# A Summary and Comparison of the Time of Delivery Factors Developed by the California Investor-Owned Utilities for Use in Renewable Portfolio Standard Solicitations

CONSULTANT REPORT

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## ABSTRACT

Time of Delivery (TOD) factors were incorporated in the 2005 Market Price Referent methodology used in the California investor-owned utilities Renewable Portfolio Standard solicitations. TOD factors account for varying energy and capacity values of electricity delivered during different time periods and are used to evaluate bids with different generation profiles on a comparable basis. This paper describes the methodology used by each utility to calculate its TOD factors and compares those factors to similar factors used in other applications (e.g. Qualifying Facility avoided cost calculations.)

## KEYWORDS

Renewable portfolio standard, time of delivery, market price referent

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# CHAPTER 1: INTRODUCTION

California's Renewable Portfolio Standard (RPS), established in Senate Bill 1078 (Sher) Chapter 516, Statutes of 2002, requires retail sellers to increase the renewable content of their electricity sales by at least 1 percent per year, with a goal of serving 20 percent of the state's retail electricity sales with renewables by 2017. California policy accelerates the target to 2010 and Governor Schwarzenegger expanded the goal to achieve 33 percent renewables by 2020. The California Energy Commission (Energy Commission) and the California Public Utilities Commission (CPUC) are collaboratively implementing the RPS.

As part of California's RPS, investor-owned utilities (IOUs) are periodically required by the CPUC to issue requests for offers for long-term contracts with renewable generators. The CPUC determines the Market Price Referent (MPR) for long-term electricity contracts, which sets the maximum price utilities are obligated to pay renewable generators competing in an RPS-solicitation. Eligible new or repowered facilities that secure a contract for a bid priced above the MPR may apply for Supplemental Energy Payments (SEPs) from the Energy Commission. SEPs are paid from public goods charge funds to cover the difference between the final bid price and the MPR. The Energy Commission may set a cap on the amount of SEPs it issues.

In 2005, the CPUC adopted Time-of-Delivery (TOD) factors for use in the MPR methodology. The TOD factors account for the varying energy and capacity values of electricity delivered in different time periods and are used to evaluate different generation profiles on a comparable basis. Each IOU uses a proprietary methodology to calculate its TOD factors. The IOUs publish the TOD factors when they release their solicitations for RPS-eligible generation, and the factors remain fixed for purposes of that solicitation. The CPUC releases the MPR after bidding for the solicitation has closed.

This paper provides a review of the TOD factors as follows:

- **Chapter 2** presents a procedural history.
- **Chapter 3** describes the methods used by each IOU to the extent possible using publicly available information.
- **Chapter 4** describes other areas in which similar methods are used to estimate time-varying energy and capacity costs.
- **Chapter 5** provides a comparison of the 2005 and 2006 TOD factors as well as comparable factors calculated using Qualifying Facility (QF) avoided cost methodology.
- **Chapter 6** provides a comparison of the IOUs' 2006 TOD factors.
- **Chapter 7** presents the resulting MPRs calculated for a photovoltaic and base load resource for each IOU.
- **Chapter 8** presents the conclusions drawn in this report.

This report was prepared to provide background material for the Energy Commission's mid-course review of the RPS as part of its 2006 Update to the Integrated Energy Policy Report.

# CHAPTER 2: PROCEDURAL HISTORY

In implementing the Renewable Portfolio Standard (RPS), the CPUC developed a methodology for determining market prices pursuant to subdivision (c) of Section 399.15 which reads:

> (c) The [CPUC] shall establish a methodology to determine the market price of electricity for terms corresponding to the length of contracts with renewable generators, in consideration of the following:
> (1) The long-term market price of electricity for fixed price contracts, determined pursuant to the electrical corporation's general procurement activities as authorized by the [CPUC].
> (2) The long-term ownership, operating, and fixed-price fuel costs associated with fixed-price electricity from new generating facilities.
> (3) The value of different products including base load, peaking, and as-available output.

The CPUC initially adopted a methodology for calculating the MPR in D. 03-06-071 (R. 01-10-024, adopted June 19, 2003) based on estimating the cost to build and operate a proxy power plant, including gas prices. The MPR is designed to approximate the long-term, all-in price of electricity (in \$/MWh) that would allow an independent generator to fully recover its fixed and variable costs, including a return on equity. The initial methodology used a combined cycle proxy plant for the base load product and a combustion turbine proxy plant for the peaking product. The CPUC further developed the methodology in D. 04-06-015 (R. 01-10-024, adopted June 9, 2004).

For the 2004 RPS solicitations, the CPUC calculated two MPR's: a base load MPR based on the costs of a combined-cycle gas turbine (CCGT), and a peaking MPR, based on the costs of a combustion turbine (CT)[1]. Independent of the MPR calculation, both Pacific Gas & Electric (PG&E) and (Southern California Edison) SCE used Time of Delivery (TOD) factors as part of the least-cost/best fit methodology used to evaluate and rank bids. The TOD factors accounted for the varying energy and capacity values of electricity delivered in different time periods and were used to compare bids with different generating profiles on a comparable basis.

For the 2005 RPS solicitations, the CPUC found TOD factors to be more accurate, flexible and transparent than the two-MPR method for representing the value of energy across different time periods. The CPUC adopted the TOD methodology for use in the 2005 RPS Solicitations and MPR methodology in D. 04-07-029. The MPR methodology set forth by the CPUC for calculating the 2005 MPR (D.05-12-042) incorporated the use of TOD factors and raised the need to evaluate the TOD factors (D.05-12-042, pages 21-22):

> We agree that the TOD factors should be approved by the Commission during the review of the utilities' short-term RPS plans and proposed [Request for Offers]. In order to do this, however, a methodology for evaluating reasonableness of the utilities' TOD profiles is required. Parties provided no specific proposals on this topic. Consequently, we will require the parties to present TOD evaluation and benchmarking proposals for the 2006 RPS procurement process, on a schedule to be set by the Assigned Commissioner and assigned Administrative Law Judge.

In a December 27, 2005 ALJ ruling, the CPUC directed the IOUs to file updated TOD factors for use in the 2006 RPS solicitations. In addition, to address concerns regarding the proprietary nature of the TOD calculations, the ALJ directed the IOUs to file proposals for benchmarking the TOD's with publicly available data[2]. The descriptions of the IOUs' TOD factors given in this report are based on filings made in response to that ruling, submitted to the CPUC in February and March of 2006.

On May 25, 2006, the CPUC adopted D. 06-05-039, *Opinion Conditionally Approving Procurement Plans for 2006 RPS Solicitations, Addressing TOD Benchmarking Methodology, and Closing Proceedings*. The decision's discussion of the CPUC's efforts to adopt a method for benchmarking TOD factors included the following (page 66):

> No comments lead us to reject any specific TOD factors, and we adopt them as proposed by IOUs, including the update provided by PG&E in its supplemental filing on February 8, 2006. We are not convinced, however, that any benchmarking proposal is sufficiently developed, documented, or explained to be explicitly endorsed or adopted by us at this time.

The IOUs are currently evaluating bids for 10 to 20 year contracts offered in response to their 2005 RPS-solicitation. The bids are compared with the 2005 MPR and will include application of the IOUs' TOD factors.

# CHAPTER 3: UTILITY TOD METHODOLOGIES

The three California IOUs independently calculated TOD factors for use in their RPS solicitations. All TOD factors are based on forward looking estimates of the combined or "all-in" energy and capacity value of electricity, but each IOU considers proprietary its specific methodology and data used in the calculations.

In general, TOD calculations involve four steps.

1. Each IOU uses NYMEX data, broker quotes for forward markets, and/or third party electric price forecasts to estimate future energy prices.
2. The IOUs then use statistical methods to translate monthly trading block forecasts to hourly prices. Based on the hourly prices, they calculate average prices for each TOD period.
3. PG&E and SCE estimate capacity values, which they allocate to certain TOD periods and combine with the energy-only component to produce all-in TOD factors. SDG&E does not include an allocation of capacity costs in its TOD methodology.
4. The IOUs calculate the TOD factors by dividing the adjusted TOD period price by the average annual forecasted price. The weighted average of the TOD factors over the course of a year must average 1.0.

# CHAPTER 4: USE OF TOD'S IN OTHER IOU APPLICATIONS

While the underlying data and methods used to evaluate the time varying value of energy and capacity are similar to those used in other utility applications, TOD factors are not explicitly published or used in other proceedings. Also, in most cases that use forecasts of the value of generation, energy and capacity values are calculated separately, not together in a single all-in factor as they are for the RPS solicitations.

The IOUs describe the use of similar inputs for Qualifying Facilities (QFs), All Source Requests for Offers, and Energy Efficiency, as summarized below.

## Qualifying Facilities

For QF payments[3], the IOUs calculate separate time-varying factors for energy and capacity, referred to in the QF program as Time-of-Use (TOU) factors and Capacity Allocation factors. These factors were originally developed in the mid 1990's using production simulation models. In all cases, the QF Time-of-Use and Capacity Allocation factors result in flatter profiles than the RPS TOD factors, as shown in Figures 8, 9 and 10 of Chapter 5. The On-Peak factors are lower and Off-Peak factors higher for QF pricing formulas than those used in RPS solicitations.

SCE initially proposed using QF TOU factors in the RPS solicitations. Several parties argued, and the CPUC agreed, that TOD factors used in RPS solicitations should be based on the most recently available forward market price data. The CPUC directed SCE to calculate new TOD factors for the 2005 RPS solicitation in a fashion similar to PG&E and SDG&E.

The CPUC originally planned to consider updating the QF TOU factors in Phase II of its Avoided Cost proceeding (R. 04-04-025). However, because the CPUC determined the issue to be complex and contentious, it was deferred to Phase III. Phase III has been delayed by the lengthy and still ongoing Phase II, but is expected to start later this year or early next year.

## All Source Request for Offers

No TOD factors have been published in connection with the IOUs All Source Request for Offers (RFO's). Nevertheless, the IOUs claim that similar data and methods will be part of the least-cost/best fit evaluation used to rank bids in the All Source solicitations.

## Energy Efficiency

Avoided cost calculations for energy efficiency and demand response cost-benefit analysis rely on data and methods similar to those used for TOD factors. In D.05-04-024, the CPUC adopted an avoided cost methodology for energy efficiency developed by Energy and Environmental Economics (E3)[4]. E3's methodology uses a forecast of average annual market prices developed for three distinct periods:

1) a period of forward market liquidity (NYMEX),
2) a transition period to resource balance, and
3) a post-resource balance year long-run marginal cost forecast.

These prices are shaped to a full 8,760 hour all-in price profile based on historical (1998-2000) California Power Exchange price data. E3's methodology also considers ancillary services, energy losses, transmission and distribution costs, and environmental costs. The hourly price shape captures the full economic benefits of demand-side measures (e.g., efficient air conditioners) that would be missed if savings were averaged over six or nine TOU periods.

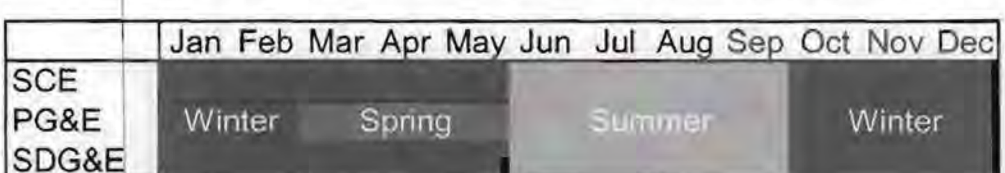
# CHAPTER 5: RPS TOD AND QF TOU FACTOR COMPARISON

This chapter compares, for each utility, updated 2006 TOD Factors, 2005 TOD factors (for PG&E and SCE) and calculated QF TOU factors that combine both energy and capacity allocation. To calculate the QF energy factors, E3 assumed an average annual energy price of $0.08/kWh ($80/MWh), based on recent QF energy price postings[5]. E3 then allocated capacity factors to each TOU period, based on the most recently approved capacity cost for each utility[6]. Finally, the QF energy and capacity factors were combined to create TOD factors for each period that are comparable to the combined energy and capacity TOD factors used for RPS solicitations.

For the 2006 RPS TOD factors, SCE calculates a capacity value based on broker price quotes using an option model. SCE then allocates capacity value using a Loss of Load Probability (LOLP) for each TOD period. PG&E also uses an option model to calculate the portion of a new CT's fixed costs that is not recovered from energy revenues (Net Capacity Value). PG&E then allocates the Net Capacity Value to each TOD period using the Capacity Allocation Factors (CAF's) used for QF capacity payments.

Direct comparison of TOD factors is complicated because each IOU defines TOU periods differently. Furthermore, each IOU used TOD periods for RPS solicitations that are different than TOU periods used for QF avoided cost calculations. Figures 1 through 7 summarize the TOU period definitions for RPS and QF purposes. As shown in Figure 1 and Figure 2, the June-September summer season is consistent for all IOUs, for both the RPS solicitations and QF avoided costs. SCE's and SDG&E's winter seasons run from October-May, while, PG&E adds a spring season, from March-May, for the RPS solicitation only.

## Figure 1. Utility RPS TOD Season Definitions




Source: SCE Renewable Power Purchase and Sale Agreement, Appendix A
PG&E Attachment G Form of Master Power Purchase and Sale Agreement, p. 24
SDG&E RFO Revision No. 2, Issued 11/10/2005, p. 12.

## Figure 2. IOU QF TOU Season Definitions

| | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| SCE<br>PG&E<br>SDG&E | | | Winter | | | | Summer | | | | Winter | |

Source: SCE, PG&E and SDG&E QF Avoided Cost Energy Price postings for May 2006.

The summer weekday RPS solicitation TOU period definitions for each utility are shown in Figure 3. Note that the SCE summer On-Peak period is six hours long as compared to eight hours for PG&E and ten hours for SDG&E.

## Figure 3. IOU RPS Summer Weekday TOD Period Definitions

| | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 | 21 | 22 | 23 | 24 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| SCE | | | Off | | | | | | | Mid | | | | | On | | | | | | Mid | | | Off |
| PG&E | | | Off | | | | | | Shoulder | | | | | | On | | | | | | Shldr | | | Off |
| SDG&E | | | Off | | | | | Semi | | | | | | | On | | | | | | Semi | | | Off |

Source: See Figure 1

Figure 4 shows that, for summer weekdays, up to four periods for each season are defined for QF TOU factors as compared to three for the RPS solicitation.

## Figure 4. IOU QF Summer Weekday TOU Period Definitions

| | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 | 21 | 22 | 23 | 24 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| SCE | | | | Off | | | | | | Mid | | | | | On | | | | | Mid | | | | Off |
| PG&E | Off | | Super Off | | | | Off | | | | Partial | | | | Peak | | | | | Partial | | | Off | |
| SDG&E | | | Super Off | | | Off | | | Semi | | | | | | On | | | | | Semi | | | Off | |

Source: See Figure 2

The winter weekday RPS TOD and QF TOU period definitions are shown in Figure 5 and Figure 6 respectively. Figure 7 shows PG&E's RPS spring weekday TOD period.

## Figure 5. Utility RPS Winter Weekday TOD Period Definitions

| | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 | 21 | 22 | 23 | 24 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| SCE | | | Super Off | | | | Off | | | | | | | | | Mid | | | | | | | Off | |
| PG&E | | | Off | | | | | | Shoulder | | | | | | | On | | | | | Shldr | | Off | |
| SDG&E | | | Off | | | | | | | Off | | | | | | On | | | | | | Off | Off | |

Source: See Figure 1

### Figure 6. Utility QF Winter Weekday TOU Period Definitions

| | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 | 21 | 22 | 23 | 24 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| SCE | | | Super Off | | | | Off | | | | | | | Mid | | | | | | | | | Off | |
| PG&E | Off | | Super Off | | | | Off | | | | | | | Partial | | | | | | | | | Off | |
| SDG&E | | | Super Off | | | Off | | | | | | | | Semi | | | | | On | | Semi | | Off | |

Source: See Figure 2

### Figure 7. PG&E Spring Weekday TOD Period Definitions

| | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 | 21 | 22 | 23 | 24 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| PG&E | | | Off | | | | | | Shoulder | | | | | | | On | | | | | Shldr | | Off | |

Source: See Figure 1

## SCE

SCE derives its TOD factors from third-party SP15 forward electricity prices. SCE uses exponential correlations between hourly load and prices to translate forward prices into a proprietary hourly power price forecast. An option analysis on the forward electricity prices determines the relative amounts of capacity and energy value implicit in the forward prices[7]. SCE creates an hourly *energy* price stream by removing the capacity value. The capacity value is, in turn, allocated to each TOD period using relative LOLP factors, as proposed in SCE's General Rate Case application[8]. LOLP is the probability that generation will not be sufficient to meet demand at some point over a specific period (in this case, SCE's TOU periods). As such, it is a measure of the relative need for, or value of, generation capacity in each TOU period. LOLP is one method commonly used by utilities to allocate capacity costs across different time periods.

SCE's 2005 TOD factors are close to the QF TOU factors on which they were based (Table 1). Differences in time period definitions used for RPS and QF payments probably account for most of the variance. The 2005 and 2006 TOD factors as well as the comparable factors calculated using QF avoided cost methodology are shown in Figure 8.

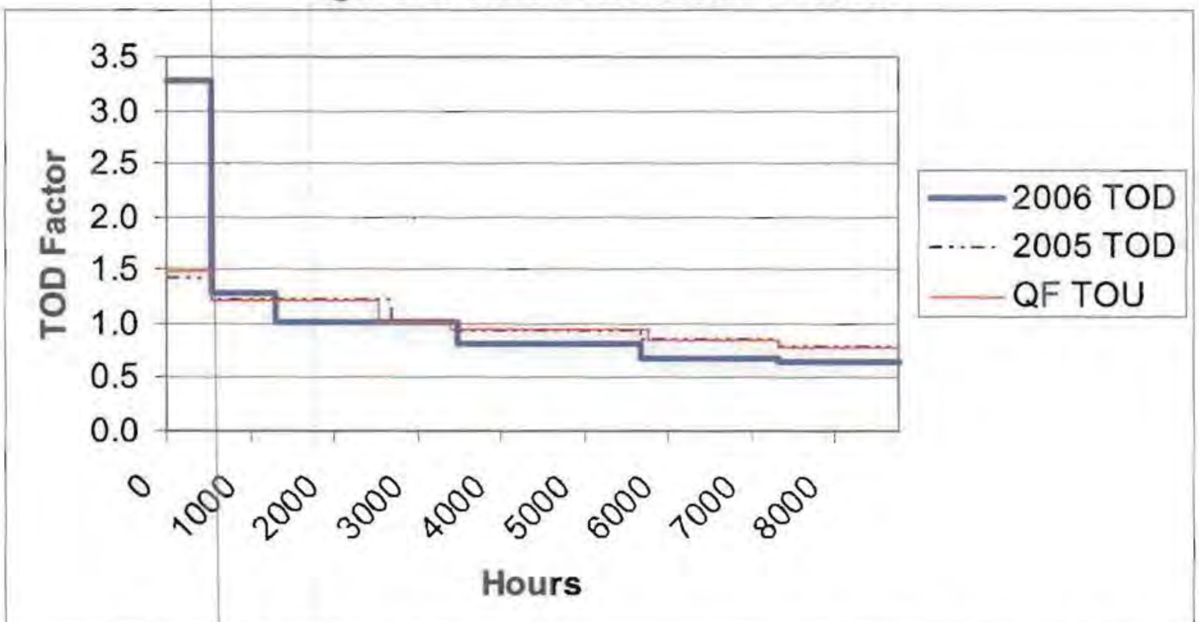
Adding the capacity value with the 2006 TOD methodology increased the SCE's Summer On-Peak factors by 130 percent compared to 2005 values. Off-Peak factors were reduced by 12-21 percent. SCE's 2006 methodology results in a Summer On-Peak TOD factor that is 67 percent higher than PG&E's and 105 percent higher than SDG&E's.

**Table 1. SCE TOD Factor Comparison**

| | | 2006 TOD | 2005 TOD | QF TOU |
|---|---|---|---|---|
| Summer | On-Peak | 3.280 | 1.425 | 1.501 |
| | Mid-Peak | 1.280 | 1.016 | 1.014 |
| | Off-Peak | 0.670 | 0.853 | 0.847 |
| Winter | Mid-Peak | 1.020 | 1.219 | 1.214 |
| | Off-Peak | 0.820 | 0.931 | 0.946 |
| | Super Off-Peak | 0.650 | 0.776 | 0.771 |

Source: Southern California Edison Company's Supplement to its Proposal for Benchmarking and Evaluating Time-of-Delivery Profiles, Filed February 8, 2006 (R. 04-04-026), p. 6, and E3.

**Figure 8. SCE TOD Factor Profiles**




Note: TOD factors are sorted from highest to lowest, regardless of the period in which they occur.
Source: E3.

## PG&E

PG&E generates proprietary hourly forward prices using market forward energy price information gathered from broker quotes and exchange prices. As PG&E describes;

> *"The forward prices are then used to develop prices for sub-period blocks of power and create PG&E's proprietary hourly price streams by scaling an hourly price shape for each month to the monthly forward price. The proprietary hourly price shapes are created by calibrating exponential functions of hourly load to prices."*[9]

PG&E's 2005 TOD factors were based exclusively on the relative market value of energy in different TOD hours. PG&E's updated 2006 TOD factors included an allocation of Net Capacity Costs. PG&E argues that it is appropriate to add capacity costs because new peaking capacity may be necessary to meet resource adequacy requirements and because the development of capacity markets may provide a separate source of revenues to generators.

PG&E calculates the Net Capacity Cost in three steps. First, PG&E calculates the real economic carrying charge (RECC) for a new CT[10]. PG&E then calculates the CT's net energy benefit in each period from sales of energy. The CT's net energy benefit is the difference between the revenues the CT earns from selling energy, and the variable costs the CT incurs to earn those revenues. PG&E uses a Black option model[11] to estimate the expected future net energy benefits of the CT. Finally, for each TOU period, PG&E calculates the CT's Net Capacity Cost as the amount, if any, by which the CT's annual inflation-adjusted RECC exceeds its net energy benefits.

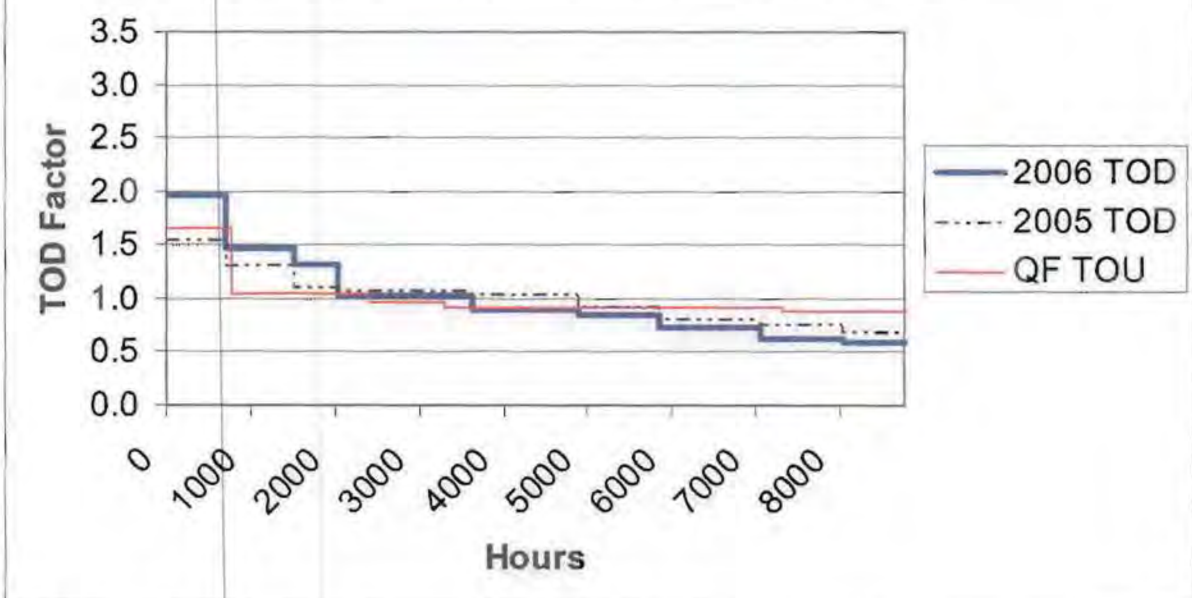
Table 2 shows that PG&E's 2006 On-Peak TOD factors are 30 percent higher in summer than in winter. The summer non-On-Peak TOD's for each monthly period are, on average, about 10 percent lower. Figure 9 compares the PG&E TOD factors with the comparable factors calculated using QF avoided cost methodology.

**Table 2. PG&E TOD Factor Comparison**

| | | PG&E 2006 TOD | PG&E 2005 TOD | PG&E QF TOU |
|---|---|---|---|---|
| Summer | On Peak | 1.959 | 1.543 | 1.731 |
| | Mid Peak | 0.903 | 1.024 | 0.953 |
| | Off Peak | 0.626 | 0.747 | 0.899 |
| | Super Off Peak | | | 0.863 |
| Winter | On Peak | 1.471 | 1.310 | |
| | Mid Peak | 1.030 | 1.065 | 1.043 |
| | Off Peak | 0.731 | 0.787 | 0.906 |
| | Super Off Peak | | | 0.867 |
| Spring | On Peak | 1.319 | 1.104 | |
| | Mid Peak | 0.843 | 0.920 | |
| | Off Peak | 0.584 | 0.673 | |

Source: Supplement to the Draft 2006 Renewables Portfolio Standard Solicitation Protocol of Pacific Gas and Electric Company, Filed February 8, 2006 (R. 04-04-026), P. 5, and E3.

**Figure 9. PG&E TOD Factor Profiles**




Source: E3

## SDG&E

SDG&E calculated its TOD factors for the 2005 RPS solicitation using the avoided costs developed by E3 and adopted by the Commission in D.05-04-024 for use in the evaluation of energy efficiency programs. This historical data was adjusted so that forward On-Peak and Off-Peak average quarterly prices equaled the On-Peak and Off-Peak average quarterly prices from the 2006 SP-15 forward electric market. The average quarterly forward SP-15 prices for 2006 were based on 60 days of forward On-Peak and Off-Peak SP-15 prices obtained from Tullet Liberty, a publication subscribed to by SDG&E. SDG&E used the same methodology for its 2006 RPS solicitation. The only change was that the Summer On-Peak TOD factor increased slightly from 1.629 to 1.641 (Table 3 and Figure 10).

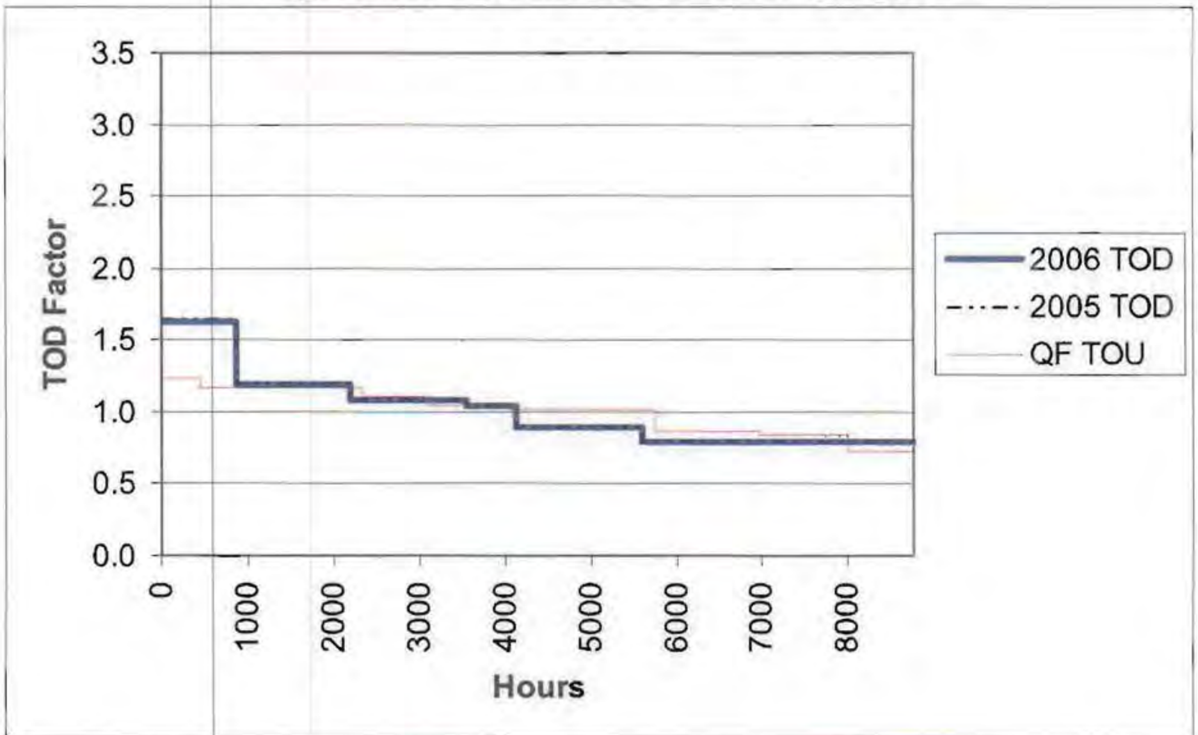
Unlike PG&E and SCE, SDG&E did not include a separate allocation of capacity values. SDG&E argued that its methodology is the most consistent with the CPUC direction (D. 05-12-042) that TOD factors should reflect actual market prices faced by a new CCGT owner. SDG&E also argued that the proceeding considered neither how capacity costs should be used, nor whether or not capacity costs should be included in the TOD methodology. In D. 06-05-039, the CPUC rejected all the IOUs proposed benchmarking methodologies, but accepted the IOUs proposed TODs for use in the 2006 RPS solicitation. The decision does not comment specifically on the issue of allocating capacity costs.

**Table 3. SDG&E TOD Factor Comparison**

| | | 2006 TOD | 2005 TOD | QF TOU |
|---|---|---|---|---|
| Summer | On-Peak | 1.641 | 1.629 | 1.107 |
| | Semi-Peak | 1.040 | 1.040 | 1.046 |
| | Off-Peak | 0.883 | 0.883 | 0.859 |
| | Super Off-Peak | | | 0.725 |
| Winter | On-Peak | 1.192 | 1.192 | 1.239 |
| | Semi-Peak | 1.079 | 1.079 | 1.167 |
| | Off-Peak | 0.793 | 0.793 | 1.004 |
| | Super Off-Peak | | | 0.835 |

Source: SDG&E RFO Revision No. 2, Issued 11/10/2005, p. 12, SDG&E 2006 RFO, Issued 07/17/2006, and E3.

**Figure 10. SDG&E TOD Factor Profiles**




Note: The line for the 2005 TOD factors is overshadowed by the line for the 2006 TOD factors because they are essentially the same.
Source: E3

# CHAPTER 6: COMPARISON OF THE UTILITIES' 2006 TOD FACTORS

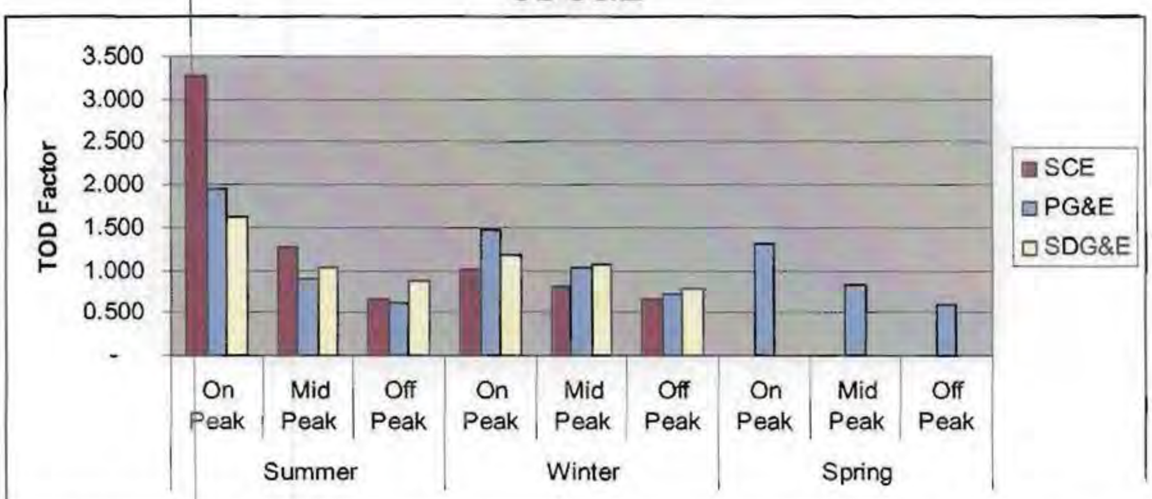
Table 4 and Figure 11 compare the IOU's 2006 TOD factors. They differ most strongly in the Summer On-Peak period. SCE's use of the LOLP capacity allocation method results in the highest Summer On-Peak capacity factor (3.280). PG&E's Net Capacity Cost methodology results in the next highest Summer On-Peak factor (1.959), while SDG&E, with no allocation of capacity costs, has the lowest (1.629). The fact that SCE's Summer On-Peak TOD period is six hours per day compared to eight for PG&E and ten for SDG&E also contributes to SCE's higher Summer On-Peak TOD factor.

**Table 4. 2006 TOD factors for SCE, PG&E and SDG&E**

| | | SCE | PG&E | SDG&E |
|---|---|---|---|---|
| Summer | On-Peak | 3.280 | 1.959 | 1.629 |
| | Mid-Peak | 1.280 | 0.903 | 1.040 |
| | Off-Peak | 0.670 | 0.626 | 0.883 |
| Winter | On-Peak | 1.020 | 1.471 | 1.192 |
| | Mid-Peak | 0.820 | 1.030 | 1.079 |
| | Off-Peak | 0.650 | 0.731 | 0.793 |
| Spring | On-Peak | | 1.319 | |
| | Mid-Peak | | 0.843 | |
| | Off-Peak | | 0.584 | |

Note: Common labels for each TOD period are used here for the sake of comparison. The actual period definitions for each utility are distinct.
Source: E3.

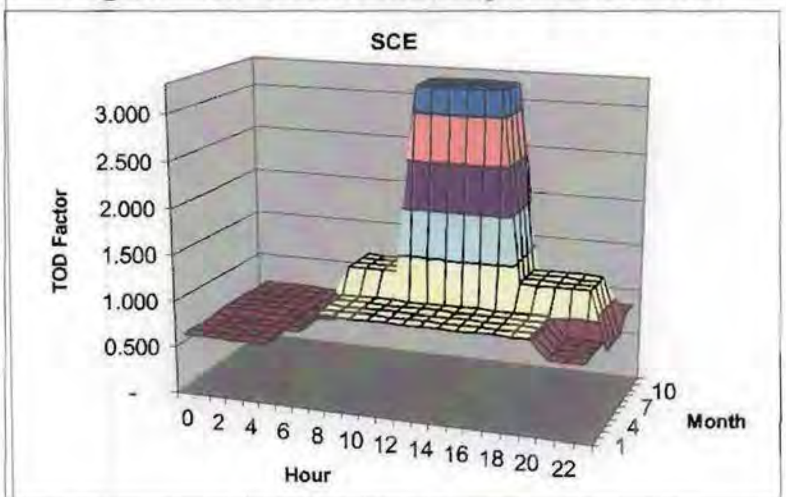
**Figure 11. Comparison of 2006 TOD factors for SCE, PG&E and SDG&E**




Source: E3.

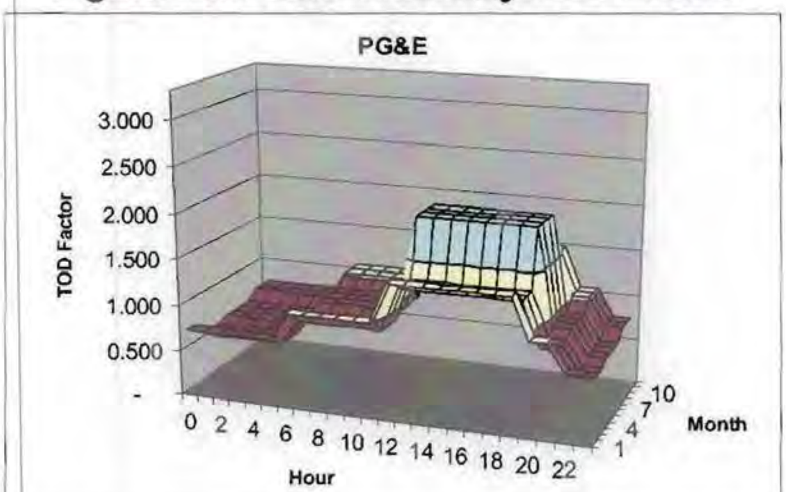
Due to capacity cost allocations, there is a greater difference between SCE's and PG&E's On- and Off-Peak TOD factors than SDG&E's respective factors. SCE's higher TOD factors are more concentrated in the summer season: SCE's Summer On- and Mid-Peak TOD factors are its highest ones. In contrast, PG&E and SDG&E's relatively high factors are spread through On-Peak periods throughout the year. The Summer, Winter (and Spring for PG&E) On-Peak periods have the highest TOD factors. These differences can be seen in Figure 12 to Figure 14, which show the applicable weekday TOD factor (Z-axis), for each hour of the day (X-axis) and each month in the year (Y-axis).

**Figure 12. SCE Weekday TOD Profile**



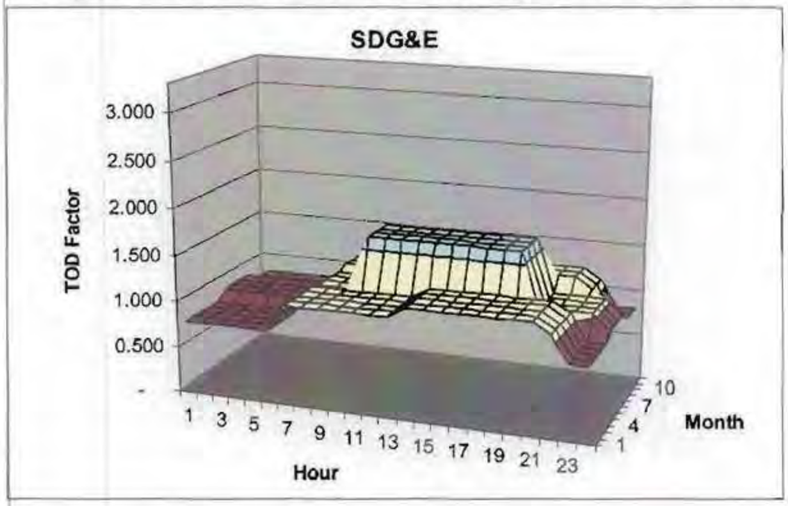

Source: E3.

**Figure 13. PG&E Weekday TOD Profile**




Source: E3.

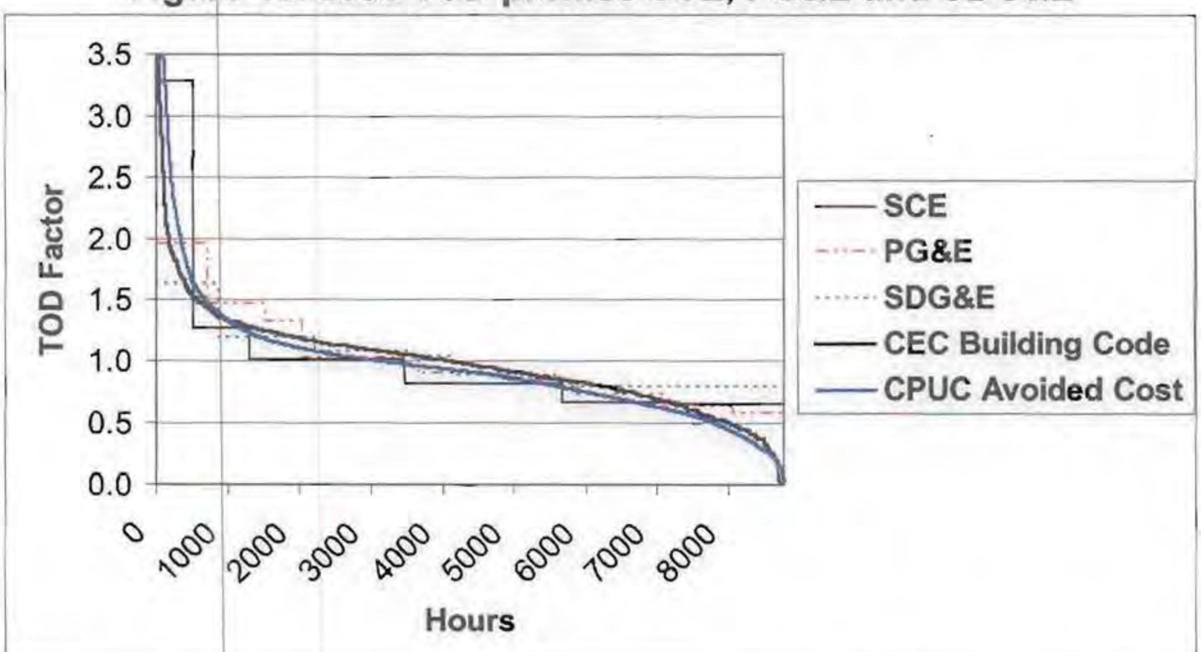
## Figure 14. SDG&E Weekday TOD Profile




Source: E3.

The annual TOD profiles for each utility are shown in Figure 15. For comparison, Figure 15 also includes representative hourly profiles for the Title 24 Building Code energy and capacity values and the appropriate components of the CPUC Avoided Costs adopted in D.05-04-024[12]. The hourly resolution of the latter profiles results in several hours with much higher and lower values than 2006 TOD factors, which are averaged over just six or nine TOD periods.

## Figure 15. 2006 TOD profiles SCE, PG&E and SDG&E




Source: E3.

To compare TODs to Avoided Costs, E3 used recently updated avoided cost values (pending approval before the CPUC) to calculate the "avoided cost TOU factors" used in Tables 5-7. CPUC avoided costs are calculated for each year up to 2030. Factors in the tables below were calculated using the 2006 and 2020 CPUC avoided costs and are compared with each IOU's TOD factors. The CPUC avoided costs profiles are based on historical California Power Exchange data, which contain all-in electricity prices. With specific allocations of capacity costs, the On-Peak TOD factors for SCE and PG&E are higher than the "avoided cost TOU factors."

### Table 5. SCE TOD Factors Compared with Factors Calculated Using CPUC Avoided Costs

| | | SCE | 2006 Avoided Costs | 2020 Avoided Costs |
|---|---|---|---|---|
| Summer | On-Peak | 3.280 | 1.854 | 1.776 |
| | Mid-Peak | 1.280 | 1.183 | 1.178 |
| | Off-Peak | 0.670 | 0.819 | 0.813 |
| Winter | On-Peak | 1.020 | 1.162 | 1.170 |
| | Mid-Peak | 0.820 | 0.963 | 0.972 |
| | Off-Peak | 0.650 | 0.628 | 0.639 |

Source: E3.

### Table 6. PG&E TOD Factors Compared with Factors Calculated Using CPUC Avoided Costs

| | | PG&E | 2006 Avoided Costs | 2020 Avoided Costs |
|---|---|---|---|---|
| Summer | On-Peak | 1.959 | 1.622 | 1.573 |
| | Mid-Peak | 0.903 | 1.067 | 1.045 |
| | Off-Peak | 0.626 | 0.679 | 0.694 |
| Winter | On-Peak | 1.471 | 1.287 | 1.294 |
| | Mid-Peak | 1.030 | 1.134 | 1.143 |
| | Off-Peak | 0.731 | 0.867 | 0.878 |
| Spring | On-Peak | 1.319 | 0.950 | 0.954 |
| | Mid-Peak | 0.843 | 0.861 | 0.865 |
| | Off-Peak | 0.584 | 0.560 | 0.573 |

Source: E3.

**Table 7. SDG&E TOD Factors Compared with Factors Calculated Using CPUC Avoided Costs**

| | | SDG&E | 2006 Avoided Costs | 2020 Avoided Costs |
|---|---|---|---|---|
| Summer | On-Peak | 1.629 | 1.618 | 1.563 |
| | Mid-Peak | 1.040 | 1.019 | 1.028 |
| | Off-Peak | 0.883 | 0.819 | 0.812 |
| Winter | On-Peak | 1.192 | 1.203 | 1.212 |
| | Mid-Peak | 1.079 | 1.070 | 1.079 |
| | Off-Peak | 0.793 | 0.799 | 0.808 |

Source: E3.

# CHAPTER 7: COMPARISON OF MPR FOR PV AND BASE LOAD RESOURCES

TOD factors will result in a higher MPR for resources, such as photovoltaic or solar thermal generation, that deliver more electricity during On-Peak periods. TOD factors do not affect the project-specific MPR calculated for a base load resource's generation distributed equally among all hours through the year. Table 8 shows the difference between the MPR calculated for a PV and a base load project. The CPUC calculated an MPR of $79.14/MWh for a contract with a 20-year term beginning in 2006. After applying TOD factors, a PV project in SCE's territory would have an MPR of $97.76/MWh. This represents an increase of 24 percent compared to a base load project MPR. A PV project delivering power to PG&E, with lower On-Peak TOD factors, would have an MPR of $88.71, an increase of 12 percent over a base load project. The MPR for a PV project contracting with SDG&E would be $87.02/MWh, ten percent above a base load project MPR.

Table 8 shows how these differences in MPR prices translate to potential project revenues. A 50 MW project operating at 23 percent capacity factor would yield approximately 100,000 MWh per year. As shown in Table 9, without receiving additional funding through SEP payments, a PV project of this size would earn a maximum of $9.78 million per year from SCE as compared to $8.70 million from SDG&E, a difference of just over $1.0 million or 12 percent (Table 9). Therefore, a project bid into the SDG&E solicitation would require just over $1.0 million in SEP payments to receive the same revenue stream.

### Table 8. MPR Calculations for a PV and Base Load Resource

| $/MWh | SCE | PG&E | SDG&E |
|---|---|---|---|
| PV | $ 97.76 | $ 88.71 | $ 87.02 |
| Base Load | $ 79.14 | $ 79.14 | $ 79.14 |
| Difference | 24% | 12% | 10% |

Source: E3.

### Table 9. Comparison of Annual Revenues for a PV and Base Load Resource

| $Million/Year | SCE | PG&E | SDG&E |
|---|---|---|---|
| PV | $9.78 | $8.89 | $8.70 |
| Base Load | $7.91 | $7.91 | $7.91 |

Note: 50 MW project operating at 23 percent capacity factor 100,000 MWh per year.
Source: E3.

# CHAPTER 8: CONCLUSIONS

This report compares TOD factors used by IOUs in California's RPS, and compares RPS TOD factors derived from the time-of-use valuation methodology used for QF payments and in CPUC calculation of avoided costs. Both PG&E and SCE include an explicit addition of capacity costs in calculating their TOD factors while SDG&E does not. SCE has the highest summer on-peak TOD factor in part due to its method for calculating capacity costs, and in part because it has the shortest on-peak period definition (6 hours). PG&E has the next highest summer on-peak TOD factor, while SDG&E's, with no explicit allocation of capacity costs, is the lowest. SCE's TOD factors tend to highly weight electricity prices for summer on- and mid-peak periods, while the PG&E and SDG&E factors give relatively high weight to prices for on-peak electricity throughout the year.

The RPS TOD factors for SCE and PG&E show a more pronounced summer peak when compared with similar factors calculated using QF avoided cost and CPUC avoided cost methodologies. SDG&E's RPS TOD factors, without an allocation of capacity costs, are similar to the factors calculated using the alternative methodologies.

## Endnotes

[1] The CPUC adopted the 2004 MPRs in Resolution E – 3942 on July 21, 2005.

[2] CPUC, *Administrative Law Judge's Ruling Requiring Submission of Proposals for Benchmarking Time of Delivery Profiles and Revising Schedule for Comments on Reporting Issues*, page 1, Rulemaking 04-04-026, December 27, 2005.

[3] See R.04-04-025. *An Order Instituting Rulemaking to Promote Consistency in Methodology and Input Assumptions in Commission Applications of Short-run and Long-run Avoided Costs, Including Pricing for Qualifying Facilities*. While both the RPS and QF programs use time-varying factors to compute payments to generators, there are major differences. For example, QF prices are computed on a monthly basis and indexed to prevailing natural gas prices, whereas the RPS prices are generally fixed when the contact is executed.

[4] See *Methodology and Forecast of the Long Term Avoided Costs for the Evaluation of California Energy Efficiency Programs, prepared for the California Public Utilities Commission by Energy and Environmental Economics and Rocky Mountain Institute*, October 25, 2004.

[5] PG&E's average SRAC June 2005-May 2006 was $0.0846/kWh. This average SRAC is somewhat higher than in recent years due to high gas costs in the Winter of 2005-06. However using a lower average SRAC price in this analysis does not materially affect the results.

[6] $68.27/kW for PG&E, $4.93/kW for SCE and $70.34/kW for SDG&E.

[7] SCE does not provide any further description of the option analysis performed.

[8] *Phase 2 of 2006 General Rate Case Marginal Cost and Sales Forecast Proposals*, A.05-05-023, at 22, 30 (filed Sept. 6, 2004).

[9] Proposal of Pacific Gas and Electric Company for Benchmarking Time of Delivery Profiles, R. 04-04-026, Filed January 17, 2006.

[10] PG&E defines the RECC as the levelized, constant dollar-denominated annual revenue requirement over the service life of the new resource necessary to recover its fixed costs, converted to nominal dollars in each year by adjusting for inflation. This is essentially equivalent in concept to the MPR but the MPR includes both fixed and variable cost components and is not converted to nominal dollars. And, in this case the MPR is based on the costs of a CCGT while PG&E utilizes the cost of a CT.

[11] The Black option model, first published in 1976, is a derivative of the widely the Black-Scholes option pricing model. It is generally used to determine the value of put and call options in commodities markets, particularly those such as electricity and natural gas with seasonal price variations. Because generation capacity can be viewed as a call option to produce electricity, option models are often used to quantify its value.

[12] See *Methodology and Forecast of the Long Term Avoided Costs for the Evaluation of California Energy Efficiency Programs*, prepared for the California Public Utilities Commission by Energy and Environmental Economics and Rocky Mountain Institute, October 25, 2004.

# APPENDIX A: RPS SOLICITATION TOD PERIOD DEFINITIONS

## SCE

**EXHIBIT J**

**TIME OF DELIVERY PERIODS AND
ENERGY PAYMENT ALLOCATION FACTORS**

| Time of Delivery Periods ("TOD Periods") | | | |
|---|---|---|---|
| *TOD Period* | *Summer Jun 1st – Sep 30th* | *Winter Oct 1st – May 31st* | *Applicable Days* |
| On-Peak | Noon – 6:00 p.m. | Not Applicable. | Weekdays except Holidays. |
| Mid-Peak | 8:00 a.m. – Noon | 8:00 a.m. - 9:00 p.m. | Weekdays except Holidays. |
| | 6:00 p.m. – 11:00 p.m. | | Weekdays except Holidays. |
| Off-Peak | 11:00 p.m. – 8:00 a.m. | 6:00 a.m. – 8:00 a.m. | Weekdays except Holidays. |
| | | 9:00 p.m. – Midnight | Weekdays except Holidays. |
| | Midnight – Midnight | 6:00 a.m. – Midnight | Weekends and Holidays |
| Super-Off-Peak | Not Applicable. | Midnight – 6:00 a.m. | Weekdays, Weekends and Holidays |

## PG&E

### TOD PERIOD

| Period | 1. Super-Peak | 2. Shoulder | 3. Night |
|---|---|---|---|
| | | | |
| A. June – September | A1 | A2 | A3 |
| B. Oct. – Dec., Jan. & Feb. | B1 | B2 | B3 |
| C. Mar. - May | C1 | C2 | C3 |

Period Definitions. The Periods are defined as follows:

A. June – September;

B. October, November, December, January and February; and

C. March - May.

TOD Period Definitions. The TOD Periods are defined as follows:

1. **Super-Peak** (5x8) = HE (Hours Ending) 13 – 20 (Pacific Prevailing Time (PPT)) Monday – Friday (*except* NERC Holidays).

2. **Shoulder** = HE 7 – 12, 21 and 22 PPT Monday – Friday (*except* NERC Holidays); and HE 7 – 22 PPT Saturday, Sunday and all NERC holidays.

3. **Night** (7x8) = HE 1 - 6, 23 and 24 PPT all days *(including* NERC Holidays).

As used herein, "NERC Holidays" include: New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day. Three of these days, Memorial Day, Labor Day, and Thanksgiving Day occur on the same day each year. Memorial Day is the last Monday in May; Labor Day is the first Monday in September; and Thanksgiving Day is the last Thursday in November. New Year's Day, Independence Day, and Christmas Day occur on the same dates each year, but in the event any of these holidays occur on a Sunday, the "NERC Holiday" is celebrated on the Monday immediately following that Sunday and if any of these holidays occur on a Saturday, the "NERC Holiday" remains on that Saturday.

## SDG&E

| | **SUMMER**<br>July 1 – October 31 | **WINTER**<br>November 1 – June 30 |
|---|---|---|
| On-Peak | Weekdays 11am – 7pm<br>1.6293 | Weekdays 1pm - 9pm<br>1.1916 |
| Semi-Peak | Weekdays 6am – 11am;<br>Weekdays 7pm - 10pm<br>1.0400 | Weekdays 6am – 1pm;<br>Weekdays 9pm – 10pm<br>1.0790 |
| Off-Peak* | All other hours<br>0.8833 | All other hours<br>0.7928 |
| | | *All hours during NERC holidays are off-peak. |

# APPENDIX B: QF AVOIDED COST TOU PERIOD DEFINITIONS

## SCE

**SEASON AND TIME PERIOD DEFINITIONS**

| Time Period | Summer<br>June 1 - September 30 | Winter<br>October 1 - May 31 | | # of Hours 5/1/06 - 5/31/06<br>Winter | <br>Summer |
|---|---|---|---|---|---|
| On-Peak | Noon - 6:00 p.m. | n/a | Weekdays except Holidays | 0 | 0 |
| Mid-Peak | 8:00 a.m. - Noon | 8:00 a.m. - 9:00 p.m. | Weekdays except Holidays | 286 | 0 |
| | 6:00 p.m. - 11:00 p.m. | | Weekdays except Holidays | 0 | 0 |
| Off-Peak | 11:00 p.m. - 8:00 a.m. | 6:00 a.m. - 8:00 a.m. | Weekdays except Holidays | 44 | 0 |
| | | 9:00 p.m. - Midnight | Weekdays except Holidays | 66 | 0 |
| | Midnight - Midnight | 6:00 a.m. - Midnight | Weekends & Holidays | 162 | 0 |
| Super-Off-Peak | n/a | Midnight - 6:00 a.m. | Weekdays, Weekends & Holidays | 186 | 0 |
| | | | Total | 744 | 0 |

2006 Holidays: New Year's Day (1/1), Presidents' Day (2/20), Memorial Day (5/29), Independence Day (7/4), Labor Day (9/4), Veterans Day (11/11), Thanksgiving Day (11/23) and Christmas Day (12/25). When any holiday listed above falls on Sunday, the following Monday will be recognized as an off-peak period. No change will be made for holidays falling on Saturday.

## PG&E

| Time Of Use Periods | Period A - Summer (May 1 - October 31) | Period B - Winter (November 1 - April 30) | Days Applicable |
|---|---|---|---|
| Peak | Noon - 6:00 PM | NA | Weekdays except holidays |
| Partial-Peak | 8:30 AM – Noon<br>6:00 PM - 9:30 PM | 8:30 AM - 9:30 PM | Weekdays except holidays<br>Weekdays except holidays |
| Off-Peak | 9:30 PM - 1:00 AM<br>5:00 AM - 8:30 AM<br>5:00 AM - 1:00 AM | 9:30 PM - 1:00 AM<br>5:00 AM - 8:30 AM<br>5:00 AM - 1:00 AM | Weekdays except holidays<br>Weekdays except holidays<br>Weekends and holidays |
| Super Off-Peak | 1:00 AM - 5:00 AM | 1:00 AM - 5:00 AM | All days |

**2006 Holidays:** New Year's Day (1/2), Presidents Day (2/20), Memorial Day (5/29), Independence Day (7/4), Labor Day (9/4), Veterans Day (11/11), Thanksgiving Day (11/23), and Christmas Day (12/25)

## SDG&E

| TIME PERIODS | SUMMER<br>MAY 1 - SEPTEMBER 30 | | WINTER<br>OCTOBER 1 - APRIL 30 | |
|---|---|---|---|---|
| ON-PEAK | 11:00 a.m. - 6:00 p.m. | Weekdays | 5:00 p.m. - 8:00 p.m. | Weekdays |
| SEMI-PEAK | 6:00 a.m. - 11:00 a.m. | Weekdays | 6:00 a.m. - 5:00 p.m. | Weekdays |
| | 6:00 p.m. - 10:00 p.m. | Weekdays | 8:00 p.m. - 10:00 p.m. | Weekdays |
| OFF-PEAK | 10:00p.m. - 12:00 mid. | Weekdays | 10:00 p.m. - 12:00 mid. | Weekdays |
| | 5:00 a.m. - 6:00 a.m. | Weekdays | 5:00 a.m. - 6:00 a.m. | Weekdays |
| | 5:00 a.m. - 12:00 mid. | Weekends | 5:00 a.m. - 12:00 mid. | Weekends |
| | 5:00 a.m. - 12:00 mid. | Holidays | 5:00 a.m. - 12:00 mid. | Holidays |
| SUPER OFF-PEAK | 12:00 mid. - 5:00 a.m. | All Days | 12:00 mid. - 5:00 a.m. | All Days |

Time periods are currently defined in accordance with the above table. All time periods listed are clock time. The time period definitions may be revised to comply with CPUC orders regarding billing hours. The Holidays specified are: New Year's Day, President's Day, Memorial Day, Independence Day, Labor Day, Veteran's Day, Thanksgiving Day, and Christmas Day as designated by California's Law.