What Factors Should Affect Selection of Time-of-Use (TOU) Periods?

Jan Grygier (Principal, Energy Policy Modeling and Analysis)
Amitava Dhar (Manager, Rate Analysis, Gas & Electric Rate Ops)

February 26, 2016

What Should Drive TOU Period Design: Cost or Load?

- TOU period design should be marginal cost based. It is a critical rate design principle.
  - Marginal Generation Cost (MGC) should be the primary driver.
- California Independent System Operator (CAISO) uses net load. However, net load is a proxy for the MGC.
- In 2015 Rate Design Window (RDW)*, PG&E has used Adjusted Net Load (ANL) in the MGC forecast model. Analysis shows that ANL is a better proxy (i.e., correlates better) for MGC.
  - ANL subtracts hydro and nuclear generation, in addition to wind and solar, from the gross load.

* The 2015 RDW Decision is D.15-11-013.

Seasonal Shapes of Average Net Load and Marginal Energy Costs

- CAISO's net load does not exclude nuclear and hydro (only wind/solar).
- What is problem? Missing nuclear/hydro misses **seasonal shape**.
  - Adjusted Net Load (ANL) excludes all resources that displace thermal.

Example: Is May a Spring or Summer month?

2018 Average Hydro Scenario (From 2015 RDW Model).

	February	March	April	May	June	
Net Load MW	20,200	18,500	17,400	20,400	22,500	May > March
Nuclear MW	1,100	2,200	2,200	2,200	2,200	
Hydro MW	2,600	3,100	3,900	4,700	4,700	
ANL	16,400	13,300	11,300	13,400	15,700	May = March
MGC	$44/MWh	$32/MWh	$24/MWh	$32/MWh	$40/MWh	May = March

Bottom line: Use the bottom lines, not the top one

Based on MGC, How Should TOU Periods be Determined?

- The selection of the Peak TOU period should maximize capturing the highest hourly MGCs while minimizing capturing hours that do not have the highest MGCs.
- An appropriate statistical method should be adopted to select the TOU period.
  - PG&E uses “Percent High Cost Hours” Maximization, and “False Positive Rate” (i.e., percent low cost hours) Minimization. This is a widely used statistical approach.
  - High cost hours are defined to be the hours that have MGCs above a chosen cost threshold (for example, 95th percentile MGC).

Thank You

Jan Grygier
Principal, Energy Policy Modeling and Analysis

Amitava Dhar
Manager, Rate Analysis, Gas and Electric Rate Operations

Appendix

Overview

PG&E believes two factors should be used to determine TOU periods:

1. Marginal Generation Costs (MGC), made up of Marginal Energy Costs (MEC) and Marginal Generation Capacity Costs (MGCC).
   – Load shifting in response to actual marginal costs reduces overall system costs, and is consistent with cost-causation, encouragement of conservation, reduction of peak demand.*
      - If we get it wrong, customers will shift load to the wrong places, and all customers (not just the load shifters) will see increased costs.

   – Net load is a decent proxy for MGC; Adjusted Net Load (ANL) is a better one.
2. Customer Considerations
   – Simple and understandable, length of time in force.

   – IOU-specific, not part of this Order Instituting Rulemaking (OIR).

* See Scoping Memo and Ruling of Assigned Commissioner in Residential Rates OIR (RROIR), R.12-06-013, issued November 26, 2012.

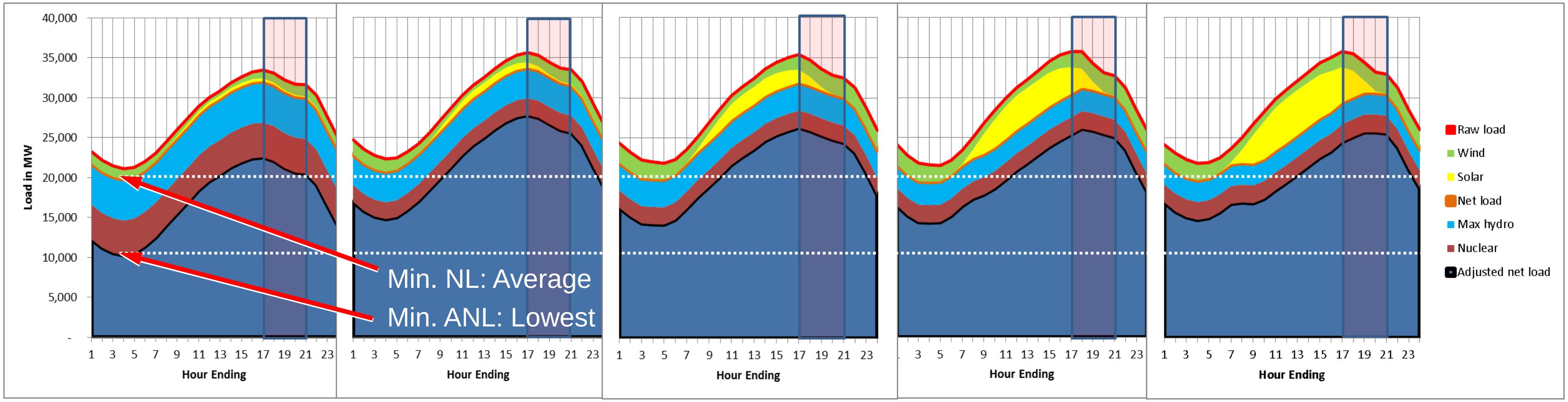
What Drives Marginal Generation Costs?

– CAISO’s net load does not exclude nuclear and hydro (only wind/solar).

– What is problem? Missing nuclear/hydro misses **year to year variability**.

– Black line at bottom is ANL, which excludes all resources that displace thermal. It is significantly lower in 2011, so is Heat Rate.

Year	2011	2012	2013	2014	2015
Hydro	Wet	Average	Dry	Driest	Driest
Nuclear	4 GW	2 GW	2 GW	2 GW	2 GW
Summer HR	5.7	7.4	7.2	7.4	7.7



2018 TOU Periods (From 2015 RDW)

Marginal Energy Cost +
Marginal Capacity Cost =
Marginal Generation Cost

ALL DAYS	Marginal Energy Cost (only, at Distribution level)								2018															
Hour Ending	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
January	36	32	30	29	32	38	45	49	45	38	35	33	31	32	34	40	51	59	60	59	57	53	48	40
February	40	38	36	35	37	42	47	50	44	39	36	33	31	32	35	41	51	58	61	61	59	56	51	45
March	37	32	29	27	27	29	33	36	32	22	16	13	12	12	14	19	28	40	50	54	55	53	49	43
April	33	29	24	22	21	22	27	31	20	9	2	(1)	(3)	(3)	1	7	17	30	43	45	49	52	48	41
May	37	31	27	25	24	26	30	27	23	17	15	16	16	18	23	29	36	44	52	53	53	55	52	45
June	44	39	36	33	32	33	35	30	27	24	24	26	27	28	32	38	45	51	57	60	58	59	57	51
July	53	48	45	42	41	41	43	41	39	37	40	43	45	48	52	57	64	74	96	104	85	81	69	59
August	51	47	44	42	41	41	44	47	42	38	39	41	43	45	50	54	58	64	74	73	68	68	62	57
September	45	41	38	36	35	36	39	43	37	29	27	28	28	30	34	40	47	53	59	58	60	59	55	50
October	46	42	39	38	37	38	42	47	45	35	31	32	31	32	35	40	47	56	58	60	61	59	56	52
November	39	35	33	32	33	38	43	44	35	28	26	24	24	27	31	42	54	60	60	59	57	54	50	43
December	38	34	32	31	33	37	44	45	39	32	28	25	24	26	30	41	54	62	62	61	60	56	51	44

ALL DAYS	Marginal Capacity Cost from PG&E Heat Rate Model in								2018															
Hour Ending	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
January	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
February	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
March	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
April	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
May	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
June	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6	17	4	-	-	-
July	-	-	-	-	-	-	-	-	-	-	-	-	-	7	16	45	97	163	295	344	246	222	126	19
August	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	54	189	167	110	102	18	-
September	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	24	13	18	8	-	-
October	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
November	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
December	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

ALL DAYS	Marginal Generation Cost (Energy plus Capacity)								2018															
Hour Ending	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
January	36	32	30	29	32	38	45	49	45	38	35	33	31	32	34	40	51	59	60	59	57	53	48	40
February	40	38	36	35	37	42	47	50	44	39	36	33	31	32	35	41	51	58	61	61	59	56	51	45
March	37	32	29	27	27	29	33	36	32	22	16	13	12	12	14	19	28	40	50	54	55	53	49	43
April	33	29	24	22	21	22	27	31	20	9	2	(1)	(3)	(3)	1	7	17	30	43	45	49	52	48	41
May	37	31	27	25	24	26	30	27	23	17	15	16	16	18	23	29	36	44	52	53	53	55	52	45
June	44	39	36	33	32	33	35	30	27	24	24	26	27	28	32	38	45	51	62	77	62	59	57	51
July	53	48	45	42	41	41	43	41	39	37	40	43	45	54	68	102	161	237	391	449	330	303	195	78
August	51	47	44	42	41	41	44	47	42	38	39	41	43	45	50	54	61	118	263	239	178	169	80	57
September	45	41	38	36	35	36	39	43	37	29	27	28	28	30	34	40	47	55	83	72	79	67	55	50
October	46	42	39	38	37	38	42	47	45	35	31	32	31	32	35	40	47	56	58	60	61	59	56	52
November	39	35	33	32	33	38	43	44	35	28	26	24	24	27	31	42	54	60	60	59	57	54	50	43
December	38	34	32	31	33	37	44	45	39	32	28	25	24	26	30	41	54	62	62	61	60	56	51	44

TOU Period Cost-Base Design Criteria

1. Determining the seasons
   - Distribution of the highest marginal generation cost hours across the months is used to determine the summer months.
   - CPUC adopted four-month summer season in PG&E's 2015 RDW.
   - PG&E's analysis for all customers shows four-month summer now.
2. Determining the TOU Periods
   - How Top 100 and 250 MGC Hours are distributed across hours of the day:
     - Provides an idea of when peak marginal generation cost hours occur during the day.
     - PG&E designs various TOU period scenarios around these peak hours to perform further analysis. (For example, comparing a 5:00 pm – 10:00 pm period versus a 4:00 pm – 9:00 pm.)

Percent Count of Highest Cost Hours (Energy + Capacity)

	Month	Top 250	Top 100
1	January	0%	0%
2	February	0%	0%
3	March	0%	0%
4	April	0%	0%
5	May	0%	0%
6	June	4%	0%
7	July	50%	28%
8	August	27%	11%
9	September	8%	0%
10	October	0%	0%
11	November	1%	0%
12	December	9%	0%

Tables show illustrative numbers for discussion purposes only.

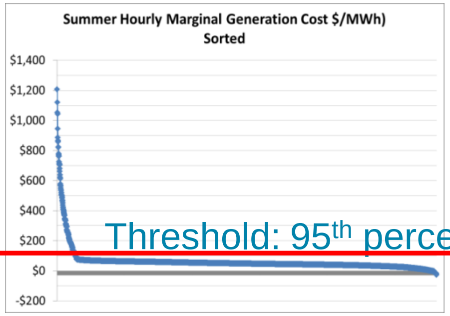
Percent Count of Highest Cost Hours (Energy + Capacity)

	Hour of Day	Top 250	Top 100
1	12 AM to 12 PM	0%	0%
2	12 PM to 1 PM	0%	0%
3	1 PM to 2 PM	0%	0%
4	2 PM to 3 PM	1%	0%
5	3 PM to 4 PM	1%	1%
6	4 PM to 5 PM	3%	3%
7	5 PM to 6 PM	10%	7%
8	6 PM to 7 PM	22%	23%
9	7 PM to 8 PM	22%	27%
10	8 PM to 9 PM	17%	18%
11	9 PM to 10 PM	16%	14%
12	10 PM to 11 PM	7%	7%
13	11 PM to 12 AM	2%	0%

TOU Period Cost-Base Design Criteria

– TOU Period Scenario Analysis/Optimization

- Select a threshold price:
  - Sort all of a year's hours (8,784 hours) to examine the marginal generation cost curve shape and see where the rate of decrease changes.
  - PG&E found 95th percentile to be a reasonable choice.
- Optimize the hours:
  - Look at various scenarios and, for each, calculate percent high cost hours and false positive rate (see formulas in table).
  - A false positive rate is the degree to which non-high cost hours are captured in a scenario peak period.
  - Select the scenario that maximizes the percent of high cost hours, while minimizing the false positive rate hours (green shaded line in first table).



Scenario ID	Description	Summer Peak: Percent High Cost Hours, A = TP/(TP + FN)	Summer Peak: False Positive Rate, B = FP/(FP + TN)
S-7	Summer Peak: From 3PM to 9PM, All days of the week Summer Partpeak(1): From 1PM to 3PM, All days of the week Summer Partpeak(2): From 9PM to 12AM, All days of the week	78%	22%
S-8	Summer Peak: From 3PM to 10PM, All days of the week Summer Partpeak(1): From 1PM to 3PM, All days of the week Summer Partpeak(2): From 10PM to 12AM, All days of the week	93%	26%
S-9	Summer Peak: From 3PM to 11PM, All days of the week Summer Partpeak(1): From 1PM to 3PM, All days of the week Summer Partpeak(2): From 11PM to 12AM, All days of the week	99%	30%
S-16	Summer Peak: From 4PM to 9PM, All days of the week Summer Partpeak(1): From 2PM to 4PM, All days of the week Summer Partpeak(2): From 9PM to 12AM, All days of the week	76%	18%
S-17	Summer Peak: From 4PM to 10PM, All days of the week Summer Partpeak(1): From 2PM to 4PM, All days of the week Summer Partpeak(2): From 10PM to 12AM, All days of the week	92%	21%
S-18	Summer Peak: From 4PM to 11PM, All days of the week Summer Partpeak(1): From 2PM to 4PM, All days of the week Summer Partpeak(2): From 11PM to 12AM, All days of the week	97%	26%
S-25	Summer Peak: From 5PM to 9PM, All days of the week Summer Partpeak(1): From 3PM to 5PM, All days of the week Summer Partpeak(2): From 9PM to 12AM, All days of the week	72%	14%
S-26	Summer Peak: From 5PM to 10PM, All days of the week Summer Partpeak(1): From 3PM to 5PM, All days of the week Summer Partpeak(2): From 10PM to 12AM, All days of the week	88%	17%
S-27	Summer Peak: From 5PM to 11PM, All days of the week Summer Partpeak(1): From 3PM to 5PM, All days of the week Summer Partpeak(2): From 11PM to 12AM, All days of the week	93%	21%

Tables show illustrative numbers for discussion purposes only.

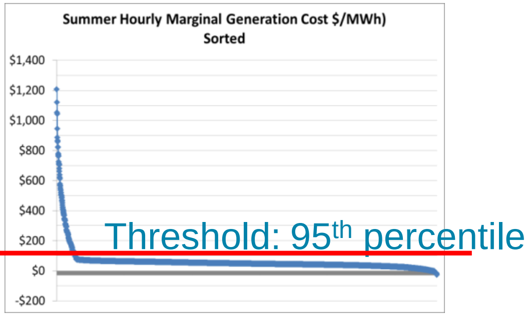
Scenario ID	Scenario Description	Summer Peak: Percent High Cost Hours, A = TP/(TP + FN)	Summer Peak: Percent Medium & Low Cost Hours, B = FP/(FP + TN)
1	Summer Peak: From 5 PM to 10 PM, All days of the week	88%	17%
2	Summer Peak: From 5 PM to 10 PM, Monday through Friday	73%	12%

TOU Period Cost-Base Design Criteria (Cont'd)

- This easy-to-understand approach (known as "confusion matrix") is standard, and is widely used to describe the performance of a classification model (or "classifier").

– Determine whether weekdays only/all days of week.

- Take target TOU peak period, and perform the same optimization analysis to determine whether all days of week maximizes the percent of high cost hours, while minimizing the false positive rate hours, versus Monday – Friday (see second table).



Scenario ID	Description	Summer Peak: Percent High Cost Hours A = TP/(TP + FN)	Summer Peak: False Positive Rate B = FP/(FP + TN)
S-7	Summer Peak: From 3PM to 9PM, All days of the week Summer Partpeak(1): From 1PM to 3PM, All days of the week Summer Partpeak(2): From 9PM to 12AM, All days of the week	78%	22%
S-8	Summer Peak: From 3PM to 10PM, All days of the week Summer Partpeak(1): From 1PM to 3PM, All days of the week Summer Partpeak(2): From 10PM to 12AM, All days of the week	93%	26%
S-9	Summer Peak: From 3PM to 11PM, All days of the week Summer Partpeak(1): From 1PM to 3PM, All days of the week Summer Partpeak(2): From 11PM to 12AM, All days of the week	99%	30%
S-16	Summer Peak: From 4PM to 9PM, All days of the week Summer Partpeak(1): From 2PM to 4PM, All days of the week Summer Partpeak(2): From 9PM to 12AM, All days of the week	76%	18%
S-17	Summer Peak: From 4PM to 10PM, All days of the week Summer Partpeak(1): From 2PM to 4PM, All days of the week Summer Partpeak(2): From 10PM to 12AM, All days of the week	92%	21%
S-18	Summer Peak: From 4PM to 11PM, All days of the week Summer Partpeak(1): From 2PM to 4PM, All days of the week Summer Partpeak(2): From 11PM to 12AM, All days of the week	97%	26%
S-25	Summer Peak: From 5PM to 9PM, All days of the week Summer Partpeak(1): From 3PM to 5PM, All days of the week Summer Partpeak(2): From 9PM to 12AM, All days of the week	72%	14%
S-26	Summer Peak: From 5PM to 10PM, All days of the week Summer Partpeak(1): From 3PM to 5PM, All days of the week Summer Partpeak(2): From 10PM to 12AM, All days of the week	88%	17%
S-27	Summer Peak: From 5PM to 11PM, All days of the week Summer Partpeak(1): From 3PM to 5PM, All days of the week Summer Partpeak(2): From 11PM to 12AM, All days of the week	93%	21%

Tables show illustrative numbers for discussion purposes only.

Scenario ID	Scenario Description	Summer Peak: Percent High Cost Hours A = TP/(TP + FN)	Summer Peak: Percent Medium & Low Cost Hours B = FP/(FP + TN)
1	Summer Peak: From 5 PM to 10 PM, All days of the week	88%	17%
2	Summer Peak: From 5 PM to 10 PM, Monday through Friday	73%	12%

Distribution System Peak Capacity Allocation Factor (PCAF)

– Distribution Demand (i.e., PCAF) profile across PG&E territory can be used to design partial peak period.

- The table below shows the percent of PCAFs in 19 divisions in the PG&E territory for the summer months (June through September) which covers approximately 90 percent of the annual PCAF, leaving 10 percent for the rest of the months (winter).
- 2014 data has been used, without taking into account possible shift of peak in the future due to additional DG installations. PG&E is working on assessing this potential shift.

Hour Ending at Summer	CENTRAL_COAST	DE_ANZA	DIABLO	EAST_BAY	FRESNO	HUMBOLDT	KERN	LOS_PADRES	MISSION	NORTH_BAY	NORTH_VALLEY	PENINSULA	SACRAMENTO	SAN_FRANCISCO	SAN_JOSE	SIERRA	SONOMA	STOCKTON	YOSEMITE	Weighted All
1:00:00 AM	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
2:00:00 AM	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
3:00:00 AM	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
4:00:00 AM	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
5:00:00 AM	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
6:00:00 AM	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
7:00:00 AM	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
8:00:00 AM	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
9:00:00 AM	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
10:00:00 AM	1%	0%	0%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	0%	0%	0%	0%	0%	0%
11:00:00 AM	3%	0%	0%	4%	0%	0%	0%	1%	0%	0%	0%	3%	0%	5%	0%	0%	0%	0%	0%	1%
12:00:00 PM	5%	1%	0%	5%	0%	1%	1%	3%	1%	0%	0%	6%	0%	7%	0%	0%	1%	0%	0%	2%
1:00:00 PM	5%	2%	0%	6%	1%	2%	2%	4%	2%	1%	0%	6%	0%	8%	2%	0%	2%	0%	1%	2%
2:00:00 PM	7%	4%	1%	9%	3%	5%	5%	7%	6%	3%	1%	8%	1%	10%	5%	1%	5%	2%	3%	5%
3:00:00 PM	8%	8%	4%	11%	7%	7%	8%	10%	9%	6%	3%	8%	3%	12%	9%	4%	8%	5%	6%	7%
4:00:00 PM	9%	14%	8%	10%	13%	9%	12%	11%	12%	11%	5%	10%	6%	13%	12%	10%	13%	10%	10%	11%
5:00:00 PM	9%	17%	21%	8%	18%	12%	14%	13%	14%	14%	13%	11%	14%	9%	17%	18%	16%	17%	15%	14%
6:00:00 PM	9%	20%	22%	2%	18%	13%	15%	10%	14%	18%	18%	11%	20%	4%	17%	20%	17%	20%	17%	15%
7:00:00 PM	10%	12%	24%	1%	18%	13%	16%	9%	9%	16%	24%	6%	24%	0%	13%	24%	13%	21%	20%	14%
8:00:00 PM	8%	8%	14%	3%	12%	13%	13%	6%	7%	10%	23%	4%	19%	0%	7%	15%	10%	13%	14%	10%
9:00:00 PM	7%	2%	6%	4%	8%	10%	9%	5%	5%	2%	10%	3%	9%	0%	4%	6%	4%	8%	9%	6%
10:00:00 PM	3%	1%	0%	2%	3%	5%	4%	2%	2%	1%	3%	0%	2%	0%	1%	1%	2%	3%	4%	2%
11:00:00 PM	0%	0%	0%	0%	0%	1%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
12:00:00 AM	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%

Distribution System Peak Capacity Allocation Factor (PCAF) (Cont'd)

- The data below shows that:
  - Distribution peaks occur during similar hours as the system generation peak.
  - A partial peak of about two to three hours before the peak period (e.g. either 3:00 pm to 5:00 pm, or 2:00 pm to 4:00 pm) should be able provide appropriate distribution price signal.
  - However, PG&E may additionally consider a partial peak from 9:00 pm or 10:00 pm to 12:00 pm due to relatively high MGC during these hours.

Hour Ending at Summer	CENTRAL_COAST	DE_ANZA	DIABLO	EAST_BAY	FRESNO	HUMBOLDT	KERN	LOS_PADRES	MISSION	NORTH_BAY	NORTH_VALLEY	PENINSULA	SACRAMENTO	SAN_FRANCISCO	SAN_JOSE	SIERRA	SONOMA	STOCKTON	YOSEMITE	Weighted All
1:00:00 AM	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
2:00:00 AM	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
3:00:00 AM	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
4:00:00 AM	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
5:00:00 AM	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
6:00:00 AM	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
7:00:00 AM	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
8:00:00 AM	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
9:00:00 AM	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
10:00:00 AM	1%	0%	0%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	0%	0%	0%	0%	0%	0%
11:00:00 AM	3%	0%	0%	4%	0%	0%	0%	1%	0%	0%	0%	3%	0%	5%	0%	0%	0%	0%	0%	1%
12:00:00 PM	5%	1%	0%	5%	0%	1%	1%	3%	1%	0%	0%	6%	0%	7%	0%	0%	1%	0%	0%	2%
1:00:00 PM	5%	2%	0%	6%	1%	2%	2%	4%	2%	1%	0%	6%	0%	8%	2%	0%	2%	0%	1%	2%
2:00:00 PM	7%	4%	1%	9%	3%	5%	5%	7%	6%	3%	1%	8%	1%	10%	5%	1%	5%	2%	3%	5%
3:00:00 PM	8%	8%	4%	11%	7%	7%	8%	10%	9%	6%	3%	8%	3%	12%	9%	4%	8%	5%	6%	7%
4:00:00 PM	9%	14%	8%	10%	13%	9%	12%	11%	12%	11%	5%	10%	6%	13%	12%	10%	13%	10%	10%	11%
5:00:00 PM	9%	17%	21%	8%	18%	12%	14%	13%	14%	14%	13%	11%	14%	9%	17%	18%	16%	17%	15%	14%
6:00:00 PM	9%	20%	22%	2%	18%	13%	15%	10%	14%	18%	18%	11%	20%	4%	17%	20%	17%	20%	17%	15%
7:00:00 PM	10%	12%	24%	1%	18%	13%	16%	9%	9%	16%	24%	6%	24%	0%	13%	24%	13%	21%	20%	14%
8:00:00 PM	8%	8%	14%	3%	12%	13%	13%	6%	7%	10%	23%	4%	19%	0%	7%	15%	10%	13%	14%	10%
9:00:00 PM	7%	2%	6%	4%	8%	10%	9%	5%	5%	2%	10%	3%	9%	0%	4%	6%	4%	8%	9%	6%
10:00:00 PM	3%	1%	0%	2%	3%	5%	4%	2%	2%	1%	3%	0%	2%	0%	1%	1%	2%	3%	4%	2%
11:00:00 PM	0%	0%	0%	0%	0%	1%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
12:00:00 AM	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%