Decision PROPOSED DECISION OF ALJ MCKINNEY (Mailed 11/1/2016)

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Assess Peak Electricity Usage Patterns and Consider Appropriate Time Periods for Future Time-of-Use Rates and Energy Resource Contract Payments.	Rulemaking 15-12-012 (Filed December 17, 2015)

DECISION ADOPTING POLICY GUIDELINES TO ASSESS TIME PERIODS FOR FUTURE TIME-OF-USE RATES AND ENERGY RESOURCE CONTRACT PAYMENTS

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Summary

This decision adopts a framework, including guiding principles, for designing, implementing, and modifying the time intervals reflected in time-of-use (TOU) rates.[1] We do not adopt specific TOU time intervals or rate design elements herein, but do adopt high-level principles to apply in rate proceedings where TOU time periods and TOU rate design elements will be adopted for each of the three investor-owned electric utilities subject to this rulemaking.[2] In this decision, we identify relevant principles and related data requirements at a broad level to assess TOU time periods during which customers, generators, and providers of energy services should be encouraged to modify electric usage and supply. These base TOU periods should then be used as the basis for designing TOU rates.

In addition, this decision orders specific actions to be taken in upcoming rate cases in order to implement the guiding principles and allows certain existing solar customers to retain their current TOU periods for five years (residential) or ten years (non-residential).

This proceeding is closed.

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[1] Time-of-Use pricing utilizes a per-unit-of consumption rate structure that varies depending on the time of day during which energy is consumed, with higher per-unit rates applied during blocks of hours in which electricity demand or costs tend to be higher.

[2] The investor-owned electric utilities subject to this decision are Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and the San Diego Gas and Electric Company (SDG&E).

1. Background

1.1. Time-of-Use (TOU) Periods and Rates

Because the cost of delivered energy differs by time of day, TOU rates were developed to reflect time-differentiated costs by providing time-differentiated price signals to customers. TOU rates have been mandatory for certain customer classes for several decades. In 2012, TOU rates became mandatory for non-residential customers. In accordance with Decision (D.) 15-07-001, most residential customers will be automatically shifted to TOU rates in the next few years. Residential customers may also opt-in to TOU rates.

This decision adopts a framework, including guiding principles, for designing, implementing, and modifying the time intervals reflected in TOU rates.[3] We do not adopt specific TOU time intervals or rate design elements herein, but do adopt high-level principles to apply in rate proceedings where TOU time periods and TOU rate design elements will be adopted for each investor-owned electric utility (IOU) subject to this proceeding.[4] In this decision, we identify relevant principles and related data requirements at a broad level to assess TOU time periods during which customers, generators, and providers of energy services should be encouraged to modify electric usage and supply. These "base" TOU periods (Base TOU periods) should then be used as the basis for designing TOU rates.

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[3] TOU pricing utilizes a per-unit-of consumption rate structure that varies depending on the time of day during which energy is consumed, with higher per-unit rates applied during blocks of hours in which electricity demand or costs tend to be higher.

[4] The IOUs subject to this decision are Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and the San Diego Gas and Electric Company (SDG&E).

In addition to Base TOU periods, TOU rate designs must consider customer understanding and ability to respond to TOU price signals. Customers' bills on TOU tariffs are determined both by how much electricity the customer uses and the times of day during which the energy is used. The retail price for energy consumed during each time period is established in advance. By varying retail price signals in relation to utility costs, TOU rates better reflect cost causation and motivate customers to shift their usage to periods that promote more efficient use of the electrical system. This shift should assist in reaching state energy goals by minimizing costs, encouraging energy conservation at appropriate times, and increasing electric supply at times that best serve the needs of the electric grid.

TOU rates are currently considered to be a form of demand response. TOU rates are load-shaping, meaning that these static TOU rates are intended to flatten the load curve. Unlike other forms of demand response, it is not dispatchable. This type of load flattening does not provide, and is not intended to provide, the same level of immediate response as other demand response tools. The benefit of TOU rates, however, is that a large number of customers making small adjustments in time of energy use will have a significant impact on the load curve, which in turn benefit the grid and reduce system costs overall.

Historically, TOU rate intervals were designed to reflect time variations in the cost to serve loads, with higher-priced periods during summer week-day afternoons when the loads were the highest. Setting higher TOU rates during peak periods signals that electricity is more valuable at certain times of day and provides customers an incentive to reduce energy use or to generate on-site energy using renewable or other technologies at those times.[5] Because residential rates have historically not been time-differentiated, and because TOU rates have historically ranged from early afternoon to early evening hours, rooftop solar systems have typically been deployed by installing south facing panels to generate the maximum amount of energy during the morning and midday, rather than installing west-facing panels or storage to maximize energy available during the afternoon and early evening. Going forward, in recognition of shifting resource availability patterns, as noted below, TOU rates should encourage customers to configure their systems to generate energy at times that better align with the later-shifted peak periods, *e.g.*, via installation of co-located energy storage.[6]

An updating of TOU periods is warranted. The deployment of grid-connected and behind-the-meter solar has increased the availability of energy during the afternoon and decreased the load on the grid. As a result, the peak periods, in terms of grid needs and cost, have shifted to later in the day. In addition, on spring days with low demand and high solar generation, there is a risk that there will be an excess of generation available, leading to curtailment of renewables and other resources.

As a result, all three large investor-owned utilities (IOUs) have begun to propose changes to their TOU rates to reflect changes in the times of day when

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[5] The effectiveness of this incentive will, of course, depend on customer ability to understand and respond to the price signal.

[6] Similarly, west-facing solar installations, rather than the more common south facing systems, may better align with later-shifted peak periods. However, a January 2016 study entitled Impacts of Distributed Energy Generation on the State's Distribution and Transmission Grid performed at the direction of Energy Division found that there were tradeoffs between west-facing solar vs south facing and that west facing solar is not necessarily superior in terms of benefits to the grid. (See Section 3.5 of this study: http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=12026).

electricity is the most expensive. Uncertainty currently exists, however, as to the minimum data and analysis to be provided in proposing a TOU period change by application or through settlement. Because TOU rate designs are often the result of settlements, adopted rates may not comport with optimum TOU periods from a grid reliability perspective.

The California Independent System Operator (CAISO) focuses on the grid reliability perspective in its analysis of TOU time periods but does not address customer acceptance of TOU changes.[7] The CAISO has been particularly concerned with times when the available renewable generation is high but load is low. This situation has forced CAISO to curtail a small percentage of renewable generation.[8] CAISO argues that in addition to peak periods, matinee rates (aka reverse demand response) with super-off peak periods during spring days may be necessary.

To avoid a situation where a TOU rate period change cannot be approved simply because of insufficient supporting data, a shared understanding is needed as to the data required to justify TOU period changes. This proceeding was thus opened to foster such shared understanding regarding the appropriate guidelines to apply in proposing changes in the design of TOU time periods.

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[7] Because CAISO is concerned with grid reliability, not with setting rates, the CAISO's analysis also does not include any analysis of cost allocation.

[8] A variety of conditions can lead to curtailment of renewables. For more information on curtailment of renewables see CAISO 2015 Annual Report (May 2016) pages 94-97 available at: http://www.caiso.com/Pages/documentsbygroup.aspx?GroupID=5BC068F2-816D-4C4C-AAEB-75B077F029BA and Agenda and Presentation – Market Performance and Planning Forum (Symposium September 20, 2016) Slide 24 available at: http://www.caiso.com/Pages/documentsbygroup.aspx?GroupID=4A06CF38-74BC-4576-82A0-0352E5721A3D.

As discussed below, we adopt the following general principles with respect to development and implementation of changes in Base TOU periods:

1. Base TOU periods and related rate designs should be established independently for each utility either in a general rate case (GRC) or a rate design window (RDW). Geographically-differentiated TOU time periods within an IOU's service territory are not required or encouraged at this time. Any proposals for geographically-differentiated rates must demonstrate that the proposed rates do not conflict with universal and non-discriminatory service requirements.
2. Base TOU periods should be based on utility-specific marginal costs, rather than on a statewide load assessment. This marginal cost analysis should use marginal generation cost, consisting of marginal energy costs and marginal generation capacity costs. Going forward, the IOUs should include information on marginal distribution costs that contribute to peak load costs and time of use information filed or adopted in FERC transmission rate proceedings. Use of marginal distribution and transmission cost information in setting future Base TOU periods will be addressed in individual IOU rate proceedings.
3. As a secondary check on the marginal cost analysis, the IOUs should provide hourly load and net load data and explain any significant differences between estimated high and low marginal cost hours and the net load shapes (including adjusted net load data for PG&E). As part of its TOU period analysis, each IOU should submit the latest data and assumptions, including those vetted in the Long Term Procurement Planning (LTPP) and/or Integrated Resource Planning (IRP) or successor proceeding.
4. Base TOU periods should be developed using forward-looking data, with the forecast year set at least three years after the year the Base TOU period will go into effect.

5. Base TOU periods should continue for a minimum of five years (unless material changes in relevant assumptions indicate the need for more frequent Base TOU period revisions) and each IOU should propose new Base TOU periods, if warranted, at least every two general rate case cycles.
6. Each IOU, in a Tier 3 Advice Letter, should propose a dead band tolerance range for determining when a change would trigger TOU period revisions more frequently than five year intervals. To evaluate whether a dead band tolerance range has been exceeded and to ensure that the Commission and the public are aware of the likelihood of future Base TOU period changes, Base TOU period analysis should be provided in each general rate case, even if the IOU does not propose a change in Base TOU periods. If such analysis shows that the dead band tolerance range has been exceeded, the IOU should propose revisions to Base TOU periods.
7. Each IOU should take steps to minimize the impact of TOU peak period changes on customers who have invested in on-site renewable generation or technology to conserve energy during peak periods. Regularly scheduled updates to TOU periods will provide predictability for these customers. Additional steps to increase certainty around TOU periods could include vintaging, legacy TOU periods, or fixed indifference payments, as well as other rate structures that provide predetermined limits on TOU period changes. Such steps must also include making information on potential shifts in peak periods available to the public.
8. A menu of TOU rate options should be developed in utility-specific rate design proceedings and should provide rate choices addressing different customer profiles and needs. IOUs are encouraged to use the Base TOU periods to develop at least one optional TOU rate design with a more complex combination of seasons and time periods and may incorporate more dynamic pricing

features and enabling technology as appropriate to address grid needs.

9. TOU periods used in rate designs should be designed around the Base TOU periods and should reflect up to date marginal costs, but may be modified to take into account customer acceptance, preferences, understanding, ability to respond and similar factors. These considerations include:
   - The extent to which customers understand TOU rates generally.
   - The time and education required for customers to transition to a new TOU rate period.
   - The ability of customers to respond at a specific time of day or over a given period of time.
   - Customers' need for predictable TOU periods, including the schedule of possible TOU rate period changes, when they make investment decisions regarding energy efficiency, storage, photovoltaics, electric vehicles and other distributed energy resources or consider major operational changes to shift usage outside of peak periods.
   - The appropriate treatment of different customer classes, as necessary, in light of the fact that customer needs and sophistication may vary by customer class.

1.2 Procedural Background

This proceeding was initiated by Order Instituting Rulemaking (OIR or R.) 15-12-012, filed December 17, 2015, to consider a framework for designing, implementing, and modifying the time periods underlying time-of-use (TOU) rates. As directed by the OIR, on January 22, 2016, the California Independent System Operator (CAISO) filed a report (CAISO TOU Report) explaining the analysis, assumptions, and analytical methods underlying its proposal for modifying TOU periods. The CAISO TOU Report originated out of a joint project between CAISO, California Energy Commission (CEC) and the Commission's Energy Division, based on 2014 data.

A workshop to discuss the CAISO TOU Report and other aspects of TOU period analysis was held on February 26, 2016 and included presentations from CAISO, Center for Accessible Technology (CforAT) and Energy Division. A Prehearing Conference (PHC) was held on the same date. By ruling on March 17, 2016, the IOUs were directed to develop an hourly marginal generation cost or MGC analysis, based on data from their most recently available rate proceedings, and to consult with Energy Division staff, the CAISO, and other interested parties. The CAISO was also invited to update its TOU analysis, and possibly develop alternative TOU periods based on 2016 LTTP load forecasts.

The March 17, 2016 ruling also solicited comments to identify TOU rate design options, stating that the Commission needed to know what rate designs are likely to utilize TOU time periods. Pursuant to the March 17, 2016 ruling, the IOUs and other parties filed comments and data on April 29, 2016. Following a second PHC on April 12, 2016, the assigned Commissioner issued a ruling adopting a scoping memo on May 3, 2016 (Scoping Memo). The Scoping Memo limited the proceeding to the issue of how TOU periods should be set and used in rate designs, as well as time-of-delivery (Time of Delivery or TOD) periods in certain resource procurement contracts. The Scoping Memo noted that although updated CAISO data would be useful for comparing different measurements of load, the data is difficult and time consuming to produce, and not essential to developing a TOU methodology.

A final workshop was held on June 8, 2016.

The Scoping Memo posed a series of questions focused on: (a) development of a methodology and data sources for identifying target TOU periods, and (b) other related aspects, including customer acceptance of TOU rate design. Responsive comments were filed on June 27, 2016, with replies on July 19, 2016.

Parties filing comments included the IOUs, (*i.e.*, Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and the San Diego Gas and Electric Company (SDG&E)), the Solar Energy Industries Association (SEIA), the California Solar Energy Industries Association (CalSEIA), the California Farm Bureau (CFB), the Environmental Defense Fund (EDF), e-Meter, a Siemens Business (e-Meter); GreenPower Institute (GPI), the Office of Ratepayer Advocates (ORA), The Utility Reform Network (TURN), the Utility Consumers Action Network (UCAN), the California Large Energy Consumers Association (CLECA), and Marin Clean Energy (MCE).

On August 30, 2016, the ALJ issued an e-mail ruling inviting the CAISO to serve and file additional comments regarding: (1) what information the CAISO should provide in future rate proceedings and (2) instructions to enable other entities to use the CAISO methodology for its TOU Report in this proceeding. The CAISO filed comments in response to this ALJ ruling on September 12, 2016.

We have taken into account the above-referenced comments and find them sufficient for purposes of this decision adopting the policies and guidelines as discussed below. Since this decision resolves all outstanding issues in this rulemaking, with the adoption of these guidelines, we close this proceeding.

1.3. Scope of Issues

Today's decision adopts guidelines for considering when and how to adjust TOU periods for use by the IOUs when developing rate designs.

We consider input from the CAISO, the IOUs, and other parties as the basis to determine when load and supply trends indicate that changes to Base TOU periods are necessary. By Base TOU periods, we refer to the periods during which it would be helpful to the California power grid for customers to modify energy use levels. These Base TOU periods serve as a starting point for designing TOU rates.

Pursuant to the Scoping Memo, the issues for resolution in this decision are:

1. In the near-term, what are the minimum requirements for data, analysis and information to support a request to change TOU time periods?
2. What methodology should be used to incorporate minimum data requirements into analysis of proposed changes in TOU time periods?
3. What other steps, if any, should be taken when evaluating proposed TOU rate changes to ensure rates appropriately address grid needs, cost causation, customer acceptance and other legal requirements of rate design?

2. Adopted Guidelines for Setting TOU Intervals

This section examines the arguments and analysis that support the following guiding principles:

1. Base TOU periods and related rate designs should be established independently for each utility either in a general rate case (GRC) or a rate design window (RDW). Geographically-differentiated TOU time periods within an IOU's service territory are not required or encouraged at this time. Any proposals for geographically-differentiated rates must demonstrate that the proposed rates do not conflict with universal and non-discriminatory service requirements.
2. Base TOU periods should be based on utility-specific marginal costs, rather than on a statewide load assessment. This marginal cost analysis should use marginal generation cost, consisting of marginal energy costs and marginal generation capacity costs. Going forward, the IOUs should include information on marginal distribution costs that contribute to peak load costs and time of use information filed or adopted in FERC transmission rate proceedings. Use of marginal distribution and transmission cost

information in setting future Base TOU periods will be addressed in individual IOU rate proceedings.

3. As a secondary check on the marginal cost analysis, the IOUs should provide hourly load and net load data and explain any significant differences between estimated high and low marginal cost hours and the net load shapes (including adjusted net load data for PG&E). As part of its TOU period analysis, each IOU should submit the latest data and assumptions, including those vetted in the Long Term Procurement Planning (LTPP) and/or Integrated Resource Planning (IRP) or successor proceeding.
4. Base TOU periods should be developed using forward-looking data, with the forecast year set at least three years after the year the Base TOU period will go into effect.
5. Base TOU periods should continue for a minimum of five years (unless material changes in relevant assumptions indicate the need for more frequent Base TOU period revisions) and each IOU should propose new Base TOU periods, if warranted, at least every two general rate case cycles.
6. Each IOU, in a Tier 3 Advice Letter, should propose a dead band tolerance range for determining when a change would trigger TOU period revisions more frequently than five year intervals. To evaluate whether a dead band tolerance range has been exceeded and to ensure that the Commission and the public are aware of the likelihood of future Base TOU period changes, Base TOU period analysis should be provided in each general rate case, even if the IOU does not propose a change in Base TOU periods. If such analysis shows that the dead band tolerance range has been exceeded, the IOU should propose revisions to Base TOU periods.

2.1. Data Requirements Underlying Base TOU Periods

Energy Division staff, with input from parties identified the types of data that could serve as the basis for determining Base TOU periods, as set forth in the May 3, 2016 Scoping Memo.

First, the Scoping Memo discussed different types of load analysis that could serve as a basis for setting TOU periods.

	Types of Load (based on specific data)
L1	Hourly Consumption
L2	Hourly metered load (net of behind-the-meter (BTM) generation)
L3	Hourly load, net of customer- and distribution-connected distributed energy resources (DERs), measured at the substations (transmission interface)
L4	Hourly "net load" as defined by the CAISO: "forecasted load and subtracting the forecast electricity production from variable wind and solar resources." Throughout this decision the term Net Load, in initial capital letters, denotes this definition of Net Load.
L5	Adjusted net load (as proposed by PG&E): Net Load, net of nuclear and certain hydro. Throughout this decision the term Adjusted Net Load, in initial capital letters, denotes this definition of load.

The IOUs and other parties such as CLECA presented information at the workshops on how IOUs currently use marginal cost analysis to identify high- and low-cost hours which are then grouped into TOU periods. The utilities determine the marginal generation cost of each hour by analyzing marginal energy cost and marginal generation capacity cost. Marginal generation capacity cost represents the marginal cost for the next unit of generation capacity. Marginal generation capacity cost represents a much larger portion of marginal generation costs during summer peak hours compared to marginal energy costs. Each utility uses a slightly different methodology for determining which hours of the year to allocate the greatest share of marginal generation costs. This IOU-specific analysis is done through IOU-specific rate cases.

Through the workshops and early rounds of comments, it became apparent that the most critical determination to be made in this proceeding is whether load or marginal cost, or a combination thereof, should be the basis for identifying high cost and low costs hours that will serve as the starting point for determining Base TOU periods and TOU rate design periods. This decision finds that both the marginal cost analysis and the CAISO Net Load analysis should be part of the TOU period analysis, but that marginal cost analysis should be the primary methodology.

The CAISO's and IOUs' analyses show three phenomena affecting the setting of TOU periods: peak shift, spring overgeneration, and steep ramp. Due to these changes in load and supply, Base TOU periods and related rate designs should be re-examined. All three IOUs have proposed new TOU periods that differ significantly from historical TOU periods in their individual rate proceedings,[9] but the transition is not yet complete. Currently there are still customers with rates that promote use during peak periods and there are no rates in place to promote increased energy usage during minimum load situations in the spring. This decision does not, however, order specific changes or specify new TOU periods.

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[9] *See*, A.15-04-012 (SDG&E), A.16-06-013 (PG&E) and A.16-09-003 (SCE).

2.2. Parties' Positions

2.2.1. CAISO

As requested by the OIR, on January 22, 2016, the CAISO filed a report that shows historical and forecasted Net Loads for the three IOUs, and develops a candidate set of TOU periods for 2021. The CAISO methodology relies on Net Load as a proxy of marginal generation costs, without consideration of the impacts of hydroelectric and nuclear generation on marginal energy costs. The proposed TOU periods included 4 different pricing periods (super-peak, peak, super off-peak, and off-peak) that differed from weekday to weekend for each of three seasons.

According to the CAISO, increases in intermittent, non-dispatchable energy from renewable sources, combined with baseload generation, are expected to result in plentiful electricity during early afternoon hours in which demand has traditionally been higher and more expensive to serve. This increase, particularly from solar generation, tends to create a potential oversupply at some times of day during certain seasons. CAISO estimates these renewable resources also produce less electricity during evening hours when electricity demand may remain high. Based on this analysis, an increasing mismatch is developing between current TOU rate design, which encourages reduced demand during afternoons in favor of evening usage while renewable generation increases during the afternoon hours. CAISO predicts that Net Load (and with it, electricity cost) will increase rapidly in evenings as demand remains high but solar power is not available after sundown.

As a result of these trends, CAISO published proposed changes to existing TOU time periods to shift peak periods to later in the day to better match peak Net Loads. The CAISO developed its proposal through a six step process, as follows:

1. Choose a load data source;

2. Establish hourly load data – calculate hourly load for the study year of interest;
3. Source wind and solar installed capacity data;
4. Source and apply wind and solar generation profiles;
5. Perform net load calculation; and
6 Develop TOU rate periods, validating against CAISO operational needs.

As noted in CAISO's comments filed September 12, 2016, the CAISO TOU Report can be replicated in the future by other parties using publicly available and vetted data. The resulting analysis can be compared against wholesale market prices and marginal cost data in assessing changes in TOU time periods to offer incentives for customers to shift their energy usage to more appropriate periods.

2.2.2. PG&E

PG&E believes that TOU periods need to be cost-based in accordance with important foundational rate design policy principles set out by the Commission. Net Load, while a proxy for marginal generation cost, may not be the best predictor of it. PG&E proposes that TOU time period definitions be based on hourly patterns of both marginal (*i.e.,* variable) generation capacity costs and marginal energy costs combined.

PG&E and SCE both believe that the IOUs should continue to rely on data and assumptions being vetted in existing proceedings, such as the LTPP and IRP, to support their individual TOU period proposals. ORA agrees, arguing that these data and assumptions be used as the base case for each IOU's marginal cost and TOU proposals in their respective GRC phase 2 applications.

PG&E believes that marginal generation costs forecast at an hourly level for a target year should be the primary input to determine Base TOU periods. The forecast is developed using Adjusted Net Load[10] as the driver of effective market heat rate and marginal energy costs, and using an hourly allocation of marginal generation capacity costs to the top hours of Adjusted Net Load.

PG&E bases the hourly allocation of marginal generation capacity costs on peak capacity allocation factors (PCAF).

PG&E believes that marginal generation capacity costs should be allocated to TOU time periods: (a) either on the basis of the top 100-to-250 hours, or a similar approach like PG&E's PCAF methodology where the number of top hours is not specifically prescribed in advance; or (b) using a Loss of Load Expectation (LOLE) model. Either method yields similar TOU periods.

PG&E agrees with many conclusions in the CAISO TOU Report, including the general pattern (though not necessarily the specific hours) of peak and off-peak periods shown therein. PG&E finds the use of Net Load alone (with no explicit consideration of cost, or of other cost drivers such as hydro and nuclear generation or ramp rate) unreasonable in that it does not adhere to the principle of cost-based rates.

PG&E recommends continuing to utilize two seasons, summer and winter, for setting TOU rates and time periods. PG&E's summer and winter seasons are determined using hourly marginal generation costs. The distribution of the highest 100 and 250 marginal generation cost hours across months is used to determine the summer months that best capture most of the highest marginal generation cost hours. Based on this approach, a four-month summer season was adopted in PG&E's 2015 RDW.

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[10] PG&E subtracts nuclear and certain hydro to calculate Adjusted Net Load.

Season-specific TOU hours are set based on how marginal generation cost hours are distributed across the day. On this basis, PG&E designs TOU period scenarios to perform detailed analysis. PG&E uses: (1) Percent Highest Cost Hours Captured, and (2) False Positive Rate, to measure how efficiently a TOU period scenario captures the highest cost hours while avoiding the non-highest cost hours.

PG&E observes that one way to provide a super-off-peak credit to encourage higher usage during potentially negative price hours would be to define an additional third season, such as spring. PG&E, however, prefers to provide the super-off-peak credit as an overlay to a TOU rate designed with just summer and winter periods. A super-off peak or matinee pricing overlay could be implemented as a "subtractor" applied during certain hours. This approach retains flexibility regarding the months to which the super-off-peak credits should apply.

PG&E prefers to determine the super off-peak period based on the distribution of the hours with negative or very low marginal generation cost.

2.2.3. SCE

SCE believes that TOU periods and seasons should ultimately be set by each IOU based on its specific hourly marginal costs, and not simply net load. SCE recommends that marginal generation capacity costs, together with marginal generation energy costs and peak load variable distribution marginal costs, serve as the basis for TOU periods.[11] SCE asserts that because marginal generation cost analysis is intended to forecast high-cost hours, these hours should be similar to

[11] SCE Opening Comments at 5.

hours identified through a forecast net load analysis. In fact, SCE's determination of high cost hours by marginal cost includes CAISO forecast data as part of its model.

Currently, SCE uses marginal generation cost to allocate costs to each hour over the year. Marginal generation cost includes two components: marginal energy cost and marginal generation capacity costs. SCE recommends that because some distribution costs are also time-variable, marginal distribution costs should also be part of the analysis. Specifically, as a first step, SCE proposes to separate distribution costs by function into costs that support day-to-day demand (not variable) and costs to meet capacity needs at times of peak demand. SCE included marginal distribution cost analysis in its September 2016 rate design window proposing new TOU periods.

Importantly, SCE, like other parties in this proceeding, asserts that there should not be different TOU periods for distribution and generation charges. Rather, marginal distribution cost should be used as another component of the analysis that sets the TOU periods.

Net load is a factor in the analysis of marginal cost by SCE. As described in SCE's April 29 Response, marginal energy cost is a forecast of wholesale power prices at the SP-15 zone for a given test year. Marginal generation capacity cost is calculated by determining the value of new generation (typically, a combustion turbine) and allocating that cost to each hour of the year based on a blend of peak (LOLE) and flex (Ramp) capacity need on the system. Flex capacity is new to the calculation.

SCE used hourly load data measured at the substation and circuit to model the Peak Load Risk Factor (PLRF) allocation of distribution marginal costs.

SCE derives hourly marginal costs using data for each cost driver. These hourly costs are sorted from largest to smallest, graphed on a "cost curve," and based on pattern changes and turning points in the cost curve. SCE then studies the hours in each segment to identify patterns. Frequent combinations of months and hours in the highest cost segment are included in the on-peak period.

SCE believes that all data and analysis should be forward looking to inform TOU periods that aim to be stable for six or more years.

SCE intends to continue using the CAISO data and operating assumptions provided in the most recent LTPP and/or relevant successor proceedings such as the IRP proceeding. Drawing upon data already vetted in other proceedings is an effective and efficient way to ensure that grid forecasts are captured in subsequent IOU proposals.

SCE currently applies a two-season definition (i.e., Summer defined as June through September, inclusive, and Winter defined as all other months). The current definition aggregates months of like-price shapes. SCE expresses caution about a switch to a three-season TOU structure only to have to return to a two-season structure as system conditions evolve and renewable supply continues to increase. SCE made a TOU period proposal in its September 2016 rate design window filing, in which billing/operational impacts and customer understandability issues were considered as factors.

Like most parties, SCE argues that TOU periods and rates should be set in individual utility rate cases. TOU periods do not need to be the same for all three utility territories. However, SCE argues that geographically-specific TOU periods within a specific IOU territory would likely lead to customer confusion and be difficult and expensive to implement.

SCE does not believe that transmission costs should play a role in setting TOU periods. SCE asserts that most transmission system investments are not directly related to peak load growth, meaning that these costs are not variable by time of day.

2.2.4. SDG&E

SDG&E believes that the type of data the CAISO and the IOUs compiled for the most recent historical year and a forecast year are sufficient to identify Base TOU periods. The use of Net Load provides a simple metric to assess TOU periods and supplements utility-specific information on costs. Net Load is the most relevant data for setting Base TOU periods and is reflective of statewide energy and capacity costs (which should include ramping costs). As the CAISO showed in the May 5, 2016 workshop, Net Load provides a good correlation with day-ahead energy prices and highlights the system ramping needs that result in the need for flexible capacity.

SDG&E also favors use of utility-specific data for setting Base TOU periods as determined in utility-specific rate proceedings. To the extent loads (or net loads) differ from statewide results, it may lead to adjustments to TOU periods suggested by statewide Net Load analysis. To the extent there may be a need for local capacity, study of LOLE analyses of the local area or transmission access charge area would be necessary to see if the peak hours differ from the state as a whole. SDG&E believes that marginal energy costs should be analyzed to see if transmission constraints lead to slight changes in the times of high and low demand compared to TOU periods based on statewide net load analysis.

SDG&E believes that marginal generation costs provide key information that can assist in determining TOU periods. Marginal generation capacity costs have been allocated by a number of methods, all of which produce similar results.

SDG&E believes these approaches should be addressed in the IOU's rate design proceedings, and not in this proceeding.

SDG&E believes it is inappropriate and premature to include transmission and distribution marginal costs in the methodology to define TOU periods. SDG&E recognizes that some percentage of transmission costs may be driven by the time of system energy usage and demand, but notes that a study would be necessary to determine what portion of transmission costs are time-dependent.

While a percentage of distribution costs are related to increased customer demand at times of circuit peak, due to the more localized nature of the drivers of circuit peak, SDG&E contends that circuit peaks do not necessarily occur at times of system peak. SDG&E argues that distribution system peak hours by individual circuit still need to be analyzed to determine: (1) if they are sufficiently aligned with on-peak TOU periods by month and hour to be considered in defining the on-peak period; and (2) whether super off-peak periods are sufficiently aligned to not conflict with projected distribution circuit peaks

SDG&E believes the CAISO analysis with modifications is a reasonable starting point for determination of TOU periods. SDG&E disagrees, however, with the specific TOU periods proposed by the CAISO. SDG&E believes the super-peak period should consider not just the amount of ramp, but the level of net load and its relationship to the needs for peak capacity that would be part of marginal generation capacity costs.

SDG&E argues that the number of seasons defined for the purpose of setting TOU rates, and which months should be included in each season, should be utility-specific based on marginal generation costs differences. To ensure that TOU periods are correctly defined, SDG&E supports the Rate Design Principles from the Residential Rates Design OIR, consistent with D.15-07-001: cost of service, affordable electricity, conservation and customer acceptance.[12] SDG&E believes the question of whether TOU periods warrant change should begin with whether such a change is justified by changes in cost of service. The Rate Design Principles provide guidance for other considerations to determine if a proposed change should be implemented.

SDG&E supports including ramping in the calculation of marginal costs in the future.[13]

2.2.5. SEIA

SEIA recommends that the Commission select TOU periods based on examination of all of the utility's marginal costs that vary with customers' usage and demand for electricity, including marginal generation, transmission, and distribution costs, excluding only marginal customer costs. SEIA believes that TOU periods can and should be set to incorporate the large majority of distribution circuit and substation peaks. SEIA also believes that the choice of TOU periods should consider the time profiles of the system loads that drive CAISO transmission costs, and that ignoring CAISO level marginal costs would exclude a significant share of costs from the analysis of appropriate TOU periods.

SEIA believes that while CAISO's views on conditions on its system are important and should be factors in the choice of TOU periods, they should not be the only factors considered. A simpler structure for TOU periods is important for customer acceptance and understandability and can produce most if not all of the system benefits that the CAISO identifies.

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[12] Section 3.1 of this decision contains the complete list of the Rate Design Principles developed for residential rates.

[13] SDG&E Opening Comments at 3.

SEIA supports the use of a longer, six-month summer season (May through October). PG&E and SDG&E already use a six-month summer; SCE has a four-month summer. SEIA argues that there is no significant difference in the time profile of SCE's marginal costs between a six-month summer (May-October) and a four-month summer (June- September). SEIA argues that, due to the anticipated impacts of climate change, summers should be defined as six months (*e.g.* May-October), not four months (*e.g.* June-September).

2.2.6. Other Parties

CalSEIA believes that TOU rate periods should differ by customer class. Because load patterns and local circuit peaks tend to be different for residential and non-residential customers, CalSEIA believes that peak periods should be different for those classes.

GPI believes that there is no purely analytical method that can be used to determine appropriate TOU time periods, but that the determination of appropriate TOU periods is as much an art as it is a science. The art is to balance considerations of simplicity and practicality with considerations of accuracy.

GPI interprets the CAISO's TOU proposal as reflecting three seasons, spring (April & May), summer (July & August), and the rest (eight non-contiguous months). GPI believes that this basic structure should work for all of the IOUs, although some of them might want to make minor adjustments, such as including some or all of September in the summer season. GPI believes that the biggest challenge to consumers in dealing with TOU rates will be the need to adjust their equipment settings when there is a change of season, and that therefore, minimizing the number of seasonal changes during the year should be a major goal of TOU design.

CLECA believes the proposals for two seasons with dynamic pricing for periods of very low or negative prices and for periods of very high prices fit the cost data and provide price signals for extreme events without complicating the overall rate structure. CLECA finds that the presumption of GPI and CalSEIA that much customer end-use load will be able to automatically respond to TOU rate differentials and seasonal changes (with perhaps seasonal adjustments to the automation in the case of GPI) is based on assumptions that do not reflect average customer behavior or technology.

ORA supports use of IOU marginal generation costs as the basis to set TOU periods. While hourly load data, Net Load data and usage data may be useful for a TOU analysis of TOU periods, ORA questions how such data could be disaggregated in a manner that is helpful in developing TOU periods. ORA argues that a marginal cost analysis assesses all supply resources against demand and pinpoints hours with high costs. ORA notes the complexity involved in analyzing peak load impacts of distribution circuits which occur at a local level, and thus believes it may be preferable to give primary importance to system-wide impacts (*i.e.*, IOU net load curves and hourly costs) rather than distribution circuit-level impacts.

ORA opposes including bill impact data that entails detailed analysis of mock-up rates as a requirement in this rulemaking. ORA also opposes including specific customer engagement data from the scope of this rulemaking, but argues that it should be incorporated in the rate design phase for each IOU's GRC phase 2.

TURN generally supports gathering the data outlined in the Scoping Memo, but believes some of the specified data may be more difficult to obtain for designing TOU rate periods in future rate proceedings. In particular, TURN points to data regarding hourly wholesale supply data, disaggregated by location and type of generation, hourly wholesale supply data, disaggregated by location and type of generation, and wholesale price data, by location and time, and estimates for the future.

TURN believes that for the sake of customer understanding and acceptance, the number of TOU periods should be limited and such periods should be as intuitive as possible.

2.3 Discussion

2.3.1 Use of IOU Specific Marginal Costs

We adopt a marginal cost-based method, rather than a load-based method, for purposes of the data requirements for determining TOU periods. Many parties noted that marginal cost should align closely with load. This alignment was reflected in the comparisons of load and marginal cost in the workshops, and is consistent with the parties' general consensus. For PG&E, PG&E's proposed adjusted net load calculation appeared to be more closely aligned with marginal generation cost than Net Load as calculated by CAISO.

Base TOU periods should be defined so that the peak periods include a high percentage of high-cost hours and a low percentage of hours that are not high-cost.

We also conclude that the time sensitivity of all elements of a utility's hourly marginal costs is relevant and, ideally, should be considered in assessing TOU periods.

Marginal distribution cost data can also be useful to help identify TOU time periods. TURN and CLECA believe that including distribution costs in analyzing TOU periods would delay and unnecessarily complicate this OIR. The May 3, 2016 Scoping Memo, however, stated that time differentiation of distribution system costs exists and should be considered in this proceeding. We conclude that evaluating the timing of distribution circuit peaks can provide useful input in defining TOU time periods. We recognize that peak demands occur at multiple levels on circuits, substations, and the system as a whole. TOU time periods, however, should take into account the large majority of distribution circuit and substation peaks. The specifics of the time profile of each IOU's marginal distribution costs then can be developed in its respective GRC or RDW proceeding. Accordingly, parties should address, in the next available GRC or RDW proceeding for each IOU, how marginal distribution costs can be used to help identify appropriate TOU periods.

In comments on the proposed decision (PD), TURN argues against using distribution marginal costs for the purpose of establishing TOU periods in retail rates. TURN asserts that "incorporating distribution marginal costs information into TOU rate design could effectively duplicate the efforts being undertaken in [the Distributed Resources Plan (R.14-08-013) (DRP) and Integrated Distributed Energy Resources (R.14-10-003) (IDER)]."[14] It is true that these two proceedings are developing methodologies for valuing distributed energy resources (DERs). However, the valuation methodologies being developed in those proceedings should not be duplicative or contradictory. The objective of using marginal distribution costs and timing of distribution system peaks in determining Base TOU periods is to better align time-differentiated rates with time-differentiated marginal costs. In contrast, the DRP and IDER proceedings are focused on incentives for DERs based on their contribution to grid-specific needs. For example, the DRP proceeding is developing a Locational Net Benefits Analysis

[14] TURN Opening Comments on PD at 4-5.

(LNBA) to be used in assessing the locational value of DERs. LNBA will be used to incent location of DERs where they can provide the most value to the distribution grid. In contrast, for setting Base TOU periods, distribution marginal cost would be used to structure a rate that encourages energy use at optimal times.

We agree with TURN, however, that the Commission must avoid creating multiple separate valuations for DERs and distribution level load-shifting. The DRP proceeding and the IDER proceeding are both ongoing. To reduce the risk of duplication or conflicting valuation methodologies, the distribution data required in future rate proceedings pursuant to this decision must include information on the status of the DRP and IDER valuation methodologies and the relationship of these methodologies to the data presented by the IOU.

TURN also asks that the Commission "recognize that any future shift to geographically deaveraged rates could undermine universal and nondiscriminatory service."[15] We agree with TURN that any shift toward "geographically deaveraged rates" needs to be closely evaluated to determine compliance with the Commission's mandate to ensure utilities provide service that is adequate, efficient, just, and reasonable.[16] Today's decision directs the IOUs to provide information on marginal distribution costs and circuit level peaks. This decision, however, does not adopt a policy of differentiating rates or TOU periods based on specific circuits. Arguments regarding the legality of geographically deaveraged rates are outside the scope of this proceeding.

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[15] TURN Opening Comments on PD at 5.

[16] It should be noted, however, that circuit-specific rates have been approved for the vehicle-to-grid (VGI) tariff in SDG&E's territory.

In comments, SEIA and CalSEIA emphasized the need to include distribution marginal costs in evaluation of Base TOU periods. SEIA and CalSEIA point out that "the incorporation of average distribution peaks into TOU rate design could motivate individual customers to shift their demand in a manner that actually exacerbates problems on some circuits."[17] We agree with this SEIA and CalSEIA that risk of conflicting price signals must be part of the process for setting Base TOU periods.

SDG&E in comments on the proposed decision pointed out that the record does not contain data on the timing of circuit peaks for SCE or PG&E. For SDG&E, the only information in the record is the chart of circuit peaks filed in SDG&E's phase 2 rate case.[18] We agree with SDG&E that the data is limited, which is why today's decision does not adopt a specific process for incorporating distribution peaks into Base TOU periods. But we do want to consider this data in the future.

SEIA and CalSEIA believe that factoring distribution and transmission costs into determination of TOU periods will result in periods that are earlier in the day. SEIA and CalSEIA are concerned that, if distribution and transmission costs are not considered in the at this time, then Base TOU periods will change significantly in the near future to take these costs into account. [19] This would result in customer confusion.

Although we lack jurisdiction to set rates for recovery of transmission costs, we are not precluded from recognizing that transmission costs included in retail

[17] TURN Opening Comments on PD at 5.

[18] [add reference]

[19] SEIA/CalSEIA Opening Comments on PD at 4-5.

rates send price signals to customers related to their use of the electric delivery system.

Choices by retail customers based on these price signals will impact transmission costs incurred by IOUs. For example, SEIA posits that the installation of distributed generation (DG) and implementation of energy efficiency and demand response measures – actions taken in response to retail rate signals – avoid the need for more bulk transmission lines. This may or may not be the case, but SEIA's assertion supports the need to consider time-varying rates and their relationship to transmission costs. Thus, while we do not regulate FERC-regulated transmission rates, we find it appropriate to recognize the time profile impacts of system loads that drive transmission costs in the design of TOU time periods.

The use of distribution and transmission marginal cost data in determining Base TOU periods will not be simple. As cost of service ratemaking becomes more time-differentiated, it will become increasingly important to evaluate distribution and transmission marginal costs by hour. The process of evaluating and incorporating this data into TOU rates will take time. When data is presented in future rate cases, as ordered by today's decision, the Commission will have the opportunity to evaluate how that data should be used in setting TOU periods.

In comments on the proposed decision, California Energy Storage Alliance (CESA) proposed that flexible ramping needs also be included in the marginal cost analysis that is used to set the Base TOU periods. We agree that flexible ramping costs should be part of marginal cost analysis for setting Base TOU periods. We expect that the costs of flexible ramping will already be included in the calculation of marginal generation costs in each IOU's separate rate proceedings.

2.3.2 Utility Specific Approach to Setting TOU Time Periods

We do not require that TOU time periods be uniform among all three IOUs. Marginal costs and load shapes differ for each IOU due to factors such as congestion and the mix of resources in each territory. Factual issues such as how to quantify and set Base TOU periods are matters best addressed in the GRC and RDW proceedings of each IOU. In this manner, an evidentiary record can be developed to determine the shape of Base TOU periods based on each IOU's specific load profiles, marginal costs and needs.

Parties can thereby evaluate and comment on the IOU proposals or suggest alternates. In this decision, we prescribe the general principles (*see* Appendix 1) as guidance to apply in developing specific proposals for setting or revising Base TOU periods, and incorporating those Base TOU periods into rate designs, in the context of a utility-specific rate proceeding.

The IOUs should rely on data and assumptions vetted in the existing proceedings, such as the LTPP and IRP, where relevant, to support individual TOU period proposals. These data/assumptions should be submitted as the base case for each IOU's TOU proposals in their respective GRC phase 2 and/or RDW applications.

We also agree with PG&E and the other IOUs, however, that imposing different TOU peak periods geographically within an IOU's service territory could be confusing and costly for customers with multiple accounts and centrally managed operations, requiring more complex energy management planning. From a utility operations perspective, geographically differentiated rates increase the costs of maintaining the billing system, training customer-facing support staff, and performing rate education and outreach.

In addition, although today's decision does not consider potential legal issues with deaveraged rates, TURN asserts that such rates have previously been found to conflict with the utilities' obligation to provide universal and non-discriminatory service.[20]

Accordingly, we do not require or recommend geographically-differentiated TOU time periods within an IOU's service territory.

We find reasonable the general principles currently used by each of the IOUs to determine the number of seasons (and months within those seasons) used for TOU rate purposes. We agree with SDG&E that the seasons and months included therein for setting TOU rates should be a utility-specific inquiry based on marginal costs. We find appeal in PG&E's approach of utilizing a super-off-peak credit as an overlay to a TOU rate designed within a two-season summer-and-winter period. In the next available rate proceeding for each IOU, we invite parties to offer more detailed proposals as to how such an overlay approach could provide additional TOU seasonal options at least for certain customers otherwise limited to a two-season TOU design.

We also adopt the rate design principles articulated in D.15-07-001 for setting TOU periods, namely: cost of service, affordable electricity, conservation and customer acceptance.

2.3.3 Role of CAISO Data

In the June 8, 2016 workshop, the CAISO stated that it does not see itself involved in an ongoing fashion in establishing TOU periods. The CAISO reiterated its position in its September 2016 comments, stating that it does not

[20] TURN Opening Comments on PD at 6, citing D.03-02-068 at 51-52.

anticipate a role in future proceedings to determine TOU periods. We agree with the CAISO's position.

We find that the CAISO TOU Report (filed on January 22, 2016) and parties' responses filed on April 29, 2016, arrive at a similar conclusion, namely, that TOU peak periods currently in effect should be shifted to later in the day. As such, using a marginal cost methodology to set TOU periods should inherently capture the "grid perspective."[21] While we do not rely on the CAISO TOU Report as a primary source document for assessing TOU time periods, we believe that the hourly load and net load data available from CAISO could serve as a secondary check, as marginal generation costs already tend to reflect CAISO's Net Load data.

In its September 2016 comments, the CAISO provides details of its methodology for developing its January 22, 2016 TOU Report so that in the future other parties can create a similar forecast.

2.3.4 Community Choice Aggregation (CCA) Area-Specific Data.

MCE argues that the IOUs should develop and disaggregate hourly metered load, net load, and wholesale supply data by CCA service area. Even imagining that the concept of net load made sense on a CCA territory-specific basis, MCE does not make clear the purpose to be served by such data. MCE argues that the data will help the IOUs and the CCAs to identify customer acceptance needs in these areas to minimize potential opt-outs from CCA services due to confusion.

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[21] We recognize, however, that traditional marginal cost methodology many not capture the ramping needs caused by increased solar penetration, and therefore we encourage innovative approaches such as SCE's "Flex" methodology that could capture the impact of ramping on marginal cost. These are issues to be resolved in the determination of marginal cost in a utility-specific GRC phase 2 or RDW.

PG&E opposes this proposal, arguing that MCE provides no reason why an updated set of more accurate TOU periods will be any more confusing to customers than the current TOU periods. MCE today tailors its own TOU rates to match the period definitions on PG&E's corresponding TOU rate schedules, and it could easily do the same thing once new TOU period definitions are adopted.

PG&E argues that its current TOU rates achieve competitive neutrality, so that the only difference in customer bills paid to PG&E versus to a CCA is due to the differences between (a) PG&E's generation rate and (b) the CCA's generation rate plus the power charge indifference amount (PCIA). The delivery components charged to PG&E bundled and CCA customers will remain identical after TOU period definitions are changed. PG&E thus argues that there is no need to collect CCA-specific data.

We agree with PG&E that there is no need to collect CCA-specific data, especially when Base TOU periods will be uniform across each IOU's service territory.

3. Adopted Guidelines for Rate Designs and Transitions

This section discusses the arguments and support for the following guiding principles:

1. Each IOU should take steps to minimize the impact of TOU peak period changes on customers who have invested in on-site renewable generation or technology to conserve energy during peak periods. Regularly scheduled updates to TOU periods will provide predictability for these customers. Additional steps to increase certainty around TOU periods could include vintaging, legacy TOU periods, or fixed indifference payments, as well as other rate structures that provide predetermined limits on TOU period changes. Such steps must also include making information on potential shifts in peak periods available to the public.

2. A menu of TOU rate options should be developed in utility-specific rate design proceedings and should provide rate choices addressing different customer profiles and needs. IOUs are encouraged to use the Base TOU periods to develop at least one optional TOU rate design with a more complex combination of seasons and time periods and may incorporate more dynamic pricing features and enabling technology as appropriate to address grid needs.
3. TOU periods used in rate designs should be designed around the Base TOU periods and should reflect up to date marginal costs, but may be modified to take into account customer acceptance, preferences, understanding, ability to respond and similar factors. These considerations include:
   - The extent to which customers understand TOU rates generally.
   - The time and education required for customers to transition to a new TOU rate period.
   - The ability of customers to respond at a specific time of day or over a given period of time.
   - Customers' need for predictable TOU periods, including the schedule of possible TOU rate period changes, when they make investment decisions regarding energy efficiency, storage, photovoltaics, electric vehicles and other distributed energy resources or consider major operational changes to shift usage outside of peak periods.
   - The appropriate treatment of different customer classes, as necessary, in light of the fact that customer needs and sophistication may vary by customer class.

3.1. Customer Preferences, Understanding and Acceptance of TOU Rates

TOU rates are intended to create an incentive for customers to modify their energy use in response to the needs of the grid. Although the primary input for TOU rates should be the time periods identified through the marginal cost analysis, rate design must take into account customer understanding and acceptance. Any resulting modifications should not stray far from the Base TOU periods and cost of service principles.

After the IOUs establish factual data supporting Base TOU periods, customer preference considerations can be used to refine TOU periods (*e.g.*, number of periods, length of each, price differentials) for translation into rate options and levels. Customer acceptance may be reason to temper cost based rates, to maintain certain existing TOU features, or to keep TOU periods stable for longer periods of time to allow for adjustment. Rulemaking 12-06-013 (Residential Rate Reform OIR), regarding residential rate reform, has set forth specific rate design principles that are applicable to residential customers and may be appropriate for other customer groups, especially small customers. Those rate design principles are:

1. Low-income and medical baseline customers should have access to enough electricity to ensure basic needs (such as health and comfort) are met at an affordable cost;
2. Rates should be based on marginal cost;
3. Rates should be based on cost-causation principles;
4. Rates should encourage conservation and energy efficiency;
5. Rates should encourage reduction of both coincident and non-coincident peak demand;
6. Rates should be stable and understandable and provide customer choice;
7. Rates should generally avoid cross-subsidies, unless the cross-subsidies appropriately support explicit state policy goals;
8. Incentives should be explicit and transparent;
9. Rates should encourage economically efficient decision-making; and

10. Transitions to new rate structures should emphasize customer education and outreach that enhances customer understanding and acceptance of new rates, and minimizes and appropriately considers the bill impacts associated with such transitions.

We recognize the importance of promoting customer understanding and acceptance as an essential element in the success of TOU rates in motivating customers to shift energy usage. The incentive offered by TOU rates can only work, however, if: 1) the customer understands that his or her rates are time differentiated, and 2) the customer is able to adjust his or her energy use in response to the price signals that time differentiation provides. For purposes of this proceeding, the Scoping Memo defined customer acceptance to capture, at a minimum, the following:

a. The extent to which customers understand TOU rates generally.
b. The time and education required for customers to transition to a new TOU rate period.
c. The ability of customers to respond at a specific time of day or over a given period of time.
d. The customer need for predictable TOU periods when they make investment decisions in energy efficiency, storage, photovoltaics and other forms of distributed generation.
e. The appropriate treatment of different customer classes, as necessary, in light of the fact that customer needs and sophistication may vary by customer class.

Although design of specific time-varying and TOU rates is not in scope for this proceeding, parties were asked to discuss such designs in light of customer acceptance requirements. A compendium of illustrative time-varying rates proposed or discussed by parties in this proceeding is attached as Appendix 2.

Appendix 2 is intended to be a resource to assist the reader in understanding the range of rate design options that could be considered.

CforAT proposes that the guideline 9, regarding customer acceptance and preference, be modified to be mandatory. CforAT points out that various laws require that rates to take certain customer attributes into consideration in rates. For example, Public Utilities Code Section 382[22] requires that the Commission "ensure that low-income ratepayers are not jeopardized or overburdened by monthly expenditures." We agree with CforAT that these statutory requirements continue to apply to rates. However, we believe the language of the statute is sufficient and that no change to the guidelines is necessary.

In addition, CforAT proposes adding express language to the guidelines referencing the Residential Rate Reform proceeding (R.12-06-013). Again, we do not feel it is necessary to add this language to the guidelines. Nothing in today's decision overrides the protections and rate design requirements adopted, or to be adopted, in R.12-06-013 for residential customers.

All parties agree that customer acceptance of rate designs will vary by customer class, and therefore rate designs for different classes may have different TOU periods. For example, sophisticated large customers assisted by automated technology are likely to be able to respond to multiple complex TOU rate periods, such as those proposed by the CAISO. However, other customers, such as small business and residential customers, will need a simpler rate design.

[22] All section references are to the Public Utilities Code unless otherwise specified.

Most parties also agree that there is good reason to offer different TOU rates within a customer class. The result is strong support for a menu-based approach giving customers choice as a means of promoting customer acceptance.

These different TOU rates should be cost-based. This does not mean that price differentials must reflect the absolute ratio of costs allocated to the different TOU periods. Rather, price signals should reflect the direction of differences in marginal costs by TOU period. This approach will ensure that different TOU rates will not send conflicting price signals, but, to maintain the relationship to costs, we have required that TOU rate designs not stray dramatically from the Base TOU periods. In addition, basing rates on TOU-period-specific marginal cost will ensure that each TOU rate should reflect the costs to serve the customers on that rate (except in case of specific, identified, policy-based or statutorily-required subsidies). Although reflection of cost-causation may be muted when new TOU rates are initially being introduced, over time each rate design should be able to reflect the cost to serve enrolled customers with increasing accuracy.

SCE believes that customer understanding and class-level considerations, including transitions to preferred TOU periods, should continue to be examined and debated in rate design proceedings where actual TOU rate differentials and optional period proposals are contemplated. Similarly, bill impacts based on actual TOU period proposals, revenue allocation, revenue requirements, and existing bill levels are best examined in those proceedings.

PG&E believes that as long as, on a portfolio-wide basis, the signal to shift away from high-cost hours is given, variations can apply as part of the menu of options. PG&E believes that larger, more sophisticated customers could be placed on rate schedules with more TOU periods (for example, a partial-peak period or super-off-peak period) than apply to smaller customers (who might see simple TOU period designs with just peak and off-peak periods).

PG&E notes that different types of agricultural operations may have different needs and system constraints. A small number of TOU options could accommodate those differing needs (*e.g*. not just a 5-hour peak from 5:00 p.m. to 10:00 p.m. but also a 3-hour peak from 6:00 p.m. to 9:00 p.m., if more manageable for some). PG&E believes that residential customers, for whom TOU rates are optional, could be offered a menu of TOU period choices. For example, customers could be offered a choice between (a) volumetric-only TOU rates or (b) a more cost-based rate with a fixed charge or a demand charge (or both), coupled with lower volumetric rates.

SCE suggests there be one default TOU period definition applicable to all rate classes, and a menu of optional rates with adjusted periods specific to the applicable rate class (*e.g*., shorter on-peak periods, longer off-peak periods) that are still cost-based. This approach is consistent with the Base TOU period approved in this proceeding. SCE believes that optional rates designed specifically to further incentivize usage, such as Real Time Pricing/Matinee Pricing and Super- Off-Peak rates, are also effective ways to address the periods of oversupply identified by the CAISO in their TOU Report.

SDG&E argues there should be no customer class differences when determining the appropriate set of TOU periods. Since commodity costs are based on an assessment of system peak, SDG&E believes there would be no difference between customer classes as to when the high cost hours occur. While supporting a single set of Base TOU period, SDG&E also supports differing options for various customers and customer classes. For example, customers who prefer simplicity could elect to take service under a rate with fewer TOU periods, (*i.e.*, 2-period TOU rather than 3-period TOU where the on-peak period is the same), whereas more sophisticated customers (*e.g.*, those with solar and energy storage) with greater ability to respond to price signals, may prefer more complex rates with multiple TOU periods and sharper TOU price signals.

SEIA, CALSEIA, and EDF believe the IOUs should provide differing TOU periods for each customer class or for customers with distributed energy resources, such as solar and energy storage. These parties cite distribution costs as one justification for multiple TOU rates.

CLECA supports having a uniform set of Base TOU periods for all customer classes within each utility since these TOU periods are incorporated into the revenue allocation process. Once the Base TOU periods are established, TOU rate options could be considered based on costs and using these cost-based TOU periods for revenue allocation.

EDF argues that customers should be allowed to choose rate period options with significant differentiation between pricing periods to most effectively achieve TOU pricing goals, noting that the effectiveness of TOU rates lies in how well customers respond to price signals, rather than what enabling technology that customer uses in order to manage their load. EDF argues that consumers should have the opportunity to adopt and learn how to respond to more complex rate period options, including the use of more than two seasons, greater differentiation between peak and off-peak pricing, and a dynamic energy price that begins to resemble the "smart home rate" that rewards the use of enabling technology and the ability to respond rapidly to sudden price changes.

GPI argues that the structure of TOU periods should be tailored to the class of the customer, just as overall rates have always been structured to the customer class. GPI believes that more sophisticated customers, who tend to be the larger customers, are best equipped to handle and respond to more granular rates. GPI argues that by making TOU tariffs optional, customers whose usage is concentrated during peak marginal generation cost periods have an off-ramp to avoid TOU rates. These are the very customers, however, that TOU rates are designed to reach. Moreover, GPI believes that some of the non-TOU alternative tariffs that might be available to customers could provide incentives to those customers that are directly contradictory to the incentives that the Commission is trying to pursue by offering the TOU tariff, actually incenting them to greater energy use during peak marginal generation cost periods. GPI further argues that changing the time-differentiated profile of energy prices does not affect the overall market price of energy. On the other hand, GPI notes, time differentiation can change the cost of powering devices that run intermittently. Devices that are run primarily during peak marginal generation cost periods, for example, will cost more with time-differentiated prices than with flat prices. This provides an incentive for customers to seek means to shift the pattern of their energy use, depending on the range of differences among rates during different hours of the day.

In comments on the proposed decision, GPI clarified that it does not object "to offering a menu of TOU rates that are consistent with respect to being based on actual and projected future energy values in the marketplace, but differ with respect to granularity and detail."[23]

Parties expressed strong support for providing a menu of different TOU and other time-varying rates as a way to maximize customer acceptance by providing a

[23] GPI Opening Comments on PD at 3.

range of rates that will be appropriate for different levels of customer sophistication, technology, and understanding. We agree. A menu of rate options should be considered in utility-specific rate design proceedings. We invite parties to present proposals in the appropriate upcoming rate proceeding regarding appropriate ways to tailor TOU rate options based on the applicable utility-specific and customer class considerations at issue.

3.2. Length of Time that TOU Periods Remain in Effect

3.2.1. Parties' Positions

Several parties argue that new TOU periods, once adopted, should remain unchanged for periods of at least five years. ORA argues that new TOU periods should be kept in place for two GRC cycles, or six years.

PG&E believes that a degree of stability is needed after new TOU periods are adopted in conjunction with the significant marketing efforts needed to make customers aware of changes in TOU periods. PG&E agrees with SEIA that the forecast horizon be at least three years from the effective date of the rates with the new TOU periods to reflect conditions in effect on average during the lifetime of the TOU period. PG&E believes that TOU periods should be valid for at least five years. Hence, the data should be updated once in every GRC phase 2 application, but not necessarily result in a change in TOU periods every filing.

SCE believes that any changes to default TOU periods should be maintained for at least six years (*i.e.*, two GRC cycles). In order to ensure that price signals remain appropriate in the attrition years, SCE believes that TOU periods must be set based on the conditions expected in the relevant time frame. SCE advocates using the end-point of the forecast period, rather than the mid-point, when setting Base TOU periods.

CLECA believes that frequent TOU rate changes would create customer confusion and serve to undermine customer acceptance rather than promote cost efficiencies. CLECA opposes automatic TOU updating, even assuming it could be implemented, because customers must be given advanced notice of TOU period changes and an opportunity to adapt to them.

Both GPI and EDF assume that customers would have much end-use automation that would seamlessly respond to any rate changes.[24] However, this is certainly not the norm, whether for residential customers (the apparent focus of GPI) or non-residential customers.

3.2.2. Discussion

TOU periods have been nearly unchanged for over thirty years. However, since 2014, all three IOUs have proposed major changes. As observed by various parties, the initial redefinition of TOU periods proposed in recent or upcoming GRC phase 2 and RDW applications could be the most dramatic changes in some time. Subsequent updates to the TOU periods are expected to be minor in comparison. As noted by ORA, the shift from tiered-rates to TOU rates is a big change for most residential customers, which will require education for customers so that they understand TOU rates. There are significant marketing, education and outreach costs inherent in adequately communicating with customers about a change to TOU periods. For residential customers, this issue is being considered in Rulemaking 12-06-013.

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[24] In comments on the proposed decision EDF clarified that it "believes that automation would be tremendously helpful in ensuring customers can easily and seamlessly respond to price signals, we recognize that technology of that kind is not widely available." EDF Opening Comments on PD at 4.

In view of these factors, we agree with the consensus that after TOU interval periods are set they should remain fixed for a reasonable period of time before being subject to modification. Frequent changes to TOU rate periods could make TOU rates less effective in motivating customers to shift load to off peak hours.

Bill impact analysis is an important part of evaluating TOU rates. TOU periods must accommodate increased self-generation, energy efficiency, storage and other technologies, as well as changes to the CAISO market. These changes bring new challenges for forecasting load under different tariffs. Forecasts will therefore play an essential role in successful development of TOU rates. Without reasonably accurate sales forecasts, these bill impact analyses have little value. Without accurate forecasts as we move to time-varying rates, the risk increases of collecting more or less than the utility's approved revenue requirement.

We conclude that TOU periods should be developed using forward-looking data, forecasted at least three years after the TOU period will go into effect, so that the resulting TOU periods will be stable. Any subsequent re-evaluation of those periods should be done in utility-specific proceedings, either in GRC phase 2 or RDW proceedings.

We also conclude that the adopted TOU time periods should remain in effect for at least five years (subject to review at each GRC), with the goal of reviewing and re-setting Base TOU periods and rates every other GRC cycle. The current GRC cycle plan directs the IOUs to file their GRCs every three years. Therefore, re-setting TOU periods every other cycle approximates the five-year minimum duration adopted in this decision. However, because the schedule for GRCs may change in the future, we adopt a minimum duration that is measured by years rather than GRC cycles. This
five-year (or every other GRC) schedule will provide stable TOU periods. This

duration is also consistent with Public Utilities Code section 745(a)(3) which directs the Commission to strive to keep the same TOU rate periods for at least five years for residential customers. The five-year period is also consistent with recent Commission decisions.

While recognizing the importance of regulatory stability, we also realize that forecast assumptions underlying TOU time periods may deviate over time as more up-to-date data becomes available. If adopted forecasts were to deviate significantly from updated actual data, an adjustment in TOU time periods more frequently than once every five years may be warranted. To address this concern, we conclude that a dead band tolerance range should be developed within which deviations between adopted forecasts and updated actual data would not be significant enough to warrant a revision in TOU time periods. In each IOU's GRC phase 2 proceeding, a comparison should be made between the adopted forecasts and corresponding updates in the actual data supporting the adopted Base TOU time periods. If the deviations of the data from the forecast exceed the adopted dead band, a revision in the Base TOU periods and related rate designs prior to five years would be appropriate. The specific magnitude, design, and implementation of such a dead band tolerance is a fact-specific inquiry that should be addressed in the next available GRC phase 2 or RDW proceeding for each IOU.

In comments on the PD several parties asked that the timing of Base TOU period changes be clarified. Appendix 3 provides a timeline for the implementation of new TOU periods pursuant to its applicable pending GRC phase 2 or a rate design window, followed by evaluation of Base TOU periods in the next GRC and by proposal of new Base TOU periods in the following GRC.

3.3 Mitigating Impact on Customers of TOU Period Transitions

New TOU periods should be introduced in a manner that reduces or mitigates negative impacts on customers.

Comments on the PD indicate that the PD's discussion of transition periods as part of TOU rate design needs to be clarified. The primary finding in today's decision is that transition mitigation measures may be necessary for some customers when transitioning to new TOU periods. This decision does not approve or disapprove any of the mitigation measures suggested. In addition, as a separate finding, this decision finds that limited grandfathering should be adopted for certain customers. The treatment of transitions for other customer groups and for future TOU periods changes should be addressed in IOU-specific rate cases by applying the guiding principles adopted today.

Importantly, the Commission recognizes that use of grandfathering as a mechanism for mitigating negative impacts from TOU period changes has twosignificant weaknesses: (i) results in "inaccurate price signals that incent customer to use more power during high-cost periods"[25] and (ii) it is not transparent to customers. Although today's decision adopts grandfathering for a specific situation, we expect that going forward the IOUs, customers, and DER technology providers will develop mitigation measures that are more transparent and more narrowly tailored than grandfathering.

In addition to these findings regarding mitigation measures generally, this decision adopts a specific mitigation measure for a limited number of customers. This mitigation takes the form of grandfathering TOU periods and applies to

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[25] PG&E Opening Comments on PD at 1.

certain customers who have installed[26] behind-the-meter solar systems. D.16-01-044 gave certain residential net energy metering (NEM) customers taking service under the NEM successor tariff the right to retain TOU periods for five years. [27] NEM customers covered under D.16-01-044 are expressly excluded from the grandfathering measures in this decision.

Unlike other technologies, once solar systems are configured and installed it is difficult to make changes. The timing of solar generation is dependent on the timing of sunlight and the orientation of the panels. Changing the sun is not possible. Changing the orientation of the panels is usually not practical. In contrast, storage technologies can be modified to adjust to new TOU periods. Similarly, it is possible to adjust business operation schedules (although we acknowledge that the lead time for changes may be significant). Because current design of solar systems is uniquely unsuited to changing TOU periods, we find that it is reasonable to adopt grandfathering for solar customers.

Today, customers should be aware of the reality of changing rate designs and TOU periods. All three utilities have made changes to TOU periods and rate designs in recent years. Proposals to significantly change TOU periods date back to at least 2013 with the filing of SCE's RDW. Although it is clear that customer education and awareness campaigns must be expanded, we believe that at this

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[26] The terms of the grandfathering allow customers who are in the planning process for installing solar to be grandfathered provided that the interconnection application is submitted prior to June 30, 2017.

[27] Importantly, the recent net energy metering (NEM) decision (D.16-01-044) already provides a similar protection for residential NEM customers who complete interconnection applications for the NEM successor tariff prior to implementation of default TOU rates for residential customers. These customers are permitted to maintain their TOU rate for up to five years.

time there is sufficient information available about changing rates for customers to consider these changes when making investment decisions.

In addition, the TOU period changes proposed in the Pending Rate Design Cases will be relatively dramatic, involving shifts of up to five hours in the start of the summer on-peak period. The reason for such significant changes is that for many years there was no reason to re-evaluate TOU periods. As discussed throughout this decision, there is now a need to re-evaluate TOU periods on a regular basis. We expect that the guidelines and schedule in this decision will result in smaller, more manageable TOU period changes in the future.

For both these reasons, we limit today's grandfathering measure to customers who have already installed solar.[28]

For purposes of transitioning to new TOU periods, non-residential customers and residential customers differ in several key respects. First, non-residential customers have already been put on mandatory TOU rates. The purpose of a TOU rate is to send proper price signals at times of low and high energy availability. Non-residential customers were expected to respond to peak TOU periods by shifting or reducing use. In light of this, as described by CalSEIA and SEIA, these customers may have already invested in solar in response to the first mandatory set of TOU periods. In contrast, residential customers are automatically put on a tiered-rate unless they affirmatively opt in to a TOU rate. Second, TOU rates are mandatory for non-residential customers. In contrast, even when TOU rates become the default rate for residential customers, residential

[28] NEM successor tariff customers covered by D.16 are excluded. For customers in the process of installing solar there is a six month grace period for eligibility.

customers will have the option of switching to a tiered-rate where the time of energy use does not affect the customer's bill.[29]

For residential customers, the Commission has previously adopted a five-year grandfathering period as reasonable. We find that a five year period is also reasonable for the residential customers covered in the limited grandfathering under today's decision. In light of the differences between residential and non-residential rates treatment, however, we find that a longer period of ten years is reasonable for non-residential customers.

It is not the goal of this proceeding to establish grandfathering or other mitigation measures for all customers. Rather, this decision establishes guidelines for mitigation measures going forward and recommends that transition measures other than grandfathering be part of the development of TOU rates in the future. This should be done in utility-specific rate proceedings. For most customers, this is the same approach that would occur in the absence of today's decision. The only difference is that additional guidelines and recommendations have been made part of the discussion.

3.3.1. Party Positions on Transitions

The Scoping Memo asked parties to comment on how to address customer acceptance of transitions to new TOU periods. Grandfathering (allowing customers to retain aspects of their existing tariff even after the tariff is no longer available to other customers) was the most common mitigation mechanism put

[29] There is one exception: residential customers taking service under the NEM successor tariff are required to be on a TOU rate.

forth by the parties. Other suggested mechanisms include phasing in new TOU periods over several years and vintaging customers by time of enrollment.[30]

In comments on the PD, SDG&E suggested a direct transition payment. The direct transition payment would result in all customers receiving "new, more accurate TOU priced signals that would come with correctly defined TOU periods."[31] This payment would take the form of a fixed indifference payment. Several other parties expressed support for this approach. SEIA/CalSEIA suggest that "existing solar customers could move onto the new TOU periods but also receive a fixed bill credit over a defined period that is calculated once and that is designed to mitigate the loss of bill savings resulting from the change in TOU periods."[32]

Today's decision emphasizes the distinction between transition mitigation mechanisms generally and the specific grandfathering measure adopted. In party comments prior to the issuance of the PD, however, the discussion of specific grandfathering provisions and general mitigation measures for transitions was combined. This section summarizes the combined party positions.

Parties representing solar manufacturers and vendors, in particular, propose that certain customers currently taking service on TOU rates with noon to 6 p.m. (or other such afternoon-hour) peak periods be grandfathered, that is, allowed to continue on those periods rather than having to take service on rates with new periods, even if the new TOU periods more accurately reflect when peak period costs are incurred. These parties argue that existing TOU customers have incurred

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30 *See* Appendix 2.

31 SDG&E Opening Comments on PD at 2.

32 SEIA/CalSEIA Opening Comments on PD at 10.

costs either to change their operations or to invest in solar or other load-shifting technologies based upon the current TOU periods. They argue that if the TOU hours are changed, the value of those operational changes and/or investments in relation to savings in utility rates will be lessened.

CalSEIA notes that in D.15-07-001 the Commission found that residential solar customers on certain existing TOU tariffs should be able to depend on the rate structure for five years before being forced "to determine how to respond to new TOU periods."[33] CalSEIA believes a similar minimum grandfathering period should apply for TOU purposes generally, and proposes that customers on TOU rates who have installed solar units be grandfathered for at least five years on their existing TOU rate to protect investments. CalSEIA and UCAN assert that such grandfathering is also appropriate for other types of investments in distributed energy resources if those investments are made based on current TOU periods.

SEIA also supports grandfathering for customers who installed on-site solar units, but proposes that the grandfathering be for ten years, with a subsequent transition to the then-effective TOU periods. After the initial ten-year grandfathering period, affected customers could be subject to on-peak TOU transition periods that shift later by one hour per year. This gradual hour per year shift would reduce the impact of new TOU periods with significantly different hours.

SEIA also proposes that the Commission explore the implementation of varying grandfathering periods depending on the underlying TOU structure. For example, customers willing to sign up for critical peak pricing (CPP) rates could be

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[33] D.15-07-001, Finding of Fact 143.

afforded a longer legacy period for the underlying TOU rate periods, with the understanding that CPP periods could be changed more frequently.

The IOUs oppose grandfathering for existing TOU customers, regardless of their circumstances, arguing that grandfathering will frustrate the goal of aligning electric rates with changed cost patterns as quickly as possible, will lead to higher costs and rates for other customers, and will reduce incentives for (and thus slow the development of) new technologies to help customers manage their loads to reduce bills and overall cost of service.

SCE opposes allowing customers to remain on grandfathered TOU periods that do not reflect the IOU's marginal costs. SCE argues that grandfathering customers may exacerbate problems that cost-based Base TOU periods are intended to alleviate. SCE recommends that any changes to the TOU period definitions apply to all customers currently enrolled in default TOU rates. SCE believes customers should be sufficiently prepared for TOU period changes in advance with marketing, education and outreach programs specific to the customer class. SCE argues that any proposals to grandfather increases the complexity of customer-class marketing, education and outreach and billing issues.

SDG&E argues that grandfathering customers on TOU periods would exacerbate existing cost shift issues that justify the need for new TOU periods and will result in minimizing the value of changing TOU periods, since not every customer would be responding to the new, more accurate, TOU price signals. Grandfathering TOU periods could result in customers receiving conflicting price signals with some customers seeing a price signal to use less at the same time other customers see a price signal to use more.

CLECA also argues that grandfathering customers on existing TOU periods will result in rates that are not cost-based and could send the wrong price signals. This would result in increased loads and decreased loads at the wrong times.

In comments on the PD, both ACWA and CFB described operational challenges that TOU rates present for specific sub-groups of customers. These operational challenges can make adjusting to new TOU periods difficult.

For example, CFB, representing agricultural customers, states that "Management around existing TOU periods required adaptive practices for irrigation methods and workforce oversight. Because the predominant use of energy by agricultural customers relates to irrigation, and the timing of irrigation requirements for a crop establishes the foundation upon which other cultural practices follow, fundamental changes in electric schedule parameters can trigger significant cost consequences."[34] CFB adds, "Farm Bureau members operate in a business environment with no certainty about production schedules, input availability (weather and water) or the price that a crop will garner."[35]

ACWA states that "[w]hile many water agencies will be able to adjust their operations in response to the proposed modifications in TOU rate periods, these adjustments could be fairly significant and will take time."[36]

In comments, ratepayer advocacy groups expressed concern about the cost of providing legacy TOU periods. TURN asks that the Commission not establish any presumption that [certain customers] will be protected against new TOU

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[34] CFB Opening Comments on PD at 2.

[35] CFB Opening Comments on PD at 4.

[36] ACWA Opening Comments on PD at 2.

period definitions. TURN argues that "[a]llowing NEM customers[37] to evade changes to TOU periods, while forcing the remainder of the customer class to accept new (and potentially more punitive) TOU periods, would only increase the inequity between the affluent (who have sufficient resources to invest in these technologies) and all other customers."[38]

In comments on the PD, UCAN urges the Commission to ensure that legacy customers only retain TOU periods.[39] Rates during the TOU periods should continue to change to reflect marginal cost. We have revised the decision to make it clear that only the TOU periods are retained.

3.3.2. Mitigation Measures for TOU Period Transitions

As noted above, we have previously provided some rate stability protection for customers' renewable technology investments in the form of grandfathering for some solar customers. Customers installing on-site renewable systems face uncertainty regarding factors such as future electric consumption levels and patterns, performance of the on-site renewable resource, construction and interconnection challenges, as well as future rate structures. Customers who shift use or conserve energy without investment in technology may still be negatively impacted by TOU period changes. In view of these factors, we find that a level of certainty is necessary to provide an incentive for customers' continued investment in solar and other renewable technologies technologies, and may also be appropriate for other customers.

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[37] Note: the grandfathering provisions adopted in today's decision only apply to those NEM customers who installed solar prior to the deadlines set forth in D.16-01-044.

[38] TURN Opening Comments on PD at 3.

[39] UCAN Opening Comments on PD at 4. UCAN also provides an example of "blending" rates during on-peak, semi-peak and off-peak time periods to better reflect cost. *Id*. at 5.

However, this decision also finds that customers who invest in solar after the implementation of the TOU periods in the Pending Rate Design Cases, and customers who invest in other types of on-site distributed energy resources, should be aware that a plan is in place to regularly review and update TOU periods every five to six years. Existence of a regular schedule for evaluating TOU periods provides predictability. We expect these customers will take this information into account when making their investment decisions. Further protections, incentives or subsidies for these customers are best addressed in a separate utility General Rate Case phase 2 or Rate Design Window.

3.3.3 Grandfathering of Specific Customers

3.3.3.1 NEM Successor-Tariff Customers Not Included

R.14-07-002 was opened for "two main purposes: 1) to develop a successor to existing net energy metering (NEM) tariffs as required in Assembly Bill 327 (Perea, 2013); and 2) to review and refine existing NEM tariffs, as necessary."[40] The proceeding was tasked with developing a successor tariff or contract that would apply to facilities interconnecting in each IOU's service territory once the IOU's NEM cap has been reached, or July1, 2017. As part of that rulemaking, D.16-01-044 set a timeline under which customers who became NEM customers after the NEM cap was reached or July 1, 2017 would be take service under a "NEM successor tariff." NEM customers include residential and commercial customers, and are not limited to solar customers. Residential customers would be required to take service on a TOU rate. However, the default residential TOU

[40] Order Instituting Rulemaking to Develop a Successor to Existing Net Energy Metering Tariffs Pursuant to Public Utilities Code Section 2827.1, and to Address Other Issues Related to Net Energy Metering

rates required under R.12-06-013 would not be established until 2019. The Commission was concerned about the timing: new residential NEM customers would be required to take service on TOU periods that could change in short period time. To address this concern, D.16-01-044 allows these customers to retain their TOU rates for five years.[41] D.16-01-044 set forth very specific eligibility and timing requirements for this program. No other customers were given this type of protection under D.16-01-044. Today's decision does not change the program set up under D.16-01-044. To ensure that there is no confusion between the two programs, customers permitted to retain TOU periods under D.16-01-044 are expressly excluded from the program set forth in today's decision.

Today's decision is designed to provide a similar protection for on-site solar customers, both residential and commercial, who are not already covered by D.16-01-044.

3.3.3.2 Implementation of Legacy TOU Periods

We agree with arguments that a limited grandfathering measure is appropriate for existing solar customers. As discussed above solar systems are difficult to reconfigure for new TOU periods. The TOU periods proposed in the Pending Rate Design Cases are significant.

On the other hand, we are not persuaded that grandfathering of TOU periods is an appropriate long-term mitigation measure to reduce the negative impacts that solar and other investors in DERs may face.

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[41] D.16-01-044 "Require[s] all residential customers interconnecting under the NEM successor tariff prior to the institution of default residential any time of use (TOU) rates to take service on any TOU rate available to them, as a condition of using the NEM successor tariff, except that residential customers of San Diego Gas & Electric Company (SDG&E) will not be required to take service on a TOU rate until after the TOU rates being developed in Application (A.) 15-04-012 are in effect." D.16-01-044 at 3.

Unreasonably long grandfathering prolongs the period during which such customers receive less accurate, and less cost-based, TOU pricing signals. As a result, the intended goals of setting more accurate TOU pricing signals will not be achieved. Also, administering a grandfathering program could be more complex as groups of customers on different timetables transition to the new TOU time periods. Maintaining multiple sets of TOU time periods for different groups of individual customers (*i.e.* vintaging) could also potentially be costly and confusing for at least some customers.

The Commission must balance the countervailing goals of sending accurate TOU price signals while mitigating the impact of rate change uncertainty. We conclude that, for a specific, limited group of behind-the-meter solar customers, a reasonable balance is achieved by adopting a limited grandfathering period.

For residential customers, a five-year grandfathering period is reasonable and consistent with the approach previously adopted for many residential solar customers in the Residential Rate Reform OIR (D.15-07-001) and for residential NEM customers in R.14-07-002 (NEM OIR) (D.16-01-044). For non-residential solar customers, including commercial, agricultural, industrial and education sector customers, a ten-year grandfathering period is reasonable and consistent with the additional challenges these customers face.

Importantly, this grandfathering protection only applies to the TOU time periods; rates should still be adjusted to reflect changes in revenue requirement and cost allocation.

As noted above, CFB expressed specific concerns about agricultural customers' ability to adapt to new TOU periods without significant cost. CFB emphasizes the need for customers to have time to plan responses to TOU period changes. Based on this, CFB suggested changes to the guidelines to clarify the mechanics and timing of the dead band tolerance trigger. The changes suggested by CFB are reasonable and will improve implementation of the guidelines. We have revised the guidelines accordingly.

The PD would have set a five year grandfathering period for certain commercial and industrial solar customers. After reviewing comments on the PD from CalSEIA, SEIA and others, we agree that a ten-year period is reasonable. As pointed out by CalSEIA and SEIA, some customers that were switched to mandatory TOU rates "installed solar systems when prices were still high . . ."[42] Customers who interconnected under a mandatory TOU rate schedule "made their investments in distributed energy resources based on the price signals given by today's TOU periods, which have been constant for decades."[43] These customers are now faced with pending TOU period changes up to five hours. CalSEIA and SEIA emphasized that residential NEM customers, including solar customers, are able to switch back to tiered rates.[44]

CalSEIA and SEIA also argue that customers who install solar in the future should have a five-year transition period. CalSEIA and SEIA argue that because future TOU periods shifts will be more modest, there is not "a significant risk of misalignment of price signals . . . "[45] While we agree that some form of mitigation measure may be necessary to reduce negative impacts for these customers, we decline to adopt the proposed five-year period. There are other forms of

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[42] SEIA/CalSEIA Opening Comments on PD at 8.

[43] *Id.* at 7.

[44] *Id.* at 8. It should be noted that NEM customers taking service under the NEM successor tariff will not have this option, but will be able to retain their TOU periods and rates for five years.

[45] SEIA/CalSEIA Opening Comments on PD at 10.

mitigation that may be appropriate and more reasonable for the future. Noteably, SEIA and CalSEIA suggest exploring the option of a fixed bill credit over a defined period of time in pending rate cases.[46] PG&E raised two concerns in its comments on the PD. First, PG&E is concerned that customers may install a token amount of solar to "lock in" the five-year legacy period. PG&E asserts that if customers are permitted to qualify by taking such actions there will be an increase in any cost shift associated with the program. PG&E suggests requiring a minimum size for systems to qualify. We agree with PG&E. It is not the intent of the Commission to give customers the opportunity to lock in a legacy period by token actions. Rather, the goal of this limited grandfathering is to mitigate the transition for customers who have recently installed solar in a configuration designed based on current TOU periods. PG&E recommends a minimum of 15% of customer's gross annual usage be offset by its on-site solar production. PG&E states that 15% is consistent with a similar requirement in PG&E's Option R Tariff and SCE's Option R Tariff.

Second, PG&E is concerned about having a significant number of customers on expired TOU periods for an extended period of time. In comments on the PD, PG&E asserted that without revisions the PD could result in "over 2,000 gigawatt-hours of non-residential load" remaining on out-dated TOU periods. While there is no evidence in the record to support a specific number of gigawatt-hours, PG&E's concern is legitimate. Ratepayers advocacy groups and the other two IOUs raised similar concerns. As drafted, the PD would have allowed customers to be eligible for grandfathering up until new TOU periods are implemented. This means an extended period of uncertainty regarding the end date for eligibility and

[46] *Id.* at 10-11.

the end date for the grandfathering period. PG&E proposes that instead the end date for eligibility be set at six months after the final decision is issued.

PG&E's proposal would have the benefit of increased certainty for the IOUs and other ratepayers. The end date for eligibility and for the grandfathering period would be known when today's decision issues. This will improve planning for the IOUs and minimize the extent of gigawatt-hours of load remaining on outdated TOU periods. Customers will also have a clear deadline for completing their interconnection applications.

One downside to this proposal is that it leaves a gap of uncertain TOU periods for prospective solar customers. This gap would start at the end date for grandfathering eligibility and continue until new TOU periods are approved by the Commission. However, at this time, with new TOU periods pending for all three IOUs, we believe there is sufficient information regarding likely changes to TOU periods for customers to make reasonable decisions on investments.

While we acknowledge that PG&E's proposal is not a perfect solution, we find that it sets the right balance of mitigation and certainty for customers and the IOUs. We therefore adopt this approach for all three IOUs.

In light of these comments on the PD, we have made some clarifying changes and set some additional limits/specifications for the legacy periods.

3.3.3.3 Terms of Legacy TOU Periods Adopted in this Decision

The following terms and conditions apply to the grandfathering measures adopted in this decision.

- Customer Eligibility: Applies to (a) residential customers with on-site solar systems, who opt-in to a TOU tariff prior to the End Date as defined in the next bullet and (b) commercial and industrial customers. This transition does not apply to customers who are already permitted to stay on a TOU rate for five years pursuant to D.16-01-044.

- Eligibility Period End Date: June 30, 2017
- System Eligibility: Systems for which interconnection applications, including final building inspection, are completed at any time prior to the End Date are eligible. The system must be designed to offset at least 15% of the customer's current annual load.
- Duration:
  - For residential systems, this transition mitigation measure continues for 5 years after issuance of a permission to operate. In no event shall the duration continue beyond June 30, 2022.
  - For commercial and industrial systems, this transition mitigation measure continues for 10 years after issuance of a permission to operate. In no event shall the duration continue beyond June 30, 2027.
- Attributes: This transition mitigation measure allows the customer to maintain the same TOU periods for the duration. Other changes in rate design, including allocating marginal costs to TOU periods and setting specific rate levels, will be litigated in utility-specific rate proceedings.[47]
- For administrative efficiency, IOUs may reduce the number of transition dates by consolidating customers into groups. This and any other administrative efficiencies should be established through the Tier 3 Advice Letter process.

[47] For example, the off- peak period for a legacy customer should continue to have a lower rate than the legacy peak period, but the differential should be modified when new TOU periods are implemented for other customers. This new differential should reflect the new marginal cost allocation, but the new electricity price for legacy peak period hours should not fall below the new price for legacy off-peak periods and the new electricity price for legacy off peak periods should not be increased above the price during legacy peak periods.

3.3.3.4 Efficient Administration

In comments on the PD, SCE proposed two ways that grandfathering could be made more administratively efficient:

- Allowing an IOU to consolidate grandfathered TOU tariffs and offer a single TOU tariff, per rate class, with the current TOU periods.
- A single date each year on which to migrate grandfathered customers to the new TOU periods.

We agree with SCE that efforts should be made to reduce the administrative burden of grandfathering customers. Although both SCE and UCAN suggest addressing these efficiencies in a rate proceeding, we believe that this issue can be resolved more expeditiously through a Tier 3 Advice Letter. We direct the IOUs, either individually or as a group, to hold a meet-and-confer with other parties to discuss the administrative options suggested by SCE and any other suggestions parties may have. Each IOU shall consider the comments from the meet-and-confer and shall file a Tier 3 Advice Letter setting forth its administrative plan. This advice letter is due no later than March 31, 2017. Proposals for reducing the number of days on which grandfathered customers will be switched to new TOU rates must be reasonable, consistent with the decision, and a minimum of one day per year.

SCE also suggests a mechanism for informing future solar customers about the potential for future TOU period changes. SCE recommends requiring customers to acknowledge awareness of this information as part of the interval data release form. CalSEIA objects to SCE's proposal. While we agree with SCE that there is benefit to requiring specific types of information be provided to new DER customers, there is not sufficient record in this proceeding to adopt a specific requirement. In addition, the requirements for connecting DERs, such as residential solar, are being addressed in many different proceedings. For these reasons we are not adopting SCE's suggestion regarding customer acknowledgement at this time.

3.3.4 Treatment of Other Customer Groups

Several parties commented that grandfathering measures adopted in this proceeding should be extended to customers installing other types of distributed energy resources, and to all on-site solar customers. This proceeding has not developed an appropriate record for establishing grandfathering or similar treatment for such a wide range of resources and customers. Instead, this decision acknowledges that the Commission has found grandfathering to be appropriate for certain solar customers and finds that similar treatment may be appropriate for other customers who invest in technologies to reduce load at peak times.

4. Forum for Consideration of Time of Delivery Issues

In contrast to TOU rates, Time of Delivery issues relate to the time-differentiated payments that an IOU makes to electricity generators.

SCE argues that TOD factors and periods for future energy resource contracts should not be considered in this proceeding. SCE believes TOD issues are better addressed in the Renewable Portfolio Standard (RPS) procurement plan proceeding, where the TOU time period analysis from this proceeding may be considered. While a variety of resources are assumed and aggregated across wide geographic regions and years to help determine TOU periods, SCE believes this relationship breaks down when one assumes that the TOU periods directly influence resource procurement.

SDG&E likewise does not believe TOD periods should be addressed in this proceeding. SDG&E changed its RPS TOD period summer definition beginning in 2005 and changed its on-peak and off-peak definitions to match RDW-proposed hours of on-peak and off-peak TOU periods in 2013 even though the Commission ultimately rejected SDG&E's proposal in D.15-08-040. For combined heat and power (CHP) contracts, the TOD periods are set through 2020 by the CHP Settlement approved in D.10-12-035 and cannot be changed.

GPI, by contrast, argues that there is a strong rationale for including both TOU and TOD in this proceeding, which is taking an overview of time-differentiation of energy values in a variety of Commission applications. Although the utility is on the opposite side with respect to TOU (payments to the utility from customers) and TOD (payments by the utility to generators), both TOU and TOD are related to the same energy marketplace and the values therein. While TOU and TOD do not have to be identical, if they are significantly different, GPI believes there ought to be a mechanism to discover why. GPI believes that the best way to ensure a concordance between TOU and TOD is to include both in this proceeding.

The scope of this decision is limited to issues relating to TOU time periods. Because the IOUs raised significant reasonable concerns about the appropriateness of linking TOD in power purchase agreements and TOU in rate designs, the Scoping Memo sought only minimal input on the relationship between TOD and TOU periods. We agree with the IOUs that issues relating to TOD issues are best addressed in the RPS or other related proceeding for each IOU. However, to promote alignment between rates and TOD, each IOU should include its current TOU rate periods in its annual RPS procurement plan and should make such information available on its website.

5. Comments on Proposed Decision

The proposed decision of ALJ McKinney in this matter was mailed to the parties in accordance with Section 311 of the Public Utilities Code and comments were allowed under Rule 14.3 of the Commission's Rules of Practice and Procedure.

Opening comments on the PD were filed on November 21, 2016 by CAISO, CforAT, CLECA, GPI, ORA, PG&E, SCE, SDG&E, SEIA/CalSEIA (jointly), TURN, UCAN, CFBF, Association of California Water Agencies (ACWA), EDF, and CESA. Reply comments were filed on November 28, 2016 by SEIA, TURN, PG&E, CLECA, SCE, UCAN, SDG&E, EDF, CAISO, and CalSEIA.

Party comments focused on the following issues: (1) grandfathering and (2) use of marginal transmission and distribution costs in determining TOU periods. In light of these comments, the decision has been revised to clarify the decision's conclusions on certain issues. The revisions include changes to the ordering paragraphs.

In light of the extensive comments on the relationship between the limited grandfathering adopted in this decision and the general discussion of transition mechanisms, Section 3.5 of the decision was revised to provide clarity. In response to comments regarding the timing of future TOU Base period evaluations and the timing of the limited grandfathering protection, Appendix 3 was added to the decision to show the anticipated schedule.

The terms and conditions of the for grandfathering measure adpted in this decision were changed based on party comments to: (a) require 10 year grandfathering for certain non-residential customers, (b) to require a minimum system size, and (c) to limit eligibility for grandfathering to customers who complete an interconnection application on or before June 30, 2017.

Where parties repeated arguments that were already addressed in the proposed decision, no changes were made.

Comments on the PD were also served by several non-parties: Agricultural Energy Consumers Associates and the Public Schools.[48] Both entities filed motions for party status with their comments. Because these motions were filed after a PD was already issued, and because these parties had ample opportunity to become parties and participate earlier in the proceeding, these motions are hereby denied. Comments from these parties have been placed in the administrative record along with other public comments. Detailed public comment was also received from the School Energy Coalition and California Association of School Business Officials. All of these entities asked for ten years of grandfathering for school solar projects currently or soon to be installed, and five years of grandfathering for schools installing solar projects after the date on which new TOU periods are implemented.

Detailed public comment on the PD was also received from the County of Santa Clara. County of Santa Clara asks for ten years of grandfathering for its solar projects. County of Santa Clara argues that future transition mitigation measures consider project financing. Specifically, the County states:

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[48] The Public Schools consist of more than 35 school districts in SDG&E's service territory: The Alpine School District, Bonsall Unified School District, Borrego Springs Unified School District, Cajon Valley Union School District, Cardiff School District, Carlsbad Unified School District, Chula Vista Elementary School District, Coronado Unified School District, Dehesa School District, Del Mar Union School District, Encinitas Union School District, Escondido Union School District, Escondido Union High School District, Fallbrook Union Elementary School District, Fallbrook Union High School District, Grossmont Union High School District, Jamul-Dulzura Union School District, Julian Union School District, Julian Union High School District, La Mesa-Spring Valley School District, Lakeside Union School District, Lemon Grove School District, Mountain Empire Unified School District, National School District, Oceanside Unified School District, Poway Unified School District, Ramona Unified School District, San Diego County Office of Education, San Diego Unified School District, San Dieguito Union High School District, San Marcos Unified School District, San Pasqual Union School District, San Ysidro School District, Santee School District, Solana Beach School District, South Bay Union School District, Spencer Valley Elementary School District, Sweetwater Union High School District, Valley Center-Pauma Unified School District, Vista Unified School District and Warner Unified School District.

> Given the variability in financial incentives and project financing methods available by customer class / sector, particularly the long periods over which public agencies repay debt and experience savings benefits, the County proposes that the guidelines focus on allowing for grandfathering of TOU periods as an acceptable TOU transition period protection, with the actual length of such periods to be determined in General Rate Cases, based on the actual financial impacts experienced by existing projects.

6. Categorization and Need for Hearing

In the OIR Opening this rulemaking, the Commission preliminarily determined that the category of this proceeding is ratesetting and that hearings may be needed. The Scoping Memo found that hearings were not required.

7. Assignment of Proceeding

Michael Picker is the assigned Commissioner and Jeanne M. McKinney is the assigned ALJ in this proceeding.

Findings of Fact

1. Setting higher TOU rates during peak periods provides customers an incentive to reduce energy use by signaling that electricity is more costly at certain hours.

2. The effectiveness of time-based price incentives is dependent on customer understanding and ability to respond.

3. By increasing customers' peak-hour avoided-cost savings, TOU rates provide incentives for customers to install solar generation that is configured to maximize energy availability during periods of peak demand, for example with co-located energy storage.

4. TOU peak periods have shifted to later in the day, several hours beyond the time of maximum solar energy production, suggesting the need for co-located

solar generation and storage to provide the best configuration to maximize energy supply during periods of peak energy use on the grid.

5. Solar generation facilities produce less electricity during evening hours.

6. Electricity demand varies seasonally, but is typically highest in the late afternoon and evening hours.

7. All three large electric utilities have begun to propose changes to TOU rates to reflect changes in the times of day when electricity is the most costly.

8. This rulemaking was opened to provide guidance as to the appropriate principles, standards, and minimum data to be provided when utilities propose a TOU period change by filing an application or through a settlement.

9. The data categories set forth in the Scoping Memo offer a useful beginning framework for developing the specific analysis needed to revise TOU time periods.

10. From both a load curve perspective and a marginal cost perspective, TOU periods shift over time.

11. These shifts in TOU time periods are the result of changes in system cost and usage patterns resulting from changes such as increased on-site solar systems and increased renewable generation connected to the grid.

12. The CAISO analysis shows a potential for curtailment of grid-connected solar generation during minimum net load events primarily in the early spring.

13. Because marginal costs and load shapes differ for each IOU due to factors such as congestion and resource mix, the factual record regarding how to set Base TOU periods is best addressed in the general rate case phase 2 or rate design window proceedings of each IOU.

14. Setting different TOU peak periods based on geographic variations within an IOU's service territory could be confusing and costly for customers with

multiple accounts and centrally managed operations, requiring more complex energy management planning.

15. Marginal generation costs, consisting of marginal energy costs and marginal generation capacity costs, constitute the primary basis for setting TOU periods, but the time sensitivity of all utility marginal cost elements, based on hourly patterns, is relevant in assessing TOU periods.

16. An updated analysis of Net Load using the methodology developed for the CAISO TOU Report may serve as a secondary check on TOU period changes.

17. The timing of distribution circuit and substation peaks can provide useful input in defining TOU time periods.

18. Peak demands occur at different times on circuits, substations, and the system as a whole. But, subject to review of specific utility data, TOU time periods can be designed to take into account the majority of distribution circuit and substation peaks.

19. Transmission costs included in retail rates send price signals to customers related to their use of the electric delivery system.

20. Drawing upon data already vetted in other proceedings is an effective and efficient way to ensure that the changing load and demand forecasts are captured in TOU time period or rate design proposals.

21. There is no need to collect CCA-specific data, especially when Base TOU periods will be uniform across each IOU's service territory.

22. Where a utility utilizes two seasons for differentiating TOU rate time periods, it is reasonable to consider proposals to create an overlay of an elective or optional third season for super off-peak usage.

23. Overlay rates provide flexibility in designing TOU rates.

24. After new TOU interval periods are set, it is reasonable to keep them fixed for a period of time. Revising TOU periods too often could make TOU rates less effective in motivating customers to shift load to off peak hours.

25. A minimum period of five years is a reasonable default duration for adopted Base TOU periods, provided that variations in TOU data assumptions over time do not exceed a reasonable "dead band" of tolerance.

26. Examining Base TOU periods every general rate case cycle (approximately every three years) is a reasonable approach for evaluating Base TOU periods, with the expectation that changes to Base TOU periods should be addressed every other general rate case cycle (approximately six years), unless variations in TOU data assumptions over time do exceed a reasonable "dead band" of tolerance.

27. The design and implementation of a "dead band" for purposes of evaluating whether changed conditions warrant TOU time period revisions more frequently than once every five years should be addressed in a separate Tier 3 Advice Letter for each IOU.

28. Because certain customers have incurred costs, and other customers will incur costs in the future, to invest in solar or other load-shifting technologies based upon the current TOU periods, the previously expected value of those investments in relation to savings in utility rates may be lessened if they are subjected to unexpected changes in TOU time periods.

29. Parties proposed a variety of rate structures to lessen the impact of TOU period changes on customers who invest in specific technology, including grandfathering, vintaging (tying TOU periods to the year the customer enrolls), critical peak pricing in exchange for longer grandfathering, limiting TOU period changes to no more than one hour per year, and fixed indifference payments.

30. Unreasonably long grandfathering periods prolong the period during which such customers receive less accurate and less cost-based TOU pricing signals.D.15-07-001 adopted a five-year grandfathering period for certain residential NEM customers that were required to change tariffs or TOU periods. D.16-01-044 adopted a five-year grandfathering period for residential residential solar customers taking service under the successor NEM tariff.

31. Based on the treatment previously accorded residential NEM customers in D.15-07-001 and D.16-01-044, a reasonable balance may be achieved by adopting a limited grandfathering period of five years for NEM customers who opt in to existing TOU rates no later than to June 30, 2017.

32. A ten-year grandfathering period for non-residential customers who complete interconnection applications prior to June 30, 2017 is reasonable.

33. The limited grandfathering adopted here for certain solar customers only applies to the definitions of the TOU periods, and not to the TOU period prices. The rate values within those fixed TOU periods, including methods for allocating costs to TOU periods and setting specific rate levels will be litigated in utility-specific rate proceedings.

34. Solar customers taking service prior to the NEM successor tariff are not covered by the grandfathering adopted in D.16-01-044.

35. This proceeding did not develop a sufficient record to address special transition treatment for other technologies.

36. This proceeding did not develop a sufficient record to address transition mechanisms other than grandfathering. It is reasonable for the IOUs to consider alternative transition mechanisms in their Pending Rate Design Cases.

37. Grandfathering of TOU periods results in customers receiving incorrect time-variant price signals.

38. The impact of grandfathering on revenue collection is not transparent to participating or non-participating customers.

39. Menus of different TOU options offer a way to ease the transition to more cost-based TOU rates.

40. Rate elements for different TOU options, including options with current TOU periods for grandfathering-eligible customers, should reflect up-to-date marginal costs.

41. TOD is a mechanism for time-differentiation of payments by an IOU to an electricity generator.

42. There is not a sufficient record in this proceeding to address whether or how similar principles applicable to TOU time periods may be applicable in the context of TOD payments applicable to electricity generators.

43. Because both TOU and TOD relate to time differentiated pricing, TOU information may be useful in the RPS-related procurement proceedings.

44. Consideration of customer acceptance is appropriate as a tool to refine the design of TOU rate periods, for example, to temper cost based rates, to maintain certain existing TOU features, or to keep TOU periods stable for longer periods of time.

45. Promoting customer understanding and acceptance is an essential element in the success of TOU rates in motivating customers to shift energy usage in an appropriate manner.

46. The development of an effective customer acceptance program relating to TOU-related changes should be addressed in the appropriate rate proceeding for each IOU.

47. Information on changing rates is important for rooftop solar vendors and their customers.

48. Significant changes to TOU periods have been proposed, and some changes already adopted, in all three IOU territories.

49. SCE's rate design window filed in 2013 and SDG&E's rate design window filed in 2014 both proposed changes to TOU periods.

50. At this time, customers who invest in solar or other DER technologies, or in operational changes to shift time of energy use, should be on notice that TOU periods will be reviewed and potentially changed every five to six years.

51. Parties in this proceeding have described a wide range of rate designs that incorporate TOU periods. Appendix 2 contains a compendium of these illustrative rate designs.

52. Agricultural Energy Consumers Associates and the Public Schools had ample opportunity to become parties and participate in this proceeding prior to issuance of the proposed decision.

Conclusions of Law

1. This rulemaking is an appropriate vehicle to develop high-level policy guidelines to apply in the consideration, development, and implementation of specific changes in TOU time periods applicable to the major California investor-owned electric utilities.

2. The scope of this decision should be limited to consideration of high-level policy guidelines for developing TOU time periods, whereas specific proposals for TOU time period changes should be addressed in each IOU's next GRC phase 2 or rate design window proceeding.

3. D.15-07-001 and D.16-01-044 recognized that limited grandfathering of TOU periods for customers with certain technologies may be appropriate.

4. The high-level guidelines set forth in Appendix 1 of this decision should be adopted for use in designing, implementing, and modifying the Base TOU periods and TOU rate designs based on those Base TOU periods.

5. A five-year grandfathering period for residential customers who complete interconnection applications prior to June 30, 2017 is reasonable.

6. A ten-year grandfathering period for non-residential customers who complete interconnection applications prior to June 30, 2017 is reasonable.

7. This decision resolves all outstanding issues within the scope of this proceeding, and accordingly, this proceeding should be closed.

8. The motions for party status of Agricultural Energy Consumers Associates and the Public Schools should be denied.

9. No hearings are necessary.

O R D E R

IT IS ORDERED that:

1. Appendix 1 of this decision, entitled: "Policy Guidelines Applicable to the Design, Implementation, and Modification of Time-of-Use (TOU) Time Intervals Reflected in Rates" is hereby adopted for use in designing, implementing, and modifying the base time intervals reflected in the design of TOU rates applicable to Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas and Electric Company, respectively, applicable in either a general rate case phase 2 or a rate design window proceeding. Any future application regarding TOU time periods should include testimony in support of compliance with the guidelines.

2. Each of Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas and Electric Company shall make its Base Time-of-Use period, as set in its respective rate proceeding, available to the public on its website and include this information in its annual Renewable Portfolio Standard procurement plan.

3. In its next filed general rate case phase 2, each of Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas and Electric Company (collectively, IOUs) shall include data on marginal distribution costs that contribute to total peak-hour marginal cost and shall provide any time-of-use information included in IOU transmission filings at Federal Energy Regulatory Commission or adopted in Federal Energy Regulatory Commission transmission rate proceedings. Along with this data, the IOU shall include information on the status of distributed energy resource valuation methodologies being developed in Rulemaking 14-08-013 and Rulemaking 14-10-003 or successor proceedings.

4. In separate Tier 3 Advice Letters, to be filed no later than March 31, 2017, each of Pacific Gas and Electric Company, Southern California Edison Company, and
San Diego Gas and Electric Company shall propose a dead band tolerance range for determining when a change would trigger time-of-use period revisions more frequently than every two rate cycles and a mechanism for implementation.

5. Each of Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDG&E) shall ensure that customers with existing behind-the-meter solar be permitted to maintain time-of-use rate periods for five to ten years. This period for retaining TOU periods applies only to qualified customers on the terms and conditions set forth below. Each IOU is permitted to structure an alternative but equivalent mitigation measure for these customers, but any such alternative must be approved by the Commission. To minimize the administrative burden of retaining time periods for these customers, each IOU should propose procedures, such as setting a limited number of dates each year on which to migrate these customers to new TOU periods, that will ease administration. Each IOU, or the IOUs collectively, shall meet with parties to consider administrative procedures and each IOU shall file its own Tier 3 Advice Letter with specific administrative procedures no later than March 31, 2017. The terms and conditions are as follows:

- Customer Eligibility: Applies to (a) residential customers with on-site solar systems, who opt-in to a TOU tariff prior to the End Date as defined in the next bullet and (b) commercial and industrial customers. This transition does not apply to customers who are already permitted to stay on a TOU rate for five years pursuant to D.16-01-044.
- Eligibility Period End Date: June 30, 2017

- System Eligibility: Systems for which interconnection applications, including final building inspection, are completed at any time prior to the End Date are eligible. The system must be designed to offset at least 15% of the customer's current annual load.
- Duration:
  - For residential systems, this transition mitigation measure continues for 5 years after issuance of a permission to operate. In no event shall the duration continue beyond June 30, 2022.
  - For commercial and industrial systems, this transition mitigation measure continues for ten years after issuance of a permission to operate. In no event shall the duration continue beyond June 30, 2027.
- Attributes: This transition mitigation measure allows the customer to maintain the same TOU periods for the duration. Other changes in rate design, including allocating marginal costs to TOU periods and setting specific rate levels, will be litigated in utility-specific rate proceedings.

6. Except as set forth in Ordering Paragraph 5, this decision shall not be binding on any rate proceeding filed prior to October 1, 2016. Parties in currently open proceedings may cite to this decision in support of their arguments, but compliance with this decision shall be required only for proceedings opened after October 1, 2016.

7. The hearing determination is changed to state that no hearings are necessary.

8. The motions for party status of Agricultural Energy Consumers Associates and the Public Schools are hereby denied. All other pending motions are denied.

9. Rulemaking 15-12-012 is closed.

Dated __________________, at San Francisco, California.

Appendix 1

Policy Guidelines Applicable to the Design, Implementation, and Modification of Time-of-Use (TOU) Periods To be Used in Rate Designs

Base TOU periods and related rate designs should be established independently for each utility either in a general rate case (GRC) or a rate design window (RDW). Geographically-differentiated TOU time periods within an IOU's service territory are not required or encouraged at this time. Any proposals for geographically-differentiated rates must demonstrate that the proposed rates do not conflict with universal and non-discriminatory service requirements.

2. Base TOU periods should be based on utility-specific marginal costs, rather than on a statewide load assessment. This marginal cost analysis should use marginal generation cost, consisting of marginal energy costs and marginal generation capacity costs. Going forward, the IOUs should include information on marginal distribution costs that contribute to peak load costs and time of use information filed or adopted in FERC transmission rate proceedings. Use of marginal distribution and transmission cost information in setting future Base TOU periods will be addressed in individual IOU rate proceedings.

3. As a secondary check on the marginal cost analysis, the IOUs should provide hourly load and net load data and explain any significant differences between estimated high and low marginal cost hours and the net load shapes (including adjusted net load data for PG&E). As part of its TOU period analysis, each IOU should submit the latest data and assumptions, including those vetted in the Long Term Procurement Planning (LTPP) and/or Integrated Resource Planning (IRP) or successor proceeding.

4. Base TOU periods should be developed using forward-looking data, with the forecast year set at least three years after the year the Base TOU period will go into effect.

5. Base TOU periods should continue for a minimum of five years (unless material changes in relevant assumptions indicate the need for more frequent Base TOU period revisions) and each IOU should propose new Base TOU periods, if warranted, at least every two general rate case cycles.

6. Each IOU, in a Tier 3 Advice Letter, should propose a dead band tolerance range for determining when a change would trigger TOU period revisions more frequently than five year intervals. To evaluate whether a dead band tolerance range has been exceeded and to ensure that the Commission and the public are aware of the likelihood of future Base TOU period changes, Base TOU period analysis should be provided in each general rate case, even if the IOU does not propose a change in Base TOU periods. If such analysis shows that the dead band tolerance range has been exceeded, the IOU should propose revisions to Base TOU periods.

7. Each IOU should take steps to minimize the impact of TOU peak period changes on customers who have invested in on-site renewable generation or technology to conserve energy during peak periods. Regularly scheduled updates to TOU periods will provide predictability for these customers. Additional steps to increase certainty around TOU periods could include vintaging, legacy TOU periods, or fixed indifference payments, as well as other rate structures that provide predetermined limits on TOU period changes. Such steps must also include making information on potential shifts in peak periods available to the public.

8. A menu of TOU rate options should be developed in utility-specific rate design proceedings and should provide rate choices addressing different customer profiles and needs. IOUs are encouraged to use the Base TOU periods to develop at least one optional TOU rate design with a more complex combination of seasons and time periods and may incorporate more dynamic pricing features and enabling technology as appropriate to address grid needs.

9. TOU periods used in rate designs should be designed around the Base TOU periods and should reflect up to date marginal costs, but may be modified to take into account customer acceptance, preferences, understanding, ability to respond and similar factors. These considerations include:

- The extent to which customers understand TOU rates generally.
- The time and education required for customers to transition to a new TOU rate period.
- The ability of customers to respond at a specific time of day or over a given period of time.

- Customers’ need for predictable TOU periods, including the schedule of possible TOU rate period changes, when they make investment decisions regarding energy efficiency, storage, photovoltaics, electric vehicles and other distributed energy resources or consider major operational changes to shift usage outside of peak periods.
- The appropriate treatment of different customer classes, as necessary, in light of the fact that customer needs and sophistication may vary by customer class.

(End of Appendix 1)

Appendix 2

Illustrative Time-Varying Rates

Compendium of Rate Designs Discussed in Rulemaking 15-12-012

This Appendix is a compendium of the different time-varying rate designs that were discussed in this proceeding. This list does not endorse specific rate designs. Rather, it is intended to provide context for the discussion of designing rates that incorporate the need to encourage or discourage energy use during certain times of the day. This proceeding started with the TOU time periods suggested by the CAISO TOU Report based on the CAISO's forecast and analysis.

Illustrative Time Periods (CAISO TOU Report)[49]

- Super-Peak: 4-9 pm weekdays, July and August
- Peak: 12:00 – 4 pm weekdays, July and August; 4 – 9 pm on all other days
- Super Off-Peak: 10 am – 4 pm weekdays March and April and weekends/holidays (except July and August)
- Off-Peak: All other periods

Illustrative Time-of-Use Rate Designs

1. TOU-Lite

TOU-Lite is a variant of a standard TOU rate design that features a minimal number of TOU periods with a mild price differential. Parties suggest that this design would work well as a default rate for smaller customers.

Parties suggest there could be two versions of TOU-Lite available as a default and a customer would be able to select or be assigned the best rate. This approach is currently used by Arizona Public Service Company. For example, one rate could have a shorter peak period with a higher price differential and the second rate could have a longer peak period with a lower price differential. Alternatively, a "late bird/early bird" design could be used to offer one rate with a peak rate period early in the Base TOU peak period and a second rate with a

[49] It should be noted that the CAISO TOU Report focuses on time periods, but not does not suggest actual rates. The CAISO provided this information to help inform the Commission's decision in this proceeding regarding methodologies for setting TOU rate periods that align with the needs of the grid.

later peak rate period. In either case, the two alternative rates could still be cost-based.

2. Complex TOU Rates

A variety of complex TOU rate designs were discussed. These complex rates could have a greater number of seasons, greater number of time periods (peak, off-peak, semi-peak), or other attributes that may not be suitable for all customers.

Illustrative Rate Design (SDG&E Residential Opt-In Pilot)

SDG&E's residential opt-in pilot features two TOU periods, an on-peak and an off-peak period. The rates in these periods are adjusted in accordance with the CAISO day-ahead hourly price. The rate also features both an hourly dynamic commodity adder that reflects the top marginal generation capacity cost (MGCC) 150 hours and a distribution adder that reflets the top marginal distribution cost (MDC) 200 hours. An hourly commodity credit is also assigned to reflect generation surplus and a fixed $10 monthly service fee is included to recover fixed costs.

- 2 period base rate + adjustment based on CAISO day ahead hourly price
- hourly dynamic commodity adder for top 150
- hourly distribution adder for top 200 hours
- hourly commodity credit
- $10 monthly service fee

Illustrative Rate Design (SDG&E Vehicle to Grid Integration Pilot)

SDG&E's Vehicle to Grid Integration (VGI) rate is available to customers enrolled in its 5-year electric vehicle charging pilot. The rate consists of the CAISO's day-ahead hourly rate and a commodity adder, commodity critical peak pricing or C-CPP, that reflects the top 150 system peak hours and a distribution adder, distribution critical peak pricing, or D-CPP, that reflects the top 200 annual hours of peak demand on circuits interconnected to VGI charging stations. An hourly commodity credit is provided to VGI customers during periods when CAISO deems there is a generation surplus. Hourly base rate with adjustments based on day-ahead hourly price

- Hourly dynamic commodity adder to reflect system's top 150 system peak hours
- Hourly distribution adder to reflect the top 200 annual hours of peak demand for individual circuits feeding the VGI charging stations, timing varies by circuit
- Hourly commodity credit during CAISO surplus events.

Illustrative Rate Design (SCE Matinee Rate Pilot)

SCE's matinee pricing pilot proposed in R.11-12-013 consists of a menu of hourly prices that reflect 9 different temperature/day-of-week profiles. The pricing menu would be determined 1 day in advance and the customer would be notified. The profiles include: Extremely Hot

Summer Weekday, Low Cost Winter Weekday, and Low Cost Weekend.

- Off-peak generation based on recent CAISO day-ahead energy price data
- Weekend and spring/winter weekday rates at 30% discount from 10 a.m. to 4 p.m.

Illustrative Rate Design (GPI proposal for hourly TOU periods)

GPI's TOU proposal is based upon setting two hourly energy profiles offered each month, one that corresponds to weekdays and the other that corresponds to weekends. Each of these 24 profiles would contain hourly energy values that would result in 576 energy prices on an annual basis.

3. Dynamic Rates with Enabling Technology or Service Provider

Technology can facilitate a customer's response to rates, making it possible for some customers to respond to complex rates and real time pricing. It should not be assumed, however, that all customers have such automated technology. Three different scenarios for these complex rate designs were highlighted:

Technology-enabled real-time pricing:
EDF envisions a "Smart Home Rate" that would reward customers for responding to price signals in real time.

Automated Demand Response
CalSEIA proposed a rate that features four seasons, presumably summer, fall, winter and spring, and four TOU periods, conceivably on-peak, partial peak, off-peak and super off-peak periods, in an automated demand response (ADR) rate. This rate design would permit customers enrolled in ADR programs to tailor energy use according to more granular price signals while serving grid needs. Specifically, CalSEIA recommends using rate differentials significant enough to encourage energy storage.

Third party service provider
EDF envisions third party service providers that can "translate" complex rates for customers by offering products that give the customer a simple rate, while the third party service provider provides the necessary automation or other service to respond to the complex rate. This reduces uncertainty and risk for retail customers by providing an intermediary service that translates complex rates. For example, the complexity of the SDG&E VGI rate provides an opportunities for third party aggregators to simplify the rate for customers while enabling integration from a grid standpoint.

4. Overlay Rates

Overlays provide a way to add additional nuances to simple or complex rates, without modifying the underlying rate design for all customers. Overlays are optional tariffs that apply adders and credits on to a customer's existing rate.

While Base TOU periods may stay in place for 5 years, overlays could provide flexible option for responding to more immediate needs.

Illustrative Rate Designs

Event-based Critical Peak Pricing. SEIA, SCE and SDG&E proposed the use of event-based Critical Peak Pricing that includes a rate adder to recover costs during high cost, on-peak TOU periods with day-ahead notification.

Seasonal Matinee Rates. PG&E proposed a the use of a seasonal matinee rate or super-off peak overlay credit to address periods of oversupply during months when minimum net load conditions are expected. As proposed in R.13-12-011, PG&E's matinee pricing pilot would include a super off-peak credit during certain hours in March – June. A 1 cent adder to all other hours in those months keep the rate revenue neutral.

Event-Based Matinee Rates. As an alternative to offering a seasonal overlay, SEIA proposes use of static matinee rate overlays on event days, or discount days, when oversupply and minimum net load conditions are forecasted.

Inner Summer Season Overlay. SEIA proposed adding an inner summer season w/shoulder periods that would assign a rate adder to shorter, more targeted super peak periods. The rates assigned to adjacent shoulder periods would recover costs from high cost hours that precede or follow these super peak periods.

Super off-peak prices Overlay.

5. Other Alternative Rates and Overlays

Illustrative Rate Design Storage Rate: – rate scenario that achieves customer cost-effectiveness for storage. CalSEIA at 9. (control technology, 4 season, 4 types of time periods). PG&E concerned that such a rate would result in a these customers being subsidized.

Illustrative Rate Design Incentive-Based Rates. Same as above, but could be non-cost based so as to promote policy goals to meet solar, EV and GHG Goals (UCAN at 13) But should retain cost based price signals

Illustrative Rate Design Rolling or Vintaged Rate Options. As the timing of price and cost peaks shifts, new TOU periods could be adopted for the new timing, with customers migrating over time. In other words, rather than shift all customers to new TOU periods at the same time, rates with the latest TOU periods could be made available to new or opt-in customers as soon as shifts in TOU periods are identified, and Fixed indifference payments.

(END OF APPENDIX 2)

Appendix 3

Anticipated Schedule for TOU Period Implementation Based on Current Rate Case Plan

Event	Approximate Date	Action related to TOU periods
SCE RDW	September 2016	Set new TOU periods.
R1512012 decision	December 2016	Adopts methodology and timing for adopting Base TOU periods
SCE Phase 2	January 2017	Phase 2 Base TOU Period Evaluation
Advice Letters pursuant to R.15-12-012	March 2017	Tier 3 AL to address dead band tolerance procedure Tier 3 AL to address administrative efficiency measures for required grandfathering
SDG&E Pending Phase 2 completed	May 2017	New TOU periods implemented.
	June 30, 2017	Final date to qualify for legacy TOU periods
PG&E pending Phase 2 completed	EOY 2017	New TOU periods implemented.
SCE pending RDW completed	EOY 2017	New TOU periods implemented
Residential RDW filed pursuant to D.15-07-001	January 2018	For all 3 IOUs, propose default TOU rates for residential customers
SDG&E Phase 2 filed	January 2018	Evaluate TOU Base periods, but no changes to Base periods unless dead band triggered
SCE Phase 2 rate design completed	April 2018	No changes to TOU periods unless dead band triggered
Residential RDW TOU rates implemented per D.15-07-001	2019 (rolling);	Residential Default TOU implemented (strive for no changes to TOU periods until 2024)
PG&E Phase 2 filed	January 2019	Evaluate Base TOU periods against dead band
SDG&E Phase 2 completed	April 2019	No changes to TOU periods unless dead band triggered
SCE Phase 2 filed	January 2020	New Base TOU periods proposed
PG&E Phase 2 completed	April 2020	No changes to TOU periods unless dead band triggered
SDG&E Phase 2 filed	January 2021	New Base TOU periods proposed
SCE Phase 2 completed	April 2021	New Base TOU periods adopted

Event	Approximate Date	Action related to TOU periods
PG&E Phase 2 filed	January 2022	New Base TOU periods proposed
SDG&E Phase 2 completed	April 2022	New Base TOU periods adopted
End of legacy periods for residential customers covered by this decision	June 30, 2022	
SCE Phase 2 filed	January 2023	Evaluate Base TOU periods against dead band
PG&E Phase 2 completed	April 2023	New Base TOU periods adopted
End of legacy periods non-residential customers covered by this decision	June 30, 2027	