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BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company To Revise Its Electric Marginal Costs, Revenue Allocation, and Rate Design. (U 39 M)	Application 06-03-005 (Filed March 2, 2006)

DECISION ADOPTING DYNAMIC PRICING TIMETABLE AND RATE DESIGN GUIDANCE FOR PACIFIC GAS AND ELECTRIC COMPANY

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DECISION ADOPTING DYNAMIC PRICING TIMETABLE AND RATE DESIGN GUIDANCE FOR PACIFIC GAS AND ELECTRIC COMPANY

1. Summary

This decision continues implementation of the Commission's policy to make dynamic pricing available for all customers. Dynamic pricing can lower costs, improve system reliability, cut greenhouse gas emissions, and support modernization of the electric grid.

First, dynamic pricing can lower costs by more closely aligning retail rates and wholesale system conditions, thereby promoting economically efficient decision-making. In more concrete terms, dynamic pricing can lower peak usage and reduce the need to build additional generation capacity to meet the peak. Furthermore, dynamic pricing, coupled with advanced meters, will enable customers to better manage their electricity usage and reduce their bills.

Second, dynamic pricing can improve system reliability by providing customers an incentive to lower their usage when the supply and demand balance is strained or in the face of a system emergency. Dynamic pricing can reduce the bills of a customer who reduces his or her usage in the face of scarce supply.

Third, dynamic pricing can connect retail rates with California's greenhouse gas policies. When wholesale energy prices are high, the most inefficient generation sources with high greenhouse gas emissions are generally operating. By linking retail rates to wholesale market conditions, dynamic pricing can discourage customers from consuming polluting power. Conversely, if other time periods are dominated by non-emitting and low-cost resources such as nuclear, water, and wind, dynamic pricing could signal to customers that the supply of power is clean.

Finally, dynamic pricing will be a building block of a smarter, more advanced electric grid.

This decision adopts a timetable that specifies when Pacific Gas and Electric Company (PG&E) is required to propose specified dynamic pricing rates. The decision also adopts rate design guidance that PG&E shall be required to adhere to in all of its future dynamic pricing proposals.

2. Procedural Background

PG&E filed its 2007 General Rate Case (GRC) Phase 2 Application (A.) 06-03-005 on March 2, 2006. On July 25, 2006, the assigned Commissioner issued an Assigned Commissioner's Ruling and Supplemental Scoping Memo that determined dynamic pricing would be addressed in the proceeding. Marginal cost, revenue allocation, and rate design were addressed separately in Decision (D.) 07-09-004.

The July 25, 2006 Ruling determined that the primary objective of the dynamic pricing phase is to create a year-by-year strategic work plan that will direct PG&E to develop and integrate well-designed dynamic pricing tariffs into PG&E's rate design for all customers by 2011. The strategic work plan should answer the following three questions:

1. What types of dynamic pricing tariffs should PG&E offer to its customers?

2. When should PG&E offer each type of dynamic pricing tariffs to each customer class?

3. How should the dynamic pricing tariffs be designed and integrated into PG&E's overall rate design?

The work plan should contain sufficient detail to guide and implement PG&E's future rate design, and PG&E will be required to follow the timetable and rate design principles.

On July 31, 2007, the assigned Commissioner issued a ruling that included a preliminary list of issues and a preliminary schedule. Parties filed comments recommending changes to the preliminary issues list.[1]

A follow-up ruling on August 22, 2007 revised the issues list based on parties' comments and requested comments on the issues. Eleven parties filed opening comments on the list of issues on October 5, 2007.[2] Eight parties filed reply comments on October 19, 2007.[3] Two days of workshops were held on November 5 and 6, 2007, at which key issues identified by parties in comments were discussed. Ten parties filed post-workshop comments on December 11, 2007.[4]

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[1] The parties that filed comments were Alliance for Retail Energy Markets and the Direct Access Customer Coalition (AReM/DACC), Building Owners and Managers Association (BOMA), California Large Energy Consumers Association (CLECA), Division of Ratepayer Advocates (DRA), Energy Producers and Users Coalition (EPUC), Ice Energy, PG&E, San Diego Gas & Electric Company (SDG&E), Southern California Edison Company (SCE), The Utility Reform Network (TURN), and Western Power Trading Forum (WPTF).

[2] The parties that filed opening comments were BOMA, CLECA, California Manufacturers and Technology Association (CMTA), California Rice Millers (CRM), DRA, Ice Energy, PG&E, SDG&E, SCE, TURN, and WPTF.

[3] The parties that filed reply comments were BOMA, CLECA, CMTA, DRA, PG&E, SDG&E, SCE, and TURN.

[4] The parties that filed post-workshop comments were BOMA, California Farm Bureau Federation (CFBF), CLECA, CMTA and EPUC, jointly (CMTA/EPUC), CRM, DRA, PG&E, SDG&E, SCE, and TURN.

A further ruling was issued on January 23, 2008. This ruling included the draft timetable and draft rate design guidance and requested comments from parties. Comments were filed by 12 parties on February 28, 2008.[5]

Another workshop, held on March 7, 2008, focused on critical peak pricing (CPP). Six parties filed post workshop comments on March 21, 2008.[6]

3. Policy Background

The Commission articulated a comprehensive demand response policy in its 2003 Vision Statement.[7] In that statement, the Commission stated that electric customers should have "the ability to increase the value derived from their electricity expenditures by choosing to adjust usage in response to price signals" as customers are equipped with advanced meters as a result of the Commission's Advanced Metering Infrastructure (AMI) decisions.

Prior to the 2003 Vision Statement, virtually all large customers had moved to time-of-use (TOU) rates. TOU rates consist of several pre-defined time periods and charge customers different pre-determined rates during each time period. For example, during the summer the rate charged during the afternoon is generally higher than the rate charged at night. The different rates reflect the fact that it is generally more expensive to serve customers during some time periods. TOU rates do not change based on current market conditions. In the

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[5] Comments were filed by BOMA, CLECA, CMTA, DRA, EPUC, Ice Energy, Kinder Morgan Energy Partners (Kinder Morgan), PG&E, SDG&E, SCE, TURN, and Wal-Mart Stores.

[6] Post workshop comments were filed by BOMA, CLECA, EPUC, Kinder Morgan, PG&E, and SDG&E.

[7] "California Demand Response: A Vision for the Future (2002-2007)," referred to here as the 2003 Vision Statement, was attached to D.03-06-032 as Attachment A.

2003 Vision Statement, the Commission recognized the value of moving beyond TOU rates to truly dynamic rates that change based on actual system prices and conditions.

The Energy Action Plan II (EAP II), developed and adopted jointly by the CPUC and California Energy Commission (CEC), sets out key actions that both agencies intend to pursue. The EAP II identifies demand response, along with energy efficiency, as the State's "preferred means of meeting growing energy needs."[8]

The EAP II concludes that "[w]ith the implementation of well-designed dynamic pricing tariffs and demand response programs for all customer classes, California can lower consumer costs and increase electricity system reliability."[9] The Commission intends to pursue its Energy Action Plan objectives in this proceeding.

One key action of special relevance in this proceeding is the following:

> Identify and adopt new programs and revise current programs as necessary to achieve the goal to meet five percent demand response by 2007 and to make dynamic pricing tariffs available for all customers.[10]

Dynamic pricing rates include CPP and Real-Time Pricing (RTP).[11]

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[8] EAP II, p. 2.

[9] *Id.*, p. 4.

[10] *Id.*, p. 5.

[11] *Definitions:*

Critical Peak Pricing (CPP): A dynamic rate that allows a short-term price increase to a predetermined level (or levels) to reflect real-time system conditions. Typically, the time and duration of the price increase are predetermined, but the days are not predetermined.

Footnote continued on next page

The Commission has identified rate design proceedings as the appropriate forum to address dynamic pricing. In D.05-11-009, the Commission determined that dynamic pricing tariff options for all types of customers should be addressed in each utility's comprehensive rate design proceeding.[12] Furthermore, in D.06-05-038, the Commission directed each utility "to incorporate default critical peak pricing tariffs for large customers into their next comprehensive rate design proceeding or other appropriate proceeding if directed by the Commission."[13]

The Commission has also directed each utility to submit RTP tariffs in its first comprehensive rate design proceeding, following the California Independent System Operator's (CAISO) implementation of its Market Redesign and Technology Upgrade (MRTU).[14]

Finally, at the May 25, 2006 Commission public meeting adopting D.06-05-038, several Commissioners indicated their desire to address CPP issues in this proceeding.

Real-Time Pricing (RTP): A dynamic rate that allows prices to be adjusted frequently, typically on an hourly basis, to reflect real-time system conditions. (*Glossary of Retail Electricity Rate Terms*, Attachment A to D.03-03-036.)

12 *See* D.05-11-009, Ordering Paragraph (OP) 3, 4, and 5.

13 D.06-05-038, p. 16.

14 D.05-11-009 states "As the CAISO moves to implement its market redesign, we anticipate that transparent pricing information will become available that will facilitate development and adoption of a true RTP tariff. However, design of such a tariff cannot be performed in isolation from comprehensive rate design examination. Therefore, we direct each utility, as part of its next comprehensive rate design proceeding application following development and final implementation of an hourly day-ahead market price by the CAISO, to submit a real time pricing tariff for consideration as part of its tariff offerings." (P. 7.)

Most dynamic pricing rates require meters that can measure a customer's usage on an hourly basis or even more frequently. Meters that have this type of capability are referred to as interval meters or advanced meters. PG&E's large commercial and industrial (C&I) and agricultural customers with maximum usage of greater than 200 kilowatts (kW) have interval meters, but the roll out of advanced meters to PG&E's smaller customers, including residential and smaller C&I customers, is just beginning. In D.06-07-027, the Commission approved PG&E's service territory-wide AMI project, and in A.07-12-009, the Commission is considering an upgrade to PG&E's project. Until metering infrastructure is more broadly available, dynamic tariff design may be constrained to certain customer groups. However, by 2012, all of PG&E's customers should have advanced meters, so all customers can take advantage of dynamic pricing.

4. What Rates Should PG&E Offer Each Customer Class and When?

This section answers the first two questions posed in the Supplemental Scoping Memo:

- What types of dynamic pricing tariffs should PG&E offer to its customers, and

- When should PG&E offer each type of dynamic pricing rate to each customer class?

This decision does not itself adopt any rates and does not commit the Commission to approve specific rates. Instead, this decision establishes dates when PG&E will be required to propose specified rates. We refer to these dates as the timetable. In the proceedings in which the Commission considers PG&E's specific rate proposals, the Commission could decide to adopt different rates or a different timetable based on the information presented to the Commission at that time.

Attachment B includes an illustrative timetable that summarizes PG&E's customers' rate options if the Commission adopts the rates that PG&E is required to propose pursuant to this decision.[15]

4.1. Dates of PG&E Filings

PG&E recommended that the timetable should adhere to the existing GRC Phase 2 and Rate Design Window process.[16] In D.07-03-044, the Commission adopted a settlement that shifted PG&E's next GRC by one year, so PG&E will file its GRC Phase 2 in March 2010, and the rates will have an effective date of January 1, 2011. According to the Rate Design Window process adopted for PG&E in D.89-01-040, PG&E files rate design revisions on November 25th of a particular year and the new rates are supposed to become effective on May 1st of the following year. In summary, PG&E's GRC Phase 2 and Rate Design Windows are subject to the following schedule from 2008 to 2012:

Filing Date	Effective Date of Rates
November 25, 2008	May 1, 2009
November 25, 2009	May 1, 2010
March 1, 2010	January 1, 2011
November 25, 2011	May 1, 2012

The filing schedule adopted in the following sections adheres in part to this schedule. However, based on comments, some filing dates have been

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[15] The dynamic pricing rates discussed in this decision are only applicable to bundled-service customers.

[16] GRC Phase 2 typically addresses revenue allocation, marginal cost and rate design.

delayed to allow more time for PG&E to prepare filings. For instance, the filing date of the 2008 Rate Design Window will be delayed from November 25, 2008 to February 28, 2009. Furthermore, the effective dates of some rates have been delayed to allow more time for PG&E to conduct customer education and make necessary system upgrades following adoption of the rates by the Commission.

4.2. Large C&I

Large C&I[17] customers with maximum load greater than 500 kW have been on mandatory TOU rates since the late 1970's or early 1980's, depending on the size of the customer.[18] In 2001, the California legislature appropriated $35 million to be used by the CEC "to provide time-of-use or real time meters for customers whose usage is greater than 200 kilowatt."[19] The interval meters installed under the CEC's program can support CPP and RTP in addition to TOU rates. In a related decision, the Commission required mandatory TOU rates for all customers with maximum demand greater than 200 kW who received new meters via the CEC's funding.[20]

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17 We define large C&I customers as those with maximum demand greater than or equal to 200 kW.

18 *See* D.85559, 1976 Cal. PUC LEXIS 1308 (Cal. PUC 1976) (ordered three major utilities to implement mandatory TOU for customers with demands greater than 500 kW); D.86632, 1976 Cal. PUC LEXIS 931 (Cal. PUC 1976) (approved mandatory TOU rates for PG&E customers with maximum load greater than 4,000 kW); D.90588, 1979 Cal. PUC LEXIS 772 (Cal. PUC 1979) (approved mandatory TOU rates for PG&E customers with maximum load between 1,000 kW and 4,000 kW); D.92553, 1980 Cal. PUC LEXIS 1279 (Cal. PUC 1980) (approved mandatory TOU rates for PG&E customers with maximum load between 500 kW and 1,000 kW).

19 Assembly Bill 1X 29 from the 2001-2002 First Extraordinary Session, Section 14(d)(4)(B).

20 *See* D.01-05-064 as modified by D.01-08-021 and D.01-09-062.

Large C&I customers also have the option to sign up for a voluntary CPP rate. Non-time-variant rates and RTP are not currently available to large C&I customers. A number of demand response programs are available to these customers as well.

As a result of these past policies, the vast majority of large C&I customers have been on TOU for over five years, and some have been on TOU for as long as 30 years.

PG&E's customers in this category are generally on Schedule E-20 (for customers with maximum demand 1,000 kW and greater), Schedule E-19 (for customers with maximum demand between 500 kW and 1,000 kW), and Schedule A-10 TOU (for customers with maximum demand between 200 kW and 500 kW). [21]

4.2.1. What Dynamic Pricing Rates Should PG&E Offer Large C&I Customers?

Parties' Comments

BOMA does not support CPP as a default rate. BOMA argues that CPP is not a truly dynamic rate since the critical peak rate is triggered administratively by the utility based on pre-determined conditions, and the periods when events are called by the utility will only reflect real-time marginal system costs by chance. BOMA believes RTP is the best rate to promote economic efficiency and rate equity. Thus, BOMA supports the prospect of RTP becoming the default rate.[22]

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[21] The relevant tariffs indicate the applicability with greater specificity.

[22] BOMA Comments, February 28, 2008, pp. 3-4.

CLECA believes that CPP is a viable rate option for some customers and should be available to large C&I customers on a voluntary basis. CLECA notes that some large customers are already on CPP and have achieved significant usage reductions by also using Auto DR enabling technologies.[23] CLECA believes RTP should be available on an optional basis.[24]

EPUC argues that large customers have relatively flat load profiles, suggesting these customers have little ability to reduce or shift load. Therefore, EPUC concludes that a mandatory CPP rate would be punitive and would not result in meaningful load reductions. EPUC is also concerned that the month-to-month bill volatility associated with CPP is not appropriate for a default rate.[25]

SDG&E supports exploring RTP as a rate option, but believes it is premature to implement until MRTU is implemented and well understood. In the interim, SDG&E supports continued implementation of CPP as a default rate for large and medium C&I customers. SDG&E further recommends the Commission adopt default dynamic pricing for each of the utility's customer classes. SDG&E explains that "[d]ynamic rates should be designed in such a fashion where a particular price signal can be provided to the customer with little or no transactions cost and that the information content embedded in such a

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[23] Auto DR is a research program managed by the Demand Response Research Center (DRRC) designed to link facility energy management control systems with external utility-generated price or emergency signals. The use of this technology is integrated with various existing utility demand response programs, such as the critical peak pricing program. In D.06-11-049, the Commission directed the utilities to develop Auto DR implementation plans.

[24] CLECA Comments, February 28, 2008, p. 3.

[25] EPUC CPP Comments, March 21, 2008, pp. 5-6.

price signal achieves corresponding behavioral actions that allow customers to manage their energy usage and resulting energy bills."[26]

Discussion

We believe RTP should be developed and made available for large C&I customers as soon as feasible. Large C&I customers already have considerable experience with TOU rates. Thus, we expect that, offered an opportunity to enroll in RTP, many large C&I customers will find new ways to deploy enabling technologies and manage their energy costs, which will benefit the customers and the efficiency of the overall market. Therefore, once MRTU becomes operational we expect the utilities to promptly develop RTP as required by D.05-11-009. We agree with BOMA that RTP is the best rate to promote economic efficiency and equity between customers.

In the interim, we agree with SDG&E that default CPP is appropriate for large C&I customers. We support default CPP because it more closely aligns the retail rate with the wholesale market, and it can give customers an opportunity to manage their usage and lower their bills.

We disagree with EPUC that default CPP is punitive. As CLECA has pointed out, many customers that have enrolled in CPP on a voluntary basis have been able to significantly reduce their usage during critical peak events, especially with the help of enabling technologies. We expect many more customers will be able to reduce their bills by doing the same.

BOMA raises another criticism of CPP by arguing that CPP is not actually a form of dynamic pricing since so many of the parameters of the rate are

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[26] SDG&E Post-Workshop Comments, December 11, 2007, p. 4.

administratively determined. We disagree with BOMA. Although the CPP price and the calling of events are not entirely market based, the CPP price and events can be good market proxies if the rate is designed well and called appropriately by the utility. In fact, one of the reasons the Commission has been pursuing CPP is that true market-based dynamic pricing that is tied to day-ahead energy prices cannot be developed until the day-ahead wholesale market is operational. In some respects, CPP is a second-best rate option until RTP can be developed and implemented. The Commission supports BOMA's desire to move to RTP as reflected in the timetable we adopt below, but we continue to believe, consistent with the Commission's determination in D.06-05-038, that CPP should be the default rate for large C&I customers.

4.2.2. When Should PG&E Introduce Dynamic Pricing to Large C&I Customers?

According to the draft timetable in the January 23, 2008 Ruling, PG&E would propose that in 2010, its large C&I customers would have to choose either TOU/CPP or RTP.[27] Starting in 2011, RTP would become the default rate. TOU and TOU/CPP would continue to be available as optional rates. The draft timetable also proposed that PG&E would file revisions to its existing CPP rate in 2008 with an effective date in 2009.

Parties' Comments

PG&E claims that metering and billing system constraints prevent moving all large C&I customers to CPP or RTP until 2011. Of PG&E's approximately 9,000 large C&I customers, about 5,500 are billed through PG&E's primary

[27] TOU/CPP is used in this decision to refer to a CPP rate with TOU pricing during non-critical peak periods.

billing system, the Customer Care & Billing (CC&B) system. The CC&B system cannot directly accept interval metering data and does not support CPP and RTP. The remaining large customers, including customers who are generally on CPP and other more complex rates, are on a different billing system — the Advanced Billing System (ABS).

PG&E is upgrading the CC&B system to bill new rates including CPP as part of the AMI project. PG&E is also planning to replace large customers' interval meters with new AMI meters. The CC&B upgrade and meter upgrade will enable PG&E to bill large customers on CPP. However, PG&E does not plan to upgrade the system for large C&I customers until the end of the AMI roll-out in 2011. PG&E explains that to implement default CPP or RTP before 2011, the 5,500 large customers currently being billed on its primary CC&B system would have to be temporarily moved to the ABS billing system until they can be moved to the upgraded CC&B system in 2011 or 2012. This will be complicated and cost approximately $30 million according to PG&E's initial rough estimates.[28] [29]

PG&E offers several reasons related to MRTU why RTP in particular cannot be implemented in 2010. First, PG&E cites the delay of MRTU start-up. The CAISO has indicated that the MRTU launch will be in the fall of 2008. PG&E wants to allow the MRTU market to stabilize over two full summers before filing an RTP rate, followed by one year for customer education. According to PG&E's preferred schedule, RTP would be available to customers in 2012.

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[28] PG&E Comments, February 28, 2008, pp. 7, 25, 26-27.

[29] In Opening Comments on the Proposed Decision PG&E estimates that modifying the AMI deployment schedule to support default CPP in 2010 and voluntary RTP in 2011 for large C&I customers will cost $16 million (p. 7.) It is unclear if the $16 million cost estimate is for the same scope of work as the $30 million cost estimate.

Second, PG&E is concerned that MRTU will continue to change after its start-up. PG&E notes that MRTU Release 1A,[30] including Scarcity Pricing, will be implemented one year after MRTU start-up. Also, the wholesale price cap will be raised to $1,000/MWh in 2010 or later. Third, PG&E notes that the communications network to deliver day-ahead prices to investor owned utilities (IOUs) and retail customers needs to be developed and installed. PG&E says this issue should be addressed by the CAISO DR Infrastructure working group.

PG&E raises other more general concerns related to the timeline. PG&E argues that the relationship between dynamic pricing and demand response programs is complicated, so new dynamic pricing should wait until the 2009 to 2011 demand response program cycle is complete. PG&E also points to the Commission's resource adequacy proceeding, R.05-12-013, where the Commission will decide whether or not to implement a centralized capacity market, which could in part determine if energy prices are volatile. PG&E argues that the dynamic pricing decision should follow the resource adequacy decision.

Given these concerns, PG&E recommends implementing default CPP for large C&I customers in 2011, delaying RTP until 2012, and keeping RTP as an optional rate.

CLECA believes 12 to 18 months of data from the new MRTU day-ahead market will be needed so that parties can be confident that the market is fully functional. Therefore, CLECA expects that 2011 is the soonest RTP could be

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[30] MRTU Release 1A is now known as Market and Performance, or MAP.

implemented.[31] CMTA and EPUC echo CLECA's timing concerns. CMTA additionally emphasizes that customers need real-time access to their usage information, which will also require some time.[32] EPUC suggests that CPP should be the default rate in 2010 given the delay in MRTU development.[33]

Discussion

We disagree with PG&E's conclusion that billing system and metering limitations require delaying default CPP and RTP until 2011 or 2012. Instead, we conclude PG&E should revise its AMI plans to support default CPP for large C&I customers in 2010 and optional RTP in 2011.

The decision approving PG&E's AMI project, D.06-07-027, does not mention PG&E's plans or timeline to upgrade its large customers' meters and billing system. The constraints identified by PG&E appear to be related to the utility's internal planning rather than any explicit Commission direction.

The Commission directed the utilities to propose AMI projects primarily because AMI enables greater demand response through dynamic pricing and demand response programs.[34] PG&E, however, argues that its AMI project is an impediment to dynamic pricing. This is inconsistent with the Commission's policy objectives. Therefore, we will require PG&E to realign its internal AMI plans with the Commission's policy objectives.

We will require PG&E to make adjustments to its AMI deployment plan so that large C&I customers have the metering and billing systems in place to

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31 CLECA Comments, February 28, 2008, p. 2.

32 CMTA Comments, February 28, 2008, p. 2.

33 EPUC Comments, February 28, 2008, p. 3.

34 See Energy Action Plan II, p. 6.

support default CPP in 2010 and optional RTP in 2011. Meeting these requirements would likely require PG&E to upgrade large C&I customers' meters more quickly and require an earlier upgrade of the CC&B system. PG&E should develop a plan that avoids moving customers back and forth between the CC&B and ABS systems unnecessarily.

To the extent PG&E believes it needs additional authorizations from the Commission to modify its AMI deployment plan, PG&E should request such authorizations in its AMI upgrade application, A.07-12-009. Also, if PG&E believes it needs authorization to spend more money to modify the schedule, PG&E should make a request in A.07-12-009 and provide the necessary justification. If the utility needs to incur incremental costs prior to a Commission decision in A.07-12-009, PG&E may record its incremental costs in a memorandum account and seek recovery in A.07-12-009.

We agree with PG&E that the delay in the on-line date of MRTU requires a delay in the development and implementation of RTP. We also agree with PG&E and other parties that we need some experience with MRTU before implementing RTP. However, we disagree that two full summers of experience are needed with MRTU before even beginning to develop RTP. Instead it is reasonable for PG&E to propose an RTP rate after one summer of experience, as part of the 2011 GRC Phase 2 filed in March 2010. The effective date of the RTP rate, if approved by the Commission, should be prior to the summer of 2011. That would allow two full summers of experience (2009 and 2010) before implementation of RTP. PG&E could conduct a customer education campaign during the latter part of 2010 and the first part of 2011.

PG&E also argues that dynamic pricing needs to be delayed due to the eventual implementation of the CAISO's MAP, the future lifting of the wholesale energy price cap, the 2009 to 2011 Demand Response programs, and the Commission's pending decision on capacity markets. We disagree with PG&E's conclusion. The wholesale and retail energy markets will continue to evolve, and PG&E's dynamic pricing rates may need to evolve as well. We believe it is more prudent to direct PG&E to proceed with dynamic pricing on a date certain with the expectation that dynamic pricing may need to be modified over time.

PG&E also raised the concern that the communications network to deliver day-ahead prices to IOUs and retail customers needs to be developed and installed. We agree that this important issue needs to be addressed. We are confident that PG&E can work with other stakeholders to provide a solution by 2011. We direct PG&E to continue working with the CAISO's DR Infrastructure working group and with stakeholders in other forums so that the necessary communications infrastructure is in place by 2011. We will also require PG&E to develop a timeline that shows what steps PG&E will take to make sure that all the necessary systems are in place to support RTP in 2011. PG&E should include the timeline in its 2011 GRC Phase 2 application.

The draft timetable in the January 23, 2008 Ruling proposed that large C&I customers would have a choice between CPP and RTP in 2010. However, since RTP needs to be delayed until 2011, we conclude that PG&E should propose to make CPP the default rate in 2010. RTP could subsequently become the default rate; however, we do not believe customers should be moved between rates too frequently, so we believe that RTP should remain an optional rate.

Past Commission decisions affirm the reasonableness of the timeline we adopt here. In D.06-05-038, the Commission declined to adopt proposed settlements that would have adopted voluntary critical peak pricing tariffs for PG&E, SCE, and SDG&E that would have been available to bundled customers with peak demands greater than or equal to 200 kW. The Commission directed the utilities to incorporate default critical peak pricing tariffs for large customers into their next comprehensive rate design proceeding or other proceeding as directed by the Commission.

PG&E had already filed its 2007 GRC Phase 2 at the time of D.06-05-038, and according to the standard three-year GRC cycle, PG&E's next GRC would have been its 2010 GRC. Although the Commission approved a settlement in D.07-03-044 that delayed PG&E's next GRC until 2011, requiring PG&E to propose a default CPP rate that would be effective in 2010 is consistent with the timetable the Commission approved in D.06-05-038 since PG&E's next GRC had been expected in 2010.

Also, in D.05-11-009 the Commission directed each utility to submit RTP tariffs in its comprehensive rate design proceeding following the CAISO's implementation of its MRTU.[35] Requiring PG&E to file an optional RTP rate as part of its 2011 GRC Phase 2 is clearly consistent with prior Commission direction.

We will not require PG&E to file an application to revise its optional large customer CPP rate 30 days after the adoption of this decision as proposed in the January 23, 2008 Ruling. Instead, when PG&E files its proposal for default CPP

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[35] D.05-11-009 states "As the CAISO moves to implement its market redesign, we anticipate that transparent pricing information will become available that will facilitate development and adoption of a true RTP tariff. However, design of such a tariff cannot be performed in isolation from comprehensive rate design examination. Therefore, we direct each utility, as part of its next comprehensive rate design proceeding application following development and final implementation of an hourly day-ahead market price by the CAISO, to submit a real time pricing tariff for consideration as part of its tariff offerings." (P. 7.)

rates, PG&E should revise its rates to be consistent with the rate design guidance adopted in this decision. We believe having PG&E propose revisions to the large customer CPP rate and propose default CPP for large C&I customers in the same application is a more efficient use of the Commission's and parties' resources.

In summary, we will require PG&E to file a proposal for a default TOU/CPP rate for large C&I customers as part of its 2008 Rate Design Window with an effective date on or before May 1, 2010. The rate must be consistent with the rate design guidance adopted in this decision. As indicated previously, the filing date of the 2008 Rate Design Window will be delayed from November 25, 2008 to February 28, 2009 to provide PG&E additional time to prepare its filing. We believe this timeline will allow sufficient time for a Commission decision and customer education. PG&E should submit a proposal for an optional RTP rate as part of its 2011 GRC Phase 2 in March 2010. The effective date of the proposed RTP rate should be on or before May 1, 2011.

4.3. Medium C&I

The January 23, 2008 Ruling grouped together all small and medium C&I customers with maximum demand less than 200 kW for the purposes of the draft timetable. PG&E recommended subdividing this group into two groups: those with maximum demand between 20 kW and 200 kW, referred to here as medium C&I[36], and those with maximum demand below 20 kW, referred to here as small commercial. We have adopted PG&E's proposed divisions in this decision.

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[36] According to PG&E, medium C&I customers are generally on the non-TOU version of Schedule A-10 or voluntarily on Schedule E-19, a TOU rate.

Medium C&I customers are not required to be on TOU rates, and most are not. Medium C&I customers will be receiving AMI meters as part of PG&E's AMI initiative.

The January 23, 2008 Ruling proposed that PG&E would make rate proposals that could result in CPP becoming the default rate starting in 2010 for medium C&I customers that have AMI meters. Customers would have the option to switch to TOU, but a flat rate would no longer be an option. RTP would become available on an optional basis beginning in 2011.

Parties' Comments

PG&E recommends making TOU the default rate for this customer class rather than TOU/CPP. CPP would remain as an optional rate. RTP would be introduced as an optional rate in 2012. PG&E's proposal does not specify whether a non-time-differentiated rate would remain an option.[37]

PG&E also argues that a customer should be allowed 18 months of experience with an AMI meter before moving to a new time-differentiated default rate. They also argue for 12 months after tariff approval for customer outreach—four months to prepare materials and eight months for customer outreach.[38] According to PG&E's proposal, the utility would file default TOU in November 2008, a Commission decision would come in December 2009, customer outreach would occur in 2010, and the rate would be effective on January 1, 2011.[39]

Discussion

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[37] PG&E Comments, February 28, 2008, Attachment A.

[38] PG&E Comments, February 28, 2008, p. 16.

[39] PG&E Comments, February 28, 2008, p. 38.

We disagree with PG&E that TOU should be the default rate. The Commission's policy is to implement dynamic pricing for all customers, and TOU is not dynamic pricing because the rate does not change based on day-ahead or real-time market or system conditions. Therefore, the timetable we adopt here requires PG&E to propose TOU/CPP as the default rate.

We agree with PG&E that customers receiving new AMI meters should have time to observe when and how they use energy before moving to a new time-differentiated rate. We believe 12 months is appropriate so that a customer may observe how its usage patterns in different weather seasons change throughout a year. Eighteen months, as proposed by PG&E, is excessive and unnecessary.

Customers should have the opportunity to go onto TOU/CPP before the initial 12 months is over. Customers should also have the option to move onto RTP, rather than TOU/CPP, before or after the initial 12 months if RTP is available.

PG&E should propose that after 12 months of experience with the new AMI meter customers should be defaulted to a TOU/CPP rate, with the first customers moving to TOU/CPP in 2011. Delaying implementation of default TOU/CPP until 2011 will give PG&E additional time for customer education and billing and other system upgrades. TOU should be available as an optional rate, and RTP should be introduced as an optional rate in 2011, the same time it is introduced for large C&I customers. We see no reason why RTP cannot be offered to medium C&I customers at the same time those rates are introduced for large C&I customers.

PG&E's current CPP rate applicable to medium C&I customers is offered as a supplement to the standard rate offerings. A customer could combine the

CPP rate with either a non-time-differentiated rate or a TOU rate. We believe a CPP rate should be a TOU rate with an additional critical peak price that is charged during critical peak periods. Therefore, we believe PG&E's medium C&I CPP rate should be coupled with PG&E's medium C&I TOU rate. We will require PG&E to file a revised medium C&I CPP rate as part of the 2008 Rate Design Window that includes TOU rates during non-CPP periods and that would be effective no later than May 1, 2010.

In summary, we will require PG&E to file a proposal for a default TOU/CPP rate for medium C&I customers as part of its 2008 Rate Design Window. The effective date of the proposed rate should be on or before February 1, 2011, allowing time for a Commission decision and subsequent customer education. PG&E should submit a proposal for an optional RTP rate as part of its 2011 GRC Phase 2 in March 2010. The effective date of the proposed RTP rate should be on or before May 1, 2011, allowing time to develop the rate and allowing time for customer education following adoption of the rate by the Commission.

4.4. Small Commercial

PG&E's small commercial customers are not required to be on a TOU rate, and most are not.[40] Small commercial customers will be receiving AMI meters as part of PG&E's AMI initiative.

According to the draft timetable in the January 23, 2008 Ruling, PG&E would propose CPP as the default rate starting in 2010 for small commercial customers that have AMI meters. Customers would have the option to switch to

TOU, but a flat rate would no longer be an option. RTP would become available on an optional basis beginning in 2011.

Parties' Comments

PG&E's proposed timetable for small commercial rates would essentially maintain the status quo with a non-time-differentiated rate as the default and TOU and CPP as optional rates. PG&E proposes to introduce RTP as an optional rate in 2013.

PG&E argues that small commercial customers will require two years of customer education and outreach before moving to a time-differentiated default rate. PG&E believes default CPP should not be considered until the 2011 GRC Phase 2. PG&E also proposes to delay RTP for small commercial customers for an additional year to learn from larger customer RTP rates.

DRA notes that only half the AMI meters will be installed by 2010, and DRA asserts that placing only half of PG&E's small commercial customers onto a TOU rate is discriminatory.[41]

SDG&E believes TOU rates for small commercial customers should be encouraged as a step toward introducing dynamic pricing.[42]

EPUC believes that the system peak is driven by residential and small commercial load; therefore, in the future there should be no flat rate options for residential and small commercial customers.[43]

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40 According to PG&E, small commercial customers are generally on Schedule A-1, a non-time-differentiated schedule, or Schedule A-6, a voluntary TOU rate.

41 DRA Comments, February 28, 2008, p. 2.

42 SDG&E Post-Workshop Comments, December 11, 2007, p. 5.

43 EPUC CPP Comments, March 21, 2008, p. 4.

Discussion

We disagree with PG&E's alternative timetable, as it is inconsistent with the Commission's desire to make dynamic pricing ubiquitous for all customers. We also believe that with AMI and customer education, small commercial customers are capable of managing their energy use in response to dynamic pricing. However, we do agree with PG&E that small commercial customers require more time for customer education and outreach. Therefore, the timetable we adopt for PG&E's default TOU/CPP rate for small commercial customers is delayed for a year relative to the large C&I customers, which puts small commercial customers on the same schedule as medium C&I customers. We will require PG&E to implement default TOU/CPP for small commercial customers starting in 2011 for those customers who have had AMI meters for 12 months or more.

We disagree with DRA that PG&E should not default customers with AMI meters to a time-differentiated rate when some customers do not have AMI meters. In D.01-05-064 as modified by D.01 08-021 and D.01-09-062, the Commission required mandatory TOU rates for all large C&I customers who received new meters via the CEC's funding. The Commission did not wait until all large C&I customers had interval meters before making TOU a mandatory rate for customers with interval meters. Instead the Commission concluded a customer's default rate depended on the customer's metering capability. We are requiring PG&E to propose a comparable requirement here for small commercial customers.

Furthermore, we believe small commercial customers should have an opportunity to benefit from their new AMI meters as soon as possible, and we believe TOU rates and dynamic pricing will benefit small commercial customers by giving them an opportunity to reduce usage during high cost periods and shift usage to low cost periods.

PG&E's current optional small commercial CPP rate is the same as the medium C&I CPP rate. Consistent with the discussion regarding the medium C&I CPP rate we will require PG&E to file revised small commercial CPP rates as part of the 2008 Rate Design Window that include TOU rates during non-CPP periods and that would be effective no later than May 1, 2010.

We disagree with PG&E that RTP needs to be delayed until 2013 for small commercial customers, especially since it is an optional rate. We expect some small commercial customers will want to take full advantage of their new AMI meters and sign up for RTP. With the development of new enabling technologies, RTP could present significant opportunities for small commercial customers to reduce their bills. The Commission desires to empower consumers, big or small, to have the tools to better manage their energy usage and their bills. Therefore, we will require that RTP be made available for small commercial customers on an optional basis in 2011.

In summary, we will require PG&E to file a proposal for a default TOU/CPP rate as part of its 2008 Rate Design Window with an effective date on or before February 1, 2011. We will require PG&E to file an optional RTP rate as part of its 2011 GRC Phase 2 in March 2010 with an effective date on or before May 1, 2011. We believe this schedule will provide time for customer education and necessary PG&E system upgrades subsequent to a decision.

4.5. Agricultural

Large agricultural customers[44] currently have interval meters and are required to take service on a TOU rate. Small and medium agricultural customers[45] generally do not have TOU or interval meters and are not required to take service on a time-variant rate. However, some small and medium agricultural customers have chosen to take service on TOU rates. Large agricultural customers can enroll in CPP on an optional basis, but PG&E does not currently offer an optional CPP rate for small and medium agricultural customers.

Based on the draft timetable in the January 23, 2008 Ruling, PG&E would be required to propose moving large agricultural customers to a CPP or RTP rate starting in 2011. Customers would have the option to opt out to a TOU rate. The date of 2011 was intended to provide time for customer education and the development and deployment of enabling technologies.

The January 23, 2008 Ruling provided that PG&E would be required to propose moving small and medium agricultural customers with new AMI meters to a default TOU rate starting in 2010. TOU/CPP would be available as an optional rate, and RTP would be offered as an optional rate starting in 2011.

Parties' Comments

According to PG&E's alternate proposal, TOU would remain the default rate for large agricultural customers. PG&E proposes considering whether to

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[44] We define large agricultural customers as those with maximum demand at 200 kW and greater.

[45] We define small and medium agricultural customers as those with maximum demand less than 200 kW.

adopt TOU/CPP as a default rate in the 2011 GRC Phase 2. PG&E would propose that an optional RTP be made available to large agricultural customers in 2012, the same time PG&E proposes RTP for large C&I customers.[46]

PG&E proposes that a non-time-variant rate would remain the default rate for small and medium agricultural customers. PG&E would consider whether to adopt TOU/CPP as a default rate in the 2011 GRC Phase 2 and would consider default TOU and TOU/CPP again in the next GRC after 2011. PG&E would propose that an optional RTP be made available starting in 2013, the same time PG&E proposes RTP for small commercial and residential customers.[47]

CFBF argues that mandatory dynamic pricing would harm agricultural customers and would result in little if any load reductions. CFBF explains that agricultural loads are primarily related to pumping water, and the pumps tend to be spread out over many acres which would make them difficult to access in response to a dynamic pricing event. Also, the pumps are generally not variable, so an agricultural customer's only possible response is to entirely shut off a pump. CFBF states that TOU rates, on the other hand, have benefited agricultural customers and the grid. CFBF recommends keeping dynamic pricing voluntary, with possible incentives for enabling technologies.[48]

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[46] PG&E Comments, February 28, 2008, pp. 38-40, Attachment A.

[47] PG&E Comments, February 28, 2008, pp. 38-40, Attachment A.

[48] CFBF Post-Workshop Comments, December 11, 2007, pp. 3-4. CFBF notes that its testimony in A.05-01-016 *et al.* expands on these concerns.

SCE notes that over 70% of the agricultural load in its territory is already on optional TOU rates.[49] SDG&E recommends default CPP for agricultural customers with TOU rates as additional options.[50]

Discussion

We believe large agricultural customers should generally have the same rate options as large C&I customers. We disagree with PG&E that TOU should remain the default rate for large C&I customers. The Commission's policy is to implement dynamic pricing for all customers, and TOU is not dynamic pricing because the rate does not change based on day-ahead or real-time market or system conditions.

In D.05-04-053, the Commission discussed issues related to agricultural pumping usage and noted that many farmers receive water based on schedules determined by the State Water Project and the Central Valley Water Project. As a result, the water projects' schedules determine when farmers use water and, thus, electricity. Nonetheless, in D.05-04-053 the Commission concluded "[W]e believe that all customers should receive price signals that indicate when power is more expensive to procure. Thus, in the longer term, especially with coordination with the State Water Project and the Central Valley Water Project, we would expect that any changes to default rates would apply to agricultural customers over 200 kW."[51] We reaffirm the Commission's prior determination and conclude that CPP should be made the default rate for the large agricultural customers.

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[49] SCE Post-Workshop Comments, December 11, 2007, p. 6.

[50] SDG&E Post-Workshop Comments, December 11, 2007, p. 4.

[51] D.05-04-053, pp. 35-36.

We expect many large agricultural customers will find ways to manage their energy usage during critical peak events. The large percentage of load on TOU rates indicate that agricultural customers can adapt to time-variant rates. CPP will give large agricultural customers an additional incentive to explore energy management solutions to lower their usage during critical peak events and, thus, lower their bills.

Therefore, the timetable we adopt here requires PG&E to propose CPP as the default rate.

We believe it is appropriate for PG&E to propose implementing default CPP for large agricultural customers in 2011, one year after large C&I customers, to allow more time for customer outreach and education. We believe optional RTP should be offered in the same timeframe. TOU should also remain as an option for large agricultural customers.

PG&E should submit a proposal for default CPP and optional RTP for large agricultural customers as part of its 2008 Rate Design Window in early 2009. The effective date of the proposed default CPP should be on or before February 1, 2011. The effective date of the optional RTP rates should be on or before May 1, 2011.

For small and medium agricultural customers, we believe it is reasonable to delay implementation by one year relative to the timetable put forth in the January 23, 2008 Ruling. PG&E should be required to propose making TOU the default rate starting in 2011 for small and medium agricultural customers with advanced meters as part of its 2008 Rate Design Window. We do not have a sufficient record in this proceeding to conclude that TOU/CPP is the appropriate default rate for these customers. However, PG&E may elect to propose default TOU/CPP for small and medium agricultural customers in its 2008 Rate Design

Window and include a justification for why TOU/CPP is an appropriate default rate.

Since many small and medium agricultural customers do not have TOU meters or interval meters, the energy usage information provided by their new AMI meter may be their first source of accurate information about when and how they use electricity. This Commission would like to ensure that these customers have the opportunity to better manage their energy usage and costs. Therefore, we will require that PG&E propose that a customer not be defaulted to a TOU rate until they have had any AMI meter for 12 months. This is the same provision we are requiring for medium and small C&I. If a small agricultural customer wants to move to a TOU, TOU/CPP, or RTP rate before they have had any AMI meter for a full 12 months, they should be permitted to do so.

For small and medium agricultural customers, PG&E should file a proposal to make TOU the default rate for customers who have had AMI meters for 12 months or more as part of its 2008 Rate Design Window. PG&E should also include an optional TOU/CPP rate for small and medium agricultural customers in its 2008 Rate Design Window filing. The proposed rates should be effective on or before February 1, 2011, allowing time for a Commission decision and customer education. PG&E should submit a proposal for an optional RTP rate as part of its 2011 GRC Phase 2 in March 2010. The effective date of the proposed RTP rate should be on or before May 1, 2011.

PG&E's proposal should not include a non-time-differentiated rate as an option after a customer has had a new AMI meter for 12 months. Non-time-differentiated rates should not be offered since such a rate would not even reflect the time varying costs of providing electricity in an average sense, like a TOU rate.

4.6. Residential

Most of PG&E's residential customers are on a non-time-differentiated rate with five tiers, each tier having a progressively higher rate. A customer's usage during a billing cycle up to a certain specified number of kWh is charged at the lowest rate. The usage above that amount, but below another specified amount is charged the second lowest rate, etc. PG&E currently offers TOU and CPP rates to residential customers on a voluntary basis. A proposal for a new peak time rebate (PTR) is before the Commission in A.07-12-009, PG&E's application to upgrade its AMI project.[52]

The draft timetable for residential customers in the January 23, 2008 Ruling included two different scenarios—one assuming that the AB1X rate protections remain in place throughout the time period and one assuming that AB1X rate protections are no longer in place.[53] The timetable did not make any assumptions about when AB1X rate protections will end.

The scenario that assumes AB1X rate protections remain in effect further assumes that residential customers can only be offered TOU, CPP, and RTP on a

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52 Peak Time Rebate (PTR): A program that provides customers a rebate for demand reductions below a customer-specific baseline when the program is called due to market or system conditions.

53 AB1X refers to Assembly Bill No. 1 from the 2001-2002 First Extraordinary Session as codified by Water Code section 80000 *et seq.* Water Code section 80110 protects the rates of residential customers for usage up to 130% of baseline quantities "until such time as the [Department of Water Resources] has recovered the costs of power it has procured for the electrical corporation's retail end use customers…."

voluntary basis. Customers could be placed on a PTR on a default basis since PTR is designed to be compliant with AB1X.

The only new rate required by the draft timetable while AB1X rate protections remain in place is optional RTP, which would be available to residential customers in 2010.

The draft timetable recommended that 30 days after the Commission or the legislature determines AB1X rate protections end, PG&E would be required to propose default TOU with CPP for residential customers with an effective date one year after AB1X rate protections end. The proposal should give customers the ability to opt out to a flat rate or TOU.

Parties' Comments

PG&E recommends that the Commission wait and see if PTR and optional CPP are successful. According to PG&E, the Commission should consider default TOU/CPP in the first GRC after the AB1X rate protections have ended. PG&E also argues RTP for residential customers should be delayed until 2013 because more time is needed to monitor the MRTU market and learn from larger customer RTP.[54]

SCE notes that any bill impacts associated with lifting the AB1X rate protections may necessitate a multi-year transition plan.[55]

DRA supports "limited experimentation" with PTR for residential customers. To reduce the potential for "free riders,"[56] DRA supports providing

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[54] PG&E Comments, February 28, 2008, pp. 27-28, 38, 40.

[55] SCE Comments, February 28, 2008, p. 5.

[56] Under a PTR, a "free rider" would be a customer who receives a rebate because its usage was below the baseline, but in fact, the customer did not reduce its usage.

larger rebates for customers with enabling technologies and lower rebates for customers without enabling technologies.[57]

DRA supports offering both PTR and CPP to customers, provided that they are limited to one of the two options. DRA expects some customers with higher than average load factors (i.e., flatter load profiles) will benefit more from CPP than PTR since CPP will allow those customers to avoid cross-subsidizing customers whose consumption profiles are characterized by "peakier" use.[58]

DRA believes that analysis performed by TURN using data for SCE suggests that the greatest potential for residential class demand response is among customers whose electric use is in the upper tiers. DRA hypothesizes that the Commission's demand response objectives could be met while AB1X rate protections remain in place by making minor changes to upper tier rates. DRA believes a time-differentiated rate for residential customers deserves special consideration in PG&E's 2011 general rate case.[59]

DRA thinks it is premature to adopt post-AB1X rate design since the timing and conditions that will exist when AB1X is lifted are so uncertain. DRA also believes bill analysis must be performed before setting the policy direction, and it is too early to perform a meaningful bill analysis.[60]

TURN urges the Commission not to consider any major change in the mandatory or default rate design for residential customers at this time. TURN believes there is no urgency since the utilities are just beginning to deploy

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57 DRA Post-Workshop Comments, December 11, 2007, pp. 8-9.

58 *Id.*, p. 10.

59 *Id.*, p. 9.

60 DRA Comments, February 28, 2008, pp. 1-2.

advanced meters. TURN believes that any consideration of mandatory or default TOU or CPP rates for residential customers would require careful analysis of relevant data and would necessitate an evidentiary hearing. TURN filed a "conditional" motion for evidentiary hearings on December 11, 2007 in which TURN moved for evidentiary hearings if the Commission intends "to consider policies that would establish a time-differentiated rate structure for the residential class on a mandatory or default basis." [61]

TURN emphasizes that whether or not AB1X rate protections remain in place, residential rates also need to comply with Public Utilities Code Sections 739(c)(1) and 739.7, which require baseline rates and an increasing block rate structure. TURN cautions that these additional legal requirements will complicate the design of a future TOU/CPP rate. TURN recommends against taking on these legal and rate design issues prior to the filing of an actual rate design proposal.[62]

SDG&E supports PTR as an interim step while AB1X rate protections remain in place. After AB1X rate protections have been removed, SDG&E supports exploring TOU and CPP as default options.[63]

EPUC believes that the system peak is driven by residential and small commercial load; therefore, in the future there should be no flat rate options for residential and small commercial customers.[64]

Discussion

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[61] TURN Post-Workshop Comments, December 11, 2007, pp. 2-3.

[62] TURN Comments, February 28, 2008, pp. 1-2.

[63] SDG&E Post-Workshop Comments, December 11, 2007, p. 5.

[64] EPUC CPP Comments, March 21, 2008, p. 4.

There is no intention to address legal interpretations as to AB1X in this proceeding. For the purposes of the timetable we adopt here, we will assume that residential customers can only be offered TOU, CPP, and RTP on a voluntary basis.[65] PTR is designed to be compatible with the AB1X rate protections, so we assume that customers could be placed on a PTR on a default basis.

However, if the Commission determines in any other forum that time-variant or dynamic pricing rates could be offered to residential customers on a default or mandatory basis before AB1X protections are totally removed, the assumptions we are making here would need to be reconsidered. Another forum where the Commission is currently examining the implications of AB1X on residential rate design is A.07-01-047, where the Commission is considering a proposal put forth by SDG&E, who has argued that AB1X allows the rate freeze to be gradually phased out. Also, we encourage DRA to make recommendations in a future rate design proceeding as to how changes to the upper tiers could allow for time-variant pricing, as suggested by DRA in this proceeding.

Given our assumptions, we will still require PG&E to make several proposals related to residential rate design. PG&E has already filed a PTR proposal in A.07-12-009, PG&E's application to upgrade its AMI project. PG&E

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[65] In D.06-10-051, the Commission found that PG&E's voluntary residential CPP rate adopted in D.06-07-027 is not prohibited by AB1X because the CPP rate is optional. Furthermore, D.06-10-057 states that "The Decision [D.06-07-027] is also consistent with other decisions where we have authorized similar tariff options enabling customers to better manage their overall electricity consumption patterns, thereby helping to ensure adequate state-wide electricity supply as more broadly intended by AB1X." (Page 5.)

has proposed that the PTR would be effective in 2010. A.07-12-009 is an appropriate forum to consider PG&E's PTR proposal.

PG&E's current residential CPP rate is offered as a supplement to the standard single family residential rate offerings. A customer could combine the CPP rate with either a non-time-differentiated rate or a TOU rate. We believe a CPP rate should be a TOU rate with an additional critical peak price that is charged during critical peak periods. Therefore, we believe PG&E's residential CPP rate should be coupled with PG&E's residential TOU rate. We will require PG&E to file a revised residential CPP rate as part of its 2008 Rate Design Window that includes TOU rates during non-CPP periods and that would be effective no later than May 1, 2010.

We disagree with PG&E that optional RTP for residential customers should be delayed until 2013. We expect that given the diverse population of residential customers, many will want to take advantage of RTP much sooner. Other utilities already offer RTP to residential customers and many customers have signed up and reduced their bills.[66]

We will require PG&E to propose optional RTP for residential customers that would be available in 2011, the same time RTP would be available for other customer classes. PG&E should submit a proposal for an optional RTP rate as

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[66] In 2006, the Illinois legislature amended Section 16-107 of Illinois' Public Utilities Act to require Ameren Utilities and Commonwealth Edison Company to offer RTP to residential customers starting in January 2007. Based on annual reports filed with the Illinois Commerce Commission, Commonwealth Edison's residential RTP program had enrolled 3,994 customers by the end of 2007 and active participants saved 13% in 2007. Ameren had 500 customers on the program by the end of 2007, and customers saved an average of 16% on their bills. The annual reports are available at http://www.icc.illinois.gov/industry/publicutility/energy/RTP.aspx.

part of its 2011 GRC Phase 2 in March 2010. The effective date of the proposed RTP rate should be on or before May 1, 2011.

Even with a 2011 effective date for PG&E's residential RTP rate, PG&E would still significantly lag behind utilities in other parts of the country.

We agree with TURN that it is premature and unnecessary to tackle the legal and policy issues surrounding the design of residential rates once AB1X rate protections are no longer in place. We do, however, believe it is important to establish a point in time when residential rate design will be thoroughly examined.

Therefore, we will require PG&E to file an application proposing default TOU/CPP for residential customers 30 days after any change in the law that changes the AB1X rate protections in a manner that could allow default or mandatory time-variant rates for residential customers. If the Commission approves a decision that interprets the AB1X rate protections in a manner that could allow default or mandatory time-variant rates for residential customers, then PG&E should file an application proposing default TOU/CPP for residential customers no later than 90 days after the Commission decision goes into effect and is no longer subject to rehearing or judicial review. The effective date of the proposed rate should be no later than one year from the filing date unless PG&E can justify a later effective date as being necessary to provide time for customer education and system upgrades.

By requiring that PG&E file a default TOU/CPP proposal for residential customers, we are not in this decision concluding that a default TOU/CPP rate will or should be adopted. We are not adopting post AB1X rate design in this decision. Rather PG&E's future proposal will trigger a thorough consideration of the policy and legal issues surrounding residential rate design. At that time, the

Commission will be able to perform bill analysis, as recommended by DRA, and will be able to fully consider all relevant legal and policy issues. The Commission can also consider a transition plan as recommended by SCE.

To clarify once again, the only policy path we are setting in this decision is that the Commission will fully evaluate residential rates after the AB1X rate design protections are no longer in place or have materially changed.

4.7. Direct Access (DA) and Community Choice Aggregation (CCA) Customers

Since dynamic pricing as discussed in this decision only relates to the generation component of the unbundled rate, DA and CCA customers would not be eligible for dynamic pricing rates offered by the utilities. However, the load serving entities that serve DA and CCA customers could themselves offer dynamic pricing options.

4.8. Standby, Net Metered, and Master Metered Customers

EPUC believes standby customers should be exempt from CPP rates since a standby customer generally only takes utility service during periods when the customer's generation equipment unpredictably fails. In those cases, the customer would be unable to respond to a CPP event.[67]

PG&E states that net metering and master-metered accounts should be restricted from eligibility, which PG&E says is consistent with current practice.[68]

We do not have sufficient input from parties to address standby customers, net metered customers, and residential master metered customers in

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[67] EPUC CPP Comments, March 21, 2008, p. 3.

[68] PG&E Comments, February 28, 2008, pp. 22-23.

this decision. PG&E and other parties should address the applicability of dynamic pricing to standby, net metered, and master metered customers in context of specific rate proposals.

However, we can address commercial submetering. In D.07-09-004, the Commission approved a settlement between PG&E and BOMA that removed the ban on submetering in commercial buildings. In removing the ban on submetering, the Commission stated that "as a matter of policy, it is important for commercial building tenants to receive appropriate price signals and to have the opportunity to effectively use dynamic pricing options and participate in energy conservation programs."[69] Since submetering in commercial buildings is intended to encourage and facilitate tenants' participation in dynamic pricing, PG&E should not exclude commercial master-metered customers from the dynamic pricing rates that the utility proposes.

5. Rate Design Guidance

The third question that the strategic work plan needs to address is "how should the dynamic pricing tariffs be designed and integrated into PG&E's overall rate design?" In other words, when PG&E proposes rates pursuant to the timetable, what should the dynamic rates look like? This section answers these questions and provides rate design guidance for PG&E to apply when developing rates. This rate design guidance will also be applied by the Commission when considering PG&E's specific rate design proposals.

The following sections address different aspects of rate design, take into consideration comments from parties, and establish rate design guidance. The

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[69] D.07-09-004, p. 34.

rate design guidance also appears in summary form as Attachment A to this decision.

5.1. All Dynamic Pricing Rates

5.1.1. The Objectives of Rate Design

The August 22, 2007 Ruling identified three objectives of rate design:

(1) to reflect the marginal cost of providing electric service so that consumers make economically efficient decisions,

(2) to flatten the load curve in order to reduce capital costs over time, and

(3) to reduce load in the face of short-term electricity supply shortfalls.

The ruling also identified several other important policy and rate design considerations including energy efficiency, greenhouse gas emission reduction, rate stability, rate simplicity, cost causation, and utility cost recovery.[70]

Based on prior comments and the workshops, the January 23, 2008 Ruling put forth the following draft rate design guidance and requested further comment:

- Rate design should promote economically efficient decision-making.
- Rates should reflect marginal cost.
- Prioritizing and balancing marginal cost with other objectives such as energy efficiency and baseline allowances should be addressed when designing specific rates.

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[70] August 22, 2007 Ruling, Attachment A, p. 1.

- Rates should also seek to provide stability, simplicity, and customer choice.

Parties' Comments

No party disagreed with the objectives of rate design proposed in the January 23, 2008 Ruling.

BOMA identifies equity as one of two primary objectives that should guide the design of dynamic pricing, the other being economic efficiency. BOMA defines equity as "a condition in which all consumers face electric rates that accurately reflect the true cost of serving their load." In other words, an equitable rate eliminates cross-subsidies between customers. BOMA believes economic efficiency is achieved by setting rates at the marginal cost of electricity production and delivery, and the marginal cost of electricity production and delivery vary with time. BOMA concludes that RTP best achieves economic efficiency and equity. BOMA believes that other objectives such as load flattening and reducing load in the face of emergencies are subsidiary goals, but generally supported by RTP.[71]

Discussion

Promoting economically efficient decision-making is the primary policy objective that can be achieved through rate design. A rate that promotes economic efficiency is one that charges a customer based on the marginal cost of providing the customer one more or one less unit of energy—in other words, a

[71] BOMA Post-Workshop Comments, December 11, 2007, pp. 2-5.

rate based on marginal cost. The Commission has had a long standing policy of adopting marginal cost-based rates.[72]

Marginal cost-based rates will tend to address the other objectives identified in the August 22, 2007 Ruling—flatten the load curve to reduce capital costs over time and reduce load in the face of short-term electricity supply shortfalls. Marginal cost-based rates also encourage energy conservation, energy efficiency, and demand response. Furthermore, marginal cost-based rates can reduce greenhouse gas emissions by discouraging consumption during high cost periods when the least efficient, and highest greenhouse gas emitting power plants are operating.[73] Finally, marginal cost-based rates improve reliability, lower overall costs, and maximize overall social welfare.

Parties identified several laws and other objectives related to residential rate design. For example, Public Utilities Code Section 739(c)(1) requires that each IOU establish rates that include baseline rates for residential customers, and requires that the baseline rates apply to the first or lowest block of an increasing block rate structure.[74] Also, Public Utilities Code Section 739.7 requires that residential rates include an "inverted rate structure."[75, 76]

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[72] *See* D.82-12-113 (10 CPUC2d 512), D.83-12-065 (13 CPUC2d 619), D.83-12-068 (14 CPUC2d 15), and D.84-12-068 (16 CPUC2d 721).

[73] In the future if rates include the marginal cost of greenhouse gas emissions, rate design can help the state achieve its greenhouse gas reduction goals.

[74] Public Utilities Code Section 739(c) (1) states, "The commission shall require that every electrical and gas corporation file a schedule of rates and charges providing baseline rates. The baseline rates shall apply to the first or lowest block of an increasing block rate structure which shall be the baseline quantity. In establishing these rates, the commission shall avoid excessive rate increases for residential customers, and shall establish an appropriate gradual differential between the rates for the respective blocks of usage." Section 739 relates to the establishment of baseline quantities and baseline

Footnote continued on next page

Baseline rates and an inverted block rate structure may not be consistent with the objective of promoting economically efficient decision-making. Advanced metering and dynamic pricing offer alternate approaches to rate design that could be more effective at lowering overall customer costs, promoting conservation, and reducing greenhouse gas emissions. Therefore, the Commission should consider seeking legislative changes to these sections to better align residential rate design with the State's other policy goals.

To the extent rates are required to satisfy legal requirements or secondary objectives, those other requirements and objectives should be addressed when designing specific rates. When addressing secondary objectives, any deviation from the primary objective of promoting economic efficiency should be minimized.

BOMA identified equity as a primary objective of rate design. Similarly, as part of the DRRC Rate Project, the DRRC's consultant, the Brattle Group, included equity among the four ratemaking objectives that it used to evaluate straw rate designs.[77]

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rates. For residential electric customers other than "all-electric residential customers," as defined, the baseline quantity means 50 to 60 percent of average residential consumption taking into account climatic and seasonal variations.

[75] Public Utilities Code Section 739.7 states, in relevant part, "In establishing residential rates, the commission shall retain an appropriate inverted rate structure."

[76] An "inverted rate structure" is a rate in which predetermined prices increase as a function of cumulative customer electricity usage within a predetermined time frame (usually monthly).

[77] *See* The Brattle Group, "Illustrating the Impact of Dynamic Pricing Rates in California," January 22, 2008, presentation prepared for DRRC Rates Project webcast. The other three ratemaking objectives were economic efficiency, choice, and simplicity.

We agree with BOMA that rates based on marginal cost will simultaneously achieve economic efficiency and equity by ensuring that customers' rates are commensurate with the costs they cause. Marginal cost-based rates should effectively eliminate cross subsidies between customers since a customer who is less expensive to serve would pay less, and vice-versa for a customer who is expensive to serve. Therefore, we conclude that equity is not a distinct objective of rate design.

We will also adopt the guidance that rates should seek to provide stability, simplicity, and customer choice. By "stability," we do not mean rates or bills should be the same month after month. Dynamic pricing by its nature changes from one time period to the next, as will the bills. However, we believe that the overall structure of dynamic pricing rates should be relatively stable over time. For example, utilities should seek to maintain a stable relationship between wholesale market conditions and dynamic rates so that customers can be confident that changes in their rates are tied to changes in wholesale markets.

Rates should provide simplicity from the standpoint of being easy for a customer to understand. Customers on dynamic pricing rates need to understand how their decisions to use more or less electricity during different times will impact their bills.

Rates should provide customers choice by offering several rate options or offering customers the ability to expose more or less of their consumption to dynamic pricing.

We conclude that, with minor modifications, the four rate design objectives proposed in the January 23, 2008 Ruling should be adopted. Accordingly, we will adopt the following rate design guidance:

- Rate design should promote economically efficient decision-making.
- To promote economically efficient decision-making, rates should be based on marginal cost.
- Other objectives, such as energy efficiency, and legal requirements, such as baseline allowances, should be addressed when designing specific rates, and any deviation from marginal cost should be minimized.
- Rates should also seek to provide stability, simplicity and customer choice.

5.1.2. Design of Rates Relative to Each Other and Handling Revenue Over- and Under-Collections

When multiple rates are offered to customers within a rate class, one design method is to set each rate such that a customer with a class-average load shape would pay the same under each rate. Rates designed as such are referred to as being revenue-neutral relative to each other. Parties differed as to whether non-time-variant, TOU, CPP, and RTP rates should be revenue-neutral relative to each other.

PG&E recommends establishing revenue-neutral tariff choices for each customer class. PG&E believes that if rates are established on a revenue-neutral basis and if the rates generally reflect avoidable procurement costs, then future year under- and over-collections should be limited.[78] PG&E believes that

[78] PG&E Opening Comments, October 5, 2007, Attachment, pp. 13-15.

revenue recovery issues should generally be addressed on a case-by-case basis as new rates are developed.[79]

SDG&E similarly advocates for basing all rates within a class on the same revenue requirement. SDG&E believes that basing rates on different revenue requirements will lead to customer migration from high cost rates to lower cost rates. SDG&E argues that over time rates should remain revenue neutral relative to one another.[80]

CLECA poses three questions that should be answered when implementing dynamic pricing to determine the appropriate way to handle revenue under- and over-collections within a rate class: (1) if a customer reduces its usage, especially at times of high system costs, does it see a reduction in its bill? (2) Do such reductions in a customer's bill reflect a reduction in costs for the utility? (3) How often should tariffs be adjusted for changes in load forecasts due to customer responses to tariffs?

CLECA answers the first two questions by arguing that, initially, CPP and RTP should be designed to be revenue-neutral relative to TOU. However, over time as customers migrate to different rates, the cost basis for each rate should be based on the cost to serve the customers on each rate. CLECA disagrees with the utilities that setting rates in this manner will result in any substantial migration between rates.[81]

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[79] PG&E Post-Workshop Comments, December 11, 2007, p. 6.

[80] SDG&E Opening Comments, October 5, 2007, Attachment, p. 7.

[81] CLECA Post-Workshop Comments, December 11, 2007, pp. 5-6; CLECA Comments, February 28, 2008, pp. 3-5.

EPUC stresses that differences between the revenues collected from customers on a dynamic pricing rate option and the costs to serve the customers on the rate option should be collected from or refunded to the customers on the rate option and not spread across other rates. Customers should not be penalized for not moving to a dynamic pricing option.[82]

Discussion

As PG&E suggested, the Commission's expectation is that dynamic pricing based on marginal cost will do a reasonably good job of aligning utility revenues and costs. As such, significant rate adjustments due to revenue over- and under-collections should be limited.

We generally agree with CLECA that the cost basis of a rate should be based on the cost to serve customers on the rate. We also agree with EPUC that mismatches between the revenues collected from customers on a rate and the cost to serve those customers should not be spread across other customers. Accordingly, as a general rate design principle, we believe that if customers on a particular rate reduce their usage in a manner that reduces a utility's costs then the customers on that rate should see a commensurate reduction in their bills.

We cannot conclude that establishing revenue-neutral rate options, as advocated by PG&E and SDG&E, is consistent with this principle. Instead, when PG&E proposes specific rates we will require PG&E to explain how the method in which it is setting rates relative to each other, and the method by which it intends to handle revenue over- and under- collections will ensure that if

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[82] EPUC Comments, February 28, 2008, p. 3.

customers on a specific rate schedule take actions that reduce the utility's costs then the customers on the rate will see a commensurate bill reduction.

In summary we will adopt the following rate design principle:

- If customers on a particular rate schedule reduce their usage in a manner that reduces a utility's costs then the customers on that rate should see a commensurate reduction in their bills.

5.1.3. Hedging Premium

The Demand Response Research Center's (DRRC) rate design issues paper describes the concept of a hedging premium in the context of rate design.[83] In a competitive retail market, if a retail provider offers a customer energy at a flat price then the retail provider assumes the risk that energy in the wholesale market might deviate from the flat price. The retail provider would charge its flat rate customer an extra premium to compensate for the price risk assumed by the retail provider. Alternatively, the retail provider could manage its risk by purchasing hedges or buying blocks of energy at a flat rate, presumably at a premium that would be passed on to the customer. The hedging premium has the effect of increasing flat rates relative to real time pricing.

Parties in this proceeding were asked whether the California utilities incur a hedging premium on behalf of their customers that are on non-time-variant and TOU rates. If so, then it could be argued that the utilities should be charging customers more to be on rates that are less time-variant and deviate the most from wholesale market conditions.

Parties' Comments

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[83] The Brattle Group, "Rethinking Rate Design," Presentation at DRRC Dynamic Pricing Issues Workshop, September 7, 2007.

Several parties note that the utilities are very significantly hedged through resource adequacy requirements and long-term contracts. However, no party argues that the hedging premium concept can be easily translated to the California IOUs. At best, parties suggest that the issue deserves further consideration.[84]

Discussion

The hedging premium may have a strong basis in competitive markets; however, we conclude the concept cannot be translated to the regulatory environment in which PG&E and the other utilities currently operate. The utilities are significantly hedged through resource adequacy contracts and other forms of long-term contracts. Many of these contracts provide some price stability for the utilities through fixed prices and fixed heat rates. However, the Commission's resource adequacy and long-term procurement policies and the utilities' procurement practices do not currently take into account the structure of retail rates. Conversely, retail rates are not designed in coordination with the utilities' procurement practices.

Furthermore, since the utilities' sales and profits have been decoupled, the utilities are generally not at risk for deviations between retail rates and actual costs. If wholesale energy prices or the amount of electricity consumed deviates from the projections, the utilities can generally refund or collect the difference in a subsequent time period.

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[84] CLECA Comments, February 28, 2008, p. 6; CMTA Comments, February 28, 2008, pp. 3-4; PG&E Post-Workshop Comments, December 11, 2007, pp. 4-5; TURN Comments, February 28, 2008, p. 4.

Because of the nature of long-term contracting and decoupling, there appears to be little cost-based justification to incorporate a hedging premium into rates at this time.

5.1.4. Customer Ability to Hedge

Distinct from the concept of a hedging premium is the idea that customers on a dynamic pricing rate should have the option to choose how much of their load is subject to a dynamic rate and how much is purchased at a fixed price. In other words, should customers be able to hedge some of their exposure to a CPP or RTP rate?

Parties' Comments

DRA is opposed to requiring that customers take service on dynamic pricing rates without having hedging options. DRA argues that a functioning market provides customers the choice of how much price certainty and reliability they want.[85]

CLECA, CMTA, and EPUC believe that customers should have the opportunity to hedge some of the price risk associated with dynamic pricing. These parties argue that the appropriate hedging products are generally not available in the marketplace, and if the hedging products are available, their price is unreasonable. CMTA and EPUC support the use of a two-part tariff, including a demand component and an energy component, in which only the energy component, or part of the energy component, is subject to dynamic pricing.[86]

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[85] DRA Post-Workshop Comments, December 11, 2007, pp. 10-11.

[86] CMTA/EPUC Post-Workshop Comments, December 11, 2007, p. 6; CMTA Comments, February 28, 2008, p. 4.

KMEP proposes a CPP rate option that would allow customers to hedge their exposure by defining a baseline for flat load customers and only transitioning to the CPP rates when a customer's load deviates from the baseline.[87]

SDG&E supports offering customers the ability to hedge their exposure to price volatility. As an example, SDG&E points to its default CPP rate which includes a capacity reservation charge that allows customers to reserve capacity during CPP events that will not be subject to CPP rates.[88]

Discussion

We believe dynamic pricing rates should give customers, especially larger commercial, industrial, and agricultural customers, an opportunity to hedge some of their load. There is no reason dynamic pricing should be all-or-nothing. Some customers may prefer a "pure" version of a CPP or RTP rate in which all of their usage is subject to the critical peak or real time price, but others may prefer to only expose some of their usage to dynamic pricing. This is consistent with our principle that rates should offer customers choice.

SDG&E has offered a good model for CPP. D.08-02-034 approved default CPP for SDG&E's large C&I customers. As part of the CPP rate design, customers can "reserve" capacity for some or their entire load by predesignating an amount of load and committing to pay fixed monthly payments for that load. SDG&E refers to this as the capacity reservation charge. During a critical peak event, the load in excess of the reserved amount is charged at the critical peak

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[87] KMEP CPP Comments, March 21, 2008, pp. 3-4.

[88] SDG&E Post-Workshop Comments, December 11, 2007, pp. 5-6. SDG&E's CPP rate with a capacity reservation charge was approved in D.08-02-034.

price. We believe this is a promising approach to give customers an opportunity to hedge.

It is premature to recommend how hedging should work under RTP, whether through a two-part tariff or some other means. However, we do believe that future RTP rates should offer customers an opportunity to choose to hedge some of their usage.

Therefore, we will adopt the following rate design guidance:

- Dynamic pricing rates should include a capacity reservation charge, or a similar feature, that allows a customer to pay a fixed charge for a predetermined amount of its load and pay the dynamic price for consumption in excess of the reserved capacity.

5.1.5. Ability to Opt Out from Default Rates and Bill Protection

This section addresses whether rates should offer the possibility to opt out to another rate.

Dynamic pricing rates can also include a provision that protects customers' bills during an initial trial period, typically, the first year. If a rate offers bill protection, a customer's bill would generally be calculated under both the new dynamic rate and the prior rate during the year. If the customer pays more during the year under the new dynamic rate than the customer would have paid under the old rate, then the customer receives a refund for the difference at the end of the year. If the customer pays less under the new dynamic rate then there is no refund at the end of the year. The experience during the year could help a customer determine whether to stay on the new dynamic rate or opt out to another rate.

Parties' Comments

SDG&E supports providing customers bill protection during the first year. SDG&E's 2008 General Rate Case Phase 2 decision, D.08-02-034, adopted bill protection for the first 12 months.

BOMA states that offering bill protection during the first year on a dynamic pricing rate is problematic for tenant-occupied commercial buildings due to the time lag between the monthly payments during the trial year and the potential refund at the end of the year. First, BOMA explains that the timing mismatch could create cash flow problems for tenants if they pay high bills during the summer but do not get a refund until the end of the year. The refund can also be challenging for landlords who may need to track down tenants that have left the building.[89]

CLECA does not support requiring a customer to stay on a dynamic pricing rate for a full year with bill protection. According to CLECA, bill protection that only comes at the end of the year can create cash flow problems for customers.[90]

EPUC believes bill protection is important if large commercial and industrial customers are required to be on dynamic pricing for one year.[91] However, EPUC notes that even with annual bill protection, customers will still focus on the monthly bill fluctuations that could occur under a CPP rate. It is also important to EPUC that customers have the ability to switch back to the TOU rate after the first year.[92]

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[89] BOMA Comments, February 28, 2008, p. 3.

[90] CLECA Comments, February 28, 2008, p. 4.

[91] EPUC Comments, February 28, 2008, p. 3.

[92] EPUC CPP Comments, March 21, 2008, pp. 6-7.

According to PG&E, if there are a variable number of CPP events the first year bill protection will be misleading since the number of events during the first year could differ from the number of events in future years.[93]

Discussion

While it is our goal to encourage customers to participate in dynamic pricing, and we expect many customers will find opportunities to save money on dynamic pricing, we also want to provide customers choice. Therefore, customers should have an opportunity to opt out to other rates.

The default CPP rate adopted for SDG&E in D.08-02-034 provided for an initial 45-day opt-out period. If a customer does not opt out to a TOU rate during the first 45 days the customer will be required to remain on CPP for a full year. We believe this is a reasonable approach. In general, some restrictions on opting out are appropriate; however, we will not dictate a particular approach.

We continue to believe that bill protection is valuable to enable customers to become familiar and comfortable with a new rate. However, there may be customers that would rather not have bill protection. Thus, we conclude that utilities should offer, but not require, bill protection during the first year.

As general rate design guidance we conclude the following:

- Customers should have the opportunity to opt out of a default dynamic pricing rate to another time-variant rate.

- Utilities should offer optional bill protection to customers on default dynamic pricing rates.

[93] PG&E Comments, February 28, 2008, pp. 21-22.

5.1.6. Integration with the CAISO Operated Wholesale Energy Markets

In comments discussing CPP, parties recommended that the utilities coordinate with the CAISO. DRA believes the utility and CAISO should coordinate to determine when CPP events should be triggered. According to DRA, the CAISO generally has a broader perspective on the energy supply-demand balance, although the utility would be the entity that actually communicates with customers.[94]

TURN argues that if the utility triggers a CPP event, the utility should bid the associated load into the CAISO day-ahead market so that the CAISO knows the load reduction is there at some price.[95]

We agree with DRA that the utilities should coordinate their use of dynamic pricing with the CAISO, and we agree with TURN that the utilities should bid demand reductions resulting from dynamic pricing into the CAISO's day-ahead market. Dynamic pricing is intended to better align retail rates with wholesale market conditions; thus, the utilities should make sure that demand reductions that result from dynamic pricing are reflected in the day-ahead energy market. If retail customer responses to dynamic pricing are reflected in the wholesale market, then the market should function more efficiently and at times clear at a lower price. The CAISO can also avoid procuring unnecessary resources if the CAISO knows that demand will be lower due to dynamic pricing.

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[94] DRA Opening Comments, October 5, 2007, pp. 18-19.

[95] TURN Opening Comments, October 5, 2007, p. 24.

The utilities could submit price-responsive hourly schedules to the day-ahead market so that the CAISO knows that demand will change in response to wholesale prices. The details of how dynamic pricing and demand response should participate in the wholesale market are the subject of working groups established by the CAISO in conjunction with the CPUC and CEC. Also, the Commission is addressing the integration of demand response into the CAISO's MRTU market in R.07-01-041, so we will not address this issue in any detail in this decision.

However, given the Commission's desire to better align retail rates with the wholesale market, we will adopt following general rate design guidance:

- The utilities should bid demand reductions due to dynamic pricing into the CAISO's day-ahead market.

5.2. Critical Peak Pricing

CPP is a dynamic rate that includes a short-term price increase to a pre-determined level to reflect real-time system conditions. Although CPP is intended to reflect real-time system conditions, the parameters of the rate design are all set administratively and are indirectly tied to wholesale market conditions. Important parameters include the level of the critical peak price, the choice of trigger for a critical peak event, the number of events per year, and the length of events when they are triggered.

This section addresses each of the key CPP rate design parameters and provides rate design guidance for PG&E's future CPP rate design proposals. The discussion relies on comments filed by parties in response to questions and draft proposals posed in prior rulings and comments filed by parties following the CPP workshop held on March 7, 2008.

5.2.1. Critical Peak Price

The critical peak price is the predefined dollar per kWh energy charge that a customer pays for energy used during the critical peak period.

Parties' Comments

Parties generally agree that the critical peak price should represent the marginal cost of capacity used to meet peak energy needs plus the marginal cost of energy during the critical peak period. Most parties also agree that the annualized cost of a new combustion turbine is an appropriate proxy for the marginal capacity cost. However, at the workshops and in comments several parties strongly recommend against litigating the marginal cost of capacity in this proceeding. For example, SDG&E states that although most parties agree that a new natural gas-fired combustion turbine should be used as a proxy for the generation marginal capacity cost, there is little consensus regarding whether or how energy profits should be netted against the capacity cost. Therefore, SDG&E recommends addressing the marginal capacity cost in each utility's separate rate design proceeding.[96]

BOMA, however, is not convinced that a new combustion turbine should be used to determine marginal generation capacity cost. BOMA recommends that the Commission investigate PG&E's actual capacity costs to determine if a combustion turbine is appropriate.[97]

DRA notes that cost studies typically use a combustion turbine as a proxy and allocate the entire combustion turbine cost to the critical peak hours. DRA suggests that analysis of actual utility cost data might show that utilities pay

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96 SDG&E Comments, February 28, 2008, p. 2.

97 BOMA Comments, February 28, 2008, p. 5.

more for capacity than the combustion turbine proxy might indicate, and since a combustion turbine would be dispatched during non-CPP hours, a different cost allocation method could be appropriate.[98]

The CAISO is in the process of developing a scarcity pricing proposal that would apply during reserve shortage conditions. TURN suggests that the CAISO's scarcity pricing would be the most logical basis for a CPP rate because it would incorporate the reliability value that is not otherwise included in wholesale energy prices.[99] DRA similarly notes that once the CAISO implements scarcity pricing, the unscaled scarcity price could be added to the pre-established CPP rate. Thereby the CPP price would be variable rather than static.[100]

At the workshops, parties discussed whether a centralized capacity market or bulletin board, if established in the future, would be useful for deriving CPP prices. PG&E is uncertain and recommends deferring consideration of such proposals.[101]

Discussion

There is general agreement that the critical peak price should represent the marginal cost of capacity used to meet peak energy needs plus the marginal cost of energy during the critical peak period. We adopt this principle as part of the rate design guidance.

We generally agree that the cost of a new combustion turbine is a reasonable proxy for the long-run marginal cost of capacity. However, BOMA

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[98] DRA Opening Comments, October 5, 2007, pp. 18, 25-26.

[99] TURN Opening Comments, October 5, 2007, p. 30.

[100] DRA Comments, February 28, 2008, p. 4.

[101] PG&E Comments, February 28, 2008, p. 22.

suggested looking at PG&E's actual capacity costs, and TURN and DRA suggested looking to the CAISO's scarcity pricing in the future. A centralized capacity market or bulletin board could also be sources of capacity costs in the future. We do not want, however, to rule out the use of other sources of information to set the critical peak price. As such, we recommend the cost of a new combustion as a reasonable proxy for the marginal capacity cost; however, if PG&E uses the price of a combustion turbine to set the critical peak price, it should explain why it did not use alternate methods including actual costs, CAISO scarcity prices (once adopted by the Federal Energy Regulatory Commission (FERC) and implemented by the CAISO), and centralized capacity market or bulletin board prices (if implemented in the future). Other parties will also have the opportunity to propose specific methodologies in specific rate design proceedings.

Based on the forgoing discussion we adopt the following rate design guidance:

- The critical peak price should represent the marginal cost of capacity used to meet peak energy needs plus the marginal cost of energy during the critical peak period.

- The utility should explain what it used as the basis for the marginal cost of capacity in its CPP rate and why the annualized cost of a new combustion turbine is a reasonable proxy for determining the marginal cost of capacity; however, alternative bases include actual utility costs, CAISO scarcity prices (if adopted by the FERC and implemented by the CAISO), and centralized capacity market or bulletin board prices (if implemented).

5.2.2. Structure of CPP

PG&E's Existing CPP Rate for Large Customers

PG&E's existing voluntary CPP rate for large C&I and agricultural customers, Schedule E-CPP, is a supplemental tariff that is applied in addition to a customer's otherwise applicable TOU rate, so we will provide a summary of PG&E's TOU rates.

PG&E's TOU rates for large customers all include summer demand charges that are applied to a customer's maximum kilowatt demand during each summer month. The maximum kilowatt demand is determined by identifying the 15-minute interval during the month in which the customer's demand was at its highest. The TOU rates that are typically used by C&I customers with demand greater than 500 kW and the large agricultural TOU rates include two summer generation demand charges—one applied to the highest demand during the summer peak periods each month, and the other applied to the highest demand during the summer partial peak periods each month.

A customer on the E-CPP rate pays all of the charges under the customer's otherwise applicable TOU rate, and receives CPP charges and credits. The E-CPP charges consist of dollar per kilowatt-hour charges that apply to usage during the on-peak period on CPP days.[102] These charges are in addition to the TOU on-peak rates. The E-CPP credits consist of dollar per kilowatt-hour discounts that apply to energy use during on-peak and partial-peak TOU periods on summer non-CPP days.

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[102] PG&E's CPP energy charges are further broken down into a "moderate-price" charge that is added to the TOU on-peak energy charge from noon to 3:00 p.m. and a "high-price" charge that is added to the TOU on-peak energy charge from 3:00 p.m. to 6:00 p.m.

The net effect of combining the TOU rate and the CPP rate is that the customer pays higher peak energy charges on CPP days, pays the full generation demand charge under the otherwise applicable TOU rate, and receives reduced peak and partial peak energy charges on non-CPP days.

SCE's and SDG&E's CPP Rate for Large Customers

SCE offers two CPP options for large customers. One offsets the higher CPP rate with lower energy rates during summer peak and partial peak periods during non-CPP days. The other options eliminates the generation demand charge.

SDG&E's CPP rate eliminates the generation demand charge. However, a customer can opt to pay a dollar per kilowatt capacity reservation charge for some of its demand.

PG&E's Existing CPP Rate for Small Commercial and Residential Customers

PG&E offers voluntary CPP rates to small commercial and residential customers who have received AMI meters— E-CSMART and E-RSMART, respectively. Like the large customer CPP rate, the small commercial and residential CPP rates are supplemental tariffs that are applied in addition to a customer's otherwise applicable rate. The otherwise applicable rate could be a TOU rate or a non-time-differentiated rate.

The design of the small commercial and residential CPP rates differs from the large customer CPP rate in several ways. First, the CPP period is shorter under the small commercial and residential CPP rate—four hours rather than six hours. Second, the CPP credit applies to all usage during the summer that is not during CPP events, rather than only applying to summer partial peak and peak usage. Third, customers receive an additional credit, referred to as a "participation credit," applied to all summer usage.[103]

Alternative CPP Rate Designs Analyzed

The January 23, 2008 Ruling directed PG&E to prepare an analysis of three different rate designs for large customers and present the results of the analysis at the March 7, 2008 workshop. The first rate design was the current tariff which is designed based on 12 CPP calls per summer, includes two-tiered CPP charges roughly equal to between $0.50 and $0.65 per kWh, and provides a roughly $0.03 per kWh credit on-peak usage during non-CPP days. The second and third rate designs were based on 15 CPP calls per summer and included a single-tiered CPP charge of $0.75 per kWh. In the second rate design 80% to 90% of the offsetting rate discount was applied to the on-peak generation demand charges with the balance applied to on-peak energy charges. In the third rate design all of the credits were applied to the demand charges.[104] PG&E was asked to calculate the bill impact of the three rate designs on customers with typical load shapes. PG&E was further directed to calculate the bill impact assuming each customer dropped load during CPP events by 10%, 20%, and 30%.

Parties' Comments

In post-workshop comments, CLECA suggests that the Commission should further consider which charges should be most appropriately reduced in the CPP rate design (energy charges, demand charges, or both) and in which time periods (on-peak, partial peak, or off-peak). CLECA recommends that in

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[103] The participation credit under the residential E-RSMART only applies to usage in Tiers 3, 4, and 5.

[104] PG&E CPP Comments, March 21, 2008, Attachment.

addition to the rate proposals presented by PG&E, the Commission could consider a CPP rate similar to that discussed in a recent Brattle Group study of dynamic rates which was presented as part of the DRRC's Rates Project. The Brattle Group's CPP rate had no demand charges and reduced energy charges during non-CPP peak hours and partial peak hours to offset the increased revenues from the CPP periods.[105]

DRA points out the inconsistency in rate designs that fully reflect the cost of a combustion turbine in the CPP price but do not eliminate the coincident demand charges, which are also intended to recover the cost of capacity.[106]

At the March 7, 2008 CPP workshop and in subsequent comments, several parties noted that according to PG&E's analysis, CPP resulted in relatively modest annual bill decreases, even with significant demand reductions during CPP periods. However, CPP could result in significant month-to-month bill volatility if a large number of CPP events fall in one month but few events fall in another month.

According to PG&E, a customer's July bill could be 50% higher than the customer's June bill if most of the CPP events occur in July. Furthermore, PG&E warns that CPP is inherently unpredictable, so predictions of customer bill impacts will be unreliable. PG&E is also concerned that CPP complicates the utility's revenue requirement recovery since CPP could increase balancing account volatility.

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[105] CLECA CPP Comments, March 21, 2008, p. 2.

[106] DRA Opening Comments, October 5, 2007, pp. 26-27.

PG&E recommends that if the Commission wants to modify the existing CPP rate, then PG&E would propose to implement the second rate design presented at the workshop which is similar to the rate PG&E had proposed in A.05-01-016 *et al.* as part of a settlement proposal.[107]

Discussion

CPP rates should include TOU pricing during non-CPP periods as a basic design element. PG&E's small commercial and residential CPP rates do not require that the customer enroll in a TOU rate, although that is an option the customer may choose. We believe that like the large customer CPP rate, the small commercial and residential CPP rates should build upon TOU rates. Therefore, we will require PG&E to propose revisions to its CPP rates and require that a CPP customer also enroll in TOU.

Since the critical peak price is intended to reflect the cost of capacity needed to meet the peak, we agree with DRA that also charging significant summer on-peak and partial-peak demand charges is duplicative. Therefore, we conclude that CPP rates should not also have summer generation demand charges. This is the approach taken by SDG&E and one of SCE's CPP rate options. This is slightly different from the rates that PG&E presented at the CPP workshop, which did not entirely eliminate the generation demand charges. If the generation demand charge is reduced to zero or the rate does not include a summer generation demand charge, then PG&E should apply any additional rate discount to all summer usage during non-CPP periods.

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[107] PG&E CPP Comments, March 21, 2008.

As PG&E notes, a CPP rate can result in additional month-to-month bill volatility if more CPP events are called in some summer months than in others. We believe this result is consistent with the purpose of CPP. As a form of dynamic pricing, CPP is intended to reflect market conditions that change from day to day. It would be a reasonable outcome if a customer pays a higher bill during a month during which market conditions are stressed and a large number of CPP events occur. CPP gives customers an opportunity to avoid high costs during high cost periods, unlike a non-time-variant or TOU rate that allocates high costs across other time periods.

Therefore, we adopt the following rate design guidance:

- Critical peak pricing rates should include a critical peak price during critical peak periods and time-of-use rates during non-critical periods.

- Since the critical peak price is intended to reflect the marginal cost of generation that is needed to meet peak period usage, CPP rates should not also have summer generation demand charges.

5.2.3. Critical Peak Events—How Many Times per Year and When Are Events Called

PG&E's large customer CPP rate is designed to be called 12 times per summer. PG&E's small commercial and residential CPP rates are designed to be called 15 times per summer. PG&E's decision to call CPP events is primarily based on a day-ahead temperature forecast. PG&E intends to call the design basis number of events each year, irrespective of system conditions, so PG&E adjusts the temperature threshold up and down as necessary. If there are few hot days PG&E will lower the temperature threshold, which means CPP events are called on cooler days. If there are many hot days PG&E will raise the temperature threshold. PG&E may also call events due to CAISO alerts or high forecasted wholesale prices.

SCE's large customer CPP rate is similar to PG&E's. The rate is designed assuming it will be called 12 times per summer. SCE will call events due to high system peak demand and/or low generation reserves, system constraints, high wholesale market prices, special alerts issued by CAISO, or high temperatures. Like PG&E, SCE will adjust the temperature threshold up or down to achieve the CPP program design basis of 12 CPP events per summer season.

SDG&E's large customer CPP rate takes a different approach. SDG&E's rate is designed assuming that it will be called nine times per summer. However, the minimum number of calls is zero and the maximum is 18. SDG&E's decision to call events will be based on forecasted temperature, system load, and extreme system conditions such as a CAISO alert. SDG&E will not adjust the triggers in order to call the events a predetermined number of times each year. SDG&E will only call events when necessary.

Parties' Comments

CLECA believes that it will be easier for customers to accept CPP events if they are tied to clear instances when electric supplies are tight, such as on hot days. If instead events are called by the utility to stabilize revenues and called on relatively cool days, customers are less likely to accept the CPP rates. Therefore, CLECA recommends providing some flexibility in the number of events called.

CLECA also points out that the supply-demand balance can be tight at times other than summer on-peak periods. Therefore, CLECA recommends allowing CPP events to be called during other times of day or year with the appropriate customer education.

CLECA suggests that additional analysis be performed to determine the level of revenue volatility associated with a divergence in the number of events called. Parties may then be able to agree on an acceptable level of volatility in a collaborative process.[108]

PG&E supports pre-determined and pre-approved criteria that could be based on forecasted demand, forecasted temperature, emergency situations, higher market prices, or other criteria. However, PG&E believes the utility should retain some discretion.

PG&E notes that calling a variable number of CPP events each year would result in a significant revenue under-collection during years when few events are called and significant revenue over-collections during years when an above-average number of events are called. PG&E recommends that the Commission consider utility revenue and customer bill impacts of using a variable number of CPP events. PG&E argues that it is not possible for the utility to collect the revenue requirement on an annual basis if there are a variable number of events each year.

PG&E believes restricting CPP events to summer weekday afternoons strikes a reasonable balance between giving customers an understanding of when events will be called and covering the periods when demand is most likely to be at peak levels and generation shortfalls are most likely to occur.[109]

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[108] CLECA Opening Comments, October 5, 2007, p. 28; CLECA CPP Comments, March 21, 2008, pp. 2-3.

[109] PG&E Comments, February 28, 2008, pp. 21-22, 25; PG&E Opening Comments, October 5, 2007, Attachment, p. 19.

SCE states that dynamic pricing events could be triggered by temperature, forecasted system load, or a wholesale market heat rate. SDG&E adds system emergencies such as fires to the list of potential triggers, but indicates that the trigger should be appropriate for the type of program.[110]

TURN argues CPP events should be called when needed, which could be on days other than summer weekdays. However, TURN notes that too many calls outside of summer weekdays could threaten customer acceptance. TURN suggests that existing revenue balancing accounts would allow for a variable number of events each year.[111]

Discussion

CPP is intended to reflect real-time system conditions, and system conditions vary from one year to the next. Therefore, we agree with the customer representatives that CPP should allow for a variable number of events each year, like SDG&E's CPP rate, rather than a fixed number of events, as is currently the case for PG&E and SCE. We agree with TURN that existing revenue balancing accounts should be sufficient to handle any year-to-year fluctuations.

If PG&E disagrees with this conclusion, then in PG&E's subsequent rate proposals the utility should provide a revenue analysis that shows the forecasted revenue over- and under-collection under plausible scenarios in which the number of events called varies from the design basis. PG&E should provide a comparison of the over- or under- collection due to a variable number of CPP

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[110] SCE Opening Comments, October 5, 2007, p. 20; SDG&E Opening Comments, October 5, 2007, p. 8.

[111] TURN Opening Comments, October 5, 2007, pp. 30-31.

calls to other common sources of over- and under- collections, such as changes in commodity prices and deviations in sales relative to forecast. PG&E should also compare the possible over- and under-collections to the revenue adjustments PG&E has requested and received in ERRA applications during the past three years.

We also agree with CLECA and TURN that CPP events should not be limited to summer weekday afternoons. While tight supply and demand conditions are most likely to occur on summer weekday afternoons, tight conditions or high wholesale energy prices can also occur on weekends and holidays, and potentially at other times of year. The increasing role of intermittent renewable resources like wind can also contribute to a tight supply-demand balance at any time of day, year-round. A study issued by the CAISO last year highlights how the addition of intermittent renewable resources can contribute to wholesale market volatility. The CAISO has identified demand response as a critical dependency that needs to be addressed to integrate renewables.[112] Furthermore, transmission and generation outages and natural disasters affecting the electric system can occur at any time.

At the same time, we recognize that CPP should be easy to understand for customers. For now we conclude that an acceptable balance is to continue calling CPP events during afternoons during a defined hour range (*e.g.*, 2:00 p.m. to 6:00 p.m.), but allow CPP events to be called any day of the week, year round. PG&E will need to appropriately educate customers that, although events are

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[112] CAISO, "Integration of Renewable Resources," November 2007; CAISO, "2008-2013 Integration of Renewable Resources Program High-Level Program Plan," http://www.caiso.com/1fac/1facbc35316e0.pdf.

most likely to be called during non-holiday weekday afternoons, events could be called on other days depending on many circumstances. We believe it is appropriate to include more flexibility in the rate, especially given the increasing role of intermittent renewable generation sources in the system.

We adopt the following rate design guidance:

- The utilities should be able to call a variable number of events each year, and the rate should be designed based on the number of events that would be called during a typical year.

- The utilities should be able to call critical peak events any day of the week, year round.

5.2.4. Time of Day and Length of Critical Peak Events

As discussed in the prior section, the CPP rates offered by the California utilities are structured so that the CPP period occurs on summer weekday afternoons. The time of day and length of a CPP event is also generally predefined.

PG&E's current large customer CPP rate includes two critical peak periods: a moderate price period from noon to 3:00 p.m. followed by a high price period from 3:00 p.m. to 6:00 p.m. PG&E's small commercial CPP rate features a four-hour critical peak period from 2:00 p.m. to 6:00 p.m. The residential CPP rate includes a five-hour critical peak period from 2:00 p.m. to 7:00 p.m.

SCE's CPP rate has the same critical peak periods as PG&E's. SDG&E's large customer CPP rate includes a seven-hour critical peak period from 11:00 a.m. to 6:00 p.m.

Parties' Comments

PG&E has proposed switching the large customer critical peak period to a four-hour period from 2:00 p.m. to 6:00 p.m. to conform the rate to the small commercial CPP rate.

Several customer groups expressed concerns that the CPP period should not be too long. CLECA recommends relatively shorter CPP periods (four hours is better than seven hours) so that customers can use a wider variety of demand reduction strategies such as pre-cooling.[113] [114] CMTA states that a long CPP period could require some businesses to shut down for the day.[115]

TURN also expresses concern that demand reductions could erode if the critical peak period is too long.[116]

DRA recommends that the length of the CPP period should be based on the individual utility's load variations. Therefore, DRA posits that it is difficult to address the issue generically in this proceeding. DRA also suggests that in the future, with enabling technologies, variable length CPP periods could make sense.[117]

SDG&E justifies its seven hour CPP period by pointing to testimony it filed in A.05-01-017, which compared CPP period durations of four, five, six, and seven hours. SDG&E concluded that a seven hour period from 11:00 a.m. to 6:00 p.m. was superior to a shorter period because it includes the greatest

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113 "Pre-cooling" means running the air conditioning earlier in the day, prior to a critical peak period, in order avoid running air conditioning during a critical peak period while maintaining a comfortable temperature.

114 CLECA Comments, February 28, 2008, p. 3.

115 CMTA Opening Comments, October 5, 2007, p. 13.

116 TURN Opening Comments, October 5, 2007, p. 30.

117 DRA Opening Comments, October 5, 2007, p. 26.

number of high load hours, it is much less likely to shift the peak load outside of the CPP hours, and it will minimize customer confusion by aligning with the TOU on-peak period.[118]

Discussion

In D.05-04-053, the Commission directed the utilities to explore narrowing the current peak period to cover the hours of 2:00 p.m. to 6:00 p.m..[119] PG&E's proposed new CPP rate includes a four-hour event period from 2:00 p.m. to 6:00 p.m.., which is a reasonable approach. However, as SDG&E points out, different CPP periods may be appropriate in different circumstances.

Ultimately setting the length of the critical peak period requires reasonable judgment, taking into account the historical and expected system conditions in a utility's service territory. It is possible that system conditions could change over time indicating a shorter or longer CPP period is reasonable. Therefore, we think flexibility is important, and thus, we will not adopt any general rate design guidance related to the length of the CPP period. The length of the CPP period should be determined in specific rate design proceedings.

5.3. Real-Time Pricing

As discussed earlier, RTP is the best rate to promote economic efficiency and equity between customers. RTP can also connect retail rates with California's greenhouse gas policies if wholesale energy prices reflect the cost of greenhouse gas emissions. For example, when wholesale energy prices are being set by inefficient generation sources with high greenhouse gas emissions, RTP

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118 SDG&E CPP Workshop Comments, March 21, 2008, pp. 2-3.

119 D.05-04-053, OP 7.

could reflect the cost of greenhouse gas emissions and discourage retail customers from consuming polluting power. Conversely, if other time periods are dominated by non-emitting resources such as nuclear, water, and wind, RTP could signal to customers that the supply of power is clean.

Development of RTP rates for the California IOUs will be a milestone achievement. However, parties generally agreed that it is premature to address the details of RTP. Thus, the discussion of RTP in this decision is abbreviated.

5.3.1. What Wholesale Prices Should RTP Be Based On?

The January 23, 2008 Ruling recommended that RTP should be based on the CAISO's day-ahead hourly market prices. The ruling also recommended that the prices should be aggregated across PG&E's service territory. As the market develops, the Commission could consider more granular pricing based on nodal prices.

Parties agreed with this approach. TURN additionally suggested that customers could be offered a voluntary RTP rate based on day-of prices since some limited number of customers may be willing to respond to day-of prices.[120]

DRA and PG&E emphasized uncertainties around how the CAISO's day-ahead prices could translate to rates in a way that aligns with PG&E's actual costs and collects the revenue requirement.

DRA believes that equating RTP directly with the day-ahead hourly market prices will result in rates that are too low because the rates would not account for the costs of forward contracting.[121] Day-ahead hourly market prices

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120 TURN Post-Workshop Comments, December 11, 2007, p. 8.

121 DRA Post-Workshop Comments, December 11, 2007, p. 6.

may need to be scaled up or down for two purposes: first, to add capacity costs; and second, to reconcile the day-ahead hourly prices with the revenue requirement. DRA comments that reconciling the day-ahead hourly prices with the revenue requirement will be challenging since the day-ahead prices are not known in advance.[122] PG&E is unclear how energy charges should be indexed to day-ahead energy prices and recommends holding an additional workshop.[123]

Developing the details of how to index the CAISO's day-ahead hourly price to the retail rate should wait until the MRTU day-ahead market is operating and can be assessed. The utilities, other parties, and the Commission will need to carefully consider how to reconcile RTP with the revenue requirement.

In this decision, we will adopt the following general guidance:

- The energy charge should be indexed to the CAISO's day-ahead hourly market prices.

- At least initially, RTP should be based on day-ahead hourly market prices that have been aggregated across PG&E's service territory. As the market develops, locational prices should be considered.

5.3.2. Do Energy Prices Reflect the Entire Cost of Generation?

Parties generally agree that in today's California market some generation costs are not reflected in wholesale energy prices. Some suggest that because resource adequacy requirements give generators an opportunity to sign contracts

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122 DRA Comments, February 28, 2008, p. 4.

123 PG&E Comments, February 28, 2008, p. 22.

for capacity, generators do not need to cover all of their costs through the sale of energy. Parties also point to out-of-market purchases made by the CAISO. However, the amount of generation cost that is not reflected in energy prices is unclear. Several parties recommend that the Commission carefully examine this issue.[124]

BOMA supports investigating the extent to which generation marginal capacity costs are imbedded in wholesale energy prices by examining PG&E's capacity payments. BOMA recommends conducting the investigation in this proceeding.[125] CLECA believes that the level of capacity costs not reflected in energy prices is "far from zero" for most generators. CLECA expects that unless California moves to an energy-only market, most generators will recover some of their costs in non-energy payments. According to CLECA, if the Commission decides to pursue a centralized capacity market, generators will receive a large amount of revenue through capacity payments. However, CLECA doubts there will ever be general agreement on how to estimate the level of capacity costs reflected in energy prices. CLECA believes this issue should continue to be litigated in the Phase 2 of utility general rate cases.[126]

We agree that this issue requires further consideration and believe that a proceeding considering a specific RTP proposal is the appropriate forum. Accordingly, we adopt the following guidance:

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124 For example, BOMA Post-Workshop Comments, December 11, 2007, pp. 5-6 and CMTA/EPUC Post Workshop Comments, p. 2.

125 BOMA Comments, February 28, 2008, pp. 4-5.

126 CLECA Comments, February 28, 2008, pp. 5-6.

- The Commission should determine the degree to which the marginal cost of capacity is not incorporated into the CAISO's day-ahead hourly market prices.

6. TURN's Proposal to Link Dynamic Pricing and Resource Adequacy

Parties emphasized the important relationship between dynamic pricing and resource adequacy and other procurement policies. For example, DRA notes that high resource adequacy requirements and forward contracting for energy by utilities results in relatively low and non-volatile real-time spot energy prices. On the other hand, the Commission has been pursuing demand response and dynamic pricing, but stable energy prices will not result in much demand response. According to DRA, the Commission's decisions regarding a capacity market and the planning reserve margin will determine which fork the Commission is heading down.[127]

In opening comments, TURN put forward a proposal that the planning reserve margin for a load serving entity (LSE) could be reduced if the LSE's customers are on dynamic pricing and are, therefore, willing to face high prices during scarcity conditions. In this case, the customers on the dynamic pricing rate should see a rate reduction that mirrors the lower planning reserve margin associated with their load.

DRA similarly believes it may be desirable for customers to have a role in determining the amount of resources procured on their behalf. To accomplish this, DRA supports investigating TURN's proposal to allow an LSE to procure a

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[127] Capacity markets are being addressed in R.05-12.013 and the planning reserve margin is the subject of R.08-04-012.

lower planning reserve margin for customers that are on CPP. DRA believes that TURN's proposal should be discussed in greater detail in R.08-04-012.[128]

[128] DRA Post-Workshop Comments, December 11, 2007, pp. 1-8.

Discussion

Advanced metering creates a new opportunity for individual customers to choose the level of price volatility and reliability that they want to pay for. Already, some residential customers are choosing air conditioner direct load control programs, and some large customers are enrolled in interruptible programs, under which the customer is in some sense accepting a lower level of reliability in return for an incentive. Advanced metering enables a much wider variety of customer options.

Linking customers' rate choices back to an LSE's resource adequacy obligations could provide a basis to create something akin to a hedging premium. If an LSE does not have to purchase as much capacity for customers on dynamic pricing, then the LSE could pass that cost savings onto the customers that are on dynamic pricing.

We believe TURN's proposal deserves further consideration and recommend that TURN introduce its proposal in R.08-04-012.

7. Measurement and Evaluation

BOMA recommends that PG&E be required to address price elasticities in its rate design proposals to understand the likely short-term and long-term price responses for different rate types.[129]

In D.08-04-050, the Commission adopted protocols and regulatory guidance to estimate the load impact of demand response. The decision requires the three major IOUs to conduct annual studies of their demand response

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[129] BOMA Comments, February 28, 2008, pp. 5-6.

activities.[130] PG&E should conduct annual studies of TOU/CPP, RTP, and PTR during years each of those rates is in effect.

PG&E should use its load impact studies to estimate the likely responses of customers to dynamic pricing rates, as desired by BOMA.

Additionally, PG&E should conduct an *ex post* review of when CPP events were called and the degree to which the calls aligned with days when a combustion turbine did or would have operated based on price and reliability considerations. This analysis could help PG&E and the Commission improve CPP rate design and the triggering of CPP events so that CPP is consistent with actual system conditions. PG&E should present the results of this analysis in its GRC Phase 2's and any other proceeding in which CPP rate design proposals are being considered.

8. Incremental Costs to Implement Dynamic Pricing

In comments filed on February 28, 2008 and in comments on the proposed decision, PG&E indicates that the utility would need to incur incremental costs to implement dynamic pricing according to the January 23, 2008 Ruling and proposed decision. PG&E indicates there would be incremental costs associated with information technology systems, billing changes, and customer outreach and education. PG&E requests authority to accumulate costs, without limitation, in a balancing account for recovery as part of the Annual Energy True-Up rate changes.[131]

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[130] D.08-04-050, OP 4.

[131] PG&E Comments, February 28, 2008, pp. 18-19, 32-34; PG&E Opening Comments on Proposed Decision, pp. 11-12.

We expect there will be reasonable incremental costs required to implement dynamic pricing rates adopted by the Commission including costs associated with systems and billing changes and customer outreach and education. However, we cannot give PG&E authority to recover incremental expenditures in this decision since we do not have a record to approve any particular expenditure level. Furthermore, since this decision does not adopt any specific rates, it is premature to determine the necessary level of incremental expenditures for system changes and customer outreach and education.

Even if this decision could approve expenditures, the Annual Energy True-Up process would not be appropriate since PG&E seeks approval for its Annual True-Up rate change through an advice letter process that does not provide an opportunity for reasonableness review. Instead PG&E should seek cost recovery through formal applications.

For expenditures that occur in 2011 and later, PG&E should seek recovery in general rate cases. In the meantime, to the extent PG&E believes it needs authority to incur incremental expenditures to implement specific dynamic pricing rates, PG&E should seek recovery in the application in which PG&E proposes the rates. If PG&E plans to start spending before the Commission has issued a decision on a dynamic pricing rate proposal, PG&E is authorized to record the incremental expenditures in a memorandum account and seek recovery in the related rate design proceeding.

For expenditures related to customer education and outreach, PG&E should explain how it is coordinating customer outreach related to dynamic pricing with the outreach the utility is conducting for energy efficiency and other demand response programs.

9. Content of Future PG&E Dynamic Pricing Rate Filings

PG&E's dynamic pricing proposals filed pursuant to the timeline adopted in this decision should at a minimum include several components. First, each proposal should be consistent with the rate design guidance in this decision, and PG&E's filing should explain how its rate design is consistent with the guidance. Second, each dynamic pricing rate proposal should include a bill analysis showing the full distribution of customer bill impacts under the proposed rate or rates. Third, PG&E should explain how it intends to conduct customer education for the new dynamic pricing rate. Fourth, PG&E should describe the bill analysis tools that PG&E will provide to customers once a rate or rates are adopted. Finally, PG&E should include any other information required by this decision.

10. Other Issues

10.1. Applicability of this Decision to SCE and SDG&E

The assigned Commissioner invited SCE, SDG&E, and their customers to participate in this proceeding. Although this is a PG&E proceeding, the policies adopted for PG&E could be applied to SCE and SDG&E in their future rate design proceedings. This is similar to how the resolution of a policy issue in one utility's general rate case may set the stage for implementation of that policy in other utility general rate cases following notice and due process.

We make clear that we are not ordering SCE and SDG&E to adhere to the timetable or rate design guidance adopted herein. However, we recommend that SCE and SDG&E take this decision into consideration. The Commission may require SCE and SDG&E to follow this guidance in those utilities' rate design proceedings.

10.2. Customer Access to Data

Parties' Comments

CMTA/EPUC emphasizes the importance of having timely access to hourly usage information so that customers can take action based on timely pricing signals.[132]

PG&E agrees and indicates that, if and when its upgraded AMI system is implemented, customers will have access to practically real-time usage information through the Home Area Network (HAN). In the meantime, customers have access to their usage information the following day. PG&E also notes that D.06-07-027 already required the utility to set up an automated data exchange through which customers and third parties authorized by a customer can access energy usage data. PG&E's automated data exchange must be filed no later than July 20, 2009 pursuant to D.07-09-037.[133]

SDG&E notes that currently its customers with interval meters can view usage data on the following day without additional technology. Accessing the data in real time would require customers to install additional devices to access the pulse data. However, once the new AMI project has been implemented, customers will be able to access their real-time usage information via the HAN if the customer installs a HAN-compatible energy management system or information display.[134]

Discussion

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[132] CMTA/EPUC Post Workshop Comments, p. 7.

[133] PG&E Post-Workshop Comments, December 11, 2007, p. 6.

[134] SDG&E Post-Workshop Comments, December 11, 2007, p. 6.

We believe it is essential for customers to have timely access to hourly usage information. Customer access to data has been addressed by the Commission in D.06-07-027 and D.07-09-037 and will be addressed in the context of PG&E's AMI upgrade application, A.07-12-009. We believe other forums are more appropriate than this one for parties to raise issues related to customer access to energy usage information. Specifically, parties can raise any concerns with PG&E's current plans in A.07-12-009 or in the application that PG&E will file pursuant to D.07-09-037.

10.3. Permanent Load Shifting (PLS)

Ice Energy stresses that the utilities' strategic plans need to consider the impact of specific rate proposals on permanent load shifting.[135]

Discussion

In Resolution E-4098, the Commission ordered that "PG&E, SCE and SDG&E shall analyze in their next rate design proceeding, the impact of their rate proposals on PLS technology, with the goal of establishing general purpose dynamic/TOU/time-variant rates that provide a customer incentive to invest in PLS technologies."[136] We do not believe PG&E needs to be provided any additional guidance in this proceeding.

11. Comments on Proposed Decision

The proposed decision of the assigned Commissioner 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

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[135] Ice Energy Comments, February 28, 2008, p. 2.

[136] Resolution E-4098, OP 6.

Practice and Procedure. Comments were filed on June 30, 2008 by BOMA, CLECA, CMTA, DRA, EPUC, Ice Energy, PG&E, SDG&E, and TURN. Reply comments were filed on July 7, 2008 by PG&E, SCE, SDG&E, and TURN.

The following discussion addresses parties' comments that identified factual, legal, or technical errors in the proposed decision. Comments that merely reargue prior comments have been accorded no weight.

PG&E requested several changes to the timetable to allow more time for customer education and billing system upgrades.[137] In response, the timetable adopted by the decision has been changed in several respects so that PG&E has additional time to prepare its filings and additional time after Commission decisions and prior to rates going into effect for customer education and billing system upgrades.

Specifically, the requirement that PG&E file a proposal to revise its large customer CPP rate 30 days after adoption of the decision has been eliminated. Instead PG&E will be required to revise the rate when it files default CPP rates for large C&I customers. Also, the effective dates that PG&E is to propose for default CPP for medium C&I and default TOU for small and medium agricultural customers have been moved from 2010 to 2011 to give the utility more time for system upgrades and customer education. Other related changes have also been made.

A new section has been added addressing PG&E's comments related to incremental costs to implement dynamic pricing and recommending an appropriate process for PG&E to seek cost recovery.

[137] PG&E Opening Comments on Proposed Decision, pp. 6-9.

PG&E and DRA argue against requiring PG&E to address changes to the large customer meter roll-out in A.07-12-009, the Smart Meter Upgrade application. PG&E says that it would need to spend money in the near-term and cannot wait for a decision in A.07-12-009 before starting work.[138] DRA is concerned that adding additional issues and costs to the proceeding could delay it.[139] We continue to believe that A.07-12-009 is the appropriate forum to address changes to the advance metering roll-out. We will authorize PG&E to record expenditures it incurs prior to a decision in A.07-12-009 in a memorandum account and to seek recovery in A.07-12-009.

BOMA and CLECA requested that the Commission direct PG&E to offer customers tools so that customers can determine bill impacts.[140] We agree that PG&E should provide customers such tools so that customers understand the implications of different rates, so we have added that requirement.

CMTA asks the Commission to establish a timeline to ensure that PG&E puts in place the necessary communications systems to support RTP in 2011. We have added the requirement that PG&E include a timeline in its 2011 GRC Phase 2 application.

CLECA and PG&E ask the Commission to pay special attention to the interactions between default dynamic pricing and interruptible and other

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[138] PG&E Opening Comments on Proposed Decision, p. 7.

[139] DRA Opening Comments on Proposed Decision, pp. 1-2

[140] BOMA Opening Comments on Proposed Decision, p. 4; CLECA Opening Comments on Proposed Decision, pp. 1-2.

demand response programs.[141] We agree that the relationship between dynamic pricing and demand response programs requires special attention and recommend that PG&E and other parties address this relationship in the specific dynamic pricing rate design applications.

BOMA, CLECA, and EPUC argue that residential customers should not be offered a flat rate as an option after the AB1X rate protections have been lifted.[142] We believe it is premature to address whether a non-time differentiated rate should be an option for residential customers after the AB1X rate protections are gone. Therefore, we have removed the requirement that PG&E propose a flat rate as an option for residential customers after the AB1X rate protections have been lifted.

TURN recommends that the Commission pay greater attention to the connection between rates and actual procurement costs. According to TURN, if the Commission adopts policies that emphasize rates linked to spot prices while procurement is focused on longer time horizons, the utility could experience significant revenue balancing challenges.[143] We agree that the relationship between retail rates and procurement policy requires further attention. One of the policy goals of this decision is to more closely link rates and costs, but this decision is just a first step. For example, if the Commission adopts default dynamic pricing rates, we will learn more about individual customers' risk

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141 CLECA Opening Comments on Proposed Decision, pp. 4-5; PG&E Opening Comments on Proposed Decision, p. 5.

142 BOMA Opening Comments on Proposed Decision, p. 8; CLECA Opening Comments on Proposed Decision, p. 3; EPUC Opening Comments on Proposed Decision, p. 8.

143 TURN Opening Comments on Proposed Decision, pp. 3-4.

preferences and preferred rate structures. These customer choices could in turn influence the Commission's and utilities' procurement policies. However, we are not convinced that dynamic pricing will lead to larger revenue imbalances than the current rate structures that also result in large under- and over-collections due to the regulatory lag between changes in costs and retail rates.

The discussion, findings of fact, conclusions of law and ordering paragraphs have been changed consistent with the discussion in this section. Other clarifying edits have also been made.

12. Assignment of Proceeding

Rachelle B. Chong is the assigned Commissioner and David K. Fukutome is the assigned Administrative Law Judge in this proceeding.

Findings of Fact

1. In "California Demand Response: A Vision for the Future (2002-2007)," attached to D.03-06-032 as Attachment A, the Commission stated that electric customers should have "the ability to increase the value derived from their electricity expenditures by choosing to adjust usage in response to price signals."

2. The EAP II identifies demand response, along with energy efficiency, as the State's "preferred means of meeting growing energy needs."

3. A key action in the EAP II is "to make dynamic pricing tariffs available for all customers."

4. Rate design proceedings are the appropriate forum to address dynamic pricing.

5. In D.06-05-038, the Commission directed each utility "to incorporate default CPP tariffs for large customers into their next comprehensive rate design proceeding or other appropriate proceeding if directed by the Commission."

6. In D.05-11-009, the Commission directed each utility to submit RTP tariffs in its first comprehensive rate design proceeding, following the CAISO's implementation of its MRTU.

7. According to PG&E's current advanced metering plans, by 2012, all of PG&E's customers will have advanced meters, so all customers can take advantage of dynamic pricing.

8. Large C&I customers with maximum load greater than 500 kW have been on mandatory TOU rates since the late 1970's or early 1980's, depending on the size of the customer.

9. In D.01-05-064, as modified by D.01-08-021 and D.01-09-062, the Commission required mandatory TOU rates for all customers with maximum demand greater than 200 kW who received new meters through a program funded by the CEC.

10. Large C&I customers have been on TOU rates for between five and thirty years.

11. RTP is the best rate to promote economic efficiency and equity between customers; however, RTP cannot be developed and implemented until MRTU becomes operational.

12. CPP more closely aligns the retail rate with the wholesale market, and it can give customers an opportunity to manage their usage and lower their bills.

13. The Commission directed the utilities to propose AMI projects primarily because AMI enables greater demand response through dynamic pricing and demand response programs.

14. PG&E's current AMI deployment plans are not consistent with the Commission's policy objectives.

15. The delay in the on-line date of MRTU requires a delay in the development and implementation of RTP.

16. Two full summers of experience with MRTU are not needed before beginning to develop RTP.

17. A means to deliver day-ahead prices to IOUs and retail customers needs to be developed to effectively implement RTP.

18. Requiring PG&E to propose a default CPP rate for large C&I customers in early 2009 with an effective date on or before May 1, 2010 provides sufficient time for customer education.

19. TOU is not dynamic pricing because the rate does not change based on day-ahead or real-time market or system conditions.

20. Non-time-differentiated rates do not reflect the time varying costs of providing electricity.

21. Medium C&I and small commercial customers are capable of managing their energy use in response to dynamic pricing.

22. Small commercial customers require more time for customer education and outreach than do large and medium C&I customers.

23. The Commission did not wait until all large C&I customers had interval meters before making TOU a mandatory rate for large C&I customers with interval meters.

24. PG&E's current medium C&I and small commercial CPP rate can be combined with either a non-time-differentiated rate or a TOU rate.

25. Large agricultural customers with maximum load greater than or equal to 200 kW currently have interval meters and are required to take service on a TOU rate.

26. Since most customers with maximum load less than 200 kW do not have TOU meters or interval meters, the energy usage information provided by their new AMI meter may be their first source of accurate information about when and how they use electricity.

27. In D.07-09-004, the Commission approved a settlement between PG&E and the BOMA that removed the ban on submetering in commercial buildings so that commercial building tenants could receive appropriate price signals and have the opportunity to effectively use dynamic pricing options and participate in energy conservation programs.

28. The default CPP rate adopted for SDG&E in D.08-02-034 provided for an initial 45-day opt-out period, and if a customer does not opt out to a TOU rate during the first 45 days the customer will be required to remain on the CPP rate for a full year.

29. Bill protection can help customers become familiar and comfortable with a new rate.

30. CPP is intended to reflect real-time system conditions, and system conditions vary from one year to the next.

31. While tight supply and demand conditions are most likely to occur on summer weekday afternoons, tight conditions or high wholesale energy prices can also occur on weekends and holidays, and potentially at other times of the year.

32. It is premature to address the details of RTP.

33. D.08-04-050 requires the three major investor owned utilities to conduct annual studies of their demand response activities.

Conclusions of Law

1. It is reasonable to require PG&E to file dynamic pricing rates as part of the Rate Design Window, but delay the effective date to allow more time to develop rates and allow time for customer education following adoption of the rates by the Commission.

2. The 2008 Rate Design Window should be delayed from November 25, 2008 until February 28, 2009 to give PG&E more time to prepare its filings.

3. PG&E should develop RTP rates and make them available to all customers as soon as feasible.

4. PG&E should adopt CPP as the default rate for C&I customers with maximum load greater than 200 kW.

5. PG&E should revise its AMI implementation plans to support default CPP for large C&I customers in 2010 and optional RTP in 2011.

6. PG&E should propose RTP rates for all customer classes after one summer of experience with MRTU as part of its 2011 GRC Phase 2 filed in March 2010.

7. It is reasonable to wait for two full summers of experience with MRTU before implementing RTP.

8. Since RTP needs to be delayed until 2011, PG&E should propose to make CPP the default rate in 2010 for large C&I customers.

9. Requiring PG&E to propose that CPP be made the default rate for large C&I customers in 2010, and requiring PG&E to propose RTP in 2011 is consistent with past Commission decisions.

10. PG&E should file a proposal for a default CPP rate for large C&I customers by February 28, 2009 with an effective date on or before May 1, 2010.

11. It is reasonable to subdivide commercial and industrial customer with maximum load less than 200 kW into two subgroups: those with maximum

demand between 20 kW and 200 kW, referred to as medium C&I, and those with maximum demand below 20 kW, referred to as small commercial.

12. TOU should not be the default rate for medium C&I and small commercial customers.

13. TOU with CPP should be the default rate for medium C&I and small commercial customers.

14. It is reasonable for PG&E to provide a customer with maximum load less than 200 kW 12 months with a new advanced meter to observe its usage before moving to a default time-differentiated rate.

15. PG&E should offer optional RTP to all customer classes at the same time it is introduced for large C&I customers.

16. PG&E's proposal should not offer non-time-differentiated rates to any C&I or agricultural customer with maximum load less than 200 kW after the customer has had a new AMI meter for 12 months, starting in 2011.

17. PG&E should propose to make TOU with CPP the default rate for medium C&I and small commercial customers starting in 2011.

18. It is reasonable for the Commission to adopt default rates for customers based on their metering capability.

19. A CPP rate should be a TOU rate with an additional critical peak price that is charged during critical peak periods.

20. PG&E should revise its CPP rates for medium C&I, small commercial, and residential customers so that the CPP rates include TOU rates during non-critical periods.

21. Large agricultural customers should generally have the same rate options as large C&I customers.

22. PG&E should propose implementing default CPP for large agricultural customers one year after large C&I customers to allow more time for customer outreach and education.

23. A.07-12-009 is an appropriate forum to consider PG&E's PTR proposal.

24. The Commission should establish a point in time when residential rate design will be thoroughly examined.

25. PG&E should not exclude commercial master-metered customers from the dynamic pricing rates that the utility proposes.

26. It is reasonable to require PG&E to follow the rate design guidance adopted in this decision.

27. Rate design should promote economically efficient decision-making.

28. To promote economically efficient decision-making, rates should be based on marginal cost.

29. Other objectives, such as energy efficiency, and legal requirements, such as baseline allowances, should be addressed when designing specific rates, and any deviation from marginal cost should be minimized.

30. Rates should also seek to provide stability, simplicity and customer choice.

31. If customers on a particular rate schedule reduce their usage in a manner that reduces a utility's costs then the customers on that rate should see a commensurate reduction in their bills.

32. Dynamic pricing rates should include a capacity reservation charge, or a similar feature, that allows a customer to pay a fixed charge for a predetermined amount of its load and pay the dynamic price for consumption in excess of the reserved capacity.

33. Customers should have the opportunity to opt out of a default dynamic pricing rate to another time-variant rate.

34. Utilities should offer optional bill protection to customers on default dynamic pricing rates.

35. The utilities should bid demand reductions due to dynamic pricing into the CAISO's day-ahead market.

36. The critical peak price should represent the marginal cost of capacity used to meet peak energy needs plus the marginal cost of energy during the critical peak period.

37. The utility should explain what it used as the basis for the marginal cost of capacity in its CPP rate and why.

38. The annualized cost of a new combustion turbine is a reasonable proxy for determining the marginal capacity prices; however, alternative bases include actual utility costs, CAISO scarcity prices (if adopted by FERC and implemented by the CAISO), and centralized capacity market or bulletin board prices (if implemented).

39. Critical peak pricing rates should include a critical peak price during critical peak periods and time-of-use rates during non-critical periods.

40. Since the critical peak price is intended to reflect the marginal cost of generation that is needed to meet peak period usage, CPP rates should not have summer generation demand charges.

41. The utilities should be able to call a variable number of events each year, and the rate should be designed based on the number of events that would be called during a typical year.

42. The utilities should be able to call critical peak events any day of the week, year round.

43. The energy charge for RTP rates should be indexed to the CAISO's day-ahead hourly market prices.

44. At least initially, RTP should be based on day-ahead hourly market prices that have been aggregated across PG&E's service territory. As the market develops, locational prices should be considered.

45. The Commission should determine the degree to which the marginal cost of capacity is not incorporated into the CAISO's day-ahead hourly market prices.

46. PG&E should conduct annual studies of TOU with CPP, RTP, and PTR during years each of those rates is in effect by applying the load impact protocols adopted in D.08-04-050.

47. PG&E's rate proposals filed pursuant to this decision should be consistent with the rate design guidance adopted in this decision.

48. PG&E should seek recovery of expenditures necessary to implement dynamic pricing incurred in 2011 and later in general rate cases.

49. PG&E should seek recovery of incremental expenditures required to implement dynamic pricing incurred before 2011 in the application(s) in which PG&E proposes the specific dynamic pricing rates.

50. PG&E should be authorized to record incremental expenditures required to implement specific dynamic pricing rates in a memorandum account and should seek recovery of any such expenditures in the related rate design proceeding.

O R D E R

IT IS ORDERED that:

1. Pacific Gas and Electric Company (PG&E) shall modify its advanced metering infrastructure (AMI) deployment plan so that customers with maximum demand greater than or equal to 200 kilowatts (kW) have the metering

and billing systems in place to support default critical peak pricing (CPP) in 2010 and optional real time pricing (RTP) in 2011.

2. If PG&E requires additional authorizations from the Commission to modify its AMI deployment plan, PG&E shall request such authorizations in its AMI upgrade Application (A.) 07-12-009.

3. Any request by PG&E for approval of expenditures to modify the AMI deployment plan shall be made in A.07-12-009 and shall include the necessary justification.

4. Prior to a Commission decision in A.07-12-009, PG&E may record incremental costs required to modify the AMI deployment plan in a memorandum account and seek recovery in A.07-12-009.

5. PG&E shall propose the following rates as part of its 2008 Rate Design Window, which shall be filed no later than February 28, 2009. The effective date of these proposed rates shall be on or before May 1, 2010:

- One or more default CPP rates for commercial and industrial (C&I) customers with maximum load greater than or equal to 200 kW; and

- Revised optional medium C&I, small commercial and residential CPP rates that include time-of-use (TOU) rates during non-CPP periods.

6. PG&E shall propose the following rates as part of its 2008 Rate Design Window, which shall be filed no later than February 28, 2009. The effective date of these proposed rates shall be on or before February 1, 2011:

- One or more default CPP rates for C&I customers with maximum load less than 200 kW that have had an AMI meter for 12 months or more. PG&E's proposal shall not offer non-time-differentiated rates to customers with maximum load less than 200 kW that have had an AMI meter for 12 months or more;

- One or more default CPP rates for agricultural customers with maximum load greater than or equal to 200 kW that have had an AMI meter for 12 months or more;

- One or more default TOU rates for agricultural customers with maximum load less than 200 kW that have had an AMI meter for 12 months or more; PG&E's proposal shall not offer non-time-differentiated rates to customers with maximum load less than 200 kW that have had an AMI meter for 12 months or more;

- One or more optional CPP rates for agricultural customers with maximum load less than 200 kW.

7. PG&E shall propose optional RTP rates for all customer classes as part of its 2011 General Rate Case Phase 2 to be filed on March 1, 2010. The effective date of the proposed rates shall be on or before May 1, 2011.

8. PG&E shall file an application proposing a default CPP rate for residential customers 30 days after any change in the law that changes the Assembly Bill 1X rate protections in a manner that could allow default or mandatory time-variant rates for residential customers. If the Commission approves a decision that interprets the Assembly Bill 1X rate protections in a manner that could allow default or mandatory time-variant rates for residential customers, then PG&E shall file an application proposing a default CPP rate for residential customers not later than 90 days after the Commission decision goes into effect and is no longer subject to rehearing or judicial review. PG&E shall propose an effective date that is no later than one year after the filing date unless PG&E can justify a later effective date as being necessary to allow time for customer education and system upgrades.

9. The rate design guidance in Attachment A is adopted. Attachment A is to be read in the context of the overall decision.

10. The rates proposed by PG&E pursuant to this decision shall be consistent with the rate design guidance in Attachment A.

11. PG&E shall conduct annual studies CPP, RTP, and peak time rebate (PTR) during years each of those rates is in effect by applying the load impact protocols adopted in Decision (D.) 08-04-050, and PG&E shall use its load impact studies to estimate the likely responses of customers to dynamic pricing rates. PG&E shall submit the studies in accordance with D.08-04-050.

12. PG&E shall conduct an *ex post* review of when CPP events were called, as described in this decision, and shall present the results of this analysis in its GRC Phase 2's and any other proceeding in which CPP rate design proposals are being considered.

13. PG&E shall seek recovery of expenditures necessary to implement dynamic pricing incurred in 2011 and later in general rate cases.

14. PG&E shall seek recovery of incremental expenditures required to implement dynamic pricing incurred before 2011 in the application(s) in which PG&E proposes the specific dynamic pricing rates and shall provide the necessary justification.

15. PG&E is authorized to record incremental expenditures required to implement specific dynamic pricing rates in a memorandum account and shall seek recovery of any such expenditures in the related rate design proceeding.

16. PG&E's dynamic pricing proposals filed pursuant to this decision shall at a minimum include the following: (1) an explanation of how its rate design is consistent with the rate design guidance summarized in Attachment A; (2) a bill analysis showing the full distribution of customer bill impacts under the

proposed rate or rates; (3) an explanation of how PG&E intends to conduct customer education for the new dynamic pricing rate; (4) a description of the bill analysis tools that PG&E will provide to customers once a rate or rates are adopted; (5) any other information required by this decision.

17. PG&E shall continue working with the California Independent System Operator's Demand Response Infrastructure working group and with stakeholders in other forums to develop the communications infrastructure necessary to support RTP by 2011.

18. PG&E shall include a timeline in its 2011 General Rate Case Phase 2 showing what steps PG&E will take to make sure that all the necessary communications systems are in place to support RTP in 2011.

19. PG&E shall offer customers tools so that customers can determine bill impacts of any dynamic pricing rates that the Commission adopts for PG&E.

20. A.06-043-005 is closed.

This order is effective today.

Dated July 31, 2008, at San Francisco, California.

MICHAEL R. PEEVEY
President
DIAN M. GRUENEICH
JOHN A. BOHN
RACHELLE B. CHONG
TIMOTHY ALAN SIMON
Commissioners

ATTACHMENT A

Rate Design Guidance

All Dynamic Pricing Rates

- Rate design should promote economically efficient decision-making.
- To promote economically efficient decision-making, rates should be based on marginal cost.
- Other objectives, such as energy efficiency, and legal requirements, such as baseline allowances, should be addressed when designing specific rates, and any deviation from marginal cost should be minimized.
- Rates should also seek to provide stability, simplicity and customer choice.
- If customers on a particular rate reduce their usage in a manner that reduces a utility's costs then the customers on that rate should see a commensurate reduction in their bills.
- Dynamic pricing rates should include a capacity reservation charge, or a similar feature, that allows a customer to pay a fixed charge for a predetermined amount of its load and pay the dynamic price for consumption in excess of the reserved capacity.
- Customers should have the opportunity to opt out of a default dynamic pricing rate to another time-variant rate.
- Utilities should offer optional bill protection to customers on default dynamic pricing rates.
- The utilities should bid demand reductions due to dynamic pricing into the California Independent System Operator's (CAISO's) day-ahead market.

Critical Peak Pricing

- The critical peak price should represent the marginal cost of capacity used to meet peak energy needs plus the marginal cost of energy during the critical peak period.

- The utility should explain what it used as the basis for the marginal cost of capacity in its critical peak pricing (CPP) rate and why. The annualized cost of a new combustion turbine is a reasonable proxy for determining the marginal capacity prices; however, alternative bases include actual utility costs, CAISO scarcity prices (if adopted by the Federal Energy Regulatory Commission and implemented by the CAISO), and centralized capacity market or bulletin board prices (if implemented)

- Critical peak pricing rates should include a critical peak price during critical peak periods and time-of-use rates during non-critical periods.

- Since the critical peak price is intended to reflect the marginal cost of generation that is needed to meet peak period usage, CPP rates should not also have summer generation demand charges.

- The utilities should be able to call a variable number of events each year, and the rate should be designed based on the number of events that would be called during a typical year.

- The utilities should be able to call critical peak events any day of the week, year round.

Real-Time Pricing

- The energy charge should be indexed to the CAISO's day-ahead hourly market prices.

- At least initially, RTP should be based on day-ahead hourly market prices that have been aggregated across PG&E's service territory.

As the market develops, locational prices should be considered.

- The Commission should determine the degree to which the marginal cost of capacity is not incorporated into the CAISO's day-ahead hourly market prices.

(END OF ATTACHMENT A)

ATTACHMENT B
Illustrative Timetable

If the Commission adopts the rates that PG&E is required to propose pursuant to this decision, PG&E's customer would have the following rate options between 2008 and 2012:

Customer Group	2008	2009	2010	2011	2012
Large Commercial and Industrial (C&I) (200 kW and above maximum load)	**Default: TOU** Optional: CPP	**Default: TOU** Optional: CPP	**Default: TOU/CPP** Optional: TOU	**Default: TOU/CPP** Optional: RTP, TOU	**Default: TOU/CPP** Optional: RTP, TOU
Medium C & I (Greater than or equal to 20 kW and less than 200 kW maximum load)	*With AMI* **Default: Flat** Optional: CPP, TOU *Without AMI* **Flat**	*With AMI* **Default: Flat** Optional: CPP, TOU *Without AMI* **Flat**	*With AMI* **Default: Flat** Optional: CPP, TOU *Without AMI* **Flat**	*With AMI* **Default: TOU/CPP*** Optional: RTP, TOU *Without AMI* **Flat**	**Default: TOU/CPP*** Optional: RTP, TOU
Small Commercial (less than 20 kW maximum load)	*With AMI* **Default: Flat** Optional: CPP, TOU *Without AMI* **Flat**	*With AMI* **Default: Flat** Optional: CPP, TOU *Without AMI* **Flat**	*With AMI* **Default: Flat** Optional: CPP, TOU *Without AMI* **Flat**	*With AMI* **Default: TOU/CPP*** Optional: RTP, TOU *Without AMI* **Flat**	**Default: TOU/CPP*** Optional: RTP, TOU
Large Agricultural (200 kW and above maximum load)	**Default: TOU** Optional: CPP	**Default: TOU** Optional: CPP	**Default: TOU** Optional: CPP	**Default: TOU/CPP** Optional: RTP, TOU	**Default: TOU/CPP** Optional: RTP, TOU
Small and Medium Agricultural (less than 200 kW maximum load)	*With AMI* **Default: Flat** Optional: CPP, TOU *Without AMI* **Flat**	*With AMI* **Default: Flat** Optional: CPP, TOU *Without AMI* **Flat**	*With AMI* **Default: Flat** Optional: CPP, TOU *Without AMI* **Flat**	*With AMI* **Default: TOU*** Optional: RTP, CPP *Without AMI* **Flat**	**Default: TOU*** Optional: RTP, CPP
Residential (Assuming AB1X rate protections remain in place)	**Default: Tiered Flat** Optional w/ AMI: CPP, TOU	**Default: Tiered Flat** Optional w/ AMI: CPP, TOU	**Default: Tiered Flat/PTR** Optional w/ AMI: CPP, TOU	**Default: Tiered Flat/PTR** Optional w/ AMI: RTP, CPP, TOU	**Default: Tiered Flat/PTR** Optional: RTP, CPP, TOU
Residential (post AB1X): PG&E must file a proposal for default TOU/CPP after AB1X rate protections end as specified in the decision with an effective date one year after the filing date.					

* A customer will not be defaulted to TOU/CPP or TOU until the customer has had an advanced meter for 12 months.

Flat = a seasonal, non-time-variant rate; TOU = Time-of-use; CPP = Critical Peak Pricing; TOU/CPP = Critical Peak Pricing with time-of-use pricing during non-critical peak periods; RTP = Real Time Pricing; PTR = Peak Time Rebate; With AMI = Customers with an advanced meter; Without AMI = Customers with a meter that cannot record interval usage data

(END OF ATTACHMENT B)

ATTACHMENT C

Glossary, Acronyms and Abbreviations

AB1X	Assembly Bill No. 1 from the 2001-2002 First Extraordinary Session as codified by Water Code section 80000 *et seq.* Water Code Section 80110 protects the rates of residential customers for usage up to 130 percent of baseline quantities "until such time as the [Department of Water Resources] has recovered the costs of power it has procured for the electrical corporation's retail end use customers…."
ABS	Advanced Billing System: PG&E's billing system for its large customers on more complex rates and programs.
AMI	Advanced Metering Infrastructure
AReM/DACC	Alliance for Retail Energy Markets and the Direct Access Customer Coalition
Auto DR	A research program managed by the DRRC designed to link facility energy management control systems with external utility-generated price or emergency signals, integrated with various existing utility demand response programs, such as the critical peak pricing program.
BOMA	Building Owners and Managers Association
C&I	Commercial and industrial customers
CAISO	California Independent Systems Operator
CC&B	Customer Care and Billing: PG&E's primary billing system

CCA	Community Choice Aggregation
CEC	California Energy Commission
CFBF	California Farm Bureau Federation
CLECA	California Large Energy Consumers Association
CMTA	California Manufacturers and Technology Association
CPP	Critical Peak Pricing: A dynamic rate that allows a short-term price increase to a predetermined level (or levels) to reflect real-time system conditions. Typically, the time and duration of the price increase are predetermined, but the days are not predetermined.
CPUC	California Public Utilities Commission
CRM	California Rice Millers
DA	Direct Access
DRA	Division of Ratepayer Advocates
DRRC	Demand Response Research Center: A research center led by Lawrence Berkeley National Laboratory. The DRRC's rates project is funded by the California Energy Commission's Public Interest Energy Research program.
E-CPP	PG&E's existing voluntary CPP rate for large C&I and agricultural customers.
E-CSMART	PG&E's voluntary CPP rate for small commercial customers.
E-RSMART	PG&E's voluntary CPP rate for residential customers.
EAP II	Energy Action Plan II

EPUC	Energy Producers and Users Coalition
ERRA	Energy Resource Recovery Account
FERC	Federal Energy Regulatory Commission
GRC	General Rate Case
HAN	Home Area Network: A communications system that connects an advanced meter with other devices in a customer's home or business.
IOU	Investor-Owned Utility
KMEP	Kinder Morgan Energy Partners
kW	Kilowatt
kWh	Kilowatt-hour
Large Agricultural Customers	Agricultural customers with maximum demand greater than 200 kW
Large C&I Customers	Commercial and industrial customers with maximum demand greater than or equal to 200 kW
Medium C&I Customers	Commercial and industrial customers with maximum demand greater than or equal to 20 kW and less than 200 kW
MRTU	Market Redesign and Technology Upgrade
PG&E	Pacific Gas and Electric Company
PTR	Peak Time Rebate: A program that provides customers a rebate for demand reductions below a customer-specific baseline when the program is called due to market or system conditions.
RTP	Real Time Pricing: A dynamic rate that allows prices to be adjusted frequently, typically on an

	hourly basis, to reflect real-time system conditions.
SCE	Southern California Edison Company
Schedule A-1	PG&E's non-time-differentiated rate for small commercial customers.
Schedule A-6	PG&E's voluntary time-of-use rate for small commercial customers.
Schedule A-10	PG&E's rate generally applied to medium and some small C&I customers. PG&E offers a non-time differentiated and time-of-use version of the rate.
Schedule E-19	PG&E's time-of-use rate for customers with maximum load greater than or equal to 500 kW. Customers with maximum load less than 500 kW may enroll on an optional basis.
Schedule E-20	PG&E's time-of-use rate for customers with maximum load greater than or equal to 1,000 kW.
SDG&E	San Diego Gas & Electric Company
Small and Medium Agricultural	Agricultural customers with maximum demand less than 200 kW
Small Commercial Customers:	Commercial customers with maximum demand below 20 kW
TOU	Time-of-Use: A rate in which predetermined electricity prices vary as a function of usage period, typically by time of day, by day of the week, and/or by season.
TOU/CPP	Used to refer to a CPP rate with TOU pricing during non-critical peak periods.
TURN	The Utility Reform Network

WPTF	Western Power Trading Forum

(END OF ATTACHMENT C)