



# White Paper on the Evolution of Non-Bypassable Charges on Community Choice Aggregation

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## Glossary of Acronyms

AB	Assembly Bill
CAISO	California Independent System Operator
CAM	Cost Allocation Mechanism
CCA	Community Choice Aggregation
CEC	California Energy Commission
CGDL	Customer Generation Departing Load
CHP	Combined Heat and Power
CIA	Conservation Incentive Adjustment
CPUC	California Public Utilities Commission
CRS	Cost Responsibility Surcharge
CTC	Competition Transition Charge
DA	Direct Access
DSP	Division of Strategic Planning
ECRA	Energy Cost Recovery Amount
ERB	Energy Recovery Bond
ESP	Electric Service Provider
GHG	Greenhouse Gas
HPC	Historical Procurement Charge
IOU	Investor Owned Utility
LAR	Local Area Reliability
LSE	Load Serving Entity
MCE	Marin Clean Energy (fka Marin Energy Authority)
MEA	Marin Energy Authority
MDL	Municipal Departing Load
NBC	Non Bypassable Charge
OIR	Order Instituting Rulemaking
PCIA	Power Charge Indifference Adjustment
PG&E	Pacific Gas & Electric
PPA	Power Purchase Agreements
POU	Publicly Owned Utility
PPP	Public Purpose Program
PROACT	Procurement Related Liabilities Account
PUC	Public Utilities Code
PX	Power Exchange
RA	Resource Adequacy
RAC	Regulatory Asset Charge
RPS	Renewables Portfolio Standard
SB	Senate Bill
SCE	Southern California Edison
SDG&E	San Diego Gas & Electric
UDC	Utility Distribution Company
URG	Utility Retained Generation

# White Paper on the Evolution of Non-Bypassable Charges on Community Choice Aggregation

## Introduction

The implementation of exit fees and non-bypassable charges has radically changed through a series of decisions, often made in times of crisis, to address short-term problems that are no longer applicable. The passage of time since deregulation and the crisis has seen significant changes to California's energy market, including a stable Direct Access (DA) market and thriving community choice aggregators (CCAs). As California continues to develop into a more competitive market, the regulatory framework must be brought up to speed. This involves a comprehensive review and modifications to the exit-fee model.

## The Transition to Deregulation and a Competitive Market

In the early 1990s, concerns were growing over California's high electricity bills and an outdated regulatory framework. The regulatory scheme at the time did not support or incentivize competition and California's investor-owned utilities (IOUs) were charging some of the highest prices in the country due to indifference and inefficiency. Moreover, the command-and-control and cost-of-service regulations and government central planning, designed for an era that had come and gone, were fundamentally at odds with the increasingly competitive electric services industry.

Due to the industry's changing landscape and the goal to achieve an improved market structure, the California Public Utilities Commission (Commission) began planning for a transition to deregulation and exploring alternatives to the current regulatory approach. The Commission first recognized that, where the areas of the electric services business exhibited natural monopoly attributes, it should replace the traditional regulatory framework with alternatives better focused on utility performance and efficiency. Second, the Commission recognized that, in those areas where competition offered a superior means of organizing the development, delivery, and consumption of services, it should allow market forces to replace the traditional framework. Thus, the Commission recommended that while IOUs would remain the providers of last resort, customers should have the option to leave bundled service for direct access. However, during this transition into a competitive market, the State soon found itself in the throes of an energy crisis. This convergence of competition and crisis eventually resulted in departed customers being held captive to a growing number of exit fees and non-bypassable charges.

## The Beginning of Exit Fees and Non-Bypassable Charges

In 1995, the Commission began the regulatory overhaul to a competitive market by setting forth a roadmap to implement deregulation.<sup>1</sup> The Commission sought to unbundle the rate components of utility services: generation, transmission, and distribution. It also introduced a non-bypassable charge, called the Competition Transition Charge (CTC), for all retail customers, to allow utilities to recover costs associated with contracts for power and prior regulatory commitments in order to smooth the transition to competition. The objective of the CTC was to collect the transition costs in a manner that was competitively neutral, fair to various classes of ratepayers, and did not increase rates.<sup>2</sup> At the time, the Commission intended the CTC to eventually terminate once the transition period to a fully competitive market was over. The Commission also recognized that, while utilities should have

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1 D.95-12-063.

2 D.95-12-063 at 110.

an opportunity to recover costs which they actually must incur, there should be balance with the need to ensure that ratepayers were not paying for costs that no longer existed.<sup>3</sup> Lastly, in structuring the CTC, the Commission sought to prevent potential barriers to entry of prospective non-utility energy providers noting it as “one of the paramount goals of [the] electric restructuring initiatives.<sup>4</sup>

In 1996, the California Legislature passed Assembly Bill (AB) 1890 (1996), providing the legal framework to transition the vertically integrated utility model to one of competition in the supply sector. The statute provided for the formation of the California Independent System Operator (CAISO) and the Power Exchange (PX) market and required utilities to divest their generation assets and functionalize their costs to generation, transmission, and distribution components. AB 1890 also codified the CTC and indicated an expiration date consistent with the Commission’s anticipation that the CTC would eventually terminate when the transition period ended in March 2002. The Legislature reiterated that the transition should provide utilities with a fair opportunity to fully recover costs associated with their generation-related assets and obligations and that the transition should be completed as expeditiously as possible.<sup>5</sup>

During this competitive transition, crisis struck the electricity market in California. In 2001, the State was experiencing statewide energy shortages and blackouts, triggering Governor Gray Davis to issue an emergency proclamation. The Department of Water Resources (DWR), per the proclamation, would step in and purchase electricity for the State. The Legislature responded to the proclamation by passing Assembly Bill (AB) 1x, which authorized DWR to procure electricity on behalf of the customers of the IOUs. The statute provided for the reimbursement of costs to DWR, laying the groundwork for non-bypassable charges related to the DWR Bond and the DWR Power Charge. Additionally, in an effort to provide DWR with a stable customer base from which to recover the cost of the power it purchased, the statute directed the Commission to set a DA suspension date to prevent customers from leaving bundled service and avoiding costs incurred by DWR.

The Commission set the DA suspension date for September 20, 2001, and in allowing DA customers to keep contracts valid prior to that date, determined that a DA surcharge or exit fee would be appropriate in order to prevent cost-shifting of DWR costs to remaining bundled service customers.<sup>6</sup> The Commission also confirmed that DA customers would continue to be responsible for CTC obligations.<sup>7</sup> Soon thereafter, the recovery of costs from DA customers would be consolidated into the Cost Responsibility Surcharge (CRS), consisting of DWR costs, a tail CTC, and an indifference charge.<sup>8</sup> The indifference charge, based on the methodology of maintaining bundled service customer indifference, covered the ongoing above-market portion of utility-related generation costs related to the deregulation transition and subsequent crisis for the specified time period. This concept of bundled customer indifference would become the mainstay for imposing exit fees on departing load customers, including customers of Community Choice Aggregators (CCAs).

## The Application of Exit Fees and Non-Bypassable Charges on CCAs

In 2002, the Legislature passed AB 117 (2002) providing for local governments to aggregate the loads in their communities in order to serve them with generation services — electricity — in a structure called Community Choice Aggregation. As a competitive alternative to customer retail choice, the statute provided for the recovery of certain costs from CCAs in order to prevent cost-shifting to IOUs’ remaining bundled customers. The

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3 D.97-08-056 at 24.

4 D.97-08-056 at 39-40.

5 Pub. Util. Code Section 330(t).

6 D.02-03-055 at 33.

7 D.02-04-067 at 11.

8 D.02-11-022 at 3-4.

costs included those related to DWR's procurement during the energy crisis, IOU purchase obligations as of the date of the statute, and additional unavoidable contract costs attributable to the departing CCA customer. The unavoidable contract costs imposed on departing load customers is today known as the Power Charge Indifference Adjustment (PCIA). AB 117 also instructed that these contract costs would only be recoverable if the costs were unavoidable and were attributable to the customer. To date, the Commission has considered all contracts entered into by IOUs as both unavoidable and attributable to the customer.

Pursuant to AB 117, the Commission adopted an initial approach of the CRS for CCAs. The Commission used the same indifference methodology adopted for DA customers.<sup>9</sup> This methodology analyzed the liabilities that would be assumed by bundled utility ratepayers and would be incorporated in the CRS to avoid cost-shifting. The Commission emphasized its policy goals to maintain accuracy, equity and certainty for CCAs and utilities when creating CRS liability.<sup>10</sup> Furthermore, the Commission noted that its complementary objective was to minimize the CRS and promote good resource planning by the utilities. The Commission also anticipated that the CRS for CCAs would terminate at some point.<sup>11</sup>

Following the implementation of the initial CRS, the Commission then implemented a vintaging methodology for CCA CRS liability.<sup>12</sup> The Commission also concluded that utilities and CCAs should work collaboratively to develop proper forecasts for CCA departing load based on when a CCA initiates service.<sup>13</sup> Specifically, the Commission implemented a binding notice of intent process with the intention that a notice of service would relieve utilities of their obligation for purchasing power for CCA customers as of the service initiation date.<sup>14</sup>

By 2006, the energy crisis and the interrupted goals of AB 1890 left California with a need to assure reliable service at a reasonable cost and a hybrid market structure of competitive energy providers and IOUs. The Commission sought to assure timely construction of necessary capacity without compromising longer-term goals of achieving competition and customer choice.<sup>15</sup> To that end, the Commission adopted a new cost-allocation mechanism that would allocate the costs of new generation across all benefiting customers, including those that had already left bundled service. The approach, originally implemented on a limited basis, is known as the Cost Allocation Mechanism (CAM) and, like the PCIA, would evolve beyond its original purposes.

Since the restructuring of the electricity market, the Commission and Legislature have responded to exigent circumstances by implementing departure fees and non-bypassable charges. However, the scope of these fees and charges have expanded beyond the crisis-era and into IOU investments that focus on preventable reliability and indifference issues. These expansions require a comprehensive review of Commission policy and principles on the exit-fee model. In fact, in the Commission's sweeping decision implementing the guiding principles and policy related to the PCIA and the CAM, it recognized the possibility of reevaluating exit fees in the future. It noted that future changing circumstances that could make non-bypassable charges unworkable, unbalanced, or unfair would warrant an investigation and modification of those charges.<sup>16</sup>

## The Expansion of Exit Fees and Non-Bypassable Charges

### A. The Power Charge Indifference Adjustment

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9 D.04-12-046 at 24.

10 D.04-12-046 at 27.

11 D.04-12-046 at 27.

12 D.05-12-041 at 57.

13 D.05-12-041 at 63.

14 D.05-12-041 at 64.

15 D.06-07-029 at 3.

16 D.08-09-012 at 108.

**Definition:** The Power Charge Indifference Adjustment (PCIA) is based on a market benchmark approach and recovers the above-market cost of power purchased on a customer’s behalf prior to their departure from IOU bundled service. The above-market cost is the difference between the contract price of energy and the market price at which excess energy is sold.

In 2004, the Commission authorized expansion of the CRS to include all utility procurement including new generation resources and utility-owned generation.<sup>17</sup> The new CRS treatment allowed for IOUs to recover “uneconomic” or “stranded” costs for contracts entered into to meet reliability and resource adequacy obligations. The Commission reasoned that utilities needed to make longer-term commitments to meet capacity and reliability requirements while avoiding stranded costs due to departing load. Furthermore, the existing overhang of utility retained generation and long-term DWR contracts significantly limited the flexibility for utilities to adjust their resource portfolios.<sup>18</sup> Therefore, the Commission determined that, in an effort to meet reasonable certainty of rate recovery for the IOUs, departing customers must assume their fair share of costs in order to avoid cost-shifting.<sup>19</sup> The Commission also required IOUs to include CCA load in its forecasts for future Long Term Procurement Plans (LTTPs) and noted that, as utilities would be acquiring new resource needs through the competitive and transparent procurement process, it expected that there would be little, if any, stranded costs.<sup>20</sup>

In 2006, the Commission replaced the DWR Power Charge component of the DA CRS with a PCIA.<sup>21</sup> The PCIA recovery was based on the market benchmark approach and recovered the above-market costs of power represented by the DWR Power Charge. Since this change was built upon the preservation of bundled customer indifference from the DA suspension date of 2001, the costs associated with this modification represented a closed universe of costs that referred back to that period of time.

Nevertheless, in 2008, the Commission authorized the implementation of stranded cost recovery for “new world” post-2001 generation and transitioned away from a capped and flat CRS. Instead, the PCIA would be based on a total portfolio approach and vintaging methodology.<sup>22</sup> The Commission emphasized that, where departure load could be projected, customers would not be responsible for the PCIA. Lastly, in more recent years, the PCIA has further been applied to costs related to energy storage procurement<sup>23</sup> and for customers departing for an IOU’s Green Tariff Shared Renewables Program.<sup>24</sup>

## B. The Cost Allocation Mechanism

**Definition:** The Cost Allocation Mechanism (CAM) allows the benefits and costs of new generation to be shared by all benefiting customers in an IOU’s service territory. Through the CAM, the capacity and energy from the new generation is unbundled and the capacity is allocated among all load-serving entities (LSEs) in the service territory. The rights to the capacity could be applied toward each LSE’s resource adequacy (RA) requirements while the LSE’s customers pay for the net cost of this capacity. The non-bypassable charge resulting from the CAM reflects the difference between the total cost of the contract and the energy revenues associated with dispatch of the contract.

After the energy crisis, the Commission began addressing issues surrounding service reliability, the costs to implement improvements, and who would bear such costs. With the implementation of CCAs, departing

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17 D.04-12-048.

18 D.04-12-048 at 57.

19 D.04-12-048 at 58.

20 D.04-12-048 at 60.

21 D.06-07-030.

22 D.08-09-012 at 4.

23 D.14-10-045.

24 D.15-01-051.



municipal load and the potential of lifting the DA suspension, the Commission became concerned about the uncertainty as to the amount of load the utilities would be responsible for serving. The Commission responded to this concern by creating the Cost Allocation Mechanism (CAM), which would allocate costs of capacity related to reliability and resource adequacy over all customers, including those who left bundled service.

In the Commission's foundational CAM Decision, the intention was to adopt CAM for a limited and transitional period to support the development of new generation.<sup>25</sup> The Commission also noted that it was supportive of and recognized that load serving entities (LSEs) that could demonstrate that they were fully resource adequate over a sufficiently long time horizon should be allowed to opt-out of the cost-allocation system.<sup>26</sup> Most importantly, the Commission signaled that it continued to be committed to the fundamental principles of competition and customer choice.<sup>27</sup>

The CAM was first utilized to address exigent circumstances related to Southern California Edison's (SCE) application to enter into a power purchase agreement in light of record-breaking demands on the system and SCE's limited reserves that could not meet those demands.<sup>28</sup> To avoid the possibility of future blackouts and unforeseeable financial risks, the Commission authorized the use of the CAM on the grounds that the new generation fell in line with reliability and resource adequacy.

In 2009, the Legislature passed Senate Bill (SB) 695 (2009), which codified the CAM and confirmed its application to all bundled service customers, Direct Access customers, and CCA customers. The Commission subsequently issued a decision that would require the Commission to determine at its discretion whether CAM treatment would be applied to generation resources.<sup>29</sup> It also authorized CAM treatment for utility-owned generation and extended CAM treatment to match the duration of the contract, beyond the original ten-year limit.

The Commission has also shown inconsistent principles in applying the CAM. For example, in its decision that confirmed the guiding principles for CAM, it denied IOUs' request for CAM-like treatment for Qualifying Facilities (QF).<sup>30</sup> The Commission reasoned that CAM was designed for new system reliability resources and there was no demonstration of need for cost recovery for QF contracts nor was it appropriate for to apply CAM to QFs due to the requirements and costs associated with its energy auction process. However, subsequent to CAM's codification in SB 695, the Commission reversed its course and eventually authorized recovery for QFs through the CAM.<sup>31</sup>

In 2013, the Commission further extended CAM treatment to local reliability needs within an IOU's service territory.<sup>32</sup> The Commission declined proposals to cap the CAM finding it contradictory to its policy to apportion costs for all benefiting customers in the service area. Lastly, the Commission also continued its reluctance to consider an opt-out mechanism for CAM noting the possibility of administrative burdens and the current uncertainty of LSE's abilities to procure adequate resources. In more recent years, the Commission has also approved allocating costs to all customers benefitting from energy storage procurement.<sup>33</sup>

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25 D.06-07-029 at 4.

26 D.06-07-029 at 5.

27 D.06-07-029 at 2.

28 D.07-01-041.

29 D.11-05-005.

30 D.08-09-012 at 37.

31 D.10-12-035.

32 D.13-02-015.

33 D.13-10-040.

## Conclusion and Recommendations

As a result of the 2000–2001 energy crisis and subsequent legislation and Commission decisions, the scope of stranded costs have expanded to include certain energy crisis related costs and additional exit fees initially intended to maintain bundled customer indifference during restructuring. However, these policies and protocols have since been extended to allow an extensive range of cost–recovery mechanisms for IOU investments and the amount of stranded costs from non–bundled customers have become highly variable and uncertain.

Aside from the costs associated with the energy crisis and historic charges, stranded costs should be comprehensively assessed in order to avoid or minimize the stranded costs associated with future resources. Modifications to IOU procurement practices would also ensure that IOUs properly plan for departing load and procure enough to meet their bundled load. In addition, the indifference–based exit fee paradigm was originally implemented to preserve competition while preventing cost–shifting to bundled customers during the energy crisis. However, the crisis has since passed and Commission decisions and statutes have authorized various mechanisms to avoid cost–shifting, including IOU long–term planning and established protocols for forecasting accurate departing load.

Moreover, years of CCA operational experience has shown that CCAs are ready, willing and capable of complying with reliability and environmental requirements. Thus, a continued reliance on IOUs to procure capacity on behalf of CCAs is no longer necessary.

Therefore, Marin Clean Energy recommends:

- » Comprehensive review of PCIA and CAM exit fees
- » Comprehensive assessment of stranded costs currently associated with particular resources
- » Assessment and modifications to IOU procurement and resource planning practices

Appendix A.  
Chronological Synopsis of Key  
Decisions, Legislation, and Events

## Appendix Contents

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- 14 // Key Decisions Regarding Exit Fees & Non-Bypassable Charges
- 16 // Timeline of Exit Fees and Origins of CCA
- 17 // 1. CPUC “Yellow Book” (February 3, 1993)  
Provides Analysis and Framework to the Reform of the Electricity Market
- 18 // 2. CPUC “Blue Book” (April 20, 1994)  
Sets Forth Proposed Policies to Reform the Electricity Industry in California
- 19 // 3. Decision 95–12–063 (December 20, 1995) as Modified by Decision 96–01–009 (January 10, 1996)  
Represented the Key Deregulation Order and the Preferred Policy Decision
- 21 // 4. Assembly Bill 1890 (September 24, 1996)  
Authorized Direct Access and Implemented a Temporary Competition Transition Charge (CTC)
- 22 // 5. Decision 97–08–056 (August 1, 1997)  
Functionalized Costs into Generation and Distribution Rates for the First Time and Prevented the Use of Anticompetitive Balancing Accounts and Non-Bypassable Charges
- 24 // 6. The Competitive Market is Launched in California (March 1998)
- 24 // 7. Proposition 9, Intending to Stop Deregulation, is Defeated (November 1998)
- 24 // 8. Decision 99–10–065 (October 21, 1999)  
Evaluated the Role of the Utility Distribution Company (UDC) in the Competitive Market and Sought to Ensure Utility Procurement is Consistent with the Public Interest and Does Not Confer an Undue Competitive Advantage on the IOU
- 25 // 9. Decision 00–06–034 (June 8, 2000) Set the Groundwork for a “More Level Playing Field” in the Competitive Market; Contemplated the CTC Tail
- 26 // 10. Governor Gray Davis (January 17, 2001) Issues an Emergency Proclamation Regarding the Statewide Energy Shortages
- 26 // 11. Assembly Bill 1x (February 1, 2001)  
Directs the Commission to Suspend Direct Access
- 26 // 12. Interim Decision 01–09–060 (September 20, 2001)  
Suspended Direct Access
- 26 // 13. Decision 02–03–055 (March 21, 2002)  
Developed Exit Fees for Recovery of Department of Water Resources (DWR) Costs from Direct Access Load with Contracts Entered Into Prior to September 20, 2001
- 27 // 14. Decision 02–04–067 (April 22, 2002)  
Established that Bundled Customers Are to Remain “Indifferent” With Regards to DWR Costs
- 27 // 15. Decision 02–07–032 (July 17, 2002)  
Imposed the Historical Procurement Charge on Direct Access Customers
- 28 // 16. Assembly Bill 57 (September 24, 2002)  
Requires Investor-Owned Utilities to Develop Long Term Procurement Plans
- 29 // 17. Assembly Bill 117 (September 24, 2002)  
Authorizes Community Choice Aggregation

- 30 // 18. Decision 02-11-022 (November 7, 2002)  
Implemented the Direct Access Cost Responsibility Surcharge (CRS) including Department of Water Resources Costs and Certain Utility Costs
- 31 // 19. Decision 03-04-030 (April 3, 2003)  
Exempted Certain Customer Generation Departing Loads from CRS
- 32 // 20. Decision 03-07-028 (July 10, 2003)  
Adopted a Cost Responsibility Surcharge (CRS) for Municipal Departing Load (MDL)
- 32 // 21. Decision 03-07-030 (July 10, 2003)  
Reevaluated and Retained the Direct Access 2.7 Cents/kWh Cap on the Cost Responsibility Surcharge
- 33 // 22. Decision 04-02-062 (February 26, 2004)  
Imposed the Regulatory Asset Charge — Later Called the Energy Cost Recovery Amount (ECRA) — on Direct Access Customers
- 33 // 23. Decision 04-11-014 (November 19, 2004)  
Provided a Limited CRS Exemption to Municipal Departing Load (MDL)
- 34 // 24. Decision 04-12-046 (December 16, 2004)  
Adopted Interim CRS Charges for CCAs and Service Protocols
- 36 // 25. Decision 04-12-048 (December 16, 2004)  
Adopted Cost Recovery for New Generation Resources and Utility Owned Generation through the CRS; Required Investor-Owned Utilities to Incorporate CCA Load into Their Long Term Procurement Planning
- 38 // 26. Decision 05-08-035 (August 25, 2005) Exempted New MDL from PG&E's RAC and Energy Recovery Bond Charges; Denied Exemption for Transferred Load
- 39 // 27. Decision 05-12-041 (December 15, 2005)  
Implemented a Vintaged PCIA for CCA; Required CCAs and Utilities to Develop CCA Departure Forecasts
- 39 // 28. Decision 06-07-029 (July 21, 2006)  
Established the Cost Allocation Mechanism (CAM) Charge
- 40 // 29. Decision 06-07-030 (July 20, 2006)  
Converted the DWR Power Charge into a Power Charge Indifference Adjustment (PCIA) and Set a Uniform Calculation of CTC
- 41 // 30. Petition 06-12-002 (December 6, 2006)  
Requested Reconsideration to Reopen Direct Access
- 41 // 31. Decision 07-01-025 (January 25, 2007)  
Confirmed the Calculation Methodology of the Cost Responsibility Surcharge
- 42 // 32. Decision 07-01-030 (January 25, 2007)  
Revised the Indifference Rate, PCIA, and CTC Methodology to Include RA/Capacity Adders and Line Loss Factors
- 42 // 33. Decision 07-01-041 (January 25, 2007)  
Authorized the First Utilization of the CAM for Utility Procurement
- 43 // 34. Decision 07-09-044 (September 21, 2007)  
Set Principles for CAM Implementation

- 43 // 35. Decision 07-12-052 (December 20, 2007)  
Found No Impact by Future CCA and DA Departing Load and Recognized That IOUs Could  
“Cherry Pick” CAM Resources for their Bundled Customers to the Detriment of DA Customers
- 44 // 36. Decision 08-09-012 (September 4, 2008)  
Set Guiding Principles for Non-Bypassable Charges and  
Substantially Revises the Exit Fee Regime
- 47 // 37. Senate Bill 695 (October 11, 2009)  
Provides for a Limited Expansion of Direct Access
- 48 // 38. Decision 10-03-022 (March 15, 2010)  
Authorized Limited DA Pursuant to SB 695 (2009)
- 48 // 39. Marin Energy Authority, California’s First Community  
Choice Aggregator Begins Service (May 7, 2010)
- 49 // 40. Proposition 16, an Initiative to Require a Two-Thirds Majority Vote  
to Establish a CCA Program, is Defeated (June 8, 2010)
- 49 // 41. Scoping Memo and Ruling R.07-05-025 (November 22, 2010)  
Revised the Scope of Phase III of the Proceeding to Include Issues Relating to the PCIA
- 49 // 42. Decision 10-12-035 (December 21, 2010)  
Allowed for “CAM-like” Procurement of CHP by IOUs
- 52 // 43. Decision 11-05-005 (May 5, 2011)  
Modified CAM to be Consistent with SB 695
- 52 // 44. Senate Bill 790 (October 8, 2011) Institutes a Community Choice Aggregation “Bill of Rights”
- 54 // 45. Decision 11-12-018 (December 07, 2011)  
Reformed the PCIA Methodology to Include, Among Other  
Changes, a “Green Adder” for Renewable Energy
- 55 // 46. Decision 12-01-033 (January 18, 2012)  
Confirmed that IOUs Are Required to Forecast CCA and DA  
Departing Load in Bundled Procurement Plans
- 56 // 47. Decision 13-02-015 (February 13, 2013) Confirmed  
Application of CAM for Local Capacity Requirements
- 56 // 48. Petition 12-12-010 (December 18, 2012)  
Sought Commission Review of Policies Regarding Cost Allocation and Non-Bypassable Charges
- 58 // 49. Decision 13-08-023 (August 20, 2013)  
Denied Marin Energy Authority’s Petition for Rulemaking to Review Commission  
Policies Regarding Cost Allocation and Non-Bypassable Charges
- 59 // 50. Decision 13-10-040 (October 17, 2013)  
Authorized IOUs to Recover Costs Associated with Energy  
Storage Procurement from CCA and ESP Customers
- 59 // 51. Decision 14-03-004 (March 13, 2014)  
Authorized CAM for Costs of Procuring Local Capacity  
Needs Impacted by the SONGS Retirement
- 60 // 52. Decision 14-02-040 (February 27, 2014)  
Required IOUs to Estimate DA and CCA Departing Load for 10-Year Term Bundled Plans

- 61 // 53. Sonoma Clean Power Begins Service (May 1, 2014)
- 61 // 54. Decision 14-10-045 (October 16, 2014)  
Authorized PCIA for Energy Storage Procurement
- 62 // 55. Decision 15-01-051 (January 29, 2015)  
Implemented the Green Tariff Shared Renewables Program and  
Applied a Vintaged PCIA to Program Customers
- 63 // 56. Lancaster Choice Energy Begins Service (May 1, 2015)
- 63 // 57. Decision 15-06-028 (June 11, 2015)  
Established Reduced CHP Procurement Targets and Ended CAM Recovery  
for PG&E's Procurement Obligations for Upcoming Period
- 63 // 58. Decision 15-06-063 (June 25, 2015)  
Adopted a Monthly CAM Value as Part of Annual Year-Ahead Allocation

## Key Decisions Regarding Exit Fees & Non-Bypassable Charges

Power Charge Indifference Adjustment (PCIA)			
Date	Decision	Description	Page
11/7/2002	D.02-11-022	Implemented CRS for DA including DWR and certain utility costs	30
7/10/2003	D.03-07-028	Adopted CRS for MDL	32
7/10/2003	D.03-07-030	Reevaluated and retained DA 2.7 cents/kWh cap on CRS	32
11/19/2004	D.04-11-014	Provided limited CRS exemption to MDL	33
12/12/2004	D.04-12-046	Adopted interim CRS charges for CCAs	34
12/16/2004	D.04-12-048	Allowed IOU to recover new generation resources and utility-owned generation through CRS; Required IOU to incorporate CCA in LTPP	36
12/15/2005	D.05-12-041	Implemented vintaged PCIA for CCA; Required CCAs and utilities to develop CCA departure forecasts	39
7/20/2006	D.06-07-030	Converted DWR Power Charge into PCIA and set uniform calculation of CTC	40
1/25/2007	D.07-01-025	Confirmed calculation methodology of CRS	41
1/25/2007	D.07-01-030	Revised indifference rate, PCIA, and CTC methodology to include RA/Capacity adders and line loss Factors	42
9/4/2008	D.08-09-012	Set guiding principles for NBCs and substantially revised exit fee regime	44
12/7/2011	D.11-12-018	Reformed PCIA methodology including Green Adder for renewables	54
8/20/2013	D.13-08-023	Denied MEA Petition Re: Cost Allocation and NBCs	58
10/22/2014	D.14-10-045	Authorized PCIA for energy storage procurement	61
2/2/2015	D.15-01-051	Implemented Green Tariff Shared Renewables Program and applied vintaged PCIA to program customers	62



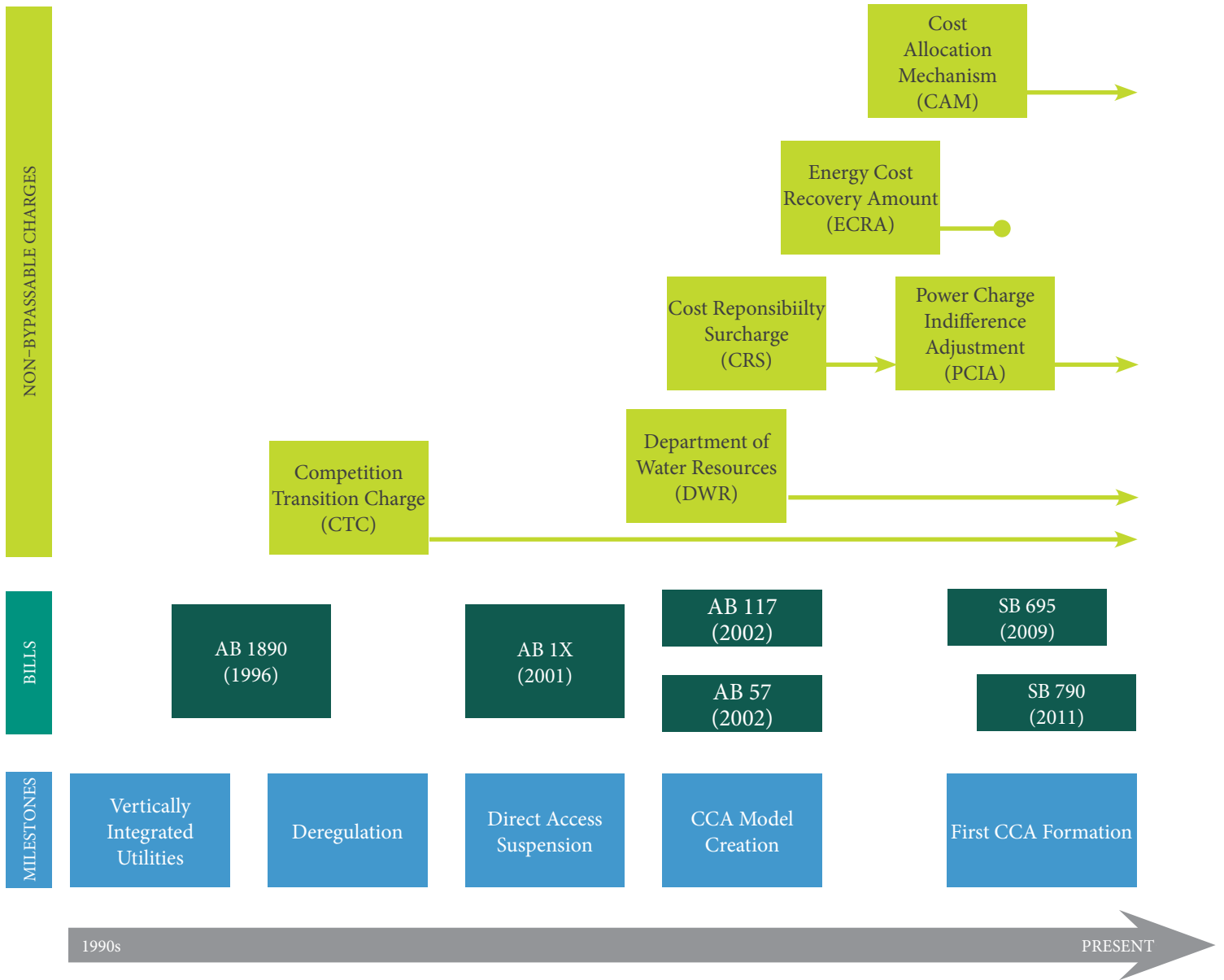
### Cost Allocation Mechanism (CAM)

Date	Decision	Description	Page
7/20/2006	D.06-07-029	Established the Cost Allocation Mechanism	39
1/25/2007	D.07-01-041	Authorized the First Utilization of the CAM for Utility Procurement	42
9/21/2007	D.07-09-044	Set principles for CAM	43
12/21/2007	D.07-12-052	Found no impact by future CCA and DA departing load and recognized that IOUs could “cherry pick” CAM resources for their bundled customers to the detriment of DA customers	43
9/4/2008	D.08-09-012	Set guiding principles for NBCs revising exit fee regime	44
12/21/2010	D.10-12-035	Allowed “CAM-like” IOU procurement of CHP	49
5/10/2011	D.11-05-005	Modified CAM to be consistent with SB 695	52
2/13/2013	D.13-02-015	Confirmed application of CAM for local capacity requirements	56
8/20/2013	D.13-08-023	Denied MEA Petition regarding Cost Allocation and NBCs	58
10/21/2013	D.13-10-040	Authorized IOUs to recover costs for energy storage from CCA and ESP	59
3/14/2014	D.14-03-004	Authorized CAM for local capacity needs from SONGS retirement	59
6/15/2015	D.15-06-028	Established reduced CHP procurement targets, eliminating future CAM recovery for PG&E obligations for next period	63
6/30/2015	D.15-06-063	Adopted 12-month CAM value as part of annual year-ahead allocation	63

### Competition Transition Charge (CTC)

Date	Decision	Description	Page
12/20/1995	D.95-12-063	Roadmap for implementation deregulation including unbundling services, performance based ratemaking, creation of the ISO/PX, divestiture in generation assets, and CTC	19
6/8/2000	D.00-06-034	Implemented steps to promote competition; Sets forth specific costs in the “CTC Tail” allowed to be recovered after 12/31/01	25
7/20/2006	D.06-07-030	Converted DWR Power Charge into PCIA and set uniform calculation of CTC	40
1/25/2007	D.07-01-030	Revised indifference rate, PCIA, and CTC methodology to include RA/Capacity adders and line loss Factors	42

# Timeline of Exit Fees and Origins of CCA



The following is intended to highlight key events, legislation, and decisions from the Yellow Book through the present day related to exit fees and non-bypassable charges.

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## 1. CPUC “Yellow Book” (February 3, 1993) Provides Analysis and Framework to the Reform of the Electricity Market

The “Yellow Book”<sup>34</sup> issued by the Commission’s Division of Strategic Planning (DSP) in 1993 provides a useful guide to the energy industry and why electricity market reform was necessary at that time. The Yellow Book recommended reforming the regulatory structure, including redefining the “regulatory compact.”

The Yellow Book resulted from Decision 92–09–088 which identified the need for structural reform and competition in the California electricity market and directed the DSP to “explore alternatives to the current regulatory approach in light of the conditions [the electric industry currently confronts] and [future] trends identified.”<sup>35</sup>

The Yellow Book sets the stage for its analysis by identifying the circumstances driving the need for significant regulatory reform:

“First, California’s current regulatory framework, significant portions of which were developed under circumstances which no longer persist, is ill suited to govern today’s electric services industry ... . Second, the state’s current regulatory approach is incompatible with the industry structure likely to emerge in the ensuing decades.”<sup>36</sup>

Specifically, the Yellow Book identifies five key issues driving the need for reform:<sup>37</sup>

1. The regulatory program blunts incentives for efficient utility operations.
2. The current regulatory program increases the potential for inefficient investment due to unbalanced incentives governing utility investment options.
3. The current regulatory approach requires many complex proceedings, which increase administrative costs and threaten the quality of public participation and Commission decisions.
4. The current regulatory approach offers utility management limited incentives and flexibility to respond to competitive pressures.
5. The current regulatory approach conflicts with the Commission’s policy of encouraging competition in the electric services industry.

The Yellow Book extensively discusses the “regulatory compact” — a “social contract” among “the Commission; the consumers of energy services; the state’s utilities; unregulated energy service providers; and the citizens of California.”<sup>38</sup> The Yellow Book states that the “regulatory compact” has changed over time as financial risks were

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34 California’s Electric Services Industry: Perspectives on the Past, Strategies for the Future, a Report to the California Public Utilities Commission by the Division of Strategic Planning, February 3, 1993. (“Yellow Book”)

35 D.92–09–088 at 1. (D.92–09–088 was preceded by D.91–06–022, which acknowledged that “All parties support increased competition among potential suppliers of Electricity to California; they differ on ways to achieve that result.”)

36 Yellow Book at 1–2.

37 Yellow Book at 147.

38 Yellow Book at 7.

shifted to ratepayers, cost recovery principles were changed, and the participants to the “regulatory compact” increased.<sup>39</sup> This concept of “regulatory compact” has been criticized for excessively protecting monopolies from risk.<sup>40</sup>

The Yellow Book provides four options for regulatory reform: limited reform, price caps, limited customer choice, and restructured utility industry.<sup>41</sup> The Commission identified five “guiding principles” that each strategy must attain, namely that each strategy:<sup>42</sup>

- » Modifies the regulatory compact and/or the means employed to uphold the compact when appropriate;
- » Clearly defines the compact’s obligations and privileges under each strategy;
- » Replaces command-and-control regulation with market-based performance targets when appropriate;
- » Creates less intrusive regulation by setting clearly articulated goals and policies, providing the utility with adequate flexibility to achieve those goals, and establishing utility accountability commensurate with the degree of flexibility provided; and,
- » Ensures that the incentives facing the utility reinforce rather than frustrate the achievement of regulatory and other state goals.

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## 2. CPUC “Blue Book” (April 20, 1994) Sets Forth Proposed Policies to Reform the Electricity Industry in California

Following its findings from the Yellow Book, the Commission instituted a rulemaking to reform the electricity market in California. This Order has come to be known as the “Blue Book.”<sup>43</sup>

The Blue Book found that:<sup>44</sup>

- » Command-and-control and cost-of-service regulation, and government central planning are fundamentally at odds with, and ill-suited to, the increasingly competitive electric services industry confronting California and its utilities. ...
- » California’s investor-owned utilities currently charge some of the highest prices in the country. This distressing fact prompts us to explore reasonable alternatives to the current framework. ...
- » This Commission has actively promoted when appropriate policies designed to harness market forces and establish market-based regulatory solutions in each of the industries it oversees, including the electric services industry. ...

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39 Yellow Book at 11–12. Similarly, changes are afoot in the current market with in the introduction of new regulatory compact participants, such as community choice aggregators (“CCAs”), and continued concerns over utility incentives and regulatory approaches.

40 See, e.g., McArthur, John Burrirt, “Cost Responsibility or Regulatory Indulgence for Electricity’s Stranded Costs?” 47 AM. U.L.R. 775 (1998) at 852. “Whether labeled regulatory reliance, regulatory contract, regulatory bargain, or regulatory compact, this argument seeks to let utilities escape any consequences for their past conduct.”

41 Yellow Book at 171.

42 Yellow Book at 170.

43 R.94–04–031: Order Instituting Rulemaking on the Commission’s Proposed Policies Governing Restructuring California’s Electric Services Industry and Reforming Regulation (“Blue Book”).

44 Blue Book at 5–6.

To achieve an improved market structure, the Blue Book sets forth its “two-track strategy” whereby:

“First, in those areas of the electric services business which exhibit natural monopoly attributes, or where market power persists, we intend to replace our traditional cost-of-service regulatory framework with alternatives better focused on utility performance and efficiency. Second, in those areas of the business where competition offers a superior means of organizing the development, delivery and consumption of services, we intend to replace the traditional regulatory framework with the discipline of market forces.”<sup>45</sup>

The Blue Book concludes that generation falls into this second category. As a result of the Blue Book’s recommendations, the Commission proposed that the investor-owned utilities would remain the providers of last resort (POLR), and that customers could continue receiving generation service from the investor-owned utility; at the same time, all customers could leave bundled service for Direct Access. Along with these substantial changes, the “regulatory compact” was to change as well. Specifically, the Commission “recognize[d] that competitive markets, where they exist and function reasonably well, offer a superior regulatory tool when compared to command-and-control regulation and government central planning designed for an era that has passed and will not return.”<sup>46</sup>

During the transition to competition, the Blue Book recommended a policy to allow investor-owned utilities to recover uneconomic costs through a competition transition charge (CTC).

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### 3. Decision 95–12–063 (December 20, 1995) as Modified by Decision 96–01–009 (January 10, 1996) Represented the Key Deregulation Order and the Preferred Policy Decision

This Decision, as modified by D.96–01–009, set forth the roadmap to implementation of deregulation. At the time, the cost of electricity in California was “50% above the nation’s average rate.”<sup>47</sup> This sweeping Decision identified the need to take next steps on the following issues:

#### 1. Unbundling or Functionalizing Rate Components

In order to achieve competitive markets for electricity services, the Decision required the investor-owned utilities to disaggregate charges by separating the elements of generation, transmission, and distribution.<sup>48</sup> This functionalization was finalized in Decision 97–08–056. This includes the disaggregation of energy efficiency costs, which was to be collected as part of a “public goods charge” applied to customers’ bills.

#### 2. Encouraging Performance Based Ratemaking (PBR) and Real-Time Pricing to Promote Efficiency

The Decision encouraged the implementation of Performance Based Ratemaking (PBR) as a means to encourage efficiency of the utility; similarly, the Commission encouraged real-time pricing to encourage customers to also act efficiently.<sup>49</sup>

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45 Blue Book at 28.

46 Blue Book at 34.

47 D.95–12–063 at 192.

48 D.95–12–063 at 202.

49 D.95–12–063 at 189.

### 3. Creating the Independent System Operator (ISO) and the Power Exchange (PX) to Protect Against Market Power

The Decision proposed to establish a separate Independent System Operator (ISO) and Power Exchange (PX) to encourage transparent information and protect against discriminatory decision-making. During the transition period, jurisdictional utilities would be obligated to sell their generation into the Power Exchange and make purchases of electric power needed to supply the needs of their full service customers from the PX.<sup>50</sup> The Decision found that “the abuse of market power reduces the societal efficiencies of competition.”<sup>51</sup>

### 4. Requiring Divestiture of the Utility’s Competitive Generation Assets

In order to achieve deregulation, the Commission required that the investor-owned utilities divest their competitive generation assets. The Commission found that this divestiture was the “only structural option which will completely eliminate the utility’s ability to engage in improper cross-subsidization.”<sup>52</sup>

### 5. Preventing Rate Increases by Instituting a Competition Transition Charge (CTC)

The Decision instituted a non-bypassable charge, called the Competition Transition Charge (CTC), for “all customers who are retail customers ... whether they continue to take bundled service from their current utility or pursue other options.”<sup>53</sup> The objectives of the CTC was to collect transition costs in a manner that was competitively neutral, fair to various classes of ratepayers and did not increase rates.<sup>54</sup> The Commission found that utilities needed an opportunity to be vital market participants in the restructured market and thus allowed the utilities to completely recover costs associated with contracts for power and prior regulatory commitments.<sup>55</sup>

At the same time, the Commission noted its goal was to “get through this transition period as quickly as possible so that full competition can begin with minimal market distortions.”<sup>56</sup> The Decision thus provided a termination date for CTC: “With the exception of CTC arising from existing contracts, no further accumulation of CTC will be allowed after 2003 and collection will be completed by 2005.”<sup>57</sup>

### 6. Permitting Limited Uneconomic Transition Costs; Competition Transition Charge (CTC) to Receive Lower Rate of Return

The utilities would be permitted to recover “net above-market costs associated with its assets, both economic and uneconomic.”<sup>58</sup> The Commission noted that “competition may threaten the utilities’ financial stability,”<sup>59</sup> but also that providing “assurance of full recovery gives the utility no incentive to minimize transition costs.”<sup>60</sup> The Commission further noted, “[W]e are not required to guarantee full transition cost recovery. We are required only to design a rate structure the total impact of which provides the utilities with the opportunity to earn a fair return on their investment.”<sup>61</sup>

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50 D.95-12-063 at 205.

51 D.95-12-063 at 192.

52 D.95-12-063 at 193.

53 D.95-12-063 at 110.

54 D.95-12-063 at 110.

55 D.95-12-063 at 111.

56 D.95-12-063 at 119.

57 D.95-12-063 at 212.

58 D.95-12-063 at 194.

59 D.95-12-063 at 119.

60 D.95-12-063 at 196.

61 D.95-12-063 at 123.

As a result, the Decision provided that CTC assets would be given a lower rate of return than the rate recovery they had previously received.<sup>62</sup>

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#### 4. Assembly Bill 1890 (September 24, 1996)

##### Authorized Direct Access and Implemented a Temporary Competition Transition Charge (CTC)

While the Commission was developing extensive policy analyses leading up to its key decision regarding deregulation, the State legislature began drafting Assembly Bill (AB) 1890 (1996).<sup>63</sup> The legislation incorporated the central elements of the CPUC plan that restructured the three vertically integrated investor-owned utilities.<sup>64</sup>

Specifically, AB 1890 provided the legal framework to transition the vertically integrated utility model to one of competition in the supply sector. It formed the California Independent System Operator (CAISO); launched the competitive Power Exchange (PX); required utilities to divest their generation assets; and required utilities to “functionalize” their costs among generation, transmission, distribution, public benefit programs, and exit fees. AB 1890 also began Public Purpose Program nonbypassable charges<sup>65</sup> and continued protections for low-income ratepayers through the California Alternative Rates for Energy (CARE) program.

The Legislature found that “competition in the electric generation market will encourage innovation, efficiency, and better service from all market participants, and will permit the reduction of costly regulatory oversight”<sup>66</sup> and to that end set forth a path to a competitive generation market structure “at the earliest possible date.”<sup>67</sup> This specifically included a temporary transition period which provided for limited exit fees.

The Legislature mandated that the competitive electric market “be available to California consumers as soon as practicable, but no later than January 1, 1998.” Due to the significant change to the regulatory framework, AB 1890 provided for a brief period to smooth the transition with specified exit fees. The Legislature stated:

“It is the further intent of the Legislature that during a limited transition period ending March 31, 2002, to provide for all of the following:

(1) Accelerated, equitable, nonbypassable recovery of transition costs associated with uneconomic utility investments and contractual obligations.”<sup>68</sup>

This exit fee created by AB 1890 is known as the Competition Transition Charge (CTC) and was implemented in Sections 330, 367 and 368 of the Public Utilities Code (PUC).<sup>69</sup> The principles of the CTC methodology are found in Section 330(s) and provides:<sup>70</sup>

“(s) It is proper to allow electrical corporations an opportunity to continue to recover, over a reasonable transition period, those costs and categories of costs for generation-related assets and obligations, including costs associated with any subsequent renegotiation or buyout of existing generation-related contracts, that the commission, prior to December 20, 1995, had authorized for collection in rates and that may not be

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62 D.95-12-063 at 124-125.

63 Weare, Christopher. *The California Electricity Crisis: Cause and Policy Options*. Public Policy Institute of California. (2003) at p. 10.

64 Id.

65 These Public Purpose Program nonbypassable charges were set to end in 2002 pursuant to Assembly Bill 1890.

66 Section 330(g).

67 Section 1(a).

68 Section 1(b).

69 All Section references are to the California Public Utilities Code unless otherwise indicated.

70 The details of the CTC methodology are set forth in Section 367.

recoverable in market prices in a competitive generation market, and appropriate additions incurred after December 20, 1995, for capital additions to generating facilities existing as of December 20, 1995, that the commission determines are reasonable and should be recovered, provided that the costs are necessary to maintain those facilities through December 31, 2001. In determining the costs to be recovered, it is appropriate to net the negative value of above market assets against the positive value of below market assets.”

Section 330(t) reiterated that this “transition to a competitive generation market should be orderly, protect electric system reliability, provide the investors in these electrical corporations with a fair opportunity to fully recover the costs associated with commission approved generation–related assets and obligations, and be completed as expeditiously as possible.” Section 330(v) required that “charges associated with the transition should be collected over a specific period of time.” CTC revenues, which were to end in 2002, were to be monetized and returned to residential and small commercial customers pursuant to Section 330(w) for the period of 1998 through 2002.

The utilities were also required to develop a cost recovery plan “for the recovery of the uneconomic costs of an electrical corporation’s generation–related assets and obligations identified in Section 367,” which was required to meet specified criteria, including:

- » **Time–Limited Transition Costs:** Recovery of CTC by the “earlier of March 31, 2002, or the date on which the commission–authorized costs for utility generation–related assets and obligations have been fully recovered.” The electrical corporation would continue to be “at risk for those costs not recovered during that time period.”<sup>71</sup>
- » **Functionalization of Costs:** Identification and separation of “individual rate components such as charges for energy, transmission, distribution, public benefit programs, and recovery of uneconomic costs.” The separation shall not result in “cost shifting among customer classes, rate schedules, contract, or tariff options.”<sup>72</sup>
- » **Uncapping Nuclear Costs:** “In order to ensure implementation of the cost recovery plan, the limitation on the maximum amount of cost recovery for nuclear facilities that may be collected in any year adopted by the commission in Decision 96–01–011 and Decision 96–04–059 shall be eliminated to allow the maximum opportunity to collect the nuclear costs within the transition cap period.”<sup>73</sup>

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## 5. Decision 97–08–056 (August 1, 1997)

### Functionalized Costs into Generation and Distribution Rates for the First Time and Prevented the Use of Anticompetitive Balancing Accounts and Non–Bypassable Charges

This Decision was the original decision that established — in detail — which costs belonged in generation and which belonged in distribution. Prior to this point, there had not been a differentiation to generation and distribution functions. The purpose of this functionalization was “to promote the development of competitive markets for generation services.”<sup>74</sup> The Commission reasoned that unbundling promoted competition by “providing customers

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71 Section 368(a).

72 Section 368(b).

73 Section 368(d).

74 D.97–08–056 at 6.



with options for individual services and sending customers price signals which would permit them to make reasoned choices about their competitive options.”<sup>75</sup>

## 1. Prohibition of Cost Shifting Among Customer Classes

In pursuing policies to promote a competitive market, the Decision prohibited against allocating generation costs to distribution customers.<sup>76</sup> Doing so would “compromise market efficiency by producing artificially low generation rates ... and provide competitive advantages, which would stifle competition to the utilities.”<sup>77</sup> Moreover, remaining utilities customers would be required to “subsidize shareholder profits.”<sup>78</sup> With regards to investor–owned utility divestitures and overhead costs, the Commission provided the following policy guidance: “It is not our intent to deny utilities an opportunity to recover reasonable costs which they actually must incur, but we must balance this with our need to ensure that ratepayers are not paying for costs that no longer exist.”<sup>79</sup> This analysis feeds directly in to the question of how exit fees should be structured and who should bear which risks.

## 2. Prohibition against Certain Anticompetitive Balancing Accounts and Non–Bypassable Charges

The investor–owned utilities requested specific balancing accounts and non–bypassable charges to shift risks and costs to departing and remaining ratepayers. These accounts and non–bypassable charges would remain in place “after December 31, 2001, providing a regulatory protection which extends beyond the period anticipated by AB 1890 for recovery of stranded generation costs.”<sup>80</sup> The Commission denied this request specifically stating that: “As the utilities admit, these three accounts are designed to reduce utility risk by guaranteeing recovery of certain costs, some of which are currently recovered under different types of ratemaking mechanisms. The nonbypassable surcharges and associated balancing accounts change the mix of risk the utilities face pursuant to Commission orders and AB 1890, contrary to our stated policy.”<sup>81, 82</sup>

The Commission stated: “As a matter of policy, we question the fairness of transferring risk to captive customers.”<sup>83</sup> As a result, in structuring the CTC, the Commission sought “to prevent any potential barriers to entry of prospective non–utility energy providers” as it is “one of the paramount goals of our electric restructuring initiatives.”<sup>84</sup> Similarly, the CTC was structured to not “fluctuate over time.”<sup>85</sup>

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75 D.97–08–056 at 7.

76 D.97–08–056 at 8.

77 D.97–08–056 at 8.

78 D.97–08–056 at 8.

79 D.97–08–056 at 24.

80 D.97–08–056 at 31.

81 D.97–08–056 at 30.

82 Regarding Pacific Gas & Electric’s (PG&E) Proposal on Nuclear Incremental Cost Incentive Pricing: “PG&E proposes to create the nonbypassable charge to recover Diablo Canyon nuclear power plant Incremental Cost Incentive Pricing (ICIP) prices that exceed market prices” (D.97–08–056 at 28). The Commission responded: “We observe that we have never authorized the creation of such a charge either implicitly or explicitly. PG&E’s cost recovery plan did not propose such a surcharge although the plan stated PG&E would not recover associated costs through the CTC. In this proceeding, PG&E provides no legal authority for the charge or analysis to support its imposition” (D.97–08–056 at 32).

83 D.97–08–056 at 31.

84 D.97–08–056 at 39–40.

85 D.97–08–056 at 41.

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## 6. The Competitive Market is Launched in California (March 1998)

In March 1998, Assembly Bill 1890 (1996) became effective, making the generation of electricity competitive in California. As a result, customers in existing electric utility service areas were allowed to shop for power in an open market. Customer choice started simultaneously with the start of the independent system operator, CAISO, and the power exchange, PX, which would handle the trades of electric power in the state.

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## 7. Proposition 9, Intending to Stop Deregulation, is Defeated (November 1998)

In November 1998, Proposition 9, a ballot initiative intending to stop deregulation, was defeated. Proposition 9 would have made significant changes to recently enacted laws restructuring the state's electricity industry. Among various provisions, the proposition would have prohibited private electric utilities from charging customers for transition costs for nuclear power plants and limited authority for electric companies to recover costs of non-nuclear power plants.<sup>86</sup> Until its defeat, Proposition 9 created uncertainty and reduced incentives for companies to invest in new electricity-generating facilities and increased the risks inherent in the newly restructured system.

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## 8. Decision 99–10–065 (October 21, 1999)

### Evaluated the Role of the Utility Distribution Company (UDC) in the Competitive Market and Sought to Ensure Utility Procurement is Consistent with the Public Interest and Does Not Confer an Undue Competitive Advantage on the IOU

This Decision took steps to “further examine the issues surrounding the emergence of competition with respect to distribution services and retail electric services. Those issues include: ... whether distribution services should be unbundled and, if so, to what extent; ... what the role of the UDCs [Utility Distribution Companies] should be in a competitive retail market; and whether the current market structure for the provisioning of default services and the procurement of electricity should be changed.”<sup>87</sup>

The Decision specifically raised concerns regarding the “the role of the UDC in providing monopoly and competitive services, including the potential for exercising market power.”<sup>88</sup> The Decision directed Commission staff to “consider whether it is necessary to identify and functionally separate the utility’s retail service business from its distribution operations.”<sup>89</sup> The Decision further question whether “the CPUC should consider instituting a new system of determining who the default providers should be, and how they would be assigned to customers, if the necessary electric service elements were unbundled.”<sup>90</sup> Lastly, the Decision emphasized that, while IOUs are not prevented from owning generation facilities, it must be “consistent with the public interest” and “not confer an undue competitive advantage on the IOU.” (At 27.)

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86 California Proposition 9 (1998) by Ballotpedia.org ([http://ballotpedia.org/California\\_Proposition\\_9\\_Prohibition\\_on\\_Use\\_of\\_Taxes,\\_Bonds\\_or\\_Surcharges\\_to\\_Pay\\_for\\_Nuclear\\_Power\\_\(1998\)](http://ballotpedia.org/California_Proposition_9_Prohibition_on_Use_of_Taxes,_Bonds_or_Surcharges_to_Pay_for_Nuclear_Power_(1998)))

87 D.99–10–065 at 3–4.

88 D.99–10–065 at 48.

89 D.99–10–065 at 48.

90 D.99–10–065 at 50.

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## 9. Decision 00–06–034 (June 8, 2000) Set the Groundwork for a “More Level Playing Field” in the Competitive Market; Contemplated the CTC Tail

This Decision represented the last Decision undertaken by the Commission prior to the Electricity Crisis. The Decision implemented “steps designed to ensure a more level playing field in order to promote competition and provide consumers with more options.”<sup>91</sup> This Decision was adopted during the “rate freeze” era, where utility rates remained fixed at June 10, 1996 levels until the end of the Competition Transition Charge (CTC) period, but no later than March 31, 2002.<sup>92</sup> Any CTC credit remaining at the end of this rate freeze period would be returned to customers.<sup>93</sup>

The Commission set forth the specific costs which were allowed to be recovered after December 31, 2001. This is considered the “CTC Tail.” The costs included in the CTC Tail are:<sup>94</sup>

- » Employee–related transition costs (which must be recovered no later than December 31, 2006);
- » Power purchase contract obligations (which continue for the duration of the contract);
- » Costs associated with any buy–out, buy–down, or renegotiation of such contracts (which also continue for the duration of the agreement);
- » Costs associated with contracts approved by the Commission to settle issues associated with the Biennial Resource Plan Update (BRPU) (which may be collected through March 31, 2002, provided that only eighty percent (80%) of the balance remaining after December 31, 2001 are eligible for recovery);
- » Costs associated with entities exempted from transition cost recovery as delineated in § 374 (which must be recovered by March 31, 2002, provided that only \$50 million of any balance remaining after December 31, 2001 is eligible for recovery); and
- » Costs associated with repaying the rate reduction bonds may be recovered until the fixed transition amounts are recovered in full.

The Commission declined to adopt a performance–based ratemaking (PBR) mechanism until the Commission further defined the utility distribution company (UDC) procurement role, if the UDC was to have a continuing role at all.<sup>95</sup> The Commission declined to adopt “prescribed procurement guidelines” since it “implies a sanction of reasonableness and tends to negate the concept of competition.”<sup>96</sup> The Commission required the utilities to procure through the PX, so that no one entity would have undue influence over market prices.<sup>97</sup>

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91 D.00–06–034 at 1.

92 D.00–06–034 at 5.

93 D.00–06–034 at 105–106.

94 D.00–06–034 at 54.

95 D.00–06–034 at 31.

96 D.00–06–034 at 91.

97 D.00–06–034 at 92.

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## 10. Governor Gray Davis (January 17, 2001) Issues an Emergency Proclamation Regarding the Statewide Energy Shortages

On January 17, 2001, Governor Gray Davis issued a Statewide Emergency Proclamation which required the Department of Water Resources (DWR) to step in and purchase electricity to mitigate the effects of the electricity shortages and blackouts affecting California.

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## 11. Assembly Bill 1x (February 1, 2001) Directs the Commission to Suspend Direct Access

In response to the energy crisis and its associated price spikes and shortages of electricity, the Legislature passed Assembly Bill 1x as an urgency statute. This bill implemented the directives set forth in the Davis Emergency Proclamation and authorized DWR to purchase and sell power to ratepayers through January 2, 2003. This statute provided for reimbursement of costs to DWR, laying the groundwork for non-bypassable charges related to the DWR Bond and the DWR Power Charge.

Section 80110 was added to the California Water Code which provided that the Commission would determine a suspension date of Direct Access. This suspension meant that as of a certain date no new departures for Direct Access would be allowed. While current customers of Direct Access customers could remain, customers who voluntarily or involuntarily returned to IOU service could not leave for Direct Access again.

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## 12. Interim Decision 01–09–060 (September 20, 2001) Suspended Direct Access

Pursuant to Section 80110, this Interim Decision suspended the right to enter into Direct Access contracts or agreements after September 20, 2001. The Commission reasoned that suspension of the ability to acquire direct access service would provide DWR with a stable customer base from which to recover the cost of the power it purchased.<sup>98</sup> However, the Decision does not reference the Cost Responsibility Surcharge (CRS) or other exit fees, as described in further detail below.

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## 13. Decision 02–03–055 (March 21, 2002) Developed Exit Fees for Recovery of Department of Water Resources (DWR) Costs from Direct Access Load with Contracts Entered Into Prior to September 20, 2001

Following on the heels of Interim Decision 01–09–060, this Decision confirmed the Direct Access suspension date of September 20, 2001. At this time, the DWR revenue requirement for the period January 1, 2001 through December 31, 2002, was over \$9 billion.<sup>99</sup>

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<sup>98</sup> D.01–09–060 at 4.

<sup>99</sup> D.02–03–055 at 30.

This Decision questioned “which end user customers will pay, so that the costs incurred by DWR in response to the energy crisis confronting California will be recovered.” It also questioned “how the Commission will prevent cost-shifting of a significant magnitude.”<sup>100</sup> The Commission reasoned that, because of the departure of Direct Access customers, a percentage of the DWR revenue requirement would become the obligation of the remaining bundled customers. It therefore found it necessary to adopt direct access surcharges or exit fees on direct access customers and allocate certain DWR costs to them.

The Commission decided that “[i]n lieu of an earlier suspension date, we determine that it is appropriate to consider the adoption of a Direct Access surcharge or exit fee.”<sup>101</sup> This exit fee was to be developed in Application 00-11-038. As a result, this Decision bifurcated the Direct Access market. Contracts that were executed prior to September 20, 2001, were allowed to remain in effect so long as bundled utility customers would be indifferent with regards to DWR charges. The execution of new contracts, or the entering into, after September 20, 2001, was prohibited.<sup>102</sup>

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#### 14. Decision 02-04-067 (April 22, 2002) Established that Bundled Customers Are to Remain “Indifferent” With Regards to DWR Costs

This Decision provided a limited rehearing on Decision 02-03-055. The Commission clarified that bundled customers were to remain “indifferent” with regards to DWR costs:<sup>103</sup>

“At this time we state that Direct Access surcharges, exit fees or similar charges should be imposed, and it is our intent that such fees or charges be fully compensable so that Direct Access customers pay their fair share of DWR costs, and bundled service customers are indifferent.”

That is, Direct Access customers would remain responsible for Assembly Bill 1890 competition transition costs.<sup>104</sup> This concept of “bundled customer indifference” returns in the post-crisis era in how the Power Charge Indifference Adjustment (PCIA) is applied today.

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#### 15. Decision 02-07-032 (July 17, 2002) Imposed the Historical Procurement Charge on Direct Access Customers

This Decision first addressed the question of non-DWR uneconomic costs with regards to Southern California Edison (SCE) and implemented the Historical Procurement Charge (HPC).

Due to the rate cap and the methodology then in place, SCE was unable to cover its procurement-related liabilities pursuant to the temporary Competition Transition Charge (CTC). Specifically, the methodology provided that Direct Access customers received a credit on their bill in circumstances where the PX price exceeded SCE’s procurement costs, resulting in an underpayment to SCE’s past uneconomic costs. As a result, the Commission-

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100 D.02-03-055 at 11.

101 D.02-03-055 at 14.

102 D.02-03-055 at 33.

103 D.02-04-067 at 22-23.

104 D.02-04-067 at 11.

SCE Settlement would circumvent the requirements of Assembly Bill 1890 to allow for continued collection of CTC.

The Procurement Related Liabilities Account (PROACT) was the solution proposed by SCE to prolong its recovery of past uneconomic costs.<sup>105</sup> The Settlement “provided for SCE to apply surplus in rates over cost of service (“headroom”) to recovery of its Procurement–Related Obligations (back debt incurred in connection with costs of purchasing wholesale energy that were not recovered in rates).”<sup>106</sup> These costs would be included in the CRS, which, under this Decision, was recommended to be capped at \$0.027.<sup>107, 108</sup>

In essence, this is the first decision allowing for the continued collection of CTC beyond the statutory deadline set forth in Assembly Bill 1890.

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## 16. Assembly Bill 57 (September 24, 2002) Requires Investor–Owned Utilities to Develop Long Term Procurement Plans

In the aftermath of the electricity crisis and the IOUs’ failure to serve their customers, the Legislature passed a statute that required investor–owned utilities to develop long term procurement plans. Assembly Bill (AB) 57 (2002) was intended to ensure that the IOUs resume procurement for the needs of customers being served by DWR. This represented a dramatic change from the after–the–fact reasonableness review of procurement costs which had been previously in place.

This urgency statute required the Commission to review for approval long term procurement plans which contained at least one of the three “features” based upon the investor–owned utility’s “individual procurement situation”:<sup>109</sup>

- » Competitive procurement processes; and/or
- » Incentive mechanisms with “balanced risk and reward incentives that limit the risk and reward of an electrical corporation”; and/or
- » Set “upfront achievable standards and criteria by which the acceptability and eligibility for rate recovery of a proposed procurement transaction will be known by the electrical corporation prior to the execution of the bilateral contract for the transaction.”

Each long term procurement plan is required to:<sup>110</sup>

- » “Enable investor–owned utilities to ... serve its customers at just and reasonable rates”;
- » “Eliminate the need for after–the–fact reasonableness reviews of an electrical corporation’s actions in compliance with an approved procurement plan”;
- » “Ensure timely recovery of prospective procurement costs incurred pursuant to an approved procurement

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105 These costs relate to the period of time prior to DWR procurement during the energy crisis.

106 Testimony of Gary Cohen, Public Utilities Commission General Counsel, “Summary of Pending Utility Energy Litigation,” Debra Bowen, Chair, Senate Energy, Utilities and Communications Committee, February 7, 2002.

107 D.02–07–032 at 3.

108 In providing room for this potential cap, the Commission acknowledged: “We have stated our policy in D.02–03–055 that there is value in maintaining DA; failure to consider an overall cap would be inconsistent with this policy” (D.02–07–032 at 24).

109 Section 454.5(c).

110 Section 454.5(d).

plan”;

- » “Moderate the price risk associated with serving its retail customers, including the price risk embedded in its long-term supply contracts, by authorizing an electrical corporation to enter into financial and other electricity-related product contracts”;
- » “Provide for just and reasonable rates.”

The “pre-approval” of procurement contracts in lieu of after-the-fact reasonableness review was considered when the Commission subsequently implemented the PCIA methodology in Decision 04-12-048.

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## 17. Assembly Bill 117 (September 24, 2002) Authorizes Community Choice Aggregation

Assembly Bill (AB) 117 (2002) provides for local governments to aggregate the loads in their communities in order to serve them with electricity in a structure called Community Choice Aggregation (CCA). While Direct Access was still constrained by the Direct Access cap, this provided a new competitive alternative to customers. This competitive alternative differed in some aspects from Direct Access. For example, CCA customers enroll on an opt-out basis whereas Direct Access customers must opt in to that service. Furthermore, CCAs operate by not-for-profit local government agencies rather than a corporation. Due to the reasonably stable rate base of customers, CCAs engage in long-term procurement to meet the need of their customers.

Assembly Bill 117 protects against cost shifting to investor-owned utilities’ bundled customers through exit fees and a bond mechanism<sup>111</sup> and provides that “any costs not reasonably attributable to a community choice aggregator shall be recovered from [investor-owned utility] ratepayers, as determined by the commission.”<sup>112</sup> The legislation also allows CCAs to administer energy efficiency programs funded through non-bypassable charges such as the Public Goods Charge.

Certain costs are allowed to be recovered from CCAs, namely those set forth in Sections 366.2(d)–(f), to prevent shifting of costs from CCA customers to bundled customers. These provisions represent three types of costs:

First, certain DWR costs:

- » A fair share of DWR Bond costs;<sup>113</sup>
- » Certain ongoing DWR costs “equal to the customer’s proportionate share of the Department of Water Resources’ estimated net unavoidable electricity purchase contract costs as determined by the commission”;<sup>114</sup>

Second, certain investor-owned utility obligations in effect as of the effective date of Assembly Bill 117:

- » Electricity purchases on or before the effective date of Assembly Bill 117;<sup>115</sup>
- » The electrical corporation’s unrecovered past undercollections for electricity purchases as of the effective

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111 The CCA Bond provisions are set forth in Section 394.25(e) and have been extensively discussed in Rulemaking 03-10-003 and Rulemaking 07-05-025.

112 Section 366.2(c)(17).

113 Section 366.2(e)(1).

114 Section 366.2(e)(2).

115 Section 366.2(d)(1).

date of Assembly Bill 117.<sup>116</sup>

Third, certain other above-market costs:

- » “Any additional costs of the electrical corporation recoverable in commission-approved rates, equal to the share of the electrical corporation’s estimated net unavoidable electricity purchase contract costs attributable to the customer, as determined by the commission, for the period commencing with the customer’s purchases of electricity from the community choice aggregator, through the expiration of all then existing electricity purchase contracts entered into by the electrical corporation.”<sup>117</sup>

The last exit fee referenced above is today called the Power Charge Indifference Adjustment (PCIA). In order for the PCIA to be lawfully recovered from CCA customers, it must represent unavoidable contract costs which are attributable to the customer. To date, the Commission has considered all contracts entered into by investor-owned utilities both “unavoidable” and “attributable to the customer.”

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## 18. Decision 02–11–022 (November 7, 2002) Implemented the Direct Access Cost Responsibility Surcharge (CRS) including Department of Water Resources Costs and Certain Utility Costs

Under this Decision, the Commission began to impose certain exit fee mechanisms on the customers of Direct Access providers to ensure that certain costs would not be solely borne by bundled customers. The costs represented the amounts needed to have bundled customers be “indifferent” to the significant departures of customers to Direct Access which occurred between “between July 1, 2001 (the suspension date originally anticipated in the ALJ Proposed Decision) and September 21, 2001 (the suspension date adopted by the Commission).”<sup>118</sup>

The recovery of these costs was called the Cost Responsibility Surcharge (CRS) and was comprised of:<sup>119</sup>

1. **The California Department of Water Resources (DWR) Bond Charge**, representing an amortization of certain past DWR costs;
2. **The DWR Power Charge**, representing uneconomic DWR procurement costs between September 21, 2001 and December 31, 2002, and prospective costs for 2003;
3. **An Indifference Charge**, to cover the ongoing above-market portion of utility-related generation costs related to the deregulation transition and subsequent crisis for the specified time period;
4. **The Historic Procurement Charge**, in the case of SCE customers pursuant to Decision 02–07–032; and
5. **Tail CTC**, as defined in Decision 00–06–034, and continued pursuant to this Decision.

In this Decision, the Commission began to assert that Tail CTC could be recovered through non-bypassable charges beyond December 31, 2002. The Commission noted that “AB 1890 provided certain exceptions to the general rule that all CTC must either be recovered within the rate freeze period, or not collected.”<sup>120</sup> The

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116 Section 366.2(f)(1).

117 Section 366.2(f)(2).

118 D.02–11–022 at 7.

119 D.02–11–022 at 3–4.

120 D.02–11–022 at 15.



Commission asserted its statutory authority to impose CRS on Direct Access as an extension of the Tail CTC, and on CCA citing to Assembly Bill 117:

“It is the intent of the Legislature that each retail end-use customer that has purchased power from an electrical corporation on or after February 1, 2001, should bear a fair share of the [DWR’s] electricity purchase costs, as well as electricity purchase contract obligations incurred ... that are recoverable from electrical corporation customers in commission-approved rates. It is further the intent of the Legislature to prevent any shifting of recoverable costs between customers.”<sup>121</sup>

The Cost Responsibility Surcharge (CRS) was determined to cover both DWR costs and utility retained generation (URG) costs pursuant to a “total portfolio” method.

With regards to the “all in” CRS costs to be borne by Direct Access customers, the Commission declined to adopt a levelized annual charge of the CRS. Rather, the charge would fluctuate over time.<sup>122</sup> However, the Commission did adopt a CRS cap to ensure that Direct Access would not become wholly uneconomic.<sup>123</sup> The initial CRS cap was set at 2.7 cents/kWh. As the actual cost of CRS declines over time, any underpayment of CRS would be made up in future years.<sup>124</sup>

Decision 02–12–045 subsequently defined the allocation methodology for the DWR 2003 revenue requirement and continued the 2.7 cents/kWh CRS cap.

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## 19. Decision 03–04–030 (April 3, 2003) Exempted Certain Customer Generation Departing Loads from CRS

This Decision provided three specific exemptions from the CRS for Customer Generation Departing Load (CGDL).

First, this Decision provided that “departing load that began to receive service from customer generation on or before February 1, 2001 ... shall be exempt from all DWR bond charges and ongoing power charges.”<sup>125</sup>

Second, the Decision exempted certain small CGDL from CRS non-bypassable charges. Specifically, the Commission found that “It is reasonable and consistent with Legislative and Commission policy to provide an exception for customer generation under 1 MW in size and eligible for either net metering, CPUC self-generation funding, or CEC financial incentives, from all CRS cost components.”<sup>126</sup> This exception set an absolute cap of 3,000 MW for CGDL.<sup>127</sup> Under this cap, renewable generation was preferred, and 1,500 MW of the cap was reserved for it; furthermore, the University of California and the California State University received a set-aside under the cap.

Third, if the CGDL is over 1 MW, but is otherwise “ultra-clean and low-emissions” it is not required to pay ongoing DWR power charges, but continues to be responsible for DWR bond charge costs and Tail CTC.<sup>128</sup>

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121 Section 366 (d)(1)

122 D.02–11–022 at 36.

123 D.02–11–022 at 115.

124 D.02–11–022 at 120.

125 D.03–04–030 at 65.

126 D.03–04–030 at 62–63.

127 D.03–04–030 at 63.

128 D.03–04–030 at 66.

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## 20. Decision 03–07–028 (July 10, 2003)

### Adopted a Cost Responsibility Surcharge (CRS) for Municipal Departing Load (MDL)

In this Decision, the Commission found that “It is consistent with the intent of D.02–03–055 to impose cost responsibility surcharges on Municipal Departing Load [MDL] to the extent necessary to prevent cost shifting to bundled customers based on generally similar principles as apply to DA load as set forth in D.02–11–022.”<sup>129</sup> As a result, the Commission imposed on MDL: the DWR Bond Charge, the DWR Power Charge, Tail CTC, and SCE’s Historical Procurement Charge.<sup>130</sup> No exemptions were given for de minimis departures of MDL.

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## 21. Decision 03–07–030 (July 10, 2003)

### Reevaluated and Retained the Direct Access 2.7 Cents/kWh Cap on the Cost Responsibility Surcharge

This Decision re-evaluated the Direct Access CRS cap of 2.7 cents/kWh decided upon in Decision 02–11–022. The Commission retained the 2.7 cents/kWh cap. This Decision struck a balance of interests by recognizing two overriding goals: “(1) maintaining bundled customer indifference with respect to DA migration and (2) avoiding making DA uneconomic to customers.”<sup>131</sup>

In particular, the Commission found that “The continuation of DA provides jobs and enhances the tax base in support of the California economy, and promotes the diversity of energy supplies within California.”<sup>132</sup> The Decision continued: “Given the risk that increases in the cap may create incentives to leave DA for bundled service, relocate out of state, or go bankrupt, and considering that the existing cap provides for payoff by 2011, maintaining the existing caps avoids risking erosion of DA levels while protecting bundled customers.”<sup>133</sup>

To preserve bundled customer indifference, the Decision stated: “[W]e must provide assurance that undercollections from DA customers resulting from the cap will be repaid in full to bundled customers, with compensatory interest, over a reasonable period of time.”<sup>134</sup> The Decision concluded that the reasonable period of time for full repayment of the DA CRS undercollection should not exceed the term of DWR contracts, which were due to expire in 2011.<sup>135</sup>

The Commission reasoned that it was “desirable to charge customers based on the costs to serve them, thereby matching customer charges with the costs of service rendered to serve them.”<sup>136</sup> The Commission further reasoned:

“[T]he period of deferral should be no longer than is absolutely necessary. Requiring repayment of the DA CRS undercollection within the DWR contract time frame promotes better matching of costs paid with service rendered. Since the costs in question arise from the contracts, the time frame for their repayment bears some relationship to the term of those contracts. Limiting the repayment to the term of the contracts

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129 D.03–07–028 at 78.

130 D.03–07–028 at 81.

131 D.03–07–030 at 8.

132 D.03–07–030 at 101.

133 D.03–07–030 at 102.

134 D.03–07–030 at 25.

135 D.03–07–030 at 25.

136 D.03–07–030 at 26.

is also desirable to minimize the period that bundled customers fund any DA CRS undercollections so as to mitigate bundled customer risk. The lower the cap, the longer the time for repayment of the undercollection, and the greater the risks imposed on bundled customers relating to payment. Accordingly, we shall adopt the requirement that the caps be set at level that assures full repayment of the DA CRS undercollection no later than the termination of the DWR contracts in 2011.”<sup>137</sup>

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## 22. Decision 04–02–062 (February 26, 2004) Imposed the Regulatory Asset Charge — Later Called the Energy Cost Recovery Amount (ECRA) — on Direct Access Customers

As Pacific Gas & Electric Company (PG&E) emerged from bankruptcy, its revenue requirement substantially dropped as PG&E was relieved of certain pre-bankruptcy obligations. As a result, PG&E sought to direct this rate decrease to customers most impacted by the rate increases of the energy crisis. Concurrently, PG&E sought recovery of the Regulatory Asset. The Regulatory Asset represented past undercollections for payment of electricity during the energy crisis and leading up to PG&E’s bankruptcy. This Regulatory Asset Charge, later called the Energy Cost Recovery Amount (ECRA), was structured to repay these costs and, in Decision 04–11–015, refinanced by Energy Recovery Bonds. This charge was to expire in 2012.

The Regulatory Asset Charge originally stemmed from Decision 03–12–035 which authorized PG&E to collect \$2.21 billion from its electric ratepayers over a nine-year amortized period. The Rate Design Settlement Agreement (“Settlement Agreement”) authorized in this Decision converted the costs related to the Regulatory Asset to a non-bypassable charge. Specifically, the Regulatory Asset Charge “shall be allocated to all customers of the utility, including but not limited to bundled and Direct Access customers, on an equal cents per kWh, nonbypassable basis (except as noted in paragraph 9 below).”<sup>138, 139</sup> Customer Generation Departing Load (CGDL) was exempted from paying the Regulatory Asset Charge.

The Settlement Agreement also adopted the following: “Other than as required by this Agreement, no customer shall be required to pay any additional amount for past undercollections to facilitate PG&E’s emergence from bankruptcy.”<sup>140</sup>

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## 23. Decision 04–11–014 (November 19, 2004) Provided a Limited CRS Exemption to Municipal Departing Load (MDL)

This Decision provided limited exemptions of CRS for new Municipal Departing Load (MDL) and transferred MDL.

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137 D.03–07–030 at 26–27.

138 Attachment A (“Settlement Agreement”) to D.04–02–062 at 4 (emphasis added).

139 The methodology for calculating non-bypassable charges results in highly divergent per kWh charges to different customer classes. For example, a “flat per kWh” basis has the greatest impact on high energy users, such as industrial users. Alternatively, the “Top 100 hours” methodology allocates costs based on how each class contributes to peak demand. This negatively impacts residential or other classes that have coincident load shape while benefiting classes with flat or off-peak loads. The PCIA is charged on this “Top 100 hours” approach and results in a higher per kWh charge to residential customers.

140 Attachment A (“Settlement Agreement”) to D.04–02–062 at 4.

Neither the investor-owned utilities nor DWR explicitly incorporated MDL loads into their procurement forecasts, however, the investor-owned utilities had incorporated MDL in their procurement modeling. Specifically, PG&E included MDL and irrigation district “bypass” in its August 2000 Bypass Report provided to DWR.

As a result, “Since provision for new MDL of publicly-owned utilities was implicitly included in the IOUs’ forecasts, there is a basis to grant a limited exception to CRS charges for new MDL of publicly-owned utilities.”<sup>141</sup> This limited exception for new MDL was capped at 150 MW to prevent cost-shifting. With regards to transferred MDL, a CRS exception was first provided to irrigation districts and municipalities identified in the August 2000 Bypass Report.

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## 24. Decision 04–12–046 (December 16, 2004) Adopted Interim CRS Charges for CCAs and Service Protocols

This Decision implemented the initial framework for Community Choice Aggregation (CCA) and the initial CRS charge structure applicable to CCA. Specifically with regards to exit fees, the Decision: (a) applied DWR Bond and DWR ongoing costs to CCA customers; (b) implemented a \$0.020/kWh temporary CRS; and (c) set forth “ratemaking and cost allocation principles for utility services offered to CCAs, implementation costs and the CRS.”<sup>142</sup>

With regards to certain charges, there was consensus on what costs CCA customers were responsible for:

“All parties agree that AB 117 requires the CCA CRS to include a variety of costs incurred on behalf of CCA customers prior to their transferring to the CCA. Such costs include (1) costs associated with power contracts and bonds entered into by DWR during the energy crisis; (2) utility power costs, including those of utility retained generation, purchased power and other commitments in approved resource plans; and (3) CTC and historic revenue undercollections and credits applicable to the customer at the time the CCA transferred the customer. No party disputes these cost elements.”<sup>143</sup>

However, these costs were balanced against the need to ensure that they were not anticompetitive. For example, the Office of Ratepayer Advocates believed “it would be ‘fundamentally unfair and against the basics of a competitive market place to make a CCA pay its competitor’s cost of taking away its customer.’”<sup>144</sup> Furthermore, the costs were required to be “unavoidable.” The Decision stated: “Section 366.2(d)(1) of AB 117 provides that the costs associated with CCA’s procurement of power for local residents and businesses must not require remaining utility customers to assume additional costs, that is, those power procurement costs that would be unavoidable when the utility loses customers to the CCA.”<sup>145, 146</sup>

### 1. Adoption of an Initial Approach to CCA CRS

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141 D.04–11–014 at 53.

142 D.04–12–046 at 4–5.

143 D.04–12–046 at 24.

144 D.04–12–046 at 18.

145 D.04–12–046 at 23 (emphasis added).

146 Section 366.2(d)(1): “It is the intent of the Legislature that each retail end-use customer that has purchased power from an electrical corporation on or after February 1, 2001, should bear a fair share of the Department of Water Resources’ electricity purchase costs, as well as electricity purchase contract obligations incurred as of the effective date of the act adding this section, that are recoverable from electrical corporation customers in commission-approved rates. It is further the intent of the Legislature to prevent any shifting of recoverable costs between customers” (emphasis added).

With regards to DWR charges, the Commission adopted the methodology proposed by DWR:

“DWR recommends that the Commission adopt for CCAs its CRS methodology, which is referred to variously as “CCA-in/CCA-out,” “total portfolio” model or the “indifference fee” approach. This methodology analyzes the liabilities that would otherwise be assumed by bundled utility ratepayers when the CCA begins serving local customers. Those liabilities would then be incorporated in the CRS so that bundled utility ratepayers are not penalized by the utilities’ loss of energy customers. This methodology is the one adopted in D.02–11–022 for Direct Access customers. It is a forecast of those DWR power costs that are assumed by PG&E, SCE and SDG&E and that are expected to exceed market prices.”<sup>147</sup>

With regards to the overall CRS, the Decision stated a “predisposition toward the concept of vintaging” the CCA CRS.<sup>148</sup> The Decision, however, raised several concerns regarding this approach. First, the Commission raised concern over regulatory complexity. Second, the Commission raised concern over the possibility that the methodology would result in “dramatic fluctuations” in the CRS, creating significant financial uncertainty.<sup>149</sup> As a result, it implemented the temporary \$0.02/kWh cap on CRS for CCAs.

## 2. Development of a “Going Forward” Framework for CCA CRS

The Commission offered the following policy analysis for the CRS: “the approach we adopt for how to develop a CRS for each generation of CCA should, to the extent possible, balance...: accuracy, equity among different generations of CCAs, administrative simplicity, and certainty for CCAs and the utilities. We also anticipate that each CCA’s CRS liability would terminate at some point.”<sup>150</sup> The Commission noted that there were different options for determining liability for CRS. For example, one model of implementing the CRS the Commission raised was: “to adopt a package of liabilities for each generation of CCA that would be fixed (although the dollar liability would vary with changes in market prices) and therefore could be paid off by a forecast date.”<sup>151</sup>

## 3. The Need for Utilities to Account for CCA in Their Procurement Plans

Importantly, the Commission also took up the issue of utility procurement. Specifically it provided that:

“The objective of AB 117 in requiring CCAs to pay a CRS is to protect the utilities and their bundled utility customers from paying for the liabilities incurred on behalf of CCA customers. Our complementary objective is to minimize the CRS (and all utilities liabilities that are not required) and promote good resource planning by the utilities.”<sup>152</sup>

With regards to utility procurement and CCA, “utility resource plans will need to balance supply security with enough flexibility to accommodate many market contingencies in addition to those associated with the CCA program.”<sup>153</sup> As a result, the Commission required that “as long as the utilities have made reasonable assumptions about future electricity demand, the CRS must include all stranded costs that occur when customers transfer their accounts to the CCA.”<sup>154</sup> The Commission found that it was not consistent with law to have the vintage and liability purely associated with the departure of the CCA customer without this need for forecasting.

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147 D.04–12–046 at 24.

148 D.04–12–046 at 27.

149 D.04–12–046 at 26.

150 D.04–12–046 at 27 (emphasis added).

151 D.04–12–046 at 27.

152 D.04–12–046 at 29 (emphasis added).

153 D.04–12–046 at 29.

154 D.04–12–046 at 29–30 (emphasis added).

“On the other hand, SCE’s proposal to include in the (vintaged) CRS all contract costs incurred up to the date customers transfer to the CCA is not consistent with the law. There will surely be circumstances where contracting for more energy, assuming all CCA load, would be “avoidable” and where those commitments would not be “attributable to the customer.” We share the parties’ concerns that the utilities must recognize CCA load in their resource planning and should not sign contracts that might create new liabilities for CCA customers and utility customers where available information suggests the power might not be needed. We understand the utilities face a difficult balancing act by assuring adequate and reliable power supplies in amounts that reflect forecasts that are changing constantly. However, the utilities are accustomed to using available information to forecast customer demand and should incorporate CCA load losses into their planning efforts, just as they would include any other forecast variable related to expected changes in supply or demand.”<sup>155</sup>

To this end, in Conclusion of Law 12, the Commission required: “The utilities should establish a CRS, consistent with this order and DWR’s model, to allow the utilities to recover costs of power purchase commitments that become stranded as a result of the CCA initiating service. Such costs include DWR bond and power purchase contracts, utility power purchase commitments and balances in power purchase accounts but should not include costs that may have been avoidable or are not otherwise attributable to the CCA’s customers.”<sup>156</sup>

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## 25. Decision 04–12–048 (December 16, 2004)

### Adopted Cost Recovery for New Generation Resources and Utility Owned Generation through the CRS; Required Investor–Owned Utilities to Incorporate CCA Load into Their Long Term Procurement Planning

This Decision adopted a CRS expansion to include all utility procurement — not simply energy crisis-era procurement. This expansion of the CRS is what is now known as the Power Charge Indifference Adjustment (PCIA). In the case of non–Renewables Portfolio Standard (RPS) contracts, cost recovery was limited to 10 years.<sup>157</sup> The Decision also ordered investor–owned utilities to include forecasts of CCA loads in their future Long Term Procurement Plans (LTTPs). While this Decision authorized the IOUs to recover stranded costs of their electric resource commitments, it did not specify the implementation mechanism for the NBC. Consequently, implementation details were deferred to R.06–02–013, and subsequently to Track 3 of that proceeding.

#### 1. The Expansion of CRS to Include New Generation

The Commission agreed that “the utilities should be allowed to recover their net stranded costs from all customers, which may require the application of additional cost responsibility surcharges or other non–bypassable surcharges.”<sup>158</sup> The Decision emphasized that the “threshold policy issue underlying cost responsibility surcharges is to ensure that remaining bundled ratepayers remain indifferent to stranded costs left by the departing customers.”<sup>159</sup>

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155 D.04–12–046 at 30 (emphasis added).

156 D.04–12–046 at 65 (emphasis added).

157 “The utilities should be allowed to recover stranded costs for these resources from departing load over either the life of the contract or 10 years, whichever is less. The ten–year recovery period will also apply to any utility–owned generation acquired as a result of the procurement process, commencing once the resource begins commercial operation” (D.04–12–048 at 61). RPS contracts are for the life of the contract.

158 D.04–12–048 at 33.

159 D.04–12–048 at 201.

By expanding the scope of the CRS to include new generation resources and utility-owned generation resources, the Decision required “departing customers to assume a fair share of their costs, and thus avoiding cost shifting, is also consistent with the Commission’s policy of holding captive ratepayers harmless as required by state law.”<sup>160</sup> This new CRS treatment allowed for the investor-owned utilities to recover “uneconomic” or “stranded” costs of these facilities from departing ratepayers. The expansion of CRS was based on the following reasons:

“[T]he Commission has now made the utilities responsible for ensuring local reliability, accelerated the resource adequacy requirement from 2008 to 2006, and adopted RPS target goals resulting in the solicitation of new renewable energy sources by the utilities. These initiatives, combined with the existing overhang of utility retained generation and long-term DWR contracts significantly limit the flexibility that the utilities have to quickly adjust their resource portfolios. All of these resource additions benefit all existing customers by improving reliability and promoting renewable energy development.”<sup>161</sup>

“Providing for stranded cost recovery provides a greater incentive for the utilities to enter into five year or longer contracts for existing capacity that many parties ... are advocating as the optimal approach to ensure the availability of these resources.”<sup>162</sup>

“[I]t appears that the utilities may need to make longer-term commitments for capacity and energy that may become stranded at some point during the life of these projects.”<sup>163</sup>

“In general we agree that the utilities should be allowed to recover their stranded costs from all customers, including an exit fee. Such an approach best meets the Commission’s goals of providing ‘the need for reasonable certainty of rate recovery’ (as required under AB 57 and noted in the June 4th ACR) as well as best ensuring that California meets its energy needs.”<sup>164</sup>

The Commission further stated that: “As the utilities will be acquiring their new resource needs through the competitive and transparent procurement process that we are adopting, it is our expectation that there should be little if any stranded costs.”<sup>165</sup>

## 2. Identification of the Need to Plan for Departing Load

The concern that the Commission held at this time was one of uncertainty regarding departing load. Specifically, the uncertainty of departing load customers — “by way of CCA, municipalization, Direct Access (DA) or a core/non-core structure”<sup>166</sup> — would potentially cause IOUs to over-procure, leading to excessive stranded costs. The Decision stated:

“A major issue in this proceeding is the extent to which the utilities will be compensated for investments or purchases that they must make in order to meet their obligations to provide reliable service to their customers. The implementation of CCA, departing municipal load, and the potential for lifting, in some form or another, the current ban on allowing new Direct Access, all create uncertainty as to the amount of load the existing utilities will be responsible for serving in the future.”<sup>167</sup>

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160 D.04-12-048 at 229.

161 D.04-12-048 at 57.

162 D.04-12-048 at 58.

163 D.04-12-048 at 58.

164 D.04-12-048 at 57.

165 D.04-12-048 at 60.

166 D.04-12-048 at 17.

167 D.04-12-048 at 196-197.

As a result of this uncertainty, the Commission required the utilities to plan for CCA departing load. In fact, even the “High Load Plan” was to include “modest development of CCA.”<sup>168</sup> Direct Access load departures were not incorporated into the LTPP projections since the legislative Direct Access cap had been reached.

The investor-owned utilities planned for departures and otherwise complied with the Commission’s directives and the IEPR.<sup>169</sup> However, with regards to departing CCA load and when the investor-owned utilities are required to stop procuring on behalf of the CCA customers, the Commission stated that: “We do not determine a precise trigger point when an IOU can stop procuring in this decision. Instead, we encourage cities and counties that intend to procure power as a CCA to work with the IOU to develop an agreement, which allocates procurement risk in subsequent periods.”<sup>170</sup> CCAs were given an option of providing a unilateral binding notice of intent. The Decision stated, “If the CCA does so, its customers will not be responsible for stranded costs of any utility commitments entered into after the agreed upon date.”<sup>171</sup>

Consequently, the Commission required:

“Future IOU procurement plans shall incorporate reasonable anticipated CCA departing load. A prospective CCA provider should inform the utility of its intentions as early in the planning cycle as possible. IOU plans shall acknowledge potential CCA departing load by identifying the CCA, estimated departing load, and the implication for utility procurement liabilities.”<sup>172</sup>

The Decision also found that: “Since CCA has been set in statute and is the subject of an on-going CPUC implementation proceeding, it is reasonable to assume that some CCA will start to occur in 2006. There was not sufficient evidence in this proceeding to prove that CCA alone will have a material effect on IOU resource needs in the next few years.”<sup>173</sup>

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## 26. Decision 05–08–035 (August 25, 2005) Exempted New MDL from PG&E’s RAC and Energy Recovery Bond Charges; Denied Exemption for Transferred Load

This Decision granted petitions to modify D.04–02–062 to “exempt new municipal departing load (new MDL) from PG&E’s Regulatory Asset Charge (RAC) and Energy Recover Bond Charges to the same extent that new MDL is exempt from the DWR Power Charge. The petitions [were] denied to the extent they [sought] to exempt transferred load from the RAC and Energy Recovery Bond [ERB] Charges.”<sup>174</sup>

The Commission determined that transferred load should not be exempted for two reasons: first, D.04–02–062 “did not contemplate an exemption for transferred load.”<sup>175</sup> Second, “exemptions from the Energy Recovery Bond Charges are limited to those authorized by Pub. Util. Code Sections 848.1(b)–(d).”<sup>176</sup> Because of the similar treatment for RAC and Energy Recovery Bond Charges, the Commission determined that transferred load should not be exempted from the RAC. However, the Commission did note that there were statutory exceptions to

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168 D.04–12–048 at 25.

169 D.04–12–048 at 30.

170 D.04–12–048 at 54.

171 D.04–12–048 at 201–202.

172 D.04–12–048 at 55.

173 D.04–12–048 at 196.

174 D.05–08–035 at 2.

175 D.05–08–035 at 9.

176 D.05–08–035 at 9.



PG&E's recovery of the principal, interest, and other costs associated with the ERBs mandated in Sections 848.1(b) (2), 848.1(c), and 848.1(d).

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## 27. Decision 05–12–041 (December 15, 2005) Implemented a Vintaged PCIA for CCA; Required CCAs and Utilities to Develop CCA Departure Forecasts

This Decision followed up on implementing concepts set forth in Decision 04–12–046. Specifically, it implemented “vintaging” for the CCA Cost Responsibility Surcharge (CRS).<sup>177</sup> The Commission adopted “the DWR’s method for calculating the CRS, which is based on the difference between the hourly average cost of power in the utility’s procurement portfolio and the market price.”<sup>178</sup> The Decision also explicitly included utility renewables portfolio standard (RPS) contract costs as part of the CRS.

The CRS was intended to work in tandem with the utilities’ procurement practices. The Commission concluded that “the utilities and CCAs should work collaboratively to develop forecasts for the load utilities will lose when a CCA initiates service.”<sup>179</sup>

The Commission also implemented a “binding notice of intent” process. The concept behind a binding notice of intent “is to minimize utility power purchases that might later become stranded when the CCA initiates service.”<sup>180</sup> Specifically, “A binding notice of intent signed by the CCA and which specifies a date for the CCA’s initiation of service... should automatically relieve the utility of its obligation for purchasing power for the CCA’s customers as of the specified service initiation date.”<sup>181</sup>

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## 28. Decision 06–07–029 (July 21, 2006) Established the Cost Allocation Mechanism (CAM) Charge

This Decision established the Cost Allocation Mechanism (CAM) charge, which allows the benefits and costs of new generation to be shared by all benefitting customers in an IOU’s service territory. The Decision designated the IOUs to procure new generation through long-term power purchase agreements (PPAs) and elect at the time it applies for approval whether or not they intend that CAM should apply to the contract. The Commission’s decision on the IOUs’ applications would then determine whether CAM would apply.<sup>182</sup>

Through the CAM, the capacity and energy from the PPAs would be unbundled and the capacity would be allocated among all LSEs in the IOU’s service territory. Such rights to the capacity could be applied toward each LSE’s resource adequacy (RA) requirements. The LSEs’ customers receiving the benefit of this additional capacity

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177 “Vintaging’ a CRS is the process of calculating a CRS that reflects the power purchase liabilities incurred on behalf of a specific group of customers. Because power purchase liabilities change over time, CRS vintaging would be conducted at regular intervals to reflect those changes” (D.05–12–041 at 57).

178 D.05–12–041 at 57.

179 D.05–12–041 at 63.

180 D.05–12–041 at 57.

181 D.05–12–041 at 64.

182 D.06–07–029 at 60.

pay for the net cost of this capacity, which is determined as the total cost of the contract minus the energy revenues associated with dispatch of the contract.

The Commission also found and concluded the following:

- » “We intend to pursue policies to develop and maintain a viable and workably competitive wholesale generation sector in order to assure least cost procurement for bundled utility customers.”<sup>183</sup>
- » “It is reasonable, and consistent with law, for the Commission to adopt this limited and transitional cost allocation mechanism to support the development of new generation by having the costs and benefits shared by all customers.”<sup>184</sup>
- » “Accordingly, we will adopt a modified version of the [Joint Parties’] proposal on a limited and transitional basis. This new cost-allocation mechanism will not apply to commitments made after new institutions are decided upon, developed and in place.”<sup>185</sup>
- » “We are supportive of the proposal that load serving entities (LSEs) that can demonstrate that they are fully resource adequate over a sufficiently long time horizon should be allowed to opt-out of the cost-allocation system.”<sup>186</sup>
- » “This mechanism disaggregates the energy and capacity components of the newly acquired generation, so that the only non-bypassable charge levied is for the net capacity costs, and the non-IOU LSEs retain the ability to manage their energy purchases.”<sup>187</sup>

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## 29. Decision 06–07–030 (July 20, 2006)

### Converted the DWR Power Charge into a Power Charge Indifference Adjustment (PCIA) and Set a Uniform Calculation of CTC

During the continued suspension of Direct Access, relevant parties came together to create a uniform calculation of CTC and developed a methodology to address the DWR Power Charge. At this point, the Cost Responsibility Surcharge (CRS) consisted of the Competition Transition Charge (CTC) and the Power Charge Indifference Adjustment (PCIA). The CRS was capped at \$0.027/kWh and this transitioned to a market-based methodology once the “undercollection” of past CRS reached zero for each utility (no later than 2008.)

#### 1. The Beginning of PCIA

Under this Decision, as of September 1, 2006, the DWR Power Charge component was to be replaced with a PCIA.<sup>188</sup> The PCIA recovery was based on a market benchmark approach and recovers the above market cost of power represented by the DWR Power Charge. This Decision was built upon Decision 02–03–055, which set forth the bargain that “as a condition of retaining the DA suspension date of September 21, 2001, bundled customer

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183 D.06–07–029 at 2 (emphasis added).

184 D.06–07–029 at 60 (emphasis added).

185 D.06–07–029 at 4 (emphasis original).

186 D.06–07–029 at 5 (emphasis added).

187 D.06–07–029 at 56.

188 D.06–07–030 at 55.

indifference should be preserved and no cost shifting from DA to bundled customer load should be allowed.”<sup>189</sup> As such, it represented a closed universe of costs in a specified period of time.<sup>190</sup>

## 2. CTC Becomes Market Based

Similarly, the Commission adopted an equivalent market benchmark approach for ongoing CTC, making a uniform methodology for all components of the CRS.<sup>191</sup>

## 3. CRS Prohibited from “Going Negative”

This Decision provided that in any given year, the CRS would be prohibited from “going negative.” Rather, any negative amounts that otherwise should have been returned to DA customers were to be applied in future (positive) years.<sup>192</sup>

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## 30. Petition 06–12–002 (December 6, 2006) Requested Reconsideration to Reopen Direct Access

In 2006, Alliance for Retail Energy Markets, along with 35 co–filers and 147 supporting entities, filed a petition to commence a rulemaking to consider the reopening of the Direct Access (DA) retail market.

Petitioners asserted that concerns regarding customer choice that led to the suspension of DA had been addressed and were no longer at issue. Specifically, issues regarding stranded costs on bundled customers from departing DA customers had been addressed by the creation of the cost responsibility surcharge (CRS) mechanism. The Petitioners also reasoned that retail choice and competitive retail markets provide economic and environmental benefits and therefore provide a strong incentive for the Commission to consider reinstating Direct Access.

The Commission thereafter granted the Petition and instituted a rulemaking proceeding (R.07–05.025) to determine the reopening of Direct Access.<sup>193</sup>

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## 31. Decision 07–01–025 (January 25, 2007) Confirmed the Calculation Methodology of the Cost Responsibility Surcharge

The Cost Responsibility Surcharge (CRS) calculation methodology was confirmed to have two steps: First, the Competition Transition Charge (CTC) is calculated and reviewed in the utility’s annual ERRA proceeding; second, the “indifference rate” is then calculated by estimating the difference between the average cost of the utility’s total portfolio compared to a market price benchmark.<sup>194</sup> The deduction of the CTC from the indifference rate leaves as a residual a Power Charge Indifference Adjustment (PCIA), which is a component of CRS.<sup>195</sup>

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189 D.06–07–030 at 49.

190 The PCIA continues today for a different purpose since it is for: (1) departed and new departing load, and (2) contains all utility contracts in addition to the DWR Power Charge.

191 D.06–07–030 at 15.

192 D.06–07–030 at 17.

193 In 2009, the Legislature passed SB 695 authorizing the lift of DA suspension in a limited capacity. The Commission issued D.10–03–022 to implement the DA requirements.

194 D.07–01–25 at 4.

195 D.07–01–25 at 4.

Additionally, this Decision established that CTC and utility-generation forecasts are to be set in each utility's ERRR proceeding and sets the CCA CRS to be consistent with the DA CRS.<sup>196</sup>

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### 32. Decision 07-01-030 (January 25, 2007)

#### Revised the Indifference Rate, PCIA, and CTC Methodology to Include RA/Capacity Adders and Line Loss Factors

This Decision resolved issues in D.06-07-030 related to the Cost Responsibility Surcharge (CRS) methodology as applied to Direct Access (DA) and Municipal Departing Load (MDL) customers. Specifically, the Decision adopted Resource Adequacy Generation Capacity (RA/capacity) adders to the indifference rate. The Commission acknowledged that these adders were necessary to capture the cost of complying with resource adequacy requirements.<sup>197</sup> The market price benchmark, used in calculating the indifference rate, was modified to incorporate published on-peak and off-peak power prices, with the average price based on a weighted average of on-peak and off-peak prices.<sup>198</sup> The market price benchmark was further modified to adjust for line loss factors. This ensured that the benchmark reflected the same average line losses that were inherent in the delivered power prices.<sup>199</sup>

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### 33. Decision 07-01-041 (January 25, 2007)

#### Authorized the First Utilization of the CAM for Utility Procurement

This Decision authorized the first time the Cost Allocation Mechanism (CAM) was applied to an IOU's new generation procurement. However, the impetus for authorizing CAM for this procurement was one of urgency.

Southern California Edison (SCE) applied before the Commission to enter into a ten-year power purchase agreement (PPA) with Long Beach Generation LLC (LBG) for 260 megawatts of natural gas-fired peaking capacity.<sup>200</sup> The Commission approved the PPA to ensure electric reliability in light of unprecedented record-breaking demand on the system during the summer heat storm of 2006 and the limited reserves in SCE's service territory.<sup>201</sup> The Commission also authorized cost recovery whereby the benefits of the capacity for resource adequacy (RA) and Local Area Reliability (LAR), cost of the PPA, and the results from the sale of the energy rights in an energy auction would be shared with all benefiting customers in SCE's distribution system.<sup>202</sup>

The Commission reasoned that the LBG PPA was an "insurance policy against interruptions in business and residential services and possible blackouts in 2007 through 2009."<sup>203</sup> Thus, this Decision applied the CAM to address exigent needs and unforeseeable circumstances where the resource adequacy framework did not suffice.

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196 D.07-01-25 at 4.

197 D.07-01-030 at 3.

198 D.07-01-030 at 6.

199 D.07-01-030 at 7.

200 D.07-01-041 at 1.

201 D.07-01-041 at 1.

202 D.07-01-041 at 11.

203 D.07-01-041 at 29.

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### 34. Decision 07–09–044 (September 21, 2007) Set Principles for CAM Implementation

This Decision adopted a settlement agreement among parties, including the three IOUs, regarding principles for the process and products for the energy auction. The Decision also made a number of changes to D.06–07–029, the foundational CAM decision.

First, although D.06–07–029 indicated the auctions were to be administered by a third party, the joint parties agreed to “IOU administration of the auctions with independent oversight.”<sup>204</sup> Second, the Commission’s Energy Division staff, rather than the California Energy Commission (CEC), would be responsible for allocating resource adequacy (RA) capacity on a quarterly basis. Third, all LSEs would be notified with the amount of RA capacity they would receive and all RA credit allocations would be provided to LSEs by the Energy Division in time for their compliance filing deadlines. The Decision also launched Track 2 of the proceeding to address how the IOUs were to “determine whether a resource qualifies as a system resource eligible for CAM treatment.”<sup>205</sup> The Commission added that it would “see that a means for ensuring fair and equitable implementation of the CAM for RA purposes” would be further discussed in a future workshop for the RA proceeding.<sup>206</sup>

The Settlement was ultimately found to be in the public interest because the transparent market process it created “should indirectly reduce the cost of energy to utility ratepayers.”<sup>207</sup> Additionally, the Commission found that “all LSEs, including the IOUs, were unwilling to sign long-term contracts because of perceived risks associated with market, regulatory and customer uncertainty... [and] concluded in D.06–07–029 that Commission action was necessary to incentivize ‘new steel in the ground.’”<sup>208</sup> Therefore, the Commission designated the IOUs as “the procurers of the long-term contracts for new generation, but [also indicated that] the costs and benefits of the capacity and energy would be shared by all benefitting parties in the IOUs’ respective service territories.

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### 35. Decision 07–12–052 (December 20, 2007) Found No Impact by Future CCA and DA Departing Load and Recognized That IOUs Could “Cherry Pick” CAM Resources for their Bundled Customers to the Detriment of DA Customers

This Decision modified and adopted the 2007–2016 Long-Term Procurement Plans (LTTP) for PG&E, SCE and SDG&E. The Commission, in requiring the LTTPs to identify need for new generation resources, developed a need determination methodology in order to bolster system reliability. The need determination would be based on: (1) the load, resource, and Planning Reserve Margin assessments, (2) other relevant information IOUs and other parties provided in the record of the proceeding, and (3) the principle that each of the three IOUs should provide approximately the same level of system reliability to its customers.<sup>209</sup>

In response to parties’ concerns over PG&E’s assessment of departing load, the Commission agreed with PG&E that its “analysis of system need is not impacted by possible future load shifting due to [Direct Access] DA and [Community Choice Aggregation] CCA ... ”<sup>210</sup> PG&E reasoned that its numbers were for its entire service area,

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204 D.07–09–044 at 4–5.

205 D.07–09–044 at 5.

206 D.07–09–044 at 6.

207 D.07–09–044 at 11.

208 D.07–09–044 at 11.

209 D.07–12–052 at 103.

210 D.07–12–052 at 32.

including DA and CCA, and that even if there is a significant load departure, PG&E would be able to adjust its portfolio to address those changes.<sup>211</sup> The Commission made similar conclusions for SCE and SDG&E, finding that their system needs would not be impacted by future CCA and DA departing load.<sup>212</sup>

The Commission also directed each IOU to present an analysis of system need and bundled customer need.<sup>213</sup> The Commission raised several concerns stemming from the absence of a standard methodology or consistent practice for identifying system versus bundled resource needs:

- » “First ... it is unclear how [IOUs with overlapping service territories] will coordinate the identification of system need to ensure that they do not procure duplicate system resources ... .
- » Second, without a standard methodology for differentiating system and bundled need, there is no way to ensure whether an IOU election to utilize the CAM for a new resource is appropriate ... .
- » Third ... without some clear methodology for identifying system need versus bundled need, there is no way to ensure that IOUs will not elect to utilize the CAM for less attractive new resource acquisitions, while keeping ‘good’ deals for bundled customers only.”<sup>214</sup>

Thus, the Commission directed IOUs and other interested intervenors to develop proposals for methodologies for identifying bundled– versus system–driven resources in the next LTPP procurement scoping document.<sup>215</sup> The Commission found:

“Based on the record in this docket, it is clear that the election of a resource for CAM treatment when the application is submitted (i.e., after an RFO) creates the potential for IOUs, in their dual role as bundled customer electricity providers and system–reliability providers, to “cherry–pick” resources for their bundled customers, to the detriment of DA customers. Until the system versus bundled methodology is developed, we anticipate that the development of a separate CAM review group ... will prevent this outcome. We direct ED to monitor the veracity of this assumption and bring any claims of unfair treatment by IOUs of CAM and non–CAM elections of selected resources to the Commission’s attention.”<sup>216</sup>

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## 36. Decision 08–09–012 (September 4, 2008) Set Guiding Principles for Non–Bypassable Charges and Substantially Revises the Exit Fee Regime

Decision 08–09–012 was a sweeping decision which implemented the non–bypassable charges set forth in D.04–12–048 (PCIA) and D.06–07–029 (CAM) for customers of Direct Access (DA), Community Choice Aggregation (CCA), Municipal Departing Load (MDL), and customer generation departing load (CGDL).<sup>217</sup>

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211 D.07–12–052 at 32.

212 D.07–12–052 at 37 and 40.

213 D.07–12–052 at 116.

214 D.07–12–052 at 117 and 119.

215 D.07–12–052 at 119.

216 D.07–12–052 at 120 (emphasis added).

217 Certain issues raised in the proceeding were determined to be outside of the scope of the proceeding, including:

- » There is a lack of statutory basis for NBCs;
- » Utilities should not be able to recover NBCs for procurement costs arising in the normal course of business;
- » NBCs will “chill” combined heat and power and CGDL development;
- » The benefits of CGDL justify an exclusion to the NBCs; and
- » Imposition of the stranded cost NBCs on customers currently eligible for direct access would hamper retail competition

To this end, the Commission took up the following question:

“What we must consider now is (1) what it means for this departing load to be reflected in the load forecast, and (2) given that meaning, whether these departing load customers should be fully responsible, partially responsible, or not responsible at all, for the new generation NBCs established by D.04–12–048 [PCIA] and D.06–07–029 [CAM]. This is integral to our determination of the departing load’s fair share.”<sup>218</sup>

### 1. Guiding Principles for Non–Bypassable Charges

The Decision set forth the Commission’s four key Guiding Principles related to NBCs: (1) bundled customers should not be worse off, nor better off as a result of the non–bypassable charges, (2) charges must be stranded, (3) costs are recovered only from those customers on behalf of whom the costs were incurred, and (4) costs should represent a “fair share” of costs.<sup>219</sup>

### 2. Implementation of a Total Portfolio Methodology to Collect “New World Generation” through the PCIA

Through the PCIA, the Decision began implementation of stranded cost recovery for “New World Generation.”<sup>220</sup> MDL (with the exception of large municipalizations) and CGDL would be exempt from the PCIA.<sup>221</sup> The PCIA would then become part of the CRS, along with CTC costs.

In its transition away from a capped, flat CRS, the Decision implemented three key mechanisms:

- » “With a few exceptions, use of a total portfolio approach that accounts for the ongoing CTC, DWR power charges and D.04–12–048 charges . . . .
- » Use of the market benchmark adopted in D.06–07–030, as modified by D.07–01–030, to determine above–market costs.
- » Use of a vinetaging methodology based on the calendar year in which customers depart and on whether they depart in the first or second half of the calendar year.”<sup>222</sup>

### 3. Bifurcation of Applicability of PCIA Based on Load Projections (“Fair Share” Approach) and Binding Notice of Intent (Actual Departure Approach)

The Decision created a bifurcated path with regards to the applicability of exit fees. The Commission found that a departing customer “should only be responsible for commitments that were made on its behalf. This principle is embodied in the determination of the fair share.”<sup>223</sup> While the Commission did not address the “partial responsibility,”<sup>224</sup> it addressed a pure binary approach of “not responsible” or “fully responsible” for the PCIA. This approach is implemented through the following steps:

#### (1) If Load Has Been Projected to Depart, Customers Are Not Responsible for PCIA

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(D.08–09–012 at 38).

218 D.08–09–012 at 22 (emphasis added).

219 D.08–09–012 at 10.

220 “New World Generation” is defined as “generation from both fossil fueled and renewable resources contracted for or constructed by the investor–owned utilities subsequent to January 1, 2003” (D.08–09–012 at 2, fn 1).

221 The Decision found that “MDL . . . and CGDL will not have to pay the new generation related NBCs because, by procuring resources based on LTPP forecasts that exclude CGDL and MDL classes, the IOU will not have incurred costs on behalf of these customers” CRS for large municipalizations would be addressed on an application basis. Returning Direct Access customers were not exempted from this charge (D.08–09–012 at 3).

222 D.08–09–012 at 4.

223 D.08–09–012 at 26.

224 D.08–09–012 at 22.

In essence, if the investor-owned utility removed departing loads from their procurement planning processes, the “fair share” of exit fees — the PCIA — to be paid by those departing loads is considered zero. This is the case for Municipal Departing Load (MDL) and Customer Generation Departing Load (CGDL).

### (2) If Load Has Not Been Projected to Depart, Customers Are Responsible for PCIA

If a projected departing load is not incorporated into the IOU’s forecasts, those customers are deemed to be responsible for exit fees through the PCIA. This responsibility was determined by setting the demarcation point of responsibility at the earlier of (i) a submission of a Binding Notice of Intent (BNI) that the load is going to depart, or (ii) the date of the actual departure of the load.

This full responsibility for PCIA is predicated on the assumption that “IOU’s are procuring and making procurement commitments on behalf of potential CCA customers until the specific dates indicated by the BNIs.”<sup>225</sup> The Decision concluded that imposing the BNI process on CCAs was “reasonable” since “CCAs and large municipalizations are similar in that there is potential for significant load migration and neither is reflected in the LTPP load forecasts.”<sup>226</sup>

### (3) The Burden of Proof Regarding Departing Load Is Different for MDL and Direct Access

The Commission also created two standards of review for determining whether a MDL or Direct Access customer is subject to PCIA through the “fair share” approach:

(1) for MDL “it is necessary that the affected IOU demonstrate on a case-by-case basis that the related annexation cannot reasonably be assumed to have been reflected as part of the historical MDL trends used in developing the adopted LTPP forecasts.”<sup>227</sup>

(2) for Direct Access departing loads, “up until the time that bundled customers who are eligible to return to DA service give proper notice that they will return to DA service, they are no different from the other bundled customers on whose behalf the IOUs are making procurement related decisions.”<sup>228</sup>

## 4. Guiding Principles Regarding CAM

The Decision confirms that “[b]undled customers will be indifferent to the choice of a customer to use alternative energy supplier, if the IOU charges the customer an NBC associated with that customer’s share of the annual net resource cost and assigns the associated RA credit to the customer.”<sup>229</sup> The Decision also confirmed that the maximum term length of the CAM would remain at ten years as adopted in D.06-07-029.<sup>230</sup>

Additionally, since the IOUs were not procuring system reliability resources on behalf of the POUs, and CGDL customers are not LSEs, there would be no direct use of RA credits for these departing customers, to the extent such customers are subject to the CAM.<sup>231</sup> Therefore, the Commission found that CGDL and MDL customers were excluded from the CAM.

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225 D.08-09-012 at 26.

226 D.08-09-012 at 29.

227 D.08-09-012 at 93.

228 D.08-09-012 at 98. The burden of proof regarding departing load for CCAs was not addressed.

229 D.08-09-012 at 82.

230 D.08-09-012 at 109.

231 D.08-09-012 at 103.



## 5. Denial of Recovery for Qualifying Facility (QF) Contract Costs through CAM

The IOUs at this time requested special non-bypassable charge treatment for Qualifying Facilities (QFs) and their contract costs. Specifically, the IOUs requested CAM treatment for these contracts. The Commission denied the utilities' request:

“We agree that the IOUs should be able to impose NBCs for the above market costs of these new QF contracts. This can be accomplished through the D.04–12–048 NBC [PCIA], and we will authorize that NBC for this purpose. However, there has been no demonstration of need for cost recovery of these new QF contracts through the CAM that was authorized by D.06–07–029, and we will not do so. The CAM was designed to get new system reliability resources built and the resigning of QF contracts does not accomplish that. Even for contracts with new QFs, cost recovery under the CAM may not make sense due to the requirements and costs associated with the energy auction process.”<sup>232</sup>

The Commission later reversed course on this policy in Decision 10–12–035.

## 6. Commission's Commitment to Revisiting Exit Fees

This Decision's modifications to the exit fee regime in California were significant and took place during a changing landscape. Direct access did not reopen for another year after this Decision, and at this time no CCA had yet launched service. The Commission acknowledged that “at this time, there is insufficient history of such transactions and limited knowledge of customers' intent to pursue such transactions in the future, for the IOUs to use in determining how much, or how long, power should be procured on such customers' behalf.”<sup>233</sup>

As such, the Commission set forth a process for reevaluating exit fees in the future:

“The D.04–12–048 NBC [PCIA] was established for a number of reasons including the uncertainty caused by potential increases in DA, CCA and DL. The need for the NBC is likely to be long lasting. Given the potential long-term nature of the charge, we must allow for the possibility that certain future circumstances may result in a need to modify the NBC related processes adopted in this decision.”<sup>234</sup>

In order to ensure that the Commission's four Guiding Principles were maintained into the future, the Commission ordered:

“If, due to future changing circumstances, the processes adopted by this decision for determining the D.04–12–48 NBC [PCIA] become unworkable, unbalanced, or unfair, parties may propose and request modifications to the form of the NBC or how the NBC should be determined or calculated.”<sup>235</sup>

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## 37. Senate Bill 695 (October 11, 2009) Provides for a Limited Expansion of Direct Access

In 2009, as California progressed beyond the energy crisis of 2000–2001, Senate Bill (SB) 695 (2009), also known as the Ratepayer Protection Act, was signed into law. SB 695 lifted the suspension of Direct Access and authorized the Commission to increase the cap on DA transactions. SB 695 also required the Commission to ensure

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232 D.08–09–012 at 37.

233 D.08–09–012 at 20.

234 D.08–09–012 at 57–58.

235 D.08–09–012 at 108.

that non-IOU providers of electricity, including Direct Access providers, are subject to procurement-related requirements,<sup>236</sup> such as resource adequacy requirements,<sup>237</sup> Renewables Portfolio Standard (RPS) requirements,<sup>238</sup> and certain greenhouse gas requirements.<sup>239</sup>

SB 695 also codified the Cost Allocation Mechanism (CAM), requiring the Commission to:

“Ensure that, in the event that the commission authorizes, in the situation of a contract with a third party, or orders, in the situation of utility-owned generation, an electrical corporation to obtain generation resources that the commission determines are needed to meet system or local area reliability needs for the benefit of all customers in the electrical corporation’s distribution service territory, the net capacity costs of those generation resources are allocated on a fully nonbypassable basis consistent with departing load provisions as determined by the commission, to all of the following:

- (i) Bundled service customers of the electrical corporation.
- (ii) Customers that purchase electricity through a direct transaction with other providers.
- (iii) Customers of community choice aggregators.”<sup>240</sup>

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### 38. Decision 10–03–022 (March 15, 2010) Authorized Limited DA Pursuant to SB 695 (2009)

This Decision authorized the increase of DA transaction limits (the “DA Cap”) in compliance with SB 695 (2009). The Decision also re-allocated local RA obligations from one LSE to another in the short-term to respond to cost-shifting concerns from the DA increase. Specifically, concerns were raised that bundled service customers would be left with a disproportionate share of Local RA procurement costs for the remainder of the current year. The Commission therefore adopted an interim solution that transferred a value representing a customer’s Local RA obligation from one LSE to another during the initial DA open enrollment period for 2010.

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### 39. Marin Energy Authority, California’s First Community Choice Aggregator Begins Service (May 7, 2010)

Community Choice Aggregation was identified in Marin County’s Greenhouse Gas Reduction Plan as one of the most effective methods to combat climate change and reduce greenhouse gas emissions.<sup>241</sup> After a collaborative stakeholder process, including feasibility studies, surveys, workshops, stakeholder meetings, and public hearings, Marin County established the Marin Energy Authority (MEA) in order to provide a higher proportion of green energy to customers in Marin County. At the time, PG&E’s energy mix consisted of twelve percent (12%) renewable energy.

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<sup>236</sup> Section 365.1(c)(1).

<sup>237</sup> Section 380.

<sup>238</sup> Section 399.11 et seq.

<sup>239</sup> Health and Safety Code Section 38500 et seq.

<sup>240</sup> Section 365.1(c)(2)(A).

<sup>241</sup> Figure 3.1 — Proposed Building Energy Use CO<sub>2</sub> Reduction Measures. Marin County Greenhouse Gas Reduction Plan (October 2006) at page 8.

After filing an implementation plan with the CPUC, MEA began service to select communities in Marin County that voted to join its Joint Powers Authority. MEA offered two products: the default “light green” product consisting of twenty–five percent (25%) renewable energy (currently fifty percent (50%) renewable energy) and the optional and slightly more expensive “deep green” product consisting of one–hundred percent (100%) renewable energy. MEA was met with a number of challenges from PG&E, including misinformation campaigns and Proposition 16, which would have effectively eliminated CCA implementation in California.

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#### 40. Proposition 16, an Initiative to Require a Two–Thirds Majority Vote to Establish a CCA Program, is Defeated (June 8, 2010)

In June 2010, Proposition 16, a ballot initiative to require a two–thirds vote of local voters to establish a Community Choice Aggregation (CCA) program, was defeated.<sup>242</sup> Proposition 16 was sponsored by the Coalition for Reliable and Affordable Electricity, a group funded by PG&E. In fact, PG&E was the primary financial sponsor of the initiative, having contributed \$46.1 million, while opponents had access to less than \$100,000.<sup>243</sup> If Proposition 16 had been approved by voters, a two–thirds local vote would have been required before a public agency could enter the retail power business, including establishing a CCA program, using public funding to implement a plan to become a CCA provider or expand electric service to new territory or new customers.

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#### 41. Scoping Memo and Ruling R.07–05–025 (November 22, 2010) Revised the Scope of Phase III of the Proceeding to Include Issues Relating to the PCIA

In September 2010, various parties, including Marin Energy Authority (MEA), Direct Access Customer Coalition, and Alliance for Retail Energy Markets, filed a joint motion seeking a separate expedited phase in the Direct Access proceeding to modify the methodology used in the PCIA calculation. The parties argued that the methodology had become unbalanced and unfair to the detriment of non–bundled ratepayers and the key concern was whether the benchmark used actually provided for bundled customer indifference.

This scoping memo agreed to address and reconsider the PCIA calculation with the remaining issues in Phase III. Other issues it included were the transitional bundled service rate components and calculations and Direct Access switching rules. Phase III’s final decision D.11–12–018 would make substantial reforms to the PCIA.

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#### 42. Decision 10–12–035 (December 21, 2010) Allowed for “CAM–like” Procurement of CHP by IOUs

This Decision adopted the proposed settlement regarding a new Qualifying Facility and Combined Heat and Power Program (CHP). The goals of the new program were “to preserve resource diversity, fuel efficiency,

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242 California Proposition 16 (2010) by Ballotpedia.org. ([http://ballotpedia.org/California\\_Proposition\\_16,\\_Supermajority\\_Vote\\_Required\\_to\\_Create\\_a\\_Community\\_Choice\\_Aggregator\\_\(June\\_2010\)](http://ballotpedia.org/California_Proposition_16,_Supermajority_Vote_Required_to_Create_a_Community_Choice_Aggregator_(June_2010)).)

243 *Santa Cruz Sentinel*, “Prop 16 is June’s priciest ballot initiative, with PG&E coughing up big money,” March 25, 2010.

greenhouse gas (GHG) emission reductions, and other benefits and contributions of CHP.”<sup>244</sup> Most significantly, this Decision authorized IOUs to procure CHP resources on behalf of CCAs and Electric Service Providers (ESPs), using the cost allocation mechanism (CAM) methodology. This substantially increased the procurement of IOUs under CAM and “CAM-like” methodologies.

The CCA and DA parties opposed certain components of the proposed settlement: (1) the Commission’s jurisdiction in requiring participation of CCAs and ESPs in the CHP program; (2) the improper application of CAM for CHP contracts; and (3) procedural issues with the settlement process. The Commission disagreed with these contentions and relied on several statutory provisions and policy precedent for its reasoning.

### 1. The Commission Has Proper Jurisdiction to Direct IOUs to Procure on Behalf of CCAs and ESPs

Regarding arguments challenging the Commission’s jurisdiction to require participation of CCAs and ESPs in the CHP Program, the Decision cited Public Utility Code Section 365.1(c)(1). Section 365.1(c)(1) requires ESPs to be subject to the same GHG emissions net reduction requirements as the IOUs. The Commission found that the settlement complied with this provision by requiring ESPs to procure their own CHP or allowing IOUs to procure on their behalf.

The Decision also cited to Section 365.1(c)(2), which requires the Commission to allocate net capacity costs and resource adequacy benefits to all customers, including ESP and CCA customers, when it authorizes IOUs to procure generation resources on their behalf through CAM. The Commission reasoned that it could direct IOUs to procure CHP on behalf of all retail customers through CAM since CHP resources provide system and local area reliability benefits.<sup>245</sup>

The Decision concluded that IOUs should procure CHP resources on behalf of CCAs and ESPs because of Commission concerns over the ability for non-IOU LSEs to procure their own, and the administrative burden for the Commission to monitor their compliance. Nevertheless, the Commission stated that they “remain open to consideration, in a future proceeding of proposals whereby ESPs and CCAs may opt out of IOU procurement and procure CHP resources on their own behalf.”<sup>246</sup>

Lastly, the Decision referred to the Commission’s previous positions about GHG-related requirements on ESPs, specifically noting that “[a]s a general policy, we believe it is imperative that GHG reduction goals and responsibilities be shared as broadly as possible.”<sup>247</sup> Further, the Commission stated that it had “direct authority” to regulate CCA and ESP procurement activities related to GHG insofar as the determination of those targets is “germane to the regulation of public utilities”<sup>248</sup> The Decision concluded that “if ESPs and CCAs were exempted from the GHG Emissions Reduction Targets, they would potentially have an improper competitive advantage because they would not be required to procure CHP.”<sup>249</sup>

### 2. The Commission Properly Applied the Cost Allocation Mechanism to CHP Procurement

CCA and ESP parties asserted that the Commission improperly applied SB 695 regarding the cost allocation methodology (CAM) set forth in Pub. Util. Code Section 365.1(c)(2). The parties argued the application to CHP was improper because the Commission had not determined it was needed for reliability. The Commission justified the application of CAM because CHP resources count toward resource adequacy requirements and provide

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244 D.10-12-035 at 2.

245 D.10-12-035 at 48.

246 D.10-12-035 at 56.

247 D.10-12-035 at 49.

248 D.10-12-035 at 49.

249 D.10-12-035 at 50.

system and local reliability benefits commensurate with their Net Qualifying Capacity.<sup>250</sup> Thus, the Commission found the procurement of CHP by IOUs “fits squarely within the parameters of SB 695.”<sup>251</sup>

The Commission further determined that IOUs would also be authorized to recover net capacity costs for CHP generation from all customers on a non-bypassable basis. The Decision cited Pub. Util. Code Section 366.2(f)(2), which requires the Commission to ensure that CCA customers reimburse IOUs for their share of procurement costs attributable to the customer. The Commission also found that “where DA and CCA customers benefit from procurement, these customers should pay their share of procurement costs.”<sup>252</sup> It based this policy on past examples, including the allocation of costs for new generation resources, costs for GHG compliance, and locational costs associated with CHP facilities. The Commission reasoned that the allocation of such costs to CCA and DA customers were justified because of the benefits those customers received from such programs. As such, it determined that allocating costs for CHP procurement followed previous policy since CCA and DA customers would benefit from such procurement.

Although the Commission had previously made the policy determination that CAM was only designed for new system reliability resources and rejected proposals of CAM treatment for QFs,<sup>253</sup> this Decision reversed its course and authorized recovery of QF/CHP through CAM.

### 3. MDL Customers Are Also Subject to Procurement Costs of CHP by IOUs

The California Municipal Utilities Association (CMUA) disagreed with the settlement in requiring municipal departing load customers to bear a share of the IOU costs incurred on their behalf. It cited to the Commission’s previous findings in D.08–09–012 which “exempted MDL from stranded cost responsibility for new generation resources because the load forecast to determine new resource needs takes into account the departure of customers for municipal service.” The Commission disagreed and reasoned that CHP procurement is not the same as new generation resources since it was not based on load forecasts but on current retail sales data of current bundled customers. The Commission found that cost allocation to MDL customers was justified, permitting a deviation from the MDL exemption in D.08–09–012.<sup>254</sup>

### 4. Due Process Requirements Were Satisfied During the Settlement Review Process

ESPs and CCAs also raised concerns that they were not consulted about or invited to participate in the settlement review process. The party raised due process concerns on the grounds that negotiations leading to the proposed settlement were conducted without notice even though DA and CCA issues had been discussed.

The Commission referred to the settlement rules stating that there was no requirement that all parties participate in settlement discussions and reasoned that the parties had the opportunity to file comments and replies on the proposed settlement and proposed decision. The Decision found that the Commission was in conformance with the settlement rules and that the process met due process requirements.

The CCA and DA parties also requested for hearings or workshops to address its issues with the proposed settlement and the underlying problems with IOU procurement and cost allocation. The Commission found it unnecessary and that the issues were appropriately addressed by notice and comments.

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250 There was no evidence in the record that CHP provided system or local reliability benefits.

251 D.10–12–035 at 51.

252 D.10–12–035 at 49.

253 D.08–09–012 at 37.

254 D.10–12–035 at 52.

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#### 43. Decision 11–05–005 (May 5, 2011) Modified CAM to be Consistent with SB 695

After the passage of Senate Bill 695 (2009), CAM treatment required modification to comport with the requirements of the new Public Utilities Code Section 365.1(c). Three major changes made in this Decision included:

1. The utilities no longer had the ability to elect or decline to elect CAM treatment for generation resources. Thus, CAM is subject to the discretion of the Commission, not the IOUs;
2. CAM treatment was allowed for utility–owned generation; and
3. The duration of CAM treatment was no longer subject to a ten–year limit. Instead, the duration of CAM treatment was required to match the duration of the underlying contract.

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#### 44. Senate Bill 790 (October 8, 2011) Institutes a Community Choice Aggregation “Bill of Rights”

In the period leading up to Assembly Bill 790, PG&E had undertaken significant anti–CCA marketing and activities — including the \$46.1 million in funding for Proposition 16. As a result, the Legislature deemed it appropriate to incorporate additional protections for CCAs into the Public Utilities Code.

##### 1. Recognition of CCA Challenges

SB 790 identified many of the challenges faced by CCAs. For example, Section 2(c) indicates: “Electrical corporations have inherent market power derived from, among other things, name recognition among customers, longstanding relationships with customers, joint control over regulated operations and competitive generation services, access to competitive customer information, and the potential to cross–subsidize competitive generation services.”

Additionally, the Legislature found and declared in Section 2(g) and 2(h): California has a substantial governmental interest in ensuring that conduct by electrical corporations does not threaten the consideration, development, and implementation of community choice aggregation programs . . . . It is therefore necessary to establish a code of conduct, associated rules, and enforcement procedures, applicable to electrical corporations in order to facilitate the consideration, development, and implementation of community choice aggregation programs, to foster fair competition, and to protect against cross–subsidization by ratepayers.

As a result of SB 790, customers that return to electrical corporation service after terminating CCA service were only required to stay with the electrical corporation for twelve months before they were again eligible to join CCA service.<sup>255</sup>

##### 2. Code of Conduct for Electrical Corporations

One of these protections was encapsulated by Section 707, establishing a code of conduct to govern the conduct of the electrical corporations relative to the consideration, formation, and implementation of CCA programs. SB 790 required the code of conduct, associated rules, and enforcement procedures to “incorporate rules that

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255 Section 366.2(c)(13).

the commission finds to be necessary or convenient in order to facilitate the development of community choice aggregation programs, to foster fair competition, and to protect against cross-subsidization paid by ratepayers.”<sup>256</sup>

### 3. Cross-Subsidization of Bundled Customers by CCA Customers Is Prohibited

Cross-subsidization by ratepayers was another issue recognized in SB 790. Section 366.2(a)(4) mandates, “The implementation of a community choice aggregation program shall not result in a shifting of costs between the customers of the community choice aggregator and the bundled service customers of an electrical corporation.” Section 380 also states, “In establishing resource adequacy requirements, the commission shall achieve all of the following objectives ... equitably allocate the costs of generating capacity and prevent shifting of costs between customer classes.”

Additionally, Section 366.2(k)(1) establishes, “[e]xcept for nonbypassable charges imposed by the commission pursuant to subdivisions (d), (e), (f), and (h), and programs authorized by the commission to provide broader statewide or regional benefits to all customers, electric service customers of a community choice aggregator shall not be required to pay nonbypassable charges for goods, services, or programs that do not benefit either, or where applicable, both, the customer and the community choice aggregator serving the customer.”

### 4. Additional Parameters for Procurement Imposed by Electrical Corporations

SB 790 added Section 366.2(a)(5), which provided that CCAs are “solely responsible for all generation procurement activities on behalf of the CCA’s customers, except where other generation procurement arrangements are expressly authorized by statute.” SB 790 further added that the “commission shall determine and authorize the most efficient and equitable means for ... ensuring that CCAs can determine the generation resources used to serve their customers.”<sup>257</sup>

Section 365.1(c)(2)(B) was also modified to “ensure that those resource [arrangements expressly authorized by statute] meet a system or local reliability need in a manner that benefits all customers of the electrical corporation. The commission shall allocate the costs of those generation resources to ratepayers in a manner that is fair and equitable to all customers, whether they receive electric service from the electrical corporation, a community choice aggregator, or an electric service provider.”

Further, SB 790 sets parameters on Resource Adequacy procurement. Section 380(b) requires, “in establishing resource adequacy requirements, the commission shall achieve all of the following objectives: [...] (4) Maximize the ability of community choice aggregators to determine the generation resources used to serve their customers.”

### 5. CCAs May Elect to Administer Energy Efficiency Programs

SB 790 also permitted CCAs to elect to administer, rather than apply to administer, energy efficiency programs for its own customers.<sup>258</sup>

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256 Section 707(a)(4)(A).

257 Section 380(h)(5).

258 Section 381.1(e)-(f).

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## 45. Decision 11–12–018 (December 07, 2011)

### Reformed the PCIA Methodology to Include, Among Other Changes, a “Green Adder” for Renewable Energy

This Decision adopted various updates and reforms in the rate setting methodologies and rules applicable to DA service in recognition of regulatory and industry changes. The Commission found that market and regulatory changes since 2006 warranted updates in order to continue to ensure that cost responsibility is appropriately assigned. Among its reform measures, the Decision significantly revised the methodology for the market price benchmark used to calculate the PCIA for DA customers, including a renewable resource attribute (“green adder”). It also revised switching rules between bundled and DA service and defined re-entry fees and ESP financial security requirements.

#### 1. Reforms to the Market Price Benchmark

##### a. Renewables Portfolio Standard Adder

While the indifference methodology recognized the cost of renewable resources in the IOUs’ total portfolio cost, it did not account for its market value in the market price benchmark (MPB).<sup>259</sup> In effect, this increased the indifference amount charged to DA and CCA customers since the market value of renewable resources were not accounted against the IOUs’ total costs. In addition, renewable resources are generally more costly than traditional generation and thus have a higher market price, which increases an IOU’s average portfolio costs.

The Commission concluded that it would be appropriate to recognize the market value of RPS-eligible resources for purposes of calculating the indifference amount. The Decision implemented an “RPS adder,” or “green adder,” which is based on IOU costs for RPS and data from the Department of Energy for western renewable energy contract premiums. This has the effect of reducing PCIA costs for departed customers.

##### b. Revised Capacity Adder

In adopting a forecast MPB methodology for calculating the PCIA, the Decision acknowledged the need for an RA/capacity adder to capture the costs of complying with RA requirements. The Commission agreed with parties that the RA capacity should be updated. The Commission implemented SCE’s proposal to use the CEC’s estimate of the going forward costs of a combustion turbine, including the Net Qualifying Capacity of all generation resources in the utility portfolio. The Commission reasoned that this approach represented the most practical way to update the capacity value for the MPB.

##### c. Elimination of CAISO Load-Based Costs for purposes of calculating PCIA

Additionally, the Commission found that the current methodology inappropriately treated avoidable CAISO costs as if they were unavoidable, above market utility generation-related costs. DA and DL customers thus paid for these CAISO costs associated with their load through their non-utility provider and also paid a share of such costs through the PCIA.<sup>260</sup> In response to this discrepancy, the Commission decided to remove CAISO costs from the total portfolio cost for purposes of calculating the PCIA and CTC. The Commission concluded: “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.”<sup>261</sup> The Commission also stated that “exclusion of the load-based CAISO costs including load-

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<sup>259</sup> The market price benchmark is a calculated proxy that represents the market value of the IOU total energy resource portfolio (D.11–12–018 at 8).

<sup>260</sup> D.11.12–018 at 31.

<sup>261</sup> D.11.12–018 at 32.



based congestion costs, that vary based on the amount of load will produce a more accurate indifference amount calculation.”<sup>262</sup>

#### d. Load Shape Variations

Lastly, concerns were raised that the load profile reflected by the MPB was flatter than what the IOU’s supply portfolio actually served. The MPB thus created an artificially low MPB value and artificially high indifference amount impacting the PCIA and CTC.<sup>263</sup> As a result, the Commission decided that the MPB should be weighted based on the historical IOU bundled load profile.

#### 2. Other Revisions regarding Direct Access

In addition to significant reforms to the PCIA methodology, the Decision revised switching rules between bundled and DA service. It reduced the requirement for a three-year stay on bundled service down to 18 months, applicable to DA customers seeking to return from DA service.<sup>264</sup> It also adopted provisions to meet statutory financial requirements for ESPs to cover the risk of an en masse involuntary return to bundled service. Lastly, it limited the re-entry fee and security requirements of ESPs to administrative costs. To prevent cost shifting to bundled customers, the Decision required large commercial and industrial DA customers to bear the risks of increased procurement costs through payment of a Temporary Bundled Service tariff.

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#### 46. Decision 12–01–033 (January 18, 2012)

##### Confirmed that IOUs Are Required to Forecast CCA and DA Departing Load in Bundled Procurement Plans

This Decision approved the IOU bundled procurement plans and confirmed that IOUs are required to forecast CCA and DA departing load, consistent with SB 695 (2009). MCE originally protested PG&E’s proposed bundled procurement plan because the forecasts of MCE’s electricity load were excluded from the plan.<sup>265</sup> PG&E responded that it was using the Commission–mandated standardized planning assumptions. SCE, however, included in its forecast the maximum allowable phase-in of new Direct Access sales permitted under SB 695.

The Commission determined, “It is appropriate to use more accurate load forecasts for MEA [MCE], consistent with SB 695, instead of the load forecast in the standardized planning assumptions. SCE is authorized to use its direct access assumptions for purposes of establishing position limits and ratable rates for its bundled procurement plan. The other utilities should engage in procurement consistent with SCE’s assumptions for direct access.”<sup>266</sup>

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262 D.11.12–018 at 100.

263 D.11.12–018 at 32.

264 This was later adjusted to a 12-month stay period with the passage of SB 790 (2011).

265 On December 5, 2013, Marin Energy Authority (MEA) changed its name to Marin Clean Energy (“MCE”).

266 D.12–01–033 at 31.

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## 47. Decision 13–02–015 (February 13, 2013) Confirmed Application of CAM for Local Capacity Requirements

This Decision authorized SCE’s long-term procurement for local capacity requirements. The Commission maintained the status quo with respect to CAM by confirming its application to generation authorized in the Decision.

The Alliance for Retail Energy Markets, Direct Access Customer Coalition and Marin Clean Energy asserted that the Commission’s goals should be to minimize CAM procurement by only allocating CAM costs when the need for the generation can be attributed to all customers and not just IOU bundled load. They maintained that such a need could be assessed by evaluating the characteristics of the load served by the IOUs against the load served by other LSEs in the IOU service area. Lastly, the parties stressed that the Commission should ensure that CAM procurement is needed to meet a specified reliability need, as defined by Public Utility Code Section 365.1(c)(2) (B). They also proposed specific reforms for CAM including a new process to determine how a particular CAM project should be approved and mechanisms to cap and opt-out of the CAM.

The Commission found that its current policy of allocating CAM costs and benefits at the IOU service area level was appropriate. It also found that the previously adopted criteria fairly apportioned costs to customers and found nothing in the proposal to improve the fairness of the allocation. The Commission concluded: “The cost allocation mechanism established in D.06–07–029 and refined in D.07–09–04, D.08–09–012 and D.11–05–005 remains reasonable for application in this proceeding without modification, and is fair and equitable as required by Section 365.1(c)(2)(A)–(B).”<sup>267</sup> In regards to the proposal to impose a cap on CAM, the Commission found it contradictory to its policy to apportion costs to all benefiting customers in an IOU service area.

The Decision also reflected the Commission’s continued reluctance to consider an opt-out mechanism of CAM. The Commission noted “[i]t is not clear that a CAM opt-out could be implemented without undue administrative burden.”<sup>268</sup> It also found uncertainty in procuring adequate generation resources over the proposed five-year period. While the Commission emphasized that it “will not rule out consideration of a CAM opt-out at a future date,” it also noted that it was “disinclined to relitigate this issue in the future unless all or nearly all impacted parties can agree on a specific, detailed and implementable proposal, or there are significant changed circumstances.”<sup>269</sup> The Commission concluded that “[t]he record is insufficient to resolve outstanding questions about a CAM opt-out at this time.”<sup>270</sup>

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## 48. Petition 12–12–010 (December 18, 2012) Sought Commission Review of Policies Regarding Cost Allocation and Non-Bypassable Charges

In 2012, Marin Energy Authority (MEA), along with 14 co-filers and 40 supporting entities, filed a Petition for Rulemaking seeking to improve the Commission’s policies related to cost allocation, protect against cross-subsidization, and properly structure non-bypassable charges in order to create a level playing field for CCA and all departing load.

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<sup>267</sup> D.13–02–015 at 130.

<sup>268</sup> D.13–02–015 at 126.

<sup>269</sup> D.13–02–015 at 112.

<sup>270</sup> D.13–02–015 at 130.

MEA presented concerns regarding the risks of addressing cost allocation issues in a diffuse manner. MEA argued, by addressing cost allocation issues within various rulemakings and applications, the Commission had reached inconsistent and contradictory outcomes. To efficiently and effectively develop clear policy principles regarding cost allocation, MEA sought to have the Commission consider the issues within one rulemaking.

## 1. MEA's Justification for Instituting a Rulemaking

MEA relied on authority from SB 790 to justify its petition. MEA made the following points:

- a. SB 790 requires the Commission to implement measures that provide protections for CCAs and better support for the formation of CCAs in California.

MEA first pointed to the legislative intent behind SB 790 to improve the competitive environment for CCAs and facilitate their growth in California. Specifically, the Petition cited SB 790's legislative findings regarding California's "substantial governmental interest" in ensuring that electrical corporations do not threaten CCA programs. MEA asserted that the Commission is charged with fostering and implementing this interest.

- b. SB 790 calls for the Commission to reframe the principles upon which it determines the appropriate cost allocation for IOU procurement and programs.

MEA also discussed SB 790's requirement that the Commission adopt policies that foster fair competition and protect against cross-subsidization. It asserted that Commission policies have led to extensive shifting of costs to departing load customers, which create anticompetitive barriers and shield IOUs from adopting reasonable procurement practices. MEA argued that the Commission has historically failed to acknowledge that all LSEs manage their own generation and load while protecting the IOU's bundled customers from stranded costs. Based on SB 790's requirement to foster fair competition and protect against cross-subsidization, MEA asserted that the Commission must re-evaluate the current policies and take a more balanced approach.

- c. SB 790 mandates that the Commission ensure that cost allocation is fair and equitable for all customers, whether they are on bundled, CCA or DA service.

MEA emphasized that an examination of these issues would fundamentally affect all non-IOU LSEs. It referred to SB 790's recognition that cost allocation issues affecting CCA formation are also relevant to retail choice in general. Thus, cost allocation, cross-subsidization, and non-bypassable charge reforms are outstanding issues that impact the whole spectrum of non-utility generation providers and their customers.

## 2. MEA's Proposed Scope

The Petition proposed the following scope for the Order Instituting Rulemaking (OIR):

- a. Adoption of a comprehensive approach for cost allocation and cross-subsidization for Commission rulemakings and utility applications.

The Petition proposed a comprehensive approach to address cost allocation issues that would replace the inconsistent policies that have been implemented over various proceedings and rulemakings. The implementation of a clearly articulated policy on cost-shifting would allow for a rigorous, transparent, and efficient process in all Commission proceedings.

Specifically, the Petition proposed regulations that would impose a rebuttable presumption that allocates costs of all IOU supply-related applications to bundled customer generation rates only. The IOU would be required to meet a burden of proof for obligation in order to allocate costs elsewhere in accordance with Commission-established principles of cost causation. IOUs would be required to show more than generalized statements that the

supply would benefit all customers. Rather, they would need to include a justification for the allocation, including a showing of significant benefits to all ratepayers and the inability for competitive third parties to offer those same benefits or share reliability requirements. The Petition also proposed the same presumption in initiated rulemakings, requiring a specific and persuasive demonstration that generation costs are more appropriate in the transmission and distribution functions.

#### b. Determination of non-bypassable charges

The Petition also proposed to establish a mechanism that provides retail choice customers and their suppliers with better tools to manage the variability of the PCIA and to receive a value commensurate with the costs they pay. Lastly, the Petition requested that the Commission investigate ways to reduce the potential for stranded costs, including reforms to IOU procurement practices that incorporate consideration of departing load and reflect variation in utility load and load growth over time.

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### 49. Decision 13–08–023 (August 20, 2013)

#### Denied Marin Energy Authority’s Petition for Rulemaking to Review Commission Policies Regarding Cost Allocation and Non-Bypassable Charges

This Decision denied MEA’s Petition for Rulemaking (P.12–12–010) seeking to review and revise the Commission’s policies related to cost allocation, protect against cross-subsidization, and properly structure non-bypassable charges.

The Commission disagreed with MEA’s assumption that current mechanisms were unfair and therefore “SB 790 does not require the Commission to re-evaluate existing cost allocation or fee mechanisms at this time.”<sup>271</sup> The Commission also stated, “It is not apparent that initiating a rulemaking on cost allocation and non-bypassable charges would increase fairness or efficiency, and it is neither necessary nor appropriate to attempt to consider the issues raised in the Petition in a single proceeding at this time.”<sup>272</sup>

The Commission also found that the current cost allocation and fee calculation determinations are “reasonable and consistent with state law”<sup>273</sup> and past decisions show that “existing fee mechanisms divide costs appropriately between bundled customers and the customers of other LSEs.”<sup>274</sup> Further, if any of the issues required additional review, the Commission believed it could be addressed in existing proceedings such as the Long Term Procurement Planning or General Rate Cases. It also found it “reasonable to address cost allocation and non-bypassable charge mechanisms as they arise in proceedings, on a case-by-case basis.”<sup>275</sup> Lastly, the Decision stated that the “determination of whether a specific IOU proposal meets the requirements for collection from unbundled customers can only be determined through a thorough review of the proposal itself by this Commission.”<sup>276</sup>

The Commission concluded by restating its policy goals, specifically noting that “significant changes in circumstances” would be the only trigger to warrant re-evaluation of departing load charges:

“The Commission remains committed to ensuring that Community Choice Aggregators and other non-utility LSEs may compete on a fair and equal basis with regulated utilities. Towards this end, we will

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271 D.13–08–023 at 23.

272 D.13–08–023 at 23.

273 D.13–08–023 at 23.

274 D.13–08–023 at 13.

275 D.13–08–023 at 23.

276 D.13–08–023 at 23.

continue to consider both the mechanics and overall fairness of cost allocation and departing load charge methodologies proposed in the future, with the specific goal of avoiding cross-subsidization. In addition, we continue to be open to re-evaluating specific departing load charges in appropriate proceedings if changed circumstances warrant doing so, and indeed some related issues are currently under review in other proceedings. If appropriate, Energy Division staff may hold a workshop to develop a process for addressing any specific departing load charges or other fee mechanisms that may benefit from review due to significant changes in circumstances since the charge's development."<sup>277</sup>

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## 50. Decision 13–10–040 (October 17, 2013)

### Authorized IOUs to Recover Costs Associated with Energy Storage Procurement from CCA and ESP Customers

This Decision established the policies and mechanisms for procurement of electric energy storage pursuant to Assembly Bill (AB) 2514. AB 2514 required the Commission to determine targets for Load Serving Entities (LSEs) to procure viable and cost-effective energy storage systems.

The Decision set a target of one percent (1%) of a ESP's or CCA's peak load in 2020. This target was slightly lower than the percentage target adopted for the IOUs. However, the Commission found that the lower percentage target was warranted since all customers, including those of ESPs and CCAs, would be "required to pay certain non-bypassable charges that may be used by the IOUs to develop energy storage systems."<sup>278</sup> Further, customers of ESPs and CCAs would also "pay for any energy storage systems procured for the IOU's distribution system as part of their distribution charges."<sup>279</sup> Since some portion of the IOUs' energy storage procurement costs will be recovered from ESP and CCA customers, the Commission found that a one percent (1%) target for ESPs and CCAs was reasonable.

Lastly, the Commission emphasized that, consistent with prior decisions, departing load customers remain responsible for any costs associated with energy storage procured on their behalf at the time they were bundled service customers.<sup>280</sup> These costs and the associated load, however, would not be counted towards meeting the CCA or ESP's one percent (1%) procurement target.

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## 51. Decision 14–03–004 (March 13, 2014)

### Authorized CAM for Costs of Procuring Local Capacity Needs Impacted by the SONGS Retirement

This Decision authorized SCE and SDG&E to procure local capacity needs impacted by the retirement of the San Onofre Nuclear Generation Stations (SONGS). The Decision also authorized CAM treatment for the costs of such procurement.

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<sup>277</sup> D.13–08–023 at 17.

<sup>278</sup> D.13–10–040 at 46.

<sup>279</sup> D.13–10–040 at 46.

<sup>280</sup> D.13–10–040 at 47–48.

In applying CAM, the Commission cited Section 365.1(c)(2)(A)–(B), which holds that in instances when the Commission determines a need for new generation to meet local or system area reliability, the net capacity costs shall be allocated to all benefitting customers. Disagreement arose between parties over whether this section applied to the special procurement authorized in response to the retirement of SONGS. The Commission reasoned that such procurement was authorized for the purpose of ensuring local reliability in the SONGS area, which in turn benefitted all utility distribution customers in that area. It concluded that such procurement met the criteria of Section 365.1(c)(2)(A)–(B) and that SCE and SDG&E could allocate costs incurred as a result of that procurement.

SCE also raised the issue that some procurement could involve contingency or option contracts for gas-fired generation which would give it the right to terminate the contracts when sufficient renewables or transmission solutions obviate the need. It argued that the CAM framework could be expanded to cover such option contracts. The Commission responded that this raised issues concerning cost allocation that it had not contemplated to date. Thus, the Commission deferred from making any determinations regarding the eligibility of CAM for contingency or options contracts. It recommended that when SCE and SDG&E introduced such contracts for approval, it should include a proposal of certain costs to be allocated through the CAM and a methodology for such allocation.

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## 52. Decision 14–02–040 (February 27, 2014)

### Required IOUs to Estimate DA and CCA Departing Load for 10–Year Term Bundled Plans

This Track 3 Decision in the 2012 LTPP proceeding made several changes to utility procurement rules. Among the changes, the Decision ordered the IOUs to estimate reasonable levels of expected DA and CCA departing load over the 10–year term of the IOUs’ bundled plans. Such departing load would then be excluded from their future bundled procurement plans so that IOUs would only procure for the assumed amounts of retained bundled load. In addition, the forecasted DA and CCA departing load “would not be subject to non–bypassable charges for any incremental stranded bundled procurement costs incurred by the IOUs for the period after the date of departure assumed in their approved bundled plans.”<sup>281</sup>

In response to concerns regarding transparency and when procurement is eligible for CAM, the Commission emphasized that CAM only applied when it authorizes or directs a utility to procure resources to meet system or local reliability needs. Absent such authorization or direction, CAM does not apply, unless otherwise stated in a specific Commission decision. Routine procurement to meet a utility’s near–term resource adequacy requirements for its bundled service customers would not be subject to CAM, nor would such procurement by a non–IOU LSE. On the other hand, long–term utility procurement undertaken to develop new or expanded infrastructure to meet system or local reliability needs in its distribution service area would typically be subject to CAM, and the RA value of such resources would be allocated to all LSEs. In addition, IOUs, ESPs and CCAs each meet their own individual RPS procurement requirements, and the costs of those contracts are not currently subject to CAM treatment.<sup>282</sup>

Parties also questioned whether resources built in one IOU’s service territory should have its costs spread across all of the Commission’s jurisdictional LSEs. The Commission found this unreasonable since some customers who paid for a CAM facility would see only incremental benefits while other customers would benefit from the

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281 D.14–02–040 at 17.

282 D.14–02–040 at 54–55.

reliability improvements without paying the costs. The Commission concluded that the criteria to justify CAM procurement should be specific to the IOU service area in order to avoid unreasonable subsidization between customers of different service areas.<sup>283</sup>

Lastly, the Commission eliminated the use of energy auctions to calculate net capacity costs subject to CAM. Instead, the Decision ordered IOUs to use the mechanism adopted in D.07–09–044 to set residual capacity costs that would be allocated to benefitting customers.

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### 53. Sonoma Clean Power Begins Service (May 1, 2014)

On May 1, 2014, Sonoma Clean Power (SCP), a county-wide CCA and the second CCA to start service in the state, began serving its Sonoma County customers, including the cities of Windsor, Sonoma, Cotati, Sebastopol, Santa Rosa and all of the County unincorporated areas.

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### 54. Decision 14–10–045 (October 16, 2014) Authorized PCIA for Energy Storage Procurement

This Decision approved the IOU applications for energy storage procurement, including the authorization of cost recovery through the PCIA mechanism, for the 2014 solicitation cycle.

#### 1. PCIA Approval for 2014 Cycle for Energy Storage Procurement

The Commission noted the difficulty in predicting the extent of how departing load would be an issue in the future or result in stranded costs attributable to IOU energy storage procurement. Specifically, it noted that, while Community Choice Aggregators (CCAs) were in a state of growth, there was not enough evidence to discern accurate forecasts based on that growth.<sup>284</sup> The Commission also stated it “supports the principle of ‘equity’ in which the Commission determines whether lower targets for ESPs and CCAs are properly balanced against the level of non-bypassable charges imposed on ESP/CCA customers from projects procured by the IOUs for bundled service on behalf of bundled customers or system reliability on behalf of all customers.”<sup>285</sup>

The Commission concluded by echoing language from its original decision adopting the energy storage program.<sup>286</sup> The Commission stated that, while it had set a procurement target for energy storage for CCAs and ESPs, “departing load customers remain responsible for any costs associated with energy storage procured on their behalf at the time they were bundled customers.”<sup>287</sup> It also reiterated that these costs would not be applied towards the CCA or ESP one percent (1%) procurement target. As a result, new CCA customers would bear the costs of meeting the procurement target for energy storage in addition to the energy storage costs procured by IOUs on behalf of the CCA via the PCIA.

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283 D.14–02–040 at 61.

284 D.14–10–045 at 45.

285 D.14–10–045 at 40.

286 See D.13–10–040.

287 D.14–10–045 at 26.

## 2. PCIA Not Yet Approved for Future Energy Storage Procurement

The Commission recognized that the PCIA had not been used to recover above-market costs of non-generation resources like energy storage. At the early stages of energy storage procurement, the Commission found it difficult to assess the potential of future PCIA-related projects beyond those already existing. The Commission also noted that implementing the PCIA involves complex policy, cost, equity, implementation, and market impact considerations. Because energy storage procurement is in its nascent stages, it concluded that it would be “premature to authorize immediate or ‘blanket’ acceptance of PCIA treatment for the longer term at this time.”<sup>288</sup>

The Commission made a distinction in its Decision stating that, while it “authorizes” the use of PCIA to recover above-market costs for the first solicitation cycle, it does not “approve” actual stranded cost recovery prior to an approved methodology to determine those above-market costs and a sufficient showing that stranded costs exist. The Commission emphasized that “IOUs have the burden of proof to demonstrate circumstances that warrant PCIA treatment for specific proposed energy storage generation/market projects procured for bundled service.”<sup>289</sup>

Thus, the Decision directed the IOUs to submit a “Joint Investor Owned Utilities Protocol” proposal that would determine the potential above-market stranded costs associated with bundled service storage. It also denied the request to extend PCIA for energy storage contracts beyond 10 years.

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## 55. Decision 15–01–051 (January 29, 2015) Implemented the Green Tariff Shared Renewables Program and Applied a Vintaged PCIA to Program Customers

This Decision implemented Senate Bill (SB) 43 (2013), requiring the IOUs to implement a Green Tariff Shared Renewables (GTSR) Program. Under the program, customers can: (1) purchase energy with a greater share of renewables; or (2) purchase renewable energy from community-based projects. Upon enrollment, GTSR customers are required to share in the above-market costs for resources that were already procured on their behalf. To protect non-participating customers from cost shifting, the Commission found that applying a vintaged PCIA was appropriate. The Decision provided the following reasons to use PCIA as the proxy on which to base the GTSR customer indifference amount:<sup>290</sup>

- » The PCIA is a Commission-approved mechanism that is already in place and does not require additional or new analysis.
- » The PCIA is designed to take into account the cost of procurement for a customer who is no longer taking service from the same procurement sources as other ratepayers.
- » The Commission, utilities, and interested parties all have experience with the calculation of the PCIA and the PCIA is subject to annual review and adjustment through the ERRA proceedings.
- » Other costs that should not be shifted to non-participating customers are already addressed by other charges, distribution rates, and inclusion of non-bypassable charges in the customer’s over all bill

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288 D.14–10–045 at 46.

289 D.14–10–045 at 47.

290 D.15–01–051 at 102–103.



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## 56. Lancaster Choice Energy Begins Service (May 1, 2015)

On May 1, 2015, Lancaster Choice Energy (LCE), a municipally-operated CCA and the third CCA to start service in the state, began serving its municipal accounts. Following the initial phase, LCE rolled out its services to both commercial and resident accounts on October 1, 2015.

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## 57. Decision 15-06-028 (June 11, 2015) Established Reduced CHP Procurement Targets and Ended CAM Recovery for PG&E's Procurement Obligations for Upcoming Period

This Decision established new procurement targets for the CHP Program's Second Program Period.<sup>291</sup> Specifically, the Decision reduced the GHG Emissions Reduction Target for the second period due to concerns regarding the cost-effectiveness of future CHP procurement and preferred resource technologies that likely had greater emissions reduction potential. The Commission also recognized that CHP resources had a significant potential to contribute to over-generation concerns, which had proven to cause reliability problems on the electric grid.

In addition to the overall reduction in the target, the Decision also removed additional procurement obligations for PG&E for the next period because it had already procured emission reductions in excess of its service territory's potential. This Decision signaled the end of future CAM recovery for new CHP procurement by PG&E.

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## 58. Decision 15-06-063 (June 25, 2015) Adopted a Monthly CAM Value as Part of Annual Year-Ahead Allocation

This Decision adopted 2016 local capacity procurement and flexible capacity obligations for LSEs. The Decision also made several minor refinements to the resource adequacy (RA) program for 2016. Most relevant was the Commission's adoption of requiring the Energy Division to provide LSEs with twelve monthly CAM values as part of its annual year-ahead allocation.

During the proceeding, MCE presented concerns regarding over-procurement and stranded costs resulting from the ongoing capacity allocation process. MCE proposed to unbundle the CAM net capacity costs so that net capacity costs would equal the resource's reliability cost plus the RA capacity cost. MCE proposed that only the reliability cost of the CAM resource should be passed to all benefitting LSEs while the capacity costs and benefits remain with the IOUs. MCE argued that this unbundling solution would provide CCAs the procurement autonomy they needed to efficiently procure their RA obligations without exposure to uncontrollable CAM allocation costs. The Commission deferred consideration for this issue to the 2014 LTPP proceeding.

MCE also proposed to either: (1) eliminate the variability of CAM allocations between September and monthly CAM allocations; or (2) weigh monthly CAM allocations to make projected and actual allocations proportionate with seasonal capacity requirements. Alternatively, it proposed that the Energy Division provide twelve monthly distinct forecast values for the full year-ahead CAM-related capacity allocation forecasts. No parties objected

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291 D.10-12-035 adopted the QF/CHP Program, which included procurement targets for the Initial Program Period.

to this alternative proposal, and PG&E believed it would increase transparency of CAM allocation values for all LSEs.

The Commission concluded that the proposal to provide monthly forecast values for CAM-related capacity was reasonable. The Decision stated, “[p]roviding LSEs with this information will help them to minimize over-procurement and improves transparency needed for efficient procurement planning.”<sup>292</sup> While this didn’t change the CAM mechanism itself, the new requirement effectively changed the way CAM allocations would be communicated to CCAs and other non-IOU LSEs, which should reduce CCA-related over-procurement of RA due to the CAM capacity allocation process.

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292 D.15-06-063 at 31.





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