PSE&G

Zone Generation Capacity &
Transmission Peak Loads and Obligations
October 2024 Update

Contents

Introduction

PJM sets rules for allocating & reporting Capacity and Transmission Loads and Obligations.

2024 Transmission Loads and Obligations are based on the actual 2023 zonal peak load and will be calculated and become effective on January 1, 2024, for the whole calendar year.

Capacity Loads are based on the weather normalized 2023 summer zonal peak load and will be calculated for January 1, 2024, but not made effective until 6/1/2024.

At that time, capacity obligations will be based on new values for the FPR (Forecast Pool Requirement), Final Zonal RPM scaling factor and PS Zonal scaling factor. Capacity obligations are updated three times a year, January, June & October.

See Table 1 below for illustrated obligation update schedule.

Table 1
Effective Obligation Dates

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan
Transmission Obligation Update	Jan 1st to Dec 31st												
Capacity Obligation Update	Jan 1st to May31st					Jun 1st to Sep 30th				Oct 1st to Dec 31st			

Note that individual customer obligations will be periodically adjusted as new customers are added to maintain a constant total zonal obligation through the operating year (June, 2023 – May, 2024). Table 2 shows Top 5-Peak Days for Transmission & Capacity Loads.

Table 2
Top 5-Peak Days for Transmission & Capacity

CAPACITY PJM		TRANSMISSION PSE&G	
Top 5 Peak Days 2023		Top 5 Peak Days 2023	
DATE	Time-Hour Ending	DATE	Time-Hour Ending
7/5/2023	18	7/27/2023	19
7/27/2023	18	7/28/2023	18
7/28/2023	18	9/5/2023	18
9/5/2023	17	9/6/2023	18
9/6/2023	17	9/7/2023	17

1. Generation Capacity

Effective June 1, 2024 through May 31, 2025, PSE&G's coincident peak forecast is 9258 (2023 Load Forecast Report Table B-10) and the weather normalized coincident 2024 zonal load is 9,420 MW, both as assigned by PJM Interconnection. The customer peak loads are based on the coincident normal zonal peak load. To see how PSE&G's total normalized load is allocated to individual PSE&G customers and to determine each customer's Peak Load Share and Generation Obligation, see below.

I. Generation Capacity Allocation for Interval Metered Customers

This group includes customers who were part of the interval metered customer group during summer, 2023. The Peak Load Share (also called generation capacity load) for each of these customers is equal to the average of their hourly loads at the time of PJM's 5 highest hourly loads in Summer 2023, times a loss expansion factor[1], times a capacity scale factor[2]. The Capacity Obligation will be equal to the customer's Peak Load Share times the Forecast Pool Reserve factor of 1.117, times PSE&G's Capacity Obligation factor of 1.0132664times Final RPM zonal scaling factor of 1.12070181. The Final RPM Zonal scaling factor and Forecast Pool Reserve factor are assigned by PJM Interconnection.

II. Generation Capacity Allocation for Billed Demand Customers

This group includes customers on rate schedules requiring billed peak demands during summer 2023, who were not part of the interval metered customer group. The Peak Load Share (also called generation capacity load) for each of these customers is equal to the weighted average of their June to September 2023 billing demands, times a loss expansion factor, times a capacity scale factor. The Capacity Obligation will be equal to the customer's Peak Load Share times the Forecast Pool Reserve factor of 1.117, times PSE&G's Capacity Obligation factor of 1.0132664times Final RPM zonal scaling factor of 1.12070181. The Final RPM Zonal scaling factor and Forecast Pool Reserve factor are assigned by PJM Interconnection.

[1] See Appendix Section for Loss Expansion Factor Table
[2] See Appendix Section for Capacity Scale Factor Table

III. Generation Capacity Allocation for Non-Demand Billed Customers

This group includes customers on rate schedules not requiring peak demands for billing purposes during summer 2023, who were not part of the interval metered customer group. The summer peak impact of these customers is based upon data from the load profile sample set identical to that used for settlement purposes. The Peak Load Share (also called generation capacity load) for each of these customers is equal to their June to September 2023 billed kWh divided by the number of hours in their summer billing period, times a capacity profile peak ratio[3], times a loss expansion factor, times a capacity scale factor. The Capacity Obligation will be equal to the customer's Peak Load Share times the Forecast Pool Reserve factor of 1.117, times PSE&G's Capacity Obligation factor of 1.0132664times Final RPM zonal scaling factor of 1.12070181. The Final RPM Zonal scaling factor and Forecast Pool Reserve factor are assigned by PJM Interconnection. (Both the Peak Load Share and the Generation Obligation for all street lighting rates is set equal to zero).

IV. Generation Capacity Allocation for New Customers

New residential customers will generally receive a default Peak Load Share of 1.7kW. The other new customers are assigned Peak Load Shares based on customer specific information. A new customer's Capacity Obligation will be equal to the customer's Peak Load Share times the Forecast Pool Reserve factor of 1.117, times PSE&G's Capacity Obligation factor of 1.0132664times Final RPM zonal scaling factor of 1.12070181. The Final RPM Zonal scaling factor and Forecast Pool Reserve factor are assigned by PJM Interconnection. (Both the Peak Load Share and the Generation Obligation for all street lighting rates is set equal to zero).

[3] See Appendix Section for Capacity Profile Peak Ratio Table

1-A) Development of Generation Capacity Profile Peak Ratios

As the generation capacity profile peak ratios include an adjustment for weather, the development of these ratios is a three-step process.

1. The appropriate weather adjustment is determined for all customers at the time of PJM's 5 highest hourly loads in 2023. Table 3 shows highest hourly loads and respective WTHI (weighted temperature humidity index).

Table 3

DATE of PJM Highest Hourly Loads	Weather Condition - WTHI
7/5/2023	80.61
7/27/2023	82.84
7/28/2023	83.36
9/5/2023	82.49
9/6/2023	83.31
Average	82.52
Normal WTHI Peak Weather	82.70
Difference	0.18
PSE&G Summer Peak Weather Sensitivity (MW)	303.38
Total System (MW)	54.00

NOTES:

1. THI = 0.55(Dry Bulb Temperature) + 0.2(Dew Point) + 17.5.
2. WTHIs are calculated by weighting the THIs for three days, including the two previous days.

2. Total weather adjustment is allocated to each Non-Demand Billed class, to calculate the amount of weather adjustment needed for each customer in this class. Table 4 shows profile peak weather adjustment for RS, RHS, RLM, WH, WHS and HS.

Table 4

Rate Class	Proportion of Weather Sensitive Load of Total	Class Adjustment (MW)	Customer Bills (Thousands)	Profile Weather Adjustment (KW/Customers)
RS	75.59%	40.59	1912.09	0.02
RHS	0.20%	0.11	6.56	0.02
RLM	0.77%	0.41	11.79	0.04
WH	0.00%	0.00	0.57	0.00
WHS	0.00%	0.00	0.01	0.00
HS	0.02%	0.01	0.73	0.01

NOTE: The total percentage of weather adjustment indicated here does not equal 100%, as the remaining portion of weather adjustment is applied to GLP, LPLS, LPLP, and HTS customers.

3. The amount of weather adjustment per customer is added to the average of the 5 hourly loads for each load class's load profile at the time of PJM's 5 highest hourly loads in Summer 2023, which is then divided by the average load of the load profile for the June to September 2023 period. Table 5 summarized this process.

Table 5

Rate Class	Profile Weather Adjustment (KW/Customers)	Avg of 5 Capacity Profile Peaks (KW/Customers)	Weather Adjusted Profile Peaks (KW/Customers)	Avg Summer Profile Load (KW/Customers)	Capacity Peak Ratio
RS	0.02	2.31	2.33	1.03	2.270
RHS	0.02	2.47	2.49	1.25	1.992
RLM	0.04	5.43	5.47	2.37	2.307
WH	0.00	0.00	0.00	0.00	1.000
WHS	0.00	0.00	0.10	0.10	1.000
HS	0.01	3.57	3.58	1.51	2.369

NOTE: For RSH customers, the generation capacity profile peak ratio is equal to the RHS generation capacity peak ratio.

1-B) Development of Generation Capacity Scale Factors

To calculate generation capacity scale factors for each rate, there was a need to know:

1. The sum of all customers' Peak Load Shares (PLS) by rate class prior to any adjustments or scaling.
2. The appropriate class peak totals based on customer, profile and interval metered data, adjusted for weather, and scaled to allow the entire system to reach its 6/1/24 target of 9420 MW.

Using the items above, the final Peak Load Shares and generation capacity scale factors for each rate class were calculated and are illustrated in Table 6.

Table 6

A	B	C	D	E	F	G
	Peak Load Shares prior to	Estimated Peaks Incl	Scaled to 9420	Special Adjustment	Peak Load Shares	Generation Capacity
	any adjustments or scaling	Weather Adj and Losses	Target	Due to Add Backs	Effective 6/1/21	Scale
Rate Class	(MV)	(MV)	(MV)	(MV)	(MV)	Factors
RS	4251.29	4603.98	0.00	0.00	0.00	0.0000
RSH	170.41	197.07	0.00	0.00	0.00	0.0000
RHS	14.01	16.32	0.00	0.00	0.00	0.0000
RLM	60.49	68.83	63.97	0.00	63.97	0.9900
WH	0.04	0.00	0.00	0.00	0.00	0.0000
WHS	0.00	0.00	0.00	0.00	0.00	0.0000
HS	1.97	2.81	2.61	0.00	2.61	1.2414
GLP- INTERVAL	1109.34	1188.00	1104.12	0.00	1104.12	0.9318
GLP- NON-INTERVAL	770.91	947.33	880.44	0.00	880.44	1.0692
LPLS- INTERVAL	1727.93	1853.83	1722.93	0.00	1722.93	0.9335
LPLS- NON-INTERVA	25.13	26.96	25.05	0.00	25.05	0.9335
LPLP	474.60	493.75	458.89	0.00	458.89	0.9294
HTS-SUB	622.41	639.13	594.01	0.00	594.01	0.9294
HTS-HV	52.25	53.01	49.27	0.00	49.27	0.9294
Total**		10135.67	9420.00	0.00	9420	19.5913
Scale Target		9420.00				
Initial Scale Factor		0.9294				

**NOTE: Due to the exclusion of a few rate classes from this chart, the above totals may differ from calculated summations of each column.

Col B. For each rate class, these are the sum of all preliminary Peak Load Shares. They are preliminary as they have not been adjusted for weather, any special circumstances (see Col F), or scaled. They include losses.

Col C[4]**.** These estimated peaks were developed using customer, profile and interval metered data. They include an adjustment for weather and include losses.

Col D. These 'scaled' values were calculated by multiplying the values in Col C times the initial scale factor of 0.9294 (9420 MW / 10135 MW). To achieve the 6/1/24 targeted 9420 MW for all rate classes.

Col E. These special adjustments are necessary to correct some customers' preliminary Peak Load Shares due to the inclusion of inaccurate data in their PLS calculations.

Col F. These are the final Peak Load Shares effective 6/1/24 for each rate class. They are calculated as the sum of Columns D, E, and F.

Col G. The generation capacity scale factors are calculated for each rate class as the product of the initial scale factor, 0.9294, and (Column C divided by Column B).

[4] See Appendix Section for calculation of column C – Capacity

2.) Transmission

Effective January 1, 2024, the sum of the transmission loads for PSE&G customers is approximately 9561 MW, equal to PSE&G's metered peak load for 2023.To see how PSE&G's total transmission load is allocated to individual PSE&G customers and to determine each customer's Transmission Obligation, see below.

I. Transmission Allocation for Interval Metered Customers

This group includes customers who were part of the interval metered customer group during summer 2023. The transmission load for each of these customers is equal to the average of their hourly loads at the time of PSE&G's 5 highest hourly loads in summer 2023, times a loss expansion factor, times a transmission scale factor[5]. The Transmission Obligation is equal to the customer's transmission load.

II. Transmission Allocation for Billed Demand Customers

This group includes customers on rate schedules requiring billed peak demands during summer 2023, who were not part of the interval metered customer group. The transmission load for each of these customers is equal to the weighted average of their June to September 2023 billing demands, times a loss expansion factor, times a transmission scale factor. The Transmission Obligation is equal to the customer's transmission load.

III. Transmission Allocation for Non-Demand Billed Customers

This group includes customers on rate schedules not requiring peak demands for billing purposes during summer 2023, who were not part of the interval metered customer group. The summer peak impact of these customers is based upon data from the load profile sample set identical to that used for settlement purposes. The transmission load for each of these customers is equal to their June to September 2023 billed kWh divided by the number of hours in their summer billing period, times a transmission profile peak ratio[6], times a loss expansion factor, times a transmission scale factor. The Transmission Obligation is equal to the customer's transmission load. (Both the transmission load and the Transmission Obligation for all street lighting rates is set equal to zero).

IV. Transmission Allocation for New Customers

New residential customers will generally receive a default transmission load of 1.7 kW. The other new customers are assigned transmission loads based on customer specific information. A new customer's Transmission Obligation is equal to their transmission load.

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[5] See Appendix Section for Transmission Scale Factor Table

[6] See Appendix Section for Transmission Profile Peak Ratio Table

2-A) Development of Transmission Profile Peak Ratios

As the transmission profile peak ratios include no adjustment for weather, for each rate, they are simply the average of the 5 hourly loads for each class's load profile at the time of PSE&G's 5 highest hourly loads in Summer 2023 divided by the average load of the load profile for the June to September 2023 period. Table 7 summarized this process.

Table 7

Rate Class	Avg of 5 Transmission Profile Peaks (KW/Customers)	Avg Summer Profile Laod (KW/Customers)	Transmission Peak Ratio
RS	2.34	1.03	2.28
RHS	2.53	1.25	2.03
RLM	5.46	2.37	2.31
WH	0.00	1.00	1.00
WHS	0.00	0.10	1.00
HS	3.68	1.51	2.43

2-B) Development of Transmission Scale Factors

To calculate transmission scale factors for each rate, there was a need to know:

1. The sum of all customers' transmission loads by rate class prior to any adjustments or scaling.
2. The appropriate class peak totals based on customer, profile and interval metered data, scaled to allow the entire system to reach its target of 9561 MW.

Using the items above, the final transmission loads and transmission scale factors for each rate class were calculated and are illustrated in Table 8.

Table 8

A	B	C	D	E	F	G
	Transmission Loads prior to	Estimated Peaks Incl	Scaled to 9561	Special Adjustment	Peak Load Shares	Transmission Capacity
	any adjustments or scaling	Weather Adj and Losses	Target	Due to Add Backs	Effective 1/1/21	Scale
Rate Class	(MV)	(MV)	(MV)	(MV)	(MV)	Factors
RS	4392.71	4729.81	4368.47	0.00	4368.47	0.0000
RSH	178.02	204.53	188.91	0.00	188.91	0.0000
RHS	14.52	16.81	15.53	0.00	15.53	0.0000
RLM	61.55	68.77	63.52	0.00	63.52	0.9662
WH	0.04	0.00	0.00	0.00	0.00	0.0000
WHS	0.00	0.00	0.00	0.00	0.00	0.0000
HS	1.94	2.88	2.66	0.00	2.66	1.2837
GLP- INTERVAL	1123.56	1200.14	1108.45	0.00	1108.45	0.9236
GLP- NON-INTERVAL	770.99	976.53	901.92	0.00	901.92	1.0952
LPLS- INTERVAL	1753.23	1872.72	1729.65	0.00	1729.65	0.9236
LPLS- NON-INTERVA	25.08	26.79	24.75	0.00	24.75	0.9236
LPLP	485.77	505.37	466.76	0.00	466.76	0.9236
HTS-SUB	631.53	648.50	598.96	0.00	598.96	0.9236
HTS-HV	54.28	55.07	50.87	0.00	50.87	0.9236
Total**		10351.87	9561.02	0.00	9561.02	19.4943
Scale Target		9561				
Initial Scale Factor		0.9236				

**NOTE: Due to the exclusion of a few rate classes from this chart, the above totals may differ from calculated summations of each column

Col B. For each rate class, these are the sum of all but new and default customers' preliminary transmission loads. They are preliminary as they have not been adjusted for any special circumstances (see Col F) or scaled. They include losses.

Col C.[7] These estimated peaks were developed using customer, profile and interval metered data. They include losses.

Col D. These 'scaled' values were calculated by multiplying the values in Col C times the initial scale factor of 0.9236 (9561 MW / 10351 MW). To achieve the targeted 9561 MW for all rate classes.

Col E. These special adjustments are necessary to correct some customers' preliminary transmission loads due to the inclusion of inaccurate data in their transmission load calculations.

Col F. These are the final transmission loads effective 1/1/24 for each rate class. They are calculated as the sum of Columns D, E, and F.

Col G. The transmission scale factors are calculated for each rate class as the product of the initial scale factor, 0.9236, and (Column C divided by Column B).

[7] See Appendix Section for calculation of column C – Transmission

3.) Appendix

1. Loss Expansion Factors

Rate Schedule	Loss Expansion Factor
RS-Interval & Non-Interval	1.068154
RSH-Interval & Non-Interval	1.068154
RHS-Interval & Non-Interval	1.068154
RLM-Interval & Non-Interval	1.068154
WH	1.068154
WHS	1.068154
HS	1.068154
GLP-Interval & Non-Interval	1.068154
LPLS-Interval & Non-Interval	1.068154
BPL, BPL-POF, PSAL	1.068154
LPLP	1.040342
HTS - SUBTRANSMISSION	1.026874
HTS - HIGH VOLTAGE	1.014582

2. Generation Capacity Scale Factors*

Rate Schedule	Generation Capacity Scale Factor
RS-Interval	0.93832
RS-Non Interval	0.94773
RSH-Interval	0.93653
RSH-Non Interval	1.14568
RHS-Interval	0.93653
RHS-Non Interval	1.14568
RLM	0.99004
WH	0.00000
WHS	0.00000
HS	1.24136
GLP-Interval	0.93179
GLP-Non-Interval	1.06920
LPLS-Interval	0.93349
LPLS-Non-Interval	0.93349
LPLP	0.92939
HTS-Subtransmission	0.92939
HTS-High Voltage	0.92939

*The generation capacity scale factors include an adjustment for weather

3. Capacity Profile Peak Ratios

Rate Schedule	Generation Capacity Profile Peak Ratio
RS	2.270202
RSH	1.991862
RHS	1.991862
RLM	2.307258
WH	1.000000
WHS	1.000000
HS	2.369086

4. Calculation of Column C in
Development of Generation Capacity Scale Factors at Table 5

For rate classes RS, RHS, RLM, WH, WHS, and HS, Column C was calculated as the weather adjusted profile peak, times the number of customer bills, times the loss expansion factor. (Please note that for the RS class, the number of customer bills was reduced by approximately 110074, which is the estimated number of RSH customers.). Below table illustrates the calculation.

Rate Class	Weather Adjusted Profile Peaks (KW/Customers)	Customer Bills (Thousands)	Loss Expantion Factor	Column C - Estimated Peaks Incl Weather Adj and Losses (MW)
RS	2.33	1912.09	1.0682	4801.05
RHS	2.49	6.56	1.0682	16.32
RLM	5.47	11.79	1.0682	68.83
WH	0.00	0.57	1.0682	0.00
WHS	0.10	0.01	1.0682	0.00
HS	3.58	0.73	1.0682	2.81

For classes that are 100% interval metered, Column C was calculated as the preliminary Peak Load Share in Column B plus the appropriate class weather adjustment. Below table illustrates the calculation.

Rate Class	Peak Load Shares prior to any adjustments or scaling (MW)	Proportion of weather sensitive load of total	Zonal Weather Adjustment (MW)	Loss Expantion Factor	Class Weather Adjustment Inc Losses (MW)	Column C - Estimated Peaks Incl Weather Adj and Losses (MW)
LPLP	474.60	0.00%	54.00	1.04034	0.00	493.75
HTS-SUB	622.41	0.00%	54.00	1.02687	0.00	639.13
HTS-HV	52.25	0.00%	54.00	1.01458	0.00	53.01

For rate classes GLP and LPLS, which have both interval metered and billed demand customers, it was necessary to first calculate a weather adjusted peak for the entire class, then disaggregate into the interval and non-interval groups. Using the GLP profile sample, a weather adjusted peak for the entire class was calculated as the estimated peak (the average of the 5 hourly loads for each load class's load profile at the time of PJM's 5 highest hourly loads in Summer 2023 times the number of customer bills) plus the appropriate class weather adjustment, all times the loss expansion factor. Below table illustrates the calculation.

Rate Class	Avg of 5 Capacity Profile Peaks (Kw/customers)	Customer Bills (thousands)	Estimated Peaks Excl Weather Adj & Losses (MW)	Proportion of Weather Sensitive Load of total %	Zonal Weather Adjustment (MW)	Class Weather Adjustment Excl Losses (MW)	Loss Expantion Factor	(FOR ENTIRE CLASS) Estimated Peaks Inc Weather Adj & Losses (MW)
GLP	6.76	295.14	1994	9.00%	0.00	1.99	1.068	2132
LPLS	183.64	9.55	1753	14.42%	0.00	0.11	1.068	1873

5. Transmission Scale Factors*

Rate Schedule	Transmission Scale Factor
RS-Interval	0.92360
RS-Non Interval	0.94176
RSH-Interval	0.92360
RSH-Non Interval	1.13851
RHS-Interval	0.92360
RHS-Non Interval	1.13851
RLM	0.96618
WH	0.00000
WHS	0.00000
HS	1.28372
GLP-Interval	0.92360
GLP-Non-Interval	1.09519
LPLS-Interval	0.92360
LPLS-Non-Interval	0.92360
LPLP	0.92360
HTS-Subtransmission	0.92360
HTS-High Voltage	0.92360

*The transmission scale factors do not include an adjustment for weather

6. Transmission Profile Peak Ratios

Rate Schedule	Transmission Profile Peak Ratio
RS	2.282648
RSH	2.028792
RHS	2.028792
RLM	2.305391
WH	1.000000
WHS	1.000000
HS	2.429285

7. Calculation of Column C in Transmission Scale Factors at Table 7

For rate classes RS, RHS, RLM, WH, WHS, and HS, Column C was calculated as the average of the 5 hourly loads for each class's load profile at the time of PSE&G's 5 highest hourly loads in Summer 2023, times the number of customer bills, times the loss expansion factor. (Please note that for the RS class, the number of customer bills was reduced by approximately 110074, which is the estimated number of RSH customers.) Below table illustrates the calculation.

Rate Class	Avg of 5 Transmission Profile Peaks (Kw/customers)	Customer Bills (thousands)	Loss Expantion Factor	Column C Estimated Peaks Incl Weather Adj and Losses (MV)
RS	2.34	1,912	1.0682	4,730
RHS	2.53	7	1.0682	17
RLM	5.46	12	1.0682	69
WH	0.00	1	1.0682	0
WHS	0.00	0	1.0682	0
HS	3.68	1	1.0682	3

For classes that are 100% interval metered, as well as the GLP and LPLS interval groups, Column C was set equal to the preliminary transmission load in Column B.

For the GLP and LPLS non-interval groups, it was necessary to first calculate a peak for the entire class. Using the GLP profile sample, a peak for the entire class was calculated as the average of the 5 hourly loads for each load class's load profile at the time of PSE&G's 5 highest hourly loads in summer 2023, times the number of customer bills, times the loss expansion factor. Below table illustrates the calculation.

Rate Class	Avg of 5 Transmission Profile Peaks (Kw/customers)	Customer Bills (thousands)	Loss Expantion Factor	(FOR ENTIRE CLASS) Estimated Peaks Inc Weather Adj & Losses (MV)
GLP	6.90	295.14	1.068154	2176.66
LPLS	186.29	9.55	1.068154	1899.51

At this point, Column C peaks for the non-interval groups were simply computed as the difference between the value for the entire class and the value for the interval group. See below table.

Rate Class	(FOR ENTIRE CLASS) Estimated Peaks Inc Losses (MV)	(FOR INTERVAL GROUPS) Estimated Peaks Inc Weather Adj & Losses (MV)	Column C Estimated Peaks Incl Losses (MV)
GLP/ NON-INTERVAL	2176.66	1200.14	976.53
LPLS/NON-INTERVAL	1899.51	1872.72	26.79