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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company for Approval of its Economic Development Rate for 2013-2017. (U39E)	Application 12-03-001 (Filed March 1, 2012)

OPENING BRIEF
OF THE DIVISION OF RATEPAYER ADVOCATES

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I. INTRODUCTION

Pursuant to Rule 13.11 of the Commission's Rules of Practice and Procedure and the Joint Ruling of the Assigned Commissioner and Presiding Administrative Law Judge ("ALJ"), the Division of Ratepayer Advocates ("DRA") hereby submits its Opening Brief on Pacific Gas and Electric Company's ("PG&E") Application for Economic Development Rates ("EDR") for 2013-2017. As discussed below, the Commission should reject PG&E's proposed EDR rates, and, instead, adopt DRA's EDR proposal. PG&E's proposal violates California law and prior Commission EDR decisions and decisions on cost shifting. Importantly, PG&E's proposal does not reliably provide a "ratepayer benefit" as required by PU Code §740.4(h). On the other hand, DRA's proposal provides a significantly higher discount than the Commission has ever approved in prior EDR proceedings, while at the same time keeping protections in place for non-participating customers. DRA's proposal, unlike PG&E's, does not violate California law, is consistent with Commission precedent, and has a high likelihood of ratepayer benefits.

II. SUMMARY OF RECOMMENDATIONS

The following is a summary of DRA's recommendations:[1]

A. DRA proposes two EDR options:

1.) A Standard Option EDR program, with a 12% discount over a 5-year contract term, should be available everywhere in PG&E's service territory, to bundled service, direct access ("DA"), and Community Choice Aggregation ("CCA") customers, subject to pricing floors which may limit the available discount in a few cases.

2.) An Enhanced Option EDR program offering a declining discount starting at 35% should be available in counties with unemployment rates of more than 125% of the statewide average. The discount would decline to 30% in year 2, then to 20%, 15%, and 10% in years 3, 4, and 5, respectively.[2] DRA's proposals are shown in Appendices A and B.

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[1] Ex. DRA-1, pp. 5-8.

[2] Discounts to DA and CCA customers may be limited by price floors.

B. The Commission should reject PG&E's proposed 35% Enhanced Option EDR discount based on a finding that it violates the additive price floor set by D.07-09-016 and could cause cost shifting and/or result in a negative CTM over the 5-year contract term. CTM calculations for PG&E's and DRA's proposals are summarized in Appendix C.

C. EDR eligibility requirements should be tightened to include more protections for non-participating ratepayers, consistent with prior EDR decisions. These protections include 3rd party review, requiring contracts to have a non-assignment clause and a liquidated damages clause for customer initiated early termination of EDR contracts. Further, the Commission should impose a cap of 200 MW on EDR program participation. Moreover, the Commission should require EDR customers to sign a customer affidavit that electricity costs constitute at least 5% of the customer's operating expenses.

D. In order to fulfill the legislative mandate of PU Code §740.4(h) and provide a benefit to nonparticipating ratepayers, PG&E's shareholders should bear 100% of any negative cumulative CTM resulting from PG&E's EDR portfolio after 10 years, from the inception of the first post- 2012 EDR contract. Further, PG&E's shareholders should bear 25% of the revenue shortfall due to EDR discounts because they will benefit from the EDR program and should therefore have to share the a portion of the program costs, provided the Commission adopts floor prices substantially as proposed by DRA. Finally, PG&E's shareholders should bear 50% of the revenue shortfall due to EDR discounts, if the Commission adopts EDR discounts without a floor price as proposed by PG&E, because PG&E's proposal will result in a greater shortfall than DRA's proposal and PG&E's shareholders should share the cost of the EDR program with nonparticipating ratepayers.

The tables below compares DRA's proposal to the current EDR program.

Table: Current EDR vs. DRA's Proposals: Rates and Price Floors[3]

Current EDR	DRA Proposal
Standard 12% Discount, 5-year term	Standard 12% Discount, 5-year term
No enhanced discount option	Declining discount for high unemployment areas, i.e. 35%-30-20-15-10%; 5-year term
Additive floor price based on Marginal cost + NBC Rate Components, enforced annually, ex ante & ex post	**NBC Rates**: Floor price includes NBCs, including all transmission charges and DRW bond charges. Applies annually. **Modified Additive** Floor prices based on NBCs + Marginal distribution cost + Marginal energy cost; floor price applies to 5-year NPV (ex ante only). **Marginal Cost:** Floor prices based on full marginal cost including generation capacity; floor price applies to 5-year NPV (ex ante only). (Five year CTM > 0)
CTM cannot be negative in any year	Net present value of CTM must be positive over 5-year contract term
Annual ex post back billing to recover negative CTM from customer	No ex post recovery from customer
Distribution constrained by marginal cost floor enforced annually	Distribution constrained by marginal cost floor enforced over the five-year contract period
Generation constrained by marginal cost floor enforced annually	Generation constrained by marginal cost floor enforced over the five-year contract period
No discounting of NBC Rate Components (including Transmission)	No discounting of NBC Rate Components (including Transmission)
No PG&E shareholder participation	PG&E shareholders bear 25% of discount PG&E shareholders bear 100% of negative 10-year CTM
200 MW cap	200 MW cap

[3] Ex. DRA-1, p.8

Table: Current EDR vs. DRA's Proposals: Eligibility and Contract Terms[4]

Current EDR	DRA Proposal
Approval of applicants by CalBIS required	Approval of applicants by CalBIS required
Limit participation to customers whose energy costs are at least 5% of operating costs	Limit participation to customers whose energy costs are at least 5% of operating costs
Implement with an affidavit provision	Implement with an affidavit provision
Require PG&E to conduct energy audit of the applicant's facility & create a checklist of EE/ conservation measures applicable to applicant	Require PG&E to conduct energy audit of the applicant's facility & create a checklist of EE/ conservation measures applicable to applicant, require audit submittal to Commission in EDR Annual Reports & reasoning for not implementing each EE/ conservation measure
Assignment of Contracts permissible only if PG&E consents in writing and the party to whom the agreement is assigned agrees in writing to be bound by the EDR agreement in all respects	Prohibit the transfer of an EDR contract if a company is sold. The purchasers of a company that was an EDR customer must reapply for the program
EDR contracts can be renewed for one additional 5-year term	Whether or not EDR contracts can be renewed will be decided in PG&E's 2017 GRC
Liquidated damages clause for customer fraud or misrepresentation	Liquidated damages clause for customer fraud or misrepresentation and a separate liquidated damages clause for customer initiated early termination of EDR contract

III. BURDEN OF PROOF

Public Utilities Code §454 states that:

> … no public utility shall change any rate … as to result in any new rate, except upon a showing before the commission and a finding by the commission that the new rate is justified….

According to Public Utilities Code §451:

> All charges demanded or received by any public utility … for any product or commodity furnished or to be furnished or any service rendered shall be just and reasonable. Every unjust or unreasonable charge demanded or received for such product or commodity is unlawful.

Finally, Section 728 provides in pertinent part: "Whenever the commission, after a hearing, finds that the rates...are insufficient, unlawful, unjust, unreasonable,

[4] Ex. DRA-1, pp. 9-10.

discriminatory, or preferential...the commission shall determine and fix, by order, the just, reasonable or sufficient rates..."

The Commission has found that these statutes "require utilities to establish that requested rates and charges are reasonable," and the Commission has consistently held that a utility bears the ultimate burden of proof of reasonableness."[5] Other parties, including DRA, do not have the burden of proving the unreasonableness of PG&E's showing.[6]

PG&E is recommending a significant rate change, including a deep rate discount available to its largest customers. Depending on actual participation in PG&E's proposed EDR program, the costs to nonparticipating customers could be substantial. The potential revenue shortfall from PG&E's enhanced EDR alone could exceed $250 million annually if a large majority of the 1,337 potentially eligible customers were to apply and qualify for the discount.[7] The magnitude notwithstanding, as with any request for a rate change, the burden is on the utility to prove affirmatively that each proposal is reasonable.

PG&E has not met its burden of proof that its proposed rate changes, including the magnitude of the EDR discounts, the method for calculating the discount, non-participant funding, and customer eligibility are reasonable. PG&E bears the burden of proof on the reasonableness of all these proposals. Clearly, PG&E's EDR proposal is a significant departure from prior Commission EDR decisions, including a much higher discount available to a potentially larger, less restricted customer population, and violating the

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[5] D.10-09-018, *Application of Pacific Gas and Electric Company for Authority to Increase Electric Rates and Charges to Recover Smart Grid Costs Relating to Compressed Air Energy Storage Demonstration Project under American Recovery and Reinvestment Act of 2009. 2010 Cal. PUC LEXIS 339 at *31 citing In the Matter of the Application of Pacific Bell, a Corporation, for Authority to Increase Certain Intrastate Rates and Charges Applicable to Telephone Services Furnished Within the State of California* [D.87-12-067] (1987) 27 Cal.P.U.C.2d 1, 20-22.; D.10-05-023, *Application of Southern California Edison Company (U338-E) to Establish Marginal Costs, Allocate Revenues, And Design Rates,* 2010 Cal. PUC LEXIS 343,*10.

[6] See D.83-05-036, *Re Southern California Edison Company* (1983) 11 CPUC 2d 474, 475; affirming that it was the utility and not DRA, TURN or any other intervenor who must meet the burden of proof.

[7] The analysis for this calculation is discussed below in Section VII.B of this brief.

price floor adopted in D.07-09-016 and retained in D.10-06-015. PG&E has not demonstrated that such a departure is necessary to meet the goals of an EDR program, has not supported the proposal by rational economic analysis or demonstrated that its proposal is consistent with the law. Therefore, the Commission should review PG&E's proposal with extreme caution because, as discussed more fully below, the proposal presents significant, unnecessary risks to the majority of PG&E's ratepayers.

In contrast, DRA, which does not have the burden of proof, has provided the Commission with a much more reasonable and less risky alternative EDR proposal. While the Commission would clearly be following law and prior decisions in rejecting PG&E's proposal for failing to meet the burden of proof, DRA believes the Commission should instead adopt DRA's EDR proposal.

IV. NEED FOR EDR-- ECONOMIC PICTURE IN NORTHERN CALIFORNIA

In its testimony, PG&E argues that "economic conditions in California justify PG&E's EDR proposal."[8] While DRA agrees with PG&E that California has suffered from a serious economic slowdown, there is no evidence that PG&E's proposals, offering a five-year, 35% discount far exceeding previous EDR discounts while eliminating nearly all of the ratepayer protections embedded in the current and past EDR programs, are necessary to improve the California economy.[9] Further, the economy in California and in PG&E's service territory in particular, has improved significantly since PG&E filed its testimony in March 2012, almost 10 months ago.

PG&E's testimony describes high unemployment rates in California, including the fact that, "since January 2001, employment has been on a consistent and persistent downward trend."[10] PG&E also describes the fact that the recession has hit California harder than other states, and that California's high energy costs may be a factor in

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[8] Ex. PG&E-1, p. 1-2.

[9] This section addresses Scoping Memo Issue #1.

[10] Ex. PG&E-1, p. 1-3.

whether or not businesses relocate.[11] Further, PG&E describes the need for an "enhanced" EDR rate in specific "high unemployment counties" that have unemployment rates in excess of 125 percent of the state average. [12]

Although the California economy has been hit hard by this severe recession, our economy has improved significantly in the last two years, including since PG&E filed its application. For instance, DRA's rebuttal testimony shows an update of the unemployment rate in the counties which would be eligible for an enhanced EDR option. PG&E's testimony shows, based on data from the California Economic Development Department ("EDD"), that these 22 counties had an average unemployment rate of 17.2 percent in 2010. For 2011, the unemployment rate in these 22 counties was down to 16.4. As of September 2012, the unemployment rate was 12.4 percent,[13] which was the overall statewide rate when PG&E filed its testimony.[14] Further, the EDD data shows that, while statewide unemployment has decreased by 2.7 percent from 2010, unemployment in the 22 economically distressed counties has decreased by an average of 4.8 percent over the same period.[15] While DRA does not think a 12.4 percent unemployment rate is acceptable for these counties, there has clearly been significant economic improvement without an enhanced EDR rate in effect.

Importantly, PG&E never makes a demonstration of why an enhanced 35 percent EDR would improve the economy in the high unemployment areas. While PG&E claims that the current program, offering a 12 percent discount subject to back billing true ups ("clawbacks"), "is not adequate to attract or retain customers considering out-of-state locations,"[16] PG&E does not show that either removing the clawbacks or providing a

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[11] Ex. PG&E-1, pp. 1-3 through 1-7.

[12] Ex. PG&E-1, pp. 2-5 through 2-7

[13] Ex. DRA-2, Attachment 1 ("PG&E Table 2-1 Extended")

[14] Ex PG&E-1, pp. 2-4 through 2-5.

[15] Ex. DRA-2, Appendix E

[16] Ex. DRA-2, p.2-3.

discount less than 35 percent would not attract or retain customers as well as PG&E's proposal. PG&E certainly never shows that the DRA proposals, which include allowing for a guaranteed rate reduction of 12 percent or 22 percent, would not attract and retain customers considering out-of-state locations.

As DRA demonstrated, and PG&E agreed, even if enrollment is low in the current EDR program, there have been prior successful EDR programs that were much more similar to DRA's proposal in this case than to PG&E's proposal. For instance, a prior PG&E EDR program provided for a discount beginning at 25 percent and decreasing down to 5 percent in the fifth year,[17] and managed to achieve an enrollment of 88.325 MW,[18] which PG&E agreed was successful.[19] This average 15 percent discount is significantly lower than the enhanced 35 percent that PG&E proposes here or the 22% average enhanced EDR discount that DRA proposes. Therefore, in determining which, if any, EDR proposal to adopt in this proceeding, the Commission should consider both the actual economic conditions in California and which EDR proposal is best tailored to improve the current economic conditions.

V. PG&E'S PROPOSED EDR DOES NOT BENEFIT NONPARTICIPATING RATEPAYERS AND VIOLATES THE PUBLIC UTILITES CODE AND COMMISSION DECISIONS

The Commission should reject the PG&E EDR proposal, and adopt the DRA proposal to ensure that both the enhanced and standard EDR programs will benefit nonparticipating ratepayers. The Commission has the authority to encourage economic development under PU Code §740.4.[20] The Commission can authorize a variety of economic development activities,[21] and it is empowered to approve and regulate PG&E's

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[17] D.05-09-018, p. 2

[18] D.10-06-015, p.6.

[19] PG&E/Hartman, 1 RT 186, lines 14-26.

[20] This section addresses Scoping Memo Issue #8.

[21] PU Code §740.4(c).

proposed EDR program. However, the Commission's authority to authorize economic development activities is constrained by PU Code §740.4(h). This statute requires that all economic development activities, approved for rate recovery by the Commission, result in a benefit to ratepayers. Specifically, PU Code §740.4(h) states:

> It is the intent of the Legislature that the Public Utilities Commission, in implementing this chapter, shall allow rate recovery of expenses and rate discounts supporting economic development programs within the geographic area served by any public utility to the extent the utility incurring or proposing to incur those expenses and rate discounts demonstrates that the ratepayers of the public utility will derive a benefit from those programs.

The ratepayer benefit test of PU Code §740.4(h) requires PG&E to make an affirmative demonstration of ratepayer benefits in order for the Commission to grant EDR program approval. The Commission should not adopt the PG&E proposal because it carries a high risk of not achieving ratepayer benefits as mandated by PU Code §740.4(h).

A. California Law Requires a "Benefit to Ratepayers" which the Commission has Defined as a Positive CTM

PG&E's proposed standard and enhanced EDR programs do not comply with PU Code §740.4(h) because the EDR proposals carry an unacceptably high risk that EDR customer contracts will not generate sufficient revenue to cover the costs of serving those customers.[22] The difference between the revenue from additional incremental sales and the additional variable costs of the additional products or services sold is defined as contribution to margin (CTM).[23] CTM explicitly measures the impact on nonparticipants who do not realize any other rate benefits from the EDR program other than those associated with the CTM. Thus, in order to satisfy the ratepayer benefit requirement of PU Code §740.4(h), a positive CTM is required over the term of the EDR customer contract.[24]

[22] This section addresses Scoping Memo Issue #7 and #29.

[23] Source, PG&E, "Resource, An Encyclopedia of Energy Utility Terms" (1992), p. 101.

[24] The following section addresses Scoping Memo Issue #9.

Using CTM as the benchmark to determine compliance with PU Code §740.4(h) is supported by the Commission's understanding of "ratepayer benefit" discussed in the following Finding of Fact in Decision ("D.") 05-09-018:

> The implementation of successful economic development projects would *benefit ratepayers* directly by *increasing the revenues available to contribute to the utilities' fixed costs of doing business*, thus lowering rates to other customers.[25]

Positive CTM is analogous with "increasing the revenues available to contribute to the utilities' fixed costs of doing business"[26] and the "fixed costs of doing business" are the margin to which new revenues are contributing. Given the equivalence of "ratepayer benefit" and a positive CTM, PU Code §740.4(h) can be read to require a positive CTM. The definition of CTM is broader than the definition of ratepayer benefits in D.05-09-018 because the latter only discusses increasing sales, which can only apply to attraction and expansion EDR contracts. For retention customers, however, a similar benefit can result from EDR programs because retaining a customer that would depart "but for" the EDR discount prevents a loss of margin. The retention of an existing customer should ensure that some revenue in excess of marginal cost will continue to be available from that customer to contribute to the utilities' fixed costs. This is important because most of the recent (5 of the past 6) EDR contracts have been for customer retention.[27] Existing ratepayers benefit from PG&E's acquisition of new customers, or from retention of existing customers[28] who would otherwise depart, but for the EDR program, as long as

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[25] D.05-09-018, p.26, FOF #2 (emphasis added).

[26] Id.

[27] Ex. DRA-3, citing 2010 & 2011 PG&E Reports on Economic Development Applications. This represents the number of signed EDR contracts that are listed in the 2010 and 2011 Annual Reports, Appendix I, Schedule ED Activity.

[28] This is based on the assumption that retained customers receiving a discount are not "free-riders"; that is, they would have closed their operations in California, but for the discount. A free-rider who receives a discount imposes a cost on nonparticipating ratepayers even though that customer may still have a positive contribution to margin.

the revenue provided by the new or retained customer is greater than the marginal cost of serving that customer.

CTM is the best measure of ratepayer benefits for an EDR contract because it results in the tangible benefit of lower rates. PG&E appears to concur that CTM is an appropriate measure of ratepayer benefits:

> To the extent that utilities can retain or attract sales at a rate that is lower than the tariffed rate, but higher than the marginal cost, helps to maintain or add to Contribution to Margin (CTM). This CTM can then be used to keep rates to customers lower than they would otherwise be. …. A program benefits ratepayers if the CTM is greater than zero.[29]

James Renzas of the LGP also appears to agree. He testified that the EDR is an investment PG&E customers are making:

> I consider it just like any other investment. You would be putting out money on the front end, potentially, and expecting return on the back end. So you don't make an investment if you think you are going to lose money.[30]

LGP's witness is correct; investments should yield a positive return. Thus PG&E's ratepayers are entitled to expect a return on the investment they are making in the EDR.[31] The only way to ensure a high likelihood that PG&E's nonparticipating ratepayers will receive a return on this investment is by requiring each EDR contract to generate a positive CTM over the 5-year contract term. DRA proposes to apply this requirement to each contract on a forecast basis to eliminate unpopular ex post billing adjustments. To the extent that conditions change, and a negative CTM materializes after ten years have elapsed, DRA proposes that PG&E's shareholders pay for the negative CTM.

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[29] Ex. PG&E-1, p. 3-2.

[30] LGP/Renzas, 3 RT 563, lines 11-16.

[31] LGP/Renzas, 3 RT 563, lines 21-23. Question "And they (PG&E's ratepayers) would expect a return on their investment? " Answer "Yes."

B. Direct Benefits

The Commission should adopt DRA's EDR proposals in order to reasonably ensure that the programs will provide direct benefits to nonparticipating ratepayers.[32] Direct benefits are provided to nonparticipating ratepayers if EDR customer contracts generate a positive CTM. This principle was adopted by the Commission in D.05-09-018, in the following Finding of Fact:

> The implementation of successful economic development projects would *benefit ratepayers directly* by increasing the revenues available to contribute to the utilities' fixed costs of doing business, thus lowering rates to other customers.[33]

In the subsequent Finding of Fact, the Commission discussed indirect benefits that the EDR program provides to ratepayers as "increased employment opportunities and improved overall local and economic vitality."[34] The Commission's choice to distinguish between direct and indirect ratepayer benefits highlights the differences between the two types of benefits and the fact that direct benefits are necessary to satisfy the ratepayer benefit test in P.U. Code §740.4(h).

The method PG&E used to quantify ratepayer benefits in its application for the 2005-2010 EDR program supports the position of requiring the EDR programs to produce a positive CTM in order to satisfy the ratepayer benefit requirement of PU Code §740.4(h). In that proceeding, PG&E used the Rate Impact Measure (RIM) Test to quantify the ratepayer benefits the EDR program would produce.[35] The RIM Test "measures what happens to customer bills or rates due to changes in utility revenues and operating costs caused by the program."[36] The RIM Test essentially measures the CTM

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[32] This section addresses Scoping Memo Issue #9.

[33] D.05-09-018, p. 26, FOF #2 (emphasis added).

[34] Id. at p. 26, FOF #3.

[35] D 05-09-018, p. 13, citing to Reply Brief of Pacific Gas and Electric Company, December 15, 2004, p. 19.

[36] California Energy Commission, Standard Practice Manual: Economic Analysis of Demand-Side

(footnote continued on next page)

impacts of a program because it measures the bill impacts of utility programs that result in changes to the utility's revenues and operating costs. The fact that PG&E used the RIM Test to quantify ratepayer benefits in a prior EDR proceeding, and that the Commission based its approval of the past EDR program on the results of the RIM Test,[37] confirms that rate impacts, captured by a CTM analysis, should be used to determine whether the proposed EDR programs will benefit ratepayers.

The Commission reaffirmed its position that the ratepayer benefit test in PU Code §740.4(h) requires a positive CTM in the most recent EDR proceeding in D. 10-05-016. In that Decision, the Commission distinguishes between direct benefits and indirect benefits by stating that the EDR program was previously approved because:

> (1) electricity is a major cost of doing business in California; (2) Economic Development tariffs lower rates for all ratepayers by increasing or retaining revenues that contribute to utilities' fixed costs; and (3) Economic Development tariffs provide indirect benefits to ratepayers by increasing local employment opportunities and economic vitality.[38]

The above quotation shows that the Commission considers the benefit of "lower rates for all ratepayers by increasing or retaining revenues that contribute to utilities' fixed costs" to be separate and different from the "indirect benefits to ratepayers by increasing local employment opportunities and economic vitality." The fact that the Commission specifically treats these two types of benefits differently supports the position that a positive CTM, as described in (2) in the above quotation, is necessary to satisfy the ratepayer benefit test in PU Code §740.4(h). These types of benefits are treated differently in that the CTM benefit was quantified whereas the indirect benefits were not. So the latter played a subordinate role in the Commission's decision-making.

(footnote continued from previous page)
Programs and Projects, October 2001, available at http://www.energy.ca.gov/greenbuilding/documents/background/07-J_CPUC_STANDARD_PRACTICE_MANUAL.PDF.

[37] D 05-09-018, p.26, FOF #4.

[38] D. 10-05-016 at pp. 9-10, citing D.05-09-018 at 27, Findings 1, 2, and 3.

The Commission should follow past precedent as discussed above, and focus on the potential direct benefits of the proposed EDR program when determining if the program will benefit nonparticipating ratepayers as is required by PU Code §740.4(h). The direct benefit of the proposed EDR programs generating positive CTM is the best way to ensure that the mandate in PU Code §740.4(h) is fulfilled because positive CTM provides a guaranteed benefit to all nonparticipating ratepayers in the form of lower energy rates.[39] Further, the Commission's purview is over rate setting and it has the authority to regulate "natural gas, electric, telephone, and water companies as well as railroads and marine transportation companies."[40] The Commission is not an economic development agency, thus if follows that the benefits it has the expertise to evaluate are rate benefits. In order to satisfy the ratepayer benefit test, the proposed EDR program must directly benefit ratepayers by producing a positive CTM over the contract term.

C. Indirect Benefits cannot Compensate for a Negative CTM

Only direct benefits in the form of positive CTM are sufficient to satisfy the ratepayer benefit test of PU Code §740.4(h). The Commission has affirmed this principle in the two prior EDR Decisions. In D.05-09-018, the Commission stated that, "the implementation of successful economic development projects would benefit ratepayers directly by increasing the revenues available to contribute to the utilities' fixed costs of doing business."[41] In D.10-05-016, it stated that, "Economic Development tariffs provide indirect benefits to ratepayers by increasing local employment opportunities and economic vitality."[42] The flaws in PG&E's EDR program proposal, specifically the risk

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[39] Provided free-riders are excluded.

[40] CPUC, CPUC History and Structure, last modified 8/28/2012, available at http://www.cpuc.ca.gov/PUC/aboutus/puhistory.htm.

[41] D.05-09-018, p. 26, FOF #2.

[42] D. 10-05-016 at pp. 9-10, citing D.05-09-018 at 27, Findings 1, 2, and 3.

of negative CTM associated with the enhanced EDR,[43] cannot be rectified by a consideration of the potential indirect benefits of the EDR program.

The Commission has recognized potential indirect benefits of the EDR program, such as increased employment opportunities and improved overall and local economic vitality.[44] They, in fact, are among the main reasons for EDR programs, but the direct benefit of CTM has been used in past EDR Decisions[45] as a binding constraint on whether the program should be approved. As DRA's witness points out, the Commission has never quantified indirect benefits and applied them quantitatively in a determination of whether or not to approve the EDR program on the basis of ratepayer benefits.[46]

A further difficulty with including indirect benefits in the ratepayer benefit analysis is that they are hard to quantify.[47] DRA's witness Dr. Levin, when asked whether such benefits can be quantified, stated:

> I think they could be, but I don't know how you would do it. I'm sure there must be economic studies somewhere that attempt to quantify those benefits.[48]

Mr. McClary, testifying on behalf of the Merced and Modesto Irrigation Districts, said the following: "I think what we've heard today is the difficulty in actually

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[43] PG&E acknowledged some of the sources of risk (uncertainties) in its CTM analyses in Ex. PG&E-4, p. 2-12. See Section VII of this brief for a more complete discussion of the risks associated with PG&E's EDR proposals.

[44] D.05-09-018, p.14.

[45] D.05-09-018; D. 10-05-016.

[46] DRA/Levin, 2 RT 441, lines 18-27. "I don't believe that the Commission … has ever quantified the indirect benefits and applied those quantitatively in a determination as to whether to grant a discount."

[47] MerMod/McClary, 3 RT 692, lines 9-14; DRA/Levin, 2 RT 442-443, lines 23-28, 1-4; Ex. LGP-1, pp. 15-16. "I need to note two things at this point: first, specific details of location, type of business and scale of the investment are all needed before any meaningful estimates are possible. Therefore it is almost impossible to be precise as to the type and scale of benefits for an option, like the EDR or enhanced EDR, until those factors are known."

[48] 2 RT 443, lines 1 – 4.

quantifying those."[49] The most powerful statement regarding the inadequacies of indirect benefits as a measure of ratepayer benefits within the context of PU Code §740.4(h), came from a strong proponent of PG&E's enhanced EDR proposal, the LGP witness, who stated:

> I need to note two things at this point: first, specific details of location, type of business and scale of the investment are all needed before any meaningful estimates are possible. Therefore it is almost impossible to be precise as to the type and scale of benefits for an option, like the EDR or enhanced EDR, until those factors are known. Second, the actual measure of the positive impact of a specific investment is invariably an after-the-fact task.[50]

Thus, while forecasts certainly can be made, they are inherently less accurate than an after-the-fact review. In fact, Mr. McClary stated that the CTM, which is the subject of his testimony, is much easier to forecast.[51] Given the innate uncertainty of any forecast of indirect benefits, it is unclear how they would be weighed against the more certain CTM benefits if they were to be considered by the Commission in approving PG&E's proposals.

The other major problem with considering the indirect benefits is that there is no record in this proceeding on how to quantify or monetize the potential indirect benefits of the proposed EDR program. As discussed above, PG&E has the burden of proof to supply such evidence.[52] As Merced and Modesto Irrigation Districts' witness points out,

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[49] 3 RT 692, lines 12 – 14.

[50] Ex. LGP-1, pp. 15-16. He also stated : "The benefits will be measurable in direct terms and in multiplier terms. Direct terms include the value of real estate transactions, of additional and/or new manufacturing facilities, numbers of employees and – more forensically – in the maintenance of profitability that protects existing jobs and investments. In multiplier terms, there are methods to calculate the likely multiplier impact of a given investment and thereafter to compare the projected impacts with actuals."

[51] MerMod/McClary, 3 RT 692, lines 14 – 18: "I think it is important that it be understood that my testimony is talking about the extent to which benefits are quantifiable and accrue to ratepayers."

[52] PUC §740.4(h) "It is the intent of the Legislature that the Public Utilities Commission, in implementing this chapter, shall allow rate recovery of expenses and rate discounts supporting economic development programs within the geographic area served by any public utility *to the extent the utility incurring or*

(footnote continued on next page)

"there is not a record on those indirect benefits, the extent to which they exist, who they go to."[53]

The bottom line is that PU Code §740.4(h) requires the utility to demonstrate that its ratepayers will benefit from an EDR program in order to receive authorization for rate recovery of expenses and rate discounts supporting economic development programs.[54] This means PG&E must demonstrate that its ratepayers will benefit from the EDR program before it can receive Commission approval of the program.

In regard to ALJ Clark's December 11, 2012 Ruling Regarding Supplementing the Record, DRA does not believe that the Commission should require that an EDR customer's reduction in CTM be proportionate to the number of jobs actually retained or created by that customer.[55] In addition to discussion of indirect benefits above DRA would like to make the following points. First, jobs created or retained are a societal benefit and not a direct ratepayer benefit. Direct ratepayer benefits of an EDR customer contract are measured by the CTM provided by customers who would otherwise not take utility service in California, but for the EDR discount.

Second, the value of a job created depends very much on the economic value added by the worker's output. Quantifying the value of jobs created must consider the quality as well as the quantity of those jobs, the former of which would be very difficult to evaluate within the scope of this proceeding. Lastly, to the extent that California or local government wishes to boost employment, tax and other incentives are arguably a more transparent means than are electric rate incentives. The Commission's primary

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proposing to incur those expenses and rate discounts demonstrates that the ratepayers of the public utility will derive a benefit from those programs." (emphasis added)

[53] MerMod/McClary, 3 RT 693, lines 2-4.

[54] PU Code §740.4(h).

[55] This section addresses the new Scoping Memo Issue raised in ALJ Clark's December 11, 2012 Ruling listed as Scoping Memo Issue #34 in Appendix E.

mission is to ensure that utility rates remain just and reasonable.[56] Other objectives, such as job creation, are best left to other public agencies. For these reasons, the Commission should base its determination of ratepayer benefits on the direct ratepayer benefit of positive CTM.

D. Each EDR Customer Contract should be Required to have a Positive CTM, on a Forecast Basis, over the Contract Period

Each EDR customer contract should be required to demonstrate a positive CTM, on an ex ante (forecast) basis over the five-year contract term.[57] PG&E's assertion that its proposed EDR program will result in benefits to ratepayers is based on a 10-year CTM analysis.[58] PG&E's 10-year analysis of CTM is a major and risky departure from the current EDR program, which includes a floor price that guarantees that EDR contracts will yield a non-negative CTM every year.[59] While DRA's EDR proposals also increase the risk to ratepayers relative to the current EDR, this risk is limited by the proposed enforcement of DRA's modified additive price floor over a five-year contract period. PG&E's proposed EDR contains no price floor and does not guarantee even a ten-year positive CTM. The Commission should adopt DRA's EDR proposals to ensure that each EDR customer contract will yield a positive CTM over the five-year contract term.

PG&E's analysis shows a number of cases in which the forecast five-year CTM is negative. The expectation of a negative 5-year CTM should raise a red flag for the Commission for two reasons. First, there is no guarantee that the customer will continue to take service from PG&E during the entire 10-year analysis period. If the customer leaves the State or goes bankrupt soon after the EDR contract expires, there may not be enough positive CTM to outweigh a 5-year negative CTM present value over the contract term. Worse, the customer could leave before the termination of the contract, thus

[56] PU Code §451.

[57] The following section addresses Scoping Memo Issues #27 and #28.

[58] Ex. PG&E-1, Table 3-1, p.3-3, Ex. PG&E-4, Table 2-1, p.2-8.

[59] D 10-06-015, p.7.

leaving ratepayers with a negative CTM with no offsetting positive CTM. The second reason for caution is the fact that the marginal cost can change during the 5-year contract term.[60] As discussed below, increases in marginal cost can cause the CTM to turn from positive to negative over the term of a five-year contract with a fixed 35% discount.[61]

PG&E has acknowledged some of the uncertainties surrounding its ten-year CTM projections, and has run sensitivity analysis for the EDR program that account for some of the uncertainties.[62] However, PG&E's 10-year CTM analysis fails to adequately address all of the risks that could significantly affect the CTM projections. For example, PG&E also proposes that "customers participating in the proposed EDR Program not be precluded from qualifying for any subsequent EDR Program that PG&E might propose[63] and that the Commission might authorize, solely based on their participation in PG&E's currently-proposed program."[64] Under this scenario, enhanced EDR customers could remain on a discounted rate schedule for 10 years[65] which could result in the negative CTM created during the first 5 years being compounded by further negative CTM in years 6-10. Under its current proposal, PG&E would then recover this negative CTM from nonparticipating ratepayers. This will result in an EDR program that results in increasing nonparticipating ratepayers' rates instead of benefiting them, in violation of PU Code §740.4(h).

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[60] Ex. DRA-1, p.2-2, lines 5-15.

[61] See, Section VII.F.

[62] Ex. PG&E-4, p.2-12, lines 9-16, Table 2-3. This analysis does not address all the risks identified by DRA. The risks to ratepayers inherent in PG&E's ten-year CTM projections are more fully discussed below, in Section VII.C. DRA identifies five separate risk factors, only three of which are addressed, in a limited manner, in PG&E's sensitivity analyses.

[63] Ex. PG&E-4, p.2-10. Under PG&E's revised proposal, the EDR program would be reevaluated in Phase 2 of the 2017 GRC.

[64] Id.

[65] PG&E acknowledged this possibility in its sensitivity cases presented in Ex. PG&E-4, p.2-12. However, it limits its analysis to "10 percent of the customers qualify for a second EDR term". There is no analysis presented of the effect of a higher percentage of customers qualifying for a second EDR term, nor any information that would preclude such a possibility.

PG&E's proposal fails to adequately address another additional uncertainty, the prevalence of free-rider participation in the EDR program. Retention customer free-ridership is especially problematic for nonparticipating ratepayers because for retention customers, marginal costs are unchanged but the CTM decreases by exactly the amount of the discount. Further, even if the CTM remains positive after the EDR discount, ratepayers are harmed relative to the status quo prior to the EDR, when the EDR retention customers were paying the full rate.[66] PG&E is proposing to remove some of the eligibility requirements that the past EDR employed to discourage free-ridership.[67] One of PG&E's sensitivity analyses presents the 5-year net present value (NPV) of CTM with a 10% free-ridership rate.[68] The results of this analysis show negative CTM resulting for enhanced EDR customers in constrained areas on all six rate schedules and for one rate schedule in unconstrained areas.[69]

Because of these and other risks,[70] the Commission should not rely on the adequacy of PG&E's ten-year projections of positive CTM, to ensure benefits to nonparticipating ratepayers. To ensure that ratepayers will benefit from the EDR program as required by PU Code §740.4(h), the Commission should instead adopt DRA's proposal so that each EDR customer contract will produce a positive CTM at the end of the 5-year contract term on a forecast basis.

E. Each EDR Program should, individually, have a Positive CTM

In order to comply with PU Code §740.4(h), both the standard and enhanced EDR programs should benefit ratepayers independently. It is not sufficient for the combined

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[66] Ex. DRA-2, p. 1-9.

[67] PG&E proposes to remove the eligibility requirements and oversight measures: requirement that EDR customers attest that energy costs constitute 5% of their operating costs, less the costs of raw materials; review and approval of EDR applications by CalBIS; liquidated damages clause for customer initiated early termination of EDR contract.

[68] Ex. PG&E-5, p. WP 2-40.

[69] Id.

[70] See Section VII below for a more complete discussion of the risks inherent in PG&E's EDR proposals.

programs generally to have a positive CTM. Each EDR program must stand on its own in passing the ratepayer benefits test. For example, a positive CTM from the standard EDR program should not be combined with, and mask, a negative CTM from the enhanced EDR program.

PG&E does not share DRA's interpretation, and believes that a showing of a positive CTM for the EDR program as a "package" would be sufficient for the Commission's authorization even if some components had negative CTM.[71] In hearings, PG&E's witness was presented with a hypothetical in which the combined standard and enhanced EDR programs had a $5 million positive CTM, but the enhanced EDR program alone had a negative $3 million CTM. PG&E's witness was asked:

> Q. So under the conditions of this hypothetical, would PG&E recommend that the Commission authorize the combined standard and enhanced EDR program?
>
> A. Well, PG&E hasn't made a proposal that gives you a negative 10-year margin, a negative CTM expectation on the enhanced option of negative $3 million. So frankly, it's a hypothetical I hadn't considered.
>
> Q. Well, you've considered the possibility that both the enhanced and the standard need to be considered together; correct?
>
> A. Yes.
>
> Q. And do you think the Commission should look at whether or not the enhanced program produces a negative CTM on its own? Should the Commission consider that in this proceeding?
>
> A. Yes. I think that the Commission should consider the analysis associated with the enhanced separately from the standard, but I think that they should authorize a program based upon the expected combination of the two. That would suggest that they could -- in my mind, it would be reasonable for them to approve the program with a $5 million positive contribution to margin over 10 years so long as the program was positive, yes.[72]

[71] PG&E/Pease, 2 RT 263 lines 17-24

[72] Id., 2 RT 264 line 22 through 265 line 23

DRA notes a significant flaw in PG&E's logic. Under conditions of this hypothetical, the ratepayers would benefit by a $5 million positive CTM if the Commission were to approve the combined standard and enhanced EDR programs. However, the Commission would also have the option to approve the standard program and deny the enhanced program. Under the hypothetical, the CTM for the standard program alone would be $8 million. Therefore, ratepayers would be better off in this hypothetical if the Commission were to approve only the standard EDR program. DRA's hypothetical illustrates the principle that ratepayer benefits are maximized to the extent that programs and contracts with negative forecast CTM are excluded. In summary, the Commission's duty to ensure that rates are just and reasonable requires it to examine each EDR program and contract separately and authorize only those programs and contracts for which a positive forecast CTM can be demonstrated.

In this case, the enhanced EDR program might not, on its own, be beneficial to ratepayers, and as proposed should not be offered or approved by the Commission.[73] According to PG&E's "Workpapers Supporting Rebuttal Testimony Chapter 2,"enhanced EDR customers in constrained distribution planning areas on all six of the rate schedules eligible of the EDR would generate a negative CTM after five years.[74]

PG&E's proposal to allow the positive CTM generated by the standard EDR program to compensate for the negative CTM created by the enhanced EDR program is based on unverified assumptions. This proposal assumes that there will be enough standard EDR customers to counteract the negative CTM that will be produced by enhanced EDR customers. PG&E has not attempted to estimate how many customers will be eligible for the enhanced or standard EDR programs.[75] Therefore, relying on the

[73] This section addresses Scoping Memo Issue #15.

[74] Ex. PG&E-5, pp. WP 2-7 – 2-12. An enhanced EDR customer in an unconstrained distribution planning area for one rate schedule, E-20T, would also generate a negative CTM after five years. Id. at WP 2-16.

[75] PG&E/Hartman, 1 RT 191, lines 13-19. ("Question: Has PG&E done analysis of how many of these customers (customers who are businesses and have the required minimum load to participate in the EDR program) would qualify for your EDR proposal? Answer: No, we have not. I would say based on our

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assumption that there will be enough participation in the standard program to offset the negative rate impacts of the enhanced EDR is a flawed approach. The negative CTM generated by the enhanced EDR under PG&E's proposal could be substantial and cannot be rectified by applying the positive CTM the standard EDR program is projected to produce. The Commission should adopt DRA's EDR proposals, rather than PG&E's, to ensure that both the standard and enhanced EDR programs will produce a positive CTM.

VI. COMMISSION POLICY REQUIRES THAT THERE BE AN ADDITIVE PRICE FLOOR THAT INCLUDES NONBYPASSABLE AND MARGINAL COSTS.

The Commission should adopt DRA's proposed price floor, which includes nonbypassable rates and marginal costs.[76] DRA proposes that the proposed EDR rates be assessed relative to both nonbypassable rates and marginal costs separately as well as relative to an additive price floor that includes both.[77]

Thus, under DRA's proposal, all EDR contracts first should be required to demonstrate a positive contribution to margin ("CTM") over the 5-year contract term on an ex ante (forecast) basis.[78] The following should be included in the marginal cost used to calculate the CTM: (a) marginal generation costs,[79] including a 15% resource adequacy adder in the marginal generation capacity cost; (b) marginal distribution cost for constrained or unconstrained areas, as applicable; and (c) the full retail transmission rate. In addition, EDR contracts may not discount nonbypassable ("NBC") rate

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experience with the current EDR it would be an extremely small subset of this number.") See also, Ex. MerMod-1, p.11: "In fact, PG&E has not even developed an estimate of the number of customers eligible for either the proposed Standard or Enhanced EDR." citing to PG&E response to Greenlining Data Request 1, Q 1.

[76] Ex. DRA-1, pages 2-2 through 2-7.

[77] This Section references Scoping Memo Issue #2.

[78] That is, the 5-year net present value of the contract revenue must exceed the 5-year net present value of the marginal cost to serve the customer.

[79] DRA recommends that the 2011 GRC Phase 2 settlement marginal energy cost value be averaged with PG&E's indexed value over the 5-year contract, with a 20% weighting of the Settlement value and 80% weighting of the indexed value. DRA also recommends that this weighted average value be used to evaluate the 10-year CTMs.

components. Finally, EDR discounts should be subject to a modified additive price floor applied over the 5-year contract term, but not necessarily annually. The modified additive price floor should consist of the NBC rate components plus the marginal energy cost and the marginal distribution cost. Thus it excludes marginal generation capacity costs, which are captured separately. The 5-year net present value of the contract revenue should exceed the 5-year net present value of the modified additive price floor.

A positive CTM is a necessary condition, but not a sufficient condition, for the Commission to authorize an EDR program or and EDR contract. In D.07-09-016, the Commission established a price floor on EDR discounted rates, consisting of the sum of marginal costs and the nonbypassable rate components.[80] The Commission should continue to enforce an additive price floor because it is required by law and Commission precedent, and because it is absolutely essential for ratepayer protection. An additive floor price is essential to ensure that customers provide sufficient revenue to cover both marginal costs and NBCs, and thus, ensure, simultaneously, that (1) NBCs are not discounted; and (2) Costs caused by EDR participants are not shifted to nonparticipants.

There is no dispute among the parties that CTM is a valid measure of ratepayer benefits. That is, PG&E's ratepayers benefit when customers who would otherwise depart or not take service in PG&E's service territory are retained or attracted at a rate sufficient to provide a positive CTM.[81] The necessity of a positive CTM is discussed above in Section V. Under the required additive price floor, the customers ***also*** must provide revenues which exceed the ***sum*** of the NBCs and the marginal costs of

[80] Rate elements such as transmission charges, which are considered as both marginal costs and NBCs, should be counted only once in determining the floor price.

[81] See. e.g., Ex. PG&E-4, p.2-1, lines 31-33; Ex. DRA-2, p.1-6, lines 17-18. There are, however, disputes as to how to compute CTM (discussed below in Section IX); whether a positive CTM should be required; if required, should it be required for the EDR program as a whole or for its components separately; and over what time frame; and finally, should a showing of positive CTM be sufficient for the Commission to authorize an EDR contact or an entire EDR program.

generation and distribution. Rates which exceed the additive price floor also will provide a positive CTM in most cases.[82]

A. NBCs defined and listed

According to D.07-09-016, the term "Nonbypassable" means "cannot be discounted."[83] Thus, the terms "nonbypassable" and "nondiscountable" are synonymous for the purposes of this proceeding.

DRA proposed that the following retail rate components be treated as nonbypassable:[84]

- Transmission charges
- Public Purpose Program ("PPP") charges
- Nuclear Decommissioning ("ND") charge
- Competition Transition Charge ("CTC")
- New System Generation Charge ("NSGC")
- Department of Water Resources bond charge ("DWR bond"
- Power Cost Indifference Adjustment ("PCIA").[85]

With the possible exception of the PCIA, which applies only to direct access ("DA") and community choice aggregation ("CCA") customers, DRA's listing of the NBCs was undisputed.[86]

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[82] If the same marginal costs are used in the additive price floor as in the CTM calculation, the CTM will always be positive when prices exceed the additive price floor. DRA's proposed modified additive price floor uses a reduced shorter-term marginal generation cost which sets the marginal cost of generation capacity at zero, but recommends that the full marginal generation cost be used for the CTM. As shown in Ex. DRA-1, Table 2-5, p.2-9, in a few cases the marginal cost floor price exceeds the modified additive floor price.

[83] Footnote 7 on page 11 of D.07-09-016 states: "The phrase 'nonbypassable and cannot be discounted' is a redundancy (also, a tautology). 'Nonbypassable' means 'cannot be discounted.' Perhaps the Legislature should have footnoted each time it enacted 'nonbypassable' with the phrase 'and we mean it'."

[84] Ex. DRA-1, p.2-4, Table 2-2.

[85] This applies only to direct access and community choice aggregation customers.

B. NBCs are nondiscountable; no exceptions are permitted

According to D.07-09-016, "The statutory term 'nonbypassable' has been consistently interpreted by this Commission to mean 'nondiscountable'."[87] Moreover, the decision states that "The term "nonbypassable" has been consistently interpreted by this Commission and state courts as meaning no exceptions."[88] This decision provides a detailed supporting legal analysis citing numerous sections of the P.U. Code. While the discussion in D.07-09-016 focuses most on PPP charges, its conclusions apply generally to all NBCs.[89]

Taking parties' testimony at face value, no party disputes the fundamental conclusion of D.07-09-016, that NBCs cannot be discounted.[90] However, as discussed below, PG&E has proposed a negative distribution rate for some rate classes.[91] For DA and CCA customers, a negative distribution rate amounts to a *de facto* discount to one or more NBCs.[92]

C. Additive price floor as required by D.07-09-016

D.07-09-016 states, in Finding of Fact ("FOF") 3: "Economic discount rates must have a floor of all nonbypassable charges."[93] In addition, FOF 6 states:

> In the Amended Proposal in D.05-09-018, the description of Floor Pricing and Marginal Costs is modified to read:

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[86] PG&E agreed with DRA that it was reasonable to treat PCIA charges as nonbypassable. PG&E/Pease 2 RT 312, lines 1-4; DRA/Levin 2 RT 325, lines 15-20. However neither party was able to cite a supporting Commission decision or statute when asked in hearings.

[87] Id. p.16

[88] D.07-09-016, p.15

[89] Id., FOF 1 and 2

[90] Ex. DRA-1, p.6, lines 4-5; Ex. PG&E-4, p.2-3, lines 4-5; p. 2-5, lines 25-27.

[91] Ex. PG&E-5, WP 2-5.

[92] Ex. DRA-1, p.2-11, lines 13-18; Ex. DRA-2, p.1-15, lines 6-8.

[93] FOF No. 3, D.07-09-016, p.34.

> Limit the discount to ensure revenue does not fall below floor price, which consists of transmission charges, PPP charges, ND charges, DWR Bond charges, CTC, marginal costs for transmission, distribution, and, if a bundled-service customer, marginal costs for generation. Floor price to be based on customer-specific marginal costs, up to the OAT. Unit marginal costs to be established at beginning of customer contract.

In short, discounted rates to bundled service customers must not fall below the sum of the NBCs and the marginal costs of distribution and generation. For DA and CCA customers, discounted rates must not fall below the sum of the NBCs and the marginal cost of distribution. DRA uses the term "additive price floor" to refer to the sum of NBCs and marginal costs adopted as a floor price in D.07-09-016.

The additive price floor serves a double purpose of simultaneously ensuring that: (1) The NBCs are not discounted; and (2) The costs caused by EDR participants are not shifted to nonparticipants. While most of the discussion in D.07-09-016 focuses on NBCs, the term "cost shifting" occurs on six separate pages of that decision,[94] in the context of a statutory or regulatory prohibition. A preceding decision, D.06-08-033, states the issue of cost shifting succinctly:

> In challenging D.05-09-018, Aglet claimed that modification of the floor price to exclude DWR Bond Charges contravenes section 366.2(d)(1). Section 366.2(d)(1) states.[95]
>
> It is the intention 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…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*. (Pub. Util. Code, §366.2, subd (d)(1) (emphasis added in D.06-08-033.).)
>
> Section 366.2 is clear regarding the Legislature's intent to prevent cost shifting in ensuring these nonbypassable charges are collected.[96]

[94] D.07-09-016, pp. 6, 11, 16, 26, 27, and 35.

[95] D.06-08-033, p.5.

Aglet's specific objection to the omission of DWR bond charges from the D.05-09-018 price floor could apply equally to any and all of the NBCs. The additive price floor adopted in D.07-09-016 ensures that EDR customers provide sufficient revenue to simultaneously fully fund both the NBCs and the marginal generation and distribution costs. If this condition is not met, then either one or more NBCs are effectively discounted, or marginal costs are not fully funded. Both outcomes are impermissible according to D.07-09-016.[97] However, even if NBCs are fully funded, failure of an EDR customer to provide enough revenue to *also* cover the customer's share of marginal generation and distribution costs means that some portion of those costs are shifted to other customers. In adopting its additive price floor, it was clearly the Commission's intent in D.07-09-016 to prohibit such cost shifting.

Further, discounts below marginal distribution and generation costs always involve cost shifting because such costs are incurred as an unavoidable consequence of the EDR participants' demand for energy.[98] If EDR customers do not provide enough revenue to cover their marginal cost, then other customers, or possibly utility shareholders, must make up the difference.[99] As a general principle, shifting costs from one group of utility customers to another group of customers, absent a clearly defined public purpose, violates longstanding Commission policy.[100] Such cost shifting clearly also violates the plain language of P.U. Code Sec. 366.2(d)(1), quoted in D.07-09-016:

> It is further the intent of the Legislature to prevent any shifting of recoverable costs between customers.[101]

(footnote continued from previous page)
[96] Id. (Emphasis Added)

[97] D.07-09-016, p.33, FOF 1 rules out discounting of NBCs.

[98] Ex. DRA-2, p.1-3, lines 21-28

[99] Id.

[100] Ex DRA-1, p.1-13, lines 17-18

[101] D.07-09-016, p.26.

In summary, the additive price floor mandated by D.07-09-016 serves the dual function of prohibiting the discounting of NBCs and of protecting nonparticipating ratepayers from unwarranted and unlawful cost shifting.

D. DRA's Proposed Modified Additive Price Floor

DRA proposes to retain the basic framework of the additive price floor adopted in D.07-09-016, but with some modifications to address concerns that application of the additive price floor has unduly restricted the discounts available to EDR customers pursuant to the expiring EDR program.

Specifically, DRA proposes that the Commission continue to require that discounted rates exceed a price floor consisting of the sum of NBC and the marginal costs of distribution and generation.[102] However, DRA proposes that the additive price floor be applied on an ex ante length of contract basis (e.g., over five years) rather than annually on an ex ante and ex post basis, as is the case in the expiring EDR program. In proposing to eliminate the annual ex post review of EDR contracts (the so-called "clawback" provision), DRA has agreed with PG&E and other parties that this provision limits the effectiveness of the current EDR program. As a secondary temporary measure, and in response to the current lack of need for new generating capacity, DRA has proposed, for the purpose of determining floor prices for this proceeding only, to set the marginal generation capacity cost at zero.

The effect of these modifications is to allow a "front-loaded" declining discount, whereby marginal costs would be fully covered over the contract period but not necessarily on a year-by-year basis. Under DRA's "modified additive price floor," large discounts can be given in the initial years of an EDR contract, when they may be most needed.[103] Thus the price floor can be retained but modified to improve the

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[102] The following section addresses Scoping Memo Issue #25.

[103] DRA's proposal to enforce the price floor over the contract term but not annually does increase the risk to ratepayers, in that there could be a negative CTM if a customer should depart before the contract term expires. DRA has proposed a liquidated damages clause similar to those adopted in past EDRs to deal with that situation. See Section X, Subsection G.

attractiveness of EDR contracts. The majority of the parties support retention of a price floor. Only two parties, PG&E and LGP, advocate full elimination of a price floor under EDR discounts.[104]

In summary, DRA's "modified additive price floor" retains the essential features and ratepayer protections of the additive price floor adopted in D.07-09-016, while permitting much larger and more flexible discounts and removing the burden on participants of after-the-fact review.

E. PG&E's EDR Proposal Violates the Additive Price Floor

In many cases, the 35% discount proposed by PG&E for its enhanced EDR program would violate the Commission's additive price floor established in D.07-09-016. To establish this fact, we compare the proposed discounted rate with the additive price floor value, on a rate schedule by rate schedule basis. DRA uses rate schedule E-20S as an exemplar of this comparison.

As noted above, the additive price floor consists of the sum of NBCs and marginal costs. Calculation of the NBC component for bundled service customers is straightforward; there was no dispute as to the identity and numerical values of the NBCs. It should be noted that PG&E and DRA agree that transmission charges, in addition to being an NBC, should be considered a marginal cost for the purpose of computing CTM, but should be counted only once in computing the additive price floor.[105]

Numerical values of the NBCs for rate schedule E-20S are shown in Table 1 below.

[104] Ex. PG&E-1, p.2-7; Ex. LGP-1, p. 11.

[105] Whether or not DWR bond charges are also marginal costs will have no effect on the additive price floor. Like transmission charges, DWR bond charges will be counted only once in computing the price floor. As explained below, DRA is now convinced by SCE's Rebuttal Testimony and no longer considers DWR bond charges to be a marginal cost.

Table 1: Numerical values of the NBCs for rate schedule E-20S.[106]

NBCs		$ per kWh
Transmission		$0.00982
Public Purpose Programs		$0.01459
Nuclear Decommissiong		$0.00055
CTC		$0.00377
NSGC		$0.00080
DWR Bond Charge		$0.00513
Total NBCs		**$0.03466**

Analysis of the marginal generation and distribution costs of serving E-20S loads requires examining six cases: 2 generation cost scenarios times 3 distribution cost scenarios. The two generation cases include the full marginal generation cost (capacity plus energy) and a reduced marginal generation cost (consisting of marginal energy costs only).[107] For E-20S, these values are $0.05824 per kWh and $0.03969 per kWh, respectively.[108] No party disputed DRA's values for the marginal generation costs applicable to the proposed five-year EDR contract term.[109]

DRA's recommended price floors[110] are based on PG&E's marginal distribution costs for constrained areas. PG&E's workpapers also provided marginal distribution costs for unconstrained areas.[111] For E-20S, these values are $0.01684 per kWh and $0.00151 per kWh, respectively. While not disputing the numerical accuracy of these

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[106] Source: Ex. PG&E-3, p.3-13. PG&E's values were not changed from PG&E's rebuttal workpapers, Ex. PG&E-5, and can be found on p.2-13 of that exhibit.

[107] The latter case was offered by DRA in connection with its proposed modified additive price floor. Ex. DRA-1, pp. 2-6, 2-7.

[108] Ex. DRA-1, Table 2-4 (rightmost two columns), p.2-8

[109] Ex. PG&E-4, pp. 2-7, 2-8, Q&A 15 and 16. In Q&A 16, PG&E agrees with DRA's calculation of marginal energy cost "for the first five years of an EDR customer's contract". This is the relevant time frame to determine compliance with the price floor. In Q&A 16, PG&E proposes that a numerically lower marginal energy cost be applied in CTM calculations for years six and beyond.

[110] Ex. DRA-1, pp.2-8, line 12 through pp.2-9, line 2.

[111] Marginal distribution costs for constrained and unconstrained areas are from PG&E's electronic workpapers but are not shown in PG&E's workpaper exhibits (Ex. PG&E-3 and PG&E-5). They are, however, shown in Ex. DRA-1, Appendix I, fourth and fifth pages of tables (E-20S constrained and unconstrained cases).

values, PG&E claims that reliance on the marginal distribution cost for constrained areas would be overly "conservative."[112] Instead, it recommends use of a "50/50 blend" of constrained and unconstrained area marginal costs,[113] which, in the case of E-20S, works out to $0.00918 per kWh.[114]

In the following table, we consider the floor prices represented by all six combinations of marginal cost discussed above.

Table 2: E-20S Floor Price For Various Marginal Cost Cases

		Distribution Marginal Cost Constraint Assumption		
Generation Assumption		**Constrained**	**50/50 Blend**	Unconstrained
Energy + Capacity	Gen MC	$0.05824	$0.05824	$0.05824
	Dist MC	$0.01684	$0.00918	$0.00151
	NBCs	$0.03466	$0.03466	$0.03466
	Floor price	**$0.10974**	**$0.10207**[115]	**$0.09441**
Energy only	Gen MC	$0.03969	$0.03969	$0.03969
	Dist MC	$0.01684	$0.00918	$0.00151
	NBCs	$0.03466	$0.03466	$0.03466
	Floor price	**$0.09119**[116]	**$0.08352**	**$0.07586**

Having calculated the floor price pursuant to D.07-09-016,[117] it is a simple matter to determine whether or not it would be violated by PG&E's proposed 35% enhanced

[112] Ex. PG&E-4, p.2-2, lines 6-13

[113] Ex. PG&E-4, p.2-10, lines 15-17, PG&E/Pease, RT 2, p. 279, lines 17-28, p. 280, lines 6-8.

[114] This is the numeric average of the distribution marginal cost values for constrained and unconstrained areas.

[115] Incorporates marginal costs used by PG&E in its CTM calculations in Ex. PG&E-4 (e.g., Table 2-1 on p. 2-8)

[116] This is DRA's recommended floor price for E-20S bundled service customers. Summary tables of DRA's recommended floor prices are presented in Appendix D. The floor prices in Appendix D supersede Tables 2-5 and 2-6 in Ex. DRA-1.

[117] D.07-09-016 provides no guidance on the specific attributes of the marginal costs required to be included in the floor price. Thus, for inclusiveness, DRA includes the six permutations discussed above.

EDR discount. PG&E's full tariff rate for bundled service E-20S customers is $0.12693 per kWh; its proposed discounted rate is $0.08251 per kWh.[118] Table 3 shows that PG&E's proposed 35% enhanced EDR discount for E-20S would violate the additive price floor. Note that the margin above the floor price is negative for five of the six marginal cost scenarios discussed below.

Table 3: E-20S PG&E 35% Enhanced EDR Discount Violates Price Floor

Generation Assumption		**Distribution Assumption**		
		Constrained	**50/50 Mix**	**Unconstrained**
	Discounted rate	$0.08251	$0.08251	$0.08251
Capacity + Energy	Floor price	$0.10974	$0.10207[119]	$0.09441
	Margin above floor	**-$0.02723**	**-$0.01956**	**-$0.01190**
	Discounted rate	$0.08251	$0.08251	$0.08251
Energy only	Floor price	$0.09119[120]	$0.08352	$0.07586
	Margin above floor	**-$0.00868**	**-$0.00101**	**$0.00665**

As discussed above, DRA's proposed modified additive price floor is based on energy-only marginal generation costs and a constrained area marginal distribution cost. While PG&E does not recommend retention of a floor price, its CTM calculations in its rebuttal testimony[121] are based on marginal generation costs that include both capacity and energy costs, and marginal distribution costs for a 50/50 blend of constrained and unconstrained areas. Thus, the additive price floor is violated in both DRA and PG&E's preferred marginal cost scenarios. The sole exception, in which the additive price floor is not violated, is an unconstrained distribution scenario, which no party has recommended

[118] Ex. PG&E-3, p.WP 3-13; Ex. PG&E-5, p.WP 2-4

[119] Incorporates marginal costs used by PG&E in its CTM calculations in Ex. PG&E-4

[120] DRA's recommended modified additive floor price.

[121] Ex. PG&E-4, Table 2-1, p.2-8

a basis for a floor price. Thus, the Commission should accord little, if any, weight to this exceptional case.

By no means is noncompliance by PG&E's proposed 35% EDR discount limited to E-20S. In its rebuttal testimony, PG&E calculated the maximum discount that would be permitted under DRA's proposed modified additive price floor for each of the six relevant rate schedules.[122] That maximum discount is less than 35% for all six rate schedules, based on constrained area marginal costs. Thus, a 35% discount would violate DRA's modified additive price floor. Even under PG&E's preferred 50/50 distribution scenario, the maximum permissible discount is less than 35% for four of the six rate schedules.[123] Thus, the noncompliance of PG&E's proposed 35% enhanced EDR with the D.07-09-016-adopted additive price floor is pervasive.

For this reason among others, the Commission should reject PG&E's enhanced EDR proposal.

F. Consequences of Violating the Additive Price Floor: either (1) NBCs are Discounted, or (2) Marginal Costs of Generation and Distribution are Shifted to Nonparticipants

As a simple consequence of mathematical logic, if an EDR customer's discounted rate is less than the sum of the NBCs and the marginal costs of generation and distribution, then either (1) The NBCs are not fully funded, or (2) The marginal costs of generation and distribution are not fully funded.[124] This can be illustrated by the following simple numerical example proposed by PG&E in Reply Comments submitted in a previous EDR proceeding,[125] as well as by the actual data in this proceeding. This section describes how PG&E's proposal violates the additive price floor and how this

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[122] Ex. PG&E 4, Table 2-5, line 2, p.2-14

[123] Id., Table 2-5, line 3, p.2-14

[124] It is possible in this situation that neither the NBCs nor marginal costs are fully funded.

[125] Reply Of Pacific Gas And Electric Company To Comments On Proposed Decision Of Administrative Law Judge Barnett And Alternate Proposed Decision Of President Peevey, A.04-04-008, dated August 20, 2007.

will either result in the discounting of NBCs or cost shifting of marginal costs to nonparticipants.

1. Consequences of Violating the Additive Price Floor are Illustrated in a Hypothetical Presented by PG&E in an Earlier EDR Proceeding

PG&E's August 20, 2007 Reply in A.04-04-008 et al states:

> A simple hypothetical may help to explain PG&E's reasoning. Assume the tariff rate is 10 cents per kilowatt-hour, comprised of 7 cents of distribution and generation components and 3 cents of nonbypassable charge components. Further assume that of the 7 cents, 5 cents are marginal distribution and generation costs. To discount the tariff rate by 25 percent, to 7.5 cents, the first 3 cents can be allocated to fully fund nonbypassable charges, and then the remaining 4.5 cents can be allocated to the distribution and generation components. If nonbypassable charges are excluded from the price floor, then the 7.5 cent rate is well above the floor price of 5 cents for distribution and generation marginal costs. But if nonbypassable charges are included in the price floor, then the discounted rate must be at least 8 cents (5 cents for distribution and generation marginal costs plus 3 cents for nonbypassable charges), and the 7.5 cents discounted rate would be impermissibly low. Yet, the customer would still be making a contribution to margin, and thus benefiting all other customers, at any rate above 5 cents per kWh.

The following Table represents PG&E's hypothetical:

Table 4: Hypothetical from PG&E August 20, 2007 Reply in A.04-04-008 et al

Line	Rate/ Cost Component	Value (cents/kWh)	Source/Calc
1	Full tariff	10	Given
2	Proposed discounted rate	7.5	Given
3	Nonbypassable charges	3	Given
4	Allocation to distribution & generation	4.5	Line 2 – Line 3
5	Marginal distribution & generation cost	5	Given
6	Marginal cost shortfall	(0.5)	Line 4 – Line 5
7	Contribution to margin	2.5	Line 2 – Line 5

In its August 2007 reply comments, PG&E argued to exclude nonbypassable charges from the EDR price floor, based on the computation of a positive CTM (2.5 cents in this example).[126] PG&E's reasoning here is incorrect because it ignores the shortfall in the marginal cost (0.5 cents in this example). The marginal costs are unavoidable and are caused by the EDR customer's demand for energy; to the extent these costs are not fully funded by revenue from the EDR customer, they are necessarily shifted to nonparticipants. As noted above, such cost shifting is generally prohibited by both statute and by multiple Commission decisions.[127]

To prevent cost shifting, while not discounting NBCs, requires revenues to satisfy an additive price floor (8 cents in this example, or 3 cent NBCs + 5 cent marginal cost). PG&E's hypothetical could be corrected by assuming a smaller discount that satisfies the additive price floor, as shown in the following table:

Table 5: DRA- Corrected Version of PG&E's Hypothetical

Line	Rate/ Cost Component	Value (cents/kWh)	Source/Calc
1	Full tariff	10	Given
2	Nonbypassable charges	3	Given
3	Marginal distribution & generation cost	5	Given
4	Additive price floor	8	Line 2 + Line 3
5	Discounted rate	8.5	Line 4 + 0.5
6	Allocation to distribution & generation	5	Line 3
6	Marginal cost shortfall	0	Line 3 – Line 6
7	Contribution to margin	3.5	Line 5 – Line 3
8	Margin above floor price[128]	0.5	Line 5 – Line 4

[126] Id.

[127] See, e.g., D.06-08-033, p.5, and D.07-09-016, p.6

[128] The "margin above the price floor" is the difference between the revenue received from the customer and the additive price floor. This is not the same as the CTM, when some rate components are NBCs.

(footnote continued on next page)

In this revised version of PG&E's 2007 hypothetical, the new discounted rate is 0.5 cents above the additive price floor, resulting in sufficient revenue to simultaneously fully fund NBCs and marginal costs, thereby avoid prohibited cost shifting.

2. Consequences of Violating the Additive Price Floor also are Demonstrated using Data from the Current Proceeding

In the following calculation, we again use E-20S as our exemplar.   The table below contains analyses based on: (1) DRA's modified additive price floor, and (2) PG&E's preferred marginal cost scenario.

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(footnote continued from previous page)
The difference between CTM and margin above the price floor are discussed below in Section IX.

Table 6: PG&E's Proposed E-20S Discounts Would Cause Prohibited Cost Shifting

Line	**Rate/ Cost Component**	**Value (cents/kWh)**		**Source/Calc**
		PG&E preferred marginal costs	DRA preferred marginal costs	
1	Full tariff	$0.12693	$0.12693	PG&E workpapers
2	Proposed discounted rate	$0.08251	$0.08251	Line 1, less 35%
3	Nonbypassable charges	$0.03466	$0.03466	See, Table 1
4	Allocation to distribution & generation	$0.04785	$0.04785	Line 2 – Line 3
5	Marginal distribution & generation cost	$0.06742[129]	$0.05653[130]	See footnotes
5a	Transmission revenue[131]	$0.00982	$0.00982	PG&E workpapers
6	**Marginal cost shifted to nonparticipants**	**($0.01957)**	**($0.00868)**	**Line 4 – Line 5**
7	Contribution to margin	$0.00527	$0.01616	Line 2 – Line 5 – Line 5a

PG&E's proposed 35% discount would result in an impermissible shifting of costs under either marginal cost scenario. The amounts of the cost shifting are shown on line 6 of the table above.

To show these results in terms of revenue, we can multiply the values above by the annual kWh sales for a typical E-20S customer, stated by PG&E as 8,568,000 kWh:[132]

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[129] PG&E bases its CTM calculations on the full marginal cost of generation, including both capacity and energy, and distribution marginal costs based on a 50/50 blend of constrained and unconstrained areas. The cost shown is the sum of the full marginal generation cost $0.05824 per kWh, and the blended distribution cost, $0.00918 per kWh.

[130] DRA bases its modified additive price floor calculations on the marginal cost of generation, including energy but with a short term zero value for marginal capacity cost, and distribution marginal costs based on a constrained area. The cost shown is the sum of the marginal generation cost $0.03969 per kWh, and the constrained area distribution cost, $0.01684 per kWh.

[131] Transmission revenue was not identified separately in PG&E's simplified 2007 hypothetical discussed above. However transmission revenue, as a proxy for transmission marginal cost, must be subtracted from the customer's total revenue to compute contribution to margin.

Table 7: PG&E's Proposed E-20S Discounts Would Cause Prohibited Cost Shifting

Line	**Rate/ Cost Component**	**Annual Revenue per Customer**		**Source/Calc**
		PG&E preferred marginal costs	DRA preferred marginal costs	
1	Full tariff revenue	$ 1,087,536[133]	$ 1,087,536	Rate x kWh sales
2	Proposed discounted revenue	$ 706,946	$ 706,946	Line 1, less 35%
3	Nonbypassable charges	$ 296,967[134]	$ 296,967	NBC rate component x sales
4	Allocation to distribution & generation	$ 409,979	$ 409,979	Line 2 – Line 3
5	Marginal distribution & generation cost	$ 577,655	$ 484,349	Marginal costs from Table 6 x sales
5a	Transmission revenue	$ 84,168	$ 84,168	Transmission rate from Table 6 x sales
6	**Marginal cost shifted to nonparticipants**	**$ (167,676)**	**$ (74,370)**	**Line 4 – Line 5**
7	Contribution to margin	$ 45,123	$ 138,428	Line 2 – Line 5 – Line 5a

As can be seen from line 6, the dollar amount of cost shifting is quite significant for an E-20S customer.

These examples illustrate that the Commission was fully justified in imposing an additive price floor in D.07-09-016, and that substantial harm to nonparticipants could result from PG&E's proposal to not use an additive price floor.

(footnote continued from previous page)
[132] Ex. PG&E-3, p. WP-10

[133] 8,568,000 kWh x $0.12693 per kWh

[134] 8,568,000 kWh x $0.03466 per kWh

G. Funding NBCs First Does not Cure the Cost Shifting Inherent in PG&E's EDR Proposal

1. PG&E Incorrectly Interprets D.07-09-016 as Hinging on an Accounting Technicality

PG&E's interpretation of D.07-09-016 (at pages 33 – 34) implies that the additive price floor required by the Decision would be moot as long as PG&E could show that the regulatory accounts associated with the NBCs were being fully funded. Specifically, PG&E's rebuttal testimony states:

> In Decision 07-09-016, the CPUC suggested that NBCs need not be included in the price floor if the utility could demonstrate that the NBCs were fully funded. (D.07-09-016, pp. 33-34.) In that instance, the CPUC ultimately required the NBCs to be included in the price floor because it said that Southern California Edison Company and PG&E had not persuasively demonstrated how NBCs could be fully funded without being included in the price floor.[135]

Thus, PG&E's interpretation of the Decision's requirement is hinged on the utility's ability to demonstrate, through regulatory accounting, that the NBCs were fully funded without being included in the price floor. If fully funded, the additive floor price requirement allegedly would be unnecessary and could be eliminated.

PG&E's rebuttal further states:

> PG&E accounts for revenue in the same manner it is billed. This means that every billed component (such as generation, PPP, ND, etc.) is separately accounted for and accrues to different ratemaking mechanisms. Thus, PG&E is currently fully funding NBCs under the current EDR Program, and will continue to do so under the proposed EDR Program.

The way PG&E accounts for NBCs is by assuring that revenue from EDR customers is first allocated to NBCs. In PG&E's paradigm, any remaining revenue is allocated to generation and distribution.[136] However, when the additive price floor is not met, the remaining revenue after NBCs are funded will be insufficient to fund the EDR

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[135] Ex. PG&E-4, p.2-15, lines 18-24.

[136] This order of the application of funds is clearly shown in PG&E's 2007 hypothetical discussed above, as well as in Ex. PG&E-4, p.2-17, lines 12-14

customer's marginal generation and distribution costs.[137] Since these costs are unavoidable, shortfalls will therefore be shifted to nonparticipants.

Thus, in PG&E's interpretation of D.07-09-016, the Commission was only concerned with full funding of the NBCs, regardless of whether shifting marginal generation and distribution costs onto nonparticipants was necessary to achieve full funding of NBCs. Such an interpretation is, however, inconsistent with the full text of D.07-09-016 and with its repeated discussion of statutory and regulatory prohibition of cost shifting. In short, PG&E could only make this interpretation by taking the cited discussion on pages 33-34 of the Decision out of context. In the context of the full Decision, the statement at issue could more plausibly be interpreted as:

> PG&E does not persuasively demonstrate how NBCs can be excluded from the price floor and fully funded at the same time, *without unwarranted shifting of costs to nonparticipants.*[138]

PG&E's "fund NBCs first" paradigm seriously fails when revenue from EDR customers fails to even cover the total cost of NBCs. Such is the case for DA and CCA customers on rate schedule E-20T. PG&E's proposed discount requires charging these customers a negative distribution rate. For DA and CCA customers, all rate components but distribution are NBCs. The following table, using data from PG&E's workpapers, shows the NBC shortfall resulting from PG&E's 35% discount:

[137] This fact is demonstrated here in Tables 7-4, 7-6, and 7-7.

[138] D.07-09-016, p.33, words in italics added by DRA.

Table 8: NBC shortfall resulting from PG&E's 35% discount (E-20T DA/CCA)

	Full Tariff	EDR Bill	NBCs
Transmission	$0.00995	$0.00995	$0.00995
Distribution	$0.00195	-$0.00981	
Public Purpose Programs	$0.01204	$0.01204	$0.01204
Nuclear Decommissiong	$0.00055	$0.00055	$0.00055
PCIA	$0.00000	$0.00000	$0.00000
CTC	$0.00317	$0.00317	$0.00317
NSGC	$0.00080	$0.00080	$0.00080
DWR Bond Charge	$0.00513	$0.00513	$0.00513
Total	**$0.03359**	**$0.02184**	**$0.03165**
NBC Shortfall (EDR bill - NBCs)			**($0.00981)**

In this example, the revenue from the EDR customer is nearly 30% short of the amount needed to cover the NBCs.[139] Thus, if the NBC accounts are to be fully funded, it cannot be with funds provided by the EDR customers; the funds must come from other customers. It was precisely this type of cost shift that the additive floor price crafted in D.07-09-016 was intended to prevent.

In fact, the foregoing analysis understates the full extent of the cost shifting in PG&E's rate proposal because it omits the marginal distribution cost, which is an unavoidable result of the EDR customer's demand for energy. The full extent of the cost shift for an E-20T DA/CCA customer is shown below:

[139] The NBC shortfall is precisely the amount of the negative distribution rate component.

Table 9: Cost shift resulting from PG&E's 35% discount (E-20T DA/CCA).

	Full Tariff	EDR Bill	NBCs		D0709016 Additive Floor Price
Transmission	$0.00995	$0.00995	$0.00995		$0.00995
Distribution	$0.00195	- $0.00981		Dist MC	$0.00082
Public Purpose Programs	$0.01204	$0.01204	$0.01204		$0.01204
Nuclear Decommissioning	$0.00055	$0.00055	$0.00055		$0.00055
PCIA	$0.00000	$0.00000	$0.00000		$0.00000
CTC	$0.00317	$0.00317	$0.00317		$0.00317
NSGC	$0.00080	$0.00080	$0.00080		$0.00080
DWR Bond Charge	$0.00513	$0.00513	$0.00513		$0.00513
Total	**$0.03359**	**$0.02184**	**$0.03165**		**$0.03247**
NBC Shortfall (EDR bill - NBCs)			**($0.00981)**		
Cost Shift (EDR bill - NBCs- MC)					**($0.01063)**

As these examples show, funding NBCs first is not in itself sufficient to prevent cost shifting. Because cost shifting is a central concern of D.07-09-016, PG&E's interpretation of pages 33-34 of D.07-09-016 is implausible and clearly at variance with the context of the full Decision, and therefore should be given no weight.

2. PG&E's Assurance that NBCs are Fully Funded Relies on Shifting Costs to Nonparticipants

PG&E's rebuttal states:

> Similarly, no one should be able to claim that NBCs are not being fully funded by EDR customers under PG&E's initial proposal, simply because the EDR reduction resulted in negative distribution charges. Further, NBCs do not need to be in the floor price to ensure that they are fully funded. All that is required is that the total revenue from DA/CCA customers exceeds the sum of distribution marginal cost and transmission revenue, and as mentioned above, revenue is first applied to NBCs. As shown in the example for CARE, the application of revenue to NBCs first is currently PG&E's practice and would continue to be under the proposed EDR Program.[140]

Again, funding NBCs first in no way precludes the possibility that the EDR customers themselves won't supply enough revenue to cover the NBCs. PG&E disposes of the possibility of a revenue shortfall in a footnote:

[140] Ex. PG&E-4, p.2-17, lines 6-15.

> In the case of the EDR Program, reduction to generation or distribution charges would be recovered through their respective generation or distribution regulatory accounts.[141]

What is not stated is who would be responsible for shortfalls to the NBCs and or for shortfalls in marginal generation and distribution costs. Clearly, under PG&E's proposal, costs would be shifted to nonparticipants, in violation of the clear intent of D.07-09-016.

3. Contrary to PG&E's Rebuttal, PG&E's CARE Program Example is Irrelevant to EDR

PG&E highlights the example of CARE in an attempt to show that negative distribution rates are compatible with full funding of NBCs. PG&E's rebuttal states:

> A useful example of how PG&E accounts for revenue to fully fund NBCs is provided by PG&E's treatment of revenue from California Alternate Rates for Energy (CARE) customers. For CARE customers, PG&E fully funds the applicable NBCs even though the distribution rate in Tier 1 is negative.
>
> An example CCA bill for CARE Schedule EL-1 is provided …. As shown in Table 2-7, NBCs are fully funded even though distribution is negative; that is, positive billed revenue for the NBCs accrues separately to each of the regulatory recovery accounts, while billed distribution revenue (positive or negative) accrues to the Distribution Revenue Adjustment Mechanism (DRAM).[142]

Contrary to PG&E's testimony, the CARE example is not useful here because, unlike EDR, the shifting of costs from CARE participants to nonparticipants is explicitly allowed by statute (PU Code §739.1) and Commission precedent. The negative Tier 1 distribution rate is nothing more than an accounting device required by the tiered residential rate design, which in itself is required to accomplish the tier 1 and 2 rates

[141] Ex. PG&E-4, p.2-16, footnote 10.

[142] Ex. PG&E-4, p.2-16, lines 7-16.

freezes allowed by Assembly Bill 1X and Senate Bill 695 (PU Code §739.9). This analogy thus is irrelevant to EDR rates.

In the case of negative distribution rates for EDR customers, Tables 8 and 9 demonstrate that such rates can cause shortfalls even to the NBCs, which must then be shifted to nonparticipants, in violation of statute and established Commission policy.

H. CONTRARY TO PG&E TESTIMONY, DISCONTINUANCE OF EX POST ENFORCEMENT DOES NOT OBVIATE THE NEED FOR AN ADDITIVE PRICE FLOOR

As noted above, in the expiring EDR program, the additive price floor is enforced annually, on an ex ante and an ex post basis. PG&E has proposed, and DRA supports, discontinuance of ex post (after the fact) annual enforcement of a price floor because it creates too much uncertainty for EDR participants. However, PG&E's rebuttal also states:

> If the Commission agrees with PG&E's proposal to eliminate after-the-fact review, then there is no need for a price floor against which to compare the customers' revenues.[143]

This assertion that a floor price would no longer be required fails to consider the underlying purpose of the price floor, which is to ensure that NBCs are fully funded and that the marginal costs caused by participants are not shifted to nonparticipants.[144] This purpose goes beyond the after-the-fact review. Assuring full funding of NBCs and marginal costs requires that an additive price floor be enforced at least on an ex ante basis and, at a minimum, over the contract period. That is, the Commission should not allow EDR contracts that do not satisfy the additive price floor on a forecast basis over the contract term.

Thus, discontinuance of ex post annual floor price enforcement in no way diminishes the continuing need for ex ante enforcement of the additive price floor. The

[143] Ex. PG&E-4, p.2-4

[144] Ex. DRA-2, pp. 1-1, 1-3 to 1-5

Commission's purpose in establishing the additive price floor remains, and it requires continued enforcement.

VII. TO LIMIT RATEPAYER RISK, PRICE FLOORS MUST BE ENFORCED, AT A MINIMUM, OVER THE TERM OF DISCOUNTED CONTRACTS

Any analysis of ratepayer benefits of EDR must consider the degree of uncertainty of those benefits, and the risk that an EDR program may do harm, rather than provide benefits to ratepayers.[145] DRA has identified two types of generic risk for EDR programs: (1) The risk of providing unjustified discounts to free-riders, and (2) The risk of a negative CTM. No party disputed this characterization, and both DRA and PG&E discuss uncertainties in the expected benefits of EDR.

A. Both PG&E's EDR Proposals and DRA's EDR Proposals Increase Ratepayer Risk, Relative to the Expiring EDR Program

The current EDR program can be characterized as "low risk" for ratepayers, due to the annual enforcement of the D.07-09-016 additive price floor on both ex ante and ex post bases.[146] However, as PG&E points out, the benefits of the current EDR program have been limited.

Accordingly, both PG&E and DRA proposed changes in the EDR program to allow greater discounts. Larger EDR discounts increase the risk that the revenue from the customer might be insufficient to cover changes in the marginal cost over the contract term, causing the CTM to become negative. Larger EDR discounts also could attract more free-riders. In hearings, PG&E's witness acknowledged that PG&E's proposed 35% EDR discount carries more risk to nonparticipating ratepayers than DRA's proposed 22% enhanced EDR discount.[147]

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[145] Ex. DRA-1, p.1

[146] Ex. DRA-1, p.1-6

[147] PG&E/Pease 2 RT 285.

B. PG&E's Enhanced EDR Proposal Carries an Unprecedented Level of Ratepayer Risk, Relative to Previous EDR Programs

As noted, PG&E has declined to forecast participation in or total CTM from its proposed EDR programs. To get some sense of the magnitude of the risk to ratepayers, DRA has pieced together an analysis of the possible revenue shortfall assuming all of the 1,337 potential participants in the 21 enhanced EDR counties identified by PG&E apply and qualify for enhanced EDR.

The typical annual usage, full tariff revenue, and discounts at 12% and 35% for the six relevant rate schedules are taken from PG&E's workpapers.[148] Enhanced EDR discounts for typical customers range from $48,000 to $380,000 annually over 5 years.

Table 10: Potential revenue shortfalls from enhanced EDR retention customers

Rate Schedule	Annual kWh	Full tariff Annual Revenue		Discount @ 12%	Discount @ 35%
E-20T	8,568,000	$ 787,825		$ 94,539	$ 275,739
E-20P	8,568,000	$ 990,809		$ 118,897	$ 346,783
E-20S	8,568,000	$ 1,087,554		$ 130,506	$ 380,644
E-19P	2,000,000	$ 255,135		$ 30,616	$ 89,297
E-19S	2,000,000	$ 277,470		$ 33,296	$ 97,115
A-10S	900,000	$ 138,804		$ 16,656	$ 48,581
Average	5,100,667	**$ 589,600**		**$ 70,752**	**$ 206,360**
Number of nongovernment customers > 200 kW In Enhanced EDR counties					**1,337**
Potential Annual Discount from Enhanced EDR					**$ 275,903,086**

In Table 10, DRA computed the simple (unweighted) average of the usage and revenues for each rate schedule, because PG&E has not estimated the relative participation by rate schedule. Table 10 shows that an average (typical) enhanced EDR customer might receive a discount of over $200,000 annually, or over $1 million over

[148] Ex. PG&E-5, pp. WP 2-7 to 2-12.

five years. If all 1,337 potentially eligible customers apply and qualify for enhanced EDR, the revenue shortfall would be $275 million annually, based on this analysis.

Of course, the revenue shortfalls shown above must be offset by corresponding increases in revenue from nonparticipating ratepayers or utility shareholders.[149] Thus, rates will increase in either retention case: whether customers actually depart or are retained with a discount. To the extent that retention customers continue to provide positive CTM, PG&E could argue that rates would increase even more if discounts are not granted and customers depart. The difficulty for EDR proponents is that they have failed to demonstrate that CTM will be positive over the five-year contract period, and, instead rely on a ten-year CTM analysis, which carries a high level of ratepayer risk.

Table 11 shows a similar analysis for a hypothetical extension of the current, expiring EDR:

Table 11: Potential revenue shortfalls from a hypothetical extension of the current EDR, with a 200 MW cap

		Full tariff			
Rate	Annual	Annual		Discount	
Schedule	kWh	Revenue		@ 12%	
E-20T	8,568,000	$ 787,825		$ 94,539	
E-20P	8,568,000	$ 990,809		$ 118,897	
E-20S	8,568,000	$ 1,087,554		$ 130,506	
E-19P	2,000,000	$ 255,135		$ 30,616	
E-19S	2,000,000	$ 277,470		$ 33,296	
A-10S	900,000	$ 138,804		$ 16,656	
Average	5,100,667	**$ 589,600**		**$ 70,752**	
Number of customers > 200 kW expected under the 200 MW cap					**87**[150]
Potential Annual Discount from Standard EDR with cap					**$ 6,155,419**

[149] Utility costs of service do not change when retention customers are given discounts.

[150] 87 approximately equals the current program cap, 200 MW, divided by the average peak load of the current EDR participants, 2.3 MW. The current program has 15 participants with a cumulative load of 34.2 MW, which equates to 2.3 MW each.

Under the current program, with an average participant peak demand of 2.3 MW, the current and proposed 200 MW cap could accommodate 87 customers. As shown in Table 11, this creates a far more modest potential shortfall barely exceeding $6 million annually.

Comparison of Tables 10 (with a potential $275 million annual revenue shortfall) and Table 11 (a hypothetical extension of the current EDR with a potential $6 million shortfall) provides a sense of the enormous risks that PG&E's proposed uncapped enhanced EDR would foist on ratepayers.

C. The Commission Should not Rely Solely on a Ten-Year Analysis of CTM, as PG&E Proposes

In its opening testimony, PG&E submitted an analysis showing a positive CTM over a ten-year period for both the standard and enhanced EDR programs. In response, DRA and other parties pointed out several reasons why the Commission should not rely solely on PG&E's showing of a positive ten-year CTM. PG&E's computed ten-year CTM could be reduced by any of the following:

- Presence of free-riders taking EDR discounts
- Departure of an EDR customer before 10 years
- A customer qualifying for a second consecutive EDR contract
- A majority of EDR customer demand located in constrained distribution areas
- Increases in marginal costs over the ten-year analysis period.

Further, DRA noted that the CTM was *negative*, using PG&E's proposed marginal costs, over the proposed five-year contract period.[151] In such cases, it is quite likely that customers departing before, or soon after the expiration of EDR contracts could yield a negative CTM.

[151] Ex. DRA-1, Table 2-1, p.2-2.

D. PG&E HAS NOT ADEQUATELY JUSTIFIED ITS RELIANCE ON A TEN-YEAR ANALYSIS OF CTM

PG&E's testimony is inconsistent with its reliance on a ten-year presentation of CTM results. PG&E's rebuttal expresses disagreement with DRA's proposal to require a positive CTM, on a forecast basis, over a five-year contract period, stating:

> PG&E agrees with the Local Government Parties (LGP) that the Commission is not limited to review of CTM over a specific period of time to determine that ratepayers of the public utility will derive a benefit from EDR, given that the legislation does not specify the timing, type or scale of benefit.[152]

However, PG&E's preferred ten year analysis period is certainly "a specific period of time" and thus subject to the same criticism as DRA's use of the five-year contract period. PG&E provides no justification for its preference for a ten-year analysis. When PG&E's witness was asked:

> Q. Did you select ten years because a shorter period would have resulted in negative CTMs in some instances?
>
> A. Actually, I selected ten years in part because it had been utilized for earlier ED analysis.[153]

And later…

> Q. Did you provide any basis for the 10-year assumption anywhere in your testimony?"
>
> A. No. As I mentioned earlier, it was the time frame used in a previous economic development reapplication. One could have picked a different time frame.[154]

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[152] Ex. PG&E-4, p.2-4, lines 8-11; PG&E/Pease 2 RT 277

[153] PG&E/Pease 2 RT 277.

[154] PG&E/Pease 2 RT 301.

E. The Commission should not rely upon PG&E's Ten-Year CTM Analysis of a Limited set of EDR Uncertainties

In rebuttal responding to parties' concerns about the uncertainties surrounding PG&E's ten-year CTM analysis, PG&E submitted a sensitivity case incorporating modest assumptions on the first three of the five bullets above.[155] This sensitivity continues to show positive, although reduced, CTMs.

PG&E's attempt to address these risks through its limited sensitivity analysis is inadequate, for several reasons. First, PG&E's analysis is based on a so called "reasonable assumption" of an equal blend (i.e., 50/50) of EDR participation in constrained and unconstrained areas.[156] However, PG&E provides little justification for its assumption and no explanation of the consequences if a majority of EDR customers were to locate in constrained areas. On the contrary, PG&E's rebuttal workpapers show a negative five-year CTM in all cases, for customers locating in constrained areas and receiving 35% discounts, even assuming zero free-riders.[157] The same workpapers show a rapidly increasingly negative CTM as the free-rider rate increases beyond the 10% incorporated in PG&E's sensitivity analysis.

In summary, PG&E's sensitivity analysis fails to include:

- Free-ridership beyond 10%
- Early customer departures beyond 20%
- More than 10% of customers taking a second EDR discount
- More than 50% of EDR customers in constrained areas
- The effects of marginal cost increases over PG&E's ten-year analysis period.

[155] Ex. PG&E-4, Table 2-3, p.2-12 is based on the assumption of 10% free-riders, 20% early departures, and 10% of customers qualifying for a second consecutive EDR term.

[156] Ex. PG&E-4, 2-10, lines 15-17.

[157] Ex. PG&E-5, pp. WP-2-7, through WP 2-12, cell E45

F. PG&E's Proposed Fixed 35% Discount over Five Years Places Ratepayers at High Risk for Negative CTM Due to Changes in the Marginal Cost

PG&E has proposed a "shelf life" of five years for its EDR programs, meaning that, if adopted in 2013 as proposed, customers could sign five-year EDR contracts in this program as late as 2017. A contract signed in 2017 would extend until 2022. Further, a customer signing an EDR contract would have two years from the signing, to commence service under the contract. Therefore a customer signing an EDR contract in 2017 and commencing service in 2019 would be served under that contract until 2024.[158]

DRA's opening testimony stated a concern that ratepayers would be at risk of negative CTM due to changes in marginal cost over such a long period.[159] This concern is reiterated in DRA's rebuttal and tied specifically to the fluctuation of marginal energy costs with the historically volatile market price of natural gas.[160]

PG&E's witness responded when questioned on this issue, as follows:

> Q. Did you use an assumption that the rate in the marginal cost would remain constant after Year 1 in this 10-year projection?
>
> A. … On the marginal costs, …The projection that we made implicitly assumes that as we move forward in time, marginal costs and revenue move in relative synch. In other words, if the marginal costs increase for gas prices -- in other words, if the marginal costs increase in time, the presumption is that retail revenue or retail rates would also increase, so they move in synch.[161]

Unfortunately, the term "in synch" was not defined in the context of this proceeding. However, information on the record suggests that "in synch" should not be taken to mean that total rates and marginal costs vary in the same proportions. A 20% increase in marginal energy costs will not cause a 20% increase in rates. This is because,

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[158] PG&E/Hartman 1 RT 198.

[159] Ex. DRA-1, p.7, lines 16-19, Id, p.1-4, lines 10-12.

[160] Ex. DRA-2, p.1-13, line 3 through p.1-14, line 2.

[161] PG&E/Pease 2 RT 272.

as parties agree, some components of rates recover fixed costs.[162] Moreover, examination of PG&E's unbundled rates shows that, for bundled service customers, generation costs generally comprise about half of the total rates.[163] The other half consists of distribution charges and NBCs, which do not vary with the marginal cost of energy. This means that a 20% increase in marginal generation costs could be expected to cause only about a 10% increase in the total rate.

Therefore PG&E's contention that rates and marginal costs move together "in synch" is not quite correct, and the effect of changes to marginal costs over the 12-year period (2013-2024) at issue here should be of concern to the Commission. A simple hypothetical based on E-20S should illustrate the point.

Table 12 below, in the column headed "2012", shows a positive annual CTM for E-20S, based on PG&E's preferred marginal cost scenario.[164] However, as marginal generation costs increase (e.g., toward 2017), rates can be expected to increase only half as fast. The result is that CTM gets "squeezed" and turns negative if generation marginal costs were to increase by as much as 50%.

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[162] See, e.g., Ex. PG&E-4, p.2-6, lines 21-22.

[163] For example, the E-20S full tariff rate is $0.12693 per kWh and the generation component of that rate is $0.06532 per kWh.

[164] As described in Ex. PG&E-4, p.2-8, lines 6-14 and p.2-10, lines 15-17.

Table 12: Sensitivity of CTM to changes in marginal cost

CTM analysis for E-20S

	2012	Increase In Generation Marginal Cost (2012 to 2017) 25%	50%	75%	100%
	A	B	C	D	E
Full Rate	$0.12693	$0.14280	$0.15866	$0.17453	$0.19040
Discounted rate	$0.08250	$0.09282	$0.10313	$0.11344	$0.12376
Generation MC	$0.05824	$0.07280	$0.08736	$0.10192	$0.11648
Distribution MC	$0.00918	$0.00918	$0.00918	$0.00918	$0.00918
Transmission rate	$0.00982	$0.00982	$0.00982	$0.00982	$0.00982
CTM[165]	**$0.00526**	**$0.00102**	**($0.00323)**	**($0.00748)**	**($0.01172)**

Appendix B of DRA's rebuttal shows that natural gas prices have decreased more than 75% since 2008.[166] Since natural gas prices are a major driver of marginal generation costs, and are now at multi-year low values,[167] it is plausible that marginal generation costs could increase by 50% relative to today's values. This logic would imply about a 25% increase in the total rate, and a negative annual CTM during the contract period, as shown in Column "C" of Table 12.

In short, if PG&E's proposal were adopted, it is quite likely that customers receiving a 35% discount from rates prevailing in the later years (e.g., 2015 and beyond) would have increasingly negative CTMs during their five year EDR contracts.

165 Calculated as the discounted rate less the marginal costs of generation, transmission, and distribution. The transmission revenue is used as a proxy for the transmission marginal cost.

166 Ex. DRA-2, Appendix B.

167 Ex DRA-2, p.1-13, lines 7-10.

G. DRA Recommends how the Commission could Address the Potential harm caused by Negative CTM Resulting from Changes to the Marginal Costs

DRA has put forward three alternative EDR rate designs that the Commission could adopt to reduce the likelihood of negative CTM resulting from increased marginal costs over time. The first alternative is DRA's primary proposal, which is to decrease the enhanced EDR discount from 35% in the first year to 10% in the fifth year, of a 5-year contract.[168] In that the discount would be less in the years that marginal costs might increase, this would greatly decrease the risk of negative CTM. If, however, the Commission prefers a fixed discount, there are two other alternatives: the Commission should either shorten the contract term, or take steps to ensure that newly signed contracts will, on a forecast basis, provide positive CTM based on the most recently adopted marginal costs.[169] [170]

H. Ex Ante versus Ex Post Enforcement of the Additive Price Floor

As noted, the additive price floor currently is enforced on an annual basis in the expiring EDR, with after-the-fact bill adjustments, if necessary, to prevent negative CTM and to ensure that the revenue from each EDR customer is sufficient to fully fund its NBC rate components. Thus, in the current EDR program, the risk of marginal cost increases is borne by the EDR participants. The current ex post enforcement creates uncertainty for the participants, and has limited the effectiveness of the EDR program.

1. PG&E's Solution, to Suspend Enforcement of a Price Floor Altogether, Transfers all the Risk from the EDR Participants to Nonparticipating Ratepayers, and must be Rejected

In arguing that a price floor is unnecessary, PG&E is asking the Commission to accept on faith that its projections of a ten-year positive CTM will come true. Yet, as explained in Section VII.C, there are at least five separate sources of risk to PG&E's

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[168] Ex DRA-1, p.5, lines 18-22.

[169] Ex. DRA-2, p.1-2, lines 22-35.

[170] See Section XI below for further discussion of these alternatives.

CTM projections, and many possible outcomes could lead to negative CTM. PG&E's proposal would shift all risk of negative CTM from participating to nonparticipating ratepayers, and strip away most of the tools that could be used to mitigate those risks. Enforcement of a price floor, at least on a forecast basis, is the most important of those tools.

2. DRA's Proposal for Ex Ante Enforcement over the Contract Period

DRA has proposed a middle ground between the admittedly burdensome annual ex ante and ex post price floor enforcement in the expiring EDR, and PG&E's proposal to have no enforcement whatsoever. As noted above, DRA has agreed with PG&E and LGP that annual ex post enforcement of a price floor is unnecessarily burdensome and should be discontinued. However, retention and continued enforcement of an additive price floor is essential.[171] DRA's proposal to enforce the price floor only on a forecast basis over the contract term would mitigate ratepayer risk, while providing certainty to EDR customers that they will in fact realize the percentage discounts that they expected on signing their EDR contract. Note that a key feature of DRA's proposal that allows dispensing with the ex post "claw-back" provisions of current EDR contracts is the shareholder funding of any negative CTM, discussed in Section XII below.

VIII. CALCULATION OF THE PRICE FLOOR

As discussed above, the additive price floor consists of the sum of NBCs and marginal costs. More specifically, it is the sum of the NBCs, and the marginal costs of generation and distribution.[172] Since transmission and DWR bond charges are already included as NBCs, we need consider only marginal generation and distribution costs here. DRA has proposed to use marginal costs that reflect the proposed five-year EDR contract

[171] For reasons discussed at length in Section VI of this brief.

[172] Since transmission is included as an NBC, it should not be added a second time to the floor price as a marginal cost. Similarly, DWR bond charges, while they were in dispute as to whether they are marginal costs, are already included in NBCs and should not be added to the floor price as a marginal cost.

term. This represents a shorter-term perspective than the long-run marginal costs sometimes quantified in general rate cases. SCE supports a similar shorter-term marginal cost perspective, if the Commission retains a price floor.[173] No party has argued that long run marginal costs be included in a price floor.

A. MARGINAL COSTS

1. Generation

Consistent with the shorter-term marginal cost approach, DRA proposed that a zero value for the marginal generation capacity cost be used in its modified additive price floor, on the basis that no new capacity is required for reliability purposes through 2017. For energy, DRA proposed a blend of PG&E's recommended marginal energy costs for years 1 and years 2-10, which reduces marginal energy costs in the first year and increases them in years 2-10. No other values of marginal energy and capacity cost were proposed for inclusion in a floor price.

2. Distribution

DRA proposes to use PG&E's average distribution costs for constrained areas. While not recommending a price floor, PG&E maintains that use of constrained area marginal costs is overly conservative.[174] For its CTM calculations, PG&E uses a 50/50 blend of constrained and unconstrained area costs. PG&E's approach could result in negative CTM if large concentrations of EDR demand are located in constrained areas. PG&E has proposed no mechanisms to assure that at least 50% of the participants or load is in unconstrained areas. The Commission should base its floor price on constrained areas to provide greater assurance of ratepayer benefits.

B. NBCS

NBCs are listed above in Section VI- A. As noted, DRA's listing of the NBCs was undisputed, with the possible exception of the PCIA, which applies only to direct

[173] Ex. SCE-1, p.4

[174] Ex. PG&E-4, p.2-2, lines 5-13.

access ("DA") and community choice aggregation ("CCA") customers. PG&E's "Workpapers Supporting Rebuttal Testimony" show the PCIA as zero for all DA and CCA customers.[175]

PG&E's numerical values for the NBC rate components shown in PG&E's workpapers were also undisputed.[176]

C. DRA's Modified Additive Price Floor

DRA's proposed price floors are shown in Appendix D.[177] A detailed calculation of the modified additive price floor for an E-20S bundled service customer is shown above, in Table 2.

1. The Modified Additive Price Floor is Unaffected by whether or not DWR Bond Charges are Treated as Marginal Costs

While treatment of DWR bond charges as a marginal cost was disputed, resolution of this issue has no bearing on the computation of the additive price floor because, like transmission, DWR bond charges will be counted only once in computing the price floor. As discussed below, however, the CTM will be affected by whether or not DWR charges are treated as marginal costs.

2. Additive Price Floor Enforcement

DRA proposes that EDR contracts demonstrate, on a forecast basis, that they will produce sufficient revenue to exceed the modified additive price floor in present value over the contract term.[178]

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[175] Ex. PG&E-5, p. WP 2-5.

[176] Id., p.WP 2-4.

[177] Appendix D supercedes Tables 2-5 through 2-7 Ex. DRA-1, pp. 2-9, 2-10.

[178] Ex. DRA-1, p.2-5.

D. Enforcement of DRA's Other Two Price Floors

1. NBC Price Floor Enforcement

DRA proposes that EDR contracts must demonstrate, on a forecast basis, that that they will produce sufficient revenue to fully fund the NBC rate components **in each year** of the contract term.[179]

2. Marginal Cost Price Floor (Positive CTM) Enforcement

DRA proposes that EDR contracts must demonstrate, on a forecast basis, that they will produce sufficient revenue to exceed the marginal cost in present value over the contract term.[180] This requirement is equivalent to requiring a positive CTM over the contract term. In calculating the CTM, DRA proposes to use the full marginal cost of generation, including the adopted capacity and energy value. Thus, DRA's proposed marginal cost floor is not redundant with the modified additive price floor, which uses a shorter-term zero value for generation capacity.

IX. CALCULATION OF THE CONTRIBUTION TO MARGIN

A. Definition of the Contribution to Margin

The CTM is defined by DRA as "the excess of the revenue provided by the new or retained customer above the marginal cost."[181] PG&E's witness concurred with this definition, and more specifically defined CTM as the total revenue received from a customer less the marginal costs of generation, transmission, and distribution.[182] The CTM essentially is an economic construct, whereas the additive price floor, in that it also includes NBCs, is more of a regulatory construct required by D.07-09-016 and the Commission's interpretation of the P.U. Code.

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[179] Id.

[180] Id.

[181] Ex. DRA-1, p.4, lines 12-14.

[182] PG&E/Pease 2 RT 304.

B. The CTM is Different from the Margin above the Additive Price Floor

As indicated above, the agreed-upon definition of CTM does not involve the NBCs, except to the extent they are also marginal costs. For the most part, NBCs are not marginal costs; transmission being the sole agreed-upon counterexample of a rate component which is both an NBC and a marginal cost.[183] Since the additive price floor established in D.07-09-016 includes NBCs, as does DRA's proposed modified additive price floor, the margin above the additive price floor is not the same as the CTM. In proposing to change the titles of two tables he sponsored, PG&E's witness acknowledged this distinction. He proposed to remove the term "CTM" since these tables actually show the margins above DRA's modified additive price floor.[184]

C. Parties' Proposals for Calculating CTM

PG&E proposes to calculate CTM by subtracting the marginal costs of generation, transmission, and distribution from the revenue received from the customer.[185] DRA proposes to calculate CTM by subtracting the marginal costs of generation, transmission, distribution, from the revenue received from the customer.[186] Thus, in concept, DRA's calculation of CTM is the same as PG&E's.

There are differences in the generation and distribution marginal costs used in PG&E's and DRA's CTM calculations. These differences are summarized in Table 13.

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[183] As discussed below, DRA also considered DWR bond charges to be marginal costs (in the short run) as well as NBCs, but has been convinced that this position was taken in error. PG&E and SCE maintain, correctly, that DWR bond charges should not be considered as marginal costs.

[184] PG&E/Pease 2 RT 286-287. The tables in question are in Ex. PG&E-4, Table 2-4 p.2-14 and Table 2-6, p. 2-15.

[185] PG&E/Pease 2 RT 304.

[186] Ex. DRA-1, Table 2, p.2-4 lists the marginal costs. However, as explained below, DRA no longer considers DWR bond charges to be marginal costs.

Table 13: Marginal Costs for Computation of CTM

Marginal Cost Component	PG&E	DRA
Generation	Adopted capacity cost, with 15% Resource Adequacy adder.[187] Blended energy cost for years 1-5; indexed energy cost years 6-10.[188]	Adopted capacity cost, with 15% Resource Adequacy adder. Blended energy cost for years 1-10;
Transmission	Use transmission rate component as marginal cost proxy	Same as PG&E
Distribution	Use blend of constrained and unconstrained areas[189]	Use constrained area marginal costs

In its initial testimony, PG&E included DWR bond charges as marginal costs in its CTM calculations.[190] DRA also proposed to treated DWR bond charges as marginal costs based on an (erroneous) understanding that the DWR bond charges remain fixed until the bonds are paid off.[191] As SCE's rebuttal points out,[192] and further investigation confirmed,[193] DWR bond charges are, in fact, adjusted annually. In its rebuttal, PG&E characterized its earlier inclusion of DWR bond charges as an error.[194] SCE agrees with

[187] See, Ex. DRA-1, p.2-7, lines 15-17. In Ex. PG&E-4, p.2-7, Q&A 15, lines 15-21, PG&E agreed to include a 15% reserve margin adder.

[188] See, Ex. DRA-1, p.2-7, lines 11-15. In Ex. PG&E-4, pp.2-7 and 2-8, Q&A 16, PG&E agreed with DRA's blended approach for the first five years of its ten year analysis, but preferred to use its indexed values for years 6-10.

[189] Ex. PG&E-4, p.2-10, lines 15-17, PG&E/Pease, RT 2, 279-280.

[190] Ex. PG&E-1, p.3-3, lines 4-6.

[191] Ex. DRA-1.

[192] Ex. SCE-1, p.3.

[193] A report on the Commission's website "Energy Roadmap: September 2008 Update" states (p.20) DWR's 2007 bond charge will be reflected on IOU tariffs effective January 1, 2007. This charge is recalculated every year.

[194] Ex. PG&E-4, p.2-6, Q&A 13.

PG&E's later interpretation. DRA also now agrees with PG&E and SCE that DWR bond charges are not marginal costs.

X. ELIGIBILITY REQUIREMENTS

The current EDR program has a number of requirements for eligibility, intended as safeguards against free-riders. PG&E proposes to weaken or eliminate some of those restrictions. Specifically, PG&E proposes to remove the following safeguards: 1) third party review and approval of customer applications; 2) the requirement that electricity costs constitute a threshold percentage of the customer's operating costs, and 3) the liquidated damages provision of the EDR contract for premature withdrawal. DRA opposes PG&E's proposed EDR eligibility changes, and recommends that the Commission tighten the eligibility criteria and oversight process for participation in the EDR program in order to limit the number of potential free-riders.[195] No party has produced convincing evidence that these requirements have kept eligible parties, either retention customers in California or out-of-state customers considering locating in California, from receiving EDR rates in the past. The eligibility requirements are not significant hurdles, but they are safeguards to help assure that the significant EDR discounts go to those customers who really need the discount in order to continue operations or to locate in California.

The table below contrasts the current EDR with PG&E's proposals and DRA's proposals on eligibility criteria.

[195] In reference to Scoping Memo Issue #23.

Table: Current EDR vs. PG&E's Proposal and DRA Proposal

Current EDR	PG&E Proposal	DRA Proposal
200 MW cap	No cap	200 MW cap
• Approval of applicants by CalBIS required; • limit participation to customers whose energy costs are at least 5% of operating costs, • implement with an affidavit provision; • requires PG&E to conduct energy audit of the applicant's facility & discuss cost effective EE/ demand side management measures with applicant.	• No third party oversight required. • implement with an affidavit provision without the provision verifying that energy costs are at least 5% of operating costs; • requires PG&E to conduct energy audit of the applicant's facility & discuss cost effective EE/ demand side management measures with applicant.	• Approval of applicants by CalBIS required; • limit participation to customers whose energy costs are at least 5% of operating costs, • implement with an affidavit provision; • require PG&E to conduct energy audit of the applicant's facility & discuss cost effective EE/ demand side management measures with applicant.
Assignment of Contracts permissible only if PG&E consents in writing and the party to whom the agreement is assigned agrees in writing to be bound by the EDR agreement in all respects	Assignment of Contracts permissible only if PG&E consents in writing and the party to whom the agreement is assigned agrees in writing to be bound by the EDR agreement in all respects	Prohibit the transfer of an EDR contract if a company is sold. The purchasers of a company that was an EDR customer must reapply for the program.
EDR contracts can be renewed for one additional 5-year term.	Whether or not EDR contracts can be renewed will be decided in PG&E's 2017 GRC[196]	Whether or not EDR contracts can be renewed will be decided in PG&E's 2017 GRC
Liquidated damages clause for customer initiated early termination of EDR contract, fraud, or misrepresentation	Liquidated damages clause for customer fraud or misrepresentation	Liquidated damages clause for customer fraud or misrepresentation and a separate liquidated damages clause for customer initiated early termination of EDR contract

[196] In its opening testimony, PG&E proposed that standard and enhanced EDR contracts can be renewed for one additional 5-year term. In its rebuttal PG&E said the issue would be decided in PG&E's 2017 GRC.

As shown above, PG&E is proposing significant changes to EDR eligibility criteria, including removing a majority of the ratepayer safeguards contained in prior EDR programs. DRA's positions on these proposed changes are discussed below. Additionally, LGP opposes nearly all of the eligibility requirements and ratepayer protections supported by DRA, including the enrollment cap and affidavit. Where relevant, DRA also contrasts its position with LGP below.

In general, on the issue of whether or not eligibility requirements should be maintained or strengthened, the Commission should remember that the rationale for these criteria is to assure that only customers who are truly considering shutting down or moving out-of-State receive EDR discounts. The criteria are not designed to make the application process difficult, and there is no evidence that such criteria will hinder qualified applicants from applying for EDR.

A. THE EDR PROGRAM SHOULD HAVE AN ENROLLMENT CAP

PG&E proposes, and LGP supports, eliminating the enrollment cap on participation of 200 MW contained in the current EDR tariff. DRA recommends that the Commission retain the participation cap required in the current EDR program.[197] DRA believes that a participation cap on the program will limit risk for non-participating ratepayers. The participation cap should be retained because both the proposed DRA and PG&E new EDR programs would offer a much larger discount than past programs, which could result in a large spike in applications. According to PG&E's most recent customer data, it currently has 5,714 businesses that could potentially qualify for the standard EDR program.[198] Further, the company has 1,337 customers who could potentially qualify for

[197] Ex. DRA-1, p.3-7. The following section addresses Scoping Memo Issue #16.
[198] Ex. PG&E-7, p.3; PG&E/Hartman, 1 RT 189, lines 1-3.

the proposed enhanced EDR discount of 35 percent a year.[199] Moreover, the average participant in the current program is 2.3 MW in size.[200]

PG&E is unable to provide a forecast of how many customers will enroll in the EDR program.[201] PG&E performed no analysis of how many of these customers would actually qualify for its proposed EDR.[202] Further, LGP performed no analysis of how many of the customers in its cities would qualify for PG&E's enhanced EDR program.[203] But clearly, if a significant number of the 5,714 potentially eligible customers sign up, the cumulative enrollment could exceed to current 200 MW cap by multiple times. Such an outcome would create large risk to PG&E's ratepayers. As indicated above, DRA estimates that there could be a potential revenue shortfall in excess of $275 million annually based on 1,337 potentially eligible enhanced EDR customers alone.[204] The remaining revenue may not be sufficient to cover the marginal costs and NBC if PG&E's eligibility proposals were adopted. Therefore, DRA recommends setting a cap on total EDR program participation, including both the standard and enhanced program, of 200 MW to limit the risk to nonparticipating ratepayers.

Although PG&E's prior EDR programs had 100 MW to 200 MW caps, PG&E and LGP oppose any cap in this proceeding. LGP testifies that it is "somewhat pointless to insist on stating the maximum passenger load for a bus that has no passengers."[205]

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[199] Ex. DRA-1, p.3-3.; Ex. PG&E-7, pp. 4-5 shows 2012 data on business who could qualify for the enhanced EDR.

[200] The current program has 15 participants with a cumulative load of 34.2 MW, which equates to 2.3 MW each.

[201] Ex. DRA-1, p.3-7.

[202] PG&E/Hartman, 1 RT 191, lines 12-16.

[203] Ex. DRA-6; LGP/Renzas, 3 RT 520, lines 14-28, RT 521, lines 21-27. Mr. Renzas agreed that it would be important for the Commission to have an idea of how many customers would qualify for the EDR discount. 3 RT 521, lines 5-13.

[204] See Table 10 and discussion in Section VII B.

[205] Ex. LGP-1, p. 22. On cross examination, the LGP witness agreed that there are laws or regulations that do in fact set the maximum passenger load for buses. 3 RT 517, lines 17-24.

PG&E says a cap could "severely undermine the benefit of attracting businesses and needlessly limit the social and ratepayer benefits."[206] As stated above, the benefits to non-participating ratepayers are projections. PG&E's projections of CTM rely on a 10-year long term analysis, which is highly speculative. Further, although the company forecasts benefits to non-participating ratepayers, the company is unwilling to report on these benefits on an annual basis to the extent that DRA proposes or to provide shareholder funding if these benefits do not materialize. A 200 MW participation limit protects ratepayers if the forecasted benefits do not materialize.

B. EDR Customer Application Should Be Reviewed By the California Business Investment Services ("CalBIS")

PG&E proposes elimination of the requirement that EDR customer applications be reviewed by an independent third party, such as California Business Investment Services ("CalBIS"). This provision of the current and past EDR programs is designed to guard against free-riders and to limit risks to non-participating ratepayers.[207] DRA supports continued use of CalBIS to review and approve EDR applications. Past EDR decisions have required independent third party review and determined that CalBIS is the appropriate state agency to conduct third party review of EDR customer applications.[208] PG&E has an interest in signing up as many EDR customers as possible because it will grow or maintain its market share, which highlights the need for independent third party review. Moreover, under PG&E's proposal, which lacks a shareholder participation component, it has little at stake if it mistakenly grants an EDR contract where none was warranted. In D.05-09-018, the Commission stated, "it is clear that CalBIS has the expertise and staff to identify and screen legitimate economic development candidates."[209] CalBIS is the State's preeminent evaluator of economic development

[206] Ex. PG&E-4, p.1-11.

[207] The following section addresses Scoping Memo Issue #17.

[208] D 05-09-018, p.25; D 10-06-015, p.7.

[209] D 05-09-018, p. 18.

issues,[210] which is another reason that it is the appropriate third party to conduct review of EDR customer applications.

PG&E proposes to remove CalBIS' third party approval authority because it "has proven to be redundant in the approval process, with PG&E and CalBIS performing similar but separate evaluations."[211] LGP also oppose CalBIS review, claiming that such review "would take time to conduct properly."[212] DRA agrees that the independent review should be done properly, but CalBIS has not been, and will not be an overly time consuming process. On July 13, 2012, DRA witness Elise Torres discussed the EDR application review process with the Deputy Director of CalBIS, Mather Kearney, and with two Senior Business Development Specialists, Jason Rancadore and Patrick McGuire. The CalBIS representatives explained their EDR application review process and said that it takes 3-5 days.[213] They felt their review was more in-depth and thorough than PG&E's review, which was highlighted in the "EDR Business Case Evaluation" form[214] they use in their review.[215] CalBIS also stressed that their knowledge of other states' economic development incentives makes them more qualified to evaluate applications and confirm that applicants have truly explored out of state options.[216] PG&E testified that "CalBIS has approved every single EDR application that has ever been submitted for their approval."[217] Therefore, there is no evidence that CalBIS has

[210] Id. p. 19.

[211] Ex. PG&E-1, p. 2-5.

[212] Ex. LGP-1, p.23.

[213] Ex. DRA-1, p.3-6. DRA phone interview with Elise Torres of DRA and Mather Kearney, Jason Rancadore, & Patrick McGuire of CalBIS. July 13, 2012.

[214] Id. A blank copy is located in Ex. DRA-1, Appendix C for reference.

[215] Id.

[216] Id.

[217] Ex. PG&E-4, p. 1-6.

unnecessarily slowed down the approval of EDR contracts or would prevent eligible customers from applying for EDR.

In fact, PG&E's testimony indicates that its review process is much more time consuming than CalBIS's independent review:

> Q. Do you know how much time it typically takes PG&E to go through its approval process?
>
> A. Well, I don't have a single number off the top of my head for you. But from my experience, I would say it could be several weeks, usually around a month to two to three months maybe at the upside.[218]

Therefore, the CalBIS is not properly to blame for any time-consuming review process. In fact, PG&E indicates that its own process, and that of prior applicants, is more time consuming.[219] For these reasons, DRA recommends that the Commission follow past EDR decisions and require CalBIS review and approval of all EDR customer applications.

C. The Commission Should Continue to Require that EDR Customers Sign an Affidavit, and Should Reject PG&E's Modifications to the Current Affidavit

Prior EDR programs have required customers to sign an affidavit, under penalty of perjury, that "but for" the proposed EDR discount, the customers load would not locate in California.[220] The most recent PG&E EDR program included an affidavit that required applicants to declare that electricity made up 5 percent of an their operating expenses.[221] DRA supports continuation of the affidavit requirement, including the 5 percent threshold. LGP proposes elimination of the affidavit requirement.[222] While PG&E

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[218] PG&E/Hartman, 1 RT 200, lines 14-21.

[219] PG&E/Hartman 1 RT 200-201, lines 17-28 though lines 1-24.

[220] See, e.g., D.05-09-018, p.7, 15, Attachment A.

[221] D. 10-06-015, p.2-6.

[222] While LGP proposes elimination of the "but for" test, the 5 percent threshold requirement, and the requirement that an applicant sign "under penalty of perjury", LGP states, "the affidavit could stay, but

(footnote continued on next page)

proposes to keep the affidavit, the company proposes to eliminate the 5 percent threshold requirement.

1. The Affidavit Provides Protection to Non-Participating Ratepayers

DRA believes that safeguards are needed to discourage free-riders and ensure ratepayer benefits. Under the EDR program, participants will receive large discounts and significant cost savings. The customer affidavit and contract are the only tangible accountability mechanisms for customers in the EDR program. The affidavit requires that the signer, under penalty of perjury, attest that "but for this rate, the business would not expand, stay in, or come to California."[223] The requirement that the affidavit be signed under the penalty of perjury is important to retain in order to protect the integrity of the EDR program.[224] Considering that the affidavit is the only tool to directly discourage free-riders who would otherwise receive an unjustified sizable discount, signing the affidavit under penalty of perjury is not overly burdensome and the requirement should be retained.

Consistent with the most recent EDR programs, DRA believes PG&E's EDR program should require applicants to demonstrate that electricity makes up a threshold percentage of their operating costs in order to qualify for the EDR discount.[225] The affidavit should contain the following provision for retention customers, "On an annual basis, the cost of electricity for [Company Name] at this facility represents at least 5% of operating costs, less the cost of raw materials." For attraction and expansion customers, a similar provision also should be included in the affidavit, though it should acknowledge

(footnote continued from previous page)
should only ever be as an option for self-certification." Ex. LGP-1, p.8. It is not clear what such an affidavit would be, and what it would actually require or accomplish.

[223] Ex. PG&E-1, p. 5.

[224] This paragraph addresses Scoping Memo Issue #20.

[225] The following section addresses Scoping Memo Issue #19.

that the percentage of operating costs is an estimate, but it should still account for at least 5%. The Commission has adopted a 5% threshold in prior EDR proceedings.[226]

The inclusion of this provision in the affidavit will guard against free-riders because it provides a measurable benchmark for eligibility. As stated above, according to PG&E's most recent customer data, it currently has 5,714 businesses that could potentially qualify for the EDR program.[227] Accordingly, maintaining this provision will ensure the integrity of the program by making it available only to customers for whom energy costs will have a meaningful impact on their decisions. The Commission should require the addition of this provision to the customer affidavit in order to discourage free-ridership and to ensure that the discount is only available to those customers for whom energy is a material cost.

2. LGP's Proposal to Eliminate the Affidavit Should Be Rejected

Only one party, LGP, supports elimination of the affidavit. First, LGP opposes the five percent threshold because it "requires an enormous degree of intrusion into the detailed operation of the business …and would become a burden."[228] The LGP testimony is not credible. Large businesses certainly track their energy costs, and five percent is not a very high threshold.[229] Further, DRA believes that the Commission and PG&E are perfectly capable of protecting confidential, trade-sensitive information. The Commission often is required to do so pursuant to P.U. Code Section 583, and other rules and regulations. Commission staff who violate Section 583 are "guilty of a misdemeanor."[230] DRA does not think compliance with this threshold review is a

[226] D 10-06-015, p.7.

[227] Ex. PG&E-7, p.3; PG&E/Hartman, 1 RT 189 lines 1-3.

[228] Ex. LGP-1, p.24.

[229] Ex. DRA-2, p.2-6.

[230] California Public Utilities Code Section 583.

burden, and even if it was, the burden would be greatly outweighed by discounts of anywhere between hundreds of thousands to millions of dollars.[231]

Second, the LGP opposes the requirement that applicants sign "under penalty of perjury."[232] LGP states that the affidavit "is not a selling point if executing under penalty of perjury[;] it is an obligation." DRA agrees that it is not a selling point. The "selling point" is the discount on the electricity rate, which is potentially worth millions of dollars. LGP also claims that the affidavit requirement amounts to an accusation of guilt: "Those various restrictions and protections seemed to imply that potential applicants were out to defraud the utility, state and other ratepayers"…. "this should not be about implying that investors are criminals."[233] DRA does not believe that a requirement that applicants tell the truth is an accusation or assumption of guilt. However, DRA does think it's important that EDR customers are actually businesses that may not locate in or that might leave California without the energy discount. The affidavit discourages free-riders, but should not be a disincentive for honest businesses to apply.

Requiring an individual or business to sign an agreement under penalty of perjury is common. LGP's witness admitted that filing a tax return requires one to sign under penalty of perjury, though he stated that "if I had another tax return that somebody was offering me from a different country that didn't have that, I would be more than likely to sign that."[234] Further, the Public Utilities Code has numerous requirements relating to signing documents or testifying under penalty of perjury.[235] One such statute, Public Utilities Code Section 2114, holds that a person who testifies falsely to the Commission

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[231] For instance, a typical EDR customer under schedule E-20T would receive a discount of approximately $300,000 a year under PG&E's proposal. Ex. PG&E-3, p. W-P 3-16; PG&E/Pease, 2 RT 262, lines 23-27.

[232] Ex. LGP-1, p.8, pp. 24-25.

[233] Ex. LGP-1, p. 8

[234] 3 RT 510, lines 19-22.

[235] See, e.g. PU Code Sections 460.7, 588, 705, 1710, 2114, 5135.5, 5378.1, and 5840.

"under penalty of perjury" … "is guilty of a felony and shall be punished by a fine not to exceed five hundred thousand dollars ($500,000)." So such a requirement is not unusual in Commission practice.

LGP's primary argument against the affidavit appears to be that "these burdens and restrictions are not found in competitor states' incentive packages."[236] However, LGP could provide no supporting evidence for this claim, and, in fact, its own data request response contradicted this argument. In a data request, DRA asked LGP's witness "to discuss what economic development rate programs that utilities in other states" offered and to "provide specifics about the type of restrictions and eligibility requirement they include."[237] LGP presented several examples of other states' EDR programs.[238]

One example was the Duke Energy Indiana program. However, review of this program shows that the "rider" or contract is actually stricter than what DRA has proposed here, and what the CPUC has previously adopted. Among other things, the Duke Energy Indiana program requires customers to show that they are employing a threshold number of jobs, that their load will result in significant capital investment "of $10 million for 1000-kilowatt demand of new or expanded load" and that "the customer must affirm that the availability [of the discount] was a factor in the customer's decision to locate the new load or retain current load in the Company's service territory."[239] When asked during cross examination about this supposedly exemplary, non-California program, EDR's witness testified, "I think companies would consider it burdensome, I just don't know if it's a successful program."[240] The Duke Energy Ohio and Duke Energy Kentucky EDR programs cited by LGP also have similar eligibility

[236] Ex. LGP-2, p.12.

[237] Ex. TURN-3, p.1.

[238] Id.

[239] Id., pp.2-3.

[240] LGP/Renzas, 3 RT 541, lines 22-27.

requirements.[241] Therefore, LGP's claims that the affidavit requirement lessens California's competitiveness are baseless and should be rejected.

While PG&E does not support the five percent threshold requirement of the affidavit, the company did testify to the importance of the affidavit, and the lack of evidence of harm:

> I think, though, that one of the main issues is this issue of free-ridership. And I think that it does help us address that. We have now about five or six years of experience with the affidavit. And we haven't encountered a lot of resistance to it. So we will keep it to help address those. We're proposing to keep it to help address those issues of free-ridership to the extent that it does.[242]

D. THE COMMISSION SHOULD LIMIT THE ABILITY TO RENEW OR ASSIGN AN EDR CONTRACT

1. The Enhanced EDR Program should not allow Participating Customers to Renew their Enhanced EDR Contracts for a Second Five-Year Term[243]

In its opening testimony, PG&E proposed to allow standard and enhanced EDR customers to reapply for the EDR program once, for a second 5-year term. In its rebuttal, PG&E modified its proposal, and, instead states that the EDR program should be reviewed in the 2017 GRC, and that "customers participating in the proposed EDR program not be precluded from qualifying from any subsequent EDR program…"[244] Therefore, PG&E is proposing that the next EDR proceeding could determine whether or not customers receiving an EDR discount authorized in this proceeding could subsequently apply for another one. DRA accepts this revised proposal. However, it is important to recognize that a second EDR term in a 2017 EDR renewal program would invalidate PG&E's 10-year CTM analyses, which (except for certain sensitivity cases) are based on the assumption that the customer will return to full tariff rates, after 5 years.

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[241] Ex. TURN-3, pp. 4-5; LGP/Renzas, 3 RT 543, lines 20-26.

[242] PG&E/Hartman, 1 RT 228, lines 2-12. (Emphasis Added)

[243] The following section addresses Scoping Memo Issues #21 and #22.

[244] Ex. PG&E-4, p.2-10.

2. The EDR Contract should Include a Non-Assignment Clause

PG&E proposes to allow for the assignment of an EDR contract "only if PG&E consents in writing and the party to whom the agreement is assigned agrees in writing to be bound by the EDR agreement in all respects."[245] PG&E's proposal does not sufficiently guard against free-riders because the buyer of the company would not be required to comply with the eligibility measures required in the initial application. DRA proposes to include a non-assignment clause in the EDR contract. EDR contracts should not be assignable in the event an EDR customer company is sold, because it creates opportunities for free-riders. The Commission should require the purchasers of an EDR customer company to reapply for the EDR program and re-sign the customer affidavit.

E. THE COMMISSION SHOULD REQUIRE PG&E TO SUBMIT ANNUAL REPORTS ON THE EDR PROGRAM TO THE COMMISSION

In D.05-09-018, the Commission required PG&E to submit annual reports to the Commission about the EDR program including a listing of all EDR applicants, the contents of the CalBIS review for these applicants, and the utility's final selection of EDR candidates.[246] In D.10-06-015, the Commission ordered additional information to be included in the Annual Reports, including a detailed process flow chart describing the Utilities' EDR screening and enrollment processes. For new EDR customers who have commenced operation under an EDR contract, information was required on the amount paid to the utility above the Floor Bill or Floor Price and the discount provided relative to the customer's otherwise applicable tariff ("OAT"), defined as the difference between the OAT and the discount rate.[247] The Commission should continue to ask PG&E to file Annual Reports containing annual and cumulative CTM and discount data by contract and EDR portfolio total. CTMs should be reported both on an ex ante and ex post basis.

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[245] Ex. DRA-1, p. 3-4 through 3-5.

[246] D 05-09-018, p.28, Order #2.

[247] D 10-06-015, p.8.

The Commission also should consider requiring PG&E to submit annually, or every other year, an ex-post assessment of how many jobs were created or retained by the program in the Annual Reports.[248]

In rebuttal, PG&E claims that the additional reporting proposed by DRA is not necessary because the company "proposes to eliminate the price floor."[249] The fact that PG&E proposes no price floor, and that both PG&E and DRA have proposed elimination of the claw back provision based on comparing what customers pay to a price floor, means that the reporting requirements proposed by DRA are even more important now than ever. While in the past, nonparticipating ratepayers were protected by an annual ex post review of CTM, there is currently no such protection in either the DRA or PG&E proposal. Therefore, in evaluating how the new EDR may be performing, it is essential that the Commission have as much relevant information as necessary to perform this evaluation.

F. PG&E Should Conduct an Energy Audit of EDR Program Applicants and Discuss Cost-Effective Conservation and Load Management Measures with Applicants

DRA recommends that PG&E be required to conduct an energy audit and to provide education programs to EDR applicants.[250] A past EDR program required PG&E to conduct an energy audit of all EDR applicants and to inform these applicants about all cost effective energy efficiency and demand side management programs that have a 5-year or less pay-back period.[251] DRA recommends that this requirement be retained. Further, DRA recommends that EDR customers implement cost effective energy

[248] This section addresses Scoping Memo Issue #33.

[249] Ex. PG&E-4, p.1-13.

[250] Ex. DRA-1, p. 3-8.

[251] D 05-09-018, p.16.

efficiency and demand side management programs that have a 2-year pay-back period.[252] This recommendation will help the Commission achieve its Total Electricity and Natural Gas Program Savings Goals.[253] Requiring EDR customers to implement measures with a 2-year bay-back period will also create savings that persist beyond the EDR contract period, which increases the potential that an EDR company will stay in business after the term of the EDR contract has run.

The Commission also has stated, "the utilities should make every conceivable effort to persuade EDR customers to meet the Commissions identified conservation and efficiency objectives."[254] The Commission explained that it would not require EDR applicants to assume the necessary costs of participating in structured energy efficiency or conservation programs because these customers were facing difficult financial constraints.[255] The Commissions rationale in D.05-09-018 is supported by the fact that EDR customers in that program were receiving an initial 25% discount that declined 5% each year for 5 years.[256] Under PG&E's proposed enhanced EDR program, customers will receive a 35% discount. This is such a sizable discount that the Commission should consider requiring enhanced EDR customers to use a portion of these significant savings to implement cost effective energy efficiency and demand side management programs that have a 2-year pay-back period.

G. Penalties for Customer Early Termination – Liquidated Damages

DRA recommends that the Commission require PG&E to include a liquidated damages clause in its customer contract. Such a clause would specify that the EDR discounts should be paid back if customers terminate service prior to the full contract

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[252] This section addresses Scoping Memo Issue #18.

[253] R. 01-08-028, Table 1E.

[254] D 05-09-018, p.15.

[255] D 05-09-018, p.16.

[256] Id., p.2.

period, except in cases of business closure or load reduction without relocation.[257] PG&E's new EDR contract proposal contains a "Termination of Agreement" clause that requires 30 days written notice from the customer but does not include any penalties for early termination.[258] The new contract proposal does contain a liquidated damages clause, but it only applies to termination due to Applicant's misrepresentation or fraud.[259]

DRA recommends including an additional provision to PG&E's proposed liquidated damages clause that would cover situations in which the customer terminates service prior to the full contract period. The provision uses the following language from the liquated damages clause established by the Commission in D.05-09-018:

> For other cases of early termination (excepting business closure or reduction of load without relocation), liquidated damages equal to the cumulative differences between (i) the bills calculated under the ED rate to the date of termination and (ii) bills calculated under the OAT.[260]

Inclusion of this provision in the EDR contract is necessary to protect non-participating ratepayers and deter free-riders. Without this provision, a customer could take advantage of the higher discounts and then cease taking service before the full term of the contract.

In D.05-09-018, the Commission described the reasons for the liquidated damages provision advocated by SCE and PG&E:

> The proposed liquidated damages penalties are severe. In most cases, the types of businesses applying for EDR exemption will be those operating on thin margins or facing difficult cost constraints. The prospect of incurring damages equal to 200% of the cumulative differences between their normal bills and their bills under the EDR, a sum that could equal hundreds of

[257] Ex. DRA-1, p. 3-9.

[258] Id.

[259] Id.

[260] D 05-09-018, p. 24. The current liquidated damages clause, uses the differences between "the bills calculated under the ED rate to the date of termination and (ii) bills calculated under the OAT less 15 % plus interest on that difference at the 90-day commercial paper rate," to determine the amount of liquidated damages. DRA proposes to simplify this provision by calculating liquidated damages as the cumulative differences between the bills calculated under the ED rate to the date of termination and bills calculated under the OAT

> thousands of dollars, will undoubtedly provide a moment of pause for any applicant considering engaging in either fraud or misrepresentation. The same can be said of the proposed penalties for early termination. Although these penalties are not as severe as those for fraud or misrepresentation, they will almost certainly act as a deterrent to any applicant contemplating abusing the EDR system for short-term gains.[261]

The Commission's recognition of the importance of the liquidated damages provision, which was previously supported by PG&E, remains relevant today, particularly in light of the other changes that PG&E is proposing to the EDR program. PG&E's CTM analysis is based on a customer maintaining PG&E service for 10 years, and early termination of EDR contracts would invalidate the conclusions of PG&E's CTM analysis.[262] While DRA's more stringent proposal requires a positive net present value of CTM over the 5-year contract term, DRA's discounting structure declines over time, making the CTM negative the first year or two. Thus premature customer departure could result in a negative CTM and shift costs to nonparticipating ratepayers if either DRA's or PG&E's proposals were adopted. For these reasons, the Commission should require the inclusion of a liquated damages clause for early termination of an EDR contract.

In rebuttal, PG&E opposed DRA's proposal claiming that businesses should not be "held hostage" by the EDR agreement.[263] DRA's proposal, consistent with what the Commission has adopted, and with what PG&E has supported in the past, is not a punishment to businesses. It is an additional and important assurance that non-participating customers are not harmed by the large discounts that PG&E will be providing to its EDR customers. As discussed elsewhere in this brief, depending on the customer size and the amount of discount offered, these EDR discounts could amount to several hundred thousand dollars a year. The EDR program must benefit

[261] Id., pp. 18-19.

[262] Id.

[263] Ex. PG&E-4, p.1-16.

nonparticipating ratepayers, and the direct benefit of a positive contribution to margin may only occur if these customers actually complete the contracts.

Further, PG&E admits that, in the many years it has administered an EDR program, it "has not encountered even one situation where an EDR customer terminated the agreement due to anything but business closure."[264] Therefore, DRA sees little harm, but plenty of potential protection for ratepayers, as the Commission recognized in adopting this EDR provision in D.05-09-018.

XI. RATE DESIGN ISSUES

The Commission should adopt DRA's proposed declining five-year enhanced EDR discount, rather than PG&E's five-year fixed 35% discount, to protect ratepayers from undue risk. DRA's declining enhanced EDR proposal, which averages a 22% discount over five years, would be the most generous EDR rate ever offered by California IOUs[265], and, unlike PG&E's proposal, would comply with the ratepayer protections established by the Commission in D.07-09-016. PG&E has not met its burden of proof that a fixed five-year 35% discount is needed and justified.

There are several issues associated with PG&E's proposed five-year fixed percentage EDR discounts, especially for the 35% discount enhanced option. First and most importantly, a 35% discount fixed for five years could violate the additive price floor adopted in D.07-09-016, shift costs from EDR customers to nonparticipants, and impose a high risk of negative CTM if marginal costs increase during the contract term.

Second, PG&E has not demonstrated that a five-year 35% discount is required to attract and retain customers, and that DRA's EDR proposals would not achieve similar benefits with less risk to ratepayers.

Finally, the Commission must take care to ensure that discounts are reflected in both generation and distribution rate components, for bundled service customers, in a

[264] Ex. PG&E-4, p.1-16.

[265] DRA/Levin 2 RT 333

manner that observes competitive neutrality between bundled service and direct access ("DA") and Community Choice Access ("CCA") customers. DRA's proposed discounted rates are shown in Appendix A for bundled service customers, and Appendix B for DA and CCA customers.

A. Background

In the current, expiring EDR rate design, EDR contracts have a nominal fixed discount of 12% over five years. The fixed discount was changed from the previous rate design, which featured a five-year declining discount from 25% to 5% in annual steps. PG&E proposes to retain the current fixed discount rate design in its standard EDR option, and in addition, proposes an enhanced EDR program with a five-year 35% discount. PG&E also proposes to eliminate the ex post contract review. This would guarantee that EDR customers actually receive the promised discount, but removes the current rigorous annual enforcement of that price floor that essentially guarantees a positive CTM.

B. DRA's Enhanced EDR Proposals are likely to Succeed at Attracting and Retaining Customers, contrary to PG&E's and LGP's Assertions

PG&E and LGP assert, but have not demonstrated, that a fixed five-year 35% discount is needed to achieve the goals of the EDR, and that DRA's EDR proposals are overly complex. Contrary to these assertions, DRA's proposed enhanced EDR rate design is similar to, and more generous than, reasonably successful EDR programs offered in the recent past. Parties provide no credible evidence that DRA's proposals would not succeed at attracting and retaining customers.

1. DRA's Declining Five-Year Discount will be Understood by Potential EDR Customers

PG&E's rebuttal states, regarding DRA's five-year declining discount enhanced EDR proposal: "DRA's proposal is unduly complex and would be hard to explain to prospective customers."[266] This statement does not comport with PG&E's earlier experience with a similar five-year declining discount: According to D.10-06-015:

> In its amended application [A.09-10-12 and A.09-11-10], PG&E requested an increase in the program cap authorized in D.05-09-018 from 100 megawatts (MW) to 200 MW. PG&E currently has 88.325 MW enrolled under the EDR program.[267]

When asked about the relative success of the earlier PG&E EDR program discussed in D.10-06-015, PG&E's witness replied:

> Q. Was it your understanding that under the program that we just described that had a hundred megawatt cap PG&E had an enrollment of 88.325 megawatts?
>
> A. Yes.
>
> Q. Do you think that that's indicative of a successful program?
>
> A. Yes. I think -- let me rephrase that. I think it could be. I think it's a positive indicator.
>
> Q. And that program was a declining discount, right?
>
> A. Yes.[268]

So the fact that PG&E was able to enroll 88 MW out of an enrollment cap of 100 MW under an earlier EDR with a five-year declining discount simply does not comport with PG&E's assertion that "DRA's proposal is unduly complex and would be hard to explain to prospective customers."

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[266] Ex. PG&E-4, p.1-8, lines 4-5.

[267] Presumably, "currently" refers to the timeframe in which D.10-06-015 was written, or shortly before, and must apply to a period of time in 2009 or early 2010.

[268] PG&E/Hartman, 1 RT 186.

2. DRA's Declining Five-Year Discount can be Effective: It is not "a Recipe of Re-imposing past failed EDR approaches"

LGP's assertions that DRA's proposed enhanced EDR rate design is doomed to failure again simply do not comport with past experience. LGP's rebuttal testimony states:

> As California's Cities and Counties struggle to attract and retain jobs, the need is for the Commission to support those efforts by approving effective EDRs. However, the intervenors' recipe of re-imposing past failed EDR approaches, or worse, pays only lip service to the needs of California's hardest hit Cities and Counties.[269]

First, as described above, some previous EDR programs have been successful; in particular, a recent PG&E EDR program offering a five-year declining discount (similar to DRA's currently proposed enhanced EDR program) attracted load of 88 MW, nearly filling the then-existing cap of 100 MW.

Second, DRA proposes to offer an average discount of 22%, compared with the average discount of 15% for the earlier program discussed above.[270] With the largest EDR discount ever authorized for California IOUs,[271] and with terms that are not materially more complex or onerous than those of the EDR programs adopted in D.05-09-018, it is not at all clear why DRA's proposed enhanced EDR program should not be successful.

Finally, DRA has agreed with PG&E and LGP that the unpopular ex post adjustments of customer bills (the "clawback" feature) should be discontinued. DRA also has proposed significant changes to the additive price floor adopted in D.07-09-016 to enable larger discounts while still protecting ratepayers from undue risk. These changes should increase the attractiveness of PG&E's EDR programs.

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[269] Ex. LGP-2, Q&A 4, p.2.

[270] DRA/Levin 2 RT 333.

[271] Id.

In summary, past EDR programs with rate designs similar to DRA current proposal have been reasonably successful. Given the unprecedented generosity of the average 22% discount that DRA is proposing over a five-year period, the Commission has every reason to believe that DRA's proposals can be successful. Neither LGP nor PG&E has made a convincing case that DRA's proposals are a "recipe of re-imposing past failed EDR approaches," and therefore such testimony should be given little or no weight.

C. DRA's Declining Five-Year Discount avoids Future Rate Shock and Maximizes the Likelihood of a Successful Transition back to a Full Tariff Rate

PG&E's proposal to design its Enhanced EDR Option as a 35% discount in each year of the five-year contract term would not only violate DRA's modified floor price proposal; it would result in a nearly 50% rate increase if the customer returns to full tariff after the five-year EDR contract term.[272] To mitigate these effects, DRA proposes a declining discount for eligible customers in high-unemployment counties, beginning with a 35% discount in contract year 1 and declining to 30%, 20%, 15%, and 10% in contract years 2-5, respectively. DRA's proposal is roughly equivalent to a 22% discount over five years, and, in most instances, would be allowed by DRA's proposed modified floor prices.[273]

Thus, DRA's proposed declining discounts facilitate a smooth transition, over the five-year contract period, to the full tariff rate, and minimize the likelihood that a customer will need to seek a second consecutive EDR contract. In contrast, under PG&E's enhanced EDR proposal, customer would face an automatic 50% rate increase after 5 years, and may therefore be incentivized to either apply for another EDR term or consider leaving the State.

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[272] Ex. DRA-1, p. 2-14, lines 1-2.

[273] Ex. DRA-1, pp. 4-5.

In summary, DRA's enhanced EDR rate design would foster a gradual return to the full tariff, while PG&E's proposal is a recipe for encouraging dependency on large discounts.

D. DRA's Declining Five-Year Discount Limits the Risk of Negative CTM Resulting from Marginal Cost Increases

DRA has demonstrated above in Section VI that PG&E's enhanced EDR rates would violate the additive price floor established in D.07-09-016 and would therefore cause improper and unlawful cost shifting. In addition, DRA has stated a concern that ratepayers would be at risk of negative CTM due to changes in marginal cost over a five-year period with a fixed 35% discount, such as PG&E proposes.[274] DRA presents an example above that shows how CTM can go from positive to negative over a five year term, if the percentage discount is held constant while marginal costs increase over time.[275] This example demonstrates that unexpected increases in the marginal cost over a five-year contract period could result in a negative CTM even if a positive CTM were expected based on initial values of the marginal costs.

A transition from a positive to a negative CTM when marginal costs increase is far less likely with when EDR contracts are required to demonstrate a positive CTM on a forecast basis, over the contract period.[276] This is a feature of DRA's proposed declining discounts, not shared by PG&E's enhanced EDR proposal.

In contrast to PG&E's proposed enhanced EDR rate design, DRA's declining discount EDR proposal is crafted to satisfy the additive price floor and provide reasonable assurance of a positive CTM over the contract period. PG&E has admitted that its 35% discount is riskier for ratepayers than DRA's proposed average 22%

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[274] Ex. DRA-1, p.7, lines 16-19, Id, p.1-4, lines 10-12; Ex. DRA-2, p.1-13, line 3 through p.1-14, line 2.

[275] See Sec. VII-F, p.65, Table 12.

[276] Ex. DRA-1, p.2-2, lines 14-19.

discount.[277] For these reasons, PG&E's fixed five-year 35% discount would have an unacceptably high potential to harm ratepayers, and should therefore be rejected.

E. If the Commission Adopts a High Fixed Discount as PG&E Proposes, it must take steps to Mitigate the Risk

As noted above, if adopted in 2013 as proposed by PG&E, customers could sign five-year EDR contracts in this program as late as 2017. A contract signed in 2017 would extend until 2022. Further, a customer signing an EDR contract would have two years from the time of signing, to commence service under the contract. Therefore a customer signing an EDR contract in 2017 and commencing service in 2019 would be served under that contract until 2024.[278] This situation presents a risk of offering large fixed percentage discounts based on stale marginal costs when marginal costs are increasing over time.

DRA's preferred remedy is its proposal for a declining discount. A declining discount coupled with PG&E shareholder funding of any negative CTM after ten years protects ratepayers. However, DRA has proposed two possible alternative risk mitigation strategies if the Commission chooses not to authorize its declining discount coupled with shareholder funding of negative CTM. The first involves shortening the contract period and the second involves adjusting the discount for newly signed contracts to reflect changes in adopted marginal costs.[279]

1. As an Alternative to DRA's Five-Year Declining Enhanced EDR Proposal, the Commission Could Require a Shorter Contract Term, (e.g., Three Years)

A three-year enhanced EDR term would ensure that rates don't become decoupled from marginal costs because the latter are updated in a three-year GRC cycle. Thus a three-year term would provide an alternative means of mitigating risk. If the

[277] PG&E/Pease 2 RT 285.

[278] PG&E/Hartman 1 RT 198.

[279] The following two subsection address Scoping Memo Issue #21.

Commission were to adopt this approach, it would still need to require that enhanced EDR contracts comply with the D.07-09-016 additive price floor (modified as proposed by DRA). In some cases, three-year discounts may need to be reduced below 35% to achieve such compliance.

Under this alternate DRA proposal, PG&E would be required to terminate any remaining EDR contracts six months after a new EDR program is adopted for PG&E in the 2017 GRC or in a subsequent proceeding.[280]

2. If The Commission Chooses To Authorize A Five-Year Fixed EDR Discount, Then It Must Require PG&E To Adjust Discounts In New EDR Contracts For Changes To Adopted Marginal Costs

Marginal costs are typically updated in GRCs. In PG&E's case, GRCs are expected in 2014 and 2017. In DRA's second alternate proposal, the Commission would require that any new enhanced EDR contracts signed have a positive CTM during the contract term using the marginal costs most recently adopted prior to the contract signing. Thus, contacts signed after the effective date of the 2014 GRC Phase 2 proceeding should have a positive CTM during the contract term using updated marginal costs adopted in that proceeding. Any EDR contracts remaining in effect beyond December 31, 2017 should have a reduced discount if needed, beginning on January 1, 2018, to ensure a positive CTM using the updated marginal costs adopted in the 2017 GRC Phase 2 proceeding.[281]

F. Discounted Rates for Bundled Service Customers should Include Discounts to both Generation and Distribution Rates subject to Length of Contract Marginal Cost Floors; Negative Distribution Rates should be Avoided

PG&E's initial EDR rate design discounted only the distribution component of the rates; in many cases PG&E's initial proposal featured negative distribution rates. Several

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[280] Ex DRA-2, p. 1-2.

[281] Id.

parties opined in their opening testimony that, for bundled service customers, generation could, and should, be discounted as well as distribution.

Accordingly, PG&E changed its position in rebuttal, and now proposes to discount both generation and distribution rates to bundled service customers.[282]

All parties now support, or do not oppose, allocating discounts to bundled service customers between generation and distribution. Parties have proposed three different methods for allocating discounts between the generation and distribution rate components:

- DRA's initial proposal: discounted EDR rates would first discount distribution down to a marginal cost floor; additional discounts would be taken from the generation rate, if warranted and consistent with DRA's threefold EDR pricing floors.[283]
- AReM's proposal to allocate discounts to generation and distribution proportionately to "headroom", defined as the difference between the full tariff rate component and the marginal cost;[284]
- PG&E's primary proposal recommends that the allocation of the rate reduction between distribution and generation be based on the total undiscounted revenue where the portion of the EDR reduction assigned to distribution is equal to the proportion of non-generation revenue compared to total revenue.[285]

1. DRA now Supports AReM's Proposed Proration of Discounts to Generation and Distribution According to Marginal Cost "Headroom"

In rebuttal, DRA changed its initial position, and now supports AReM's proration proposal, stating:

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[282] Ex. PG&E-4, p.2-3, lines 7-11.

[283] Ex. DRA-1, p.2-12, lines 23-26.

[284] Ex. AReM-1, p.3.

[285] Ex. PG&E-4, p.2-18, lines 12-16.

> DRA now believes that AReM's proration approach achieves a better balance between the distribution and generation functions. Both functions would contribute to margin under AReM's proposal.[286]

PG&E, in rebuttal, appears not to oppose AReM's proposal, characterizing the choice between its preferred allocation of discounts and AReM's proposed allocation as "a policy decision for the Commission to make".[287]

2. PG&E's Primary Rebuttal Rate Design Proposal is Flawed and should not be Adopted

First, PG&E's revised rate design proposal continues to feature a five-year 35% discount, and, as shown in PG&E's "Workpapers Supporting Rebuttal Testimony" would provide a negative five-year CTM for customers located in distribution-constrained areas.[288]

Second, in some cases, PG&E's revised proposed rates continue to feature negative distribution rates.[289] This is a significant flaw, as described below.

3. Marginal Cost Floors should apply for Generation and Distribution Rate Components over the Contract Period

As discussed in DRA's opening testimony, DRA's declining discount rate proposals allow negative CTM in the initial years of a five-year contract period, as long as the CTM is positive over the full period (in present value).[290] Initially, DRA proposed that distribution be subject to an annual marginal cost floor,[291] so that only generation cost be (temporarily) priced below marginal cost.

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[286] Ex. DRA-2, pp. 1-15, 1-16, FN 26.

[287] Ex. PG&E-4, p.2-19, line 13.

[288] Ex. PG&E-5, pp.2-7 through 2-12. The "Expected NPV 5-yr NPV net benefits" are all negative, even with zero free-riders.

[289] Id., pp. 2-5 and 2-14. Rate schedule E-20T has a negative distribution rate component.

[290] Ex. DRA-1, p.2-6, lines 21-23.

[291] Id, p.6, lines 13-14.

To be consistent with AReM's proposed proration of discounts between generation and distribution, which DRA now supports, DRA recognizes that both distribution and generation should be (temporarily) priced below marginal cost, to achieve a 35% discount in the first year of the five-year contract period.

Thus, marginal cost floors should apply to discounted rates for bundled service customers, but the floor prices should be applied over the entire contract period and not on a year-by-year basis.[292]

4. Distribution Rate should Never be Negative in the Context of EDR

DRA's opening testimony on this issue can be summarized in the following three propositions:[293]

- For direct access ("DA") and community choice aggregation ("CCA") customers, a negative distribution rate is equivalent to discounting one or more NBCs, and is, per D.07-09-016, unlawful. This point is further explained below.
- For competitive neutrality, bundled service customers should pay the same distribution rates as similarly situated DA and CCA customers.
- Taken together, these propositions imply that distribution rates should not be negative for any customer.

G. Discounted Rates for DA and CCA Customers should include Discounts to Distribution Rates subject to Length of Contract Marginal Cost Floors; DA and CCA Customers should Pay the same Distribution Rates as Similarly Situated Bundled Service Customers; Negative Distribution Sates should be Avoided

As with bundled service customers, distribution marginal cost floors should apply to discounted rates for DA and CCA customers, but the floor prices should be applied

[292] As shown in Appendix D, for bundled service customers DRA's proposed modified additive floor price is more constraining than the marginal cost floor price.

[293] Id, pp. 2-11, 2-12, Ex. DRA-2, pp. 1-14, 1-15. This section addresses Scoping Memo Issue #3.

over the entire contract period and not on a year-by-year basis. DRA's recommended discounted rates for DA and CCA customers are shown in Appendix B.

1. Distribution Rates should be Identical for Similarly Situated DA, CCA, and Bundled Service Customers[294]

DRA's testimony states: "There is no difference in the distribution services provided to DA or CCA and bundled service customers. Therefore it appears that PG&E's proposal [to offer a different distribution discount to bundled service than to DA or CCA customers] violates a fundamental principle of competitive neutrality and should be rejected."[295] No party has alleged a difference in the distribution services provided to these types of customers, that would justify a distribution rate differential among them. DRA recommends, based on the policy grounds of competitive neutrality, that distribution rates, with or without EDR discounts, be equal for DA/CCA and bundled service customers within the same rate schedule.[296]

2. For DA and CCA Customers, a Negative Distribution Rate Implies Unlawful Discounting of NBCs

As noted in Section VI above, for DA and CCA customers, all rate components, with the sole exception of Distribution, are nondiscountable. A negative distribution rate means, therefore, that the total revenue from such a customer would be insufficient to cover the total of that customer's nondiscountable rate components.[297] This would result in effectively discounting one or more nondiscountable rate components; a logical contradiction. There is no other reasonable interpretation. PG&E states that

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[294] The following section addresses Scoping Memo Issue #5.

[295] Ex DRA-1, p. 2-11, line 21, through p. 2-12, line 6.

[296] In some cases, to avoid violating a price floor constraint, DRA proposes a higher distribution rate component for a constrained area DA or CCA customer than for a similarly situated bundled service customer. See, Ex. DRA-1, pp. 2-14, 2-15.

[297] The following section addresses Scoping Memo Issue #4.

nonbypassable rate components would be fully funded;[298] this cannot be true for funds provided by DA/CCA customers paying a negative distribution rate, because the total of such funds would be insufficient to cover the total of the NBCs.

The only way in which NBCs can be fully funded in such a scenario is by applying funds from other customers. This type of cost shifting is specifically prohibited by Commission policy and statute.[299]

3. AReM's DA/CCA Rate Proposal, Which Would Discount Distribution More Deeply To DA/CCA Customers Than To Bundled Customers Should Be Rejected

AReM's testimony states:[300]

> For DA customers, the EDR discount should be the lesser of the same discount that the customer would have received had it been on bundled service or an amount that does not create a negative contribution to margin (i.e., EDR discount does not exceed distribution rate headroom).

DRA interprets this quotation to as saying that the DA or CCA customer should receive the lesser of the total discount (i.e., generation and distribution) given to bundled customers and the DA or CCA customer's distribution headroom. If so, there is a significant flaw in AReM's proposal, which can best be illustrated by reference to the simple numerical example shown in DRA's rebuttal.[301]

DRA objects to this AReM proposal because DA and CCA customers would pay a lower rate for distribution services than similarly situated bundled service customers. In DRA's rebuttal Table 1-1, bundled service customers receive a total discount of 4 cents/kWh, 2 cents/kWh each for generation and distribution. These discounts represent two-thirds of the available 3 cent headroom in each function.

[298] Ex. PG&E-1, p.3-2.

[299] Prohibition of cost shifting is discussed above in Section VI.

[300] Ex. AReM-1, p.3

[301] Ex. DRA-2, Tables 1-1 and 1-2, pp. 1-16 and 1-17.

Under AReM's DA/CCA pricing proposal, DA customers would receive a discount equal to the lesser of the 4 cents/kWh discount it would have received as a bundled service customer, or the 3 cents/kWh of available distribution headroom, as the highlighting in DRA rebuttal Table 1-2 indicates. In other words, a DA or CCA customer would receive a 3 cent distribution discount, down to its distribution marginal cost, while a similarly situated bundled service customer would only receive a 2 cent discount to its distribution rates. DRA recommends that the Commission reject this proposal on the grounds that it violates competitive neutrality with respect to pricing of distribution services.[302]

XII. PG&E SHAREHOLDERS SHOULD FUND SHARE SOME OF THE EDR PROGRAM COSTS WITH RATEPAYERS, AND BEAR SOME OF THE RISK FOR NEGATIVE CONTRIBUTION TO MARGIN

DRA recommends that the Commission require PG&E shareholders to pay for 25% of the EDR discounts if DRA's proposed floor price is adopted. If PG&E's proposal to not include a floor price is adopted, DRA recommends the Commission require shareholders to pay for 50% of the EDR discounts. In addition, PG&E shareholders should pay for 100% of any negative CTM, on an aggregate EDR program basis, that might remain after 10 years.[303] DRA believes that requiring PG&E to share the costs of this discount will provide the utility with a strong incentive to limit discounts to the intended target participants and, as a result, reduce free-ridership. The fact that PG&E shareholders derive benefits from these discounts serves as an additional reason for sharing such costs. Requiring shareholders to cover any negative CTM at the end of 10 years also assures compliance with the ratepayer benefits provision of PU Code §740.4(h). PG&E shareholders will benefit from the EDR program because it will attract new customers to PG&E and help retain current customers. The EDR program will help secure the long term interests of PG&E shareholders by helping maintain and expand the

[302] See also, Ex. DRA-1, pp.2-11 and 2-12.

[303] Ex. DRA-1, p.3-10.

customer base and thus the long term economic health of the company. Trends in sales and revenues affect the recommendations made by market analysts about the company, which in turn affects the stock price. For example, Reuters stock quote page for PG&E states the number of PG&E customers at the beginning of its discussion of the company. It also mentions that PG&E's revenues are generated mainly through the sale and delivery of electricity and natural gas to customers.[304] This shows that the size of a utilities customer base is an important indicator of financial strength considered by market analysts. Utilities with stable or increasing sales and revenues will be perceived as financially healthy. Thus, retaining customers through EDR programs is beneficial to shareholders.

PG&E's annual reports to shareholders acknowledge the importance of the size of the company's customer base. In the 2011 Annual Report, Financial Highlights section, the first thing listed is PG&E's operating revenues.[305] Electric operating revenues are made up of "amounts charged to customers for electricity generation, transmission and distribution services."[306] This indicates that PG&E considers its operating revenues to be paramount and PG&E's revenues are directly related to the number of customers it has. This further supports the assertion that PG&E financial results and shareholders are directly affected by the size of the Company's customer base.

Also, in PG&E's Securities and Exchange Commission ("SEC") filing for 2011, Exhibit 13-Management's Discussion & Analysis of Financial Conditions & Results of Operations, PG&E names the following as a "Risk Factor":

> PG&E Corporation's and the Utility's financial results can be affected by the loss of Utility customers and decreased new customer growth due to municipalization, an increase in the number of community choice

[304] Ex. DRA-1, p.3-10 citing Reuters, Overview of PG&E Corp. Retrieved August 14, 2012, available at http://www.reuters.com/finance/stocks/overview?symbol=PCG.N. Ex. DRA-1, Appendix F.

[305] Id., p.3-11, citing PG&E 2011 Annual Report, p.1. Ex. DRA-1, Appendix D.

[306] Id.

aggregators, increasing levels of "direct access," and the development and integration of self-generation technologies.[307]

PG&E's has filed two Quarterly Reports to the SEC in 2012. Both of these reports also discuss the loss of customers due to various forms of bypass and competition, including loss of generation revenue due to customers switching to DA and CCA providers, as factors that could affect PG&E's future financial situation.[308] The above references to PG&E's SEC filings indicate that PG&E considers customer loss, as a risk to its financial condition, therefore gaining or retaining customers would benefit its financial condition and subsequently its shareholders.

Furthermore, PG&E seems to be concerned and has taken action in situations where it perceived the potential for losing some of its customer base. Threats to PG&E's customer base come from municipalization, annexation of portions of PG&E's service area by another utility, the formation of CCAs, as well as the loss of the industrial and commercial customers that is the subject of this proceeding. PG&E certainly does not seem indifferent to these circumstances. Indeed, DRA has observed that PG&E has taken action to try to prevent these events and the associated loss of customers. For example, PG&E shareholders spent $28 million[309] to sponsor Proposition 16, a ballot initiative in June 2010 that, if it had passed, would have required a two-thirds vote of the electorate before a public agency could create a CCA.[310] PG&E also spent $11 million to launch

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[307] Id., citing Thomson Reuters, "PGECORP 10-K, Annual report pursuant to section 13 and 15(d) of the SEC Act of 1934, For the Fiscal Year Ended December 31, 2011." Filed on 2/16/2012, p.40. Ex. DRA-1, Appendix F.

[308] Id., citing Thomson Reuters, "PGECORP 10-Q, Quarterly report pursuant to section 13 and 15(d) of the SEC Act of 1934, For the quarterly period ended March 31, 2012." Filed on 3/31/2012, p.42; Thomson Reuters, "PGECORP 10-Q, Quarterly report pursuant to section 13 and 15(d) of the SEC Act of 1934, For the quarterly period ended June 30, 2012." Filed on 8/7/2012, p.45. Ex. DRA-1, Appendix F.

[309] Id., p.3-10 quoting *Santa Cruz Sentinel*, "Prop 16 is June's priciest ballot initiative, with PG&E coughing up big money," March 25, 2010. Ex. DRA-1, Appendix F.

[310] Id., citing Ballotpedia, California Proposition 16, Supermajority Vote Required to Create a Community Choice Aggregator, June 2010. Retrieved August 14, 2012, from http://ballotpedia.org/wiki/index.php/California_Proposition_16,_Supermajority_Vote_Required_to_Crea

(footnote continued on next page)

an initiative campaign to prevent Yolo County residents from designating the Sacramento Municipal Utilities District as their power company.[311] PG&E has consistently taken action to maintain its customer base; hence, DRA concludes that it is in PG&E's long-term interest in continuing to do so.

PG&E shareholders also will benefit from the EDR program because it will improve PG&E's corporate image and credibility by showing that it cares about its customers and the state of California. In Moody's Credit Evaluation Guidelines, it discusses the criteria used to establish PG&E's credit rating, including a discussion of seven "Ratings Drivers." One of these drivers is titled "New management focused on credibility issues."[312] Moody's also labels PG&E's credibility as an "important factor"[313] in its discussion of detailed rating considerations. Moody's also recognizes California's improving economy as a "Rating Driver"[314] and discusses job growth in California.[315] This shows a direct correlation between both PG&E's corporate image and the number of jobs in California with PG&E's credit rating. Having a good credit rating benefits PG&E's shareholders because it makes the company appear financially strong which increases stock prices.

The Commission has acknowledged that utility shareholders accrue benefits from EDR programs in past Decisions and Resolutions. In Resolution E-3654, the Commission discussed specific benefits PG&E derives from the EDR program:

> PG&E gains strategic competitive advantages by attracting new customers and locking in sales over the long term due to the nature of the Schedule

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(footnote continued from previous page)
te_a_Community_Choice_Aggregator_(June_2010)#cite_note-1. Ex. DRA-1, Appendix F.

[311] Id., p. 3-12, citing *The People's Vanguard of Davis,* "PG&E Trying to Make Fight for Public Power Nearly Impossible," July 24, 2009. Ex. DRA-1, Appendix F.

[312] Id., citing Moody's Investors Service, Moody's Credit Evaluation Guidelines, August 2009. Appendix B, p.1-2. Ex. DRA-1, Appendix F.

[313] Id.

[314] Id., p.3-13.

[315] Id.

> ED contract. Once PG&E begins serving the new customer it gains the additional advantage of having been the first competitor to establish a relationship with the customer, arguably making it easier to sell additional services and placing the burden on competitors to lure the customer away from their existing provider.[316]

Further, in D.07-09-016, the Commission found that the EDR program benefits shareholders:

> "b. Do any of the benefits of retaining EDR customers accrue to shareholders? If so, how should this be considered when determining cost shifting?
>
> In 2000, the Commission noted the strategic competitive advantages associated with attracting new customers. (Resolution E-3654, 2000 Cal. PUC LEXIS 420, Findings 14, 18, and 19.) EDR discounts benefit shareholders by maintaining or increasing customer base and market share. EDR price advantages assist utility efforts to compete for customers at the borders of their service territories, for example against irrigation districts that might serve existing utility customers. EDR discounts help promote alliances with local business communities, which could assist utility political efforts, for example opposition to municipalization initiatives. Shareholders as well as ratepayers obtain the benefits of the EDR customers. The consideration of benefits accruing to shareholders should result in some allocation of costs to the utility, but this record does not support a finding of a particular percent."[317]

DRA shares the Commissions above stated beliefs that PG&E's shareholders benefit from maintaining PG&E's customer base and market share, and thus it is appropriate to allocate some of the cost of the discount to PG&E's shareholders. PG&E did not, and cannot rebut the fact that its shareholders benefit from maintaining or increasing its customer base. PG&E's rebuttal testimony states that "shareholders do not derive a direct financial benefit from increased sales" due to decoupling.[318] While the company does not receive higher revenues from selling more electricity this does not mean that all

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[316] Ex. DRA-1, quoting Resolution E-3654, p. 6.

[317] D.07-09-016, p. 27.

[318] Ex. PG&E-4, p.2-19.

of the other benefits described above do not accrue to shareholders or that shareholders are not harmed by the company losing customers. Further, PG&E claims that it will not offer an EDR program "if one is approved contingent upon, or requiring, shareholder funding."[319] DRA has difficulty understanding this position, which contradicts the testimony of PG&E's witness who stated "We want to see California succeed. We want to see Californians do well."[320] If PG&E is confident that its projections on contribution to margin are sufficiently accurate to justify approval of the program, than it should be willing to bear some risk that these projections do not come to fruition. Otherwise, as discussed above, non-participating ratepayers will all the risks associated with the EDR program, even though shareholders would be receiving a benefit if the program is successful. PG&E has aggressively spent tens of millions of dollars in shareholder money in the past 5 years in the pursuit of maintaining its customer base[321] and it should be willing to spend shareholder money for the same reasons in this situation. The record of this case supports the propriety of shareholder funding of the some of the EDR discount.

A. To Guard against Increased Ratepayer Risk, PG&E Shareholders should be Responsible for 100% of Negative CTM after Ten-Years

DRA recommends that shareholders be required to bear the cost of the EDR rate differential if an ex-post review of the EDR program reveals that it has not resulted in

[319] Ex. PG&E-4, p.2-20.

[320] PG&E/Adolph, 1 RT 162, lines 13-15.

[321] Ex. DRA-1, p.3-10 quoting *Santa Cruz Sentinel*, "Prop 16 is June's priciest ballot initiative, with PG&E coughing up big money," March 25, 2010. PG&E shareholders spent $28 million to sponsor Proposition 16, a ballot initiative in June 2010 that, if it had passed, would have required a two-thirds vote of the electorate before a public agency could create a CCA. Ex. DRA-1, Appendix F; Ex. DRA-1, p.3-10 citing Ballotpedia, California Proposition 16, Supermajority Vote Required to Create a Community Choice Aggregator, June 2010. Retrieved August 14, 2012, from http://ballotpedia.org/wiki/index.php/California_Proposition_16,_Supermajority_Vote_Required_to_Create_a_Community_Choice_Aggregator_(June_2010)#cite_note-1. Ex. DRA-1, Appendix F; Ex. DRA-1, p. 3-12, citing *The People's Vanguard of Davis,* "PG&E Trying to Make Fight for Public Power Nearly Impossible," July 24, 2009. Ex. DRA-1, Appendix F.

benefits to ratepayers after 10 years.[322] This requirement should pose little risk to shareholders – if PG&E's positive 10-year CTM projections prove accurate. In fact, if DRA's proposed Enhanced EDR Option discounts are adopted, the 10-year positive CTMs will be even greater, decreasing the risk to shareholders from a negative CTM.

After the commencement of the EDR program, the Commission should require PG&E to track CTM for each EDR customer and for the EDR program portfolio on an annual basis.[323] Any negative CTM generated from the EDR program should be tracked in a balancing account established for that purpose. Beginning at year 6 (2018), and each year thereafter through 2022, any negative CTM balance would be earmarked for shareholder funding and credited to ratepayers. If, at any time between year 5 and year 10 after the commencement date of the EDR program, the cumulative CTM turns positive for the EDR portfolio, shareholders could then recover the negative CTM through a debit to ratepayers through the balancing account.

In the event that the EDR program portfolio does not yield a positive CTM after 10 years, PG&E shareholders would not be eligible to recover the funds that were credited to ratepayers through the balancing account. Shareholder funding of EDR program generated negative CTM is supported by PU Code §740.4(h), which allows for rate recovery of economic development programs cost only if "…the utility … demonstrates that the ratepayers of the public utility will derive a benefit from those programs." Ratepayer benefit under PU Code §740.4(h) requires a positive CTM.[324] Accordingly, if the EDR program results in a negative CTM, then ratepayers will not benefit from the program and costs from the program are not eligible for rate recovery.

If program costs cannot be recovered through rate recovery under PU Code §740.4(h), then PG&E shareholders are responsible for funding the entire negative CTM. PG&E acknowledged this principle, "under circumstances where a utility was not able to

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[322] Ex. DRA-1, p.3-15. This section addresses Scoping Memo Issue #31.

[323] The following section addresses Scoping Memo Issue #28.

[324] Ex. DRA-1, Chapter 1, Section E (1), pp. 1-11 – 1-14.

demonstrate that ratepayers will derive a benefit from EDR programs, the Commission may have discretion to allocate all, or some portion, of a negative margin to shareholders."[325] Therefore, if PG&E is not able to show a ratepayer benefit in the form of a positive CTM within 10 years from the start of the EDR program, then the Commission should require PG&E shareholders to pay for 100% of the negative CTM.

Though shareholder funding of negative CTM was not adopted in the most recent EDR proceeding, it should be noted that negative CTM was not even possible under the EDR tariff language that was implemented pursuant to D.10-06-015. This tariff language provided that EDR participants' discounts would be trued up after the fact, if marginal costs changed, to assure that negative CTM did not occur. Moreover, the liquidated damages language that was used was much more stringent than what PG&E proposes in this proceeding. PG&E is proposing an entirely different EDR paradigm in this proceeding where non-participants rather than participants pay for any negative CTM. This new paradigm requires that PG&E shareholders, not non-participating ratepayers, pay for the negative CTM in order to assure compliance with the ratepayer benefit provision in PU Code §740.4(h).

B. PG&E Shareholders should Pay for 25% of the Economic Development Rate Discounts if the Commission Adopts DRA's Price Floor Proposal. If the Commission Adopts PG&E's Proposal that does not Include a Price Floor, PG&E Shareholders should have to Pay for 50% of the EDR Discounts

DRA recommends that shareholders be required to bear 25% of the cost of the EDR discounts, assuming that the Commission adopts a floor price on those discounts.[326] The Commission has the discretion to allocate all or some portion of the cost of the EDR discount to shareholders. This principle was affirmed in D.07-09-016, in which the Commission determined its discretion was dependent "on the facts of a particular

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[325] Ex. DRA-1, p.3-16, citing TURN Data Request Response 3, question 09. Ex. DRA-1, Appendix E.

[326] This section addresses Scoping Memo Issue #30.

application."[327] The Commission chose not to require shareholder funding in D.07-09-016, but it should in this application because the facts emphasize the need for shareholder contribution.

First, for the enhanced EDR program, PG&E proposes to offer a much larger discount than it ever has before, which creates more risk for non-participating ratepayers. Second, PG&E is proposing to remove a majority of the non-participating ratepayer safeguards the past EDR programs have required. While DRA opposes many of PG&E's proposals to relax ratepayer safeguards in the current EDR program, DRA acknowledges that there is a need to offer greater discounts, in some circumstances, than are available from the current EDR. Therefore, as discussed elsewhere in this brief, DRA has proposed a less stringent price floor than that required currently. DRA has also proposed to allow negative CTM in the initial years of a 5-year contract, a departure from current EDR practice. DRA's proposed changes would increase ratepayer risk relative to the current EDR program, though not nearly to the extent of the much greater risk imposed by PG&E's current proposals.

If implemented carefully, PG&E's proposals, modified as recommended by DRA, would provide benefits relative to the current EDR program, in terms of increased customer participation, and increased CTM. Because both ratepayers and shareholders stand to benefit from a successful EDR program,[328] both should share in the increased risk needed to achieve these benefits. Therefore, according to the facts of this application, the Commission should exercise its discretion by adopting DRA's proposed discounts, price floors, and eligibility requirements and requiring PG&E shareholders to fund 25% of the EDR discount.

In the alternative, if the Commission chooses to adopt PG&E's proposed discounts, eligibility requirements, and *no* price floor, it should require PG&E

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[327] D 07-09-016, p. 27.

[328] As discussed above, positive CTM exerts downward pressure on rates; and sales and revenue growth exerts upward pressure on stock prices.

shareholders to fund *50%* of the EDR discount, in light of the much greater risk to ratepayers from the lack of ratepayer safeguards in PG&E's proposals. It also must adopt 100% shareholder funding of any negative CTM after 10 years as described below to maintain legal compliance with PU Code §740.4(h).

XIII. CONCLUSION

For the reasons discussed above, the Commission should reject PG&E's unacceptable EDR proposal and adopt DRA's proposed EDR proposal.

Respectfully submitted,

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