Decision 11-12-018 December 1, 2011

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Rulemaking regarding whether, or subject to what Conditions, the suspension of Direct Access may be lifted consistent with Assembly Bill 1X and Decision 01-09-060.	Rulemaking 07-05-025 (Filed May 24, 2007)

DECISION ADOPTING DIRECT ACCESS REFORMS

Table of Contents

Title	Page
DECISION ADOPTING DIRECT ACCESS REFORMS	1
1. Introduction	2
2. Procedural Background	4
3. Changes to the Indifference Amount Methodology	6
3.1. Changes in the Market Price Benchmark (MPB) to Account for Renewable Resource Requirements	10
3.1.1. Parties' Positions	10
3.1.2. Discussion	17
3.2. Revised Capacity Adder for the MPB	25
3.2.1. Parties' Positions	25
3.2.2. Discussion	28
3.3. CAISO Load-Based Costs	30
3.3.1. Parties' Positions	31
3.3.2. Discussion	31
3.4. Shaping Profile to Reflect MPB value of Portfolio Resources	32
3.4.1. Parties' Proposals	33
3.4.2. Discussion	34
3.5. Credit for Negative Indifference	35
3.6. Adjustment to Account for Congestion	36
3.7. Setting a Zero Default PCIA Value	37
3.7.1. Parties' Positions	37
3.7.2. Discussion	39
4. Conforming Changes to Temporary Bundled Service (TBS) Rate Calculations	41
5. DA Switching Rules	42
5.1. Minimum Stay Requirements	43
5.1.1. Parties' Positions	43
5.1.2. Discussion	46
5.2. Advance Notice Period to Switch Service	49
5.2.1. Parties' Positions	51
5.2.2. Discussion	51
5.3. Preservation of the Safe Harbor	52
5.3.1. Parties' Positions	53
5.3.2. Discussion	53
6. ESP Financial Security Requirements	54

Table of Contents
(Cont'd)

Title	Page
6.1. Necessity for ESPs to Post Financial Security Instruments	56
6.1.1. Parties' Positions	56
6.1.2. Discussion	57
6.2. Definition of Reentry Fees	60
6.2.1. Parties' Positions	60
6.2.2. Discussion	67
6.3. Financial Instruments that Satisfy Section 394.25(e) Requirements	73
6.3.1. Parties' Positions	73
6.3.2. Discussion	75
6.4. ESP Financial Security Bond Methodology	76
6.4.1. Parties' Positions	76
6.4.2. Discussion	82
6.5. Tariff Service for Involuntarily Returned DA Customers	85
6.5.1. Parties' Positions	86
6.5.2. Discussion	90
6.6. Timing of Bond Calculations and Posting	93
6.7. Collecting Re-entry Fees on an Involuntary Return	94
7. Implementation of Changes in Indifference Methodologies	95
8. Categorization and Assignment of Proceeding	98
9. Comments on Proposed Decision	98
Findings of Fact	98
Conclusions of Law	107
ORDER	113

DECISION ADOPTING DIRECT ACCESS REFORMS

1. Introduction

The Direct Access (DA) program provides for limited retail competition for electric power procurement[1] whereby eligible retail customers can choose to purchase electric power directly from an independent electric service provider (ESP) rather than through an investor-owned utility (IOU). This decision resolves Phase III issues in this proceeding relating to the rules and methodologies applicable to DA and Departing Load (DL) electric service.

In this decision, we adopt various updates and reforms in the rate setting methodologies and rules applicable to DA service in recognition of regulatory and industry changes that have occurred in recent years. In 2006, we last adopted major changes in methodologies to determine surcharges on DA and DL customers to ensure that cost responsibility continue to be accurately assigned, consistent with the principles of bundled ratepayer indifference. Regulatory and market changes since 2006 warrant updates to the adopted methodologies so that we continue to ensure that cost responsibility is appropriately assigned.

We thus adopt the following reform measures. First, we revise the methodology for the market price benchmark used to calculate DA customers' cost responsibility necessary to maintain bundled customer indifference. The same market price benchmark, as specified herein will continue to be used to compute the Competition Transition Charge (CTC) and the Power Charge Indifference Adjustment (PCIA). Specifically, we adopt a provision to recognize

---

[1] *See* Decision (D.) 95-12-063, as modified by D.96-01-009 (1995) 64 Cal. PUC 2d 1, 24 (Preferred Policy Decision). The Legislature codified the Preferred Policy Decision in Assembly Bill (AB) 1890 (Stats. 1996, ch. 854) (AB 1890).

renewable resource attributes in the market benchmark. We remove from the total portfolio calculation load-related costs incurred by the independent system operator. We revise the total portfolio load profile calculation to better reflect time of use load variations. We also adopt conforming changes in the temporary bundled service rate to be consistent with the changes adopted in the market price benchmark calculation.

We also review the rules governing the rights and obligations for switching between bundled and DA service. We retain the existing six-month advance notice requirements for switching, but reduce the requirement for a three-year stay on bundled service down to only 18 months, applicable to DA customers seeking to return from bundled back to DA service. We also adopt provisions to meet the statutory financial security requirements applicable to Electric Service Providers (ESPs) to cover the risk of an en masse involuntary return of ESP customers to bundled service. This decision addresses the financial security issues pertaining only to ESPs and the DA/DL market. We make no prejudgment concerning how those issues may be resolved with respect to Community Choice Aggregators, which matter remains pending in Rulemaking (R.) 03-10-003.

We define the applicable re-entry fee and ESP financial security requirements for en masse involuntarily returned DA customers as generally being limited to the administrative costs of switching customers to bundled service. In order to prevent cost shifting to bundled customers, we require that involuntarily returned large commercial and industrial DA customers bear the risks of increased procurement costs through payment of the Temporary Bundled Service tariff. However, we also determine that the re-entry fee and ESP financial security requirements for involuntarily returned small commercial and residential DA customers should include a provision to cover their incremental procurement costs. For this purpose, we intend to limit this latter requirement to exclude small commercial DA customers that are affiliated with a large DA customer. We defer to the next phase of this proceeding the specific process by which to define small commercial customers for purposes of calculating the ESP financial security requirement.

While we conclude that our adopted re-entry fee and ESP financial security requirements meet applicable statutes, we recognize that evolving conditions over time may warrant a subsequent review of cost responsibility for involuntarily returned customers at a future date. The Commission may undertake such a future review as conditions warrant. The provisions we adopt advance the principles of promoting competitive choice for electric procurement within the limits permitted by statute and Commission rules while also continuing to protect bundled ratepayers from cost shifting.

2. Procedural Background

The scope of this decision resolves issues designated as Phase III of this proceeding. Phase III addresses prospective revisions in the Direct Access (DA) program and rate setting methodologies in view of relevant regulatory and industry changes since the DA methodologies were last revised. On October 11, 2009, Senate Bill (SB) 695 (Stats. 2009, ch. 337) was signed into law. SB 695 added Section 365.1(b) to the Public Utilities Code, enacting changes to allow limited growth in DA. By ruling dated November 18, 2009, the assigned

Commissioner amended the scope of the proceeding to implement the provisions of SB 695 relating to DA.[2]

A subsequent ruling dated December 17, 2009, modified the scope of issues to address provisions of SB 695 allowing for new enrollments of DA. Decision (D.) 10-03-022 implemented measures to begin processing the new enrollments of DA load effective April 11, 2010.

An amended scoping memo issued on April 19, 2010, set forth remaining Phase III issues. The Joint Parties in this proceeding, identified specifically below, filed a motion on September 23, 2010, seeking an expedited phase to consider modifications to the methodology to determine the calculation of the Power Charge Indifference Amount (PCIA). A ruling dated, November 22, 2010, granted the motion and expanded the scope of Phase III accordingly. Parties participated in a series of workshops to address technical issues for Phase III, held on December 7, 14-15, 2010 and January 4, 2011.

Parties participating in this phase of the proceeding are the three investor-owned utilities (IOUs), Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDG&E), consumer advocates, the Division of Ratepayer Advocates (DRA) and The Utility Reform Network (TURN). Various parties also

---

[2] Phase I of this proceeding examined whether, or under what conditions, the suspension of DA could be lifted. The Commission determined that the DA suspension continued to apply as long as the California Department of Water Resources (DWR) sold power to retail customers through its supplier contracts. Phase II examined the feasibility of accelerating the early termination of DWR power supply contracts through novation or other renegotiation. With the passage of SB 695, Phase II was discontinued, and the scope of Phase III was redefined to focus on implementing SB 695 provisions dealing with DA.

participated, representing the interests of DA customers and Electric Service Providers (ESPs): California Large Energy Consumers Association (CLECA) and California Manufacturers and Technology Association (CMTA), City and County of San Francisco (CCSF), Commercial Energy, a group of parties identified as DA Parties, Alliance for Retail Energy Markets (AReM), the Direct Access Customer Coalition, BlueStar Energy, and Pilot Power. An additional group identified as the "Joint Parties:" CCSF, AReM, the Direct Access Customer Coalition, BlueStar Energy, Marin Energy Authority, the Energy Users Forum, San Joaquin Valley Power Authority, and the California Municipal Utilities Association. Mr. L. Jan Reid (Reid) also participated in the proceeding representing himself.

A ruling issued on January 7, 2011, scheduled early briefing on legal issues pertaining to the ESP financial security requirements arising under Pub. Util. Code § 394.25(e). By ruling issued in Rulemaking (R.) 03-10-003 (re: Rulemaking to implement provisions of Assembly Bill (AB) 117 concerning Community Choice Aggregation), the briefs were filed jointly in both proceedings to address the relevant issues that were common to both proceedings. Parties submitted briefs in both above-captioned dockets, filed on January 24, 2011, with reply briefs on February 11, 2011.

Opening testimony on Phase III issues was served January 31, 2011, and reply testimony was served February 25, 2011. Evidentiary hearings occurred during March 28 through 30, 2011. Opening briefs were filed on May 6, 2011, and reply briefs were filed on May 27, 2011.

3. Changes to the Indifference Amount Methodology

Parties generally agree that revisions are warranted in the methodology to derive the Power Charge Indifference Amount (PCIA or indifference amount) paid by DA customers. Parties disagree, however, as to what the modifications should be. As a framework for evaluating proposed changes, we review the principles underlying the indifference methodology.

The indifference amount is designed to ensure that DA customers that have departed from bundled IOU procurement service remain responsible for paying any IOU costs incurred on their behalf. In other words, remaining bundled customers must be protected from any cost shifting and left economically indifferent as the result of DA customers leaving the system.

The DA program was suspended following the events of 2000-2001 which led to extraordinary wholesale power cost increases, threatening the solvency of California's major electric utilities and the reliability of service. On February 1, 2001, AB 1 from the First Extraordinary Session (Ch. 4, First Extraordinary Session 2001) (AB1X) was signed into law to address the energy crisis. AB1X suspended DA, and required DWR to procure electric power supplies sufficient to meet the needs of retail customers.[3]

We implemented the DA suspension, permitting DA contracts executed on or prior to September 20, 2001, to continue on the condition that DA customers bear their fair share of cost responsibility, thereby leaving bundled customers indifferent to DA departure from bundled load. AB 117 required bundled customer indifference to prevent any shifting of recoverable costs among customers.

Except for the limited authorization for increased DA under SB 695, DA remains suspended until repealed by legislation, or otherwise authorized. The Commission issued Decision (D.) 10-03-022 to implement preliminary provisions

---

[3] The net short is the difference between customer loads and the power already under contract to the utilities or generated from a utility-owned asset.

relating to SB 695, by adopting capped limits for the maximum DA load in each of the IOUs' service areas, to be phased-in over four-years.

The DA load caps imposed under SB 695 reflect the historic highs in DA load in the IOU's service areas. Even with the caps, the DA market size would tend to be higher on an absolute kilowatt-hour basis than it was in 2003, when the market was limited by the suspension imposed by AB 1X. The DA load caps provide the IOUs with certainty as to the maximum DA load they can expect in their service area, even though the actual amount of DA load at any particular time remains uncertain.

In D.02-11-022, the Commission established a cost responsibility surcharge (CRS) methodology which incorporated an indifference amount. A revised methodology to determine the indifference amount was approved in D.06-07-030, (subsequently modified by D.07-01-030, D.07-05-022, and D.07-05-005). The indifference amount is updated annually in each IOU's Energy Resource Recovery Account (ERRA) proceeding.

The Indifference principle involves the interaction of three elements;

a) a non-bypassable surcharge which DA customers pay to offset any cost impacts on bundled customers associated with their departure from or return to bundled service;

b) switching rules which govern the movement of customers between DA and bundled service; and

c) Transition Bundled Service (TBS) rates which accommodate customer movement while allowing the utility to adjust its generation portfolio without cost impacts on bundled customers.

To derive the indifference amount, the market value of the IOU's supply portfolio is subtracted from the total portfolio cost. The market price benchmark (MPB) is a calculated proxy which represents the market value of the IOU total energy resource portfolio. The IOU total portfolio includes IOU-owned generation, purchased power, DWR contracts, fuel costs, and California Independent System Operator (CAISO) costs. A positive indifference amount indicates that the IOU portfolio cost is above-market for that year. The indifference amount is recovered from DA customers through a non-bypassable surcharge to maintain bundled service customer indifference.

A distinct vintage portfolio of generation resources is calculated for each year which is assigned a separate indifference amount. The total portfolio cost for each vintage year is calculated and compared to the market value of energy and capacity produced by the portfolio. Assigning costs by vintage ensures that the customers departing in a particular year pay only the costs incurred on their behalf prior to departure. For each vintage year, the cost of the total portfolio is calculated for resources procured for that year to serve bundled customer load. The generation portfolio for each vintage includes all resources and contracts entered into to serve bundled load, including all previous contracts still in place and new ones signed for that vintage year. To ensure that departing load does not pay for above-market costs of utility procurement commitments after the load departs, the Commission approved the vintage methodology for DA departing load to ensure the proper matching of departing load with the utility procurement process.

While these underlying indifference principles have not changed, the manner in which indifference is calculated needs to be updated to reflect changes in regulatory and industry conditions that have occurred in recent years. Accordingly, we adopt provisions in this Phase III as set forth below.

3.1. Changes in the Market Price Benchmark (MPB) to Account for Renewable Resource Requirements

The current indifference methodology only recognizes the IOUs' cost of renewable resources in the calculation of the Total Portfolio Cost, but does not account for the market value of renewable resources in the MPB. Parties generally agree that the indifference methodology should be revised to reflect the market value of renewable resources in the MPB, but disagree on how to do so.

All load serving entities are subject to increasing requirements to procure renewable resources pursuant to Pub. Util. Code, Article 16, commencing with § 399.1. Renewable resources are more costly than traditional gas-fired generation, and thus have a higher market price as compared to the embedded cost of the utilities' portfolios. As the utilities add renewable generation, their average portfolio costs will increase. ESPs are facing the same mandate to buy a certain percentage of their power from renewable generation sources, and their costs are affected as well. Both the utilities and the ESPs thus face new requirements to purchase renewable power for a certain percentage of their load, causing their average portfolio costs to increase.

3.1.1. Parties' Positions

Parties agree (except for Reid) that the MPB should be amended to reflect the value of Renewable Portfolio Standard (RPS)-compliant renewable resources in the portfolios of the IOUs (i.e., RPS adder). However, parties disagree on the methodology by which to do so.

PG&E and SDG&E disagree with the DA parties as to the treatment of energy associated with renewable pre-2004 Qualifying Facility contracts and irrigation district contracts. The MPB used to determine the PCIA is multiplied by the entire amount of RPS-eligible energy in the IOU's portfolio. Much of the RPS-eligible energy in PG&E's portfolio, however, is from pre-2004 QF contracts and irrigation district contracts that are not included in the PCIA. These contracts are included instead in the Ongoing Competition Transition Charge (CTC).

PG&E and SDG&E contend that pre-2004 resources in the IOUs portfolios should not be valued using RPS adder because, although these resources count for purposes of determining IOU compliance with the RPS standards and contribute significantly towards such compliance, the IOUs are unable to sell this RPS benefit to a third party. PG&E thus proposes that the MPB used to determine the indifference amount only include an RPS adder that reflects the percentage of RPS-eligible energy in contracts signed after 2003. PG&E would not include the energy associated with renewable QFs in the vintaged portfolio's MPB adder. Instead, the renewable benefit associated with the renewable QF would be accounted for in the MPB used to calculate the Ongoing CTC.

PG&E argues that prior Commission decisions reaffirmed that Ongoing CTC is calculated based on the statutory methodology and that the indifference calculation has no bearing on the determination of Ongoing CTC. PG&E argues that California Renewable Energy Credits (REC) cannot be derived from resources under contract prior to 2005. Thus, PG&E argues that it is not appropriate to impute a REC value into the MPB used to determine Ongoing CTC when the underlying contracts do not transfer ownership of the REC to the buyer and the underlying megawatt-hours (MWhs) are not eligible to be unbundled and counted as a California tradable REC. Otherwise PG&E claims the MPB used to determine the Ongoing CTC would overstate the value in the underlying portfolio relative to the energy (or REC attribute) value in the market place.

The Joint Parties object to the extent any RPS-eligible volumes are excluded from the MPB. They argue that the exemption proposed by PG&E and SDG&E would have the effect of substantially reducing the volume of energy from renewable resources for which the value of renewable attributes is recognized. The reduced RPS volumes would be compared against the system (brown) power benchmark, understating the value of those resources.

Reid recommends adopting the proposal in TURN's post-workshop comments which maintains the current MPB methodology such that the PCIA would incorporate the entire RPS adder premium inherent in the IOUs'costs of procurement to meet the RPS goals, but non-utility retail suppliers would be given RPS credit for their proportionate share of the IOU's RPS purchases. Reid's rationale appears to be that this would obviate the need for bundled customers to pay for the renewable attributes they retain.

The Joint Parties object to Reid's proposal, arguing that it reduces the ability of a competitive provider to manage a resource portfolio that is optimized to meet the specific demands of its customer base. Competitive providers may have specific renewable resource technology or resource locational preferences that appeal to their customers or otherwise fit well within their supply portfolio, and an allocation of RPS resources from the IOU portfolio may be inconsistent with those preferences. In short, customers who choose to depart utility service are simply not looking to have their supply come from the utility portfolio.

CLECA witness Barkovitch testified that Reid's proposal undermines the potential benefit of retail competition, which is to give DA and Community Choice Aggregator (CCA) customer the opportunity to receive power from a different portfolio, as long as it meets state and Commission procurement requirements.

The IOUs, DRA, and TURN disagree with the Joint DA Parties as to how the RPS-eligible energy should be valued (i.e., the RPS adder). The Joint DA Parties propose that the MPB incorporate a Green Benchmark for RPS-eligible energy using available information regarding the IOUs' current cost to obtain RPS-compliant renewable resources. The Joint Parties agree that if the MPB is otherwise adjusted for capacity, the Green Benchmark should be adjusted to subtract the value of capacity provided by those resources, to prevent double counting of capacity. The Joint Parties proposed using resources expected to commence delivery or having commenced delivery in the upcoming or most recent past year in order to recognize that new generating resources are not added in a smooth fashion.

For purposes of calculating the RPS adder under the Joint Parties' proposal, for illustrative purposes, the value of renewables in each IOU vintaged generation portfolio would be established as follows for 2011:

1. Each utility would identify all RPS-compliant resources that began delivery in year 2010 and those projected in their ERRA forecast applications to begin delivery in 2011. This would include both contracts and IOU-owned resources.
2. The IOUs would identify the projected costs of energy produced by each of these resources in 2011, and the net qualifying capacity (NQC) of those resources.
3. IOUs would provide these data (costs in dollars and volumes in MWh and QC in kW)) to the Energy Division.
4. The Energy Division would then calculate the average cost of power from these resources in 2011 by summing up all the costs from all three IOUs, subtracting the product of the NQCs of those resources times the CAISO's Interim Capacity Procurement

Mechanism, and dividing by the sum of all the MWhs from all three IOUs.

In addition to PG&E's proposal to exclude pre-2004 resources from the RPS adder, as noted previously, PG&E proposes that the RPS adder incorporate use of publicly available market indices for California Tradable Renewable Energy Credits (TRECs). SCE proposes that pending the availability of publicly available, transparent market indices, the Commission should determine a RPS value by use of a variety of data sources. SDG&E proposes setting an interim RPS adder using data compiled by the Department of Energy (DOE) National Renewable Energy Laboratory (NREL) reflecting premiums paid by retail energy consumers in the market and self-reported by utilities and other ESPs. This data reflects premiums paid by retail energy consumers in the market and self-reported by utilities and other energy service providers. This data is publicly available and reflects premiums paid by energy consumers in the market for renewable energy over and above the prices for non-renewable energy.

The Joint Parties assert that no functioning market exists for renewable attributes, and consequently, that no relevant market indices are available that meet the following necessary criteria:

1) The indices must be for the same types of products as those to be valued;
2) The indices should be transparent and robust; and
3) The indices should be based on sufficient volume and consistent information.

The Joint Parties maintain that given the lack of a functioning market and available index, the MPB adder should be based on an average of the forecasted cost of RPS resources built or contracted for by the IOUs that commenced or are projected to commence delivery during the year in question and the prior year. The Joint Parties thus propose that the RPS adder be based on the percentage of RPS-eligible energy included in an IOU's portfolio. For example, if the IOU had 18% RPS-eligible energy, the MPB would equal 0.82 times the commodity price plus 0.18 times the RPS-eligible energy.

PG&E and SCE claim that the benchmark proposed by the Joint Parties does not reflect the value of renewable energy. The MPB is designed to determine the market value of an IOU's resource portfolio. The Joint Parties' benchmark uses IOU contract costs rather than market value. If IOU cost rather than market value is used for the MPB, and the MPB is then compared to the same costs in the IOU portfolio, PG&E contends that there will never be a difference between the MPB and the IOU portfolio cost. PG&E argues that the Joint Parties' proposal will thus cause bundled customers to pay a substantial portion of the above-market costs associated with RPS-eligible resources created when load departs.

PG&E supports use of publicly available TREC market indices. The Commission approved the use of TRECs in January 2011. PG&E claimed that a transparent TREC market would be available by third quarter 2011, to include the development of published, transparent REC indices.

PG&E proposes that a renewables adder be based on the REC price published in the SNL Financial Publications California REC index. SNL Financial publishes an index for REC prices throughout the United States, including for California. SNL's published index reflects the value of renewable attributes (i.e., RECs) based on multiple broker quotes, and updated on a weekly basis. Pricing information is from Evolution Markets, Karbone, CFS Traditions, and Clear Energy. (PG&E/Pappas, Tr. Vol. 2, at 286:26-28, 287:1-3.) PG&E

claims that the SNL Index is transparent in that the sources of data (i.e., the specific brokers) have been identified and the index is publicly available. PG&E claims the index is robust and liquid, and includes quotes from a number of California brokers that represent numerous buyers and sellers. Information is reported and updated weekly.

DRA supports use of publicly available, transparent REC market values to determine a market value for the MPB when this information becomes available. DRA confirmed that SNL Financials publishes a California REC index using data provided by Evolution Markets, Traditional Financial Services, and Clear Energy Brokerage and Consulting. DRA finds no reason to doubt the accuracy of the published data or the appropriateness of using it to determine the value of the renewable attributes. Because a broader pool of data generally results in greater accuracy, DRA suggests that the Commission may want to use additional data sources as more REC indices become available in the future.

The Joint Parties argue that although RPS market and related indices could be useful for valuing renewables in the future, this alternative is premature. Given the limits on the use of TRECs for purposes of RPS compliance in California, the Joint Parties contend that TREC price indices will likely understate the value of RPS-compliant renewables in the IOUs portfolio. Moreover, the Joint Parties argue that specific indices were not available for review in this proceeding to evaluate whether they are adequate.

SCE proposes that the Commission set an interim RPS adder based on consideration of a variety of available data points and range of value. SCE specifically identifies four possible sources of data, as follows.

a. The United States (U.S.) DOE survey of reported contract premiums for renewable energy in the Western U.S. of approximately $20/MWh. The DOE data was recently adopted for use as the "green premium" for net surplus compensation pursuant to AB 920 in D.11-06-016 issued in A.10-03-001 et al.

b. IOU data on the cost of renewable generation resources in their total portfolios as of 2009, which – for SCE – showed a renewable premium relative to the 2011 forward strip price-based MPB of $20 to $40 per MWh, depending on whether the premium reflects energy costs only, or energy and capacity costs.

c. The Marin Energy Authority (MEA) renewable cost data in its power purchase agreement, showing two renewable energy premiums of $10.50/MWh and $39/MWh.

d. Since the majority of SCE's RPS contracts have been below the Market Price Referent (MPR), as confirmed by a recent DRA report,[4] SCE suggests this MPR amount could serve as a maximum value for a proxy.

3.1.2. Discussion

We affirm the consensus among parties that the MPB methodology needs to be revised to recognize the market value of RPS-eligible resources for purposes of calculating the indifference amount. The correct way to adjust the MPB would be based on a benchmark that accurately reflects the market value of all relevant sources of the California renewables market. To accurately reflect the market value of RPS-compliant renewables, the benchmark should reflect prices paid by buyers and sellers in recent transactions for delivery of RPS-compliant power in California for the forecast year. Based on the record developed in this proceeding, however, we are left with conflicting proposals, all of which suffer from various deficiencies in completeness, relevance, and/or

---

[4] See SCE Rebuttal Testimony, at 12, citing DRA's February 11, 2011 Report, *Green Rush*, at 10, Figure 2.

transparency of the data proposed to be used. We discuss the flaws in the various proposals before setting out our adopted RPS adder methodology.

We conclude that Reid's proposal is unduly complex and not sufficiently developed to warrant adoption at this time. Reid proposes that instead of a renewables adder, DA providers would receive RPS credit for their proportional share of the IOU's RPS purchases. Reid's proposal lacks specificity regarding the intended mechanism for allocating RPS credits. It is unclear whether Reid is proposing to create a new RPS compliance product called an "RPS Credit" or if he is proposing to allocate existing Western Renewable Energy Generation Information System (WREGIS) certificates to load-serving entities (LSEs).[5] The latter approach would require a methodology be developed to fairly allocate the various renewable resources in the IOU portfolio to LSEs.

The Joint Parties' proposed RPS benchmark does not reflect all California-delivered RPS-eligible wholesale supply, but is only limited to IOU procurement costs. The Joint Parties' benchmark excludes RPS costs of ESPs, CCAs and publicly-owned utilities that make up more than 32% of California load. The IOUs' load represents 68% of the load subject to the RPS requirement. To the extent that the RPS costs incurred by other LSEs are lower than that of the IOUs, the exclusion of the other LSEs' RPS sources would overstate the benchmark. The IOU portfolios have higher percentages of new renewable resources than those of ESPs and CCAs. IOUs also have restrictions on contracting that do not apply to ESPs or CCAs, which tends to restrict what IOUs

---

[5] The WREGIS is an independent renewable energy tracking system for the region covered by the Western Electricity Coordinating Council.

can do to meet RPS. Thus, the inclusion of ESP and CCA cost data would be expected to lower the perceived market value.

The Joint Parties' proposal also only applies IOU average RPS resource contract prices from the first two contract years, regardless of contract duration. This approach fails to capture the benefit of long-term contracts and overestimates the average cost of front-loaded generation facilities. The Joint Parties' proposal relies on IOU data filed with the Commission annually in ERRA proceedings. To maintain the confidentiality of the data, the Energy Division would need to compile the data from the respective IOU filings to develop the RPS adder, consistent with the current practice where the Energy Division calculates the MPB

Some parties express concern that the Joint Parties proposed RPS methodology could result in double counting of the capacity value of renewable resources. The Joint Parties suggested a refinement to eliminate from the price any value for capacity in order to avoid double counting. SCE witness Schichtl agreed that the correction proposed by the Joint Parties would address the concern. PG&E claims that the Joint Parties' proposed methodology will result in an inflated value because it includes long-term transactions. PG&E contends that the MPB should reflect short-term transactions only, citing testimony by Joint Parties witness Fulmer that the MPB is based on a one-year forward price.

PG&E's proposes to use published indices from SNL Financial Publications to determine RPS market value although no specific SNL indices were introduced into the record. The SNL Energy Power Daily report compiles data from a range of indicative market data that may not necessarily represent completed trades or transactions. The record is not clear about the types of transactions reflected in the SNL indices; which indices should be used; and if more than one index is used, how to weight them. The record does not indicate the California REC volumes represented in the reported indices. When Joint Parties representatives contacted the brokerage services purportedly surveyed to compile the SNL information on California RECs, these services said they do not provide California REC data systematically to SNL. The information in the report is thus subject to deficiencies regarding data reliability.

Questions also remain concerning the effects of Senate Bill (SB) 2 (2011-12 First Extraordinary Session, Stats. 2011, Ch 1)(SB 2 (1X)) which was signed into law after the conclusion of evidentiary hearings. Under SB 2 (1X), three product categories can be used to meet RPS requirements: (1) bundled products, (2) firmed and shaped products, and (3) a category of products that includes unbundled RECs. It is uncertain whether or how the SNL data would evolve in view of SB 2 (1X), and whether the index reflects an appropriate level of market liquidity.

SB 2 (1X) requires that initially, an RPS-compliant portfolio include at least 50% bundled products, increasing to 75% in 2017. SB 2 (1X) initially allows use of firmed and shaped products for up to 50% of the RPS requirement, but decreases the limit on these to no more than 25% by 2017. The third category of products, including unbundled renewable energy credits, remains limited to no more than 25% initially, ramping down to no more than 10% in 2017.

If California REC market indices are used to establish the RPS adder, it is uncertain which of the three categories of products the market indices would reflect. The Joint Parties express concern about the exclusive use of market indices tied to a product that can only be used to fulfill a limited part of the RPS requirement, to value *all RPS* products in the IOUs' portfolio.

Joint Parties witnesses Meal, Dalessi, and Fulmer testified that the TRECs traded in the market envisioned to arise as a result of D.11-01-25 cannot be used broadly for compliance purposes, as the decision explicitly limits the amount and price of TRECs that can be used for RPS compliance. They believe that the TREC is unlikely to fully reflect the renewable attribute value of resources in the IOU portfolio and would not be a good basis for the renewable price component of the MPB.

CLECA/CMTA witness Dr. Barkovich testified that the Commission decision cited by PG&E as permitting the use of RECs for compliance with renewable portfolio standard requirements limits the use of RECs for such compliance. Thus, most of the renewable compliance will come from renewable generation contracts, not REC contracts. According to Barkovich, it is too soon to be able to determine if the price of unbundled RECs in the market will track what utilities are paying for the renewable attribute in their renewable generation purchases.

SCE proposes that the Commission should reject an approach based on the cost of IOU's renewable contracts in the current year and instead, administratively set a proxy renewable premium price - to be used in the interim pending the development of the REC index – based on the all available data points on the value of renewable attributes, including the costs of all RPS-compliant renewables in the IOUs' portfolios as of 2009, which could include resources committed to decades ago. SCE doesn't justify why the average cost of *recent* IOU RPS-compliant renewables should not be considered, particularly since these procurements comprise 68% of the activity in the market.

SCE points to DOE data as another data source, even though this data refers to a different product, and is well below the value of California RPS renewables. Dr. Barkovich testified that this source of data is not a suitable proxy as it captures an entirely different metric and has nothing to do with a wholesale market premium for renewable generation compared to gas-fired generation.

For a third source, SCE points to the prices committed to by MEA in 2010 for both RPS-compliant and non-RPS compliant resources (a premium of $39/MWh and $10.50/MWh respectively). SCE fails to show how prices paid by MEA for non-RPS compliant resources represent the value of RPS-compliant resources.

Since none of the parties' proposals for computing a market-based RPS value are entirely acceptable, we shall determine a suitable proxy to serve as a RPS value based upon a weighting of different data sources. We shall utilize, in part, the IOUs' costs for RPS based on the methodology proposed by the Joint Parties, but only in combination additional data covering a broader spectrum of the California RPS market. If the IOUs' cost to purchase RPS-eligible power was to be used as the sole measure of the RPS market proxy, the IOUs argue that there would never be any above-market RPS costs to recover as an indifference amount. In order to produce a more broad-based weighting of the RPS adder, therefore, we shall make use of sources of RPS data that incorporate transactions of other load serving entities. In the absence of any superior source that has been identified for this purpose, we shall make use of the western regional renewable energy contract premiums published by U.S. DOE.

We shall weight the adopted RPS adder by 68% allocated to the IOU costs for RPS based on Joint Parties' proposed methodology. We shall weight the remaining 32% of the RPS adder allocated to the DOE data. This weighting corresponds to the percentage of the total load subject to RPS requirements currently represented by IOU load. The applicable percentages are subject to updated data in subsequent years.

We recognize that questions and concerns have been raised regarding the usefulness of the DOE data sources as representative of the California market. We conclude, however, these concerns go to the weight that should be accorded to the DOE data sources. Considering the lack of more accurate alternative RPS data sources other than IOU resource data, we conclude that some recognition of the DOE data sources offers an opportunity for a broader measure of the California RPS market compared with exclusive reliance on IOU resource data. We conclude that a weighting of DOE data together with IOU resource data is preferable to the alternative proposals by parties given the deficiencies noted above.

We shall thus direct the IOUs each to submit a subsequent advice letter filing, due within 30 calendar days following the issuance of this decision, providing the most recent DOE index figure or figures of reported contract premiums for renewable energy in the Western U.S. suitable for use in calculating the RPS adder. For purposes of developing the relevant RPS adder, we shall also direct the IOUs each to include in the advice letter filing with the Energy Division the following data.

Each IOU advice letter shall provide the following information:

1. All RPS-compliant resources that are used to serve customers during the current year (i.e., most recent 12 months) and those projected to serve customers during the next year, including both contracts and IOU-owned resources.
2. The projected costs together with the net qualifying capacity of energy produced by each of these resources (providing relevant costs in dollars and volumes in MWh and qualifying capacity in kW).

The Energy Division will then calculate the average cost of power from these resources by summing up all the costs from all three IOUs, subtracting the product of the NQCs of those resources times the IOU's current RA capacity adder used in the Market Price Benchmark, and dividing by the sum of all the MWHs from all three IOUs.

As better sources of market indices of California RPS values become available in the future, we shall consider them in setting the MPB in subsequent periods.

We further direct that pre-2004 resources be included in the RPS adder calculation. All the IOUs confirmed that they claim RPS compliance credit for renewables procured before 2004. The requirement to procure additional RPS-compliant renewable resources is reduced one for one, for every MWh of pre 2004 renewable resources generated in the IOU portfolio. We reject the claim that the renewable attributes associated with pre-2004 renewables in the IOUs' portfolios are of no value to the IOUs and bundled customers. Even if the IOUs cannot sell the renewable attributes, they still benefit from them.

The pre-2004 renewable resource volumes in question are substantial, so it is critical to ensure that these volumes are treated appropriately in the methodology. Excluding such resources would significantly understate the value of renewable resources in each of the IOUs portfolios.

SCE witness Schichtl testified there is no reason to limit the application of the renewable adder only to post-2003 renewable resources: Because SCE's proposal was simply to create a weighted average market price benchmark using the percentage of renewable resources in each vintage year, SCE saw no reason to exclude the renewable resources from any particular vintage of resources.

We disagree with PG&E's argument that exclusion of pre-2004 resources is justified because recognizing the value of renewable attributes in pre-2004 resources, including those resources used to calculate CTC, would result in double counting. As Joint Parties observe, no double counting would occur as long as all portfolios are weighted based on RPS-eligible volumes, and the MPB is calculated the same for all portfolios, including for CTC resources. Therefore, we shall include pre-2004 resources in calculating the RPS adder for calculating the indifference amount. Once the requisite data has been provided to the Energy Division, we shall consider a draft resolution to adopt an interim RPS adder, weighted 68% for IOU costs and 32% for DOE data sources.

3.2. Revised Capacity Adder for the MPB

The current MPB includes a capacity adder to reflect the cost of resource adequacy (RA). In this manner, the RA benefits of generation resources acquired to meet system or local area reliability needs is reflected in the value allocated among customers. The RA capacity adder was agreed to by the parties as a part of an overall settlement, and approved in D.06-07-030. Current capacity values used in the MPB are based on the annualized cost of a combined cycle combustion turbine; but there is no means of updating the capacity values over time. Parties generally agree that RA capacity reflected in the MPB should be subject to updating, but disagree on how to do so for purposes of this proceeding.

3.2.1. Parties' Positions

The IOUs' joint workshop proposal would establish the capacity value of the utility portfolio based on the total "Net Qualifying Capacity" (NQC) of all generation resources (utility owned and power purchases) in the utility portfolio and the price for capacity established by the CAISO for the Capacity

Procurement Mechanism (CPM), as that price is modified and approved by the Federal Energy Regulatory Commission (FERC) from time to time. The capacity value would vary for each portfolio vintage, as the NQC would reflect the specific resources included in each vintage. Specifically, the NQC of each vintaged supply portfolio and the currently approved CPM would be used to value the capacity of the portfolio. The supply portfolio NQC would be the sum of the individual NQC of all resources included in each vintaged supply portfolio, varied by vintage. These data would be made available for verification by the Energy Division.

SCE also proposed adjusting the MPB calculation to incorporate an RA value based on the amount of capacity actually included in each vintaged portfolio. SCE believes that a reasonable method of updating the RA adder is preferred over a fixed RA adder price to account for market changes.

SCE proposed a method of updating the RA capacity adder based on the California Energy Commission's (CEC's) determination of the going-forward cost of a simple cycle combustion turbine, evaluated bi-annually as part of the CEC's generation cost study. This same method was used by the CAISO to establish the short-term capacity price currently represented by the CPM. The current capacity value is set at $7/MWh for SCE and $4/MWh for PG&E.

The Joint Parties agreed with the approach described above as proposed by the IOUs.

At the time of the workshop, the CAISO had filed a proposal for the CPM with FERC based on the going forward costs of a hypothetical 50 MW simple-cycle, gas-fired unit built by a merchant generator, based on studies conducted by the CEC, with a 10 percent adder. Based on this methodology, the price for CPM was proposed at $55/kilowatt (kW)-year. At the time, FERC had not acted on the proposal. Reid proposes the use of the Interim CPM (ICPM) price of $41/kw-year pending further developments on the CPM.

A few days before evidentiary hearings began, FERC issued an order expressing concern about the methodology proposed to set the CPM price and establishing a technical conference to address this issue. Given the uncertainty about the CPM price going forward, the Joint Parties recommend that the Commission adopt a revised capacity price that uses the methodology proposed by the IOUs, but with the caveat the proposed CPM value of $55/kW-year be used until further action by the Commission. Upon issuance of a final FERC order on the CPM, the Joint Parties would seek a limited opportunity to file further comments on whether or how the final FERC order should affect the updated capacity adder.

Because the MPB is calculated on an annual basis to determine if an IOU's portfolio costs for a single year exceed market prices, PG&E proposes to look at short-term, RA capacity values. PG&E and DRA support continued use of the existing RA capacity adder, claiming the existing adders more accurately reflect current RA prices. The existing adder was agreed to by parties as part of a settlement approved in D.06-07-030. PG&E and DRA argue that the ICPM and CPM prices are too high to reflect short-term capacity prices. PG&E testified that in general, short-term RA is less than the $41/kW-year ICPM backstop price of capacity. The sources relied on by PG&E show that RA prices have been at or below $45/kW-year. The ICPM price of $41/kW-year was on the high side of the range, but was within the range of prices cited by PG&E's sources as reflective of RA capacity prices.

DRA believes that although the CPM price is publicly available and transparent, it is not accurate or appropriate for determining the market value of

RA capacity. DRA thus does not support using the CPM to determine the market value of RA capacity, and recommends maintaining the existing RA capacity adder.

3.2.2. Discussion

We agree that it is reasonable to provide a means for updating the RA capacity value included in the MPB over time as more updated data becomes available. We conclude that SCE proposes the most appropriate alternative for determining the capacity adder based on the going-forward costs of a simple combined-cycle combustion turbine as estimated by the CEC. Both PG&E and SCE indicated at hearings that they no longer supported use of the CPM to determine the RA capacity value. Both the ICPM and CPM prices are substantially higher than the general level of resource adequacy. (PG&E/Martyn, Transcript (Tr.) Vol. 2, at 300:22-24.) Although SCE had proposed to use the CPM for determining for the RA adder, this support was based on SCE's understanding that the CPM would reflect the going-forward costs of RA capacity. (SCE/Schichtl, Tr. Vol. 1, at 123-125.) However, if the CAISO were to change its CPM Compensation methodology as a result of the recent FERC decision on CPM Compensation, SCE may not continue this support. (SCE/Schichtl, Tr. Vol. 1, at 125, 9-19; 126:1-9.)

FERC has determined that the CPM may be unjust and unreasonable. FERC allowed the CPM to go into effect April 1, 2011, but made the CPM subject to refund and established a process to review the reasonableness of the CPM price. FERC has initiated an effort to modify the CPM so that it reflects the value of long-term capacity investments.

The CPM was not developed to be a proxy for short-term RA values, but was developed as the price paid to generators to provide a backstop to procure capacity in cases of system deficiencies. The CPM is intended to be a proxy for the going forward costs of operating a specific unit and a 10% adder for the generator. The CPM does not reflect the market price for RA capacity or short-term capacity costs. Thus, there is a fundamental mismatch between the short-term capacity adder meant to reflect RA values to be included in the MPB, and the CPM that was developed as a part of a backstop mechanism to compensate generators for operating costs plus a 10% adder.

The Commission has previously determined that the CPM overstates the value of RA capacity. In December 2, 2010 comments filed with FERC on the CAISO's CPM proposal, the Commission stated that the proposed $55/kW-year CPM price was above prices observed in the current RA capacity markets.[6] PG&E argues that the Commission cannot approve as just and reasonable using the CPM as a proxy for short-term RA capacity prices since it argued at FERC that the CPM is significantly higher than actual RA costs. PG&E argues that CPM does not reasonably reflect the value of RA capacity.

The existing capacity adder was agreed to by parties as a result of a settlement process and approved by the Commission in D.06-07-030 as just and reasonable.

In adopting a forecast market price benchmark methodology for calculating the indifference rate, D.06-07-030 acknowledged the need for an RA/capacity adder to capture the cost of complying with resource adequacy requirements. The Decision stated that no capacity market was then available to

---

[6] The Commission attached to its FERC comments a declaration from Aram Shumavon of the Energy Division stating that the RA capacity values were significantly below the CPM price

provide transparent RA/capacity adders, for 2006. D.06-07-030 adopted the parties' consensus for RA/capacity cost adders, which were negotiated as part of workshop discussions. For 2007 and beyond, D.06-07-030 directed the Energy Division to coordinate a meeting of the Working Group to discuss RA/capacity adders based on publicly reported transactions in a California capacity market or another suitable public index once available.

In D.07-01-030, the Commission adopted the Working Group's consensus for the 2007 RA/capacity adders of $7/MWh for SCE and SDG&E, and $4/MWh for PG&E. If a functioning and transparent capacity market or a suitable public index became available, the Working Group Parties agreed to recommend, for 2008 and beyond, a RA/capacity adder based on such a market or public index. Otherwise, Working Group Parties were to formulate the RA/capacity adder based on consensus until such market or public index becomes available.

Accordingly, we shall adopt SCE's proposal to update the RA capacity adder using the California Energy Commission's estimates of the going forward costs of a combustion turbine, which is updated biannually, including the Net Qualifying Capacity of all generation resources in the utility portfolio. Adopting this approach represent the most practical way to updatethe RA capacity value in the MPB.

3.3. CAISO Load-Based Costs

The total portfolio calculation currently includes certain CAISO load-related costs. No party disputes that the IOUs avoid load-related CAISO charges when load departs for DA service. Parties agree that all load-based CAISO costs that vary based on the amount of load should be excluded from the total portfolio and MPB calculation. The exclusion of such data will eliminate the need to calculate the reduction in load-related CAISO costs as load departs.

3.3.1. Parties' Positions

PG&E agreed that only CAISO load-related costs should be excluded from the total portfolio calculation instead of all CAISO charges because some of the charges are not load-related. PG&E originally proposed simply excluding all CAISO charges from the total portfolio calculation as an administratively simple approach to addressing this issue since it is difficult to determine exactly which CAISO charges are load-related.

SCE testified that the load-related subset is fairly easy to identify; thus, only load-related CAISO costs should be removed from the total portfolio costs in the interest of bundled service customer indifference. The Joint Parties entered into evidence a list of load-related CAISO charge types, which no party challenged.[7]

3.3.2. Discussion

Currently the IOUs include forecasted CAISO costs in the ERRA proceeding for recovery in generation rates. These costs are also included in the Total Portfolio Cost for purposes of calculating the PCIA and CTC. The current methodology inappropriately treats avoidable CAISO costs as if they are unavoidable, above market utility generation-related costs. DA and DL customers thus pay for the CAISO costs associated with their load through their non-utility provider and also pay a share of bundled service customers' CAISO costs through the PCIA. The load-based costs of CAISO services should be removed from the Total Portfolio Cost for purposes of calculating the PCIA and

---

[7] See Exh. 100, Appendix A.

CTC so that DA and DL customers don't pay more than necessary to maintain bundled customer indifference.

We thus conclude that all load-driven CAISO costs be excluded from the total portfolio calculation. It is not appropriate for ESPs to pay a share of the CAISO charges for bundled load when they pay the same charges for their own load. This is a cost that varies directly with the load served. Accordingly, we adopt the consensus recommendation that utility load-related CAISO charges be excluded from the total portfolio cost used in the indifference calculation.

We adopt the list of load-related CAISO charges identified by the Joint Parties in Exhibit 100, Appendix A, as constituting the pertinent charges to be excluded from the total portfolio and MPB calculation. Exclusion of CAISO congestion costs, including load-based congestion costs, from the IOUs' total portfolio costs is appropriate because these costs are also avoided when load departs for DA service.

3.4. Shaping Profile to Reflect MPB value of Portfolio Resources

Under the current method for calculating the indifference amount, the total portfolio reflects the profile of the underlying generation resources or contracts; however, the MPB calculation essentially reflects a flat load profile. Prices used in determining the MPB vary for on-peak and off-peak periods, but there is currently no weighting in the MPB to reflect variations in load shape by time-of-use (TOU) periods. The current MPB is thus based on an implicit assumption that the IOU supply portfolio serves a flatter load profile than it actually serves, creating an artificially low MPB value and artificially high Indifference Amount impacting the PCIA and CTC. Parties agree that the MPB methodology should be modified to reflect load shape variations by TOU period, but disagree on how to do so.

3.4.1. Parties' Proposals

The Joint DA Parties propose a weighting that aligns the MPB with the load shape, to increase the weighting of the on-peak portion of the market price and lower the weighting of the off-peak price. Because the IOU supply portfolio is constructed to serve the load of bundled service customers as that load varies from hour-to-hour, the Joint DA Parties argue that the load profile of bundled service customers should be used as a weighting factor. The Joint DA Parties prefer use of the bundled load profile rather than the generation profile because the bundled load profile is more transparent. They argue that the public would have no way of validating the generation profile without access to the IOU's confidential system dispatch and production cost simulation model. The bundled load profile, on the other hand, they believe can be estimated using publicly available information.

PG&E agrees that the weighting factor should be modified, but rather than basing the weighting factor on bundled load data, PG&E proposes that the MPB weighting be based on the generation profile, consistent with the profile underlying the total portfolio cost. Since the MPB is used as a part of the indifference calculation to determine the combined production profile of generation in the utility's portfolio, PG&E and SCE argue that it should be weighted based on a generation portfolio. In addition, they believe a single weighting factor should be used for the MPB, rather then trying to develop a separate generation weighting for each vintage. Developing a single weighting factor would make calculating of the MPB administratively easier.

DRA argues that proposals to use either load or generating profiles would require use of confidential data, which is inconsistent with the objective of transparency. In response to DRA, SCE proposed to use historical bundled load profiles from prior calendar years to weight the MPB, because the historical data is not confidential. The bundled load profile is not expected to differ substantially from the generation output profile, and would therefore "serve as a reasonable and transparent alternative." The Joint Parties acknowledge that historical bundled load profiles are an acceptable alternative and could be used to derive a profile adjustment for the MPB. They concur that there appears to be little difference in the adjustment factor whether one uses the generation profile or the bundled load profile.

3.4.2. Discussion

The proposals of the Joint Parties and the IOUs yield similar results for the peak and off peak weighting factors. The current weighting factors give significantly more weight to off-peak energy prices than do either the Joint Parties or IOU proposed weighting factors.

We conclude that the MPB should be weighted based on the historical IOU bundled load profile. In order to promote transparency, we shall direct that historical bundled load data be used, as suggested by SCE. The use of historical bundled load data will avoid the need to use confidential data, and will still promote reasonable accuracy. The use of such data will promote consistency with the load profile reflected in the total portfolio. Because SCE already makes historical bundled load profiles by rate group publicly available, as do the other IOUs, no additional calculations should be required for purposes of the MPB. The use of current generation profile data would involve confidential data, with the necessity for the Commission's Energy Division to validate the confidential data and calculations.

We shall not require a separate calculation of load shape for each vintage year as proposed by DRA. Otherwise, the IOU would have to run multiple calculations rather than just one. This difference would grow larger as the number of vintages increases. We conclude that there will be no significant variation in the load shapes adjustment from year to year and the extra analysis required to develop different profiles for different vintages is not likely to change the numbers sufficient to warrant the effort involved. Adoption of these modifications will cause the MPB to more accurately reflect the profile of the supply portfolio to more accurately measure bundled customer indifference.

3.5. Credit for Negative Indifference

CLECA/CMTA argue that bundled service ratepayers should pay DA-eligible customers departing for DA service when the indifference calculation results in a negative indifference amount. Under current rules adopted in D.06-07-030, DA customers cannot be paid by bundled customers if the indifference calculation shows that bundled customers are better off if DA or CCA load departs (i.e. negative indifference). Instead, if the indifference calculation results in an amount less than zero, the PCIA is set to the opposite of the CTC, resulting in an indifference amount of zero.

The difference between the PCIA that results from this calculation and the PCIA that would result from recognizing the value of negative indifference is carried forward. The benefit of this additional negative PCIA is not available to the DA customer until later in time. If a DA or CCA customer returns to bundled service, it would never get the value of this negative PCIA in rates.

CLECA/CMTA acknowledge that the negative indifference offsets future positive indifference, but complain that if a DA or CCA customer returns to bundled service, it would never get the value of this negative indifference. CLECA/CMTA find this result inequitable, arguing that departing customers should be able to be paid for leaving the system if this creates a benefit for remaining bundled customers. Under this circumstance, they should certainly not receive credit for energy or capacity or renewable attributes of the utility contracts

SCE opposes the CLECA/CMTA proposal, arguing that they bring forth no new evidence to support a change in policy on this issue.

We do not find sufficient basis to adopt the CLECA/CMTA proposal. This issue was previously considered and rejected in the Commission's adoption of an indifference methodology in D.06-07-030. CLECA/CMTA simply reargue for adoption of a policy previously rejected by the Commission in D.06-07-030. We find no new arguments that warrant a change in the treatment of negative indifference amounts that has been previously adopted.

3.6. Adjustment to Account for Congestion

The Joint Parties propose adjusting the MPB using a "basis adjustment" to account for congestion. PG&E agrees that CAISO load-related costs, which include congestion costs, should be excluded from the total portfolio cost calculation, but does not agree with the Joint Parties' proposal to increase the MPB by using an adder that compares prices at the NP 15 trading hub and default load aggregation point. PG&E states that congestion costs are load-related. Since PG&E has already agreed to remove all CAISO load-related costs from the total portfolio calculation, PG&E contends there is no need to make an additional adjustment to address congestion costs.

The Joint Parties' proposal comparing trading hub and load aggregation point prices would capture both congestion and losses. However, the MPB already includes and adjustment for losses and thus PG&E argues that the Joint Parties' proposed adder would be duplicative

We agree with PG&E that there is no need to make a separate adjustment for congestion costs since we have already required the exclusion of CAISO load-related costs from the total portfolio calculation which includes congestion costs.

3.7. Setting a Zero Default PCIA Value

3.7.1. Parties' Positions

PG&E, SDG&E and Jan Reid propose that in the event PCIA is negative, the PCIA charge should be set to zero and any negative PCIA should only be used to offset positive PCIA in future periods, rather than first offsetting that year's CTC charges. The DA parties contend this would be a violation of the indifference standard and should be rejected.

In D.06-07-030, the Commission applied the indifference principle in addressing the calculation of CTC. Specifically, we required that bundled customers be indifferent due to customers migrating from bundled to DA load, and that there be no cost shifting. To prevent cost shifting, we adopted a methodology to capture the relevant costs in the form of a CRS to be assessed on designated DA load. The CRS incorporates, among other elements, a DWR power charge and the ongoing CTC.

The Indifference Amount is determined on a total portfolio basis in order to achieve bundled customer indifference. The Indifference Amount consists of two elements: CTC and PCIA. The CTC is determined first, and then the PCIA is determined on a residual basis: Equal to the difference between the indifference amount and the CTC. In D.06-07-030, the Commission modified the Indifference Amount calculation in part by allowing the PCIA to go negative up to the level of the Ongoing CTC. A negative PCIA would result when CTC is higher than the indifference amount.

PG&E argues, however, that this treatment is discriminatory whereby some customers (i.e., bundled and exempt departing load) are required to pay Ongoing CTC, while other customers (i.e., DA and CCA departing load) are effectively not required to pay Ongoing CTCs. These latter customers get an offset (credit) through the negative PCIA. Thus, in this situation, exempt and non-exempt customers are treated differently. In addition, a negative PCIA effectively results in increased ERRA costs, which bundled customers are required to pay. Thus, while non-exempt customers would be paying a net result that is zero or at least lower than the Ongoing CTC, bundled customer costs in ERRA would increase.

Under statutory law, and Commission precedent, all customers are required to pay Ongoing CTC. Thus, PG&E argues that the current Indifference Amount methodology is contrary to original legislative intent articulated in Public Utilities Code Section 367(a), and contrary the Commission's attempt to resolve the issue as articulated in D.05-12-045.

SDG&E agrees with PG&E that none of the changes to the MPB proposed for purposes of calculating the PCIA should apply in the context of calculating CTC. SDG&E does not believe that the revised MPB methodology should be used to determine CTC revenue requirements. The revision to the MPB methodology for determining the indifference amount is intended to provide a better estimation of bundled customer indifference. SG&E argues that this reasoning does not extend to the CTC revenue requirement determination.

PG&E proposes that if the Indifference Amount is less than the Ongoing CTC, the PCIA would be set to zero. All customers would then make the same contribution towards Ongoing CTC obligations, and the actual negative PCIA that would have resulted under the formula would be banked to offset potential positive PCIA in future years. PG&E argues that this modification will correct a logical flaw in the current indifference calculation and results in fair and equal treatment for all affected customers.

3.7.2. Discussion

The current Indifference Amount is calculated as the sum of the Ongoing CTC and the PCIA. If the Indifference Amount is negative (i.e., the total portfolio costs are less than the market value of the portfolio), the Indifference Amount is set to zero.

The use of negative PCIA was first addressed in D.06-07-030, where the Commission stated that the PCIA component of DA CRS may be a negative number in those instances in which Ongoing CTC is larger than the indifference charge, so that overall indifference is maintained. The Commission addressed a similar issue in D.07-05-005, issued in response to a petition for modification filed by PG&E. PG&E argued that negative CRS amounts should not be carried-forward to offset positive CRS amounts. In D.07-05-005, the Commission rejected PG&E's proposed modification, finding that the proposed modification would not result in bundled customer indifference. We affirmed that in order to maintain indifference, both positive and negative indifference effects must still be tracked, with the negative amounts offsetting positive amounts.

In R.06-02-013, we examined how the indifference amount should be calculated with the inclusion of so-called "new world" generation resources. In that proceeding, PG&E advanced a proposal that would have resulted in a negative indifference element not being used to offset the CTC. PG&E proposed to calculate CRS elements separately, not allowing the netting and carrying forward of any negative amount associated with new world generation resources. We rejected PG&E's proposal in D.08-09-012, affirming the ongoing relevance of D.07-05-005 with respect to the principle of bundled customer indifference, and stating that "[w]hile the Commission's reasoning in [D.07-05-005] applied to the existing DA/Departing Load (DL) CRS calculations, the basic principles directly relate to handling of negative charges in this proceeding…." (D.08-09-012 at 47.) As previously concluded in D.07-05-005, we likewise concluded in D.08-09-012 that "[i]t is similarly necessary that negative indifference amounts be carried over for use in subsequent years to maintain bundled customer indifference. The total portfolio approach is consistent with this principle. PG&E's separate approach is not." (*Id.*) we expressly concluded in D.08-09-012 that the total portfolio approach allows CTC to be offset by other negative CRS elements.

Consistent with our prior review of similar proposals as noted in the above-referenced decisions, we find no basis to approve PG&E's proposed modification here. Bundled customer indifference is determined with reference to total portfolio costs, not isolated costs related to just the ERRA costs. PG&E's proposal would violate the bundled customer indifference principle by recognizing only the cost to bundled customers from using more above-market CTC resources, while not recognizing the offsetting benefit accruing to bundled customers from also using more below-market utility resources. Accordingly, we decline to adopt PG&E's proposed change in the treatment of CTC in the calculation of the Indifference Amount.

4. Conforming Changes to Temporary Bundled Service (TBS) Rate Calculations

In D.03-05-034, we required that DA customers returning on a TBS basis pay for the incremental cost imposed on the system due to additional short-term spot supplies procured to serve them.[8] The TBS rate applies to DA customers that wish to serve out their six-month advance notice period to return to bundled portfolio service (BPS) on the IOU's procurement service rather than on DA service, or need a 60-day "safe harbor" period while they switch ESPs. Parties support maintaining the TBS rate.

Remaining bundled customers were not to be burdened with these added costs but were to be left indifferent as to whether DA customers use the utility as temporary "safe harbor." (D.03-05-034, at 19–20.) The TBS rate thus is a market-based price to reflect costs that the IOU incurs to serve DA customers that have not provided the required notification to return to fully bundled service. This policy ensures that IOUs' bundled customers do not incur additional costs because DA customers return to IOU service before the IOU can incorporate that load into its procurement planning

Although parties disagree on various changes to the MPB methodologies, they generally agree that whatever changes are adopted with respect to the PCIA and MPB, consistent modifications should be reflected in the TBS. This includes the commodity cost of power, the incremental cost of RPS compliance, and any incremental capacity/RA costs.

---

[8] The current TBS rate equals the CAISO's hourly Integrated Forward Market Locational Marginal Price at the respective IOUs' Load Aggregation Points, multiplied by an allowance for unaccounted for energy plus an allowance for Ancillary Services and the CAISO Grid Management Charges

While the DA Parties recommend removing CAISO charges from the Total Portfolio Costs and the MPB, however, they do not recommend removing load-related CAISO costs from the TBS rate.

We adopt the parties' consensus recommendations to apply the adopted modifications with respect to the MPB in calculating the TBS rate. While we have determined that CAISO load-related charges are to be removed from the total portfolio cost and MPB calculation, we agree with the DA parties that load-related CAISO costs should remain in the TBS rate because they are incurred by the IOUs to serve DA customers on TBS. With regard to the timing for modifications to the TBS rate, changes to the TBS should be implemented concurrent with changes to the PCIA, MPB and Indifference Amount.

5. DA Switching Rules

The Commission has adopted rules whereby customers may switch between DA and bundled service. The current process of managing customer switches from bundled service to DA is through Notices of Intent (NOI) supplied by the customer. This process requires the validation of the incoming forms and, in some cases, the clarification or correction of the forms.

DA switching rules accomplish several purposes. There are administrative issues and timing requirements related to switching a bundled customer to DA service, or allowing an existing DA customer to switch back to bundled service. The switching rules also guard against placing any burden on bundled customers while at the same time promoting customer choice and economic efficiency. Phase III of this proceeding is to address possible changes to the switching rules.

The switching rules prescribe both advance notice periods prior to switching and minimum durations for a customer to remain on bundled service before becoming able to switch back to DA. The four main components of the DA switching rules are:

a. Six-month advance notice to transfer from bundled back to DA service;

b. Six-month advance notice to return from DA to bundled portfolio service (BPS);

c. Three-year minimum BPS stay period; and

d. TBS option, which allows a DA customer to receive temporary procurement service from the IOU while switching to a new ESP, or returning to IOU procurement service in advance of the requisite six-month advance notice.

5.1. Minimum Stay Requirements

The current rules require that customers returning from DA to bundled service remain on bundled service for a minimum of three years. The Commission adopted this requirement to preserve bundled customer indifference without potential gaming. The three-year requirement was intended also to allow sufficient time for the IOUs to adjust their portfolios if returning DA customers elected to switch back to an ESP. Without a minimum stay requirement, the potential would exist for cost shifting if DA customers could abandon bundled service at will without responsibility for payment of ongoing utility costs incurred under multi-year contracts that were undertaken to serve the DA customer when that customer was served as part of bundled load.

5.1.1. Parties' Positions

No party advocates eliminating a minimum stay commitment, but parties disagree on the duration of stay necessary to reasonably protect bundled service customers from cost shifting. DRA supports maintaining the three-year commitment period adopted in D.03-05-034.

The IOUs propose to reduce the minimum stay to 18 months, claiming that an 18 month minimum stay is necessary for several reasons. First, consistent with D.03-05-034, a minimum stay requirement prevents returning DA customers from gaming the system to capture lower prices when the bundled service rates are lower. If a returning DA customer can elect to return to bundled service after giving six months notice, and has no requirement to stay on bundled service for a specific period of time, as soon as market prices change, the customer may try to return to DA service and capture lower prices. The Commission sought to address this type of price arbitrage when requiring a minimum stay for returning DA customers.

In addition to preventing gaming, the minimum stay requirement minimizes stranded costs. As noted in D.03-05-034, if DA customers were permitted to depart bundled service without restriction, they could leave long-term supply commitments stranded, and thereby shifted to the remaining bundled customers. When DA customers return to bundled service, the IOU cannot simply enter into short-term energy transactions to serve these customers. Instead, the IOU must meet certain regulatory requirements, such as RA and RPS requirements, which require the IOU to enter into intermediate-term transactions on these customers' behalf.

SCE states that demand for DA service has fluctuated over the years, and the DA market can experience large swings depending on market conditions. When demand for DA service drops off, the cap on the DA load will not mitigate the risk of gaming. The DA Parties' conclusions depend on continued high demand for DA service, which itself indicates lower price power available in the competitive market. But these market conditions are not the circumstances with which the IOUs are concerned. According to SCE, as prices rise in the market and DA service becomes potentially less competitive with IOU service, opportunities for gaming increase at the same time customer interest in DA service would be expected to diminish. It is these changes over time in the competitive market prices which the minimum stay requirement is intended to address.

SCE testified that nothing prohibits the entire maximum DA load from returning to SCE's procurement service in stressed market conditions. If even half of that load returned to SCE's procurement service in a stressed market, without a long-term commitment to bundled service, the risk of stranded costs when that load departs for DA service would be substantial. It is also possible that a significant reduction in the minimum stay provision would, in the face of the potential for a mass return, result in a change in the mix of short, medium and long-term contracting by the IOUs over time. This could have the affect of increasing the average cost of procurement, which would impact all customers.

The DA Parties advocate reducing the minimum stay requirement from 36 months to 12 months, arguing that "greater load stability" in the capped market justifies reducing the minimum stay, and that 12 months is sufficient to protect against seasonal gaming. To the extent six-month advance notices for migrating load are maintained, the existing DA load cap provides some mitigation of the risks of gaming and cost shifting as a result of migrating load, which supports some reduction to the minimum stay period.

The DA Parties recommend that the minimum stay for voluntary return customers should be 12 months, which begins at the end of the safe harbor period or when the customers returns to IOU service after having given six months notice. They propose a minimum stay for an involuntary return customer of 12 months to begin at the end of the six month TBS rate period.

The DA parties argue that given the limited nature of DA re-opening, a minimum stay is unnecessary or should be very short. They believe it is unclear whether DA will continue to be fully subscribed in future years. Moreover, some parties are advocating that DA be further re-opened in the future. They propose that the Commission adopt switching rules to prevent gaming now and in the future.

5.1.2. Discussion

We adopt the IOUs' proposal to revise the minimum stay requirement to 18 months. We recognize that the SB 695 cap on the DA market provides some mitigation in the risk of stranded costs and supports some lowering of the minimum stay requirement from its current three years. We conclude, however, that a one-year period is too short to mitigate the risk of stranded costs. Under the current RA requirements, even with the six-month advance notice requirement, the risk of stranded costs with a one-year minimum stay requirement is high. The DA Parties conducted no studies or analysis to determine if their proposed 12-month minimum stay requirement provided the utilities adequate time to adjust their portfolios to reflect shifting load.[9] During hearings, DA Parties Witness Fulmer admitted that this knowledge about the utilities' procurement adjustment practices was limited and that "[t]he utilities'

---

[9] When asked if the DA Parties conducted any studies or analysis to determine if the 12-month minimum stay would ensure bundled customer indifference, DA Parties Witness Fulmer testified that "Due to the confidentiality of returns, I wouldn't be able to do a detailed study to demonstrate that. That's just based on my readings of other testimonies and inferences from that." Transcript of March 28 Hearing, at 518.

procurement departments would obviously know more about how they procure than I would."[10] When questioned if the DA Parties' 12-month proposal was tied to the utilities' procurement adjustment activities, DA Parties' Witness Fulmer testified that the 12-month proposal was based on "one instance where one of the procurement folks at Edison had noted their flexibility in their contracting. The 12 months notice is based on that quote and the fact that there's the indication that the six months is sufficient time for the notifications to come to and from."[11]

Therefore, given the lack of supporting evidence, we conclude the minimum stay requirement should be longer than one year, but shorter than three years. While the precise length of time is difficult to quantify, we conclude that the IOUs' proposed 18-month minimum stay requirement achieves a reasonable approximation, however, mitigating the risk of stranded RA and other potential stranded costs, while acknowledging that the capped DA market supports some lowering of the minimum stay requirement from its current length of three years. The IOU proposal represents the expertise of procurement planners who must maintain sufficient resources to serve bundled load.

The DA Parties assume continued high demand for DA service, which indicates lower priced power available in the competitive market. As market prices rise and DA service becomes potentially less competitive with IOU service, however, opportunities for gaming increase at the same time customer interest in DA service would be expected to diminish. This sort of change over

---

[10] Transcript of March 28 Hearing, at 527.

[11] Transcript of March 30 Hearing, at 516.

time in competitive market prices is what the minimum stay requirement is intended to address.

Gaming is not the only concern the Commission seeks to address by the minimum stay requirement. The Commission also seeks to mitigate the risk of stranded costs from the utilities' prospective procurement obligations by considering the mix of resources and the average duration of contractual obligations. The minimum stay period is intended to mitigate the risk of stranded costs from the utilities' prospective procurement obligations by considering the mix of resources and the average duration of contractual obligations. The proposed 12-month minimum stay requirement increases the likelihood that costs will be misallocated from departing DA customers to remaining utility customers. Requiring returning DA customers to stay on bundled service for a minimum of 18 months will minimize stranded costs associated with intermediate-term procurement. If returning DA customers could leave bundled service without a minimum stay requirement, costs for transactions entered into on these customers' behalf would effectively be shifted to the remaining bundled customers.

Parties also disagree as to when the minimum stay requirement period would start. Under current rules, a returning DA customer must provide six months notice before returning to bundled service rates. A returning DA customer that gives six months notice is placed on the bundled rate when it returns to bundled service six months after giving notice. A returning DA customer who fails to give six months notice s placed on the TBS rate for six months. After the six months end, the customer goes on the bundled service rate.

As determined in D.03-05-034, the minimum stay period commences when a returning DA customer begins paying bundled service rates. Thus, if a customer provides six months notice and then returns to the bundled service rate, the minimum stay period commences when the DA customer returns. If a DA customer returns with no notice, and is on the TBS rate for six months, the customer's minimum stay period commences after the six months TBS rate period has concluded and it starts paying the bundled service rate.

No party offered evidence as to why the existing Commission rule as to when the minimum stay period commences should be modified. Requiring the minimum stay period to commence when a returning DA customer begins paying the bundled service rate treats all returning customers equally, whether they provide sufficient notice or not. Since no party has provided any reason to modify this aspect of the switching rules, the Commission should not modify its existing rule.

With regard to the minimum stay requirements, we conclude that the distinction between voluntary and involuntary returns is not relevant. Whether a customer returned voluntarily or involuntarily, the utility still must enter into short- and intermediate-term transactions to provide energy and satisfy regulatory requirements on behalf of that customer. The minimum stay requirement applies under whatever circumstances a DA customer returns to bundled service, and commences when the returning customer begins paying the bundled service rate.

5.2. Advance Notice Period to Switch Service

A six-month advance notice is currently required for customers returning to BPS or departing to DA service, as adopted in D.03-05-034. The advance notice period is designed to preserve bundled service customer indifference to migrating load. The Commission in D.03-05-034 found that a six-month advance notice to return to bundled service was a necessary added precaution to give the IOUs sufficient time to adjust their procurement to accommodate the change in load. The Commission noted that the six-month advance notice, together with the minimum BPS commitment period, would guard against arbitrage or other gaming practices that could be detrimental to bundled customers.

There are two exceptions to the six-month notice requirement. First, if a customer is involuntarily returned to bundled service by an ESP, the customer obviously cannot give six months notice before returning. This situation may occur when, for example, an ESP goes bankrupt and suddenly stops providing service. In this case, the customer would be immediately returned to their utility's TBS tariff.

Second, a DA customer may voluntarily return to utility service for a 60 day safe harbor period if they are transitioning to a new ESP. However, the voluntarily returning DA customer needs to give notice when it returns that it is electing to use the safe harbor option. The safe harbor period starts on the day that the voluntarily returning DA customer returns to bundled service, unless the customer gives notice to the IOU that it is not returning for a safe harbor period.

During the safe harbor period, voluntarily returning DA customers pay the TBS rate. A customer returning under a safe harbor period does not need to give six months advance notice, but the safe harbor period is limited to 60 days and commences on the first day the customer returns to bundled service. If the DA customer does not find a new ESP and submit a DA Service Request (DASR) to be switched to the new ESP during the 60-day safe harbor period, the customer would then be considered a returned DA customer, would pay the TBS rate for the six month notice period and then would be required to stay on bundled service, and pay bundled rates, for 18 months under the minimum stay provision.

5.2.1. Parties' Positions

The IOUs, the DA Parties, CLECA/CMTA and DRA all support the continuation of the six month advance notice for DA customers to return to bundled service. No party opposes the requirement. DA customers may serve out the six-month advance notice period while on DA service, in which case they will return directly onto BPS, or they may elect to take the IOU's TBS during the advance notice period. Therefore, customers have reasonable flexibility under the rule.

The DA Parties, however, propose eliminating the six-month notice requirement for a customer departing from bundled service to be served by an ESP. The DA Parties do not believe there is any justification to impose this restriction on the movement of DA customers, particularly since DA caps have been established by D.10-03-022, thus mitigating uncertainty as to the load changes.

SCE argues that even though the Commission has established caps on maximum DA load pursuant to D.10-03-022, demand for DA service will vary with market conditions, in which case the cap will not mitigate the risks of cost shifting, arbitrage, or similar activities by customers.

5.2.2. Discussion

We adopt the uncontested proposal to continue to apply the six-month notice requirements for customers seeking to return from DA to bundled service. The six-month notice is necessary in order to allow the IOUs to reasonably mitigate the risk of having to dump energy and RA capacity in a depressed market due to departing load, which increase the risk of stranded costs. The six-month advance notice of customers returning to be served by an ESP is also needed to allow the IOUs to reasonably mitigate the sudden swings in bundled service customers' load that make it difficult for the IOU to reasonably procure for its bundled service customers.

We thus conclude that the six-month advance notice requirement remains reasonable even though maximum DA load caps were established by D.10-03-022. Representatives from customer groups have indicated that the six-month advance notice requirement to switch to DA does not pose a problem for DA customers.

All customers returning to BPS, including those that fail to timely switch to DA out of the safe harbor, should provide the same advance notice. We find no evidence to show that the IOUs can adjust their portfolios to accommodate returning DA load in as little as four months. The IOUs testified that six months advance notice is required to adjust their portfolios to accommodate DA load returning to BPS.

5.3. Preservation of the Safe Harbor

In D.03-05-034, the Commission found that DA customers should be permitted to return to the safe harbor of bundled service for a temporary period of not more than 60 days while switching ESPs. Limiting the safe harbor to 60 days addresses concerns regarding the possible need for limits on the amount of load that can elect the safe harbor during a particular year. The Commission found that "imposing this 60-day time limit should have some effect on limiting the amount of DA load in the safe harbor at any given time." Customers failing to switch to DA from the safe harbor remain on TBS during the requisite six-month advance notice period and are subject to the minimum stay requirement. Thus, under the current DA switching rules, a customer that elects the safe harbor but fails to timely switch to DA will be on TBS for the safe harbor period plus an additional six months before returning to BPS.

5.3.1. Parties' Positions

Under current rules, if a customer does not submit a DASR during the 60-day safe harbor period, the six-month period for notice to return to bundled service is initiated. The DA Parties propose, however, that the safe harbor period count as the first 60 days of the 6-month advance notice requirement. The DA Parties thus propose to modify the safe harbor rule, such that any DA customer that elects the safe harbor but fails to timely switch to DA would serve out a total of six months on TBS before going to BPS.

The IOUs oppose the DA Parties' proposed change, arguing that it would effectively leave the IOUs with only four months to adjust their procurement portfolio to accommodate DA customers' return to bundled service. SCE argues that the IOUs cannot adjust their portfolios for returning DA load in as little as four months.

5.3.2. Discussion

The current safe harbor rules are reasonable and shall be maintained without modification for voluntarily returning DA customers. We do not adopt the proposal to treat the six-month advance notice period as starting concurrently with the 60-day safe harbor period. This change would effectively reduce the six-month advance notice to only four months. In order for the IOUs to change their procurement to accommodate customers electing to return from DA to bundled service, the IOUs must know which customers will elect to return. Yet, during the 60-day safe harbor period, the IOU has no way of knowing for which DA customers will return unless the customer provides notice before or during the safe harbor. Accordingly, reducing the notice period from six months to four months would create undue risk and uncertainty to bundled ratepayers. In order to maintain bundled customer indifference, the existing safe harbor rules should continue to apply.

6. ESP Financial Security Requirements

The Commission previously adopted requirements in D.03-12-015 for registration of all ESPs, including requirements for each ESP to furnish various forms of documentation, fees, and security deposits with the Commission. Among the requirements, ESPs were to post a security deposit in amounts of up to $100,000, depending on the number of customers served. Since D.03-12-015 previously established administrative procedures for the posting of ESP financial security deposits with the Commission, those procedures shall continue to apply, subject to any revisions in the amount or form of ESP financial security based on the results of this proceeding. In this proceeding, we adopt modified financial security requirements for ESPs pursuant to Pub. Util. Code § 394.25(e) to cover estimated re-entry fees due to DA customers that may be involuntarily returned to IOU procurement service. Although § 394.25(e) imposes the obligation to post a bond or to demonstrate insurance sufficient to cover re-entry fees on both Community Choice Aggregators (CCAs) and ESPs, the scope of this decision only addresses the applicability of the re-entry fee and financial security requirements to ESPs. We make no prejudgment here concerning whether the provisions should be interepreted similarly or differently for CCAs or whether the bond amounts would be different.

The statute requires that ESPs cover the appropriate amount of any re-entry fees to avoid imposing costs on other customers of the electric corporation. The statute provides that the ESP or CCA post a bond or demonstrate insurance "sufficient to cover those re-entry fees as a condition of its registration." (§ 394.25(e)).

AB 117 (Stats. 2002, ch. 838) amended § 394.25 by adding subdivision (e), which addresses re-entry procedures that might be obligatory as a demonstration of fitness to serve in the event an ESP fails to meet its contractual obligations. The addition of subdivision (e) to § 394.25 requires that if a customer of an ESP is returned to utility electric service due to the fault of the ESP, any re-entry fee imposed by the IOU, if deemed necessary by the Commission to avoid imposing costs on other customers of the utility, must be paid for by the ESP or the CCA. The statute also provides that the ESP shall post a bond or demonstrate insurance sufficient to cover those re-entry fees as a condition of registration. The re-entry fee is imposed to prevent shifting of costs to other customers of the IOU.

The existing maximum bond amount of $100,000 was established prior to AB 117, and was never intended to meet the requirements of § 394.25(e). It was established as a means for ESPs to prove financial viability (per § 394(b)(9)) to the satisfaction of the Commission at that time. After AB 117 was enacted, the Commission expressed uncertainty as to whether the $100,000 amount was sufficient to cover re-entry fees required in § 394.25(e). In D.03-12-015, the Commission asked for further comments on the issue. Comments filed indicated that it was difficult to address the issue without an adopted means of calculating the re-entry fees. This matter has not previously been resolved in any Commission proceeding, and is now before us here.

The primary legal issues in dispute concern (a) whether § 394.25(e) requires the ESP customers to post a bond or insurance to cover re-entry fees;

and (b) whether the statute should be interpreted to protect only bundled utility customers, or also to protect ESP customers in the event of an ESP failure.

The statute reads:

> If a customer of an electric service provider or a community choice aggregator is involuntarily returned to service provided by an electrical corporation, any re-entry fee imposed on that customer that the commission deems is necessary to avoid imposing costs on other customers of the electrical corporation shall be the obligation of the electric service provider or a community choice aggregator, except in the case of a customer returned due to default in payment or other contractual obligations or because the customer's contract has expired. As a condition of its registration, an electric service provider or a community choice aggregator shall post a bond or demonstrate insurance sufficient to cover those re-entry fees. In the event that an electric service provider becomes insolvent and is unable to discharge its obligation to pay re-entry fees, the fees shall be allocated to the returning customers.

6.1. Necessity for ESPs to Post Financial Security Instruments

6.1.1. Parties' Positions

Parties dispute whether it is necessary for the Commission to require ESPs to post a security bond to be in compliance with the requirements of § 394.25(e). SCE, PG&E, DRA, and TURN argue that an ESP security bond or a related security instrument is required under § 394.25(e) to cover the risks that could result from the involuntary return of DA customers. These parties interpret the ESP's obligation for re-entry fees as including all incremental procurement costs irrespective of whether some of those costs may be paid by a returning DA customer through a TBS rate. As a result, the IOUs argue that each ESP must be required to post a bond or related security instrument sufficient to cover all incremental costs resulting from an involuntary return of the ESP's customers.

SDG&E and parties representing DA interests argue that § 394.25 (e) grants the Commission discretion to find that no ESP bond requirement is necessary. SDG&E and DA parties argue that any ESP bond should be limited to covering incremental administrative costs. Commercial Energy argues that the TBS rate, if set appropriately, will provide revenues sufficient to prevent cost shifting to bundled customers, and that no additional re-entry fee needs to be paid by the ESP. In particular, SDG&E and the DA parties believe that if returning DA customers absorb incremental procurement costs through payment of the TBS rates, any remaining re-entry costs would be nominal and not be large enough to warrant a significant ESP bond.

CLECA argues that the extraordinary regulatory and market conditions which led to the mass return of DA customers in 2000-2001 do not exist today and will not exist in the future. Further, the utilities' purchases of power are now hedged rather than fully dependent on the spot market as they were in 2000. Utility retail rates are no longer frozen as they were in 2000. CLECA argues that given these changed conditions, it is very unlikely that there will be another mass return of DA customers because the conditions which might lead to such are no longer present, and ESPs are not exposed financially to the sudden loss of payments.

6.1.2. Discussion

The ESP security requirements prescribed in § 394.25(e) address the risk of cost shifting in the event of an involuntary return, and by assigning responsibility to the ESP for any resulting re-entry fees. The question of whether an ESP security instrument is necessary, or how large it should be, turns largely on parties’ disagreements concerning whether the ESP would ultimately be legally responsible for all incremental procurement costs resulting from an involuntary return, or whether the returning DA customers, themselves, should bear sole responsibility at least for incremental costs covered through a TBS rate.

We conclude that mass involuntarily returned DA customers are to be protected by the ESP's financial security instrument covering re-entry fees imposed on those returned customers. Consistent with our interpretation of § 394.25(e), we conclude that re-entry fees cover the administrative costs resulting from switching an involuntary return of its customers to IOU bundled procurement, and for residential and small commercial DA customers, re-entry fees also cover procurement costs. As discussed in § 6.2, we determine that an ESP bond or equivalent financial security is required, sufficient to cover such re-entry costs. We recognize that the stressed market conditions that prevailed during the 2000-2001 energy crisis are not currently present. Nonetheless, the procurement market could become stressed in the future, and an ESP could be forced to terminate service and immediately return its customers to the IOU without prior notice.

An ESP could default or otherwise cease service resulting in the ESP's customers being involuntarily returned to the IOU. This involuntary return could occur at a time when market rates are higher than bundled electric rates. A mass involuntary return of DA customers would require additional bundled procurement beyond what was originally forecasted. If this occurs, the IOU and its bundled customers will be protected from cost shifting by requiring returning DA customers to pay the TBS tariff rate.

We are concerned that a bond that covers all incremental procurement costs could be commercially infeasible for an ESP. The DA Parties argue that if the ESP bonds were to include procurement cost exposure, as proposed by SCE and PG&E, that the exposure could result in excessive amounts, thereby undermining the viability of DA. The DA Parties point to historical prices during the commodity price run-up in 2008, which would have resulted in a bond amount in SCE's service area of $55/MWh, or about $112 million for an ESP with 2 million MWh in annual sales.

SCE observes that the price of a $112 million bond would be expected to cost about 1% of the face value of the bond – or $1.1 million – in the above example for an ESP with investment grade credit. SCE argues that an ESP with investment grade credit should have little difficulty obtaining a bond or insurance policy on the commercial market at an annual cost of about one percent (1%) of the face value of the bond/policy. An ESP with less than investment grade credit would be expected to provide sufficient collateral (most typically cash and/or letters of credit, up to one hundred percent of the value of the bond) to obtain a commercial bond or insurance policy. We conclude that requiring all incremental procurement costs to be covered under an ESP bond in the manner proposed by PG&E and SCE could potentially have a material adverse impact on the viability of DA. Because PG&E and SCE have only presented illustrative bond calculations, there is uncertainty concerning how large an ESP's resulting bond obligation could be, which could tend to make DA less cost effective. Particularly in view of the uncertainties over the potential magnitude of procurement costs under the PG&E/SCE proposed bond methodology, as discussed further below, we find insufficient justification to expand the ESP bonding requirement to include all incremental procurement costs. Instead, involuntarily returned large commercial and industrial DA customers shall bear the risk for increased procurement costs through payment of the TBS rate as discussed further in Sec. 6.2 . This arrangement preserves stability in the DA market while protecting bundled customers from cost shifting.

We address below the rationale for our findings regarding what constitutes re-entry fees and the resulting financial security requirements for purposes of covering those fees in compliance with § 394.25(e).

6.2. Definition of Reentry Fees

In order to implement the § 394.25(e) security requirement for ESPs sufficient to cover re-entry fees, we must determine what costs are to be included as re-entry fees to ensure bundled service customer indifference in the event of involuntary returns of ESP customers to IOU procurement service. The statute does not define *what costs* must be included in re-entry fees. We must accordingly determine what costs are necessary to include in the re-entry fees. We must also consider how to forecast the amount of re-entry costs to establish the bond or insurance during registration; and how to determine the re-entry fees when an involuntary return occurs.

6.2.1. Parties' Positions

Parties disagree concerning what costs constitute the ESP's obligation for "re-entry fees" as used in § 394.25. Pub. Util. Code § 394.25(e) specifies that "in the event that an electrical service provider become insolvent and is unable to discharge its obligation to pay re-entry fees, the fees shall be allocated to the returning customers." The actual term "re-entry fee" is not defined in the statute, but we apply the statute's guiding principles concerning how re-entry fees are intended to implemented.

The re-entry fees cover those costs incurred by the IOU attributable to serving the involuntarily returned DA customers. Parties generally agree that incremental administrative costs are reasonable to include as re-entry fees.

The principal controversy relating to re-entry fees concerns whether the ESP bears legal responsibility for incremental procurement costs resulting from an involuntary return of its customers to IOU service. In particular, parties disagree concerning whether payment of a TBS rate by involuntarily returned customers would count as a re-entry fee within the meaning of § 394.25(e), and whether, the ESP should ultimately be liable through a bond obligation for such procurement costs paid by the DA customer.

The TBS rate covers the IOU's costs of incremental procurement to serve returning customers. Charging the DA customers the TBS rate protects bundled customers against cost-shifting. Since the TBS rate is based on the spot market price, the returning customer may pay more procurement than do bundled IOU customers.

SDG&E and the DA parties argue that imposing a re-entry fee on the ESP is unnecessary if the Commission adopts appropriate terms and conditions for the IOU service provided for involuntarily returned customers. The DA Parties argue that DA customers involuntarily returned to bundled utility service should be allowed to be placed on TBS for a period of up to six months. The TBS rate would reflect the utility's short-term procurement costs, and include a capacity adder to reflect RA requirements. At the end of the six-month period, the customer would take service under the otherwise applicable bundled utility rate unless the customer had previously elected to return to DA service.

SDG&E proposes a six-month TBS period for voluntarily returned customers and a 12-month TBS period for involuntarily returned DA customers in order to provide the IOU with sufficient time to accommodate the returning customers.

If involuntarily returning DA customers pay the TBS rate, CLECA/CMTA argue that re-entry fees should be based on the ESP's expected load over a six-month period multiplied by expected, reasonable differences between the TBS rate and market prices, if any, plus estimated administrative fees to enroll the expected ESP load into utility bundled service.

CLECA/CMTA argue that if returning DA/CCA customers cover incremental costs through the TBS rate, it would be redundant to include such costs in posting ESP/CCA bonds as re-entry fees. CLECA/CMTA argue that such a requirement would make ESP/CCA bond requirements so large as to act as a market entry barrier and deterrent. CLECA/CMTA argue that ESPs and CCAs would consequently be less competitive compared to the IOUs and would likely pass along such bond costs to their customers.

Commercial Energy similarly argues that if the Commission provides that all customers returning to utility service without six months notice will return to the TBS rate, no re-entry fee is necessary except for nominal administrative fees already provided for in the utilities' tariffs. Commercial Energy argues that it the TBS rate is fully compensatory, actual costs incurred in a return of DA customers to utility service are de minimus (a tariffed administrative fee). Commercial Energy contends that there is no evidence that commercial or industrial DA customers or their ESPs will be unable to pay the small administrative fee, and thus, no justification for imposing what it deems to be a significant and burdensome security requirement on ESPs.

The DA Parties believe that the ESP's financial security obligations protect only bundled customers, but do not extend to the ESP's own customers. The statute requires the ESP to post a bond sufficient to avoid imposing costs on other customers of the IOU. AReM argues that the reference to other customers means bundled service customers at the time of an involuntary return, but does not extend to involuntarily returned DA customers. AReM argues that the common sense meaning of other customers must be a reference to customers of the IOU other than the involuntarily returned customer. The DA parties thus argue that involuntarily returned DA customers may absorb the costs associated with a mass involuntary return – particularly procurement related costs.

SDG&E proposes that customers who elect to transfer to DA be required to sign an affidavit acknowledging that they accept the risks associated with a potential en masse involuntary return to IOU procurement whereby they would pay a TBS rate that is potentially higher than the BPS rate. Commercial Energy would be agreeable to provide the respective IOU with a standardized disclosure duly signed by the DA customer, acknowledging the risks associated with opting for DA service. This disclosure would apply to new DA customers and would be forwarded to the utility along with the Direct Access Service Request (DASR) for the utility's safekeeping. The same disclosure would be generated for existing customers at the time of future contract renewals and thereafter promptly forwarded to the utility.

The DA parties argue that imposing a re-entry fee on ESPs is not required to the extent that the TBS rate provisions adequately guards against shifting costs to bundled customers. The DA parties argue that nothing in § 394.25(e) precludes adoption of their proposal to hold involuntarily returned ESP customers responsible for incremental procurement costs through payment of TBS tariffs for up to six months

DA Parties' Witness Fulmer agreed that if the incremental cost to serve involuntarily returned customers dragged on for nine months, the utility should recover this incremental cost from the involuntarily returned customers for the full nine months. (DA Parties/Fulmer, Tr. Vol. 2, at 433-436.) Fulmer also stated that after six months, all incremental costs should be shared by all bundled ratepayers, but admitted that this may result in cost shifting to bundled service customers. (DA Parties/Fulmer, Tr. Vol. 3, at 534:11-28, 535:1-3.)

SCE and PG&E believe that in order to avoid imposing costs on bundled service customers, § 394.25(e) re-entry fees must include *all incremental costs* (including procurement and administrative) arising out of an involuntary return to IOU procurement service. PG&E and SCE argue that including all incremental costs in the § 394.25(e) is consistent with the intent in AB 117 to prevent *any* shifting of recoverable costs between customers, and indemnifies the involuntarily returned customers.

PG&E, SCE, TURN, and DRA disagree that payment of the TBS rate would relieve ESPs of incremental procurement costs as re-entry fees. SCE believes that the re-entry fee obligations of ESPs under Pub. Util. Code § 394.25(e) apply irrespective of whether DA customers pay the TBS rather than BPS rate when they are involuntarily returned en masse to IOU procurement service. They argue that TBS should not be viewed as a substitute for the ESP's bond and re-entry fee obligations under Pub. Util. Code § 394.25(e).

SCE, PG&E, DRA and TURN interpret the "other customers" referenced in § 394.25(e) to include *both* bundled service customers *and* ESP/CCA customers that are involuntarily returned to bundled service. They argue that the ESP ultimately bears responsibility for any incremental procurement costs in excess of the BPS rate even if the returned customers pay the TBS rate.

DRA agrees that if the DA customers indeed prefer to address the risk of an ESP failure in the contract between the DA customer and the ESP, involuntary returns should already be anticipated and will not be a total surprise to the customer. Therefore, these customers will not need additional time beyond the sixty-day safe harbor period to find another ESP. If the Commission determines that additional protection for involuntarily returned customers is warranted, DRA urges the Commission to apply this principle consistently in determining the bonding requirements as recourse to contract damages can be less than ideal for some customers, particularly smaller business and residential customers.

SCE believes that nothing in § 394.25(e) *requires* mass involuntarily returned DA customers to be placed directly onto BPS. SCE argues that the Commission can implement the bond protections of § 394.25(e) and also require these customers to be placed on TBS to doubly ensure that bundled service customers do not experience cost shifting as a result of DA customers' mass involuntary returns to IOU procurement service. SCE argues that doing so would place additional administrative burdens on the IOU to credit the DA customers for the monies collected from their ESPs for the re-entry fees, but it would likely be comparable to the process of charging the DA customers who are placed directly on BPS for any residual re-entry fees not collected from the ESP, which may be necessary under SCE's proposal.

SCE claims that involuntarily returned DA customer re-entry fees should include all incremental costs to which bundled customers would be exposed in the following categories: (a) administrative,(e.g., meter reading, billing, processing; (b) procurement (e.g., energy, RA, RPS), and (c) other incremental costs (e.g., Carbon Emission Reduction).

To forecast incremental procurement costs for purposes of establishing the bond, SCE proposes to forecast assuming a 95 percent confidence interval, to include the average price of power, RA and renewables necessary to serve the DA customers for the first year after their return. SCE would compare this projected total procurement cost to projected procurement costs to serve bundled service customers for this same time period assuming a stressed market, given the composition of the bundled portfolio. If the projected procurement cost added to SCE's bundled portfolio to serve the DA customers exceeds the projected procurement cost to serve bundled service customers assuming a stressed market, the difference would be multiplied by the volume (in MWh) of returning DA load to established the forecast incremental procurement costs to be covered by the bond.

PG&E proposes that an ESP bond be required to protect against mass involuntarily returned DA customers covering the IOU's incremental and administrative costs to serve those customers for a one year period. PG&E leaves open the possibility, however, that those customers could be placed on TBS rather than directly onto BPS. Under such a scenario, funds collected from the ESP's bond would presumably be credited to the DA customers to offset the costs they incur on the TBS rate. Other parties, including SDG&E and the DA Parties, proposed that mass involuntarily returned DA customers be placed on TBS.

DRA believes that involuntarily returned customers should be responsible for all incremental costs; otherwise, the result would be cost shifting to bundled service customers. While the TBS period is designed to recover the incremental costs of involuntarily returned customers, this period, in some cases, is no more than an estimate of how long it will take to recover the incremental costs from involuntary return customers. Thus, DRA believes that the proposed six-month TBS period alone may be insufficient to cover all costs.

DRA argues that involuntarily returned customers are responsible for all re-entry fees and incremental costs, regardless of the time period over which they are incurred, to prevent cost shifting to bundled service customers.

DRA argues that even if load serving entities are better hedged and have a greater portion of long term contracts as compared with those that defaulted in 2001, a sudden, en mass return of ESP customers to bundled service remains a possibility. DRA argues that these factors should be taken into consideration in determining the ESP security requirement.

6.2.2. Discussion

We interpret § 394.25 (e) as holding the ESP financially responsible for all re-entry fees, from a mass involuntary return of its DA customers to the IOU. The financial security requirement specified in § 394.25(e) must be sufficient to cover "any re-entry fee imposed on [the involuntarily returned DA customer] that the commission deems is necessary to avoid imposing costs on other customers of the electrical corporation…"

Section 394.25(e) gives the Commission discretion to determine "any re-entry fee" deemed necessary to avoid imposing costs on "other customers" of the IOU. Once the Commission defines the relevant "re-entry fees", however, the requirement for an ESP to "post a bond or demonstrate insurance sufficient to cover those re-entry fees" is mandatory as a matter of law under § 394.25(e). We exercise our discretion to define the re-entry fee applicable to large commercial and industrial customers as covering only the administrative costs relating to switching the customer back to bundled service. We do NOT define the procurement costs to serve large commercial and industrial involuntarily returned DA customers as a reentry fee under § 394.25(e), provided that such returning customers bear full responsibility for such procurement costs through payment of a TBS rate. By paying the TBS rate, such returning DA customers avoid shifting costs to utility bundled customers, and therefore, there is no need for a reentry fee to cover large commercial and industrial procurement costs in order to satisfy Section 394.25(e). Defining the reentry fee for large commercial and industrial customers in this way prevents shifting costs to bundled customers.

A very small percentage of DA load currently serves residential and small commercial customers. Residential and small commercial customers are not similarly situated to large commercial and industrial customers. As sophisticated businesses with experience in obtaining goods and services via contracts, large commercial and industrial customers should be able to negotiate contractual provisions with their ESP to protect themselves in event of a breach, recognizing the potential to be subject to TBS rates if they return to the IOU.

Residential and small commercial customers subscribing to DA, however, may not possess the same degree of business sophistication in terms of protecting themselves in the event of a breach by their ESP. Accordingly, additional measures are appropriate to protect residential and small commercial customers from the risk of higher procurement costs resulting from an involuntary return to bundled service. To the extent that an ESP provides DA service to small commercial and residential customers, therefore, we shall require that the ESP bond requirement include a provision for the expected IOU incremental procurement costs to serve those DA customers.

Correspondingly, the small commercial and residential customer shall be limited to paying the BPS rate upon their involuntary return to bundled service. Any additional procurement costs relating to serving such involuntarily returned customers will be covered by the ESP bond. We shall otherwise provide small commercial and residential DA the same rights and restrictions with respect to switching back to DA as applies to large commercial and industrial DA, including the safe harbor provisions, six-month notice, and 18-month minimum stay requirements.

Consistent with our determination to require the ESP bond to incorporate the risk for incremental procurement costs for involuntarily returned small commercial and residential customers, we exercise our discretion to define reentry fees as including such procurement costs only in reference to such customers. We thus interpret § 394.25(e) as providing broad discretion for the Commission to interpret the scope of reentry fees as covering a different range of costs for small commercial and residential in contrast to large commercial and industrial DA customers, recognizing the different characteristics of each customer group.

Because the ESP bond calculation proposed by SCE and PG&E anticipated covering energy procurement risks for all involuntarily returned DA customers, the degree of complexity in the bond formulas and assumptions underlying those calculations may not be necessary for a bond that covers a much more modest procurement risk limited only to small commercial and residential DA. In view of the more limited risk exposure involved in covering procurement for this limited customer group, more simplified assumptions may be appropriate with respect to the methodology for estimating the incremental amount of the ESP bond necessary to cover such risks. Accordingly, we defer to a subsequent decision the determination of how incremental ESP bond amounts limited to procurement costs for involuntarily returned small commercial and residential DA customers should be determined. For purposes of defining small commercial DA customers applicable to the ESP bond requirements, we shall treat small customers affiliated with a large commercial or industrial DA customer as being subject to the same ESP bond requirements as the large customer. We shall likewise defer to a subsequent decision the precise determination and criteria as to how to distinguish small versus large commercial DA customers for purposes of the ESP bond calculation. For purposes of our subsequent discussion in this decision, unless otherwise specified, all references to the ESP bond presume that this additional protection for the involuntarily returned small commercial and residential DA customers will be provided as determined in a subsequent decision.

The payment of the TBS rate, together with the safe harbor provisions in existing tariff rules, will allow an involuntarily returned customer to find a new ESP and to resume DA service after completion of a six-month notice period. A period of six months to find a new ESP also allows time for the utility to adjust its portfolio so that bundled customers do not bear costs due to involuntarily returned DA customers. Thus the ESP's obligation for re-entry fees under § 394.25(e) only includes administrative costs associated with implementing the involuntary return of ESP customers to IOU bundled service, to ensure that no cost shifting results from the involuntary return of DA customers.

The determination of re-entry fees serves as the basis for determining the dollar amount of bonds to be covered by an ESP bond.

The administrative costs of an involuntary return include any incremental meter reading, billing, and tracking and monitoring costs. Parties offered no specific dollar estimate of the administrative costs necessary to process involuntarily returned DA customers, and no Commission approved cost figure has previously been adopted. To determine the incremental administrative costs to use for purposes of an ESP security bond, we shall thus adopt use of the re-entry fee approved for a CCA customer, as proposed by SCE. We conclude that the existing Commission-approved CCA re-entry fee offers the best available proxy for forecasting the incremental administrative costs in relation to an involuntary return of an ESP's customers to IOU procurement service.

We therefore authorize that administrative fees to cover involuntarily returned DA customers be set using the IOU's authorized service fee rate for voluntarily returning CCA accounts. The per-customer fee would be multiplied by the relevant number of ESP customers. The currently applicable administrative fees per customer account would be for PG&E, $3.94; for SCE, $1.49; and for SDG&E, $1.12.

We conclude that the re-entry fee obligation of the ESP does not include incremental procurement costs for large commercial and industrial DA customers in excess of the costs covered in the BPS rate paid by bundled customers. We shall instead direct that such involuntarily returned DA customer be placed on the TBS rate schedule for reasons discussed above. The TBS rate is for transitional service that imposes spot prices on migrating customers to avoid shifting any incremental procurement costs to bundled customers.

As mandated by § 394.25(e) , ESPs are responsible for re-entry fees necessary to avoid imposing costs on the other customers of the electric corporation when a customer is "involuntarily returned to service provided by an electrical corporation." The term "electric/electrical corporation" used here refers to utility service.

If a DA customer of an ESP is involuntarily returned to IOU procurement service and pays its own re-entry fee, that re-entry fee remains the obligation of the ESP, which must be covered through a bond or insurance. The statute requires ESPs to indemnify their customers from the re-entry fees imposed on them as a result of an involuntary return to IOU procurement service. Under § 394.25(e), if an ESP becomes insolvent and cannot discharge its bonding obligation and cover the re-entry fees, the returning customers will then be responsible for re-entry fees as necessary to avoid imposing costs on "other customers" of the electric utility.

In any event, if the ESP bond amount in combination with the TBS rate assigned to the large commercial and industrial customer, provides insufficient revenues to cover the incremental costs incurred by the IOU in connection with providing involuntarily returned customers with bundled service, the DA customer shall bear the cost responsibility for such incremental costs. The bundled customer must be protected from any potential cost shifting.

We reach this conclusion regarding the ESP financial responsibility as a matter of law. While the DA customer bears responsibility for the financial consequences of entering into a DA contract with an ESP with respect to differences in prices charged by the ESP versus the IOU, the risks relating to re-entry fees for an involuntary return must be borne by the ESP.

We adopt the SCE proposal to calculate the re-entry fees within 60 days of the start of the involuntary return. To provide certainty to the ESP, re-entry fees should be calculated as a binding estimate of the incremental administrative costs (equal to the adopted re-entry fee approved for CCA customers) and procurement costs (applicable only to small commercial and residential DA customers) that the IOU expects to incur under then-current market conditions to serve those involuntarily returned DA customers for a safe harbor period starting on the actual date of the involuntary return and then for an additional six-month period for those customers remaining on bundled service. For such small commercial and residential DA customers, the IOU will be reimbursed for incremental procurement costs based on the difference between the TBS rate and the BPS rate multiplied by the actual kWh usage of the returned DA customer for the six-month period. As such, the re-entry fees, once demanded from the ESP, shall not be subject to true up.

6.3. Financial Instruments that Satisfy Section 394.25(e) Requirements

6.3.1. Parties' Positions

The DA parties recommend that ESPs be allowed maximum flexibility to meet any financial security requirements pursuant to § 394.25(e) through any of the following means: having an investment grade credit rating, a parent company guarantee, a surety bond, a letter of credit, or cash deposits.

SCE believes that the ESP may elect to use letters of credit or cash deposits to provide flexibility to an ESP as a supplemental tool to meet its bond obligation. Letters of credit are typically issued by banks. Like commercial bonds/insurance policies, letters of credit provide the advantage of being commercially available from banks that specialize in issuing credit guarantees.

Commercial bonds or insurance instruments have the advantage of being commercially available from surety companies that specialize in assessing risk and guaranteeing credit. As for risks, issuers of commercial bonds or insurance policies may pose counter-party risk to the IOU (i.e., risk that the issuer will not be able to pay upon the IOU's demand under the terms of the bond or insurance policy). SCE would seek to mitigate any counter-party risk through collateral arrangements with the issuer. Such risk typically arises with issuers having less than high quality credit (less than AA investment grade credit).

Another risk of commercial bonds/insurance policies is that the issuer may elect not to renew the credit guarantee upon the expiration of the bond or insurance policy. The ESP would then need to obtain another bond or insurance coverage or make other acceptable credit guarantee arrangements prior to the expiration of the bond or insurance policy. If unable to do so, the ESP would be subject to service termination (either at the ESP's election or on the Commission's order.

As with surety companies, some banks may pose counter-party risk to the IOU which may be mitigated through collateral arrangements with the bank. Additionally, the bank may elect not to renew the letter of credit upon its expiration, in which case the ESP would have to secure another letter of credit or make other acceptable credit guarantee arrangements prior to the expiration of the letter of credit. If the ESP is unable to do so, it should result in an ESP service termination (either at the ESP's election or on the Commission's order).

A guarantee agreement would involve a creditworthy third party agreeing to guarantee the ESP's financial obligations to the IOU and its customers as a result of an involuntary return if the ESP is unable to satisfy such obligations. A guarantee agreement may provide an advantage to the ESP of allowing it to obtain a credit guarantee under more favorable terms than would otherwise be available on the commercial market.

SCE opposes allowing an ESP to use self-insurance to satisfy the security requirements of § 394.25(e). Self insurance typically involves payment of an insurance premium to a captive insurance company or making an on-balance sheet provision for the amount of money to be set aside to pay for possible losses. SCE believes that self insurance involves substantial risk to the IOU, because there is no way to ensure that the ESP is actually making self insurance premium payments or setting aside the money to cover the self-insured losses. Additionally, even if the ESP were to set aside self insurance funds, SCE does not believe it would have a security interest in those funds as a secured creditor of the ESP. As such the IOU would not be able to access the self insurance funds in the event the ESP were to file for bankruptcy protection. In such circumstances, as an unsecured creditor, the IOU would have no way to recover its losses fully in an involuntary return if the ESP were to file for bankruptcy protection.

6.3.2. Discussion

We conclude that an ESP may satisfy the requirements of § 394.25(e) by posting a bond or demonstrating insurance sufficient to pay cover re-entry fees of the ESP, through comparable financial instruments that provide equivalent coverage. Acceptable instruments include surety bonds, letters of credit, cash deposits or third party guarantees with a credit worthy entity.

An ESP will not be permitted to meet the security obligation simply through use of self-insurance or by showing that it has an investment grade credit rating. As noted by SCE, there is no way to ensure that the ESP is actually making premium payments or setting aside the money sufficient to cover estimated self-insured losses. The IOU would have no assurance recovering its losses from the ESP through self-insurance of some or all of its re-entry fee obligations, if the ESP failed to set aside the necessary funds, and then become unable to discharge its obligations under § 394.25(e).

Third party guarantors may pose counter-party risk to the IOU, which may be mitigated through collateral arrangements with the third party. Third party guarantors should at least have investment grade credit. The essential requirement is that whatever instruments are used, the requisite re-entry fee obligations are covered. We address in the following section the applicable methodologies that should apply for calculating re-entry fees to be covered by an ESP's bond or related forms of insurance.

Risks associated with a cash security deposit would mainly arise if an ESP were to file for bankruptcy protection upon an involuntary return of its customers. In such a circumstance, the IOU may be obligated to seek relief in the bankruptcy court before applying the security deposit to involuntary return costs, including seeking relief from the bankruptcy court's stay or filing a secured claim, up to the amount of the security deposit, in the bankruptcy proceeding for the damages resulting from the involuntary return and awaiting the court's resolution of such claim.

Where surety companies typically accept only cash or letters of credit as collateral, banks may be willing to accept other forms of collateral, such as priority liens on assets (e.g., investment portfolio or treasury bills). An agreement with a creditworthy third party who will guarantee the ESP's financial obligation in the event the ESP cannot do so (a guarantee agreement) would also meet § 394.25(e) requirements.

6.4. ESP Financial Security Bond Methodology

6.4.1. Parties' Positions

PG&E and SCE were the only parties to propose a methodology to calculate an ESP security bond. SCE and PG&E propose a methodology for calculating ESP bonds based closely a proposed settlement in the CCA docket (Rulemaking 03-10-003) (proposed CCA settlement).[12] PG&E attaches the CCA

---

[12] The Commission has not yet addressed the merits of the proposed CCA settlement in R.03-10-003.

settlement to its testimony and advocates that the CCA methodology be used to calculate ESP bond requirements. We discuss the merits of their proposal below.

Their proposal is based on the CCA Bonding Settlement proposal previously presented in R.03-10-003. The details of their proposed bond model and re-entry fee calculations are provided in SCE's opening testimony, Attachment 1 of PG&E's opening testimony, which was previously submitted to the Commission as a Settlement Agreement, Attachment A in R.03-10-003, on September 8, 2010.

PG&E and SCE argue that the CCA bond model settlement methodology provides an appropriate, commercially feasible framework for quantifying re-entry fee exposure risk applicable to ESPs. PG&E believes that the proposed model provides a formula to derive a prudent level of security to protect the IOUs' bundled customer from involuntary DA or CCA customer returns.

The PG&E/SCE bond proposal incorporates a methodology for calculating both actual re-entry fees and the bond amount necessary to cover estimated re-entry fees. The methodology calculates re-entry fees for an *en masse* involuntary return of DA customers by estimating (a) the utility's incremental procurement costs to serve the returned load for a 12-month period plus, and (b) the utility's administrative costs for processing the returned customers. In turn, the estimated incremental procurement costs are based on the difference between: (a) the market price for a one-year forward strip of power to serve the returned load, with certain adjustments, and (b) the average bundled price for electricity paid by the returning customers under the utility's applicable rates. If the market price were lower than the bundled customer price, there would be no incremental procurement costs associated with the involuntary return.

SCE presents its proposal for calculating the incremental costs of an ESP bond in Section V of its opening testimony.[13] DA Parties oppose applying the proposed CCA settlement methodology as a basis to calculate ESP bonds, particularly with respect to procurement costs. CCSF disputes PG&E's claim that the prudency of the settlement's methodology is not under question. Prior to the service of PG&E's testimony in this proceeding, CCSF and MEA had filed comments in the CCA docket challenging the proposed settlement's methodology for calculating bond amounts and re-entry fees. CCSF states that for many of the same reasons that it opposed the settlement in the CCA docket, the proposed CCA settlement should likewise not be used to establish financial security requirements for ESPs.

Commercial Energy likewise objects to the SCE/PG&E proposal, claiming that the bond calculation proposed is very complex, but not fully developed. SCE and PG&E concede that certain figures in the bond calculations are illustrative only. Commercial Energy questions whether the sample bond calculations have any relationship to realistic market situations. Commercial Energy argues that the burden of proof is on SCE and PG&E to demonstrate with real dollars the practical determination of the costs they suggest be borne by ESPs in this market.

CCSF likewise argues that the CCA bond settlement produces unreasonably high bond requirements that go far beyond covering the risk against which the bonds are designed to insure. CCSF claims these excessive bond amounts are derived from a black-box model using unreliable inputs.

---

[13] See SCE Opening Testimony (Exh. 300), Section V.C.2, entitled "Method for Forecasting the Incremental Cost for the Bond.

CCSF expresses concern that other elements of the model are similarly suspect. CCSF argues that an unreasonable bond requirement could drive even a financially healthy ESP out of business, and it is critically important that the bond be calculated using reliable data.

CCSF claims that unreasonable bond amounts would increase the likelihood that an ESP that is fully meeting its other financial commitments would fail to meet the bond requirement and thereby be subject to termination. In this way, the proposed CCA settlement would have the counter-productive effect of making involuntary returns more likely. The bond is supposed to protect the utility and bundled customers from bona fide risks, not be so excessive as to increase those risks.

The DA parties object to the bond calculation designed to cover procurement cost risk is based on forecasted market prices -- with certain adjustments -- multiplied by a stress factor. The stress factor reflects the likelihood that an involuntary return would occur when markets are stressed and wholesale prices are high. The settlement then subtracts from this stressed market price a forecast stressed generation rate received by the utility, consisting of average bundled rates plus a $10/MWh stress adder. A key determinant of the bond amount is the stress factor mark-up of forecast market prices, which can be significant. In the sample calculation attached to the proposed bond settlement, the stress factor increases the market price by 57%. (Tr. 621: 17-21, Hessami/PG&E).

A key input used to determine the stress factor multiplier is an estimate of "implied volatility." The CCA settlement relied on implied volatility data to calculate the stress factor multiplier, but the settlement itself does not specify the data and data sources that would be used to calculate implied volatility. CCSF claims that PG&E and SCE fail to propose a viable source for volatility data that can be reliably used to calculate the stress factor multiplier for ESPs.

PG&E states that implied volatility would be based on "independent broker quotes" from independent brokers North of Path (NP) 15 and South of Path (SP) 15 forward and options prices and implied volatilities. For any ESPs that return load to PG&E, the applicable market prices and implied volatilities would be for NP 15. The DA Parties testified that implied volatility data is not readily available for NP 15 for PG&E's service area. PG&E's Hessami admitted that there is no product available from any broker that estimates the volatility of NP 15 prices. The table of data sources in that testimony listed only one provider of volatility data, Amerex. PG&E's Hessami acknowledged that Amerex does not provide NP 15 volatility data.

CCSF argues that the relatively new idea in the CCA settlement of using historical data is inherently suspect given the questionable premise that past price volatility is a good predictor of future volatility. Given the stakes involved and the concern by CCAs and ESPs that security requirements can be used for anti-competitive purposes, CCSF argues that utility persistence in making volatilities and a stress factor multiplier a centerpiece of their proposal is sure to be vigorously contested.

The DA Parties testified that certain brokers declined to provide implied volatility data quotes to consultants. The DA Parties thus concluded that this data is not publicly available. SCE disputes this conclusion, observing that the data may not be directly available to a consultant if that consultant is viewed as a competitor by a broker. However, just as the IOUs do with their own consultants, an ESP can access a broker's data under a subscription and share the data with a consultant pursuant to appropriate confidentiality and non-disclosure obligations. Even if a broker may decline to provide its data directly to a competitor who is consulting for an ESP, the ESP, itself, may be able to access such data from the broker.

In order to forecast the bond amount necessary to cover procurement costs, SCE proposes to forecast using a 95% confidence interval the average price of power, RA and renewables that will have to be added to the IOU portfolio to serve the returning DA customers for the first year after their return. The DA parties object to the assumption of a 95% confidence interval, arguing that it produces an unreasonably high assessment of risk.

CCSF claims that the bond amounts produced by the proposed CCA settlement would significantly exceed the utility exposure from involuntary returns of DA customers and would have the perverse effect of increasing the risk that otherwise healthy ESPs would default and involuntarily return their customers to bundled utility service.

Commercial Energy argues that the bond proposal would unfairly impose a new, costly methodology on existing contractual relationships, where the costs for compliance cannot be passed through the same way a cost of service regulated utility can. Approximately 12% of the California energy market is exposed to these excessive new security costs, while only the remaining 1% of customers representing the DA load in the final open season will have the time to address this issue prior to contracting in the 2013 queue.

Commercial Energy argues that the IOUs' proposed bond calculation seems premised on the idea that because ESPs are not regulated and are required to have certain business practices that they therefore do not utilize sound business practices. While ESPs are not regulated to the same extent as utilities, Commercial Energy claims that there are legal, regulatory, credit, business and practical factors effectively controlling how ESPs conduct their business. Part of that business is planning future exposure to risk and mitigating such risks accordingly. Today, many more tools exist to manage risk exposure and no prudent executive in the industry lacks the tools to survive. PG&E Witness Hessami pointed out that although there were no bank failures from 2000 to 2007, but that does not mean there would never be any such failures.

Commercial Energy further argues that the IOUs' proposed bond calculation is based on the premise that anomalously high price spikes will last for a year. In addition, the concerns of SCE and PG&E about procurement costs appear to assume that the majority of ESP-served load fails simultaneously.

Commercial Energy asserts there is no evidence that the failure of one ESP in any given service territory would necessitate adjustments to a utility's resource portfolio that would exceed the amount of flexibility in a utility's portfolio already required to respond to annual changes in weather, economic and other conditions. In fact, there is only one example of a mass return of DA customers since the energy crisis, and that return took place in an orderly manner based on a decision of one ESP to exit the California market in 2008-2009.

6.4.2. Discussion

We conclude that although an ESP bond or evidence of other forms of insurance *is* required to comply with § 394.25(e), the proposed bond model offered by PG&E/SCE does not offer a suitable framework for determining the applicable ESP bond amount.

The SCE/PG&E proposed bond model was originally developed through a settlement in R.03-10-003 for the limited purpose of determining CCA financial responsibility pursuant to § 394.25(e). The Commission has not yet adopted any decision in that proceeding regarding the proposed settlement. Although the

PG&E/SCE bond proposal here is based on a settlement in a proceeding dealing with CCAs, our settlement rules do not apply for purposes of evaluating the proposal in this proceeding. Instead, since the proposal was not developed through a settlement in this proceeding, we evaluate the bond proposal on its substantive merits.

We conclude that the PG&E/SCE proposed timeframe of one year for calculating incremental costs is excessive. Also, a one-year timeframe is consistent with the presumption in CCA tariffs that one year is likely to be sufficient to reintegrate mass returns of CCA customers to bundled service.

The DA Parties claim that the proposed bond methodology is flawed in applying a 95% confidence interval for forecasting procurement costs. They argue that even if the market events that result in wholesale costs are above the 95th percentile, simply because wholesale prices are exceptionally high does not in itself indicate the likelihood that an ESP would default. They argue that the probability of the ESP actually defaulting is not accounted for in the proposed bond calculation.

As noted by SCE, however, the probability of an ESP actually defaulting is accounted for in the bond calculation's assumption that stressed market prices correlate with increased risk of default. The bond model cannot reasonably account for each ESP's unique circumstances. The underwriter of an ESP's financial security instrument, however, can assess each ESP's individual circumstance in pricing the bond.

We are not persuaded that the bond methodology is reasonable in calculating forecast incremental procurement costs based on a 95% confidence interval. The 95% confidence interval was adopted in D.07-12-052 as the risk level used to manage rate level risk for bundled customers.

We conclude the proposed steps to calculating incremental procurement costs for determining the ESP bond amount set forth in SCE's testimony[14] conflict with our determination to exclude procurement costs from the ESP bond requirement for large commercial and industrial customers. Accordingly, we do not approve the use of these formulas for calculating bond amounts for procurement costs.

We recognize, however, that questions have been raised concerning the approach used in the PG&E/SCE proposal to measure implied procurement cost volatility, particularly for NP 15. The proposed formula would use implied volatility data from a third-party broker. PG&E provides information in its testimony on sources available to parties to access market prices and volatilities, although access to the information requires a fee-based subscription. Such data is available for SP 15, but is not available for NP 15.

In light of the unavailability of this NP 15 data, PG&E offered two alternatives for the NP 15 implied volatility calculations. PG&E's first choice would be to use SP 15 data as a proxy for NP 15 prices. However, PG&E's witness did not know whether NP 15 prices are generally more or less volatile than SP 15 prices. PG&E has not performed a study of volatilities comparing NP15 and SP 15. Thus, we have no basis for concluding that SP 15 volatilities would serve as a reasonable proxy for NP 15 volatilities or whether SP 15 volatilities could be adjusted to become a reliable proxy.

PG&E's second suggested alternative was to use historical volatility data. However, PG&E witness Hessami testified although that the period to use for

---

[14] See SCE Opening Testimony (Exh. 300) Sec. V. C. 2. b)

calculating historical volatility would be important, PG&E had no proposal for an appropriate time period. In view of the unresolved factual issues regarding an accurate measurement of implied volatility and its effect on the potential size of any ESP bond in a stressed market, we find that the PG&E/SCE proposal is not sufficiently developed to determine the magnitude of re-entry fees and the resulting size of an ESP bond. Moreover, because PG&E and SCE have only presented illustrative bond calculations, and omitted key inputs relating to implied volatility, there is uncertainty concerning how large an ESP's resulting bond obligation which could tend to make DA service less cost effective. In view of these uncertainties, we find insufficient basis to determine the specific magnitude or financial impacts of the PG&E/SCE proposal.

6.5. Tariff Service for Involuntarily Returned DA Customers

As noted above, parties dispute whether involuntarily returned DA customers should be automatically placed on the BPS or TBS rate. The Commission realized based on experience with the 2000-2001 market collapse, that there should also be provisions for customers who are involuntarily returned to the IOU by their ESP but who wish to find another ESP without having to wait multiple years for the opportunity to arrive. Thus, a Safe Harbor provision was adopted, providing the IOU with 60 days notice of a customer's intent to take DA service or to return to bundled service.

The Commission in D.03-05-034 found that by charging DA customers for the incremental costs of short-term power during the six-month advance notice period or the safe harbor period, no costs would be shifted to bundled service customers. With the addition of RA and RPS requirements to the IOUs' procurement obligations, as well as recognition of CAISO's load-related costs, recovery of incremental power cost requires recognition of such requirements to avoid cost shifting from DA customers on TBS to bundled service customers. We have adopted appropriate measure to recognize such requirements, as adopted in Section 3 above.

6.5.1. Parties' Positions

SCE testified that providing a temporary safe harbor in the context of mass involuntary returns is not feasible because the IOU needs certainty as to the load it will be obligated to serve so that it can continue to reasonably procure for its bundled service customers, begin to hedge for the returned customers, and to calculate the re-entry fees due from the ESP and/or the returning customers (for residual re-entry fees) as a result of the involuntary return.

SCE recommends that ESPs provide their customers with as much advance notice of an involuntary return as possible to allow customers to switch ESPs prior to being involuntarily returned to the IOU's procurement service. Otherwise, SCE proposes that DA customers included in an ESP's mass involuntarily return to IOU procurement service be placed on bundled service, which would not provide for a safe harbor; however, they should be permitted to provide the IOU with a six-month advance notice to depart to DA.

SCE's Default Bundled Service is defined in Rule 22 as "service [that] preserves traditional SCE electric services, where SCE performs all energy services for the end-use customer." SCE believes the rule contemplates placing mass involuntarily returned DA customers on BPS, not TBS. SCE believes that TBS is designed for customers that elect to return to the IOU's procurement service for a safe harbor or while serving out their six-month advance notice period (i.e., voluntarily returning customers).

SCE assumes that DA customers will be protected by ESP bonds sufficient to cover incremental administrative and procurements costs. SCE thus believes that the ESP is liable for all incremental costs associated with an involuntary return of DA customers to IOU procurement service, including procurement costs. SCE thus believes that involuntarily returned DA customers should be placed on BPS upon their involuntary return to IOU procurement service, and not be subject to TBS. SCE holds this view even if the IOU receives no advance notice from the ESP of the involuntary return.

SCE argues that placing involuntarily returned DA customers on TBS in such circumstances would be tantamount to penalizing them for the ESP's failure, because involuntary returns are most likely to occur during stressed markets, when spot market prices are high. DA customers placed on TBS would have substantial exposure to high spot market prices during a stressed market.

If, however, ESPs are not required to post security bonds to cover incremental procurement costs in an involuntary return of DA customers to IOU procurement service, SCE believes that only then should DA customers be subject to TBS upon their mass involuntary return to IOU procurement service, subject to a duration of a minimum of one year unless their ESP provided the IOU with a one-year advance written notice of the mass involuntary return.

PG&E proposes that involuntarily returning DA customers have the following option with regard to the safe harbor: (a) upon their return to the utility's bundled service, involuntarily returned DA customers will be given a 30 calendar day window to decide, via a formal written request to PG&E, if they wish to remain on DA by making use of the safe harbor provision; (b) those customers would then be placed on the TBS rate retroactively to the first day that they were returned to utility bundled service (Day 1); (c) they would then have to find a new ESP and submit their new DASR by Day 60; and (d) if the activities in (c) are not completed in time (i.e., by Day 60), those customers would remain on TBS for six months (from Day 1), be returned to the utility's bundled service, and be required to stay on bundled service and pay bundled rates for 18 months under the minimum stay provision.

In short, involuntarily returning DA customers electing to exercise the safe harbor provision within 30 days of returning to utility bundled service would be treated similarly to a voluntarily returning DA customer that elected the safe harbor provision. Both involuntarily and voluntarily returning DA customers have 60 days after returning to bundled service to find a new ESP and to submit a DASR. Both groups of customers are on the TBS rate the entire time they are in the "safe harbor." The only difference is that voluntarily returning DA customers have to give notice to the utility that they are exercising the safe harbor option when they return. Since involuntarily returning DA customers did not elect to return to bundled service, and may need some time to evaluate their options, these customers can elect the safe harbor any time within the first 30 days of their return.

Absent the TBS requirement under the DA switching rules and assuming involuntarily returning customers immediately begin receiving service under the utility's bundled portfolio service rate, there are essentially two types of costs incurred by the utility that might expose bundled customers to cost-shifting when a customer returns to bundled service without advance notice: a) the incremental costs associated with procuring additional resources to serve the returning load that increase average cost; and b) the costs associated with the administrative process to switch the customer from DA to utility procurement service. The Commission must therefore decide if the DA re-entry fee includes one or both sets of costs.

SDG&E proposes that customers involved in an *en masse* involuntarily return to bundled service should receive utility procurement service under the modified TBS rate for 12 months. Additionally, to ensure that customers realize and appreciate the risks associated with a potential *en masse* involuntary return to utility procurement service under the TBS rate, and to further provide comfort to SDG&E that it has provided its customers with information they need to make fully-informed decisions, SDG&E proposes that customers who elect to transfer to DA Service be required to sign and return an acknowledgement form to the utility at least five days prior to the ESP submitting a DA Service Request on behalf of the customer. By signing the form, customers transferring to DA acknowledge and agree to pay the TBS rate, even if it is higher than the utility's bundled service rate.

PG&E and SCE argue that the DA parties define "involuntary returns" in an overly narrow fashion. PG&E and SCE believe that involuntary returns should identify any returns to utility bundled service that are not initiated by the customer but instead are the result of a service termination by an ESP or CCA provider. The return to bundled service would not be considered "involuntary" if the customer defaulted on its payment obligation or if the service contract expired.

The DA Parties question how an IOU would determine whether a mass involuntary return has occurred. SCE acknowledges that in some instances, the circumstances of a return could be questionable, but believes the issue should turn on whether the ESP has ceased operations in California or has been forced to do so for cause. Thus, where an ESP serves two customers, and decides to cease operations or must do so for cause, and returns both customers back to the IOU's procurement service, both customers would be entitled to have their re-entry fees paid by the ESP. Likewise, if the ESP returns half its customers to the IOU's procurement service, and waits for some time before involuntarily returning the other half, SCE believes this would be a phased approach to involuntarily returning all of the ESP's customers to the IOU's procurement service, which should be considered a mass involuntary return.

6.5.2. Discussion

The DA switching rules currently draw no distinction between DA customers that voluntarily return to the IOU's procurement service and those that are involuntarily returned as a result of service termination by their ESP. The statutory requirements for a bond (or financial security) for involuntarily returned customers under § 394.25(e) drives the need to distinguish between voluntarily and involuntarily returned DA customers for purposes of the switching rules.

Section 394.25(e) does not expressly define an involuntary return. It only partially defines the term by carving out from its protections certain cases of involuntary returns.

We define an involuntary return of a DA customer to service from an IOU as when the IOU has initiated the DASR process to return a customer to IOU bundled service due to any of the following events:

a. The Commission has revoked the ESP registration.
b. The ESP-IOU Agreement has been terminated.
c. The ESP or its authorized CAISO Scheduling Coordinator (SC) has defaulted on its CAISO SC obligations, such that the ESP is no longer has an appropriately authorized CAISO SC.

An involuntary return of a DA customer to IOU bundled service has not occurred as a result of the following events:

a. A customer's contract with an ESP has expired.

b. An ESP discontinues service to a customer due to that customer's default under their service agreement with the ESP.

We conclude that involuntarily returned DA customers should be placed (a) on the TBS rate if they are large commercial and industrial DA and (b) on the BPS rate if they are small commercial and residential DA. If an involuntarily returned DA customer seeks to resume DA service with a new ESP, they may do so upon executing a DASR within the 60-day safe harbor period. Placing involuntarily returned large commercial and industrial DA customers on the TBS rate will hold them responsible for potential cost increases caused by the failure of their ESP, and would avoid shifting costs to bundled customers.

Under existing rules, DA customers that return to IOU service without six-months advance notice is placed on the TBS rate for six months. The TBS rate was designed for DA customers that elect to return to the IOU's procurement service for a safe harbor or while serving out their six-month advance notice period (i.e., voluntarily returning customers). We now conclude that the TBS rate is also suitable for involuntarily returned large commercial and industrial DA customers during their transition either to a new ESP or back to bundled service.

Involuntary DA customer returns are most likely to occur during stressed markets when spot market prices high. DA customers placed on TBS will thus bear the exposure risk to high spot market prices during a stressed market.

Although PG&E proposes that involuntarily returned DA customers be allowed to elect safe harbor status, PG&E does not address how or when an involuntarily returned customer would elect the safe harbor option and go on TBS. If the mass involuntary return occurs with little or no notice, presumably the customer cannot make this election prior to returning to IOU procurement service. In such case, the customer would have to elect a safe harbor while on BPS or TBS (depending on which rate the involuntarily returned customers is required to take).

Since IOUs require six months advance notice to place customers on BPS, safe harbor customers that fail to timely switch to DA will need to serve another six months advance notice period on TBS after the safe harbor period ends.

PG&E does not reconcile its proposed safe harbor option with the calculation of the ESP's re-entry fees under its bond proposal. It is unclear how the uncertainty surrounding the safe harbor customers factors into PG&E's demand for re-entry fees from the ESP.

We shall permit involuntarily returned customers to utilize the provisions of the 60-day safe harbor as follows. We shall direct the IOUs to reserve the involuntarily returned customers' space under the SB 695 cap for the duration of the 60-day safe harbor period. If the involuntarily returned customer finds a new ESP and submits a DASR within this 60-day period, the customer may utilize the reserved space under the cap to resume DA service upon execution of the DASR. If the returned customer fails to find a new ESP and to execute a DASR during the 60-day safe harbor period, the following rules apply: (a) In the case of large commercial and industrial DA, the customer would continue to pay the TBS rate for the six months following the end of the 60-day safe harbor period. (b) In the case of the small commercial and residential DA, the customer would continue to pay the BPS rate , and for the next six months, the ESP bond would cover reimbursement of the customer's incremental procurement costs.

After that, all remaining involuntarily returned DA customers would pay the BPS rate and must remain on BPS service for the adopted minimum stay period of 18-months.

6.6. Timing of Bond Calculations and Posting

We shall require that the amount of an ESP's bond or demonstration of insurance be calculated once annually, by April 10 of each year. Bonds shall be posted by June 30, subject to approval by the Energy Division. The posting requirement applies to new and existing ESPs. For an ESP that begins service in Month M+2 (where M denotes the month when the IOU will calculate the bond amount, the bond calculation shall be performed using Month M-1 data, and the bond shall be for the period from the start date through the next annual calculation.

The initial bond calculation should be submitted to the Commission by each of the IOUs in a separate advice letter filings for each applicable ESP, designated as a Tier 2 advice letter. All subsequent years calculations shall be submitted as Tier 1 advice letters for each ESP to the Energy Division that should be deemed accepted unless the Energy Division suspends the advice letter during the review period (30 days). An unredacted version of each advice letter will be filed under confidential seal.

The ESP should be required to post the bond amounts in the advice letter within 30 days of notification by the Energy Division, subject to correction for any detected errors. If an ESP believes that its financial security amount has been calculated inaccurately or in conflict with the adopted processes, the ESP may file comments with the Energy Division, and served on the relevant IOU, indicating any appropriate corrections with relevant supporting explanation and detail within 20 days of the advice letter filing.

Upon Commission approval of the relevant ESP financial security amounts, the Energy Division shall notify each ESP of the final amount due on an aggregate statewide basis. In any event, for newly-registered ESPs, the ESP's bond should be required to be posted before ESP service is permitted to begin.

After the initial bond has been posted, the ESP's gross and posted bond amounts should be calculated annually, and adjusted if/when it is more than 10% above or below the then-current ESP posted bond amount. Posted bond may be in the form of a third-party guarantee from an investment grade guarantor, parental guarantee of a surety bond, letter of credit, cash or cash equivalent financial instrument or security, or such other instrument reasonably acceptable to the IOU and should be payable to the IOU directly in the event an ESP fails to timely pay the re-entry fees demanded by the IOU as discussed in the section below.

6.7. Collecting Re-entry Fees on an Involuntary Return

We adopt the SCE proposal to calculate the re-entry fees within 60 days of the earlier of (i) the start of the involuntary return, or (ii) the IOU's receipt of the ESP's written notice of involuntary return, using the method described below. The re-entry fees shall be calculated as a binding estimate of the incremental administrative costs the IOU expects to incur (based on the comparable fees for CCA customers) and the incremental procurement costs under then-current market conditions to serve the involuntarily returned small commercial and residential DA customers for the safe harbor period and the next six months. However, the re-entry fees shall be demanded from the ESP only after the involuntary return is initiated.

The IOU's demand for the re-entry fees shall be made no later than 60 calendar days after the start of the involuntary return of DA customers to IOU procurement service, and that re-entry fees be due and payable to the IOU within 15 calendar days after the issuance of the demand. This timeline will ensure that the bond will be available to the IOU to cover the re-entry fees, should the ESP fail to pay the fees upon the IOU's demand. This is because commercial financial instruments (like letters of credit or surety bonds) available to meet the bond obligation often contain a 90 day notice of termination provision in the event of a default. An ESP's involuntary return of DA customers to IOU procurement service is likely to be considered an event of default, which would trigger the creditor's right to terminate the credit line within 90 days. Accordingly, the demand process should take no longer than 75 days to permit at least 15 days for the IOU to call on the letter of credit, bond, etc. to cover the re-entry fees.

7. Implementation of Changes in Indifference Methodologies

We shall implement the changes in methodologies adopted in this decision in accordance with the procedure set forth in the Administrative Law Judge (ALJ) April 14, 2011 Ruling, as amended by the subsequent ruling dated April 22, 2011. In accordance with Pub. Util. Code § 310, the directives of the April 14, and April 22, 2011 Rulings are hereby affirmed by the Commission.

Pursuant to these ALJ rulings, the IOUs' previously adopted 2011 PCIA rates were made subject to true-up once the IOUs calculate and implement revised 2011 PCIA rates determined in accordance with the revised methodologies adopted in this proceeding. The effective date of the true-up for SCE and SDG&E was to be the date their 2011 ERRA rates become effective. For PG&E, the effective date was to be the date of the April 14, 2011 Ruling.

The following implementation process shall apply to SCE and SDG&E for purposes of finalization and implementation of the revised PCIA for 2011 made pursuant to the methodologies adopted in this proceeding. SCE and SDG&E shall calculate the difference attributable to the revised PCIA compared with the PCIA previously adopted in their 2011 ERRA proceedings. This difference shall be applied by issuing bill adjustments to transactions beginning from the effective date of the PCIA rate change adopted in their respective ERRA proceedings for 2011 through the effective date of the revised PCIA implemented pursuant to the revisions adopted in this proceeding. This resulting difference shall be incorporated into the prospective 2011 PCIA rates based upon the revised PCIA methodology. .

Since PG&E implemented 2011 PCIA rates prior to the ALJ ruling dated April 14, 2011, PG&E's adjustment for the PCIA methodology change cannot be applied retroactively prior to April 14, 2011. Instead, the PCIA adjustment for PG&E shall be applied beginning from the effective date of the April 14, 2011 Ruling going forward. In the ALJ ruling, PG&E was directed to utilize a deferred account to track the difference in PCIA methodology under the previously adopted versus revised PCIA methodology based upon this proceeding.

The calculation of PG&E's 2011 PCIA will be adjusted to reflect the difference between the currently adopted 2011 PCIA versus the PCIA amounts that would result utilizing the revised methodology adopted in this proceeding.

For PG&E, any difference between the existing 2011 PCIA rate versus the rate that would result from the revised methodology to be adopted through this proceeding was to be calculated in a deferred account. The resulting adjustment shall be passed through as a PCIA rate adjustment upon the adoption of a revised PCIA methodology in this proceeding.

Upon the implementation of the revised PCIA determined pursuant to this proceeding, each of the IOUs should promptly adjust its 2011 PCIA rate prospectively to be consistent with the revised PCIA methodology. Once PG&E implements the revised PCIA consistent with the methodologies adopted in this proceeding, PG&E shall promptly revise its previously adopted 2011 PCIA rate to incorporate this deferred difference.

SCE argues that if the Commission affirms the April 14 Ruling, the Commission should also require a retroactive true-up of the IOUs' TBS rates as of the effective dates of the 2011 PCIA true-up. This decision determines that the TBS rate shall be modified to be consistent with the modifications adopted for the indifference rate calculation. There is no dispute that TBS must be modified to be fully compensatory for procurement related costs, consistent with the changes to the indifference amount calculation. The April 14, and April 22, rulings, however, only authorized the true-up of PCIA rates, but omitted any mention of TBS rates. Accordingly, without a prior ruling calling for a TBS rate true up, we cannot retroactively authorize an adjustment for TBS rates for periods prior to the effective date of this Commission order

PG&E was scheduled to file its 2012 ERRA Forecast application in June 2011 to implement rates effective January 1, 2012. Although the 2012 ERRA Forecast is filed in June, updated testimony is typically filed in November to reflect more recent information. Therefore, relevant rate effects resulting from the Commission decision in this proceeding must be reflected as an update or amendment in PG&E's November 2011 ERRA update filing. These changes will be reflected in PG&E's 2012 rates to become effective January 1, 2012.

8. Categorization and Assignment of Proceeding

This proceeding is categorized as Ratesetting. The assigned Commissioner is Mark J. Ferron and the assigned ALJ is Thomas R. Pulsifer.

9. Comments on Proposed Decision

The proposed decision of the ALJ in this matter was mailed to the parties in accordance with Section 311 of the Public Utilities Code and comments were allowed under Rule 14.3 of the Commission's Rules of Practice and Procedure. Comments were filed on September 12, 2011, and reply comments were filed on September 19, 2011 by multiple parties. We have reviewed the comments and incorporated appropriate corrections and revisions in finalizing this decision.

Findings of Fact

1. The existing Commission-adopted methodology used to calculate the Indifference Amount has become outdated in view of industry and regulatory changes over time.

2. Pursuant to Pub. Util. Code § 365.1(b), individual retail nonresidential end-use customers may acquire electric service from other providers in each electrical corporation's distribution service territory, up to a maximum allowable total annual limits established in D.10-03-022.

3. Under current rules, customers on bundled utility service must provide six months' notice in order to leave bundled utility service. The six-month notice requirement also applies to customers that switch back to bundled service. A DA customer who returns to bundled service must commit to stay for at least a three-year period.

4. SB 695 requires that other providers of electricity in California are to be subject to the same procurement-related requirements that apply to the IOUs,

including RA requirements, renewable portfolio standards, and greenhouse gas emission reductions.

5. The current indifference methodology only recognizes the IOUs' cost of renewable resources in the calculation of the Total Portfolio Cost, but does not account for the market value of renewable resources in the MPB.

6. An adjustment to the MPB to account for the market value of renewable resources will result in a more accurate measure of indifference costs.

7. An accurate market-based measure for use in a renewable resource adder calls for data sources that represent transactions among all load serving entities in California, not just those of the IOUs.

8. Relying solely upon IOU transactions as the data source to construct a renewables adder is deficient to the extent it fails to account for transactions of other categories of California load serving entities.

9. All of the parties proposals for adjusting the MPB to account for renewable resources have deficiencies that make the proposals unsuitable as a basis for calculating the indifference amount.

10. The utilities' renewable resources constitute 68% of total California load subject to RPS requirements; the remaining 32% of such resources come from other load serving entities.

11. The data on renewable resource transactions from SNL Publications is not a reliable source for purposes of calculating a renewable adder to determine indifference costs.

12. The data reported by the United States Department of Energy survey of reported renewable energy contract premiums in the Western United States compiled by the National Renewable Energy Laboratory offers a proxy value

that can be used in conjunction with California utility data to produce a weighted RPS adder.

13. The MPB incorporates a capacity adder value to reflect the cost of resource adequacy based on the annualized cost of a combined cycle combustion turbine, but the current methodology does not provide for updating the value over time.

14. SCE's proposal to update the capacity adder using the California Energy Commission's estimates of the going forward costs of a combustion turbine, which is updated biannually, and the Net Qualifying Capacity of all generation resources (utility owned and power purchases) in the utility portfolio, is a practical approach to update the RA capacity value in the MPB.

15. The currently pending CEC proposed "Capacity Procurement Mechanism" price before the Federal Energy Regulatory Commission is not suitable as MPB capacity adder value, particularly because the CPM price is above current RA capacity market values. The FERC has raised questions about the CPM price and has made it subject to refund pending further study.

16. The total portfolio calculation currently includes certain CAISO load-based costs which the IOUs avoid when load departs for DA service. Exclusion of the load-based CAISO costs including load-based congestion costs, that vary based on the amount of load will produce a more accurate indifference amount calculation.

17. Under the current method for calculating the indifference amount, the total portfolio reflects the profile of the underlying IOU generation resources or contracts; however, the MPB calculation essentially is weighted based on the number of peak and off-peak hours in a year.

18. The current MPB is based on an implicit assumption that the IOU supply portfolio serves a flatter load profile than it actually does, thus creating an artificially low market value and artificially high indifference amount.

19. Parties identified two alternative approaches by which to revise the MPB to reflect more accurately the shaped profile of portfolio resources, weighted either by using the IOU generation profile or the IOU bundled load profile.

20. The IOU generation profile would more closely track actual portfolio costs, but the IOU load profile follows the shape of how load varies from hour to hour.

21. By using the utility's bundled load profile for the weighting factors, the shaped energy price for "brown" power would be the same for all PCIA vintages and for the CTC portfolio.

22. The IOUs historical bundled load profile by rate groups is publicly available and adequately reflects the shape of the IOU generation portfolios.

23. Bundled customer indifference is determined with reference to total portfolio costs, not isolated costs related to just the ERRA costs.

24. Short-term power purchases for terms of less than one year, do not belong in the calculation of total portfolio costs.

25. PG&E's proposal would violate the bundled customer indifference by recognizing only the cost to bundled customers from using more above-market CTC resources, while not recognizing the offsetting benefit accruing to bundled customers from also using more below-market utility resources.

26. An 18-month minimum stay requirement for bundled service strikes a reasonable balance, mitigating the risk of stranded RA and other potential stranded costs, while acknowledging that the capped DA market supports some lowering of the minimum stay requirement from its current length of three years.

27. The re-entry fees which are covered under the provisions of § 394.25(e) should cover administrative costs resulting from the involuntary return of DA customers to bundled service, and also incremental procurement costs for involuntarily returned residential and small commercial customers that are necessary to avoid imposing costs on bundled customers. For purposes of re-entry fees and ESP financial security requirements, it is reasonable to treat small commercial DA customers affiliated with a large commercial or industrial DA customers in the same manner as their large customer affiliate.

28. A security bond, letter of credit, or secured cash deposits are alternative means that can meet the ESP financial security obligations of § 394.25(e). The use of self insurance or showing of an ESP's investment-grade bond ratings are inadequate alternatives that fail to provide the requisite financial security required by § 394.25(e).

29. The fees that are currently in effect by utility tariff to cover administrative costs for the voluntary return of a CCA customer offer a reasonable proxy to use for purposes of securing a bond and calculating re-entry fees for administrative costs applicable to involuntarily returned DA customers.

30. A 60-day safe harbor period followed by a six-month period offers a reasonable time frame for calculating the duration of re-entry fees for involuntary returned residential and small commercial DA customers, in terms of keeping the bond costs manageable while protecting bundled customers against cost shifting.

31. The determination of re-entry fees is required under § 394.25(e) for purposes of securing an ESP bond and calculating actual costs of re-entry once an involuntary return occurs.

32. PG&E and SCE have failed to demonstrate that their proposed financial security bond methodology is necessary to prevent shifting costs to utility bundled customers.

33. Placing involuntarily returned large commercial and industrial DA customers on the TBS rate during the safe harbor period and for a period of six months thereafter avoids the need to include procurement costs as a reentry fee and associated financial security requirements under § 394.25(e). The only "re-entry fee" necessary to meet § 394.25(e) requirements are administrative costs associated with the switching the customer from the ESP to the IOU procurement service and incremental procurement costs for residential and small commercial customers.

34. Any actual incremental costs incurred in connection with serving an involuntarily returned DA customer that are not covered by the ESP bond or the TBS rate shall be the obligation of the involuntarily returned customers, as necessary to prevent cost shifting to bundled service customers.

35. Under the financial security bond methodology proposed by PG&E and SCE, the financial security bond amount would be recalculated every 6 months upon the filing of an Advice Letter.

36. DA customers, particularly industrial and commercial customers, seek fixed price DA contracts to minimize risks of uncertainty as to energy costs.

37. The financial security methodology proposed by PG&E and SCE lacks a definitive calculation for implied volatility.

38. Because PG&E and SCE have only presented illustrative bond calculations, and omitted key inputs relating to implied volatility, there is uncertainty concerning how large an ESP's resulting bond obligation could be, as

well as the resulting costs which could tend to make DA service less cost effective.

39. Substantial uncertainty regarding the financial security costs required to provide DA service could have an adverse effect on the viability of the DA market.

40. Requiring the ESP bond to be recalculated twice a year would result in uncertainty regarding the costs of providing the bonds.

41. One of the purposes of SB 695 is to expand the availability of Direct Access.

42. The TBS rate is designed to cover the incremental procurement-related costs associated with a DA customer's voluntary return to bundled utility service from an ESP.

43. The TBS rate is also suitable to cover incremental procurement-related costs associated with large commercial and industrial DA customers involuntary return to bundled service from an ESP.

44. Eliminating existing safe harbor provisions would significantly impede a customer's ability to return to DA service once it is involuntarily returned to IOU bundled procurement service.

45. Through a combination of the TBS rate and the safe harbor provisions in existing tariff rules, a customer who is returned by an ESP will be positioned to find a new ESP to supply its energy and to go back to DA service within a limited period of time.

46. The updated TBS rate, incorporating the effects of this decision, will include all procurement related costs, including the commodity cost of power, the incremental cost of RPS compliance, any incremental capacity/RA costs, and CAISO costs.

47. As sophisticated businesses with experience in obtaining goods and services via contracts, large commercial and industrial DA customers (and small commercial customers affiliated therewith) should have the ability to negotiate contractual provisions with an ESP to protect themselves in event of a breach, recognizing the potential to pay TBS rates if they return to the IOU.

48. Because residential and small commercial customers subscribing to direct access may not possess the same business sophistication as large commercial and industrial customers in terms of protecting themselves in the event of a breach by their ESP, additional measures are appropriate to protect residential and small commercial customers from the risk of higher procurement costs resulting from an involuntary return to bundled service. Small commercial customers affiliated with a large commercial or industrial customer, however, should be treated the same as their large customer affiliate for purposes of ESP bonds and applicable bundled service rates for an involuntary return.

49. Including the risk of higher procurement costs as part of the ESP bond requirement to cover the risk of higher procurement costs resulting from an involuntary return of small commercial and residential customers will provide appropriate protection to such customers.

50. Placing involuntarily returned residential and small commercial customers on the BPS rate will protect them against the risk of higher procurement costs, and will transfer that risk of higher procurement costs to the ESP .

51. Because the ESP bond calculation proposed by SCE and PG&E anticipated covering energy procurement risks for all involuntarily returned DA customers, the degree of complexity in the bond formulas and assumptions underlying

those calculations may not be necessary for a bond that covers a much more modest procurement risk limited only to small commercial and residential DA.

52. There has been no mass involuntary return of customers since the energy crisis.

53. The CCA settlement adopting a bonding requirement has not been approved by the Commission.

54. A very small percentage of DA load currently serves residential customers. Residential and small commercial customers are not similarly situated to large commercial and industrial customers.

55. The SCE and PG&E proposed calculation of a financial security requirement to cover potential re-entry fees as set forth in their respective testimony does not provide an appropriate methodology for use in determining an ESP bond amount to cover the involuntiary return of large commercial and industrial DA customers under § 394.25(e).

56. The SCE/PG&E methodology to calculate ESP bond amounts relies on non-existent or unreliable data, an unduly extended time period and an unjustified and excessive confidence factor. The proposed bond methodology would use implied volatility data from a third-party broker if that data is available. Information is available to parties to access market prices. However, limited information is available to parties to access implied volatilities. Access to the limited implied volatility information requires a fee-based subscription. Such data is available for SP 15 based on a proprietary model, from one broker only, and has not been shown to be reliable or verifiable as an indicator of future market price.

57. PG&E has not performed a study of volatilities comparing NP 15 and SP 15. Thus, we have no basis for concluding that SP 15 volatilities would serve

as a reasonable proxy for NP 15 volatilities or whether SP 15 volatilities could be adjusted to become a reliable proxy for use in calculating a provision for incremental procurement costs to be included in an ESP bond.

58. PG&E has not performed a study comparing historic volatilities and their relationship to implied volatilities. Thus, there exists no basis for concluding that historic NP 15 volatilities are reasonable proxy for NP 15 implied volatilities or whether historic NP 15 volatilities could be adjusted to become a reliable proxy.

59. The calculation of re-entry fees set forth in the testimony of PG&E and SCE does not provide a reasonable methodology for determining actual re-entry fees due to an involuntary DA return.

60. An ESP with investment grade credit should be able to obtain a bond or insurance policy on the commercial market at an annual cost of about 1% of the face value of the bond/policy amount.

61. The procedures for the filing of advice letters to implement the provisions of the ESP bond requirements set forth in the Ordering Paragraphs below are reasonable.

62. The implementation of true-up procedures in accordance with the ALJ ruling dated April 14, 2011, as amended by the ALJ ruling dated April 22, 2011, provides a reasonable means of incorporating the revisions in methodologies adopted in this proceeding into the PCIA rates for 2011, taking into account the effects of those revisions for periods of time prior to the effective date of this decision.

Conclusions of Law

1. In administering the DA program, any adopted rules are subject to the provisions of Pub. Util. Code § 366.1(d) that all retail customers bear their fair

share of purchase power obligations with no shifting of recoverable costs between customers.

2. Consistent with the increased allowances for DA transactions authorized pursuant to SB 695, any revised rules adopted for administering the DA program should also seek to preserve the benefits of customer choice.

3. The total portfolio methodology used to determine bundled ratepayer indifference should be calculated in a manner that subtracts the total portfolio from a market price benchmark that includes recognition of the market value of RPS and RA resources applicable to all load-serving entities. The total portfolio cost methodology should exclude short term power purchases for terms of under one year.

4. Since the existing proposals do not offer a suitable basis to determine a market-based adder for RPS resources, the Commission needs to determine a suitable proxy based upon available information.

5. SCE's proposal for updating the resource adequacy capacity adder using the CEC's most recent estimates of the going forward costs of a combustion turbine and the Net Qualifying Capacity of all generation resources (utility owned and power purchases) in the utility portfolio should be adopted.

6. Section 394.25(e) gives the Commission discretion to determine re-entry fees deemed necessary to avoid imposing costs on other customers of electrical corporations.

7. Section 394.25(e) requires ESPs to post financial security to cover any re-entry fees deemed necessary by this Commission to avoid imposing costs on other customers of electrical corporations.

8. It is reasonable to determine the financial impact of any proposed financial security bond methodology based on actual sample calculations in considering its merits.

9. The financial security bond methodology proposed by PG&E and SCE could pose a material adverse impact on the continued viability of DA.

10. Commission has previously recognized the benefits of the continuation of DA and has sought to avoid measures making DA uneconomic.

11. Involuntarily returning large commercial and industrial DA customers (and small commercial DA customers affiliated therewith) should be placed on the TBS rate in order to avoid shifting costs from DA customers to utility bundled customers. DA customers should be permitted to reserve their space under the DA cap in order to find a new ESP and return to DA service during the 60-day safe harbor period without having to compete for the oversubscribed demand for additional DA capacity under the SB 695 caps.

12. The Commission has the discretion to deem that the TBS rate is not a re-entry fee as defined by § 394.25(e).

13. Holding involuntarily returned large commercial and industrial DA customers responsible for payment of the TBS rate reduces the size of a re-entry fee and associated ESP financial security requirements for procurement costs under § 394.25(e).

14. All load-related CAISO costs including load-based congestion costs, should be excluded from the calculation of the total portfolio and market price benchmark in order to produce a more accurate measure of indifference.

15. The determination of the MPB should be revised to more accurately reflect the bundled load shape based upon time-of-use variations.

16. Under Pub. Util. Code § 394.25(e), the ESP is responsible for procuring a bond or related evidence of insurance as delineated in this decision to cover all re-entry fees imposed due to the ESP's customers that are involuntarily returned to bundled service. The ESP shall not be obligated for any re-entry fees, however, if a DA customer returns to the IOU due to default in payment to the ESP or other contractual obligations, or because the DA customer's contract with the ESP has expired.

17. For purposes of assessing re-entry fees, an involuntary return of a DA customer to bundled service may occur due to any of the following:

a. The Commission revokes the ESP registration;
b. The ESP Agreement with the utility becomes terminated; and
c. The ESP or its authorized CAISO SC has defaulted on its obligations, such that the ESP no longer has an authorized SC.

18. If an ESP becomes insolvent and is unable to discharge its obligations to pay re-entry fees, the returning DA customers must bear responsibility for the payment of the re-entry fees.

19. The purpose of § 394.25(e) is to protect against costs of re-entry fees being shifted on to other customers in the event of an involuntary return of DA customers to IOU service.

20. The requirements of § 394.25(e) must be satisfied through posting of a bond, letters of credit, cash security deposits, equivalent evidence of insurance or parental guarantee from an investment grade rated institutions or corporate parent, as applicable, as delineated in this decision sufficient to cover re-entry fees as defined in this order.

21. The re-entry fees as required under § 394.25(e) resulting from an en masse involuntary return of an ESP's customers to bundled utility service must include

all costs incurred by the IOU as a result of the DA customers' involuntary return necessary to avoid cost shifting to bundled customers.

22. If involuntarily returned DA customers are charged for incremental procurement costs through a TBS rate, such charges imposed on involuntarily returned customers are not a legal obligation of the ESP pursuant to § 394.25(e).

23. Because incremental procurement costs resulting from serving involuntarily returned DA customers must not be shifted to bundled customers, if those associated incremental costs are not included in re-entry fees pursuant to § 394.25(e), the costs should be recovered through a TBS rate.

24. Section 394.25(e) provides broad discretion for the Commission to interpret the scope of reentry fees as covering a different range of costs for small commercial and residential in contrast to large commercial and industrial DA customers, recognizing the different characteristics of each customer group.

25. In order to implement a requirement to incorporate the risk for incremental procurement costs in the ESP bond amount for involuntarily returned small commercial and residential customers, the Commission has the discretion to define reentry fees as including those procurement costs only in reference to such customers.

26. A subsequent decision should determine how incremental ESP bond amounts limited to procurement costs for involuntarily returned small commercial and residential DA customers should be measured and implemented.

27. Because the ESP bond proposal sponsored by PG&E and SCE is not offered as a settlement in this proceeding, the proposal must be evaluated on its substantive merits rather than based upon the Commission's settlement rules. Nothing in this decision should be construed as a prejudgment regarding the

merits of re-entry fees or bond obligations that may be deemed applicable to CCAs which are under consideration in R.03-10-003 in the context of the record in that proceeding and policy considerations relevant to CCAs.

28. The ESP bond proposal of PG&E and SCE fails to offer a reasonable means of complying with the requirements of § 394.25(e) for determination of an ESP bond obligation for involuntarily returned DA customers.

29. The calculation of the ESP bond amount for estimated re-entry fees for involuntarily retuned DA customers as proposed by SCE/PG&E should not be adopted.

30. The calculation of actual re-entry fees under § 394.25(e) to be paid at the time of an involuntary DA customer return as proposed by SCE/PG&E should not be adopted.

31. The procedures for implementation of the revised methodologies for calculating the PCIA and TBS rates as adopted in this proceeding should be implemented by tier 2 advice letter filings. The PCIA rate adjustments shall be in accordance with the directives set forth in the ALJ Ruling issued in this proceeding on April 14, 2011, as amended by ruling dated April 22, 2011. The Commission affirms both of the ALJ Rulings pursuant to the provisions of Pub. Util. Code § 310.

32. Unless otherwise expressly approved in the ordering paragraphs below, any proposals for revisions in the methodologies for calculating the indifference amount, CTC or TBS rate should be deemed denied.

O R D E R

IT IS ORDERED that:

1. The calculation of the Power Charge Indifference Amount and the Competition Transition Charge applicable to Community Choice Aggregation, and other non-exempt Direct Access, and Departing Load customers must be modified to incorporate revisions in the calculation of the total portfolio and market price benchmark as directed in the following ordering paragraphs.

2. The Market Price Benchmark used to calculate the Power Charge Indifference Amount, and Competition Transition Charge must be revised to incorporate an adder to reflect the market value of renewable portfolio standard resources.

3. All pre-2004 procurement resources must be included in the Total Portfolio cost calculation for purposes of comparing it with the Market Price Benchmark used in the calculation of the Power Charge Indifference amount and Competition Transition Charge.

4. Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company must each file a Tier 2 advice letter with the Energy Division within 30 calendar days following the issuance of this decision, identifying the relevant data necessary to revise the Power Charge Indifference Amount, Competition Transition Charge, and Temporary Bundled Service tariffs, in accordance with this decision. The information shall include:

   a. most recent 12 months figures derived from US Department of Energy survey of Western US renewable energy premiums in calculating a weighted proxy for the Market Price Benchmark compiled by the National Renewable Energy Laboratory; and

   b. all RPS-compliant resources that are used to serve IOU customers during the current year (i.e., most recent 12 months) and those projected to serve customers during the next year, including both contracts and IOU-owned resources, including the projected costs together with the net qualifying capacity of energy produced by each of these resources (providing relevant costs in dollars and volumes in MWh and qualifying capacity in kW). Confidential data submitted to the Energy Division will be protected from public disclosure.

5. The Energy Division will prepare a resolution to adopt the Renewable Portfolio Standard adder to be used to determine a Market Price Benchmark proxy value based on consideration of a 32% weighting of the DOE data in relation to a 68% weighting of the investor-owned utility cost data as relevant in the Commission's adoption of an appropriate adder to reflect renewable resources in the calculation of the Power Charge Indifference Amount and Competition Transition Charge. The applicable percentage weightings are subject to relevant updated data in subsequent years. The Energy Division will calculate the average cost of power from the IOU resources by summing up all the costs from all three IOUs, subtracting the product of the NQCs of those resources times the IOU's current RA capacity adder used in the Market Price benchmark, and dividing by the sum of all the MWHs from all three IOUs.

6. All California Independent System Operator (CAISO) charges that vary based on the amount of load including congestion charges, shall be excluded from the total portfolio cost and Market Price Benchmark for purposes of calculating the Power Charge Indifference Amount and Competition Transition Charge. The list of load-related CAISO charges identified in the testimony of the Joint Direct Access parties (Exhibit 100, Exhibit A) is adopted for use in identifying the applicable load-related charges to be excluded. As the CAISO charges change over time, the IOUs shall file tier 2 advice letters to update the excluded charges.

7. The Market Price Benchmark (MPB) calculation must be weighted to reflect variations in load shape on a time-of-use basis based upon the most recent investor-owned utility (IOU) bundled load profile data that is publicly available.

8. The capacity adder in the MPB shall be updated using the Net Qualifying Capacity of the utility electric supply portfolio and the most recent California Energy Commission estimate of the going forward costs of a combustion turbine.

9. The calculation of the temporary bundled service (TBS) rate shall be conformed to be consistent with the relevant changes in the methodology for calculating the total portfolio and Market Price Benchmark (MPB) as adopted in this decision. Specifically, the adopted MPB changes for Renewable Portfolio Standard resources shall be reflected in the TBS rate. Load-related California Independent System Operator charges, however, shall continue to be included in the TBS rate so that all relevant short-term charges are paid by Direct Access customers.

10. The minimum stay commitment for Direct Access customers electing to return to investor-owned utility procurement service shall be reduced from three years to 18 months.

11. The six-month advance notice requirement shall continue in effect for Direct Access (DA) customers to return to investor-owned utility (IOU) service or for bundled customers departing IOU service to be served by an electric service provider.

12. The proposal for bundled customers to be charged to pay Direct Access customers for negative indifference amounts is denied.

13. The proposal is denied to set the Power Charge Indifference Amount to zero in those instances where the indifference amount is less than the ongoing Competition Transition Charge.

14. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company must each file a Tier 2 Advice Letter within 30 days of this order to amend their tariffs to incorporate the ESP financial security provisions and re-entry fee provisions to cover administrative costs applicable to the involuntary return of DA customers, as adopted in this decision.

15. A subsequent phase of this proceeding shall address the determination of ESP financial security and re-entry fee provisions applicable to the involuntary return of small commercial and residential DA customers, including the methodology to calculate a provision for incremental procurement costs relating to such customers' involuntary return. A related issue to be resolved is to precisely define the distinction between small versus large DA customers for purposes of applying the relevant ESP financial security and re-entry fee provisions consistent with the intent of this decision.

16. The advice letter required by Ordering Paragraph 14 shall set forth the calculation of the financial security amount applicable for each ESP operating in the utility's service territory. Any confidential data relating to an ESP utilized in the calculations shall be redacted. An unredacted version of the advice letter shall be submitted to the Energy Division under confidential seal. Concurrently with submitting the advice letter to the Energy Division, the utility shall serve by electronic means on each applicable ESP a copy of the advice letter, with the relevant supporting data and calculations of each respective ESP's financial security amount provided confidentially only to that specific ESP in complete and unredacted form.

17. If an ESP believes that its financial security amount has been calculated inaccurately or in conflict with the adopted processes, the ESP may file

comments with the Energy Division, and served on the relevant IOU, indicating any appropriate corrections with relevant supporting explanation and detail within 20 days of the advice letter filing.

18. Upon Commission approval of the relevant ESP financial security amounts, the Energy Division shall notify each ESP of the final amount due on an aggregate statewide basis. Each ESP shall post the designated financial security amount with the Commission within 30 days. The applicable ESP financial security amount shall be subsequently updated annually, with an updated calculation to be submitted to the Energy Division by April 10 of each year, and with the updated amount posted by June 30 of each year.

19. Upon Commission approval of the above-referenced advice letters to implement the procedures for the posting of financial security in accordance with this decision, each electric service provider offering Direct Access service within California shall be responsible for posting a bond and/or other equivalent proof of insurance (e.g., letter of credit, cash deposit, third party guarantee) that covers re-entry fees pursuant to § 394.25(e).

20. The electric service provider re-entry fee must incorporate as a proxy for administrative costs, the administrative fees that are included in the respective retail utility tariff for returning Community Choice Aggregator customers.

21. The financial security bond methodology to include procurement costs for large commercial and industrial customers proposed by Pacific Gas and Electric Company and Southern California Edison Company is not adopted.

22. All large commercial and industrial involuntarily returned DA customers returning to IOU service shall be placed on the TBS tariff rate.

23. The electric service provider re-entry fee applicable to the involuntary return of small commercial and residential direct access customers must include

a provision for incremental IOU procurement costs necessary to serve such customers.

24. Upon the involuntary return of small commercial and residential direct access customers, those customers shall be placed on the bundled procurement service tariff rate. In all other respects, such customers shall be subject to the same rights and obligations of other direct access customers with respect to the safe harbor, advance notices, and minimum stay provisions.

25. The determination of the appropriate methodology to determine the applicable electric service provider bond provision to cover the risk of incremental procurement costs for the involuntary return of small commercial and residential direct access customers shall be addressed in a subsequent decision.

26. Involuntarily DA returned customers are authorized to utilize the 60-day safe harbor on the same basis as DA customers that return voluntarily.

27. Sufficient space shall be reserved under the SB 695 cap to enable involuntarily returned customers to resume DA service with a new electric service provider (ESP), as follows. If the involuntarily returned customer finds a new ESP and submits a DASR within the 60-day safe harbor period, the customer may reclaim the reserved space under the cap to resume DA service after executing a DASR. If the returned customer fails to find a new ESP and to execute a DASR during the 60-day safe harbor period, the customer will continue to pay the applicable bundled procurement rate for the six months following the end of the 60-day safe harbor period (i.e., the TBS rate for large commercial and industrial DA customers and the BPS rate for small commercial and residential DA customers. After that, the customer will be placed on the BPS rate and must remain on BPS service for the adopted minimum stay period of 18-months.

28. The TBS rate tariff for each IOU shall be revised by tier 1 advice letter to incorporate the provisions of this decision, including those relating to the incremental cost of RPS compliance, and incremental capacity/RA costs, and CAISO costs. The advice letter filing shall be deemed accepted unless protested during the 30-day review period.

29. The amount of an electric service provider's bond must be calculated annually, by April 10 of each year. Bonds shall be posted by June 30 of each year.

30. For an electric service provider that begins service in Month M+2 (where M denotes the month when the investor-owned utility will calculate the bond amount,), the bond calculation must be performed using Month M-1 data, and the bond shall be for the period from the start date through the next annual calculation.

31. The gross ESP bond amount to cover incremental administrative costs, and the actual re-entry fees applicable upon involuntary return of Direct Access customers must be determined in accordance with this decision.

32. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company must submit the initial ESP bond calculation methodology to the Commission's Energy Division in a Tier 2 advice letter filing, calculated in a manner consistent with this decision.

33. After the Commission approves the initial bond calculation methodology by resolution, all subsequent updates in the bond calculations shall be submitted as a Tier 1 advice letter. Any formulas shall be supported with Excel spreadsheets provided to the Energy Division. The filing shall be deemed accepted unless protested by an ESP or the Energy Division suspends the advice letter during the 30-day review period.

34. The electric service provider (ESP) is responsible for covering all applicable re-entry fees for its customers that are involuntarily returned. Only if, or to the extent, that the ESP is unable to cover all of the applicable re-entry fees, any unreimbursed fees from the ESP's must be covered by the returned Direct Access customers.

35. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company must each calculate actual re-entry fees due within 60 days of the earlier of the start of the involuntary return, or the receipt of the electric service provider's written notice of involuntary return, using the method described below.

36. Re-entry fees must constitute a binding estimate of the incremental administrative costs to switch the involuntarily returned Direct Access customers to bundled service.

37. The re-entry fees must be demanded from the electric service provider only after the involuntary return is initiated.

38. The changes in Power Charge Indifference Amount methodologies adopted in this decision shall be implemented in accordance with the procedure set forth in the Administrative Law Judge (ALJ) April 14, 2011 Ruling, as amended by the April 22, 2011 Ruling. In accordance with Public Utilities Code Section 310, the directives of the April 14, 2011 ALJ ruling, as amended by the April 22, 2011 ruling, are hereby affirmed by the Commission

39. To implement of the revised Power Charge Indifference Amount (PCIA) determined pursuant to this proceeding, Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company each must promptly adjust its 2011 PCIA rate prospectively to be consistent with the revised PCIA methodology. Each of the advice letter filings shall also

calculate the difference between their existing temporary bundled service (TBS) rate and the revised TBS rate calculated in accordance with the directives in this proceeding.

40. Southern California Edison Company and San Diego Gas & Electric Company must calculate the difference attributable to the revised Power Charge Indifference Amount (PCIA) compared with the PCIA previously adopted in their 2011 Energy Resource Recovery Account (ERRA) proceedings. This resulting billing adjustment amounts shall be refunded to each of the utility's customers who were direct access, community choice aggregation or non-exempt departing load customers during the period from the effective date of the PCIA rate change adopted in their respective ERRA proceedings for 2011 through the effective date of the revised PCIA implemented pursuant to the revisions adopted in this proceeding. Future changes to the PCIA shall be incorporated as an adjustment to the prospective 2011 PC1A rates in the Tier 2 Advice Letter filing based upon the revised PCIA methodology adopted in this proceeding.

41. Once Pacific Gas and Electric Company (PG&E) implements the revised Power Charge Indifference Amount (PCIA) consistent with the methodologies adopted in this proceeding, PG&E shall promptly revise its previously adopted 2011 PCIA rate to incorporate this deferred difference. This resulting difference shall be remitted in the form of a refund to each of the utility's customers who were direct access, community choice aggregation or non-exempt departing load customers during the period from April 14, 2011, through the effective date of the revised PCIA implemented pursuant to the revisions adopted in this proceeding. Future changes to the PCIA shall be incorporated as an adjustment to the prospective 2011 PCIA rates based upon the revised PCIA methodology adopted in this proceeding.

42. Rulemaking 07-05-025 remains open for further proceedings to resolve outstanding issues necessary to determine ESP financial security requirements and related re-entry fee provisions to cover incremental procurement costs for involuntarily returned small commercial and residential DA customers in accordance with the principles and directives adopted in this decision.

This order is effective today.

Dated December 1, 2011, at San Francisco, California.

MICHAEL R. PEEVEY
President
TIMOTHY ALAN SIMON
MICHEL PETER FLORIO
CATHERINE J.K. SANDOVAL
MARK J. FERRON
Commissioners

I abstain.

/s/ MICHEL PETER FLORIO
Commissioner