

PSE&G Zone Generation Capacity and Transmission Peak Loads and Obligations

(For use: 1/01/09 - 12/31/09 for Transmission and 6/1/2009- 9/30/2009 for Capacity)

NOTE: Effective 1/1/08, PJM instituted changes to the rules for allocating and reporting capacity and transmission loads and obligations. As in the past, new transmission obligations (based on the actual 2008 zonal peak load) will be calculated and become effective on January 1, 2009. Similar to last year, capacity loads based on the weather normalized 2008 summer zonal peak load will be calculated by January 1, 2009 but not made effective until 6/1/2008. At that time, capacity obligations will be based on new values for the FPR (Forecast Pool Requirement) as well as other RPM related factors including the final zonal RPM scaling factor and daily zonal scaling factor. Prior to June 1, 2009 capacity obligations will continue to be based on the peak loads that became effective January 1, 2008 and the Final Zonal scaling Factor of 1.04145. However, a new daily scaling factor based on the end of December sum of the peak values was applied on January 1, 2009 resulting in a reduction in individual customer obligations of 0.27% from the December 31, 2008 value. This value will be effective until May 31, 2009.

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, 2009 – May, 2010).

The calculations shown below reflect the new capacity load values (effective June 1, 2009) and the new transmission load/obligation values effective January 1, 2009. For capacity load values effective January 1, 2009 – through May 31, 2009, refer to the previous web site information.

Generation Capacity:

Effective June 1, 2009 through May 31, 2010, PSE&G's coincident peak forecast is 10,446 and the weather normalized coincident 2008 zonal load is 10,440 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, click the links directly below.

[Generation Capacity Allocation for Interval Metered Customers](#)

[Generation Capacity Allocation for Billed Demand Customers](#)

[Generation Capacity Allocation for Non-Demand Billed Customers](#)

[Generation Capacity Allocation for New Customers](#)

Transmission:

Effective January 1, 2009, the sum of the transmission loads for PSE&G customers is approximately 10,654 MW, equal to PSE&G's metered peak load for 2008 (adjusted for a voltage reduction).

To see how PSE&G's total transmission load is allocated to individual PSE&G customers and to determine each customer's Transmission Obligation, click the links directly below.

[Transmission Allocation for Interval Metered Customers](#)

[Transmission Allocation for Billed Demand Customers](#)

[Transmission Allocation for Non-Demand Billed Customers](#)

[Transmission Allocation for New Customers](#)

Generation Capacity Allocation for Interval Metered Customers:

This group includes customers who were part of the interval metered customer group during summer, 2008. 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 2008](#), 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 1.0795, times PSE&G's Capacity Obligation Scaling Factor which is a combination of the daily scaling factor and the Final RPM zonal scaling factor of 1.05980, as assigned by PJM Interconnection.

[Back to Top](#)

Generation Capacity Allocation for Billed Demand Customers:

This group includes customers on rate schedules requiring billed peak demands during summer 2008, 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 2008 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 1.0795, times PSE&G's Capacity Obligation Scaling Factor which is a combination of the daily scaling factor and the Final RPM zonal scaling factor of 1.05980, as assigned by PJM Interconnection.

[Back to Top](#)

Generation Capacity Allocation for Non-Demand Billed Customers:

This group includes customers on rate schedules not requiring peak demands for billing purposes during summer 2008, 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 2008 billed kWh divided by the number of hours in their summer billing period, times a [capacity profile peak ratio](#), 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 1.0795, times PSE&G's Capacity Obligation Scaling Factor which is a combination of the daily scaling factor and the Final RPM zonal scaling factor of 1.05980, as assigned by PJM Interconnection. (Both the Peak Load Share and the Generation Obligation for all street lighting rates is set equal to zero).

[Back to Top](#)

Generation Capacity Allocation for New Customers:

New residential customers will generally receive a default Peak Load Share of 3.0 kW. The other new customers are assigned Peak Load Shares based on customer specific information. A new customer's Capacity Obligation is equal to the customer's Peak Load Share times the forecast pool reserve factor of 1.0795, times PSE&G's Capacity Obligation Scaling Factor which is a combination of the daily scaling factor and the Final RPM zonal scaling factor of 1.05980, as assigned by PJM Interconnection.

[Back to Top](#)

[Back to Development of Generation Capacity Scale Factors](#)

Transmission Allocation for Interval Metered Customers:

This group includes customers who were part of the interval metered customer group during summer 2008. 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 20068, times a [loss expansion factor](#), times a [transmission scale factor](#). The Transmission Obligation is equal to the customer's transmission load.

[Back to Top](#)

Transmission Allocation for Billed Demand Customers:

This group includes customers on rate schedules requiring billed peak demands during summer 2008, 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 2008 billing demands, times a [loss expansion factor](#), times a [transmission scale factor](#). The Transmission Obligation is equal to the customer's transmission load.

[Back to Top](#)

Transmission Allocation for Non-Demand Billed Customers:

This group includes customers on rate schedules not requiring peak demands for billing purposes during summer 2008, 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 2008 billed kWh divided by the number of hours in their summer billing period, times a [transmission profile peak ratio](#), 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).

[Back to Top](#)

Transmission Allocation for New Customers:

New residential customers will generally receive a default transmission load of 3.0 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.

[Back to Top](#)

[Back to Development of Transmission Scale Factors](#)

Time of PJM’s 5 Highest Hourly Loads in Summer 2008:

Date	Time - Hour Ending
6/9/08	5pm
6/10/08	5pm
7/17/08	5pm
7/18/08	5pm
7/21/08	5pm

[Back to Generation Capacity Allocation for Interval Metered Customers](#)
[Back to Development of Generation Capacity Profile Peak Ratios](#)
[Back to Calculation of Column C in Development of Generation Capacity Scale Factors chart](#)

Time of PSE&G’s 5 Highest Hourly Loads in Summer 2007:

Date	Time - Hour Ending
6/9/08	5pm
6/10/08	5pm
7/17/08	5pm
7/18/08	5pm
7/21/08	5pm

[Back to Transmission Allocation for Interval Metered Customers](#)
[Back to Development of Transmission Profile Peak Ratios](#)
[Back to Calculation of Column C in Development of Transmission Scale Factors chart](#)

Loss Expansion Factors:

Rate Schedule	Loss Expansion Factor
RS	1.08750
RSH	1.08750
RHS	1.08750
RLM	1.08750
WH	1.08750
WHS	1.08750
HS	1.08750
GLP-Interval & Non-Interval	1.08750
LPLS-Interval & Non-Interval	1.08750
BPL, BPL-POF & PSAL	1.08750
LPLP	1.05983
HTS-Subtransmission	1.03599
HTS-High Voltage	1.02042

[Back to Generation Capacity Allocation](#)
[Back to Transmission Allocation](#)

Generation Capacity Scale Factors:

(The generation capacity scale factors include an adjustment for weather.)

Rate Schedule	Generation Capacity Scale Factor
RS	0.839
RSH	0.965
RHS	0.965
RLM	0.813
WH	1.403
WHS	0.954
HS	1.041
GLP-Interval	0.967
GLP-Non-Interval	0.743
LPLS-Interval	0.967
LPLS-Non-Interval	0.809
LPLP	0.970
HTS-Subtransmission	0.965
HTS-High Voltage	0.954

[How were these generation capacity scale factors developed?](#)

[Back to Generation Capacity Allocation](#)

Transmission Scale Factors:

(The transmission scale factors do not include an adjustment for weather.)

Rate Schedule	Transmission Scale Factor
RS	0.876
RSH	1.008
RHS	1.008
RLM	0.849
WH	1.47
WHS	0.997
HS	1.087
GLP-Interval	0.997
GLP-Non-Interval	0.762
LPLS-Interval	0.997
LPLS-Non-Interval	0.832
LPLP	0.997
HTS-Subtransmission	0.997
HTS-High Voltage	0.997

[How were these transmission scale factors developed?](#)

[Back to Transmission Allocation](#)

Generation Capacity Profile Peak Ratios:

Rate Schedule	Generation Capacity Profile Peak Ratio
RS	2.43
RSH	2.118
RHS	2.118
RLM	2.254
WH	1.000
WHS	1.000
HS	2.633

[How were these generation capacity profile peak ratios developed?](#)

[Back to Generation Capacity Allocation for Non-Demand Billed Customers](#)

Transmission Profile Peak Ratios:

Rate Schedule	Transmission Profile Peak Ratio
RS	2.35
RSH	2.042
RHS	2.042
RLM	2.172
WH	1.000
WHS	1.000
HS	2.539

[How were these transmission profile peak ratios developed?](#)

[Back to Transmission Allocation for Non-Demand Billed Customers](#)

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 6/1/09 target of 10,440 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 the following chart. For a description of each column, please see directly below the chart.

A	B	C	D	E	F	G	H
Rate Class	Peak Load Shares prior to any adjustments or scaling (MW)	Estimated Peaks Incl Weather Adj and Losses (MW)	Scaled to 10,361 MW Target (MW)	Adjustments for Default and New Customers (MW)	Special Adjustments (MW)	Peak Load Shares Effective 6/1/08 (MW)	Generation Capacity Scale Factors
RS	4463	4267	4072	44	0	4116	0.839
RSH	123	135	129	1	0	130	0.965
RHS	31	34	33	0	0	33	0.965
RLM	93	86	82	0	0	82	0.813
WH	0	0	0	0	0	0	1.403
WHS	0	0	0	0	0	0	0.954
HS	5	6	5	0	0	6	1.041
GLP-INTERVAL	2	3	3	0	0	3	0.967
GLP- NON-INTERVAL	2764	2340	2233	19	0	2252	0.743
LPLS-INTERVAL	1162	1280	1222	0	0	1222	0.967
LPLS- NON-INTERVAL	1352	1246	1190	17	0	1207	0.809
LPLP	619	667	637	2	0	639	0.970
HTS-SUB	676	707	675	17	-27.8	664	0.965
HTS-HV	31	32	30	0	0	30	0.954
<i>Total**</i>		<i>10863</i>	<i>10367</i>	<i>100</i>	<i>-27.82</i>	<i>10439</i>	
<i>Scale Target</i>		<i>10367</i>					
<i>Initial Scale Factor</i>		<i>.95438</i>					

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

Column Descriptions:

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

Col C. These estimated peaks were developed using customer, profile and interval metered data. They include an adjustment for weather, and also include losses. [Additional information on calculation of Column C.](#)

Col D. These 'scaled' values were calculated by multiplying the values in Col C times the initial scale factor of 0.89134 (10,329 MW / 11,589 MW). In order to achieve the 6/1/08 targeted 10,430 MW for all rate classes, these are scaled to total 10,329 MW due to the fact that default and new capacity and special adjustments are not included in the scaling calculation.

Col E. These are the sum of all new and default customers' Peak Load Shares for each rate class. They are not included in the scaling calculation. Please see [Generation Capacity Allocation for New Customers](#) for more information.

Col F. 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 G. These are the final Peak Load Shares effective 6/1/08 for each rate class. They are calculated as the sum of Columns D, E, and F.

Col H. The generation capacity scale factors are calculated for each rate class as the product of the initial scale factor, 0.89134, and (Column C divided by Column B).

[Back to Generation Capacity Scale Factors](#)

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 10,378.7 MW.

Using the items above, the final transmission loads and transmission scale factors for each rate class were calculated, and are illustrated in the following chart. For a description of each column, please see directly below the chart.

A	B	C	D	E	F	G	H
Rate Class	Transmission Loads prior to any adjustments or scaling (MW)	Estimated Peaks Incl Losses (MW)	Scaled to 11,018 MW Target (MW)	Adjustments for Default and New Customers (MW)	Special Adjustments (MW)	Transmission Loads Effective 1/1/07 (MW)	Transmission Scale Factors
RS	4316	4127	4113	44	0	4156	0.876
RSH	118	130	130	1	0	131	1.008
RHS	30	33	33	0	0	33	1.008
RLM	89	83	83	0	0	83	0.849
WH	0	0	0	0	0	0	1.470
WHS	0	0	0	0	0	0	0.997
HS	5	6	6	0	0	6	1.087
GLP-INTERVAL	2	3	3	0	0	3	0.997
GLP-NON-INTERVAL	2764	2300	2292	19	0	2311	0.762
LPLS-INTERVAL	1162	1264	1260	0	0	1260	0.997
LPLS-NON-INTERVAL	1352	1228	1223	17	0	1240	0.832
LPLP	619	657	654	2	0	656	0.997
HTS-SUB	676	700	698	17	-28.7	686	0.997
HTS-HV	31	32	32	0	0	32	0.997
<i>Total**</i>		<i>10620</i>	<i>10583</i>	<i>100</i>	<i>-28.70</i>	<i>10655</i>	
<i>Scale Target</i>		<i>10583</i>					
<i>Initial Scale Factor</i>		<i>.91862</i>					

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

Column Descriptions:

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 do, however, include losses.

Col C. These estimated peaks were developed using customer, profile and interval metered data. They include losses. [Additional information on calculation of Column C.](#)

Col D. These ‘scaled’ values were calculated by multiplying the values in Col C times the initial scale factor of 0.91862 (10277 MW /11188 MW). In order to achieve the targeted 10378.7 MW for all rate classes, these are scaled to total 10277 MW due to the fact that default and new transmission and special adjustments are not included in the scaling calculation.

Col E. These are the sum of all new and default customers’ transmission loads for each rate class. They are not included in the scaling calculation. Please see [Transmission Allocation for New Customers](#) for more information.

Col F. 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 G. These are the final transmission loads effective 1/1/08 for each rate class. They are calculated as the sum of Columns D, E, and F.

Col H. The transmission scale factors are calculated for each rate class as the product of the initial scale factor, 0.91862, and (Column C divided by Column B).

[Back to Transmission Scale Factors](#)

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.

First, the appropriate weather adjustment is determined for all customers at the time of PJM’s 5 highest hourly loads in 2008.

Time of PJM Highest Hourly Loads	Weather Condition
6/10@5pm	84.15 WTHI
6/09@5pm	84.41 WTHI
7/18@5pm	81.78 WTHI
7/21@5pm	80.90 WTHI
7/17@5pm	79.12 WTHI
Average Weather for 5 Peak Days	82.07 WTHI
Normal Peak Weather	82.8 WTHI
Difference	.73 WTHI
PSE&G Summer Peak Weather Sensitivity	310.3 MW/WTHI
Total 5 Day Summer Weather Adjustment	226.10 MW

NOTES:

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

Second, the 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.

Rate Class	Proportion of Weather Sensitive Load of Total	Class Adjustment (MW)	Customer Bills (Thousands)	Profile Weather Adjustment (kW/Customer)
RS	59.5%	133	1812.70	0.07
RHS	0.5%	1	12.65	0.09
RLM	1.3%	3	13.73	0.21
WH	0%	0	2.2	0.00
WHS	0%	0	0.03	0.00
HS	0.1%	0	1.72	0.14

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.

Third, 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 2008](#), which is then divided by the average load of the load profile for the June to September 2008 period.

Rate Class	Profile Weather Adjustment (kW/Customer)	Avg of 5 Capacity Profile Peaks (kW/customer)	Weather Adjusted Profile Peaks (kW/customer)	Avg Summer Profile Load (kW/customer)	Capacity Peak Ratio
RS	0.07	2.17	2.25	0.92	2.429
RHS	0.09	2.39	2.48	1.17	2.118
RLM	0.21	5.55	5.76	2.55	2.254
WH	0.00	0.21	0.21	0.21	1.000
WHS	0.00	0.10	0.10	0.10	1.000
HS	0.14	2.91	3.05	1.16	2.633

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

[Back to Generation Capacity Profile Peak Ratios](#)

[Back to Calculation of Column C in Development of Generation Capacity Scale Factors chart](#)

[Back to Calculation of Column C in Development of Transmission Scale Factors chart](#)

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 2007](#) divided by the average load of the load profile for the June to September 2007 period.

Rate Class	Avg of 5 Transmission Profile Peaks (kW/customer)	Avg Summer Profile Load (kW/customer)	Transmission Peak Ratio
RS	2.17	0.92	2.350
RHS	2.39	1.17	2.042
RLM	5.55	2.55	2.172
WH	0.18	0.21	0.850
WHS	0.10	0.10	1.000
HS	2.94	1.16	2.539

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

[Back to Transmission Profile Peak Ratios](#)

Calculation of Column C in Development of Generation Capacity Scale

Factors chart:

For the RS, RHS, RLM, WH, WHS, and HS rate classes, 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 **66,000**, which is the estimated number of RSH customers.)

Rate Class	Weather Adjusted Profile Peaks (kW/customer)	Customer Bills (Thousands)	Loss Expansion Factor	Column C - Estimated Peaks Incl Weather Adj and Losses (MW)
RS	2.25	1812.70	1.08750	4435.50
RHS	2.48	12.65	1.08750	34.12
RLM	5.76	13.73	1.08750	86.01
WH	0.21	2.20	1.08750	0.50
WHS	0.10	0.03	1.08750	0.00
HS	3.05	1.72	1.08750	5.71

For the RSH rate class, Column C was calculated as the RHS estimated peak (31.4 MW), divided by the RHS preliminary peak load share (31.0 MW), times the RSH preliminary peak load share (122.63 MW). It was necessary to take this approach and use the closely representative RHS customer class, as there exists no profile sample for the RSH rate class.

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.

Rate Class	Peak Load Shares prior to any adjustments or scaling (MW)	Proportion of Weather Sensitive Load of Total	Zonal Weather Adjustment (MW)	Loss Expansion Factor	Class Weather Adjustment Incl Losses (MW)	Column C - Estimated Peaks Incl Weather Adj and Losses (MW)
LPLP	619	5%	226.1 MW	1.05983	10	666
HTS-SUB	676	3%	226.1 MW	1.03599	7	707
HTS-HV	33	0%	226.1 MW	1.02042	0	34

For the GLP and LPLS rate classes, 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 2008](#) times the number of customer bills) plus the appropriate class weather adjustment, all times the loss expansion factor. Since the profile for LPLS was not representative of the entire class, an estimated value of 290 kW/customer (based on previous values) was used.

Rate Class	Avg of 5 Capacity Profile Peaks (kW/customer)	Customer Bills (Thousands)	Estimated Peaks Excl Weather Adj and Losses (MW)	Proportion of Weather Sensitive Load of Total	Zonal Weather Adjustment (MW)	Class Weather Adjustment Excl Losses (MW)	Loss Expansion Factor	(FOR ENTIRE CLASS) Estimated Peaks Incl Weather Adj and Losses (MW)
GLP	8.25	256.52	2117	16%	226.1 MW	37	1.0875	2340
LPLS	172.49	7.90	2291	15%	226.1 MW	17	1.0875	2509

To determine Column C for the GLP and LPLS interval groups, the class weather adjustment first had to be proportioned down to the interval amount. The weather-adjusted peaks in Column C were then calculated as the preliminary Peak Load Share in Column B plus the interval weather adjustment.

Rate Class	Peak Load Shares prior to any adjustments or scaling (MW)	Proportion of Interval Load of Class Total	Class Weather Adjustment Excl Losses (MW)	Loss Expansion Factor	Interval Weather Adjustment Incl Losses (MW)	Column C - Estimated Peaks Incl Weather Adj and Losses (MW)
GLP-INTERVAL	2	0.1%	37	1.0875	0.03	3

LPLS-INTERVAL	1162		46%	17	1.0875	15		1177
---------------	------	--	-----	----	--------	----	--	------

At this point, Column C weather adjusted 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.

Rate Class	(FOR ENTIRE CLASS) Estimated Peaks Incl Weather Adj and Losses (MW)	(FOR INTERVAL GROUPS) Estimated Peaks Incl Weather Adj and Losses (MW)	Column C - Estimated Peaks Incl Weather Adj and Losses (MW)
GLP-NON-INTERVAL	2340	3	2337
LPLS-NON-INTERVAL	2509	1177	1332

[Back to Development of Generation Capacity Scale Factors](#)

Calculation of Column C in Development of Transmission Scale Factors chart:

For the RS, RHS, RLM, WH, WHS, and HS rate classes, 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 2008](#), 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 66,000, which is the estimated number of RSH customers.)

Rate Class	Avg of 5 Transmission Profile Peaks (kW/customer)	Customer Bills (Thousands)	Loss Expansion Factor	Column C - Estimated Peaks Incl Losses (MW)
RS	2.17	1812.65	1.0875	4256.9
RHS	2.39	12.65	1.0875	32.9
RLM	5.55	13.73	1.0875	82.8
WH	0.65	2.20	1.0875	0.43
WHS	1.08	0.03	1.0875	0.00
HS	2.94	1.72	1.0875	5.53

For the RSH rate class, Column C was calculated as the RHS estimated peak (33 MW), divided by the RHS preliminary transmission load (30 MW), times the RSH preliminary transmission load (118 MW). It was necessary to take this approach and use the closely representative RHS customer class, as there exists no profile sample for the RSH rate class.

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 2008](#), times the number of customer bills, times the loss expansion factor. Since the profile for LPLS was not representative of the entire class, an estimated weather adjusted value of 290 kW/customer (based on previous years' profile values) was used.

Rate Class	Avg of 5 Transmission Profile Peaks (kW/customer)	Customer Bills (Thousands)	Loss Expansion Factor	(FOR ENTIRE CLASS) Estimated Peaks Incl Losses (MW)
GLP	8.25	256.5	1.0875	2302.7
LPLS	290	7.9	1.0875	2491.63

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.

Rate Class	(FOR ENTIRE CLASS) Estimated Peaks Incl Losses (MW)	(FOR INTERVAL GROUPS) Estimated Peaks Incl Losses (MW)	Column C - Estimated Peaks Incl Losses (MW)
GLP-NON-INTERVAL	2303	3	2300
LPLS-NON-INTERVAL	2492	1177	1315

[Back to Development of Transmission Scale Factors](#)