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Commissioner	:	Michael Peevey
Admin. Law Judge	:	Thomas Pulsifer
DRA Witness	:	Ke Hao Ouyang

DIVISION OF RATEPAYER ADVOCATES
CALIFORNIA PUBLIC UTILITIES COMMISSION

REPLY TESTIMONY ON THE METHODOLOGY FOR CALCULATING DEPARTING LOAD NON-BYPASSABLE CHARGES, DIRECT ACCESS SWITCHING RULES, ELECTRIC SERVICE PROVIDER FINANCIAL SECURITY REQUIREMENT AND TRANSITIONAL BUNDLED SERVICE RATE

San Francisco, California
February 25, 2011

445331

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(Witness: Ke Hao Ouyang)

I. INTRODUCTION

In accordance with the Assigned Commissioner's Ruling Adopting Amended Scoping Memo and Schedule (ASM) issued on November 22, 2011, and per Administrative Law Judge Pulsifer's Ruling Amending Procedural Schedule, issued on January 7, 2011, the Division of Ratepayer Advocates (DRA) submits this reply testimony on the methodology for calculating departing load non-bypassable charges and other Direct Access (DA) Phase III issues pertaining to DA switching rules, minimum stay provisions, transitional bundled service (TBS) rates and electric service provider (ESP) financial security requirements.

DRA received and reviewed opening testimony from the California Large Energy Consumers Association (CLECA), California Manufacturers and Technology Association (CMTA),[1] Joint Parties,[2] L. Jan Reid,[3] Pacific Gas and Electric Company (PG&E),[4] Southern California Edison Company (SCE)[5] and San Diego Gas and Electric Company (SDG&E).[6] The parties expressed a common goal to use publicly available, transparent data whenever possible and to ensure that bundled customers are indifferent (i.e., no better or worse off) as a result of departing load. The apparent common understanding

[1] Testimony of Dr. Barbara R. Barkovich on behalf of the California Large Energy Consumers Association and the California Manufacturers and Technology Association (CLECA-CMTA Testimony), January 31, 2011.

[2] Testimony of John P. Dalessi, Mark E. Fulmer, Margaret A. Meal on behalf of the Joint Parties on a Fair and Reasonable Methodology to Determine the Power Charge Indifference Adjustment and the Competition Transition Charge and Testimony of Mark E. Fulmer on behalf of the Direct Access Parties concerning the Transitional Bundled Service Rate, Direct Access Switching Rules, Minimum Stay Provisions, and Energy Service Provider Financial Security Requirements (Joint Parties' Testimony – Parts 1-2), January 31, 2011.

[3] Direct Testimony of L. Jan Reid on Phase III Direct Access Issues (L. Jan Reid Testimony)., January 31, 2011.

[4] Pacific Gas and Electric Company Direct Access Reopening Phase III Prepared Testimony (PG&E Testimony), January 31, 2011.

[5] Direct Access Rulemaking Phase III Testimony of Southern California Edison Company (SCE Testimony), January 31, 2011.

[6] Prepared Direct Testimony of James Spurgeon, Cynthia S. Fang and Toni Choi for San Diego Gas & Electric Company (SDG&E Testimony – Chapters 1-3), January 31, 2011.

from the December 2010 and January 2011 workshops is confirmed by a uniform recommendation on several key issues. However, the parties remain divided on several other key issues in the absence of publicly available, transparent data.

Some parties proposed using confidential investor-owned utilities' (IOU) information, subject to review and verification by the California Public Utilities Commission's (CPUC) Energy Division or a third party non-market participant to resolve the remaining key issues. However, these same parties do not want to share their individual, confidential information with other parties. Some parties also suggested, for administrative ease, to use a single estimation for all power charge indifference adjustment (PCIA) vintages despite acknowledging such action may risk the integrity of the data. DRA addresses all of these issues in detail in the sections below.

II. DRA RECOMMENDATIONS

DRA recommends the Commission adopt the parties' uniform recommendation on the following proposals on several key PCIA, switching rule, and TBS rate issues:

<u>PCIA Issues:</u>

1. Remove all load-related California Independent System Operator (CAISO) costs from total portfolio costs.
2. Adopt a uniform treatment for short-term energy market transactions with contract terms of less than one year for all IOUs by excluding such transactions from total portfolio costs.
3. ***<u>Switching Rules</u>:*** Maintain current rule requiring customers to provide six months' advance notice before switching between bundled and DA services.
4. ***<u>TBS Rate</u>:*** Make the TBS rate consistent with the proposed changes to the PCIA by including resource adequacy (RA) and renewable portfolio standard (RPS) charges and reflecting modifications to the PCIA methodology.

Due to the lack of a renewable energy market with publicly available, transparent market data, the parties could not agree on the appropriate methodology for determining the market value of RPS-eligible resources. Furthermore, until the legal issues pertaining to ESP financial security requirements are resolved, it seems highly unlikely that parties would be able to agree to a particular bonding methodology. Based on its review of testimony and participation in workshop discussions, the following are DRA's recommendations for resolution of the unresolved issues:

PCIA Issues:

1. Use a publicly available, transparent renewable energy credit (REC) market value to determine the market value of RPS resources.
2. Use accurate and publicly available information to determine the market value for RA capacity.
3. Use publicly available information to determine on-peak and off-peak weights for the market price benchmark (MPB).
4. ***ESP Financial Security:*** Adopt a bonding methodology that prevents cost shifting to bundled customers when DA customers are involuntarily returned to bundled service.

III. DISCUSSION

PART 1: CONSENSUS ISSUES

Some parties were unwilling to commit to any agreement in principle despite an apparent common understanding on several key issues after constructive discussions during the December 2010 and January 2011 workshops. However, this common understanding is confirmed by a uniform recommendation in their opening testimony on several key issues pertaining to load-related CAISO costs, short-term energy market transactions, six months' advance notice requirement, and TBS rates. DRA recommends the Commission adopt the parties' uniform recommendations on the following "consensus" issues:

1. Load-Related CAISO Costs

The IOUs should remove all load-related CAISO costs from total portfolio costs. This will eliminate the need to calculate the reduction in load-related CAISO costs as load departs.

2. Short-Term Energy Market Transactions

The IOUs should adopt a uniform treatment of short-term energy market transactions with contract terms less than one year by excluding such transactions from total portfolio costs. This will ensure the IOUs use a consistent and uniform PCIA methodology.

3. Six Months' Advance Notice

Customers switching voluntarily between DA service and bundled service must continue to provide a six months' advance notice. During the six month waiting period, a voluntarily returned DA customer may remain with the ESP or return to bundled service under the applicable TBS rate. A voluntarily returned DA customer going to bundled service without providing six months' advance notice will be placed under the applicable TBS rate for six months. After six months, returning customers are subject to the same pricing terms and conditions as apply to other bundled customers. Requiring six months' advance notice is also consistent with Commission Decision (D.) 03-05-034, and provides a reasonable opportunity for the utility to adjust its portfolio, process Notices of Intent (NOI) supplied by the customer, adjust RA compliance filings, and process DA Service Requests (DASR).[7]

4. Transitional Bundled Service Rate

The TBS rate should be made consistent with the updates to the PCIA by including RA and RPS charges and reflecting any modifications to the PCIA methodology. RA and RPS charges are currently not included in the TBS rates. Therefore, they must be reflected in the TBS rates to ensure DA customers returning to bundled service pay their fair share of RA and RPS charges. Under the current PCIA methodology, an RA adder is included in the MPB to account for RA charges. The proposed modification to the PCIA methodology will include the equivalence of a RPS adder in the MPB to account for RPS charges. DRA recommends that the same RA and RPS adders be added to the TBS rates to reflect RA and RPS charges.

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[7] D.03-05-034, pp. 39-43, 48, 52.

PART 2: UNRESOLVED ISSUES

A. Value of RPS-Eligible Resources

CLECA-CMTA,[8] DRA,[9] the Joint Parties,[10] PG&E,[11] SCE[12] and SDG&E[13] generally agree to update the calculation of the MPB to reflect the cost of renewable resources by multiplying the percentage of RPS resources by the market value of RPS resources, and the percentage of non-RPS resources by the market value of non-RPS resources. However, there is no agreement on the appropriate methodology for determining the market value of RPS resources. The parties are also supportive of using a transparent REC market value to determine the market value of RPS resources. However, such information is not yet available, and the Joint Parties expressed concerns on the accuracy of preliminary REC market data, due to Commission-imposed restrictions on the use of tradable renewable energy credits (TRECs) and on TREC prices.

The Joint Parties believe that an open, transparent, and liquid market for renewable power that will provide transparent market price information for RPS resources will exist in the future. However, they are skeptical that initial market pricing information from the newly established market for TRECs that may arise out of D.11-01-025 would be appropriate due to the restrictions on the use of TRECs.[14] The Joint Parties did not provide any information on how the Commission imposed restrictions will affect the market value for TRECs.

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[8] CLECA-CMTA Testimony, pp. 11-12.

[9] Division of Ratepayer Advocate Testimony on the Methodology for Calculating Departing Load Non-Bypassable Charges, Direct Access Switching Rules, Electric Service Provider Financial Security Requirement and Transitional Bundled Service Rate (DRA Testimony), January 31, 2011, pp. 2-3.

[10] Joint Parties' Testimony – Part 1, p. 4.

[11] PG&E Testimony – Chapter 1, p. 13.

[12] SCE Testimony, p. 25.

[13] SDG&E Testimony – Chapter 2, p. 5.

[14] Joint Parties' Testimony – Part 1, pp. 22-23.

The Commission, in D.10-03-021, permitted the IOUs to fulfill up to 25% of their annual RPS procurement obligations using TRECs.[15] The Commission also imposed a transitional price cap of $50/REC in REC-only contracts used for RPS compliance until December 31, 2011 to protect ratepayers from excessive payments for TRECs in the early stages of the TREC market.[16] The $50/REC price cap was extended until December 31, 2013 in D.11-01-025.[17] In addition, the 25% limit on REC usage was extended to all ESPs in D.11-01-026.[18]

The Commission-imposed restrictions on the use of TRECs are intended to protect ratepayers from excessive payments for TRECs in the early stages of the TREC market and to promote the development of new RPS-eligible generation. However, the Commission also noted that in the early years of a California TREC market, prior to load serving entities' (LSE) attaining the goal of 20% of retail sales from RPS-eligible generation resources, demand for TRECs is likely to exceed supply.[19] Therefore, in DRA's view, the Commission-imposed restrictions should have little to no impact on TREC prices given the expected supply shortage.

DRA reiterates its preference to use the best and most accurate and publicly available information, but acknowledges that the most accurate and up-to-date information is not always available due to confidentiality concerns. Some parties proposed using confidential IOU RPS resource contract information subject to review and verification by the CPUC's Energy Division or a third party non-market participant, but these parties have concerns over sharing their individual, confidential RPS resource contract information with other parties and are reluctant to do so.

If the Commission were to consider using confidential information to determine an interim proxy price for RPS resources, DRA recommends the Commission include

[15] D.10-03-021, pp. 40-49, 89, 93.

[16] D.10-03-021, pp. 54-61, 89-90, 101-102.

[17] D.11-01-025, pp. 20-24, 35-36, 44.

[18] D.11-01-026, pp. 16-18, 27-29.

[19] D.10-03-021, Finding of Fact (FOF) 9, p. 89.

confidential information from all LSEs, since non-IOUs represent a considerable portion of total load. The information could be submitted to the Energy Division and then shared on a blind and aggregated basis. As shown in Table 1 below, despite representing only 0.3% of total utility distribution company (UDC) customers, DA customers accounted for approximately 10.1% of total UDC load as of December 31, 2010. The Joint Parties also projected that in 2011, non-IOUs will represent 12% of the load subject to the 20% RPS requirement.[20]

DRA supports using publicly available, transparent REC market values to determine the market price of RPS resources when this information becomes available. In the event that this information is not available, DRA supports developing an interim proxy price that is either agreed upon by all parties or decided by the Commission based on parties' input. There is no perfect solution to this problem, so the Commission may have to determine which proposal is the most appropriate and reasonable. Below is DRA's analysis of the proposals for determining the market value of RPS resources.

Table 1

Direct Access Load and Customers as of December 31, 2010

Activities	Total
1) Total Direct Access Customers	32,814
2) Total UDC Customers	11,516,053
3) Percent Direct Access Customers	0.3%
4) Total Direct Access Load (MWh)	18,806,798
5) Total UDC Load (MWh)	186,164,992
6) Percent Direct Access Load (MWh)	10.1%

Source: California Public Utilities Commission http://www.cpuc.ca.gov/PUC/energy/Retail+Electric+Markets+and+Finance/Electric+Markets/Direct+Access/, accessed on February 22, 2011.

1. PG&E Proposal

PG&E proposes to determine the market value of RPS resources using a transparent, published REC index that represents the value of renewable generation in

[20] Joint Parties' Testimony – Part 1, p. 25.

California.[21] PG&E anticipates that a transparent REC market will be available by the third quarter of 2011. PG&E also anticipates that transparent REC indices will be included with the development of a REC market. If a transparent, published REC index has not been developed by the time a decision is issued on the Phase III issues, PG&E suggests that parties develop an interim proxy market value using the information from the IOU's energy resource recovery account (ERRA) forecast application. However, PG&E did not provide additional information on the process for developing an interim proxy price.

DRA finds the proposal to use a transparent, published REC index to determine the value for RPS resources reasonable. In the event that published REC indices are not readily available, it is reasonable to have the parties develop an agreed upon interim proxy price, though the task may be difficult, given the parties' disagreement. DRA believes the Commission may have to determine an interim proxy price based on parties' inputs.

2. SCE and SDG&E Proposal

SCE and SDG&E propose to determine the market value of RPS resources using the United States Department of Energy's (DOE) survey of reported contract premiums for renewable energy in the Western United States. DRA recommends conducting further studies before considering this proposal due to the concerns of the Joint Parties. The Joint Parties pointed out that green pricing program premiums may not reflect the cost of RPS resources, since the premiums are merely invested in green power sources as opposed to paying for an additional kilowatt-hour of green power.[22]

According to the DOE website, the survey data is based on utility green pricing programs, an optional utility service that allows customers an opportunity to support a greater level of utility company investment in renewable energy technologies. Participating customers pay a premium on their electric bills to cover the incremental cost

[21] PG&E Testimony – Chapter 1, pp. 13-14.

[22] Joint Parties' Testimony – Part 1, pp. 26-27.

of additional renewable energy.[23] DRA concludes that there is insufficient information at this point to determine how much revenue is generated by the voluntary green pricing program premiums, and how much additional RPS resources are procured as a result.

3. Joint Parties Proposal

The Joint Parties propose to determine the market value of RPS resources using confidential IOU RPS resource contract prices for resources that began delivery in the current year and those projected to begin delivery in the following year, subject to verification by the CPUC Energy Division.[24] The proposal will only use average IOU RPS resource contract prices from the first two contract years, regardless of contract duration. In DRA's view, this proposal fails to capture the benefit of long-term contracts, overestimates the average cost of front-loaded generation facilities, and excludes contract costs of other LSEs. The Joint Parties' own analysis also revealed that Marin Energy Authority (MEA) was able to purchase RPS resources at a price below the IOU's 2010 and 2011 RPS resource procurement costs. Therefore, DRA does not support this proposal.

Under the Commission's long-term procurement plan (LTPP) and RA programs, all LSEs have the obligation to acquire sufficient reserves for its customer loads, and most procure a range of short-, medium-, and long-term contracts. In particular, the IOU's RPS resources may come from long-term energy contracts and/or generation ownership. Long-term contracts can offer protection from the highly volatile energy markets, and are usually priced higher than spot market prices. Long-term contracts also provide a reliable supply of energy at a predetermined price for a fixed time period. Some of the benefits of long-term contracts are difficult to quantify. Yet, it is still important to take these unquantifiable attributes into consideration when comparing the costs of contracts of different durations.

[23] http://apps3.eere.energy.gov/greenpower/markets/pricing.shtml?page=0, accessed on February 1, 2011.

[24] Joint Parties' Testimony – Part 1, pp. 24-26.

The IOUs also indicated that some RPS resources are generated from utility owned generation (UOG) facilities, which are often front loaded, meaning prices are higher in early years and lower in later years. The lower prices in the later years balance out the higher prices in the early years to make overall costs comparable to non-front loaded facilities. In order to compare apples to apples, the levelized costs of front-loaded facilities should be compared to the levelized costs of facilities that are not front-loaded to account for the price balancing effect over time.

In DRA's view, the Joint Parties' proposal to use only contract costs from the first two delivery years heavily discounts the benefit of long-term contracts by ignoring the fact that renewable energy would be delivered under the terms and conditions of the long-term contract. The Joint Parties' proposal also fails to capture the savings from later contract years, especially for front-loaded UOG resources. Failure to recognize these long-term benefits would result in an overestimation of the total cost of RPS eligible resources.

The Joint Parties' proposal relies on confidential RPS contract information, but the Joint Parties suggested that their RPS contract information, which includes community choice aggregations (CCAs) and ESPs, be withheld. The Joint Parties' rationale for relying only on confidential IOU data is that the IOUs are the counterparties to the vast majority of renewable transactions in the State, and this information is readily available in the IOU's ERRA forecast applications. However, as shown in Table 1 above, DA customers alone accounted for approximately 10.1% of total UDC load as of December 31, 2010. In addition, the Joint Parties also projected that in 2011, non-IOUs are projected to represent 12% of the load subject to the 20% RPS requirements.[25] Failure to account for RPS contract information from LSEs representing such a considerable portion of total UDC load would reduce the accuracy of the estimated market value for RPS resources.

[25] Joint Parties' Testimony – Part 1, p. 25.

Finally, the Joint Parties contradict their claim that the IOU's RPS resource contract price represents the market price for RPS resources with evidence that another LSE was able to purchase RPS resources at a price below the IOU's 2010 and 2011 RPS resource procurement costs.[26] The Joint Parties' testimony estimated that PG&E's average 2010 RPS procurement cost is approximately $145/MWh, SCE's average 2011 RPS and non-RPS procurement cost is approximately $150/MWh, while MEA's RPS procurement cost is only approximately $110/MWh. Marin Clean Energy's (MCE) website also provided a link to an article in the Marin Independent Journal, which reported that MEA will pay G2 Energy about $100/MWh for 25,000MWh of renewable electricity per year from landfill gas facilities over at least 20 years, scheduled for delivery in mid- to late 2011.[27] If MEA is able to purchase RPS resources below the average IOU RPS resource contract price, then this clearly shows that the average IOU RPS resource contract price is not the market price for RPS resources.

4. CLECA-CMTA Joint Proposal

CLECA-CMTA proposes to determine the market value of RPS resources using confidential IOU renewable resource contract prices that will be used to serve bundled customers in the upcoming ERRA year, subject to verification by the CPUC Energy Division and/or an independent third party non-market participant.[28] CLECA-CMTA acknowledges that renewable power provides some RA capacity, so the RA adder for the renewable portfolio would have to be reduced by the amount of RA value provided by the utility's net qualifying capacity (NQC). CLECA-CMTA also acknowledges that this process would involve yet another calculation by the Energy Division or a third-party consultant.

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[26] Joint Parties' Testimony – Part 1, pp. 12-18.

[27] Marin Independent Journal, "Marin Energy Authority signs deals to buy more power as it prepares to expand," dated January 24, 2011, by Richard Halstead, available at http://www.marinij.com/sananselmo/ci_17186476, accessed on February 15, 2011.

[28] CLECA-CMTA Testimony, pp. 11-12.

The CLECA-CMTA proposal is basically a modified version of the Joint Parties' proposal, with additional features for capturing the quantifiable benefits of long-term contracts and a different methodology for accounting for RA capacity. Despite these improvements, this proposal is still subject to some of the pitfalls of the Joint Parties' proposal, such as not including information from all LSEs, accuracy problems, and heavy reliance on analysis and verification by the Energy Division or a third party non-market participant. Therefore, DRA also opposes this proposal.

5. L. Jan Reid Proposal

L. Jan Reid recommends adopting the proposal in The Utility Reform Network's (TURN) post-workshop comments which maintains the current MPB methodology such that the PCIA would incorporate the entire green attribute premium inherent in the IOUs' costs of procurement to meet the RPS goals, but non-utility retail suppliers would be given RPS credit for their proportionate share of the IOU's RPS purchases.[29] As indicated in DRA's post-workshop comments, this proposal was discussed and garnered considerable support at the workshop.[30]

Although this proposal avoids the difficult task of determining an appropriate market value for RPS resources, many logistical questions remain. Additional information is necessary to determine when and how the RPS credit transfer should occur, who should be responsible for any administrative and transactional costs that may arise, and whether the credit will count towards the 25% limit on REC usage. DRA request that more detailed information be provided to help answer these and other questions parties may have before the Commission seriously considers this proposal.

B. Resource Adequacy Capacity Value

DRA supports the idea of using accurate and publicly available, transparent data. However, DRA reiterates its concerns over using the maximum CAISO backstop price to determine the RA capacity value, in light of the fact that RA prices have been trading at

[29] L. Jan Reid Testimony, pp. 11-12.

[30] Opening Comments of the Division of Ratepayer Advocates on Workshop Issues (DRA Opening Comments), January 14, 2011, p. 2.

well under the $41/kW-year interim capacity procurement mechanism (ICPM) price.[31] DRA is also concerned by SCE's assertion that without a six month advance notice, it may not be possible to find a buyer for excess RA capacity in the absence of a short-term or spot market for RA capacity, so no value may be realized for the capacity.[32] SCE also indicated that the RA market is very illiquid and even with six months' advance notice it may not be possible to realize any value for the excess capacity. Therefore, DRA recommends the Commission reject the CAISO's ICPM as the market value for RA capacity. DRA is open to reviewing reasonable proposals for determining the value of RA capacity. However, in the absence of an alternate proposal, the current RA adders should remain in place.

C. Load Profile Weighing of the Market Price Benchmark

DRA understands there is a tradeoff between accuracy and transparency, but still prefers to maintain the current method of using publicly available, transparent data to determine the on-peak and off-peak weights for the MPB. PG&E and SCE propose using non-public IOU generation profiles to determine the on-peak and off-peak weights while acknowledging that generation profiles may differ by PCIA vintage due to a different generation mix. PG&E and SCE also acknowledge that calculating a different set of on-peak and off-peak weights for each PCIA vintage would be overly burdensome.[33] Therefore, PG&E and SCE suggest using only the current year weighting factor for all vintages for administrative ease. In DRA's view, under this proposal, nothing is gained, because the estimate will be accurate for the current PCIA vintage, but will be inaccurate for all other PCIA vintages.

There is no rationale for switching from publicly available, transparent data to confidential data, if it does not result in a more accurate estimation. Administrative ease is not an acceptable justification for reducing the number of calculations, and thus

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[31] DRA Testimony, pp. 5-6.

[32] SCE Testimony, p. 8.

[33] PG&E Testimony – Chapter 1, p. 15, and SCE Testimony, pp. 27-28.

reducing the accuracy of the estimation. The Commission should only consider using confidential IOU generation profiles if the actual on-peak and off-peak weights for each PCIA vintage were calculated. (It is also important to note that this same problem exists under the Joint Parties' proposal to use the confidential IOU bundled load profiles as opposed to the confidential IOU generation profiles.)[34]

D. ESP Financial Security Requirement

The most contentious ESP financial security requirement issues are: (1) what should be included in the "re-entry fees" referenced in Public Utilities (PU) Code Section 394.25(e) and, (2) who should be responsible for paying the re-entry fees? DRA believes a resolution on the legal issues will resolve the issue surrounding who is responsible for the re-entry fees and provide guidance on which bonding methodology is the most appropriate and reasonable.

Despite the absence of a resolution on the legal issues, the parties' testimony suggests that the administrative fees imposed by the utility for implementing the customer's change of service request should be included in the re-entry fees. The parties' testimony also suggests that the incremental cost of TBS rates should either be included in the re-entry fees or be paid for directly by the involuntarily returned customer. Some parties stated that the TBS rate essentially served the same purpose as a re-entry fee but is not technically a re-entry "fee" for which the bond amount should cover. It is also important to note that RA and RPS costs will be accounted for and don't need to be included in the re-entry fees, since the parties have agreed to update the TBS rates to reflect RA and RPS charges.

Although there is some agreement among parties as to the incremental cost of TBS rates, disagreement remains over the TBS rate duration. SCE and SDG&E argue that the TBS rate duration should be extended to a year, since the cost impact of a mass involuntary return of DA customers to IOU procurement service can extend well beyond

[34] Joint Parties' Testimony – Part 1, pp. 29-30.

the price of the TBS rate for six months, or even one year.[35] A one-year TBS period is also consistent with the one-year advance written notice requirement to the Commission and IOU of the CCA's intention to discontinue its CCA service.[36] CLECA-CMTA and the Joint Parties argue that the TBS rate duration should only be six months to be consistent with the TBS duration of customers returning to bundled service voluntarily without six months' advance notice.[37] CLECA-CMTA also argue that the high utility reserve margins forecasted for the IOUs would limit the risk of insufficient supplies to serve a mass return of DA customers to bundled service. On the other hand, CLECA-CMTA did not address the potential impact on the IOU's RA and RPS requirements, which are expected to increase as total load served increases.

The ESP bonding methodology proposals appear to be split by the expected outcome on the legal issues pertaining to the ESP financial security requirements. The CLECA-CMTA, Joint Parties, and SDG&E proposals all assume that the IOUs are permitted to place involuntarily returned customers on the TBS rate, so the re-entry "fee" is limited to the administrative fees. The PG&E and SCE proposals assume that involuntarily returned customers must be placed on the same bundled service rate as other bundled customers immediately; in their view, the re-entry "fee" must cover both the administrative fees and the incremental cost of going on the TBS rate. In DRA's view, in instances where DA customers are involuntarily returned to bundled service as a result of the ESP unilaterally discontinuing DA service, the ESP, not the DA customers, should be responsible for all re-entry fees and incremental costs. Involuntarily returned DA customers should not be penalized for circumstances beyond their control. DRA recommends that at a minimum, the bonding requirement be sufficient to cover the administrative fees and incremental cost of TBS rates.

Regardless of how the legal issues are resolved, all parties agree that the purpose of the bonding requirement is to prevent cost shifting to bundled customers in the event

[35] SCE Testimony, pp. 43-45 and SDG&E Testimony – Chapter 1, pp. 7-8.

[36] PG&E Electric Rule No.23.S, SCE Electric Rule No. 23.S, and SDG&E Electric Rule No. 27.S.

[37] CLECA-CMTA Testimony, pp. 22-24 and Joint Parties' Testimony – Part 2, pp. 14-17.

customers are involuntarily returned to bundled service. DRA believes all CCA/DA customers should be informed of all risks and costs associated with CCA/DA service prior to signing up. In the event the Commission determined that involuntarily returned customers are responsible for the incremental cost of TBS rates, DRA urges the Commission to order the IOUs to inform all potential and existing CCA/DA customers that they will be responsible for the incremental cost of TBS rates in the event they are involuntarily returned to bundled service. This will ensure that customers are aware of the risks prior to signing up and provide ample time for existing CCA/DA customers to provide six months' advance notice and return to bundled service voluntarily.

APPENDIX A

QUALIFICATIONS AND PREPARED TESTIMONY
OF
KE HAO OUYANG

Q.1. Please state your name and business address.

A.1. My name is Ke Hao Ouyang. My business address is 505 Van Ness Avenue, San Francisco, CA 94102.

Q.2. By who are you employed and what is your job title?

A.2. I am employed by the California Public Utilities Commission as a Public Utilities Regulatory Analyst III in the Electric Pricing and Consumer Program Branch of the Division of Ratepayer Advocates ("DRA").

Q.3. Please describe your educational background and professional experience.

A.3. I received a Bachelor of Arts Degrees in both Applied Mathematics and Economics from the University of California, Berkeley in 2005.

I joined the Electric Pricing and Consumer Program Branch of the Division of Ratepayer Advocates in June 2010, and work on Community Choice Aggregation, Direct Access, and Demand Response related issues.

Q.4. What is your area of responsibility in the Direct Access proceeding?

A.4. I am sponsoring DRA's prepared testimony in the Direct Access proceeding.

Q.5. Does this conclude your reply testimony?

A.5. Yes, it does.

CERTIFICATE OF SERVICE

I hereby certify that I have this day served a copy of the foregoing document "**REPLY TESTIMONY ON THE METHODOLOGY FOR CALCULATING DEPARTING LOAD NON-BYPASSABLE CHARGES, DIRECT ACCESS SWITCHING RULES, ELECTRIC SERVICE PROVIDER FINANCIAL SECURITY REQUIREMENT AND TRANSITIONAL BUNDLED SERVICE RATE**" in **R.07-05-025**.

A copy was served as follows:

[X] **BY E-MAIL**: I sent a true copy via e-mail to all known parties of record who have provided e-mail addresses.

[ ] **BY MAIL**: I sent a true copy via first-class mail to all known parties of record.

Executed in San Francisco, California, on the **25** day of **February**, **2011**.

/S/ MARTHA PEREZ

Martha Perez