manner

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 to be 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**

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Errata (2023/12/20)

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P37: Table 3-4 Electric Energy Generated by Hydro and Thermal Generation Sources	Part of net electric energy generation is altered
P37: Table 3-6 Electric Energy Transition Generated by All Generation Sources	Part of net electric energy generation is altered
P38: Figure 3-4 Net Electric Energy Generation for FY 2020	Part of ratio of electric energy generation is altered
P39: Table 3-7 Capacity Factors by Power Generation Source (Nationwide)	Part of capacity factor is altered
P40: Figure 3-5 Capacity Factors by Power Generation Source (Nationwide)	Part of capacity factor is altered

Errata (2021/9/27)

P18: Table 2-2 Monthly Projection of the Least Reserve Margins	Part of areal reserve margin is altered
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P33: Figure 3-2 Installed Power Generation Capacity at the end of FY2020	Part of composition of installed capacity is altered
P38: Figure 3-4 Net Electric Energy Generation for FY 2020	Part of electric energy generation is altered
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P40: Figure 3-5 Capacity Factors by Power Generation Source (Nationwide)	Capacity factor for FY 2020 is altered
P44: Table 4-2 Development Plans under Construction	Part of in-service date is altered
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P47: Table 4-5 Development Plans under Construction	Part of transformer voltage is altered, one case is transferred to Table 4-6, and one case is transferred from Table 4-6
P48: Table 4-6 Development Plans in Planning Stages	Part of transformer voltage, construction and in-srevice date is altered, one case is transferred to Table 4-6, and one case is transferred from Table 4-6
P49: Table 4-7 Decommissioning Plan	Part of retirement is altered
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A4 Table A1-11 Monthly Projection of Reserve Margin for Each Regional Service Area in FY 2022	Part of reserve margin is altered

I. Electricity Demand Forecast

1. Actual and Preliminary Data for FY 2020 and Forecast for FY 2021 and 2022 (Short Term)

a. Peak Demand (Average Value of the Three Highest Daily Loads[1]) in August

Table 1-1 shows the actual data for the aggregated peak demand for each regional service area[2] submitted by the 10 general transmission and distribution (GT&D) companies for FY 2020 and the forecast[3] value for FY 2021 and 2022.

The peak demand (average value of the three highest daily loads) for FY 2021 was forecast at 159,030 MW, which represents a 0.1% decrease over 159,160 MW; i.e. the temperature-adjusted[4] value for FY 2020.

Peak demand for FY 2022 was forecast at 159,530 MW, which represents 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 2020 Actual (temperature adjusted)	FY 2021 Forecast	FY 2022 Forecast
15,916	15,903 (-0.1%*)	15,953 (+0.2%*)

*% change compared with actual data for FY 2020 (temperature adjusted)

b. Forecast for FY 2021 and 2022

Tables 1-2 and 1-3 show the monthly peak demand in FY 2021 and 2022, respectively, from the aggregated peak demand for each regional service area submitted by the 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.

[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 2021 is based on normal weather. Thus, weather conditions for forecast assumption may vary in contrast to the actual data or estimated value in FY 2020.
[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 2021
(nationwide, 10^4 kW at the sending end)

	Apr.	May	Jun.	Jul.	Aug.	Sep.
Peak Demand	11,541	11,334	12,543	15,860	15,903	13,917
	Oct.	Nov.	Dec.	Jan.	Feb.	Mar.
Peak Demand	11,798	12,387	14,085	14,855	14,835	13,337

Table 1-3 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	11,593	11,381	12,596	15,909	15,953	13,960
	Oct.	Nov.	Dec.	Jan.	Feb.	Mar.
Peak Demand	11,833	12,415	14,115	14,883	14,863	13,362

c. Annual Electric Energy Requirements

Table 1-4 shows the preliminary data[5] for FY 2020 and the forecast value for FY 2021 from the aggregated electric energy requirements of each regional service area submitted by the 10 GT&D companies.

The electric energy requirements for FY 2021 are forecast at 866.7 TWh, a 1.9% increase over the 850.8 TWh in the preliminary data for FY 2020.

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

FY 2020 Preliminary (temperature- and leap-year-adjusted)	FY 2021 Forecast
850.8	866.7(+1.9%*)

* % 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 major economic indicators developed and published on November 25, 2020 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 ¥502.3 trillion in FY 2020 and ¥555.2 trillion in FY 2030 with an annual average growth rate (AAGR) of 1.0%. The index of industrial production (IIP)[7] is projected at 88.2 in FY 2020 and 104.5 in FY 2030 with an AAGR of 1.7%. By contrast, the population is estimated at 125.72 M. in FY 2020 and 119.50 M. in FY 2030 with an AAGR of -0.5%.

Table 1-5 Major Economic Indicators Assumed for Demand Forecast

	FY 2020	FY 2030
Gross Domestic Product(GDP)	¥502.3 trillion	¥555.2 trillion [+1.0%]*
Index of Industrial Product(IIP)	88.2	104.5 [+1.7%]*
Population	125.72 M	119.50 M [-0.5%]*

* Average annual growth rate for the forecast value of FY 2020.

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

Table 1-6 shows the peak demand forecast for FY 2021, FY 2025, and FY 2030 as the aggregation of peak demand for each regional service area submitted by the 10 GT&D companies. In addition, Figure 1-1 shows the actual data and the forecast of peak demand from FY 2009 to 2030.
The peak demand nationwide is forecast at 158,720 MW in FY 2025 and 156,950 MW in FY 2030, with an AAGR of -0.1% from FY 2020 to FY 2030.

The peak demand forecast over 10 years shows a slightly decreasing trend, which is largely due to negative factors, such as efforts to reduce electricity use, wider 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 2021 [aforementioned]	FY 2025	FY 2030
15,903	15,872 [-0.1%]*	15,695 [-0.1%]*

* Average Annual Growth Rate for the forecast value of FY 2020.

6 GDP expressed as the chained price for calendar year (CY) 2011.
7 Index value in CY 2015 = 100.

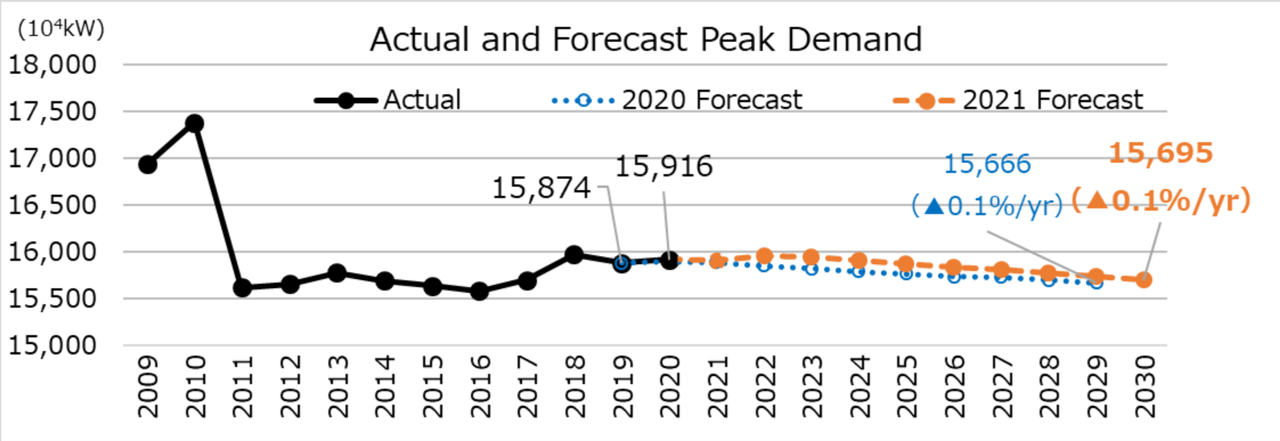


Figure 1-1 Actual and Forecast Peak Demand (August for Nationwide, 10^4 kW at the sending end)

b. Annual Electric Energy Requirement

Table 1-7 shows the forecast for annual electric energy requirements in FY 2021, FY 2025, and FY 2030 as the aggregation of the electric energy requirements for each regional service area submitted by the 10 GT&D companies.

The nationwide annual electric energy requirement is forecast at 866.3 TWh in FY 2025 and 857.9 TWh in FY 2030, with an AAGR of +0.1% increase from FY 2020 to FY 2030.

The annual electric energy requirement forecast over 10 years shows a slightly increasing trend, which is considered to be attributed to positive factors such as the expansion of economic scale and greater dissemination of electric appliances, offseting the negative factors, such as efforts to reduce electricity use, and a shrinking population under the circumstances that stagnant economic activity triggered by the global outbreak of COVID-19 is shortly remained to economic activity in the projected period.

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

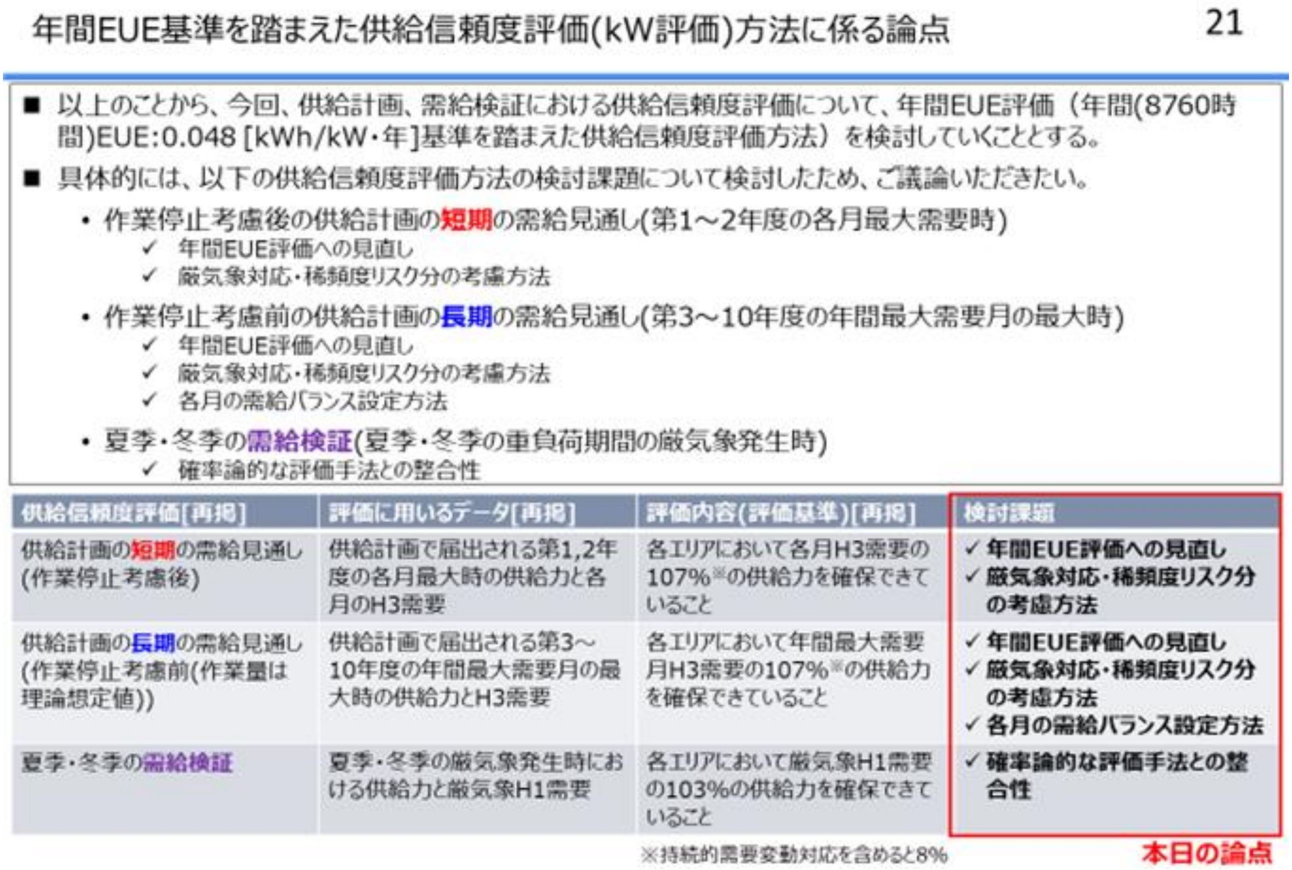
FY 2021 [aforementioned]	FY 2025	FY 2030
866.7	866.3 [+0.1%]*	857.9 [+0.1%]*

* AAGR for the forecast value of FY 2020.

II. Electricity Supply and Demand

1. Supply Reliability Criteria

The Organization has prepared to apply expected unserved energy (EUE) as a new reliablility criterion to the electricity supply plan based on the review of reliability criteria. Based on the discussions of the 58th meeting of the Study Committee on Regulating and Marginal Supply Capability and Long-Term Supply–Demand Balance Evaluation (March 3, 2021), the Organization has applied EUE as a reliability criterion. Annual EUE values of 0.048kWh/kW-year and 0.498kWh/kW-year for nationwide and for the Okinawa area, respectively, are the newly applied reliability criteria for the electricity supply plan. Figure 2-1 shows the summary of supply reliability evaluation (kW evaluation) based on annual EUE (available only in Japanese).



年間EUE基準を踏まえた供給信頼度評価(kW評価)方法に係る論点　21

■ 以上のことから、今回、供給計画、需給検証における供給信頼度評価について、年間EUE評価（年間(8760時間)EUE:0.048 [kWh/kW・年]基準を踏まえた供給信頼度評価方法）を検討していくこととする。

■ 具体的には、以下の供給信頼度評価方法の検討課題について検討したため、ご議論いただきたい。

- 作業停止考慮後の供給計画の短期の需給見通し(第1～2年度の各月最大需要時)
  - ✓ 年間EUE評価への見直し
  - ✓ 厳気象対応・稀頻度リスク分の考慮方法
- 作業停止考慮前の供給計画の長期の需給見通し(第3～10年度の年間最大需要月の最大時)
  - ✓ 年間EUE評価への見直し
  - ✓ 厳気象対応・稀頻度リスク分の考慮方法
  - ✓ 各月の需給バランス設定方法
- 夏季・冬季の需給検証(夏季・冬季の重負荷期間の厳気象発生時)
  - ✓ 確率論的な評価手法との整合性

供給信頼度評価[再掲]	評価に用いるデータ[再掲]	評価内容(評価基準)[再掲]	検討課題
供給計画の短期の需給見通し(作業停止考慮後)	供給計画で届出される第1,2年度の各月最大時の供給力と各月のH3需要	各エリアにおいて各月H3需要の107%※の供給力を確保できていること	✓ 年間EUE評価への見直し ✓ 厳気象対応・稀頻度リスク分の考慮方法
供給計画の長期の需給見通し(作業停止考慮前(作業量は理論想定値))	供給計画で届出される第3～10年度の年間最大需要月の最大時の供給力とH3需要	各エリアにおいて年間最大需要月H3需要の107%※の供給力を確保できていること	✓ 年間EUE評価への見直し ✓ 厳気象対応・稀頻度リスク分の考慮方法 ✓ 各月の需給バランス設定方法
夏季・冬季の需給検証	夏季・冬季の厳気象発生時における供給力と厳気象H1需要	各エリアにおいて厳気象H1需要の103%の供給力を確保できていること	✓ 確率論的な評価手法との整合性

※持続的需要変動対応を含めると8%　本日の論点

Figure 2-1 Summary of Supply Reliability Evaluation (in kW) based on Annual EUE

[Source]Marerial 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

Figure 2-2 shows the evaluation of supply capacity by the conventional approach, which is supplementally implemented as well as EUE approach (available only in Japanese).

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

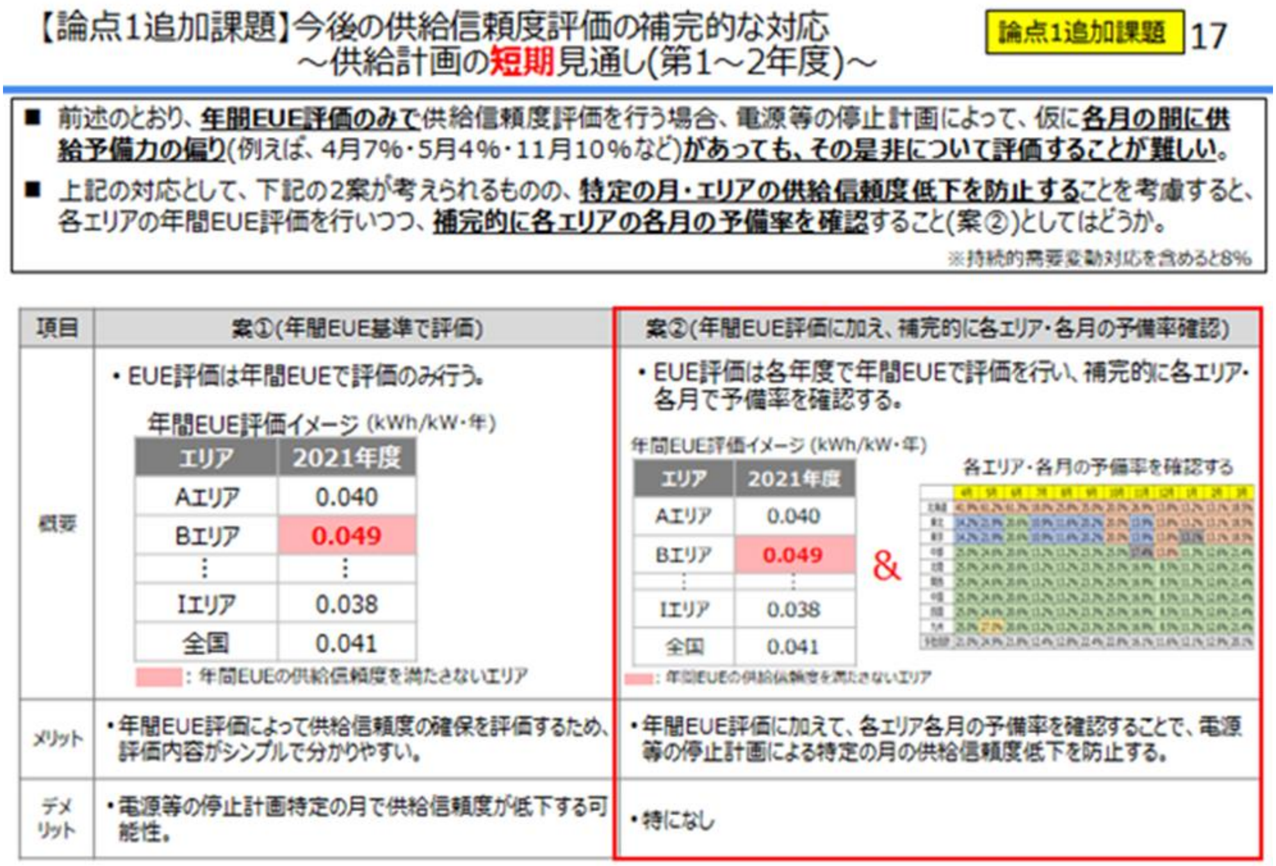


Figure 2-2 Summary of Evaluation of Supply Capacity by Conventional Approach

[Source]Marerial 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

(Reference) Characteristics of Annual EUE

Figure 2-3 shows characteristics of annual EUE. For evaluation by annual EUE criteria, the stable supply is secured through the year at the usual level if annual EUE value is less than 0.048 kWh/kW-year.

However, 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 implements an evaluation of the reserve capacity for each month by a conventional approach.

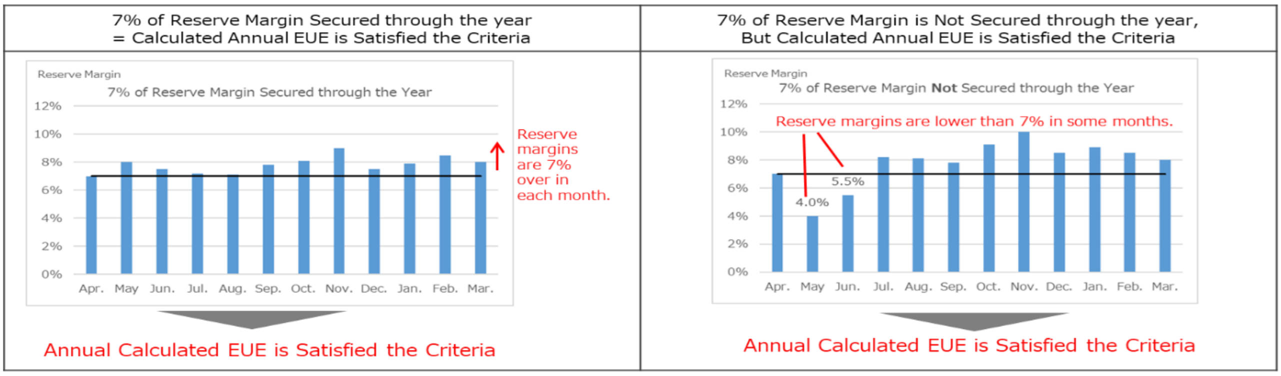


Figure 2-3 Characteristics of Annual EUE

2. Evaluation of Supply Capacity by EUE Approach in the Projected Period (FY 2021 through 2030)

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 in nationwide, 0.498kWh/kW-year in Okinawa). The maximum value in the projected period is 0.046kWh/kW-year for the Tokyo area in FY 2022, which means that there is rather high probability of supply interruption in the projected period.

In the long term, the calculated result for the Kyushu area after FY 2026 exceeds the criteria, which is because of uncertainty in the commercial operation of some large generating facilities in the area at the moment.

Currently, there are some areas and years that 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)

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Hokkaido	0.000	0.000	0.004	0.008	0.005	0.012	0.008	0.007	0.008	0.000
Tohoku	0.003	0.002	0.013	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Tokyo	0.028	0.046	0.026	0.001	0.000	0.000	0.000	0.000	0.000	0.000
Chubu	0.004	0.003	0.006	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Hokuriku	0.005	0.001	0.001	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Kansai	0.005	0.001	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Chugoku	0.005	0.001	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Shikoku	0.005	0.001	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Kyushu	0.008	0.001	0.013	0.022	0.041	0.594	0.508	0.581	0.493	0.184
Interconnected	0.013	0.016	0.012	0.003	0.004	0.057	0.049	0.056	0.047	0.018
Okinawa	0.035	0.031	0.034	0.023	0.292	0.058	0.061	0.069	0.080	0.087

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

The Organization will evaluate the supply–demand balance for each regional service area as well as nationwide using the supply capacity[8] and peak demand data for the regional service areas.

The Organization will implement its evaluation using the criterion of whether or not the reserve margin (%)[9] 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 and the evaluation will be implemented at the time of the least reserve margin.

Figure 2-4 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 production of surplus power[10] of generation companies. The supply capacity currently secured by retail companies includes power procured[11] from other regional service areas through cross-regional interconnection lines. Thus, the surplus power of generation companies or the reserve capacity of retail companies might provide the supply capacity for other regional service areas in the future.

Under the circumstances in which the operation of a nuclear power plant becomes uncertain, the supply capacity of the corresponding unit or plant is recorded as zero where the corresponding supply capacity is reported as "uncertain" according to Procedures for Electricity Supply Plans of FY 2021, published in December 2020 by the Agency for Natural Resources and Energy. In the electricity supply plans for FY 2020, the supply capacity was reported as "uncertain" for all nuclear power plants except those that had resumed operation by the time of the submission of the electricity supply plans (March 1, 2021).

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

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

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

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

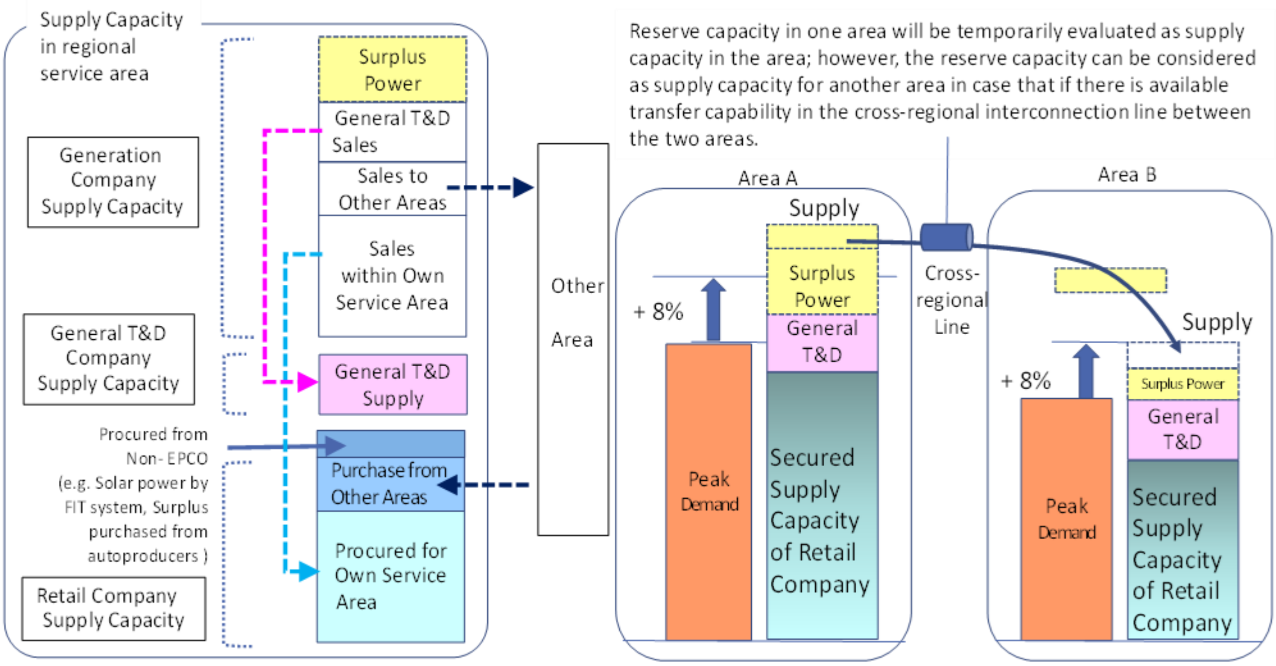

Figure 2-4 Summary of Supply–Demand Balance Evaluation

[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"[12](Agency for Natural Resources and Energy: December 2020) and "Procedures for Electricity Supply Plans of FY 2021"[13](Agency for Natural Resources and Energy: December 2019).

[12] 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

[13] 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).

<u>Short term</u>

(1): Based on "Transfer Capability of Cross-regional Interconnection Lines FY 2021-2030" [annual and long-term plans] (February 12, 2021: The Organization)[14]

(2): Based on "Transfer Margin of Cross-regional Interconnection Lines FY 2021 and 2022" [annual plan] (February 12, 2021: The Organization)[15][16]

(3): Based on monthly scheduled power flows reported in the "Plan for Transaction of Electricity (Table 36)" of the electricity supply plan for FY 2021

<u>Mid-to-Long term</u>

(1): For FY 2021 and 2022, the August value calculated from (1) in short term above; for FY 2023-2030, based on "Transfer Capability of Cross-regional Interconnection Lines FY 2021-2030" [annual and long-term plans] (February 21, 2021: The Organization)[14]

(2): For FY 2021 and 2022, the August value calculated from (2) in short term above; for FY 2023-2030, based on "Transfer Margin of Cross-regional Interconnection Lines FY 2021-2030" [long-term plans] (Febrary 21, 2021: The Organization) [15]

(3): Based on 15:00 h in August scheduled power flows of the period reported in "Plan for Transaction of Electricity (Table 32-8)" of the electricity supply plan for FY 2021

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[14] 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/2020/unyouyouryou_2020_4_haifu.html

[15] Reference: material from the "3rd Meeting of the Working Group on Transmission Margin" (only in Japanese) http://www.occto.or.jp/iinkai/margin/2020/margin_kentoukai_2020_3.html

[16] The value of the transfer margin for FY 2022 is calculated based on the "Transfer Margin of Cross-regional Interconnection Lines FY 2021 and 2022" [annual plan] (Mar. 1, 2021: The Organization)

a. Projection of Supply–Demand Balance in FY 2021 and 2022

(i) Projection for FY 2021

Table 2-2 shows the monthly projection of the least reserve margin for each regional service area recalculated to levelize using power exchanges to areas below the 8% reserve margin from areas of over the 8% reserve margin based on the ATC.[17]

Further, information on environmental assessment of thermal power plants[18] 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, although 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. Table 2-2 includes the result of the investigation, which shows that the reserve margins are below the criteria of 8% in the Tokyo area for July 2021 and January 2022. In addition, reserve margins for February 2022 are below 8% in the regional service areas of Tohoku, Tokyo, Chubu, Hokuriku, Kansai, Chugoku, Shikoku, and Kyushu.

Table 2-2 Monthly Projection of the Least Reserve Margins Nationwide and for Each Regional Service Area (with power exchanges through cross-regional interconnection lines and generating facilities not included in the electricity supply plans, at the sending end)

	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.	Jan.	Feb.	Mar.
Hokkaido	29.5%	55.6%	54.0%	32.9%	37.7%	47.9%	43.6%	25.7%	13.1%	13.4%	12.3%	14.9%
Tohoku	17.7%	26.5%	21.0%	17.5%	16.1%	16.6%	19.2%	10.5%	13.1%	13.4%	12.3%	13.3%
Tokyo	17.7%	22.7%	21.0%	**7.5%**	8.9%	16.6%	19.2%	10.5%	11.5%	**7.7%**	**5.8%**	13.3%
Chubu	23.6%	24.6%	25.2%	9.2%	10.3%	16.6%	27.2%	20.1%	11.5%	8.8%	**5.8%**	14.8%
Hokuriku	23.6%	24.6%	25.2%	9.2%	10.3%	16.6%	27.2%	20.1%	11.5%	8.8%	**5.8%**	14.8%
Kansai	23.6%	24.6%	25.2%	9.2%	10.3%	16.6%	28.1%	20.1%	11.5%	8.8%	**5.8%**	14.8%
Chugoku	23.6%	24.6%	25.9%	9.2%	10.3%	16.6%	28.1%	20.1%	11.5%	8.8%	**5.8%**	14.8%
Shikoku	23.6%	24.6%	25.9%	9.2%	10.3%	16.6%	28.1%	20.1%	11.5%	8.8%	**5.8%**	14.8%
Kyushu	28.9%	27.1%	27.6%	10.6%	15.5%	27.2%	28.1%	20.1%	11.5%	8.8%	**5.8%**	14.8%
Interconnected	21.7%	25.4%	24.6%	10.0%	11.5%	18.5%	24.5%	16.2%	11.7%	9.0%	**6.6%**	14.2%
Okinawa	55.8%	54.4%	30.9%	30.3%	32.3%	38.7%	48.9%	56.2%	74.2%	66.4%	64.7%	86.0%
Nationwide	22.1%	25.7%	24.7%	10.2%	11.7%	18.7%	24.7%	16.6%	12.2%	9.4%	**7.0%**	14.7%

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

In the Okinawa EPCO regional service area,[19] which is a small and isolated island system unable to receive power through interconnection lines, the criterion of stable supply is to secure supply capacity over peak demand by deducting the capacity of the largest generating unit and the balancing capacity with frequency control ('Generator I', 301 MW in total), without applying the criteria of other interconnected areas.[20]

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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: Information on 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

19 In the Okinawa EPCO regional service area, the evaluation excludes the reserve margins of several isolated islands.

20 The evaluation is implemented at the time of the least reserve margin instead of the peak demand occurrence.

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

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

	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.	Jan.	Feb.	Mar.
Okinawa	26.7%	29.1%	10.0%	9.4%	11.6%	18.0%	25.7%	29.3%	43.1%	36.6%	34.5%	53.7%

(ii) Projection for FY 2022

Table 2-4 shows the result of the similar calculation for FY 2022, which shows reserve margins are below the criteria of 8% in the Tokyo area for July, November 2022, and January through March 2023. In addition, reserve margins for July 2022 are below 8% in each regional service area of Chugoku, and Shikoku.

Table 2-4 Monthly Projection of the Least Reserve Margins Nationwide and for Each Regional Service Area
(with power exchanges through cross-regional interconnection lines and generating facilities not included in the electricity supply plans, at the sending end)

	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.	Jan.	Feb.	Mar.
Hokkaido	23.8%	36.4%	45.2%	32.2%	35.0%	42.8%	31.8%	22.4%	23.8%	20.8%	23.7%	27.9%
Tohoku	23.8%	29.6%	20.9%	17.6%	17.9%	28.6%	31.8%	22.4%	22.8%	20.8%	23.7%	27.9%
Tokyo	15.9%	26.6%	20.9%	**6.8%**	8.0%	13.2%	20.2%	**7.6%**	12.0%	**6.3%**	**6.1%**	**7.5%**
Chubu	19.2%	26.6%	22.3%	**7.1%**	8.9%	13.2%	20.2%	10.7%	12.4%	10.8%	10.0%	17.8%
Hokuriku	19.2%	26.6%	22.3%	**7.1%**	8.9%	16.4%	20.2%	10.7%	12.4%	10.8%	10.0%	18.9%
Kansai	19.2%	26.6%	22.3%	**7.1%**	8.9%	16.4%	22.0%	18.2%	12.4%	10.8%	10.0%	18.9%
Chugoku	19.2%	26.6%	22.3%	**7.1%**	8.9%	16.4%	22.0%	18.2%	12.4%	10.8%	10.0%	18.9%
Shikoku	19.2%	26.6%	22.3%	**7.1%**	8.9%	16.4%	23.5%	18.2%	12.4%	10.8%	10.0%	18.9%
Kyushu	29.7%	34.2%	28.7%	9.7%	11.7%	32.2%	35.5%	26.8%	12.4%	13.4%	10.0%	18.9%
Interconnected	19.6%	27.9%	23.0%	8.7%	10.3%	18.1%	23.6%	14.6%	13.6%	10.8%	10.4%	16.1%
Okinawa	62.8%	51.4%	39.7%	40.3%	43.6%	45.0%	49.8%	53.0%	58.3%	58.3%	84.4%	92.6%
Nationwide	20.0%	28.1%	23.2%	9.0%	10.6%	18.4%	23.9%	15.0%	14.0%	11.2%	10.9%	16.7%

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

In the Okinawa EPCO regional service area,[21] which is a small and isolated island system unable to receive power through interconnection lines, 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', 301 MW in total), without applying the criteria of other interconnected areas.[22]

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

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

	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.	Jan.	Feb.	Mar.
Okinawa	34.0%	26.5%	19.1%	19.7%	23.2%	24.6%	26.9%	26.4%	27.5%	28.8%	54.5%	60.6%

[21] See footnote 19.
[22] See footnote 20.

b. Difference Between Projected Supply Capacity and Target Reserve Capacity (As the Criterion of 8% Reserve Margin)

(i) Projection for FY 2021

Table 2-6 shows the difference between projected supply capacity and target reserve capacity, calculated with a 8% reserve margin for FY 2021. It shows some shortage in the Tokyo area for 270 MW in July, 120 in January, and 2,840 in February for the Tokyo through Kyushu areas in total.

Table 2-6 Difference between Projected Supply Capacity and Target Reserve Capacity in FY 2021

[10^4 kW]

<table>
<tr><th></th><th>Apr.</th><th>May</th><th>Jun.</th><th>Jul.</th><th>Aug.</th><th>Sep.</th><th>Oct.</th><th>Nov.</th><th>Dec.</th><th>Jan.</th><th>Feb.</th><th>Mar.</th></tr>
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</table>

(ii) Projection for FY 2022

Table 2-7 shows the difference between projected supply capacity and target reserve capacity, calculated with a 8% reserve margin for FY 2022. It shows some shortage in the Tokyo area of 630 MW in July, 170 in November, 80 in January, 910 in February, 200 in March, and 660 in July for the Chugoku and Shikoku areas.

Table 2-7 Difference between Projected Supply Capacity and Target Reserve Capacity in FY 2022

[10^4 kW]

<table>
<tr><th></th><th>Apr.</th><th>May</th><th>Jun.</th><th>Jul.</th><th>Aug.</th><th>Sep.</th><th>Oct.</th><th>Nov.</th><th>Dec.</th><th>Jan.</th><th>Feb.</th><th>Mar.</th></tr>
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<tr><td>Nationwide</td><td></td><td></td><td></td><td>129</td><td></td><td></td><td></td><td>17</td><td></td><td>80</td><td>91</td><td>20</td></tr>
</table>

c. Difference Between Forecasted Peak Demand for FY 2021 Evaluated by the Conventional Approach

Table 2-8 shows a comparison of the peak demand forecast for FY 2021 between the supply plans of FY 2021 (the 1st year) and supply plans of FY 2020 (the 2nd year), for July 2021, January and February 2022, which has a lower reserve margin against the 8% criterion.

For the peak demand forecast, a slight increase is shown in July, but a decrease of 1,000 MW is expected in January and February 2022.

Table 2-8 Comparison of Peak Demand Forecast for FY 2021 between the FY 2021 Supply Plan (the 1st year) and FY 2020 Supply Plan(the 2nd year)

【Peak Demand Forecast】 [10^4 kW]

	FY 2021(2nd year of 2020 Plan)			FY 2021(1st year of 2021 Plan)			Balance		
Area	Jul.	Jan.	Feb.	Jul.	Jan.	2月	Jul.	Jan.	Feb.
Hokkaido	409	498	491	404	497	493	-5	-1	2
Tohoku	1,265	1,366	1,351	1,265	1,350	1,335	0	-16	-16
Tokyo	5,307	4,762	4,762	5,329	4,773	4,773	**22**	**11**	**11**
Chubu	2,473	2,305	2,305	2,453	2,285	2,285	-20	-20	**-20**
Hokuriku	495	490	490	492	489	489	-3	-1	**-1**
Kansai	2,663	2,449	2,449	2,726	2,431	2,431	63	-18	**-18**
Chugoku	1,046	1,036	1,036	1,032	1,025	1,025	-14	-11	**-11**
Shikoku	496	457	457	492	453	453	-4	-4	**-4**
Kyushu	1,538	1,492	1,492	1,521	1,451	1,451	-17	-41	**-41**
Total	15,692	14,855	14,833	15,714	14,754	14,735	**22**	**-101**	**-98**

d. Difference Between Projected Supply Capacity for FY 2021 Evaluated by the Conventional Approach

Table 2-9 shows a comparison of the supply capacity projection for FY 2021 between the supply plan of FY 2021 (the 1st year) and supply plan of FY 2020 (the 2nd year), for July 2021, January and February 2022, which has a lower reserve margin against the 8% criterion.

For the supply capacity projection, a significant decrease is shown, for 3,000 MW in July, 4,000 in January, and 5,500 in February.

Table 2-9 Comparison of Supply Capacity Projection for FY 2021 between FY 2020 Supply Plan (the 2nd year) and FY 2021 Supply Plan (the 1st year)

【Supply Capacity Projection】 [10^4 kW]

	FY 2021(2nd year of 2020 Plan)			FY 2021(1st year of 2021 Plan)			Balance		
Area	Jul.	Jan.	Feb.	Jul.	Jan.	2月	Jul.	Jan.	Feb.
Hokkaido	541	639	636	576	578	578	35	-61	-58
Tohoku	1,586	1,657	1,643	1,534	1,568	1,562	-52	-89	-81
Tokyo	5,545	5,082	4,989	5,636	5,091	5,014	**91**	**9**	**24**
Chubu	2,632	2,453	2,397	2,571	2,503	2,446	-61	51	**49**
Hokuriku	568	534	536	564	506	505	-4	-28	**-31**
Kansai	2,889	2,652	2,693	2,777	2,559	2,426	-112	-93	**-267**
Chugoku	1,320	1,165	1,179	1,283	1,128	1,123	-37	-37	**-56**
Shikoku	617	545	536	612	530	527	-5	-16	**-9**
Kyushu	1,869	1,758	1,648	1,736	1,627	1,528	-134	-132	**-119**
Total	17,568	16,485	16,257	17,290	16,089	15,708	**-277**	**-396**	**-549**

e. Difference Between Scheduled Maintenance of Generating Facility for FY 2021 Evaluated by the Conventional Approach

Figure 2-5 shows the monthly scheduled maintenance planned for FY 2021 in the 2021 Supply Plan. Figure 2-6 shows the difference in scheduled maintenance for FY 2021 between the supply plans of FY 2021(the 1st year) and supply plans of FY 2020 (the 2nd year).

The Organization has requested that all EPCOs avoid the peak period in the summer and winter for their scheduled maintenance of generating facilities as " Request for Systematically Securing Supply Capacity"; however, the schedule maintenance in February 2022 is particularly increasied compared with the 2020 Supply Plan.

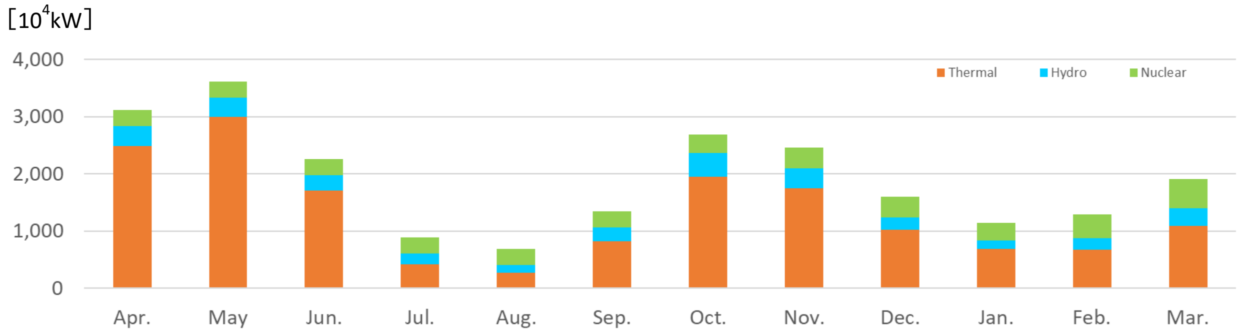


Figure 2-5 Monthly Scheduled Maintenance Planned for FY 2021 in 2021 Supply Plan

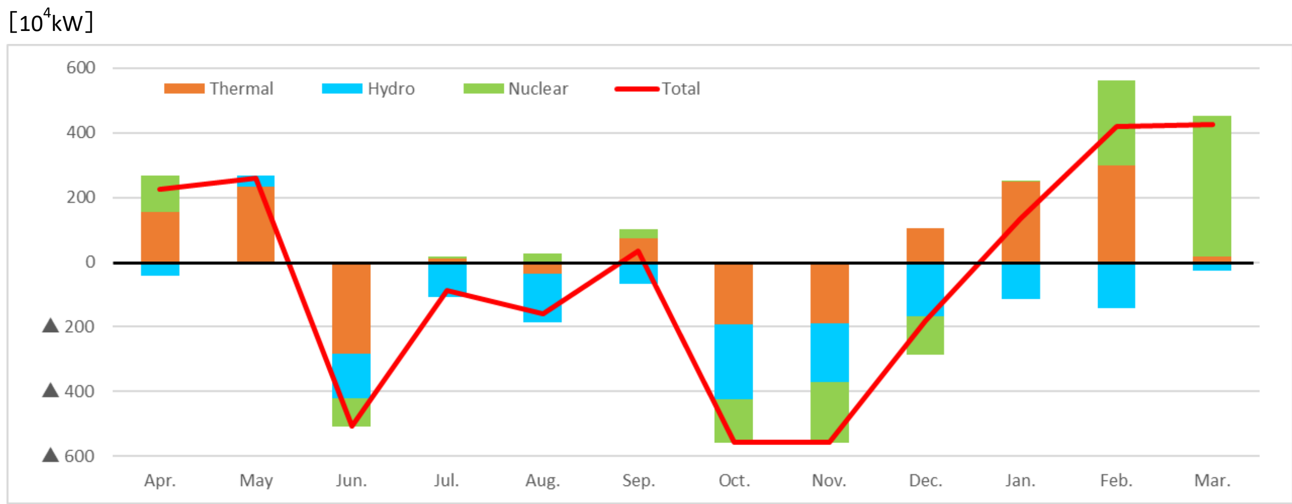


Figure 2-6 Difference in Scheduled Maintenance for FY 2021 between FY 2020 (the 2nd year) and FY 2021 (the 1st year) Supply Plan

f. Suspension and Decommissioning of Generating Facilities in 2021 Supply Plan

Table 2-10 shows suspension and decommissioning of generating facilities in the 2021 Supply Plan. In the plan, additional capacity of 660 MW is newly included in the suspension and decommissioning plan.

Besides, there is 5,490 MW of generating facilities which has already been included in the suspension and decommissioning plan after FY 2021. In total, there is 6,150 MW capacity planned for the suspension and decommissioning in the projected period.

Table 2-10 Suspension and Decommissioning of Generating Facilities in 2021 Supply Plan (10^4 kW)

Fuel	Newly Added	Already Included	Total Capacity to be Decommissioned
LNG	10	549	559
Oil	20	–	20
Coal	36	–	36
Total	**66**	**549**	**615**

g. Capacity Secured and Surplus Power Evaluatied by the Conventional Approach

Figure 2-7 shows a comparison between the supply capacity to be procured* 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 January and Februrary 2022.

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

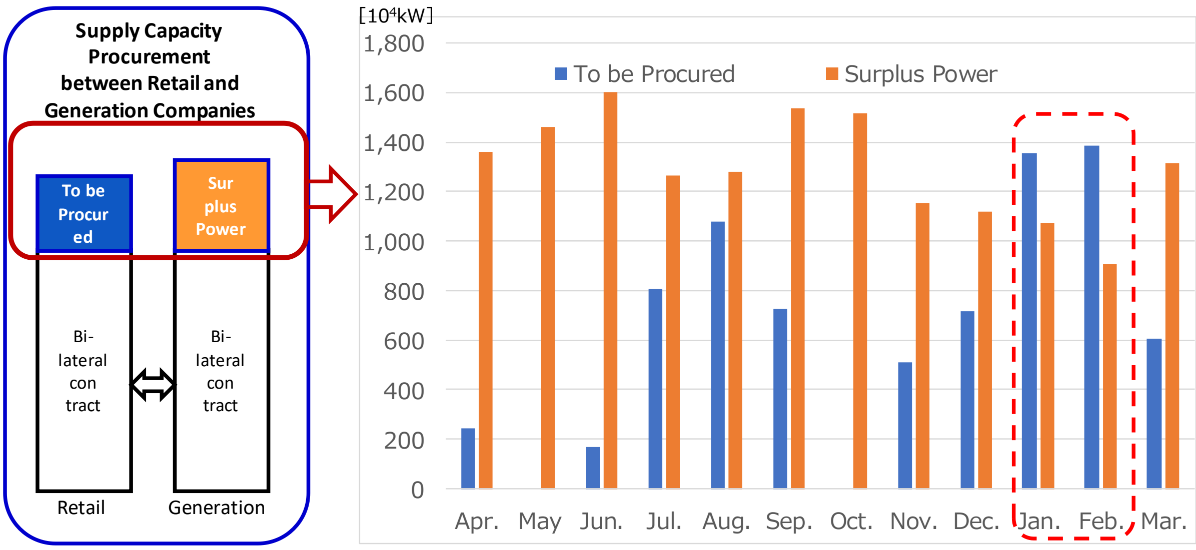


Figure 2-7 Comparison between Supply Capacity to be Procured by a Retail Company for their Forecasted Peak Demand and Surplus Power of Generation Companies

h. Summary of Supply Capacity Evaluated by the Conventional Approach

As mentioned, the Organization has confirmed that the reserve margin of 8% will not be achieved for multiple regions in particular in February 2022, due to the tendency of th reserve capacity in each month caused by scheduled maintenance of the generating facility, even if annual EUE is achieved for the short term. The Organization has been concerned with the probability of a tight supply-demnd balance by a major shutdown of the generating facility during the peak demand period in winter unless proper countermeasure are implemented.

Therefore, the Organization has confirmed with the EPCOs that if their scheduled maintenance plans and long-term suspension plans are capable of changing their schedules, and are coordinated so that the subject generating facility can be counted as additional supply capacity.

The Organization has continued the above measures to achieve further improvement of the reserve margin. Thus, the Organization decided not to implement a review of safeguard measures of capacity procurement at this point.

4. Evaluation of Energy Supply

For evaluation of the energy supply (kWh), the Organization plans to implement an annual evaluation, known as an Electricity Supply-Demand Verification," in autumn, when information for winter demand forecast, such as weather forecast is obtained, and additional generation fuel can be available. In addition to the evaluation in autumn, the Organization plans to monitor energy supply twice a month and publish the results.

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

a. Projection of Energy Supply

Figure 2-8 shows the monthly energy supply balance for a total of interconnected nine areas in FY 2021(the 1st year of projected period of FY 2021 plans). Table 2-11 shows the forecasted energy requirement of the FY 2021 plan, and volumes and rates of shortage from the forecast. It seems that the energy supply* will be less than the forecasted energy requirement by 0.1 to 3.2 TWh/month of volume (equivalent to 0.1 to 4.3% against the forecast energy requirement) throughout the year.
* 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.

The Organization expects that retail companies shall premeditatedly accomplish procurement of supply capacity, and generation companies shall additionally procure generation fuel to increase energy generation for actual demand and supply timing based on the projection.

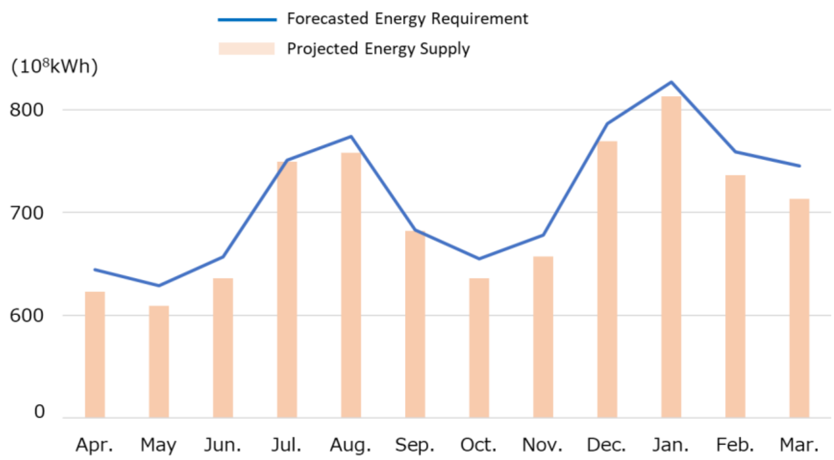


Figure 2-8 Monthly Energy Supply Balance for a Total of Interconnected Nine Areas in FY 2021

Table 2-11 Forecasted Energy Requirement of FY 2021 Plan, Volumes and Rates of Shortage from the Forecast

(10^8kWh)

	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.	Jan.	Feb.	Mar.	Annual
Forecasted Energy Requirement	644	629	657	751	774	683	655	678	786	827	759	745	8,588
Projected Shortage from Energy Requirement	-21	-20	-21	-2	-16	-1	-19	-21	-17	-14	-23	-32	-207
Shortage Rate for Energy Requirement	-3.4%	-3.2%	-3.2%	-0.4%	-2.0%	-0.1%	-2.8%	-3.1%	-2.0%	-1.8%	-3.0%	-4.3%	-2.4%

For increase in energy supply, it is seen that some EPCOs will add supply capacity for actual supply-demand timing. Actual increases in energy supply by about 7% compared with the projected figure (mainly from thermal power generation) were experienced at the past supply plan, and generation companies intend to procure additional generation fuel, which became clear at the hearing opportunity in the aggregation of supply plans. In particular, as a tighter supply-demand balance is projected in the winter peaking period, the Organization implements an evaluation of the electricity supply-demand verification, monitors the balance twice a month afterward, and publishes its result.

[Reference] Actual Supply-Demand Balance of Energy Supply in FY 2020 Supply Plans

Figure 2-9 shows the actual supply-demand balance of energy supply in the FY 2020 supply plans. Table 2-12 indicates the actual energy supply and requirement, and the balance and rates against the projected supply. There were times when the projected energy supplies were below the forecasted energy requirement by 0.7 to 2.8% in FY 2020. However, when the actual timing of supply-demand became nearer, according to procurement of supply capacity by retail companies, increased energy generation was added by the generation companies. (Basically, fluctuation of the energy requirement is absorbed by thermal power generation.)

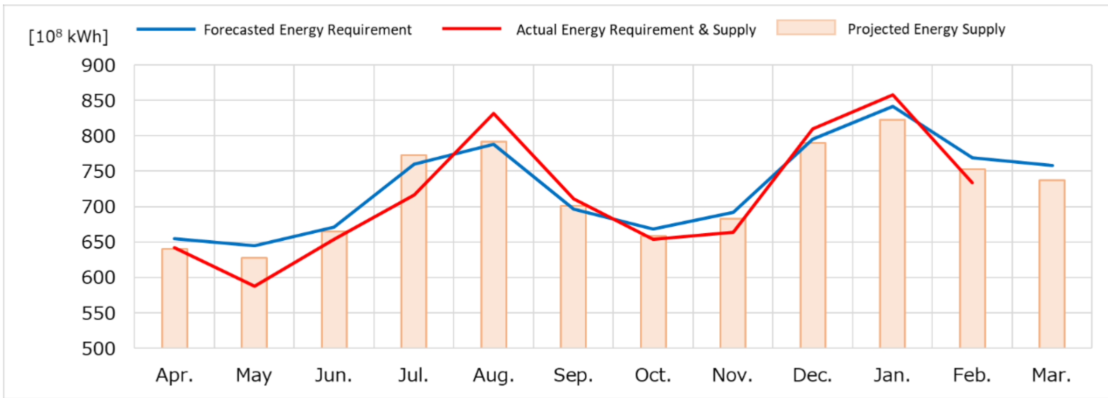


Figure 2-9 Actual Supply-Demand Balance of Energy Supply in FY 2020 Supply Plans

Table 2-12 Actual Energy Supply and Requirement, Balance and Rates against the Projected Supply

(10^8 kWh)

	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.	Jan.	Feb.	Mar.	Annual
a. Forecasted Energy Requirement	655	645	671	760	788	696	668	692	795	841	769	758	8,738
b. Projected Energy Supply	640	627	665	772	792	701	658	683	790	823	752	737	8,640
c. Balance between Projected Energy Supply and Forecasted Energy Requirement (b-a)	-14	-17	-7	12	4	5	-10	-8	-5	-19	-17	-21	-97
d.Variance from Forecasted Energy Requirement (c/a)	-2.2%	-2.7%	-1.0%	1.6%	0.5%	0.7%	-1.6%	-1.2%	-0.7%	-2.2%	-2.2%	-2.8%	-1.1%
e. Actual Energy Requirement & Supply	642	587	653	716	831	711	654	664	810	858	734		
f. Balance between Actual Energy Supply and Projected Energy Supply (e-b)	1	-40	-11	-56	39	10	-4	-19	20	36	-19		
g. Excess Rate of Actual Supply from Projected Supply (f/b)	0.2%	-6.3%	-1.7%	-7.2%	5.0%	1.4%	-0.6%	-2.8%	2.5%	4.3%	-2.5%		

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

Figure 2-10 shows the comparison of energy supply, which retail companies plans to procure at energy market and surplus energy that the generation companies are expected to provide to the market. Retail companies plan more energy procurement in the energy market in April, June, August, Februrary and March. However, it is expected that surplus energy provided will be less than what the retail companies expect in those months.

The Organization expects that retail companies shall premeditatedly achieve enregy procurement, and generation companies shall increase their energy generation based on this information.

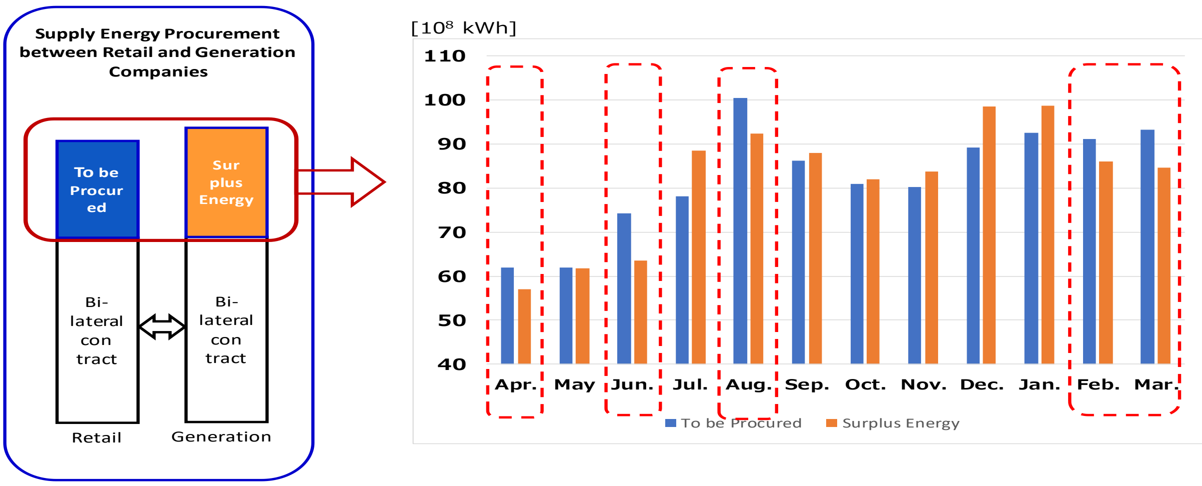


Figure 2-10 Comparison of Energy Supply Procurment of Retail Companies and Surplus Energy Provision

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

・ Evaluation of Supply Capacity by the EUE Approach

For short term of the projected period (FY 2021 and 2022), indices of EUE is satisfied in all areas and years. By contrast, for the mid-to-long term, the indices of EUE exceed the criteria for the Kyushu area after FY 2026.

・ Evaluation of Supply Capacity by the Conventional Approach

It is confirmed that the 8% resereve margin is not secured in FY 2021 and 2022 in several areas and for several months.

・ Evaluation of Energy Supply

It is expected that the energy supply in FY 2021 will be less than the forecasted energy requirement by 0.1 to 3.2 TWh/month of volume (equivalent to 0.1 to 4.3% against the forecast energy requirement) throughout the year.

Based on these evaluation, The Organization will implement the measures stated below. Figure 2-11 indicates the implementation schedules afterward (in Japanese only).

The Organization has confirmed that there are some areas and months that cannot secure an 8% reserve margin even if the annual EUE has satisfied its criteria in FY 2021 and 2022, and is concerened with the probability of a tight supply-demnd balance by a major shutdown of the generating facility during peak demand period in winter, unless proper countermeasure are implemented.

However, for immediate implementation of safeguard measures of generator procurement at this point, it shall lead to excessive supply capacity and procurement cost that may be procured in market trading at the proper cost; thus, the Organization considers that implementation of safeguard measures of generator procurement is not rational.

On this account, the Organization confirmed with EPCOs whether any rescheduling of scheduled maintenance work is available, or suspension of aged generators will be postponed. It has coordinated that the confirmation above leads to additional supply capacity to be used. Hereafter, publishing the result of the confirmation and the coordination above, the Organization will reconfirm with retail and generation companies sufficient preparedness for supply-demand tightness. If they do not have sufficient countermeasures, the Organization recommends to them proper measures for supply capacity procurement.

Further, in the event of not achieving improvement of the supply-demand balance with proper countermeasures of retail and generation companies, the Organization will determine again the implementation of safeguard measures of generator procurement in the short term period at the April meeting of the Study Committee on Regulating and Marginal Supply Capability and Long-Term Supply–Demand Balance Evaluation.

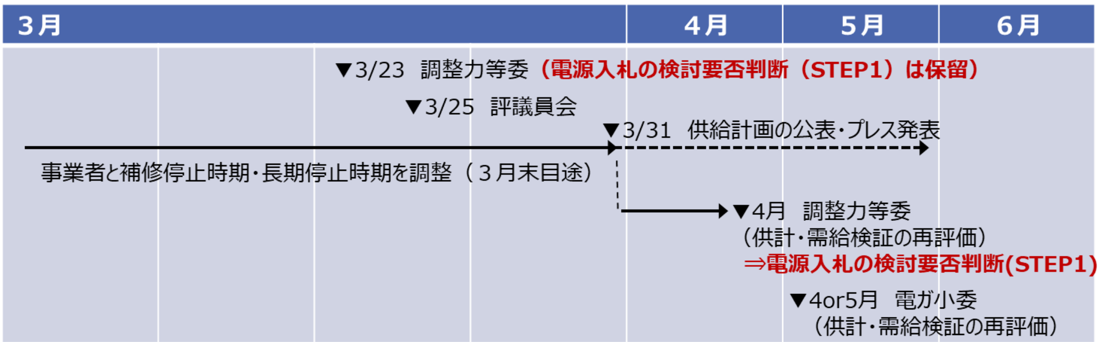
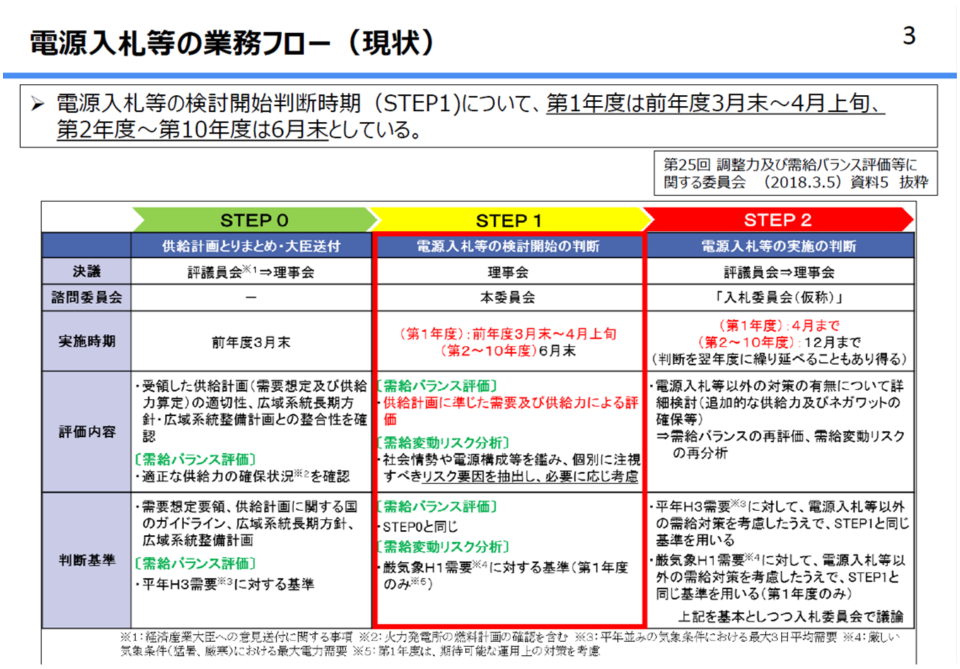


Figure 2-11 Review and Implementation Schedules of Supply-demand Evaluation and Supply Capacity Procurement

[Reference] Safeguard Measures of Generator Procurement

Figure 2-12 indicates the operational flow of safeguard measures for generator procurement (in Japanese only).

Safeguard measures for generator procurement is a scheme that procures supply capacity to secure the supply-demand balance. This scheme is composed of two steps: at STEP 1, the Organization determines the necessity for review of the procurement after the aggregation of electricity supply plans and the result of verification of demand and supply, and at STEP 2, the Organization launches a "Bidding Committee" (provisional name) to determine implementation of the procurement based on the determination of STEP 1.



	STEP 0	STEP 1	STEP 2
	供給計画とりまとめ･大臣送付	電源入札等の検討開始の判断	電源入札等の実施の判断
決議	評議員会※1⇒理事会	理事会	評議員会⇒理事会
諮問委員会	―	本委員会	「入札委員会(仮称)」
実施時期	前年度3月末	(第1年度):前年度3月末～4月上旬 (第2～10年度)6月末	(第1年度):4月まで (第2～10年度):12月まで (判断を翌年度に繰り延べることもあり得る)
評価内容	･受領した供給計画(需要想定及び供給力算定)の適切性、広域系統長期方針･広域系統整備計画との整合性を確認 〔需給バランス評価〕 ･適正な供給力の確保状況※2を確認	〔需給バランス評価〕 ･供給計画に準じた需要及び供給力による評価 〔需給変動リスク分析〕 ･社会情勢や電源構成等を鑑み、個別に注視すべきリスク要因を抽出し、必要に応じ考慮	･電源入札等以外の対策の有無について詳細検討(追加的な供給力及びネガワットの確保等) ⇒需給バランスの再評価、需給変動リスクの再分析
判断基準	･需要想定要領、供給計画に関する国のガイドライン、広域系統長期方針、広域系統整備計画 〔需給バランス評価〕 ･平年H3需要※3に対する基準	〔需給バランス評価〕 ･STEP0と同じ 〔需給変動リスク分析〕 ･厳気象H1需要※4に対する基準(第1年度のみ※5)	･平年H3需要※3に対して、電源入札等以外の需給対策を考慮したうえで、STEP1と同じ基準を用いる ･厳気象H1需要※4に対して、電源入札等以外の需給対策を考慮したうえで、STEP1と同じ基準を用いる(第1年度のみ) 上記を基本としつつ入札委員会で議論

※1:経済産業大臣への意見送付に関する事項 ※2:火力発電所の燃料計画の確認を含む ※3:平年並みの気象条件における最大3日平均需要 ※4:厳しい気象条件(猛暑、厳寒)における最大電力需要 ※5:第1年度は、期待可能な運用上の対策を考慮

Figure 2-12 Operational Flow of Safeguard Measures of Generator Procurement

[Source]Marerial 3, 36th meeting of the Study Committee on Regulating and Marginal Supply Capability and Long-Term Supply–Demand Balance Evaluation (February 19, 2019)
https://www.occto.or.jp/iinkai/chouseiryoku/2018/files/chousei_jukyu_36_03.pdf

[Reference] Detailed Analysis of the Aggregation

a. Transition of Supply Capacity by Generation Sources

Figure 2-13 shows the supply capacity (nationwide in August, at 15:00 h) by power generation source in the projected period.

Supply capacity of new energy, etc. is projected to increase. Thermal power is projected to temporarily decrease through replacement according to future power development and reach its bottom in FY 2022 and 2023, after which it increases due to replacement or new installations.
As a whole, supply capacity is projected to decrease slightly in the coming years, but thereafter increases.

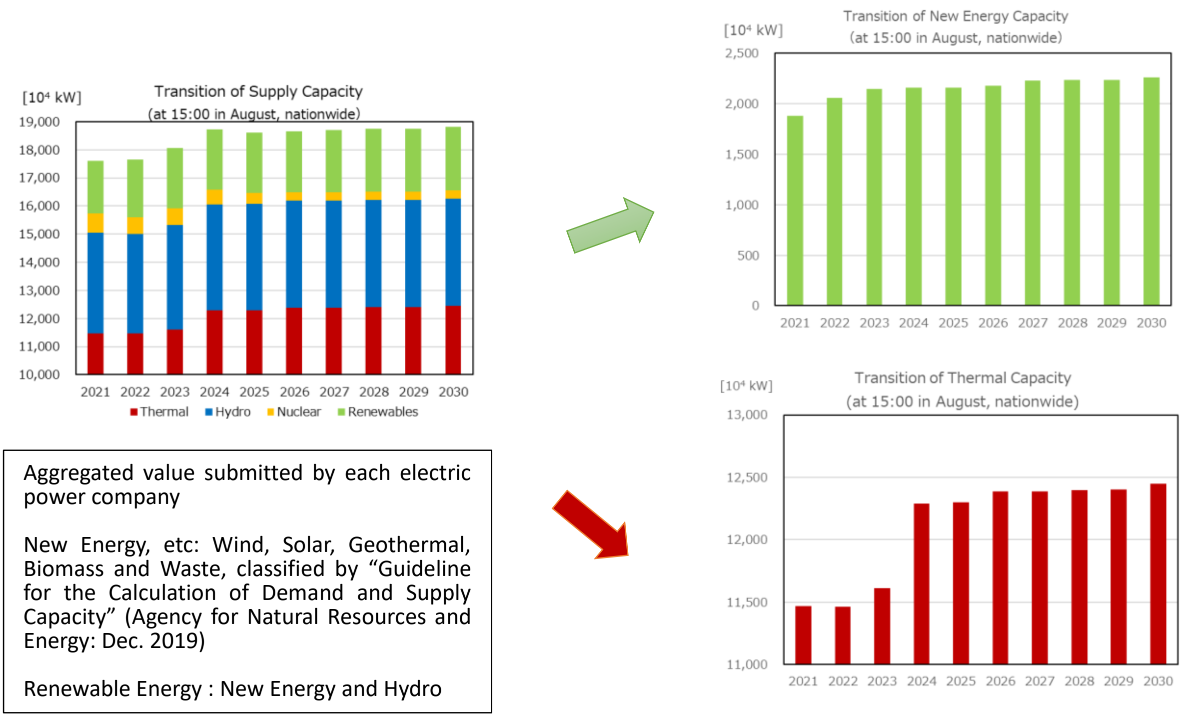


Figure 2-13 Transition of Supply Capacity by Generation Sources

b. Transition of Suspended Thermal Power Plants

Figure 2-14 shows mid-to-long-term projections of suspended thermal power plants (18-22 GW), which are not counted as part of the supply capacity due to long-term planned outage. The Organization has conducted hearings from EPCOs regarding whether the suspended plants can postpone their decomission or they can return power generation around one year with judgment and preparation in the proper timing. As a result, it is possible that suspended thermal 6-11 GW power plants will be counted on as an additional supply capacity.

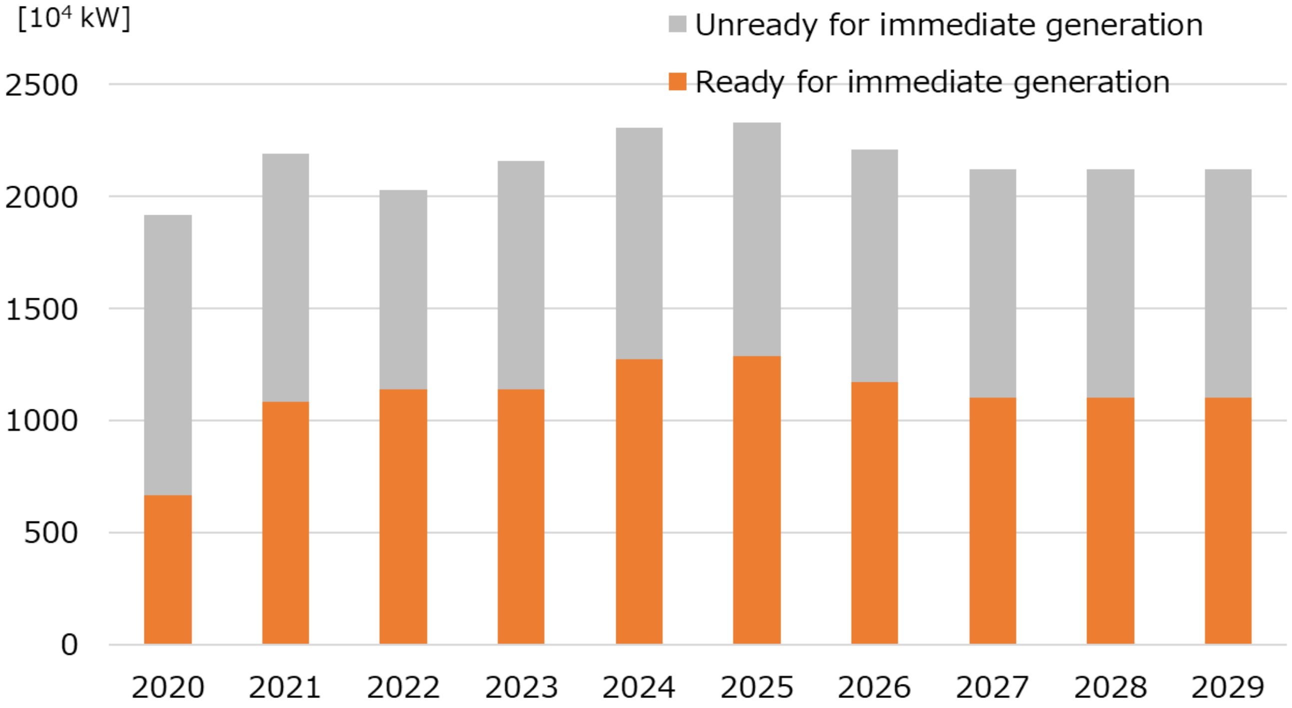


Figure 2-14 Projections of Suspended Thermal Power Plants

III. Analysis of the Transition of Power Generation Sources

The analysis in this chapter is based on the automatic aggregation of values submitted by EPCOs. It is noted that 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 electric power plants owned by EPCOs and feed-in-tariff (FIT) generators owned by companies other than EPCOs that are registered as procurers of supply capacity of retail and GT&D companies in the projected period. For the development plans of EPCOs, only generating facilities that have a given probability of development are included in the calculation; however, not all development plans will necessarily be realized, and inefficient facilities will proceed toward decomission resulting from actions 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
For existing facilities, the generation company aggregates the generating facility that it owns. For a newly installed facility, a generating facility such as in the course of proceeding with its environmental assessment or publishing its commercial operation, is included in the aggregation. The same concept is applied to geothermal, biomass and wastes power generation sources.

*2 Nuclear
The generation company aggregates its generating facilities that have actual operation experience, in addition to 33 units for which the date for resuming operation is uncertain, and excluding 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 aggregated values of the EPCOs submission based on the concepts above.

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

Power Generation Sources		2020	2021	2025	2030
Thermal*1		15,990	15,809	16,524	16,437
	Coal	4,593	4,815	5,284	5,281
	LNG	8,430	8,113	8,453	8,367
	Oil and others[23]	2,967	2,882	2,787	2,789
Nuclear*2		3,308	3,308	3,308	3,308
Renewables		11,958	12,519	14,044	15,136
	Conventional Hydro	2,167	2,171	2,188	2,195
	Pumped Storage	2,747	2,747	2,747	2,747
	Wind*3	444	540	978	1,505
	Solar*3	6,123	6,569	7,490	8,051
	Geothermal*1	53	53	55	55
	Biomass*1	339	366	517	513
	Waste*1	84	74	69	69
Miscellaneous		27	24	27	27
Total		31,283	31,661	33,903	34,909

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

*1 The Organization automatically aggregates the value of the genererating facility that the generation company owns; however, not all development plans will necessarily be realized, and inefficient facilities will proceed to be retired resulting from actions due to political measures in the future. For newly installing facility, generating facility such as in the course of proceeding its environmental assessment or publishing its commercial operation, is included in the aggregation.

*2 Included are the facilities which has actual operation experience, in addition to 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 application of preliminary consultation and the available connecting capacity of its transmission lines or the actual growth trend of integration.

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

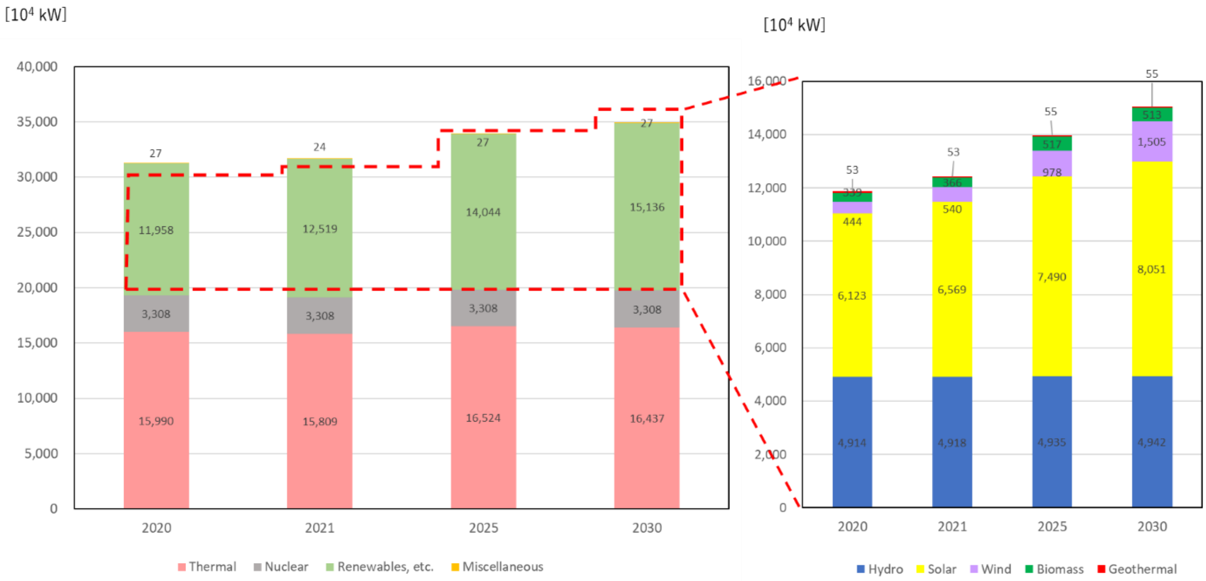


Figure 3-1 Transition of Installed Power Generation Capacities by Power Generation Sources (Nationwide)

* The sum of the installed power generation capacity by each power generation source 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 2020.

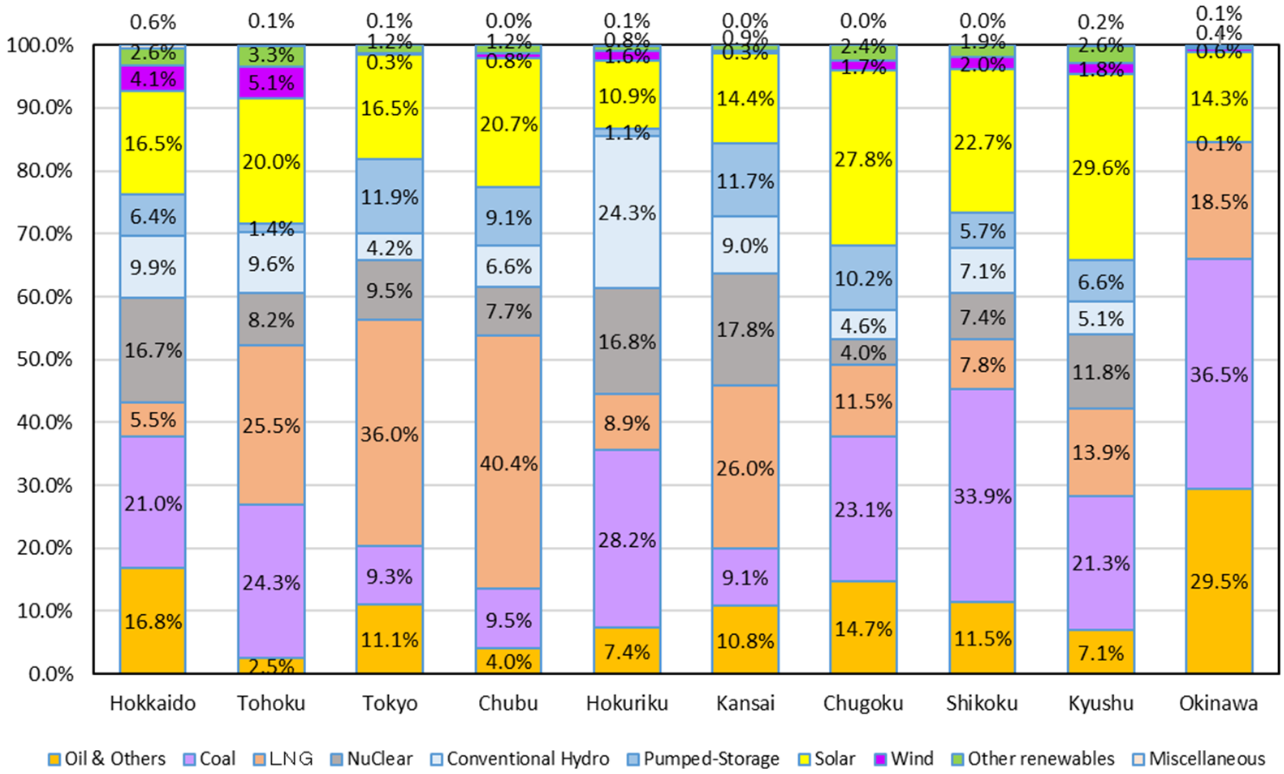


Figure 3-2 Composition of Installed Power Generation Capacity (kW) for Each Regional Service Area

* The ratio of the installed power generation capacity by each power generation source is calculated from 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 by each regional service area (at the end of the indicated fiscal year).[24]

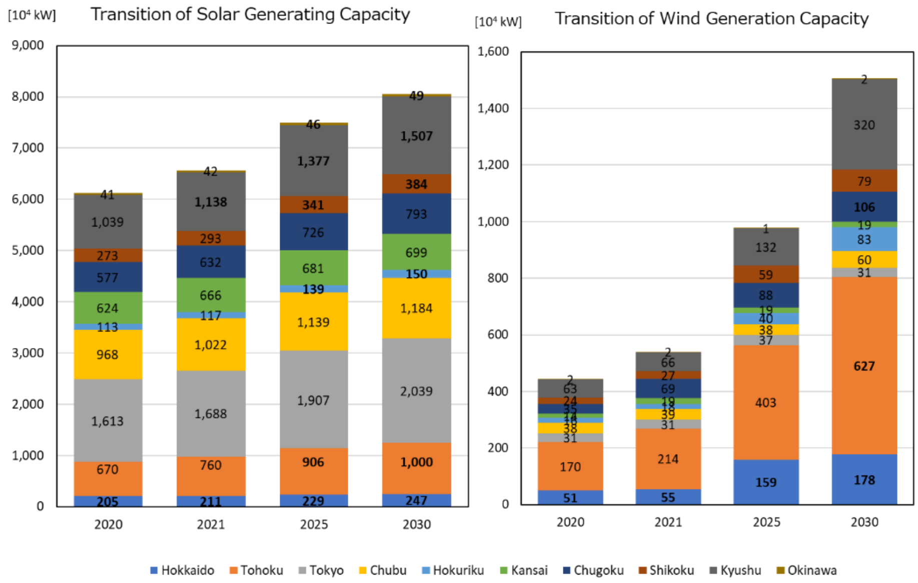


Figure 3-3 Transition of Solar and Wind Generating Capacity for Each Regional Service Area

[24] The GT&D company of each regional area aggregates the projected value of generation facility integration according to 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 development plans[25] up to FY 2030 submitted by generation companies, according to their new developments, uprated or derated installed facilities, and planned decommission of facilities in the projected period.

Table 3-2 Generation Development Plans up to FY 2030 by Stages[25] (Nationwide, 10^4 kW)

Power Generation Sources		New Installation		Uprating/Derating		Decommissioning	
		Capacity	Sites	Capacity	Sites	Capacity	Sites
Hydro		**39.1**	**61**	**6.0**	**36**	**△18.3**	**33**
	Conventional	39.1	61	6.0	36	△18.3	33
	Pumped Storage	—	—	—	—	—	—
Thermal		**1,163.8**	**30**	**0.0**	**0**	**△660.3**	**35**
	Coal	441.3	6	—	—	△51.8	3
	LNG	717.4	15	—	—	△432.6	12
	Oil	5.1	9	—	—	△175.9	20
	LPG	—	—	—	—	—	—
	Bituminous	—	—	—	—	—	—
	Other Gas	—	—	—	—	—	—
Nuclear		**1,018.0**	**7**	**15.2**	**1**	**0.0**	**0**
Renewables		**595.3**	**250**	**0.2**	**1**	**△64.7**	**66**
	Wind	156.6	54	—	—	△47.4	52
	Solar	332.3	168	—	—	△0.2	1
	Geothermal	4.4	3	—	—	△2.4	1
	Biomass	96.8	20	—	—	△7.5	5
	Waste	5.2	5	0.2	1	△7.5	7
Total		2,816.2	348	21.4	38	△743.2	134

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

25 These are aggregated including facilities for which the date of commercial operation is "uncertain."

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

Each generation company has submitted 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. In addition, 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 energy mix of the country.
The calculation method and the result of net electric energy generation by power generation source are stated below.

* This estimation includes the electric energy generated from generation facilities owned by generation companies as well as that of generation facilities such as FIT generators, which retail companies or GT&D companies procure from sources other than generation companies.

(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 their energy generation based on the generation plan that the company develops.

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		2020	2021	2025	2030
Renewables		1,023	1,123	1,448	1,574
	Wind	78	93	179	260
	Solar	706	756	870	919
	Geothermal	24	26	30	32
	Biomass	189	223	345	339
	Waste	26	25	24	24

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

The generation company calculates their energy generation based on the generation plan that the company develops. 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		2020	2021	2025	2030
Hydro		826	846	857	901
	Conventional	770	765	784	804
	Pumped Storage	56	81	74	97
Thermal		6,378	6,206	6,023	5,792
	Coal	2,638	2,899	3,033	3,022
	LNG	3,548	3,090	2,779	2,565
	Oil and others [233]	193	217	211	204

(3) Nuclear (Table 3-5)

The generation company calculates their energy generation based on the generation plan that the company develops for units resuming operation at the end of February 2021. However, 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 resumption of operation are not included in 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	2020	2021	2025	2030
Nuclear	382	395	377	324

Table 3-6 sums up 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)

	2020	2021	2025	2030
Total	9,107	9,025	9,066	8,970

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

Figure 3-4 shows the net electric energy generation for each regional service area in FY 2020.

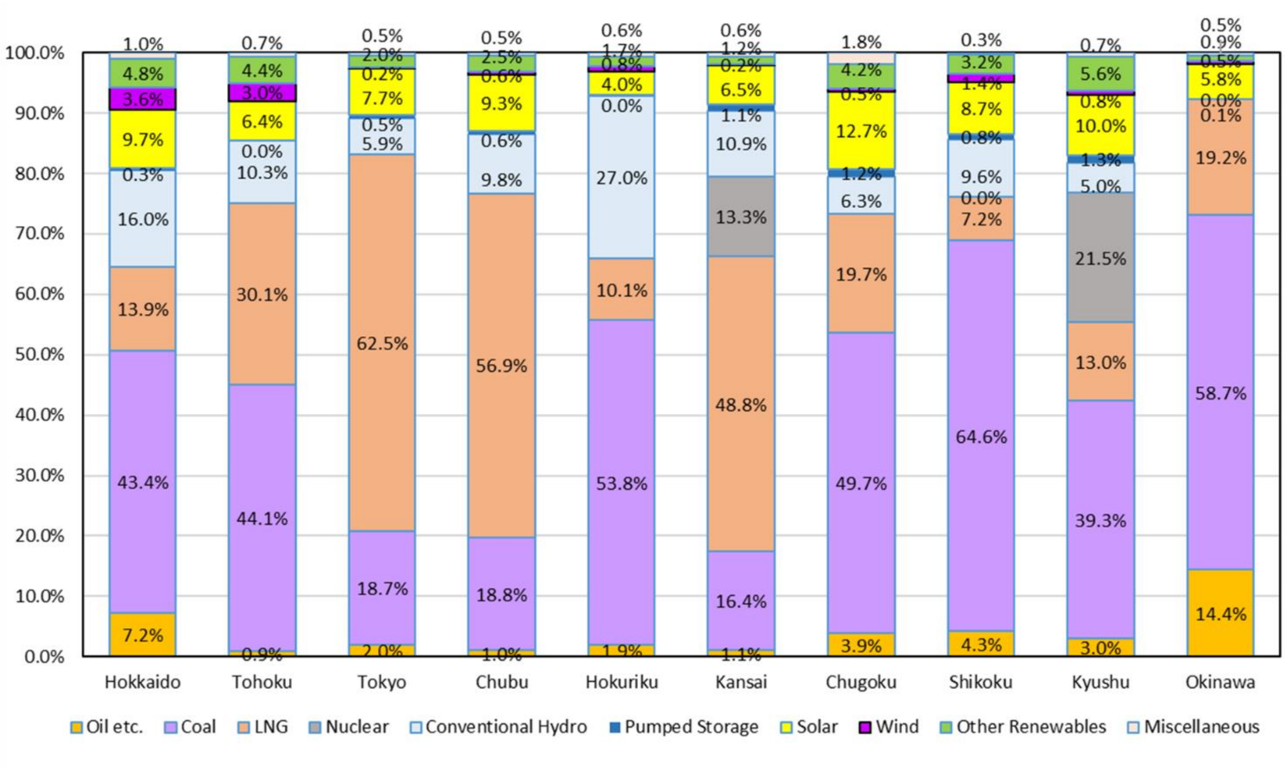


Figure 3-4 Composition of the Net Electric Energy Generation (kWh) for Each Regional Service Area

[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 by the Organization.

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

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

Power Generation Sources		2020	2021	2025	2030
Hydro		19.2%	19.6%	19.8%	20.8%
	Conventional	40.5%	40.2%	40.9%	41.8%
	Pumped Storage	2.3%	3.4%	3.1%	4.0%
Thermal		45.5%	44.8%	41.6%	40.2%
	Coal	65.6%	68.7%	65.5%	65.3%
	LNG	48.0%	43.5%	37.5%	35.0%
	Oil and others [233]	7.4%	8.6%	8.6%	8.3%
Nuclear		13.2%	13.6%	13.0%	11.2%
Renewables		16.6%	16.9%	18.1%	17.6%
	Wind [26]	20.1%	19.6%	20.9%	19.7%
	Solar [266]	13.2%	13.1%	13.3%	13.0%
	Geothermal	52.2%	56.3%	62.6%	65.3%
	Biomass	63.6%	69.6%	76.2%	75.4%
	Waste	35.7%	38.3%	39.1%	39.6%

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

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

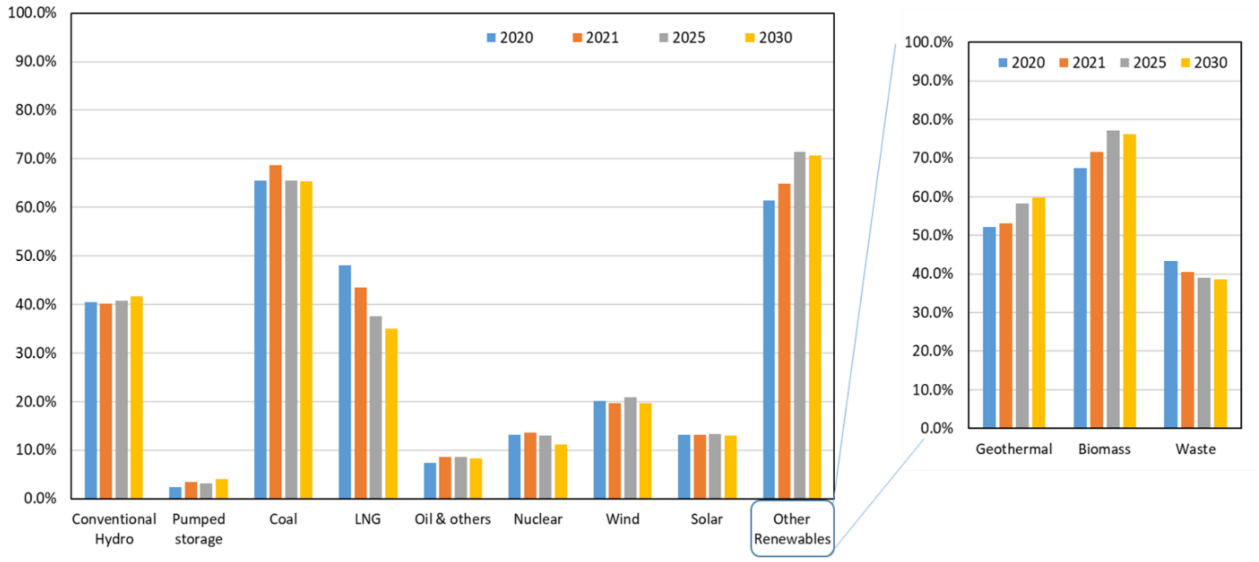


Figure 3-5 Capacity Factors by Power Generation Source (Nationwide)

IV. Development Plans for Transmission and Distribution Facilities

The Organization has aggregated the development plans[27] for cross-regional transmission lines and substations (transformers and AC/DC converters) up to FY 2030, as submitted by GT&D and transmission companies. Table 4-1 shows the development plans for cross-regional transmission lines and substations. Figure 4-1 shows the outlook for electric systems nationwide. 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[28]

Increased Length of Transmission Lines [29]*[30]		635 km (726 km)
	Overhead Lines*	597 km (687 km)
	Underground Lines	39 km (39 km)
Uprated Capacities of Transformers		29,235 MVA (28,290 MVA)
Uprated Capacities of AC/DC Converters [31]		900 MW (1,800 MW)
Decreased Length of Transmission Lines (Decommissioning)		△61 km (△61 km)
Derated Capacities of Transformers (Decommissioning)		△4,300 MVA (△2,700 MVA)

[27] Development plans for transmission lines and substations are required to 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.
[28] Figures in parentheses are those from the previous year.
[29] 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'.
[30] Increased length does not include the item with * because of an undetermined in-service date.
[31] Installed capacity for the converter station on one side is included in the DC transmission system.

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

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
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: 20 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

Interconnection Facility Enhancement Plan between Chubu and Kansai
(in service: undetermined)*under review in the master plan [32]

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

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

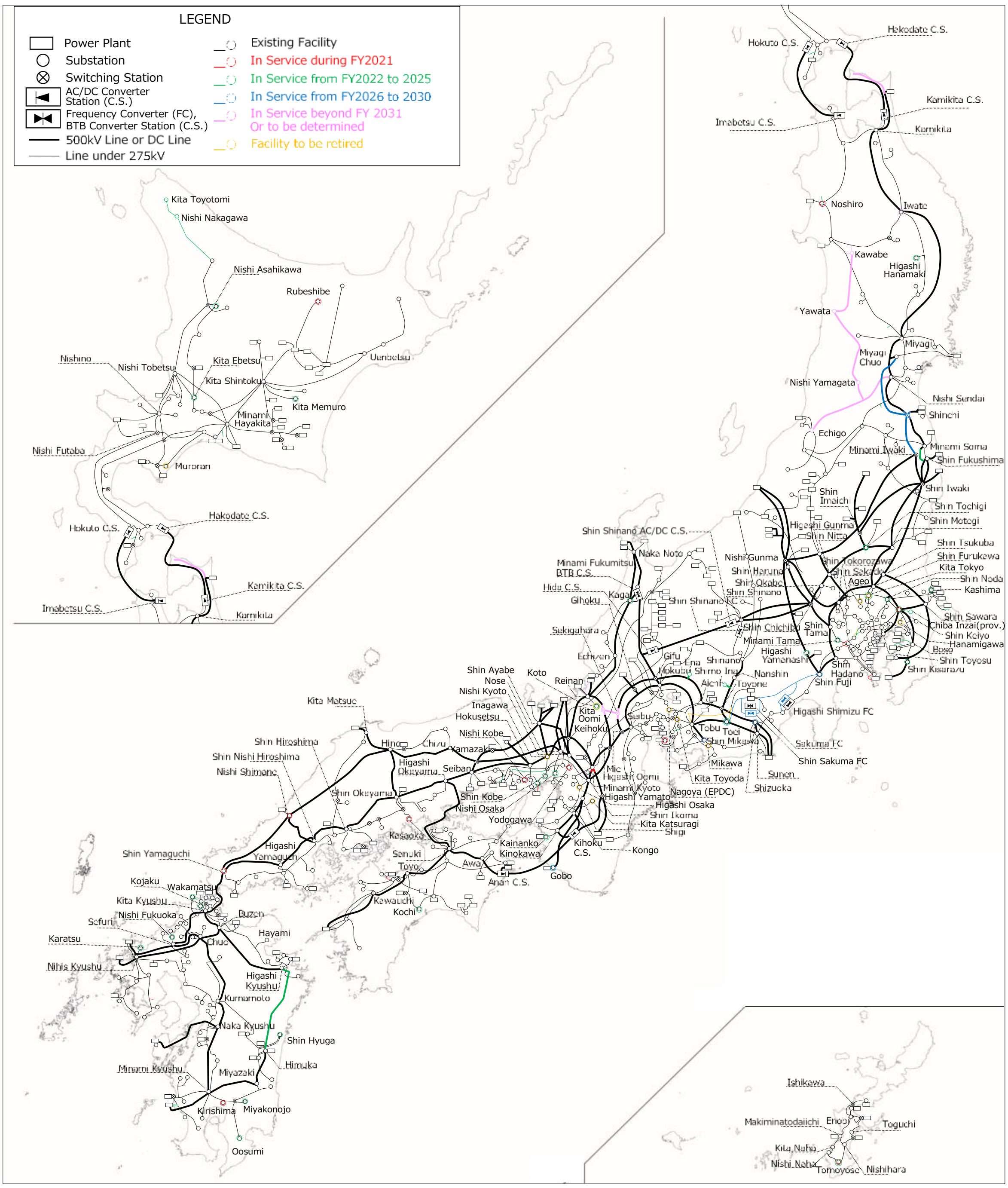


Figure 4-1 Power Grid Configuration in Japan

1. Development Plans for Major Transmission Lines

Table 4-2 Development Plans under Construction

Company	Line[33]	Voltage	Length[34,35]	Circuit	Under construction	In service	Purpose[36]
Hokkaido Electric Power Network, Inc.	Tsuruoka branch Line	187kV	0.1km	1	Sep. 2020	Aug. 2022	Generator connection
TEPCO Power Grid, Inc.	Shinjuku Line replacement	275kV	22.1km→ 21.2km(No.1) *2*3 19.9km→ 21.2km (No.2,3)*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
Chubu Electric Power Grid Co., Inc.	Ena Branch Line	500kV	1km	2	Jun. 2020	Oct. 2024	Demand coverage
	Higashi Nagoya -Tobu Line	275kV	8km*3	2	Apr. 2019	Jun. 2025	Aging management Economic upgrade
Kansai Transmission and Distribution, Inc.	Kobelco Power Kobe daini Access Line*1	275kV	4.4km*2	3	Apr. 2017	Jan. 2021(No.1) Apr. 2021(No.2) Jan. 2022(No.3)	Generator connection
	(prov.) Himeji Access Line*1	275kV	0.9km*2	2	Mar. 2021	Jan. 2025	Generator connection
Shikoku Electric Power Transmission & Distribution Co., Inc.	Saijo Access Line*1	187kV	7km*3	2	Nov. 2019	May 2021	Generator connection
Kyushu Electric Power Transmission & Distribution Co., Inc.	Hyuga Bulk Line	500kV	124km	2	Nov. 2014	Jun. 2022	Aging management Economic upgrade
	JR Shin Isahaya Branch Line	220kV	1km	2	May 2019	Jan. 2022	Demand coverage
	Shin Kagoshima Line/ Sendai Plant π lead-in*1	220kV	2km→ 4km*3	1→2	Aug. 2020	Dec. 2023	Economic upgrade
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

33 Line with *1 denotes the line renamed not to be identified the fuel of the connecting power plant.
34 Length with *2 denotes "underground," otherwise "overhead."
35 Length with *3 denotes that the change in line category or circuit numbers is not included in Table 4-1.
36 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 proper update of facilities 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

Table 4-3 Development Plans in Planning Stages

Company	Line [33]	Voltage	Length [34,35]	Circuit	Under construction	In service	Purpose [36]
Hokkaido Electric Power Network, Inc.	Kita Horonobe Line partly uprating	100kV→187kV	69km	2	May 2021	Jul. 2022	Generator connection
	(prov.) Tomakomai Access Line*1	187kV	0.2km	1	May 2021	Jun. 2022	Generator connection
Tohoku Electric Power Network Co., Inc.	Plant A Access Line*1	275kV	3km	1	Apr. 2021	Dec. 2022	Generator connection
	Plant B Access Line*1	275kV	0.2km	1	Apr. 2023	May 2024	Generator connection
	Northern Akita Prefecture HS Line	275kV	0.3km	2	Jun. 2023	Dec. 2024	Generator connection
	(prov.)Cross-regional North Bulk Line	500kV	79km	2	Jul. 2022	Nov. 2027	Generator connection Reliability upgrade*4
	(prov.)Cross-regional South Bulk Line	500kV	64km	2	Jul. 2024	Nov. 2027	Generator connection Reliability upgrade*4
	Soma-Futaba Bulk Line/connecting point change	500kV	16km	2	Feb. 2022	Nov. 2025	Generator connection Reliability upgrade*4
	(prov.)Shinchi Access Line/ Cross-regional Switching Station lead-in*1	500kV	1km	2	May 2024	Jun. 2026	Generator connection Reliability upgrade*4
	(prov.)Joban Bulk Line/ Cross-regional Switching Station Dπ lead-in	500kV	1km	2	Nov. 2023	Jul. 2026	Generator connection Reliability upgrade*4
	(prov.)Cross-regional Switching Station	500kV	-	10	May 2022	Nov. 2027 (Jun. 2026)	Generator connection Reliability upgrade*4
	Akita Bulk Line/ Kawabe Substation DT lead-in	275kV	5km	2	Beyond FY 2022	Beyond FY 2029	Generator connection
	Akimori Bulk Line/ Kawabe Substation DT lead-in	275kV	0.2km	2	Beyond FY 2025	Beyond FY 2029	Generator connection
	Asahi Bulk Line uprating	275kV→500kV	139km→138km	2	Beyond FY 2026	Beyond FY 2030	Generator connection
	Minami Yamagata Bulk Line uprating	275kV→500kV	23km→23km	2	Beyond FY 2029	Beyond FY 2030	Generator connection
	Dewa Bulk Line	500kV	96km	2	Beyond FY 2021	Beyond FY 2031	Generator connection
	Yamagata Bulk Line uprating/ extension	275kV→500kV	53km→103km	2	Beyond FY 2025	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	Beyond FY 2024	Nov. 2032 (No.2) Nov. 2025 (No.3)	Aging management
	(prov.)G7060005 Access Line	275kV	0.5km*2	1	Apr. 2021	Feb. 2022	Generator connection
	MS18GHZ051500 Access Line (prov.)	275kV	0.1km	2	Jun. 2024	Jun. 2025	Generator connection
	Keihin Line No.1&2 /connecting point change	275kV	0.4km*3	2	Sep. 2021	Mar. 2022	Generator connection
	Higashi Shimizu Line	275kV	13km 7km (diversion)	2	Mar. 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

Company	Line [33]	Voltage	Length [34,35]	Circuit	Under construction	In service	Purpose [36]
	Goi Access Line*1	275kV	11.1km	2	Oct. 2021	Oct. 2023	Generator connection
	(prov.) G5150013 Access Line	275kV	0.5km	2	May 2021	May 2022(No.1) Jun. 2022(No.2)	Generator connection
Chubu Electric Power Grid Co., Inc.	Shimo Ina Branch Line	500kV	0.3km	2	Dec. 2021	Oct. 2024	Demand coverage
	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 Yamato Line/ Minami Kyoto Substation Lead-in change	500kV	0.1km→ 0.2km	2	Jun. 2021	Dec. 2021	Economic upgrade
	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
	Shin Kakogawa Line	275kV	25.3km→ 25.3km*3	2	Jul. 2021	Jun. 2025	Generator connection Aging management
	(prov.) Himeji Access West Branch Line*1	275kV	1.2km*3	2	Nov. 2022	Mar. 2023	Aging management
Kyushu Electric Power Transmission & Distribution Co., Inc.	Saibu Gas/ Hibiki Access Line*1	220kV	4km	2	Mar. 2023	Jul. 2025	Generator connection
	Shin Kokura Line	220kV	15km→ 15km*2*3	3→2	Apr. 2021	Oct. 2029	Aging management
J-POWER Transmission Network Co.,Ltd.	Sakuma Higashi Bulk Line/ Shin Sakuma FC Branch Line	275kV	3km	2	FY 2022	FY 2026	Reliability upgrade*4
	Sakuma-Toei Line/ Shin Sakuma FC Branch Line	275kV	1km	2	FY 2022	FY 2026	Reliability upgrade*4
	Shin Toyone-Toei Line	275kV	1km	1	FY 2022	FY 2026	Reliability upgrade*4
	Sakuma-Toei Line	275kV	10.6km→ 11km*3	2	FY 2022	FY 2027	Reliability upgrade*4
	Sakuma-Toei Line	275kV	2km	2	FY 2022	FY 2026	Reliability upgrade*4
	Sakuma Higashi Bulk Line	275kV	123.7km→ 123km*3	2	FY 2022	FY 2027	Reliability upgrade*4

Table 4-4 Decommissioning Plans

Company	Line	Voltage	Length	Circuit	Retirement	Purpose [36]
J-POWER Transmission Network Co.,Ltd.	Shin Toyone-Toei Line	275kV	△2.6km	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 [33,37]	Voltage	Capacity	Unit	Under construction	In service	Purpose [36]
Hokkaido Electric Power Network, Inc.	Rubeshibe	187/66kV	60MVA×2→ 100MVA	2→1	Feb. 2021	Oct. 2021	Aging management
	Nishi Nakagawa*6	187/100kV	100MVA×2	2	Apr. 2020	Jul. 2022	Generator connection
Tohoku Electric Power Network Co., Inc.	Noshiro	275/66kV	100MVA	1	Oct. 2019	Jun. 2021	Generator connection
TEPCO Power Grid, Inc.	Shin Keiyo	275/154kV	300MVA×2→ 450MVA×2	2→2	Aug. 2018	Sep. 2019 (5B) Nov. 2021 (6B)	Aging management
	Higashi Yamanashi	500/154kV	750MVA	1	Nov. 2019	Dec. 2022	Demand coverage
	Shin Kisarazu	275/154kV	450MVA×2	2	Aug. 2020	May 2022	Generator connection
Chubu Electric Power Grid Co., Inc.	Chita Plant*1	275/154kV	300MVA×1→ 450MVA×1	1→1	Jul. 2019	Apr. 2021	Aging management
	Chita Plant*1	275/154kV	450MVA×2	2	Jul. 2019	Nov. 2020 (N 1B) Aug. 2021(N 2B)	Generator connection
	Higashi Shimizu	—	300MW→ 900MW	—	Dec. 2020	FY 2027	Reliability upgrade*4
Kansai Transmission and Distribution, Inc.	Nishi Kobe	275/77kV	200MVA×2→ 300MVA	2→1	Nov. 2020	Jun. 2021	Aging management
	Yodogawa	275/77kV	300MVA×2→ 300MVA	2→1	Dec. 2020	Oct. 2021	Aging management
	Nishi Osaka	275/77kV	300MVA	1	Feb. 2021	May 2023	Demand coverage
Chugoku Electric Power Transmission & Distribution Co., Inc.	Shin Yamaguchi	220/110kV	400MVA×2	2	Apr. 2019	Jun. 2021	Economic upgrade
	Kasaoka	220/110kV	250MVA→ 300MVA	1→1	Aug. 2020	May 2021	Aging management
	Nishi Shimane	500/220kV	1,000MVA	1	Apr. 2020	Mar. 2022	Generator connection
Kyushu Electric Power Transmission & Distribution Co., Inc.	Kirishima	220/66kV	300MVA	1	Jan. 2020	Dec. 2021	Generator connection
	Nishi Fukuoka	220/66kV	180MVA×2→ 300MVA	2→1	Sep. 2020	Apr. 2022	Aging management
The Okinawa Electric Power Co., Inc.	Tomoyose	132/66kV	125MVA×2→ 200MVA×2	2→2	Oct. 2017	Apr. 2021 (1B) May 2024 (2B)	Aging management
NHWETC	Kita Toyotomi*6	187/66kV	165MVA×3	3	Apr. 2019	Sep. 2022	Generator connection

[37] 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 Ebetsu	187/66kV	100MVA→ 150MVA	1→1	May 2021	Jul. 2022	Aging management
	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
Tohoku Electric Power Network Co., Inc.	Higashi Hanamaki	275/154kV	300MVA	1	May 2022	Oct. 2024	Demand coverage
	Iwate	500/275kV	1,000MVA	1	Beyond FY 2024	Beyond FY 2028	Generator connection
	Echigo	500/275kV	1500MVA×3	3	Beyond FY 2024	Beyond FY 2030	Generator connection
	Yawata	500/154kV	750MVA	1	Beyond FY 2025	Beyond FY 2031	Generator connection
	Kawabe	500/275kV	1500MVA×3	3	Beyond FY 2024	Beyond FY 2031 (Beyond FY 2029)	Generator connection
	Nishi Yamagata	275/154kV →500/154kV	300MVA×2 →450MVA×2	2→2	Beyond FY 2024	Beyond FY 2031 (Beyond FY 2030)	Generator connection
TEPCO Power Grid, Inc.	Minami Tama	275/66kV	200MVA→ 300MVA	1→1	Jul. 2021	Jun. 2022	Demand coverage
	Shin Tochigi	500/154kV	750MVA	1	Jun. 2021	Nov. 2022	Generator connection
	Shin Fuji	500/154kV	750MVA	1	Oct. 2023	Mar. 2027	Reliability upgrade*4
	Kita Tokyo	275/66kV	300MVA	1	Jun. 2022	Feb. 2024	Economic upgrade
	Shin Keiyo	275/154kV	450MVA	1	Apr. 2022	Mar. 2023	Demand coverage
	(prov.)Chiba Inzai*6	275/66kV	300MVA×2	2	Jun. 2021	Apr. 2024	Demand coverage
	Kashima	275/66kV	300MVA	1	Jun. 2023	Jun. 2024	Generator connection
	Shin Noda	275/154kV	220MVA→ 300MVA	1→1	Dec. 2022	Oct. 2023	Aging management
Chubu Electric Power Grid Co., Inc.	Ena*6	500/154kV	200MVA×2	2	Jun. 2022	Oct. 2024	Demand coverage
	Shimo Ina*6	500/154kV	300MVA×2	2	Jun. 2021	Oct. 2024	Demand coverage
	Toei	500/275kV	800MVA×1→ 1,500MVA×2	1→2	Apr. 2022	FY 2024 (N 2B) FY 2026 (1B)	Reliability upgrade*4
	Shizuoka	500/275kV	1,000MVA	1	FY 2024	FY 2026	Reliability upgrade*4
	Shin Mikawa	500/275kV	1,500MVA	1	Jul. 2027	Aug. 2030	Generator connection
Hokuriku Electric Power Transmission & Distribution Co.	Kaga	275/154kV	400MVA	1	Nov. 2021	Dec. 2023	Reliability upgrade
Kansai Transmission and Distribution, Inc.	Gobo	500/154kV	750MVA×2	2	Aug. 2024	Nov. 2027	Generator connection
	Koto	275/77kV	200MVA→ 300MVA	1→1	Jan. 2022	Oct. 2022	Aging management
	Kainanko	275/77kV	300MVA×1、 200MVA×2→ 300MVA×2	3→2	Sep. 2022	Jun. 2024	Aging management
	Shin Kobe	275/77kV	300MVA×1、 200MVA×1→ 200MVA×1	2→1	Aug. 2022	Jan. 2024	Aging management
	Itami	275/154kV	300MVA	1	Feb. 2023	Jun. 2024	Aging management
Shikoku Electric Power Transmission & Distribution Co., Inc.	Kochi	187/66kV	200MVA→ 300MVA	1→1	Sep. 2021	Apr. 2022	Aging management Demand coverage
	Miyakonojo	220/110kV	150MVA	1	Sep. 2021	Mar. 2024	Generator connection

Company	Substation [33,37]	Voltage	Capacity	Unit	Under construction	In service	Purpose [36]
Kyushu Electric Power Transmission & Distribution Co., Inc.	Shin Hyuga	220/110 /66kV	250/150 /200MVA	1	Jun. 2021	Apr. 2023	Generator connection
	Wakamatsu	220/66kV	250MVA	1	Nov. 2022	Oct. 2024	Generator connection
	Oosumi	110/66kV → 220/110 /66kV	60MVA → 250/100 /200MVA	1→1	Mar. 2022	Feb. 2025	Generator connection
	Kojaku	220/66kV	150MVA→ 200MVA	1→1	May 2021	Apr. 2023	Aging management
	Karatsu	220/66kV	150MVA→ 250 MVA	1→1	Jul. 2022	Nov. 2023	Aging management
J-POWER Transmission Network Co.,Ltd.	(prov.)Shin Satkuma FC*6	—	300MW	—	FY 2024	FY 2027	Reliability upgrade*4
Fukushima souden	Abukumaminami*6	154/66/33kV	170MVA	1	Nov. 2021	May 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	Jun. 2023	Aging management
TEPCO Power Grid, Inc.	Hanamigawa	275/66kV	300MVA	1	Mar. 2024	Demand coverage
	Kita Tokyo	275/154kV	300MVA	1	Jan. 2022	Economic upgrade
	Ageo	275/66kV	300MVA	1	Feb. 2025	Economic upgrade
Chubu Electric Power Grid Co., Inc.	Kita Toyoda	275/154kV	450MVA	1	FY 2023	Aging management
	Mikawa	275/154kV	450MVA	1	Apr. 2025	Aging management
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	Nov. 2024	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 2030 submitted by GT&D and transmission companies.

Table 4-8 Development Plans for Major Transmission Lines

Category	Voltage	Lines	Length [38]	Extended Length [39]	Total Length	Total Extended Length
Newly Installed or Extended	500kV	Overhead	646 km*	1,293 km*	646 km*	1,293 km*
		Underground	0 km	0 km		
	275kV	Overhead	△175 km	△354 km	△158 km	△317 km
		Underground	17 km	37 km		
	220kV	Overhead	5 km	10 km	5 km	10 km
		Underground	0 km	0 km		
	187kV	Overhead	120 km	240 km	120 km	240 km
		Underground	0 km	0 km		
	154kV	Overhead	0 km	0 km	22 km	22 km
		Underground	22 km	22 km		
	Total	Overhead	597 km	1,189 km	635 km	1,248 km
		Underground	39 km	59 km		
To be Decommis-sioned	275kV	Overhead	△61 km	△119 km	△61 km	△119 km
		Underground	0 km	0 km		
	Total	Overhead	△61 km	△119 km	△61 km	△119 km
		Underground	0 km	0 km		

Table 4-9 Revised Plans for Line Category and the Numbers of Circuits [40]

Voltage	Length Extended	Total Extended Length
500kV	0 km	1 km
275kV	227 km	476 km
220kV	19 km	38 km
187kV	7 km	14 km
Total	253 km	528 km

38 Length denotes both 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 of lengths and the overall total lengths are not necessarily equal due to independent rounding.

39 The total length denotes the aggregation of length multiplied by the number of circuits. Development plans corresponding to change 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."

40 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 [41]	Voltage [42]	Increased Numbers	Increased Capacity
Newly Installed or Extended	500kV	25 [4]	23,000 MVA [1,000 MVA]
	275kV	6 [2]	3,280 MVA [600 MVA]
	220kV	6 [0]	1,740 MVA [0 MVA]
	187kV	4 [5]	955 MVA [695 MVA]
	154kV	1 [1]	170 MVA [170 MVA]
	132kV	0 [0]	150 MVA [0 MVA]
	110kV	△1 [0]	△60 MVA [0 MVA]
	Total	41 [12]	29,235 MVA [2,465 MVA]
To be Decommis-sioned	500kV	△1	△750 MVA
	275kV	△13	△3,450 MVA
	187kV	△1	△100 MVA
	Total	△15	△4,300 MVA

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

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

Category	Company and Number of Sites	Capacity
Newly Installed or Extended	Chubu Electric Power Grid Co.,Inc. 1	600 MW
	J-POWER Transmission Network Co., Ltd. 1	300 MW

4. Aging Management of Existing Transmission and Distribution Facility

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

41 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.
42 Voltage class by upstream voltage.

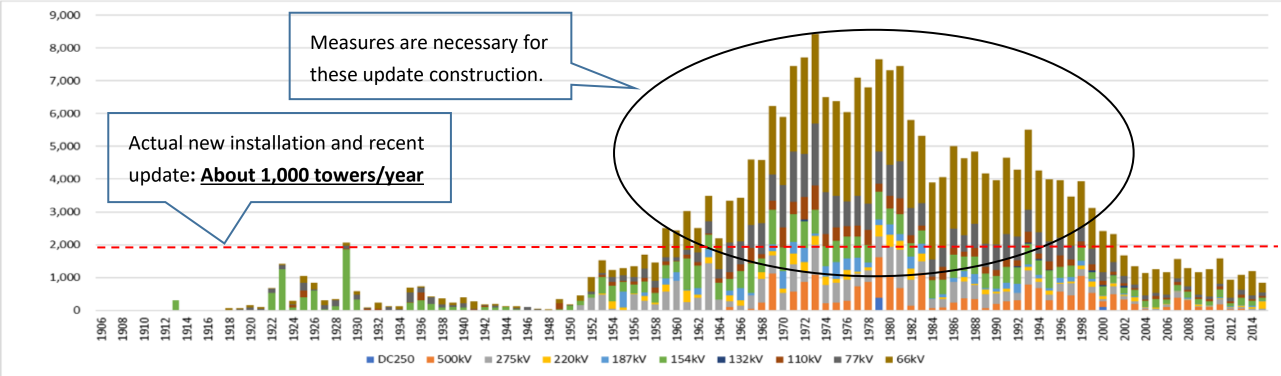


Figure 4-2 Actual Installation Year of Existing Transmission Towers (66kV-500kV)

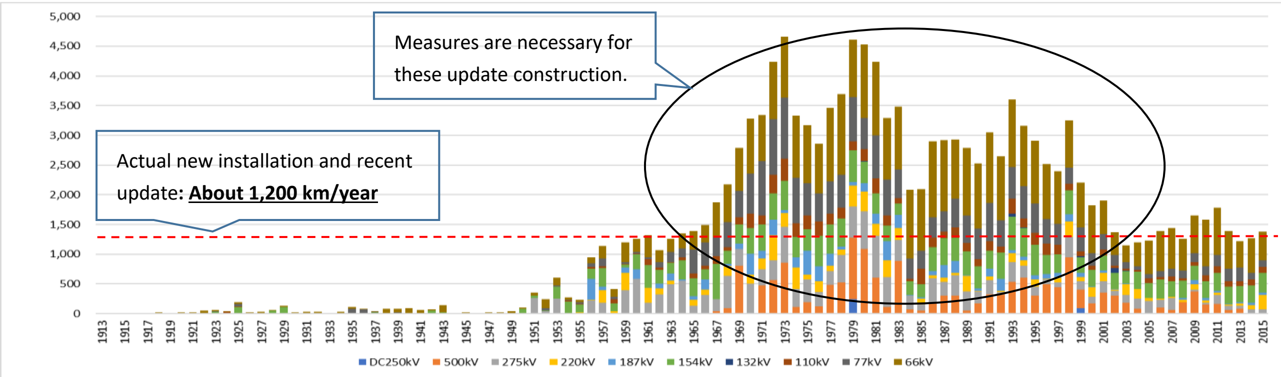


Figure 4-3 Actual Installation Year of Existing Overhead Lines (66kV-500kV)

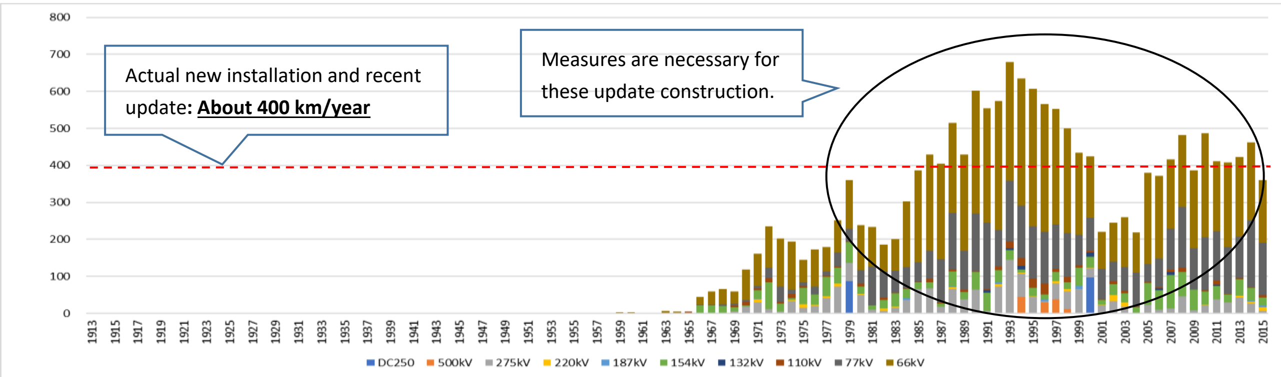


Figure 4-4 Actual Installation Year of Existing Underground Cables (66kV-500kV)

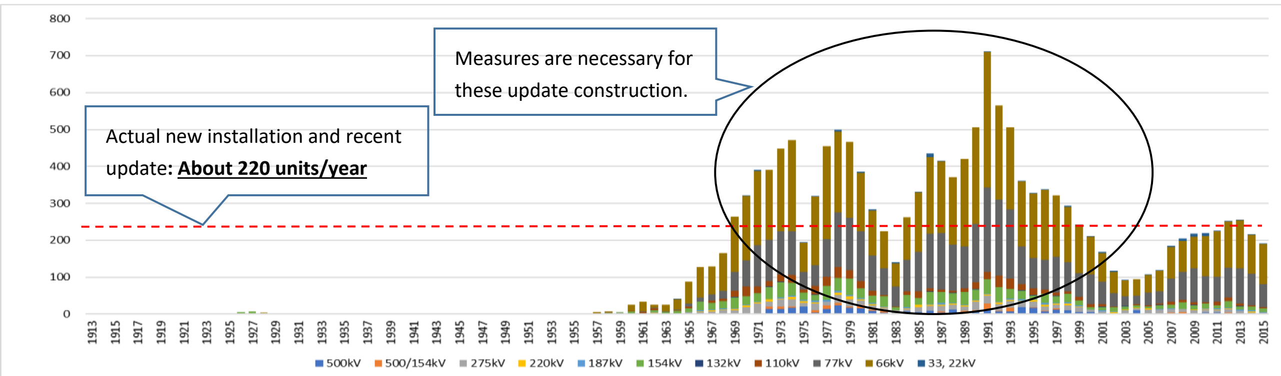


Figure 4-5 Actual Installation Year of Existing Transformers (66kV-500kV; one those of 22kV is partly included)

Furthermore, in recent years the number of working linesmen tends to decrease, and workforce with skills and ability in short supply. Figure 4-6 shows the transition of numbers of tower-climbing linesmen working at the transmission construction.[43]

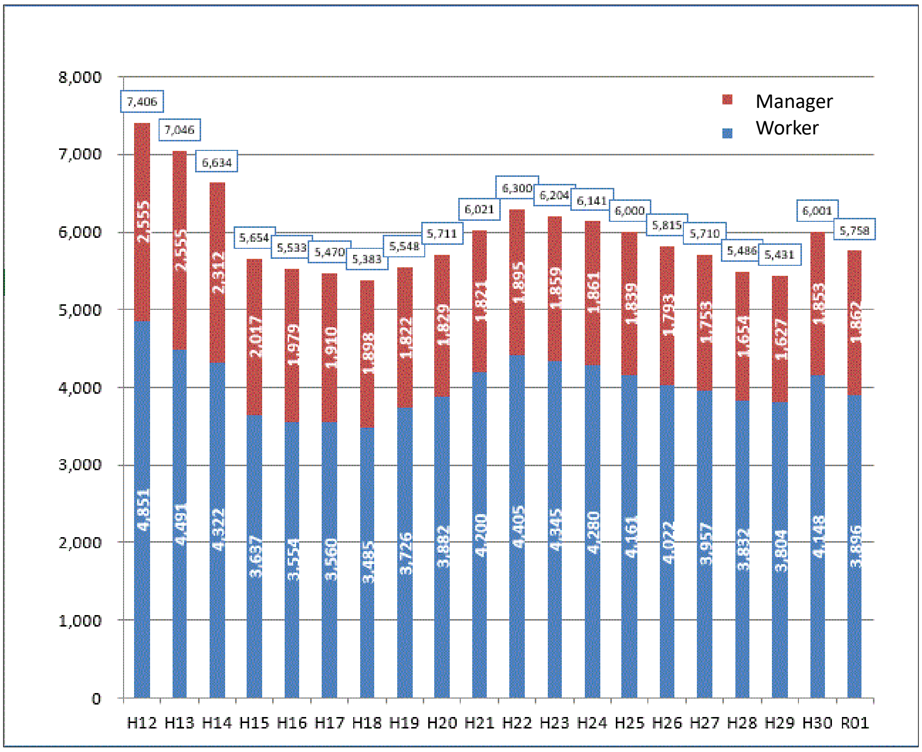


Figure 4-6 Transition of the Number of Tower-climbing Linesmen[43]

[43] 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 will procure the supply capacity for their customers in their regional service areas. The scheduled procurement from external service areas at 15:00 h during August 2021 is illustrated in four figures. Figures 5-1 and 5-2 show the supply capacity and the ratio of the supply capacity, respectively, at 15:00 h during August. Figures 5-3 and 5-4 show the energy supply and the ratio of the energy supply, respectively, in FY 2021.

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

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

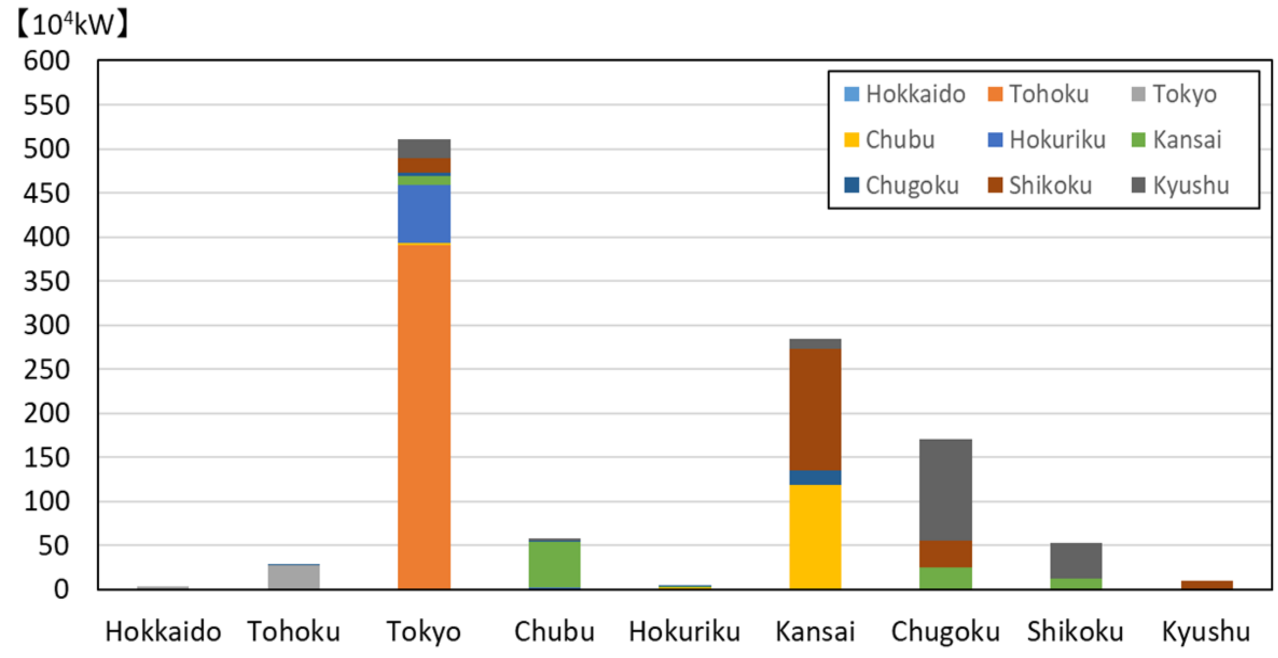


Figure 5-1 Scheduled Procurement of Supply Capacity from External Regional Service Areas

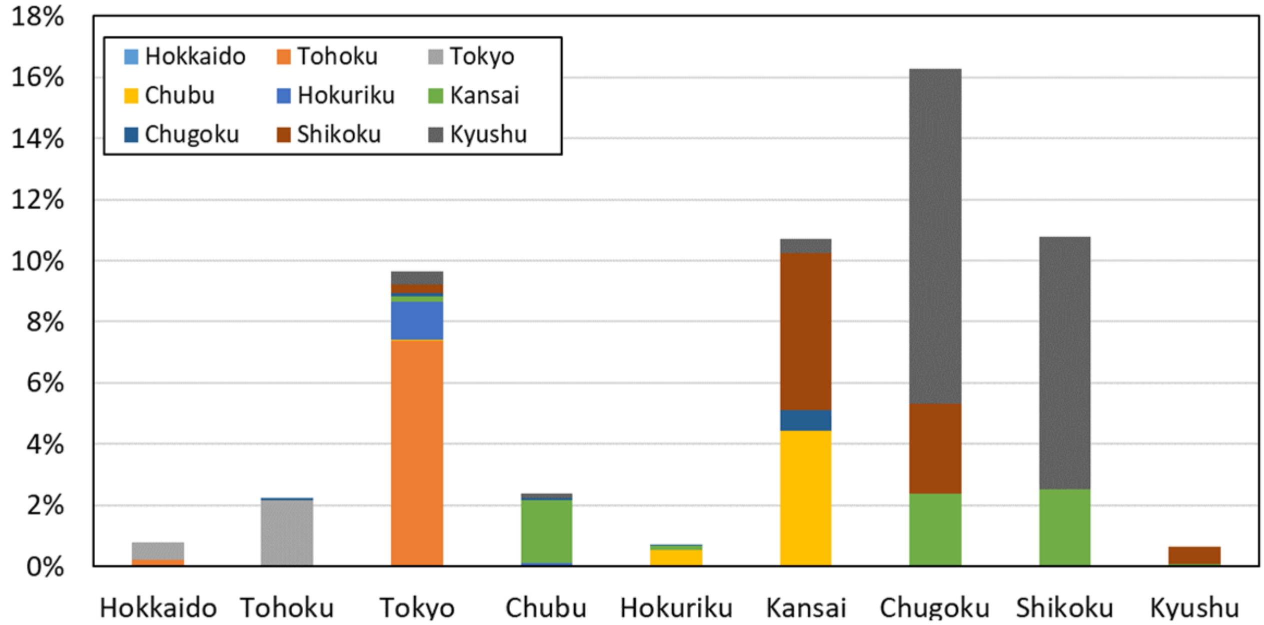


Figure 5-2 Ratio of Scheduled Procurement of Supply Capacity from External Regional Service Areas

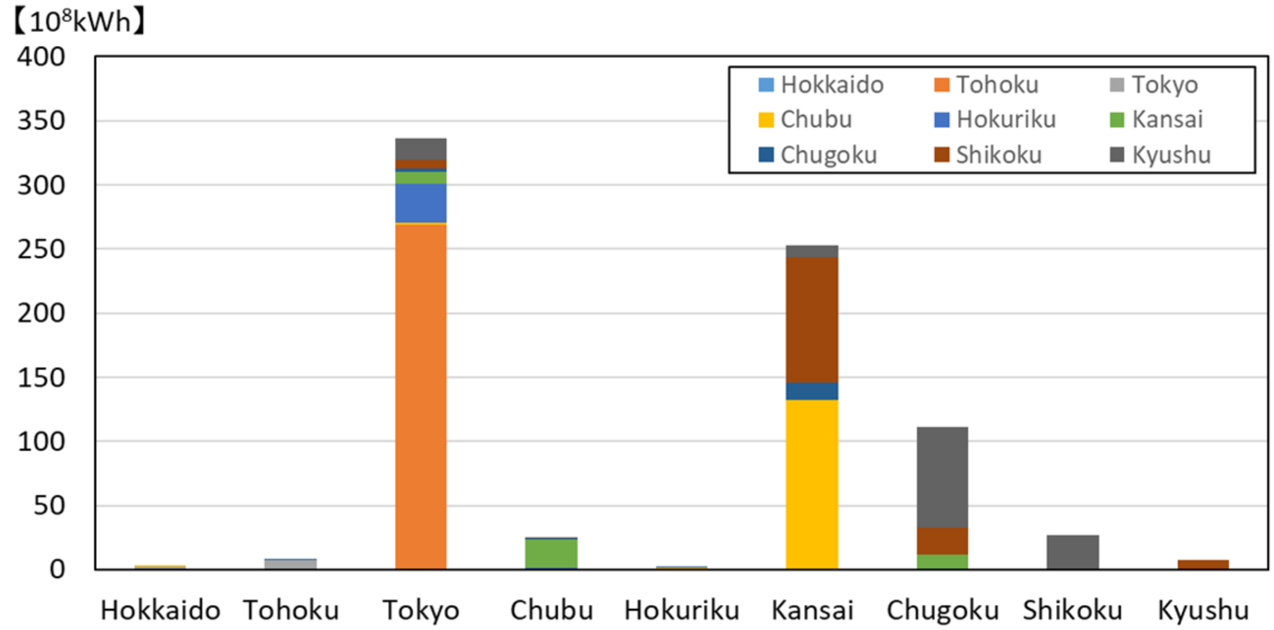


Figure 5-3 Scheduled Procurement of Energy Supply from External Regional Service Areas

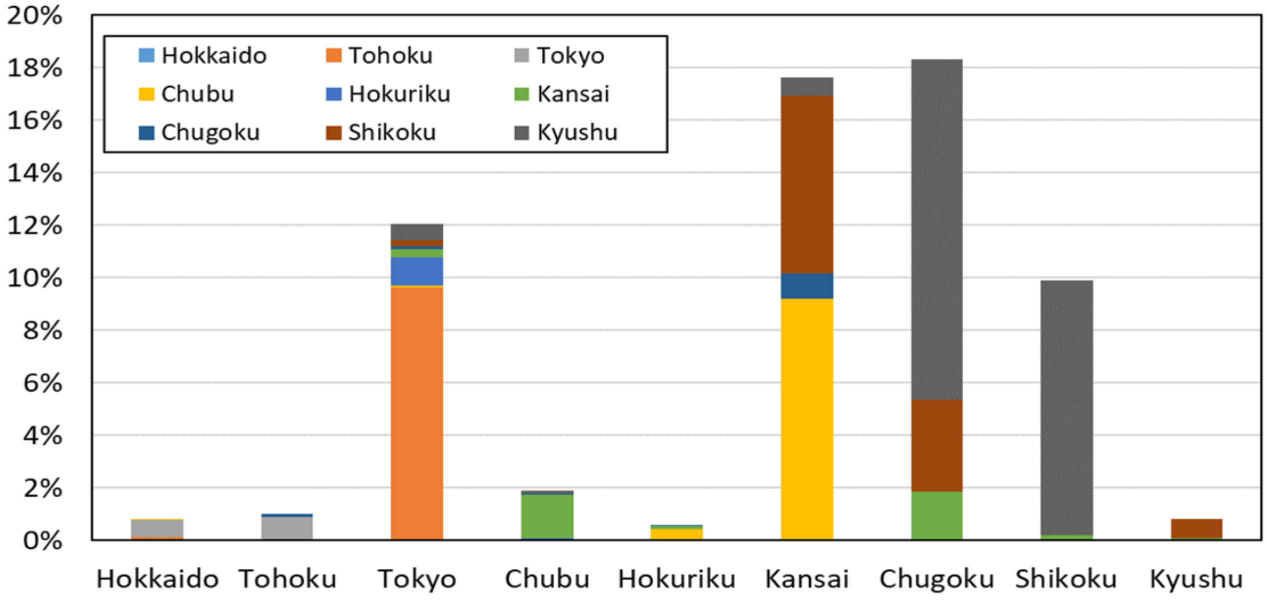


Figure 5-4 Ratio of Scheduled Procurement of Energy Supply from External Regional Service Areas

VI. Analysis of Characteristics of EPCOs

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

In total, 660 retail companies submitted their electricity supply plans, and these are classified by the business scale of the retail demand forecast by the corresponding companies. 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 business.

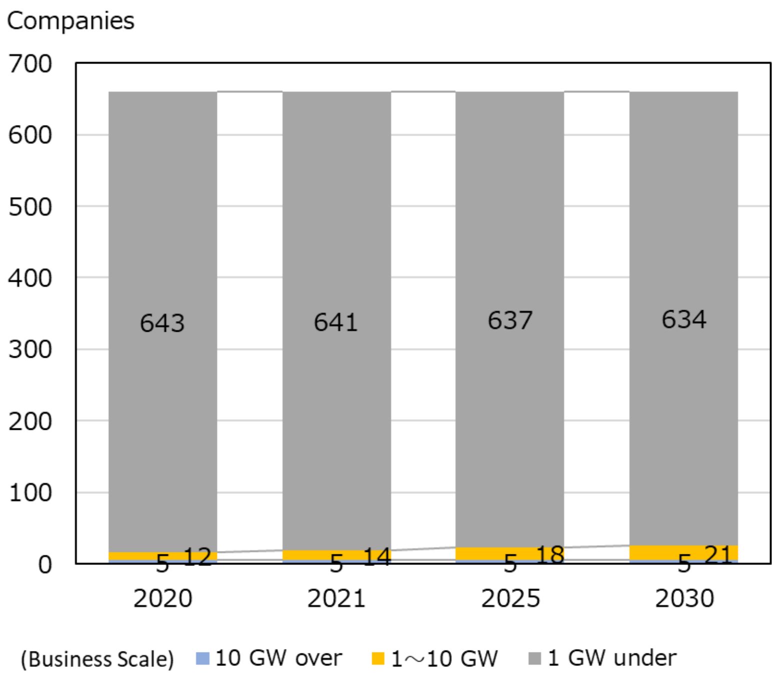


Figure 6-1 Distribution of the Retail Demand by Retail Companies by Business Scale

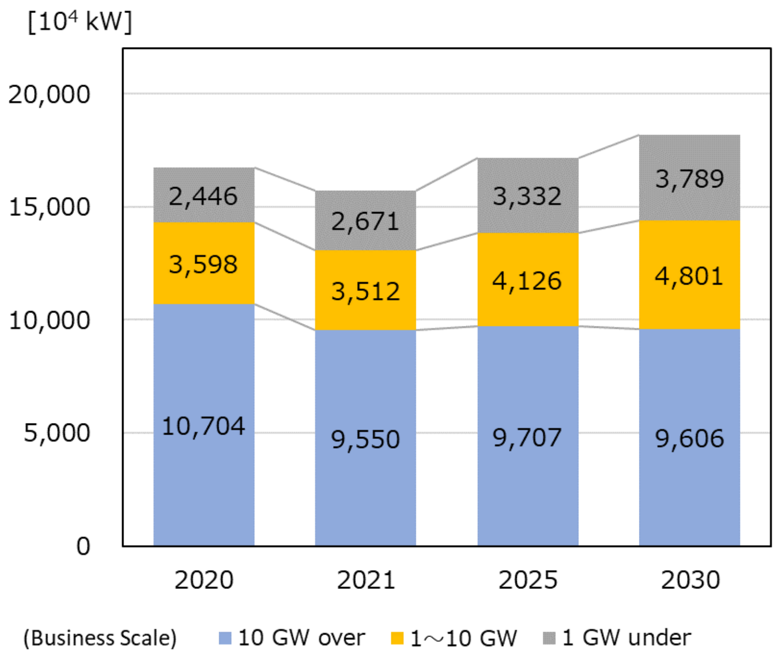


Figure 6-2 Distribution by Accumulated Retail Demand by Retail Companies

Again, retail companies are classified by the business scale of the retail energy sales forecast by the corresponding companies. 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 business.

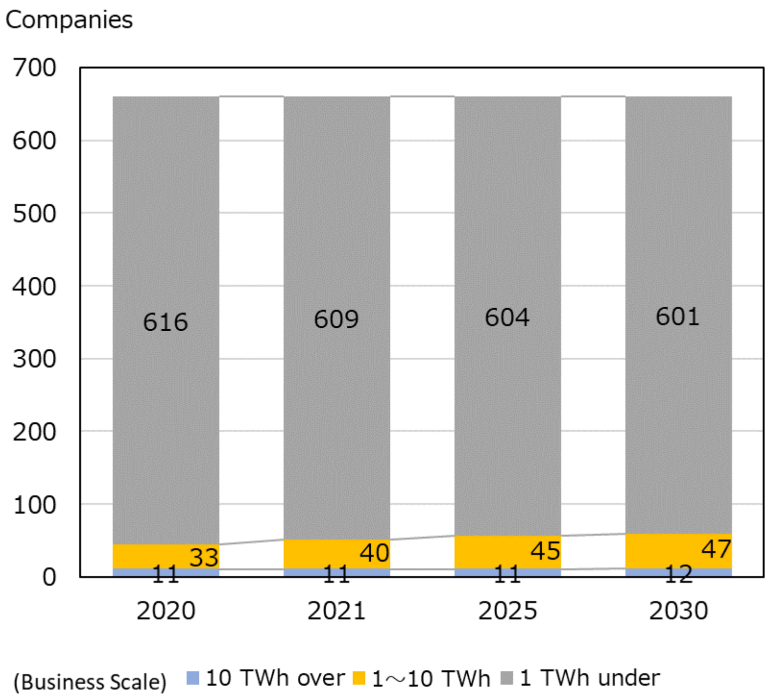


Figure 6-3 Distribution of Retail Company Energy Sales by Business Scale

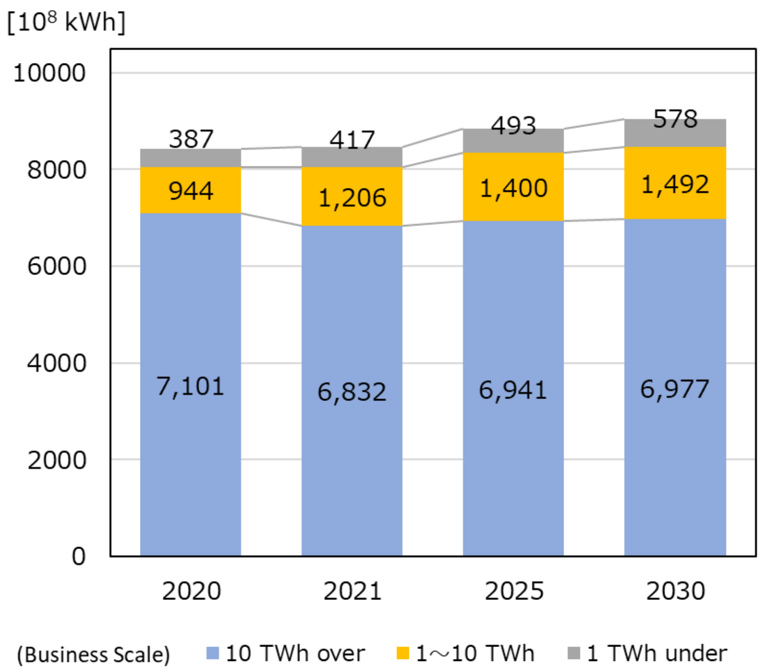


Figure 6-4 Distribution by Retail Company of Accumulated Energy Sales

2. Retail Company Business Areas

Figure 6-5 shows the ratio of retail companies by the number of areas where they plan to conduct their business. Figure 6-6 shows the number of retail companies by their business planning areas in FY 2021. The figures exclude 86 retail companies that had not yet developed their retail business plans. Half of the retail companies plan their business in a single area.

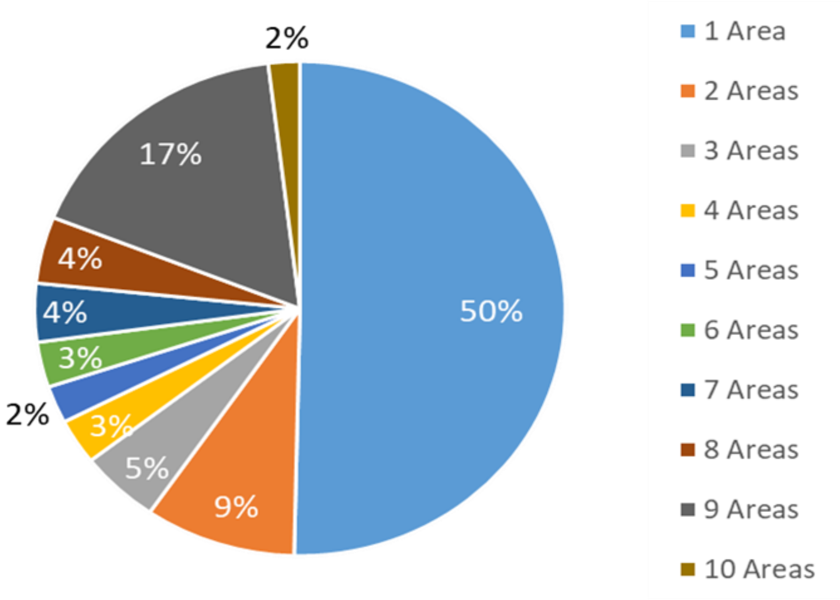


Figure 6-5 Ratio of Retail Companies by the Number of Planned Business Areas in FY 2021

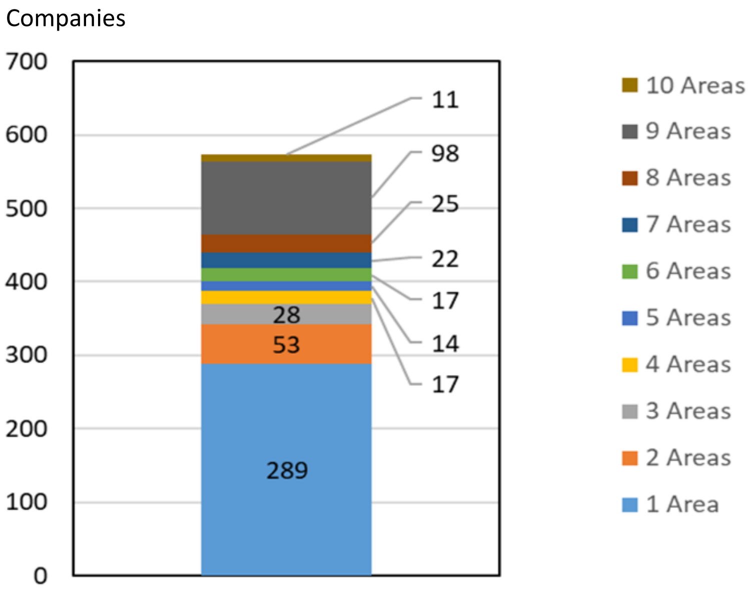
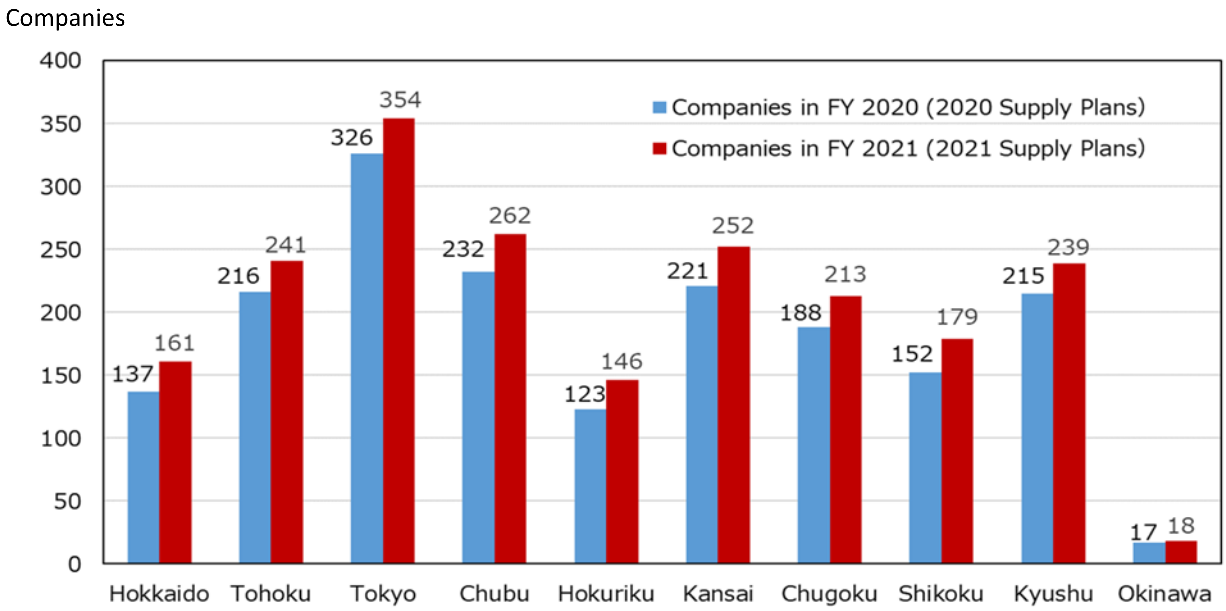


Figure 6-6 Number of Retail Companies by their Business Planning Areas in FY 2021

Figure 6-7 shows the number and the retail demand of retail companies in each regional service areas for GT&D companies in FY 2021. As retail companies increase their numbers in every regional service area, the choice of retail company for electricity customers is expanding.



Projected Peak Demand in FY 2021 (10^4 kW)

Hokkaido	Tohoku	Tokyo	Chubu	Hokuriku	Kansai	Chugoku	Shikoku	Kyushu	Okinawa
415	1,293	5,329	2,453	492	2,726	1,032	492	1,521	150

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.

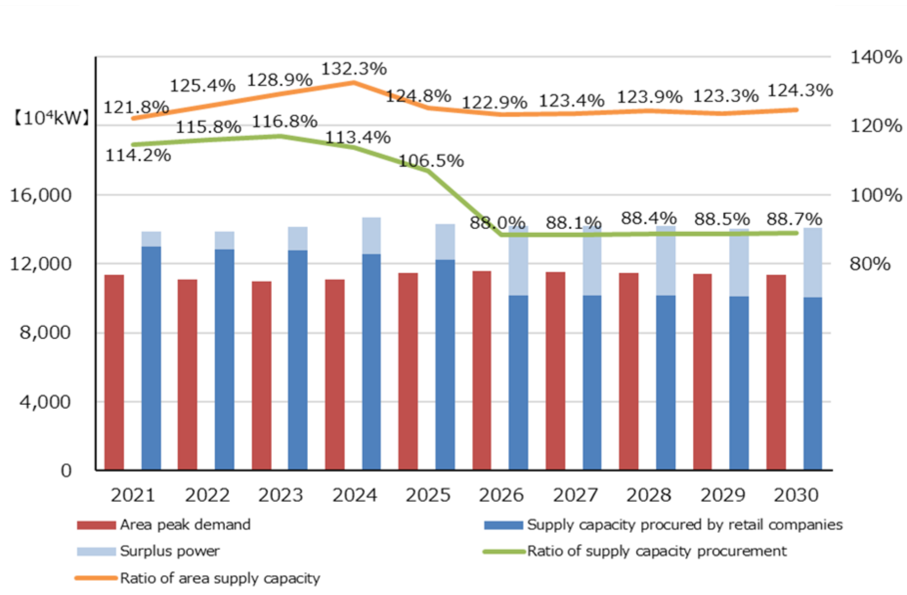


Figure 6-8 Ratio of Secured Supply Capacity to Forecast Retail Demand of Their Own Area for Former General Electric Utilities[44] (at 15:00 in August, at the sending end)

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

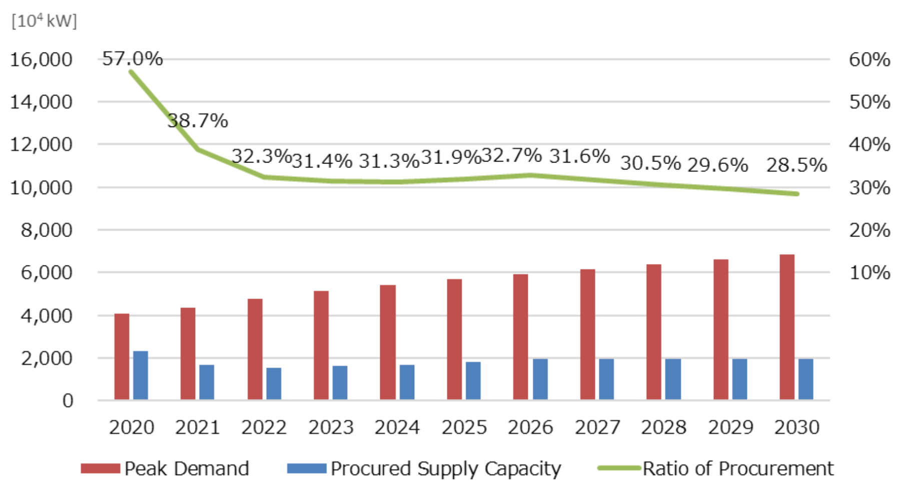


Figure 6-9 Ratio of Procured Supply Capacity to Forecast Retail Demand by Retail Companies [Former General Electric Utilities in External Areas and by PPSs] (at 15:00 in August, at the sending end)

[44] Includes surplus power of a group of companies deducting the balancing capacity to the secured supply capacity by retail companies.

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

In total, 935 generation companies submitted their electricity supply plans, and these are classified by the business scale of the installed capacity operated by the corresponding companies. Figure 6-10 shows the distribution by business scale and Figure 6-11 shows the installed capacity operated by the corresponding companies.

Generation companies with an installed capacity of under 10 GW are planning to enlarge the scale of their business.

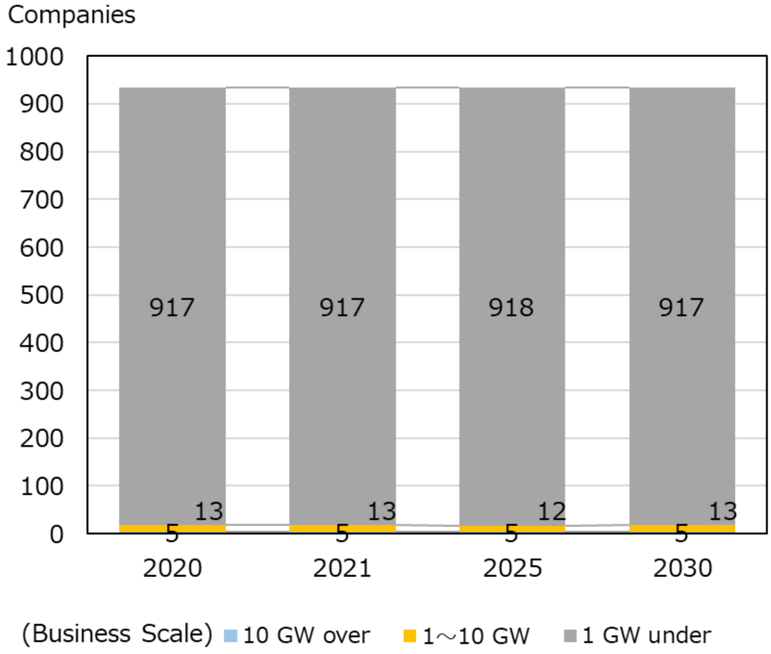


Figure 6-10 Distribution by Business Scale of Generation Company Installed Capacity

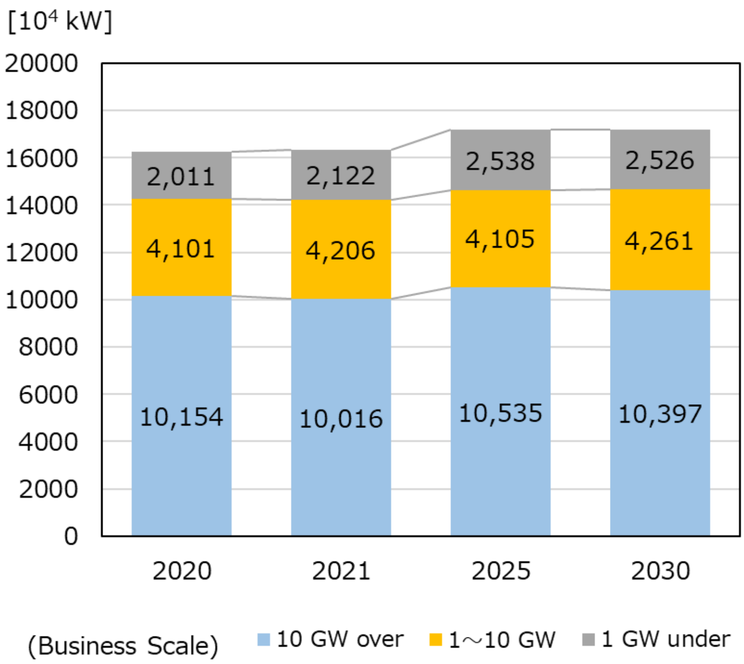


Figure 6-11 Distribution by Generation Company Accumulated Installed Capacity

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

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

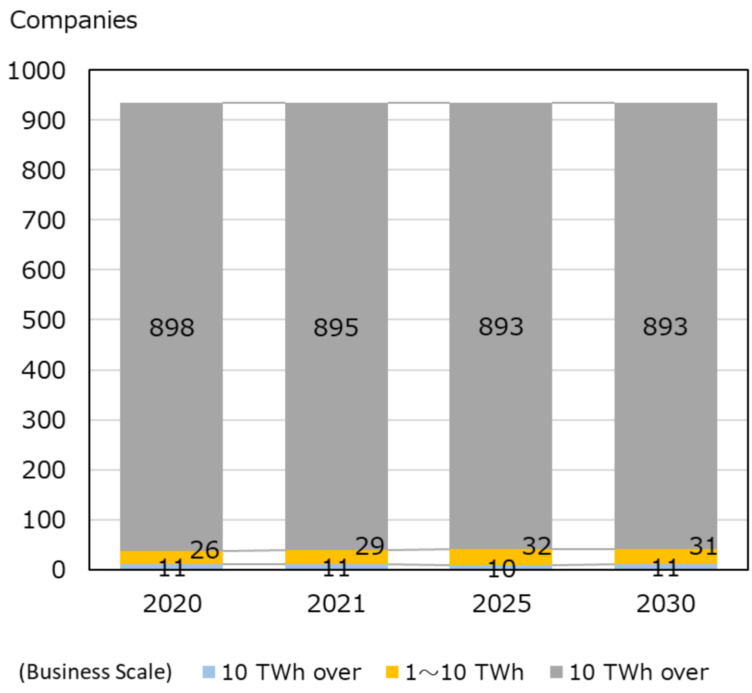


Figure 6-12 Distribution of Generation Company Energy Supply by Business Scale

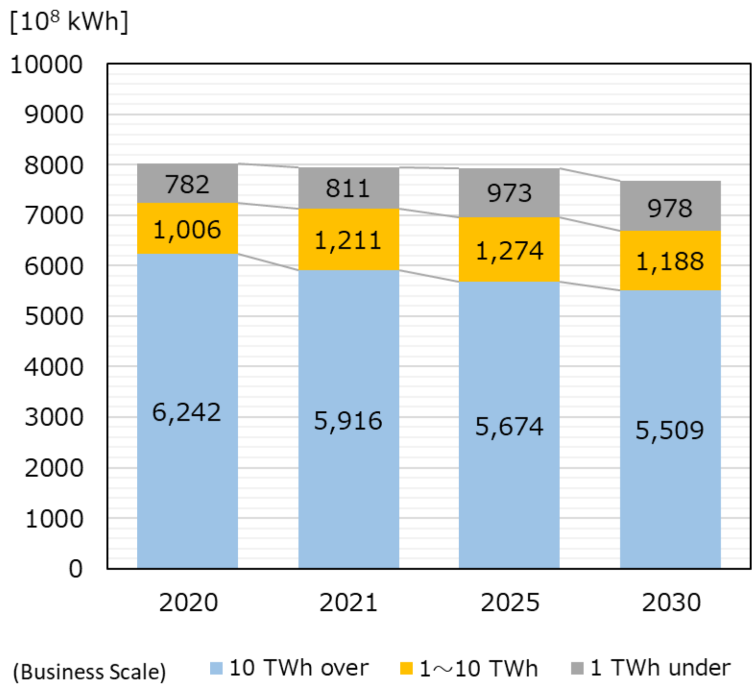


Figure 6-13 Distribution of Generation Company by Accumulated Energy Supply

Figure 6-14 shows the number of generation companies at the end of FY 2020 by the power generation sources of their own generators. The figures exclude 117 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 company with renewable energy generation, solar power in particular, is increasing, and a stronger introduction of renewable energy is led by new generation companies.

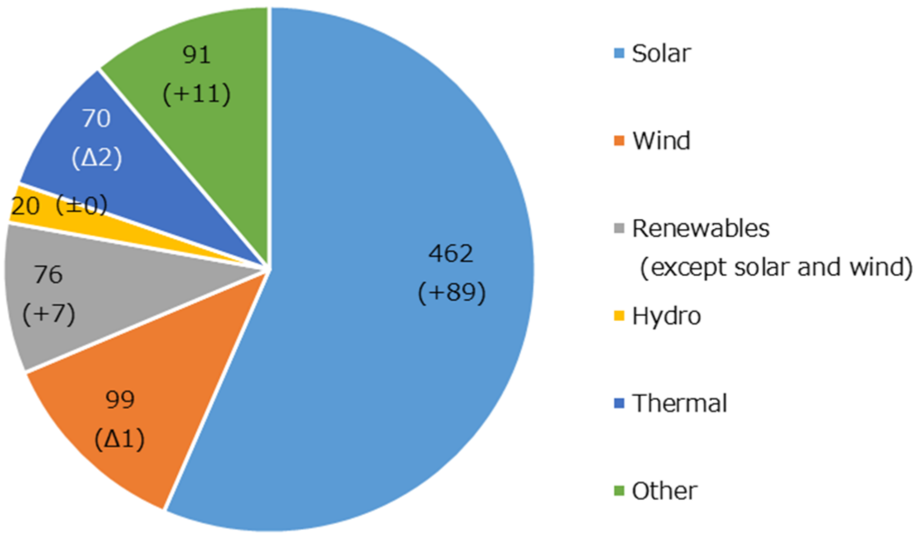


Figure 6-14 Number of Generation Companies by Power Generation Sources

5. Generation Company Business Areas

Figure 6-15 shows the ratio of generation companies to the number of areas where they plan to conduct their business. Figure 6-16 shows the number of generation companies by their business planning areas in FY 2021. The figures exclude 168 generation companies that do not own their generation plants.

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

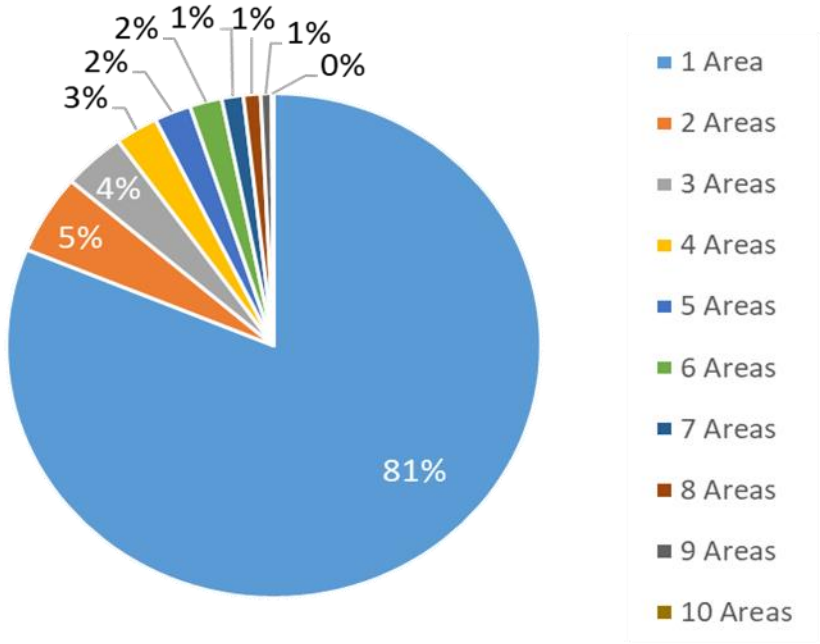


Figure 6-15 Ratio of Generation Companies by the Number of Planned Business Areas in FY 2021

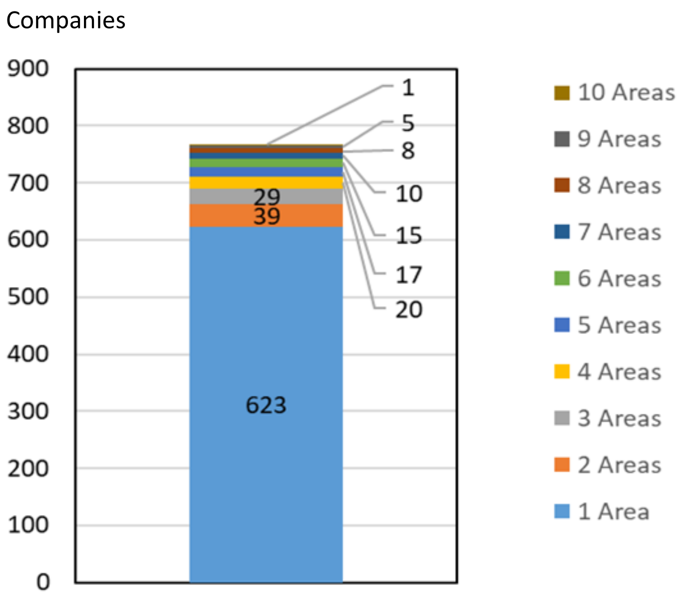
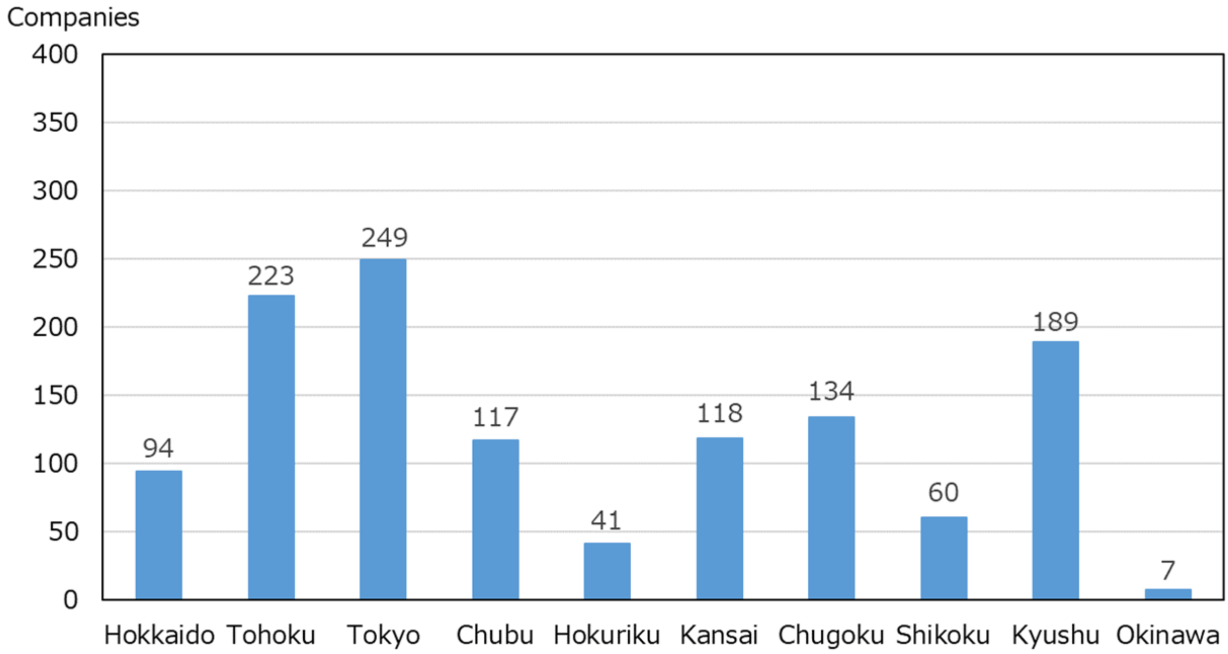


Figure 6-16 Number of Generation Companies by Their Business Planning Areas in FY 2021

Figure 6-17 shows the number and the installed capacity of generation companies in each regional service area for GT&D companies in August 2021. In the Hokkaido, Tohoku, Chugoku, and Kyushu regional service areas, the scale of generation companies is rather small and their supply capacity is comparatively small despite the number of generation companies in these regional service areas.



Projected Supply Capacity in FY 2021 (10^4 kW)

Hokkaido	Tohoku	Tokyo	Chubu	Hokuriku	Kansai	Chugoku	Shikoku	Kyushu	Okinawa
566	1,859	4,835	2,388	579	2,436	1,029	676	1,872	196

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. Concerns about shortage of supply capacity (kW)

The Organization has introduced a new reliability criterion, i.e. the EUE, which is based on estimated supply interruption in a year. For FY 2021 and 2022, the evaluated result from the aggregated supply plans satisfies the new reliability criterion. However, evaluation implemented by the conventional approach shows that the reserve margins is 5.8% and below the criterion of 8% for February 2022 in each of the areas of Tohoku, Tokyo, Chubu, Hokuriku, Kansai, Chugoku, Shikoku, and Kyushu. In addition, fluctuation risk analysis of supply-demand during the winter peaking period of 2021/2022 implemented by the Organization, shows that the reserve margin against the H1 peak demand (estimated maximum peak demand) will be lower than 3% for most ares; particularly the Tokyo area; the reserve margin will also be lower than 3% in January 2022, and that will be a very severe situation.

This is mainly attributable to a decrease in supply capacity in the winter peaking period due to significant planned maintenance work of generators for 1,300 MW in February 2022. In considering that a supply shortage occurred in the recent winter, the Organization believes that generation companies that have large generating unit should carefully plan their maintenance work schedule based on supply-demand balance instead of bilateral contract of supply capacity with retail companies.

The Organization broadly addresses preparedness for a tight supply-demand situation publishing a severe result of supply-demand balance evaluation, and in areas of severe supply-demand situation, the Organization deales with improving this balance by scheduling coordination of maintenance work of generation companies and premeditated procurement of supply capacity by retail companies. In case of difficulty in securing a stable supply capacity, even if these countermeasures are implemented, the Organization further proceeds to ensuring a secure and stable supply by utilizing safeguard measures of generation procurement.

Furthermore, the reserve margin in July 2021 is nationally estimated at 3.4%; that is slightly over the smallest reserve margin of 3%, and the supply-demand situation is not safely secured. The Organization expects the Government to review preparedness of the tightened supply-demand situation, such as appealing to electricity customers to save power.

2. Countermeasures against tight supply-demand balance based on energy supply balance (kWh) and recent tight supply-demand conditions during winter 2020/2021

It is assumed that the increasing factor of scheduled maintenance work stated above comes from an increase in undetermined procurement of supply capacity by retail companies. As a result, the energy supply balance worsens by 1.3% annually in FY 2021 compared with FY 2020. It is confirmed that procurement of the energy supply is lower than in the previous year.

The Organization will evaluate the energy supply balance, including fuel procurement, by verification of the electricity supply-demand after autumn in 2021 in addition to the conventional supply capacity evaluation. To prevent a tight supply-demand situation, the Organization will continuously monitor supply-demand situation before the winter peaking period begins, and will publish the information on the supply-demand situation. On this account, the Organization expects premeditated procurement of the supply capacity by the retail companies preparing for the tight supply-demand situation, security of sufficient energy supply from generation companies, as well as restraining the suspension or decommission of generators that are used as supply capacity under the circumstances of increasing procurement by bilateral or forward contract.

The Organization expects the Government to specifically review the measures for the tight supply-demand using the monitoring implemented by the Organization.

3. Countermeasures for achieving the energy mix toward FY 2030

The Japanese Government shall decdicate all its energy toward the realization of the energy mix toward FY 2030 at the 5th Energy Basic Plan determined in July 2018.

By contrast, it is revealed that the composition of the energy supply (kWh) projected in FY 2030 shows 36% for coal-fired thermal and 4% for nuclear generation, and a gap exists between the projected energy supply and the energy mix. The aggregation of the electricity supply plans sums the generation plans that each EPCO counts as securing a stable supply based on certain given premises. It is probable that this trend of energy supply will continue. Unless EPCOs change their generation plans, based on further political initiative or transformation of business environment, the achievement of the energy mix in FY 2030 will be difficult.

For the achievement of the energy mix, it is necessary to accumulate initiatives that fit the circumstances of each generation source faces, such as proper implementation of regulatory measures or inducive measures. The Organization expects the Government to properly implement initiatives toward a steady achievement of the energy mix.

VIII. Conclusions

1. Electricity Demand Forecast

The AAGR of peak demand nationwide in the mid-to-long term is forecast to decrease by 0.1%. AAGR is forecasted to be negative, and is attributable to a number of major decreasing factors, such as a shrinking population, and efforts to reduce electricity use, notwithstanding increasing factors such as growth of economic activity and wider use of electric appliances.

2. Electricity Supply and Demand

The Organization is prepared to apply EUE as a new reliablility criterion to the electric supply plan based on the review of reliability criteria. In the short term (the first and second year of the projected period), all the areas and all the 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 after FY 2026 exceeds the criteria. By contrast, the supply–demand balance evaluation by the conventional approach (the criterion of a stable supply, that is, a reserve margin of 8% in interconnected areas, and supply capacity over the peak demand by deducting the capacity of the largest generating unit and balancing capacity with frequency control [Generator I] in Okinawa) shows that the 8% reserve margin will not be achieved in particular months and particular areas in the short term as FY 2021 and 2022.

For energy–supply requirement evaluation, it seems that energy supply will be below the forecasted energy requirement by 0.1 to 3.2 TWh/month of volume (equivalent to 0.1 to 4.3% against the forecast energy requirement) throughout FY 2021.

On this account, the Organization has verified with the EPCOs whether any deferral of scheduled maintenance work is possible, or suspension of aged generators can be postponed, and the confirmation above leads to additional supply capacity to be used. Hereafter, publishing the result of the confirmation and the coordination above, the Organization will reconfirm with the retail and generation companies that there is sufficient preparedness for supply-demand tightness. If they do not have sufficient countermeasures, the Organization recommends that they take proper measures for supply capacity procurement.

Further, in case of not achieving improvement of the supply - demand balance with proper countermeasures of retail and generation companies, the Organization will determine again the implementation of safeguard measures of generator procurement in the short term period at the April meeting of the Study Committee on Regulating and Marginal Supply Capability and Long-Term Supply–Demand Balance Evaluation.

3. Analysis of the Transition of Power Generation Sources Nationwide

Regarding the transition of installed power generation capacity and net electricity generation, renewable energy such as solar power and wind power is projected to increase. For 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, generator access lines are significantly planned anew, and development plans for cross-regional interconnection lines include 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 in both areas, with higher procurement from external service and in with 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 the 10-year period. In addition, the ratios of the secured supply capacity are reviewed. In particular, small and medium-sized retail companies have planned their supply capacity as "unspecified procurement," as in the previous year's plan. As a result, the ratios of the secured supply capacity indicate a declining tendency.

7. Findings and Challenges

The Organization has communicated to METI its opinions concerning three major challenges in relation to the aggregation of electricity supply plans for FY 2021.

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

APPENDIX 1 Supply–Demand Balance for FY 2021 and 2022 (Short-term)

i) Projection for FY 2020

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 2021, respectively. Table A1-5 shows the monthly projection of the reserve margin for each regional service area recalculated with power exchanges to areas below the 8% reserve margin from areas with over 8% reserve margin with additional supply capacity according to provision of Article 48 of the Act. Further, 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 2021 (10^4kW at the sending end)

[10^4 kW]

	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.	Jan.	Feb.	Mar.
Hokkaido	393	356	355	404	415	388	396	454	481	497	493	454
Tohoku	1,056	984	1,059	1,265	1,293	1,164	1,052	1,164	1,291	1,350	1,335	1,241
Tokyo	3,819	3,671	4,077	5,329	5,329	4,516	3,758	4,042	4,427	4,773	4,773	4,366
50 Hz areas Total	5,268	5,011	5,491	6,998	7,037	6,068	5,206	5,660	6,199	6,620	6,601	6,061
Chubu	1,829	1,868	2,017	2,453	2,453	2,316	1,958	1,935	2,108	2,285	2,285	2,082
Hokuriku	387	354	397	492	492	436	369	404	456	489	489	446
Kansai	1,833	1,857	2,105	2,726	2,726	2,284	1,890	1,935	2,326	2,431	2,431	2,129
Chugoku	748	739	811	1,032	1,032	922	772	835	1,014	1,025	1,025	901
Shikoku	344	342	390	492	492	432	356	365	453	453	453	397
Kyushu	1,028	1,044	1,188	1,521	1,521	1,312	1,118	1,141	1,433	1,451	1,451	1,228
60 Hz areas Total	6,169	6,204	6,908	8,716	8,716	7,702	6,463	6,615	7,790	8,134	8,134	7,183
Interconnected	11,437	11,215	12,399	15,714	15,753	13,770	11,669	12,275	13,989	14,754	14,735	13,244
Okinawa	104	119	144	144	146	145	130	112	97	101	100	93
Nationwide	11,541	11,334	12,543	15,858	15,899	13,915	11,798	12,387	14,085	14,855	14,835	13,337

Table A1-2 Monthly Projection of Supply Capacity for Each Regional Service Area in FY 2021 (10^4kW at the sending end)

[10^4 kW]

	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.	Jan.	Feb.	Mar.
Hokkaido	574	605	573	576	608	584	602	633	585	578	578	588
Tohoku	1,260	1,304	1,305	1,534	1,566	1,434	1,240	1,290	1,472	1,568	1,562	1,413
Tokyo	4,380	4,346	4,854	5,636	5,699	5,273	4,448	4,386	5,022	5,091	5,014	4,872
50 Hz areas Total	6,214	6,255	6,732	7,746	7,874	7,291	6,291	6,310	7,080	7,237	7,154	6,874
Chubu	2,281	2,285	2,469	2,571	2,618	2,528	2,370	2,339	2,421	2,503	2,446	2,401
Hokuriku	488	474	485	564	546	543	491	472	509	506	505	494
Kansai	2,105	2,135	2,475	2,777	2,773	2,510	2,380	2,350	2,511	2,559	2,426	2,326
Chugoku	955	980	1,169	1,283	1,333	1,156	1,073	1,005	1,028	1,128	1,123	1,115
Shikoku	473	510	556	612	616	584	495	489	525	530	527	505
Kyushu	1,408	1,420	1,559	1,736	1,811	1,710	1,423	1,301	1,556	1,627	1,528	1,411
60 Hz areas Total	7,710	7,804	8,714	9,544	9,698	9,031	8,231	7,956	8,549	8,852	8,554	8,252
Interconnected	13,924	14,059	15,447	17,290	17,572	16,322	14,522	14,266	15,629	16,089	15,708	15,126
Okinawa	161	184	189	188	193	202	193	175	168	168	164	173
Nationwide	14,086	14,243	15,635	17,478	17,764	16,524	14,715	14,440	15,797	16,257	15,872	15,300

Table A1-3 Monthly Projection of Reserve Capacity for Each Regional Service Area in FY 2020 (10^4kW at the sending end)

[10^4 kW]

	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.	Jan.	Feb.	Mar.
Hokkaido	181	249	218	172	193	196	206	179	104	81	85	134
Tohoku	204	320	246	269	273	270	188	126	181	218	227	172
Tokyo	561	675	777	307	370	757	690	344	595	318	241	506
50 Hz areas Total	946	1,244	1,241	748	837	1,223	1,085	650	881	617	553	813
Chubu	452	417	452	118	165	212	412	403	313	218	161	319
Hokuriku	101	121	88	72	54	107	122	69	54	17	16	49
Kansai	272	278	370	51	47	226	490	415	185	128	-5	197
Chugoku	207	241	358	251	301	234	301	170	14	103	98	214
Shikoku	129	168	166	120	124	152	139	124	72	77	74	108
Kyushu	380	376	371	215	290	398	305	160	123	176	77	183
60 Hz areas Total	1,541	1,600	1,806	828	982	1,329	1,769	1,342	760	718	420	1,070
Interconnected	2,487	2,844	3,048	1,576	1,819	2,552	2,854	1,991	1,640	1,335	973	1,883
Okinawa	58	65	45	44	47	56	63	63	72	67	64	80
Nationwide	2,545	2,909	3,092	1,620	1,866	2,608	2,917	2,054	1,712	1,402	1,038	1,963

Table A1-4 Monthly Projection of Reserve Margin for Each Regional Service Area in FY 2021

	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.	Jan.	Feb.	Mar.
Hokkaido	46.0%	69.9%	61.4%	42.6%	46.6%	50.4%	52.1%	39.5%	21.7%	16.3%	17.2%	29.6%
Tohoku	19.4%	32.5%	23.3%	21.3%	21.1%	23.2%	17.9%	10.8%	14.0%	16.1%	17.0%	13.9%
Tokyo	14.7%	18.4%	19.1%	**5.8%**	**6.9%**	16.8%	18.4%	8.5%	13.4%	**6.7%**	**5.0%**	11.6%
50 Hz areas Total	18.0%	24.8%	22.6%	10.7%	11.9%	20.1%	20.8%	11.5%	14.2%	9.3%	8.4%	13.4%
Chubu	24.7%	22.3%	22.4%	**4.8%**	**6.7%**	9.1%	21.0%	20.9%	14.8%	9.6%	**7.0%**	15.3%
Hokuriku	26.1%	34.2%	22.3%	14.6%	10.9%	24.4%	33.2%	17.0%	11.7%	**3.4%**	**3.3%**	11.0%
Kansai	14.8%	15.0%	17.6%	**1.9%**	**1.7%**	9.9%	25.9%	21.5%	**7.9%**	**5.3%**	**-0.2%**	9.2%
Chugoku	27.7%	32.6%	44.2%	24.4%	29.2%	25.4%	39.0%	20.4%	**1.4%**	10.0%	9.5%	23.7%
Shikoku	37.6%	49.0%	42.7%	24.5%	25.3%	35.3%	38.9%	34.0%	15.8%	16.9%	16.3%	27.1%
Kyushu	36.9%	36.0%	31.2%	14.1%	19.1%	30.3%	27.3%	14.0%	8.6%	12.1%	**5.3%**	14.9%
60 Hz areas Total	25.0%	25.8%	26.1%	9.5%	11.3%	17.3%	27.4%	20.3%	9.8%	8.8%	**5.2%**	14.9%
Interconnected	21.7%	25.4%	24.6%	10.0%	11.5%	18.5%	24.5%	16.2%	11.7%	9.0%	**6.6%**	14.2%
Okinawa	55.8%	54.4%	30.9%	30.3%	32.3%	38.7%	48.9%	56.2%	74.2%	66.4%	64.7%	86.0%
Nationwide	22.1%	25.7%	24.7%	10.2%	11.7%	18.7%	24.7%	16.6%	12.2%	9.4%	**7.0%**	14.7%

Below 8 % criteria

Table A1-5 Monthly Projection of Reserve Margin for Each Regional Service Area in FY 2021

(with power exchanges through cross-regional interconnection lines and generating facilities not included in the electricity supply plans, at the sending end)

	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.	Jan.	Feb.	Mar.
Hokkaido	29.5%	55.6%	54.0%	32.9%	37.7%	47.9%	43.6%	25.7%	13.1%	13.4%	12.3%	14.9%
Tohoku	17.7%	26.5%	21.0%	17.5%	16.1%	16.6%	19.2%	10.5%	13.1%	13.4%	12.3%	13.3%
Tokyo	17.7%	22.7%	21.0%	**7.5%**	8.9%	16.6%	19.2%	10.5%	11.5%	**7.7%**	**5.8%**	13.3%
Chubu	23.6%	24.6%	25.2%	9.2%	10.3%	16.6%	27.2%	20.1%	11.5%	8.8%	**5.8%**	14.8%
Hokuriku	23.6%	24.6%	25.2%	9.2%	10.3%	16.6%	27.2%	20.1%	11.5%	8.8%	**5.8%**	14.8%
Kansai	23.6%	24.6%	25.2%	9.2%	10.3%	16.6%	28.1%	20.1%	11.5%	8.8%	**5.8%**	14.8%
Chugoku	23.6%	24.6%	25.9%	9.2%	10.3%	16.6%	28.1%	20.1%	11.5%	8.8%	**5.8%**	14.8%
Shikoku	23.6%	24.6%	25.9%	9.2%	10.3%	16.6%	28.1%	20.1%	11.5%	8.8%	**5.8%**	14.8%
Kyushu	28.9%	27.1%	27.6%	10.6%	15.5%	27.2%	28.1%	20.1%	11.5%	8.8%	**5.8%**	14.8%
Interconnected	21.7%	25.4%	24.6%	10.0%	11.5%	18.5%	24.5%	16.2%	11.7%	9.0%	**6.6%**	14.2%
Okinawa	55.8%	54.4%	30.9%	30.3%	32.3%	38.7%	48.9%	56.2%	74.2%	66.4%	64.7%	86.0%
Nationwide	22.1%	25.7%	24.7%	10.2%	11.7%	18.7%	24.7%	16.6%	12.2%	9.4%	**7.0%**	14.7%

Improve to 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 2020 (10^4kW at the sending end)

[10^4 kW]

	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.	Jan.	Feb.	Mar.
Peak Demand	104	119	144	146	150	147	130	112	97	101	100	93
Supply Capacity	161	187	189	197	206	206	193	175	168	168	164	173
Reserve Capacity	58	67	45	51	56	59	63	63	72	67	64	80
Resreve Margin	55.8%	56.5%	30.9%	35.3%	37.5%	39.7%	48.9%	56.2%	74.2%	66.4%	64.7%	86.0%

ii) Projection for FY 2022

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 2022, respectively. 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 provision of Article 48 of the Act. Further, 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 2022 (10^4kW at the sending end)

[10^4 kW]

	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.	Jan.	Feb.	Mar.
Hokkaido	394	357	356	405	416	389	397	455	482	498	494	455
Tohoku	1,053	981	1,056	1,261	1,289	1,160	1,051	1,163	1,290	1,349	1,334	1,240
Tokyo	3,842	3,690	4,096	5,337	5,337	4,522	3,759	4,037	4,419	4,761	4,761	4,353
50 Hz areas Total	5,289	5,028	5,508	7,003	7,042	6,071	5,207	5,655	6,191	6,608	6,589	6,048
Chubu	1,843	1,882	2,033	2,472	2,472	2,334	1,974	1,950	2,124	2,302	2,302	2,098
Hokuriku	389	355	399	494	494	438	370	406	458	491	491	448
Kansai	1,840	1,863	2,113	2,736	2,736	2,293	1,897	1,942	2,335	2,440	2,440	2,137
Chugoku	750	741	814	1,035	1,035	924	774	837	1,017	1,028	1,028	904
Shikoku	344	342	390	493	493	433	356	365	453	453	453	398
Kyushu	1,033	1,049	1,194	1,529	1,529	1,318	1,124	1,147	1,440	1,459	1,459	1,235
60 Hz areas Total	6,199	6,232	6,943	8,759	8,759	7,740	6,495	6,647	7,827	8,173	8,173	7,220
Interconnected	11,488	11,260	12,451	15,762	15,801	13,811	11,702	12,302	14,018	14,781	14,762	13,268
Okinawa	105	121	146	146	147	147	131	113	98	102	101	94
Nationwide	11,593	11,381	12,596	15,908	15,948	13,958	11,833	12,415	14,115	14,883	14,863	13,362

Table A1-8 Monthly Projection of Supply Capacity for Each Regional Service Area in FY 2022 (10^4kW at the sending end)

[10^4 kW]

	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.	Jan.	Feb.	Mar.
Hokkaido	519	544	538	579	587	583	582	622	671	666	665	592
Tohoku	1,283	1,352	1,410	1,612	1,672	1,494	1,403	1,453	1,624	1,664	1,680	1,576
Tokyo	4,444	4,559	4,788	5,529	5,586	5,219	4,463	4,244	4,836	4,963	4,968	4,681
50 Hz areas Total	6,245	6,455	6,736	7,719	7,845	7,295	6,448	6,319	7,131	7,293	7,313	6,849
Chubu	2,105	2,254	2,503	2,612	2,674	2,434	2,182	2,030	2,318	2,446	2,415	2,339
Hokuriku	494	478	457	486	511	482	504	464	509	505	502	514
Kansai	2,224	2,327	2,394	2,697	2,754	2,563	2,195	2,262	2,637	2,669	2,734	2,533
Chugoku	854	908	1,059	1,274	1,261	1,154	1,046	1,017	1,186	1,224	1,198	1,131
Shikoku	461	496	544	589	622	589	546	489	505	516	509	525
Kyushu	1,361	1,480	1,622	1,762	1,760	1,794	1,548	1,523	1,645	1,731	1,629	1,518
60 Hz areas Total	7,499	7,943	8,579	9,419	9,581	9,016	8,020	7,784	8,799	9,091	8,987	8,559
Interconnected	13,745	14,398	15,314	17,139	17,426	16,311	14,468	14,103	15,930	16,383	16,300	15,409
Okinawa	170	183	204	205	212	213	197	173	155	161	186	181
Nationwide	13,915	14,581	15,518	17,344	17,638	16,524	14,665	14,277	16,085	16,545	16,486	15,590

Table A1-9 Monthly Projection of Reserve Capacity for Each Regional Service Area in FY 2021 (10^4kW at the sending end)

[10^4 kW]

	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.	Jan.	Feb.	Mar.
Hokkaido	125	187	182	174	171	194	185	167	189	168	171	137
Tohoku	230	371	354	351	383	334	352	290	334	315	346	336
Tokyo	602	869	692	192	249	697	704	207	417	202	207	328
50 Hz areas Total	956	1,427	1,228	716	803	1,224	1,241	664	940	685	724	801
Chubu	262	372	470	140	202	100	208	80	194	144	113	241
Hokuriku	105	123	58	-8	17	44	134	58	51	14	11	66
Kansai	384	464	281	-39	18	270	298	320	302	229	294	396
Chugoku	104	167	245	239	226	230	272	180	169	196	170	227
Shikoku	117	154	154	96	129	156	190	124	52	63	56	127
Kyushu	328	431	428	233	231	476	424	376	205	272	170	283
60 Hz areas Total	1,300	1,711	1,636	660	822	1,276	1,526	1,138	973	918	814	1,340
Interconnected	2,257	3,138	2,864	1,377	1,625	2,500	2,766	1,802	1,913	1,602	1,538	2,141
Okinawa	66	62	58	59	64	66	65	60	57	59	85	87
Nationwide	2,322	3,200	2,922	1,436	1,689	2,566	2,832	1,862	1,970	1,662	1,623	2,228

Table A1-10 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	31.8%	52.5%	51.0%	42.8%	41.2%	49.8%	46.5%	36.7%	39.3%	33.7%	34.6%	30.2%
Tohoku	21.8%	37.8%	33.5%	27.8%	29.7%	28.8%	33.5%	24.9%	25.9%	23.3%	25.9%	27.1%
Tokyo	15.7%	23.5%	16.9%	**3.6%**	**4.7%**	15.4%	18.7%	**5.1%**	9.4%	**4.2%**	**4.4%**	**7.5%**
50 Hz areas Total	18.1%	28.4%	22.3%	10.2%	11.4%	20.2%	23.8%	11.7%	15.2%	10.4%	11.0%	13.2%
Chubu	14.2%	19.8%	23.1%	**5.7%**	8.2%	**4.3%**	10.5%	**4.1%**	9.1%	**6.3%**	**4.9%**	11.5%
Hokuriku	27.1%	34.6%	14.7%	**-1.7%**	**3.4%**	10.0%	36.3%	14.4%	11.2%	**2.8%**	**2.2%**	14.8%
Kansai	20.9%	24.9%	13.3%	**-1.4%**	**0.7%**	11.8%	15.7%	16.5%	12.9%	9.4%	12.1%	18.5%
Chugoku	13.8%	22.5%	30.1%	23.1%	21.9%	24.9%	35.1%	21.5%	16.6%	19.1%	16.5%	25.1%
Shikoku	33.9%	45.2%	39.4%	19.4%	26.1%	36.1%	53.5%	34.0%	11.4%	13.9%	12.3%	31.8%
Kyushu	31.8%	41.1%	35.8%	15.2%	15.1%	36.1%	37.7%	32.8%	14.2%	18.6%	11.7%	22.9%
60 Hz areas Total	21.0%	27.5%	23.6%	**7.5%**	9.4%	16.5%	23.5%	17.1%	12.4%	11.2%	10.0%	18.6%
Interconnected	19.6%	27.9%	23.0%	8.7%	10.3%	18.1%	23.6%	14.6%	13.6%	10.8%	10.4%	16.1%
Okinawa	62.8%	51.4%	39.7%	40.3%	43.6%	45.0%	49.8%	53.0%	58.3%	58.3%	84.4%	92.6%
Nationwide	20.0%	28.1%	23.2%	9.0%	10.6%	18.4%	23.9%	15.0%	14.0%	11.2%	10.9%	16.7%

Below 8 % criteria

Table A1-11 Monthly Projection of Reserve Margin for Each Regional Service Area in FY 2022

(with power exchanges through cross-regional interconnection lines and generating facilities not included in the electricity supply plans, at the sending end)

	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.	Jan.	Feb.	Mar.
Hokkaido	23.8%	36.4%	45.2%	32.2%	35.0%	42.8%	31.8%	22.4%	23.8%	20.8%	23.7%	27.9%
Tohoku	23.8%	29.6%	20.9%	17.6%	17.9%	28.6%	31.8%	22.4%	22.8%	20.8%	23.7%	27.9%
Tokyo	15.9%	26.6%	20.9%	**6.8%**	8.0%	13.2%	20.2%	**7.6%**	12.0%	**6.3%**	**6.1%**	**7.5%**
Chubu	19.2%	26.6%	22.3%	**7.1%**	8.9%	13.2%	20.2%	10.7%	12.4%	10.8%	10.0%	17.8%
Hokuriku	19.2%	26.6%	22.3%	**7.1%**	8.9%	16.4%	20.2%	10.7%	12.4%	10.8%	10.0%	18.9%
Kansai	19.2%	26.6%	22.3%	**7.1%**	8.9%	16.4%	22.0%	18.2%	12.4%	10.8%	10.0%	18.9%
Chugoku	19.2%	26.6%	22.3%	**7.1%**	8.9%	16.4%	22.0%	18.2%	12.4%	10.8%	10.0%	18.9%
Shikoku	19.2%	26.6%	22.3%	**7.1%**	8.9%	16.4%	23.5%	18.2%	12.4%	10.8%	10.0%	18.9%
Kyushu	29.7%	34.2%	28.7%	9.7%	11.7%	32.2%	35.5%	26.8%	12.4%	13.4%	10.0%	18.9%
Interconnected	19.6%	27.9%	23.0%	8.7%	10.3%	18.1%	23.6%	14.6%	13.6%	10.8%	10.4%	16.1%
Okinawa	62.8%	51.4%	39.7%	40.3%	43.6%	45.0%	49.8%	53.0%	58.3%	58.3%	84.4%	92.6%
Nationwide	20.0%	28.1%	23.2%	9.0%	10.6%	18.4%	23.9%	15.0%	14.0%	11.2%	10.9%	16.7%

Improve to 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 2022 (10^4kW at the sending end)

[10^4 kW]

	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.	Jan.	Feb.	Mar.
Peak Demand	105	121	146	147	152	149	131	113	98	102	101	94
Supply Capacity	170	185	204	214	226	217	197	173	155	161	186	181
Reserve Capacity	66	65	58	67	74	69	65	60	57	59	85	87
Resreve Margin	62.8%	53.6%	39.7%	45.3%	48.6%	46.0%	49.8%	53.0%	58.3%	58.3%	84.4%	92.6%

APPENDIX 2 Long-Term Supply–Demand Balance for the 10-year Period FY 2021–2030

Tables A2-1 to A2-4 show a 10-year projection of the annual peak demand, annual supply capacity, annual reserve capacity, and reserve margin for each regional service area from FY 2021 to 2030, respectively. Table A2-5 shows the annual projection of the reserve margin for each regional service area recalculated with power exchanges from areas with over 8% reserve margin to areas below the 8% reserve margin with additional supply capacity according to provision of Article 48 of the Act. Tables A2-6 to A2-9 show a 10-year projection of the annual peak demand, annual supply capacity, annual reserve capacity, and reserve margin for winter peak areas of Hokkaido and Tohoku, respectively. Table A2-10 shows the 10-year 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. Further, Table A2-11 shows the annual peak demand, monthly supply capacity, monthly reserve capacity, and reserve margin for the projected period at the designated time.

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

[10^4 kW]

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Hokkaido	415	416	416	416	415	415	415	415	414	414
Tohoku	1,293	1,289	1,284	1,278	1,271	1,264	1,257	1,250	1,243	1,236
Tokyo	5,329	5,337	5,333	5,328	5,323	5,316	5,309	5,302	5,294	5,286
50 Hz areas Total	7,037	7,042	7,033	7,022	7,009	6,995	6,981	6,967	6,951	6,936
Chubu	2,453	2,472	2,464	2,456	2,448	2,440	2,432	2,425	2,418	2,411
Hokuriku	492	494	496	497	496	494	493	491	490	488
Kansai	2,726	2,736	2,728	2,719	2,711	2,703	2,694	2,686	2,677	2,669
Chugoku	1,032	1,035	1,036	1,036	1,035	1,035	1,035	1,035	1,034	1,034
Shikoku	492	493	491	490	488	487	486	484	483	481
Kyushu	1,521	1,529	1,534	1,532	1,529	1,526	1,524	1,521	1,519	1,516
60 Hz areas Total	8,716	8,759	8,749	8,730	8,707	8,685	8,664	8,642	8,621	8,599
Interconnected	15,753	15,801	15,782	15,752	15,716	15,680	15,645	15,609	15,572	15,535
Okinawa	146	147	149	150	151	152	153	153	154	155
Nationwide	15,899	15,948	15,931	15,902	15,868	15,832	15,798	15,762	15,726	15,690

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

[10^4 kW]

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Hokkaido	608	587	621	644	644	642	643	643	646	646
Tohoku	1,566	1,672	1,741	1,692	1,642	1,677	1,687	1,705	1,711	1,720
Tokyo	5,699	5,586	5,718	6,048	6,269	6,268	6,275	6,352	6,357	6,364
50 Hz areas Total	7,874	7,845	8,080	8,384	8,556	8,586	8,604	8,700	8,714	8,730
Chubu	2,618	2,674	2,534	2,902	2,818	2,821	2,837	2,834	2,824	2,821
Hokuriku	546	511	515	532	515	510	508	500	498	497
Kansai	2,773	2,754	2,975	2,983	2,859	2,978	2,988	2,967	2,976	2,977
Chugoku	1,333	1,261	1,320	1,296	1,300	1,308	1,307	1,289	1,291	1,293
Shikoku	616	622	645	654	655	655	657	650	651	657
Kyushu	1,811	1,760	1,768	1,739	1,698	1,575	1,580	1,566	1,570	1,620
60 Hz areas Total	9,698	9,581	9,758	10,107	9,844	9,847	9,878	9,805	9,809	9,865
Interconnected	17,572	17,426	17,837	18,491	18,400	18,433	18,481	18,506	18,523	18,594
Okinawa	193	212	215	219	202	214	214	214	214	214
Nationwide	17,764	17,638	18,052	18,710	18,602	18,647	18,695	18,720	18,737	18,808

Table A2-3 Annual Projection of Reserve Capacity for Each Regional Service Area
(at 15:00 in August, 10^4kW at the sending end)

[10^4 kW]

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Hokkaido	193	171	205	228	229	227	228	228	232	232
Tohoku	273	383	457	414	371	413	430	455	468	484
Tokyo	370	249	385	720	946	952	966	1,050	1,063	1,078
50 Hz areas Total	837	803	1,047	1,362	1,547	1,591	1,623	1,733	1,763	1,794
Chubu	165	202	70	446	370	381	405	409	406	410
Hokuriku	54	17	19	35	19	16	15	9	8	9
Kansai	47	18	247	264	148	275	294	281	299	308
Chugoku	301	226	284	260	264	273	272	254	256	259
Shikoku	124	129	154	164	167	168	171	166	168	176
Kyushu	290	231	234	207	169	49	56	45	51	104
60 Hz areas Total	982	822	1,009	1,377	1,137	1,162	1,214	1,164	1,188	1,266
Interconnected	1,819	1,625	2,055	2,740	2,683	2,753	2,836	2,897	2,951	3,059
Okinawa	47	64	65	69	51	62	61	60	60	59
Nationwide	1,866	1,689	2,121	2,808	2,734	2,815	2,897	2,958	3,010	3,118

Table A2-4 Annual Projection of Reserve Margin for Each Regional Service Area
(resource within own service area only, at 15:00 in August)

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Hokkaido	46.6%	41.2%	49.3%	54.9%	55.3%	54.7%	54.8%	55.1%	56.0%	56.0%
Tohoku	21.1%	29.7%	35.6%	32.4%	29.2%	32.7%	34.2%	36.4%	37.7%	39.2%
Tokyo	**6.9%**	**4.7%**	**7.2%**	13.5%	17.8%	17.9%	18.2%	19.8%	20.1%	20.4%
50 Hz areas Total	11.9%	11.4%	14.9%	19.4%	22.1%	22.8%	23.2%	24.9%	25.4%	25.9%
Chubu	**6.7%**	8.2%	**2.9%**	18.2%	15.1%	15.6%	16.7%	16.9%	16.8%	17.0%
Hokuriku	10.9%	**3.4%**	**3.9%**	**7.1%**	**3.8%**	**3.2%**	**3.1%**	**1.8%**	**1.7%**	**1.9%**
Kansai	**1.7%**	**0.7%**	9.0%	9.7%	**5.5%**	10.2%	10.9%	10.5%	11.2%	11.5%
Chugoku	29.2%	21.9%	27.4%	25.1%	25.5%	26.4%	26.3%	24.6%	24.8%	25.0%
Shikoku	25.3%	26.1%	31.3%	33.5%	34.1%	34.4%	35.2%	34.2%	34.8%	36.5%
Kyushu	19.1%	15.1%	15.3%	13.5%	11.0%	**3.2%**	**3.7%**	**2.9%**	**3.3%**	**6.9%**
60 Hz areas Total	11.3%	9.4%	11.5%	15.8%	13.1%	13.4%	14.0%	13.5%	13.8%	14.7%
Interconnected	11.5%	10.3%	13.0%	17.4%	17.1%	17.6%	18.1%	18.6%	18.9%	19.7%
Okinawa	32.3%	43.6%	43.9%	45.6%	33.5%	40.7%	40.0%	39.4%	38.6%	38.0%
Nationwide	11.7%	10.6%	13.3%	17.7%	17.2%	17.8%	18.3%	18.8%	19.1%	19.9%

Below 8 % criteria

Table A2-5 Annual Projection of Reserve Margin for Each Regional Service Area
(with power exchanges through cross-regional interconnection lines and generating facilities not included in the electricity supply plans, at the sending end)

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Hokkaido	37.7%	35.0%	38.9%	44.5%	44.8%	45.1%	45.2%	45.4%	46.3%	46.4%
Tohoku	16.1%	18.4%	26.6%	23.3%	20.1%	20.8%	22.3%	18.6%	19.0%	19.5%
Tokyo	8.9%	8.0%	9.3%	16.1%	16.0%	16.7%	17.3%	18.6%	19.0%	19.5%
Chubu	10.3%	8.7%	9.3%	16.1%	16.0%	16.7%	17.3%	18.6%	19.0%	19.5%
Hokuriku	10.3%	8.7%	13.3%	16.1%	16.0%	16.7%	17.3%	17.3%	17.8%	18.3%
Kansai	10.3%	8.7%	13.3%	16.1%	16.0%	16.7%	17.3%	17.3%	17.8%	18.3%
Chugoku	10.3%	8.7%	13.3%	16.1%	16.0%	16.7%	17.3%	17.3%	17.8%	18.3%
Shikoku	10.3%	8.7%	13.3%	16.1%	16.0%	16.7%	17.3%	17.3%	17.8%	18.3%
Kyushu	15.5%	11.7%	13.3%	16.1%	16.0%	14.7%	15.0%	14.8%	15.2%	18.3%
Interconnected	11.5%	10.3%	13.1%	17.4%	17.1%	17.6%	18.2%	18.6%	19.0%	19.7%
Okinawa	32.3%	43.6%	43.9%	45.6%	33.5%	40.7%	40.0%	39.4%	38.6%	38.0%
Nationwide	11.7%	10.6%	13.4%	17.7%	17.3%	17.8%	18.4%	18.8%	19.2%	19.9%

Improve to over 8%

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

Table A2-6 Annual Peak Demand Forecast for Winter Peak Areas of Hokkaido and Tohoku
(at 18:00 in January, 10^4kW at the sending end)

[10^4 kW]

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Hokkaido	497	498	498	498	498	497	497	497	497	496
Tohoku	1,350	1,349	1,347	1,342	1,337	1,332	1,327	1,322	1,317	1,311

Table A2-7 Annual Projection of Supply Capacity for Winter Peak Areas of Hokkaido and Tohoku
(at 18:00 in January, 10^4kW at the sending end)

[10^4 kW]

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Hokkaido	578	666	673	656	661	659	660	663	663	714
Tohoku	1,568	1,664	1,685	1,698	1,666	1,716	1,736	1,765	1,795	1,818

Table A2-8 Annual Projection of Reserve Capacity for Winter Peak areas of Hokkaido and Tohoku
(at 18:00 in January, 10^4kW at the sending end)

[10^4 kW]

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Hokkaido	81	168	175	158	163	162	163	166	166	218
Tohoku	218	315	338	356	329	384	409	443	478	507

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

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Hokkaido	16.3%	33.7%	35.0%	31.7%	32.7%	32.6%	32.8%	33.4%	33.4%	44.0%
Tohoku	16.1%	23.3%	25.1%	26.5%	24.6%	28.9%	30.8%	33.5%	36.3%	38.7%

Table A2-10 Annual Projection of Reserve Margin for Winter Peak Areas of Hokkaido and Tohoku
(at 18:00 in Januar, with power exchanges through cross-regional interconnection lines and generating facilities not included in the electricity supply plans, at the sending end)

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Hokkaido	16.2%	28.1%	28.2%	28.3%	27.2%	30.3%	31.7%	33.9%	35.9%	40.5%
Tohoku	16.2%	25.4%	28.2%	28.3%	27.2%	30.3%	31.7%	33.9%	35.9%	40.5%

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

Table A2-11 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%