PSE&G

Zone Generation Capacity & Transmission Peak Loads and Obligations Update

Contents

Introduction

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

Effective dates are outlined below;

- 1/1/22 - 12/31/22 – Transmission Loads
- 6/1/22 - 5/31/23 – Capacity Loads
- 1/1/22 - 5/31/22 – Capacity Obligation

2022 Transmission Loads and Obligations are based on the actual 2021 zonal peak load and will be calculated and become effective on January 1, 2022.

Capacity Loads are based on the weather normalized 2021 summer zonal peak load and will be calculated for January 1, 2022 but not made effective until 6/1/2022. 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.

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, 2022 – May, 2023). Table 1 shows Top 5-Peak Days for Transmission & Capacity Loads.

Table 1
Top 5-Peak Days for Transmission & Capacity

CAPACITY		TRANSMISSION	
PJM		PSE&G	
Top 5 Peak Days 2021		Top 5 Peak Days 2021	
DATE	Time-Hour Ending	DATE	Time-Hour Ending
6/29/2021	17	6/29/2021	18
7/6/2021	17	6/30/2021	18
8/12/2021	17	8/12/2021	17
8/24/2021	18	8/13/2021	18
8/26/2021	16	8/26/2021	17

1. Generation Capacity

Effective June 1, 2022 through May 31, 2023, PSE&G's coincident peak forecast is 9479 (2022 Load Forecast Report Table B-10) and the weather normalized coincident 2022 zonal load is 9,270.00 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, 2021. 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 2021, 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 1.0906, times PSE&G's Capacity Obligation factor of 0.9965755 times Final RPM zonal scaling factor of 1.0978092. 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 2021, 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 2021 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 1.0906, times PSE&G's Capacity Obligation factor of 0.9965755 times Final RPM zonal scaling factor of 1.0978092. 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 2021, 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 2021 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 1.0906, times PSE&G's Capacity Obligation factor of 0.9965755 times Final RPM zonal scaling factor of 1.0978092. 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 1.0906, times PSE&G's Capacity Obligation factor of 0.9965755 times Final RPM zonal scaling factor of 1.0978092. 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 2021. Table 2 shows highest hourly loads and respective WTHI (weighted temperature humidity index).

Table 2

DATE of PJM Highest Hourly Loads	Weather Condition - WTHI
6/29/2021	85.18
7/6/2021	82.23
8/12/2021	84.31
8/24/2021	80.25
8/26/2021	82.89
Average	82.97
Normal WTHI Peak Weather	82.60
Difference	(0.37)
PSE&G Summer Peak Weather Sensitivity (MW)	297.04
Total System (MW)	-110.50

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, in order to calculate the amount of weather adjustment needed for each customer in this class. Table 3 shows profile peak weather adjustment for RS, RHS, RLM, WH, WHS and HS.

Table 3

Rate Class	Proportion of Weather Sensitive Load of Total	Class Adjustment (MW)	Customer Bills (Thousands)	Profile Weather Adjustment (KW/Customers)
RS	64.12%	-70.39	1878.64	-0.04
RHS	0.18%	-0.20	7.40	-0.03
RLM	0.74%	-0.82	11.74	-0.07
WH	0.00%	0.00	0.74	0.00
WHS	0.00%	0.00	0.01	0.00
HS	0.02%	-0.02	0.84	-0.03

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' load profile at the time of PJM's 5 highest hourly loads in Summer 2021, which is then divided by the average load of the load profile for the June to September 2021 period. Table 4 summarized this process.

Table 4

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	-0.04	2.35	2.31	1.11	2.080
RHS	-0.03	2.54	2.51	1.38	1.818
RLM	-0.07	5.39	5.32	2.56	2.081
WH	0.00	0.00	0.00	0.00	1.000
WHS	0.00	0.00	0.10	0.10	1.000
HS	-0.03	4.07	4.05	1.73	2.335

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

In order 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 6/1/22 target of 9270 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 5.

Table 5

A	B	C	D	E	F	G
	Peak Load Shares prior to	Estimated Peaks Incl	Scaled to 9270	Special Adjustments	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	4072.08	4638.38	4263.21	0.00	4263.21	0.9801
RSH	144.88	204.38	187.85	0.00	187.85	1.2139
RHS	14.09	19.87	18.26	0.00	18.26	1.2139
RLM	61.75	66.70	61.30	0.00	61.30	0.9295
WH	0.06	0.00	0.00	0.00	0.00	0.0000
WHS	0.00	0.00	0.00	0.00	0.00	0.0000
HS	2.01	3.63	3.33	0.00	3.33	1.5547
GLP- INTERVAL	77.47	82.33	75.67	0.00	75.67	0.9144
GLP- NON-INTERVAL	2294.62	1924.10	1768.47	0.00	1768.47	0.7215
LPLS- INTERVAL	1801.44	1900.08	1746.39	0.00	1746.39	0.9076
LPLS- NON-INTERVAL	44.17	46.59	42.82	0.00	42.82	0.9076
LPLP	471.08	486.85	447.48	0.00	447.48	0.9131
HTS-SUB	595.35	611.35	561.90	0.00	561.90	0.9191
HTS-HV	50.20	50.93	46.81	0.00	46.81	0.9191
Total**		9481.86	9270.00	0.00	9270	16.6768
Scale Target		9270.00				
Initial Scale Factor		0.9191				

**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 also include losses.

Col D. These 'scaled' values were calculated by multiplying the values in Col C times the initial scale factor of 0.9191 (9270 MW / 10085.77 MW). In order to achieve the 6/1/22 targeted 9270 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 6/1/22 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, 0.9191, and (Column C divided by Column B).

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

2.) Transmission

Effective January 1, 2022, the sum of the transmission loads for PSE&G customers is approximately 10064.09 MW, equal to PSE&G's metered peak load for 2021.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 2021. 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 2021, 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 2021, 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 2021 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 2021, 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 2021 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.

[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 2021 divided by the average load of the load profile for the June to September 2021 period. Table 6 summarized this process

Table 6

Rate Class	Avg of 5 Transmission Profile Peaks (KW/Customers)	Avg Summer Profile Laod (KW/Customers)	Transmission Peak Ratio
RS	2.48	1.11	2.23
RHS	2.73	1.38	1.97
RLM	5.77	2.56	2.26
WH	0.00	1.00	1.00
WHS	0.00	0.10	1.00
HS	4.27	1.73	2.46

2-B) Development of Transmission Scale Factors

In order 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 10064.09 MW.

Using the items above, the final transmission loads and transmission scale factors for each rate class were calculated, and are illustrated in Table 7.

Table 7

A	B	C	D	E	F	G
Rate Class	Transmission Loads prior to any adjustments or scaling (MV)	Estimated Peaks Incl Weather Adj and Losses (MV)	Scaled to 10064 Target (MV)	Special Adjustments Due to Add Backs (MV)	Peak Load Shares Effective 1/1/21 (MV)	Transmission Capacity Scale Factors
RS	4359.38	4966.65	4729.56	0.00	4729.56	1.0157
RSH	156.48	220.94	210.39	0.00	210.39	1.2588
RHS	15.26	21.54	20.52	0.00	20.52	1.2588
RLM	67.35	72.38	68.92	0.00	68.92	0.9581
WH	0.06	0.00	0.00	0.00	0.00	0.0000
WHS	0.00	0.00	0.00	0.00	0.00	0.0000
HS	2.12	3.83	3.65	0.00	3.65	1.6119
GLP- INTERVAL	78.96	84.34	80.31	0.00	80.31	0.9523
GLP- NON-INTERVAL	2294.66	1997.89	1902.52	0.00	1902.52	0.7762
LPLS- INTERVAL	1807.80	1931.00	1838.83	0.00	1838.83	0.9523
LPLS- NON-INTERVAL	44.13	47.14	44.89	0.00	44.89	0.9523
LPLP	476.35	495.57	471.91	0.00	471.91	0.9523
HTS-SUB	602.68	618.87	589.33	0.00	589.33	0.9523
HTS-HV	53.90	54.69	52.08	0.00	52.08	0.9523
Total**		10568.59	10064.09	0.00	10064.09	17.3543
Scale Target		10064				
Initial Scale Factor		0.9523				

**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 0.9523 (10064.09 MW / 10568.59 MW). In order to achieve the targeted 10064.09 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 1/1/22 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, 0.9523, 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	1.068154
RSH	1.068154
RHS	1.068154
RLM	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	0.980136
RSH	1.213886
RHS	1.213886
RLM	0.929461
WH	0.000000
WHS	0.000000
HS	1.554730
GLP-Interval	0.914436
GLP-Non-Interval	0.721531
LPLS-Interval	0.907586
LPLS-Non-Interval	0.907586
LPLP	0.913065
HTS-Subtransmission	0.919116
HTS-High Voltage	0.919116

*The generation capacity scale factors include an adjustment for weather

3. Capacity Profile Peak Ratios

Rate Schedule	Generation Capacity Profile Peak Ratio
RS	2.080286
RSH	1.817945
RHS	1.817945
RLM	2.080684
WH	1.000000
WHS	1.000000
HS	2.334791

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 105252, 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	2.31	1878.64	1.0682	4842.77
RHS	2.51	7.40	1.0682	19.87
RLM	5.32	11.74	1.0682	66.70
WH	0.00	0.74	1.0682	0.00
WHS	0.10	0.01	1.0682	0.00
HS	4.05	0.84	1.0682	3.63

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	471.08	2.83%	-110.50	1.04034	-3.10	486.98
HTS-SUB	595.35	0.00%	-110.50	1.02687	0.00	611.35
HTS-HV	50.20	0.00%	-110.50	1.01458	0.00	50.93

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 2021 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	6.63	285.22	1890	10.93%	0.00	-11.68	1.068	2008
LPLS	198.02	9.32	1846	21.17%	0.00	-0.55	1.068	1971

5. Transmission Scale Factors*

Rate Schedule	Transmission Scale Factor
RS	1.015693
RSH	1.258754
RHS	1.258754
RLM	0.958107
WH	0.000000
WHS	0.000000
HS	1.611881
GLP-Interval	0.952264
GLP-Non-Interval	0.776205
LPLS-Interval	0.952264
LPLS-Non-Interval	0.952264
LPLP	0.952264
HTS-Subtransmission	0.952264
HTS-High Voltage	0.952264

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

6. Transmission Profile Peak Ratios

Rate Schedule	Transmission Profile Peak Ratio
RS	2.227511
RSH	1.971096
RHS	1.971096
RLM	2.257949
WH	1.000000
WHS	1.000000
HS	2.464986

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' load profile at the time of PSE&G's 5 highest hourly loads in Summer 2021, 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 105252, 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	2.48	1,879	1.0682	4,967
RHS	2.73	7	1.0682	22
RLM	5.77	12	1.0682	72
WH	0.00	1	1.0682	0
WHS	0.00	0	1.0682	0
HS	4.27	1	1.0682	4

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 2021, 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	6.83	285.22	1.068154	2082.23
LPLS	198.69	9.32	1.068154	1978.15

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	2082.23	84.34	1997.89
LPLS/NON-INTERVAL	1978.15	1931.00	47.14