Decision **PROPOSED DECISION OF ALJ PULSIFER** **(Mailed February 9, 2010)**

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

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

DECISION REGARDING INCREASED LIMITS FOR DIRECT ACCESS TRANSACTIONS

Table of Contents

DECISION REGARDING INCREASED LIMITS FOR DIRECT ACCESS TRANSACTIONS

1. Summary

By this decision, we authorize and implement a plan for increased limits in the allowed level of direct access (DA) transactions within the service territories of California's three major investor-owned electric utilities: Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric.

The authorization for increased limits in DA transactions is implemented in accordance with the provisions of Senate Bill (SB) 695 (Stats. 2009, ch. 337). Among other issues, SB 695 amends the previously effective suspension of DA, and requires the Commission to authorize increases in the maximum kilowatt-hour limit on DA transactions. Effective April 11, 2010, all qualifying customers will be eligible to take DA service, up to the new maximum cap subject to the conditions as set forth herein. The increased DA allowances shall be phased in over a four-year period, subject to annual caps in the maximum DA increase allowed each year. DA remains suspended, except as provided by this decision implementing SB 695. Existing rules and processes currently in place for DA service shall remain in place, except for changes specified herein as necessary to implement the provisions of SB 695.

This decision only addresses those implementation issues that must be resolved in order to begin the process of new enrollments of DA load effective April 11, 2010. Additional issues that relate to SB 695 implementation will be addressed expeditiously in a subsequent decision.

2. Background

Through direct access (DA), eligible retail customers have the choice to purchase electric power directly from an independent electric service provider (ESP) rather than only through an investor-owned utility (IOU). DA was first instituted as an option for retail electric service in 1998, as part of an industry restructuring program to bring retail competition to California electric power markets.[1]

The electric industry restructuring program was cut short, however, by the events of 2000-2001 which led to extraordinary wholesale power cost increases, threatening the solvency of California's major electric utilities and the reliability of electric service. On February 1, 2001, AB 1 from the First Extraordinary Session (Ch. 4, First Extraordinary Session 2001) (AB1X) was signed into law, implementing measures to address the energy crisis. Among other measures, AB1X required the California Department of Water Resources (DWR) to procure electric power supplies sufficient to meet the net short for customers of the IOUs.[2]

DWR formally began procuring electric power for customers in the service territories of the three major IOUs in early 2001. AB1X authorized DWR to recover its power costs from electric charges established by the Commission. (Water Code § 80110.)

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

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

To ensure that DWR procurement costs were assigned fairly and recovered from a stable customer base, the Legislature, among other measures, suspended the DA program. Pursuant to AB1X, the Commission suspended the right to enter into new contracts for DA after September 20, 2001,[3] permitting no new DA contracts, but allowing preexisting contracts to continue in effect. The Commission opened this proceeding to investigate conditions whereby DA may be reinstituted in the future, although the suspension has continued in effect up until the present time.

On October 11, 2009, Senate Bill (SB) 695 was signed into law as an urgency statute. SB 695 adds Section 365.1 (b) to the Public Utilities Code, which states in pertinent part:

> The commission shall allow individual retail nonresidential end-use customers to acquire electric service from other providers in each electrical corporation's distribution service territory, up to a maximum allowable total kilowatt hours annual limit.

Except for this express authorization for increased DA transactions under SB 695, the previously enacted suspension of DA transactions remains in effect until repealed by legislation, or until additional DA transactions are otherwise authorized.

Within six months from the effective date of SB 695[4] or July 1, 2010, whichever is sooner, the Commission must adopt and implement a schedule to begin the phase-in of authorized increases in the maximum amount of DA transactions over a period of at least three years, but not more than five years.

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[3] *See* D.01-09-060 and Pub. Util. Code §§ 366 or 366.5.

[4] SB 695 was chaptered on October 11, 2009 and as urgency legislation, took effect immediately. Six months from the effective date of SB 695 is April 11, 2010.

The allowable limit of DA power supplied by other providers in each electric utility's distribution service territory will be increased to the maximum allowable annual limit for that utility's distribution service territory as of the effective date of SB 695. The Commission may, if appropriate, modify its currently effective rules governing DA transactions, but such review shall not delay the phase-in schedule.

In order to expeditiously implement SB695, the assigned Commissioner initiated this sub-phase of the proceeding by issuing a ruling amending the scope of this proceeding to address issues as necessary for implementing the provisions of SB 695 relating to DA. By ruling dated November 18, 2009, the assigned Commissioner identified the pertinent DA provisions of SB 695 to be addressed in this proceeding, and established a schedule to meet the SB 695 timing requirements. Parties filed comments on the scope of issues to be addressed in this sub-phase on December 7, 2009. The assigned Commissioner issued a ruling modifying the scope of issues to be addressed by ruling dated December 17, 2009. The record was developed through the filing of written comments, with one workshop. No evidentiary hearings were necessary.

Substantive comments were filed on January 5, 2010.[5] A workshop was convened on January 11, 2010, to facilitate discussion and seek consensus on issues in dispute. Reply comments were filed on February 1, 2010.

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[5] Opening Comments and/or reply comments were filed by the California Alliance for Choice in Energy Solutions and the Alliance for Retail Energy Markets (CACES/AReM), the Direct Access Customer Coalition (DACC), Pacific Gas and Electric Company (PG&E), BP America (BP), the California Large Energy Consumers Association (CLECA), California Manufacturers and Technology Association (CMTA), Commercial Energy of California (CEC), the Division of Ratepayer Advocates (DRA),

Footnote continued on next page

3. Authorized Increases for Direct Access Cap

We herein authorize increased limits on the maximum level of DA transactions that may be allowed beginning effective April 11, 2010[6]. The basis for the increased allowances is prescribed by Sec. 365.1 which states that the maximum limit:

> … shall be established by the commission for each electrical corporation at the **maximum total kilowatthours supplied by all other providers to distribution customers of that electrical corporation** during any sequential 12-month period between April 1, 1998, and the effective date of this section. (Emphasis added.)

The statute defines "other provider" as any person, corporation, or other entity that is authorized to provide electric service within the service territory of the electrical corporation, but does not include sales to or by a community choice aggregator. Individual retail non-residential end-use customers in an electrical corporation's service territory will be allowed to acquire electric service from providers other than the electrical corporation up to a maximum total kilowatt hour (kWh) annual limit. In response to the Administrative Law Judge (ALJ) ruling issued November 18, 2009, each of the IOUs provided the relevant data identifying the applicable amount of DA load subject to the increased DA cap pursuant to the requirements of SB 695.

The Utility Reform Network (TURN), the Natural Resources Defense Council (NRDC), Southern California Edison Company (SCE), the Safeway Parties (Safeway), San Diego Gas & Electric Company (SDG&E), Silicon Valley Leadership Group, School Project for Utility Rate Reduction, the California State Universities, and Customized Energy Solutions, LTD.

[6] The implementation date of April 11, 2010 represents the time limit required to begin implementation under SB 695, representing six months from the statute's effective date.

The IOUs and the Commission's Energy Division provided clarification at the workshop of the differences between the numbers in the December 3, 2009 and December 29, 2009, informational filings and the numbers provided in the IOUs' monthly DA activity reports. The general consensus among parties at the workshop was that formal independent verification of the data submitted by the IOUs was not necessary, and that the time required to implement such verification process could unduly delay the reopening of DA. The Commission already has the ability to verify the load data provided by the IOUs in case of a dispute.

The applicable new DA load increase relating to each of the IOU service territories is set forth as follows:

		In gigawatt hours		
Line No.		**SCE**	**PG&E**	**SDG&E**
1	Load Cap Pursuant to SB 695	11,710	9,520	3,562
2	Existing Base Line DA	7,764	5,574	3,100
3	New DA Load Allowance (Line 1 less Line 2)	3,946	3,946	462

The new load eligible for DA service represents a relatively small portion of each of the utilities' portfolios, involving less than 10 million megawatt hours (MWh) of annual usage across the entire state. This amount is less than 6% of the entire load served, and is much less than the annual variation in electricity consumption across the state due to the weather and the economy.

The SB 695 cap limits any potential risk associated with reopening of DA by eliminating uncertainty associated with load migration. The adopted phase-in schedule will provide enough lead time for the IOUs to account for small shifts in load and thereby avoid unwarranted cost shifting and stranded load.

3.1. Discussion

We conclude that the utilities reported load figures reasonably comply with the criteria set forth in SB 695. We adopt those figures for use in this decision in implementing SB 695 caps. The SCE figures require some explanation.

In its opening comments, SCE set forth the overall DA cap under SB 695 and the baseline amount for SCE's service area,[7] as follows:

- Based on kWh sales data maintained in SCE's billing system, the maximum recorded sales to SCE distribution customers by all other providers for any sequential 12-month period was 11,710 GWh from July 2003 through June 2004.
- SCE's current level of DA in its service territory, expressed as the annual load of those customers taking DA as of November 30, 2009, is 7,627 GWh.

Subsequent to the filing of these comments, SCE subsequently amended its initial calculation of DA baseline amounts to recognize the effects of the MWh set-aside granted for the City of Cerritos (Cerritos). The Commission issued D.10-01-012 determining the rights of Cerritos under AB 80. As a result of this decision, SCE revised its reported baseline of current DA load in its service territory to include the set-aside of MWh for Cerritos, which the Commission found to be required by AB 80.

In D.10-01-012, the Commission concluded that AB 80 authorizes Cerritos to enter into direct transactions with any retail end-use customer in its jurisdiction on an opt-in basis up to Cerritos' generation entitlement share of the

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[7] *See* SCE Opening Comments at 7, citing its December 3 and December 29, 2009 data response filed in this proceeding.

Magnolia Power Plant (MPP) output.[8] D.10-01-012 clarified that AB 80 does not require Cerritos to provide *opt-out* service, as is provided by community choice aggregators.[9]

Cerritos currently serves about 13.02 megawatts (MW) of opt-in, non-residential load. However, D.10-10-012 makes clear that Cerritos has a right "to sell all of its entitlement share [of MPP's output] on a retail basis."[10] SCE has calculated Cerritos' share of the annual MPP output as 137.5 gigawatt hours (GWh).[11] Therefore, under D.10-01-012, Cerritos is entitled to serve 137.5 GWh of annual, opt-in load.

D.10-01-012 affects the implementation of SB 695 in the following manner:

- Because Cerritos is not a community choice aggregator, it is considered to be an "other provider" within Section 365.1 of the Public Utilities Code. Therefore, the maximum allowable total kWh annual limit in SB 695 should include customers' acquisition of electrical service from Cerritos.
- Unlike all other providers, Cerritos has been found by the Commission to have a right to sell a certain annual amount of energy via direct transactions to retail end-use customers. This necessitates a permanent "set-aside" for Cerritos under SB 695's overall annual kWh cap, thereby increasing the baseline for SCE's service area.

Accordingly, SCE's current level of DA in its service territory, expressed as the annual load of those customers taking DA as of November 30, 2009, *plus*

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8 *See generally* D.10-01-012, issued January 21, 2010 in A.09-06-008.

9 *See id.* at 7-8.

10 *See* D.10-01-012 at 13.

11 SCE must file an advice letter to set forth Cerritos' share of the MPP output; therefore SCE's calculation is subject to Commission review for compliance with D.10-01-012.

Cerritos' set-aside of 137.5 GWh under D.10-01-012, is adjusted to 7,764.5 GWh. Cerritos' set-aside will not be available for other providers, even if Cerritos does not sell all 137.5 GWh annually to retail end-use customers in SCE's service area.

4. Phase-In Schedule for Increased Cap

4.1. Parties' Positions

The statute requires that the new DA load growth be phased in over a period of not less than three years and not more than five years.[12] Certain parties express support for a three-year phase-in period, arguing that it offers the most efficient and consumer-friendly approach. PG&E, SDG&E, and various parties representing DA interests believe that a three-year phase-in period will accommodate IOU long-term procurement and resource planning needs. All parties generally agree to defining the duration of each phase-in interval as a calendar year, with the exception of the first year, which would cover only the period from the effective date of this decision through December 2010.

PG&E recommends an annualized usage cap increment of 1,500 GWh/year for each year of the phase-in period. If additional DA load is fully subscribed each year, the phase-in would then be completed in three years. If, however, DA demand varied from year to year, the cap would guard against the potential for extreme load changes from any one year to the next, but could extend the phase-in period up to the five years allowed under the statute.

PG&E states that establishing an annual cap will address the potential procurement issues that could otherwise occur if there were extreme differences in demand for new DA from one year to the next during the phase-in period.

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[12] Pub. Util. Code § 365.1(b).

To provide additional flexibility, however, PG&E expresses a willingness to employ a "soft" cap each year of the phase-in period to allow a customer whose load may slightly exceed the annual cap to proceed with enrollment onto DA service. PG&E believes that an additional 5% over the annual cap is reasonable.

A group of parties (Joint Parties) entered into discussions after the initial round of comments were filed, and agreed upon a joint proposal.[13] In entering into the joint proposal, some of the Joint Parties modified their previous position set forth in opening comments.

The Joint Parties propose a four-year phase-in period, structured to allow up 50% of the room available under the cap in the first year, up to 70% in the second year, up to 90% in the third year, and up to 100% in the fourth year of the phase-in period. The Joint Parties argue that a four-year phase-in with a larger increment available initially, will accommodate a larger influx while avoiding the need for customers to rush to get in under the cap at the outset if they are not ready to do so.

SCE argues that allowing excessive DA enrollment in the first year could detrimentally impact the administration and processing of Direct Access Service Requests (DASRs) as well as the utility's ability to meet procurement requirements to accommodate changes in load.

TURN joins with the other Joint Parties in proposing a four-year phase-in period. Alternatively, assuming that the Commission is convinced that a rush of

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13 Parties sponsoring the joint proposal were TURN, SCE, CACES/AReM, the California State Universities, DACC, Silicon Valley Leadership Group, and School Project for Utility Rate Reduction.

new customers could reasonably be expected at the initial reopening, TURN believes that a three-year phase-in might be warranted. TURN supports the establishment of annual GWh caps in advance, independent of the amount of actual load migration in prior years of the transition.

TURN believes that monitoring must continue beyond the initial phase-in period to keep up with changes in DA load. The level of the DA cap will remain in effect beyond the end of the phase-in period unless or until changed by future legislation. The IOUs will need to know on an ongoing basis whether or not they can accept new DASRs, and ESPs will need to know whether they is any further room available for marketing purposes.

CLECA and California Manufacturers & Technology Association (CMTA) jointly argue that the Commission should phase in the reopening over the full five-year period, rather than a three-year period. DRA agrees with CLECA and CMTA. CLECA believes that three-year phase-in period, with as much as 75% of the available headroom made available to new customers during a 60-day open-enrollment period, will create a "gold rush" mentality, resulting in a variety of negative consequences. For example, CLECA expresses concern that customers would be motivated to act quickly, perhaps precipitously, to exercise their option to acquire DA, without having adequate time to analyze and absorb the many factors that should be weighed in such a decision. CLECA also argues that a gold rush environment would tend to increase transactional costs, particularly for the IOUs' processing of new requests to switch to DA.

CLECA notes that if a DA-eligible customer returned to bundled service in July 2009, that customer could return to DA service immediately during the initial enrollment period after the April 2010 reopening of DA, but if the customer did not make the election during the initial enrollment period, the customer would have to wait more than two years after that reopening to make its return to DA service. CLECA expresses concern that an existing DA-eligible customer could find that it had lost entirely the ability to return to DA if the Commission were to permit a rapid phase-in of the new DA service for non-DA-eligible customers.

CLECA also proposes that the Commission should permit additions per year of no more than 20% of the total allowed increment in new DA. CLECA argues that this slower pace of phase-in would reduce transitional and generational planning issues.

CEC suggests a three-year phase-in schedule, with 75% of total load permitted in the first year, and the remaining 25% spread equally over the following two years. In this manner, subsequent adjustments can be made based on the first year's experience.

4.2. Discussion

We have considered the range of proposals as to the duration and pacing of phase-in, ranging from three years to five years. We conclude that a three year period is too short, and could cause an excessive surge in demand for new DA, resulting in potential negative consequences, as noted by CLECA and DRA. We likewise conclude that a five-year phase-in period is too long, and would unduly prolong the phase-in of new DA. We shall therefore adopt a four-year phase-in period. Our adopted phase-in generally incorporates the Joint Parties' proposed four-year phase-period, but we shall apply a more gradual pace in annual DA limits compared with the Joint Parties' proposed first-year limit of up to 50%. A front-loading of 50% in the first year could create a surge in demand for DA concentrated in the open enrollment window between mid April and June 30, 2010. This surge could be amplified especially since Year 1 will be truncated to nine months with an April 11 start date. Joint Parties' proposal for a cumulative DA load cap of 70% by the second year only leaves 20% in the second year if enrollment reaches 50% in the first year. As a result, customers could feel pressured to rush to sign up before the June 30th deadline.[14] The truncated first year could create an undue burden on the program's first year.[15]

We shall therefore adopt annual DA caps of up to 35% in the first year, up to 70% in the second year, up to 90% in the third year, and up to 100% in the fourth year. Limiting the adopted limits in this manner reduces the burden on potential DA customers to sign up in the first year, and correspondingly increases the load available for new DA customers in the second year. Moderating the first year's cap to 35% will help prevent the potential for customers to become aggrieved by being rushed into signing up for direct access without adequate time to consider all of the factors involved.

We conclude that the four-year phase-in period, with the related annual limits on new enrollments, strikes a reasonable balance, providing for an orderly implementation schedule that is manageable by the IOUs while still satisfying the requirements of SB 695 in a timely manner. We find that adopted phase-in schedule reasonably addresses the relevant concerns that must be balanced in crafting the appropriate pacing of the phase-in process. The first year of the phase-in covers the partial period beginning on the effective date of this decision,

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14 Appendix 2 at 4, 8.a., "Customers may submit 6-month advance NOIs starting July 1, 2010 to switch to DA in 2011."

15 Reply Comments of The Division of Ratepayer Advocates on Assigned Commissioner's Ruling Regarding Issues Associated With Senate Bill 695 Relating To Direct Access Transactions (February 1, 2010) at 5.

and continuing through the end of the 2010 calendar year. Each subsequent phase-in period shall cover a full 12-month calendar year.

If any annual allocation of DA allotments under the cap is not fully subscribed in any one year, the unused portion shall be rolled over to the subsequent years. Each individual year's DA limit shall stand alone, and not be dependent on the amount of actual migration in prior years of the phase-in.

All DA-eligible customers will be free to switch to DA at any time, subject to the applicable switching rules, as long as room exists under the overall cap. Monitoring shall continue beyond the phase-in period because the cap on DA will remain in effect and must be enforced unless or until changed by future legislation.

5. Process to Implement New DA Enrollments

5.1. Parties' Positions

The Joint Parties presented a detailed proposal for a utility enrollment process during the phase-in period that is set forth in Appendix 2 of this decision. SCE joined in the Joint Party proposal. The Joint Party proposal calls for an initial open enrollment period going through June 30, 2010, with a temporary one-time waiver of the 6-month advance notice requirement and one-time waiver of the bundled service commitment under Rule 22.1. The details of the proposal for the receipt, review, and approval of customer requests to switch to DA service under SB 695 are set forth in detail in Appendix 2 of this decision.

PG&E presented its own separate proposal for enrollments. Every customer would be required to submit a notice to their IOU that they want to switch to DA service. Upon acceptance of a customer notice to switch to DA service, PG&E will provide instructions for DASR submittal in a confirmation letter. If a valid DASR is submitted during the DASR window indicated in the customer confirmation letter, the customer will switch on the date indicated. If no DASR is received by the close of the DASR window, the account will be placed on Transitional Bundled Service or "safe harbor" status. That means it will be billed on the Transitional Bundled Commodity Cost (TBCC) rates and given an additional 60 days in which to submit a valid DASR. If no DASR is submitted during this additional 60-day period, the customer notice is cancelled, the account continues on the TBCC rates for an additional six months, and then the account is committed to bundled portfolio service for a three-year period. In addition to following the existing switching rules, this would also discourage speculative submittals of customer notices, and allow customers who are serious about switching to DA service the ability to do so without the impediment of over-subscription of available load under the cap by more speculative participants.

SDG&E also presented its own proposal (as Attachment A of its February 1, 2010 Reply Comments) as to the processing protocols for enrolling customers under the provisions of the SB 695 cap. SDG&E's proposed approach is similar to the approaches proposed by SCE and CACES/AReM. SDG&E's process calls for the customer to submit a notice of intent (NOI) within the designated open enrollment period, subject to a daily batching process. SDG&E would apply a "soft cap," not to exceed 10% of the annual cap, in evaluating whether a request was to be approved. Customers would be notified within 20 calendar days as to whether their NOI was accepted. DASRs would be processed in accordance with SDG&E's Rule 25.

DACC points to the customer application and tracking process adopted for the California Solar Initiative as an example to follow for administering the DA allocations. As proposed by DACC, a customer interested in transferring load to

DA service would submit a "Customer-Originated Direct Access Service Request" (CODASR) to its local IOU(s). Each CODASR would correspond to a customer utility service identification (ID) account number, covering the entire load served through that ID, as measured by the preceding 12-month billing period. Customers submitting completed CODASRs would be allocated priority rights to the available DA capacity on a first-come, first-served basis. The customer would have 30 calendar days to complete negotiations with a supplier, and for the supplier to submit a traditional DASR for the customer. If no DASR was submitted on behalf of a customer within the 30-day period, the rights to the available DA capacity previously allocated to that customer would be allocated to the customer with the next lower priority of rights.

5.2. Discussion

We shall adopt an enrollment process for customers to sign up for direct access subject to the revised SB 695 limits under the provisions adopted in this decision, as set forth in Appendix 2 of this decision.

The adopted process incorporates the four-year phase-in discussed above. It also incorporates a uniform treatment of all qualifying customers, without a separate set-aside or preferential treatment of existing DA-eligible customers. We address this issue further in Section 6. We also adopt a two-day window for customers to correct NOI deficiencies. The two-day limit will facilitate timely processing of daily NOI batches.

In comments to the proposed decision, the Joint Parties argued that each IOU should be authorized to maintain a limited wait-list during the OEW to back-fill any room under the first-year allocation occupied by NOIs that are submitted but ultimately voided for failure to submit a DASR or correct a deficiency. We find this proposal to be reasonable, and shall incorporate a wait-list process into the adopted procedure set forth in Appendix 2.

The utilities shall begin placing submitted NOIs on an OEW wait-list on a first-come, first-served basis when or if the Year 1 allocation becomes fully subscribed during the OEW. There will be no wait-list after the OEW closes. The OEW shall be filled up to 25% of the Year 1 allocation. The IOU shall notify the customer that they are on the wait-list within 20 days after submission of the customer's NOI. Notifications to customers that they are eligible to come off the wait-list (on a first-come, first-served basis) shall be made by email within one business day of the utility's determination that space is available under the Year 1 allocation. All such notices shall be made no later than June 29, 2010, the last day of the OEW. The submission and processing schedule, as set forth in Appendix 2 shall apply.

Each IOU shall be required to indicate on its public website whether notices of intent to switch to DA service are being accepted, and to update this information regularly. This information should be sufficient to inform customers and ESPs whether there is room under the annual limits during the phase-in period or the overall cap after the phase-in. Each IOU shall notify all DA-eligible customers of their opportunity to obtain generation service from another provider of the Effective Date. Each IOU shall provide a link to the new DA provisions on their respective web sites and shall also provide additional notification via bill inserts and onserts. ESPs shall notify their customers of their procurement-related obligations.

6. Waiver of DA Switching and Notice Rules and Subsequent Rights to Acquire DA

6.1. Parties' Positions

Under current rules,[16] former DA customers currently receiving bundled utility service must provide six-months' notice in order to leave bundled utility service. The same six-month notice requirement applies for customers that switch back to DA. Also, a DA customer who returns to bundled service must commit to stay for at least a three-year period.

PG&E proposes that the current three-year minimum bundled service commitment for customers now on bundled portfolio service be waived for an initial implementation period, starting on the date established by the Commission and extending for 60 days. Absent such a waiver, existing Bundled Portfolio Service (BPS) customers may be precluded from switching to DA service if the maximum load cap is reached before these customers complete their three-year commitment period.

In addition to waiving the three-year commitment period, PG&E would support giving BPS customers a higher priority to return to DA compared with "new prospective" DA customers, limited to the initial implementation period.

SCE does not support providing a preference to existing DA-eligible load, but proposes that all DA-eligible customers be provided an equal opportunity to enroll in DA if they so choose. SCE supports a temporary, one-time waiver of the six-month advance notice requirement during the open enrollment period. SCE also supports a one-time waiver to all DA-eligible customers under current BPS commitments, so that these customers can take DA service at any time upon

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[16] *See* D.03-05-034 and D.03-06-035.

notice of intent (during the open enrollment) or a six-month advance notice (after the open enrollment), assuming that there is sufficient room under the annual limits or overall cap. SCE proposes that the three-year BPS commitment period continue to apply anytime that a DA customer returns to BPS.

After the open enrollment period ends, SCE proposes that the DA switching rules apply equally to all DA-eligible customers, including bundled service customers wishing to switch to DA for the first time, unless and until the Commission reviews and modifies these rules in a subsequent phase of the proceeding.

SCE proposes to establish a wait list and to enroll customers on DA service on a first-come, first served basis, as room becomes available under the annual limits or overall cap.

TURN argues that there is no compelling need for granting any special preference for load that is DA-eligible under the current rules. TURN believes that there is minimal risk that load that is DA-eligible under the current rules, and subject to the three-year minimum stay on bundled service will be "squeezed out" by new DA load. The highest annual figure reported by any of the IOUs for potential DA-eligible bundled load returning to DA service is 475 GWh for PG&E during the period from April 2010 through April 2011. That amount is only about 50% of the quantity proposed by TURN to be made available in the first year of the phase-in period. The other utilities and the other years for PG&E show an even smaller percentage.

TURN argues that no special set-aside preference should be granted to existing customers who are DA-eligible under current rules other than to allow them to terminate their three-year minimum commitment on bundled service in April of the year which the commitment would otherwise expire. In this manner, these customers could request DA service as soon as the next phase-in step occurs. TURN believes that such provision would be sufficient to prevent any DA-eligible customer from being "stranded" on bundled service because of the new total GWh cap on DA. TURN argues that updates on DA load should be posted at least monthly, and perhaps more frequently in a month when a utility's DA load is approaching the cap level.

TURN does not object to a temporary suspension of the six-month notice requirement for customers switching from bundled service to DA, but only during the first year of the phase-in period. TURN does not believe that a continued waiver period beyond the first year is necessary, because customers will be in a better position to provide notice in subsequent years of the phase-in period.

TURN proposes that any and all customers returning to bundled service from DA should remain subject to at least a six-month notice period during which time they would be subject to the Transitional Bundled Service (TBS) rate if they return to bundled service prematurely. TURN believes that at least a one-year notice should be required in order for the returning customer to avoid becoming subject to the TBS rate. If a customer returns to the IOU with less than a one-year notice, the IOU would have to obtain additional resource adequacy (RA) resources outside of the normal procurement cycle, potentially resulting in higher costs for the IOU and bundled customers.

The Joint Parties argue that all customer eligible to switch to DA under SB 695 should be provided an equal opportunity to enroll in DA as of the effective date if they so choose.

6.2. Discussion

We shall grant all DA-eligible customers currently under BPS commitments a one-time waiver of their BPS commitments to allow them an equal opportunity to enroll in DA as of the Effective Date of this decision. A temporary one-time waiver of the six-month advance notice requirement shall also be granted to all DA-eligible customers to allow them an equal opportunity to enroll in DA during the initial open enrollment window, as described in Appendix 2 hereto. The waivers shall apply only during the initial open enrollment window. The long-term applicability of the three-year minimum BPS commitment and six-month advance notice requirements shall be addressed in a subsequent phase of this proceeding. We shall not grant a special preference or set-aside of load to existing DA-eligible customers. Instead, an equal opportunity to enroll in DA shall apply to all eligible customers.

SCE suggested in its comments that residential customers who have taken DA service in the past, but now take utility bundled service (considered as "DA-eligible" under the Commission's rules in effect prior to the enactment of SB 695), would be permitted to switch back to DA service during the phased reopening period. TURN disagrees, however, arguing that SCE's interpretation is inconsistent with SB 695.

SB 695 repealed the prior statutory provisions regarding the suspension of DA which had been in effect since 2001, and replaced those provisions with a new statute, Public Utilities Code Section 365.1. The new statute provides, in relevant part, as follows:

> 365.1. (a) Except as expressly authorized by this section, and **subject to the limitations in subdivisions (b) and (c)**, the right of retail end-use customers pursuant to this chapter to acquire service

> from other providers is **suspended** until the Legislature, by statute, lifts the suspension or otherwise authorizes direct transactions. . . .
>
> b) The commission shall allow individual retail **nonresidential** end-use customers to acquire electric service from other providers in each electrical corporation's distribution service territory, up to a maximum allowable total kilowatt hours annual limit. . . . . (Emphasis added.)

TURN argues that Section 365.1(a) suspends the right of retail end-use customers provided elsewhere in statute (in the AB 1890 revisions to the Public Utilities Code) to acquire service from other providers ***except*** as authorized therein ***and subject to the limitations*** in subdivisions (b) and (c). Among those limitations is the provision that allows only ***nonresidential*** end-use customers to acquire DA service, up to a maximum annual kWh limit.

We agree with TURN's interpretation. Nothing in the statutory language indicates that any residential customer not *already* taking DA service would be permitted to take service from another provider under the annual kWh limit during the period of the suspension. Accordingly, we affirm that the right to acquire new DA pursuant to SB 695 excludes residential customers who are not already taking DA service. However, an existing DA-eligible residential customer on bundled service that has already given its 6-months notice to return to DA prior to the effective date of this decision would still retain the right to return.

7. Meter Installation Waiver

7.1. Parties' Positions

Under current rules, any customer with a peak load that is greater than 50 kilowatts (kW) is required to install an approved interval meter. Interval meters allow customers better access and control to their load consumption, and are a step toward a smarter, more efficient electric grid.

CACES believes that the requirement for DA customers to install interval meters in order to receive DA service should be modified to allow a customer to choose whether or not they want to install such a meter in advance of the "Advanced Meter Initiative" deployment. CACES argues that such DA customers should not be required to pay for an interval meter that will soon be replaced by an Advanced Metering Infrastructure (AMI) meter, particularly because they are already paying for the AMI deployment.

All customers with load greater than 200 kW already have interval meters. CACES argues that any commercial/ industrial customers whose peak load is between 50 kW and 200 kW should have the choice of whether to install an interval meter.

SCE proposes that service accounts with demand between 50 kW and 199 kW be granted a temporary waiver from the DA interval meter requirement pending the scheduled installation of an Edison SmartConnect meter, unless the meter is required by the ESP. SCE proposes that if the customer's ESP requires an interval meter, the ESP would be billed for the cost of such meter.

SCE argues that a waiver should not apply to customers with service accounts having a demand of 200 kW or greater since under SCE's tariffs, such accounts are required to have interval metering.

7.2. Discussion

A temporary waiver of each utility's DA interval meter installation requirement applicable to service accounts with demand between 50kW and 199 kW shall be granted, pending the scheduled installation of an AMI smart meter by the utility, unless an interval meter is specifically requested by the customer's ESP. If the customer's ESP requests an interval meter, the ESP will be billed for the cost of such meter. If a DASR is submitted for a customer who does not have an interval meter in place, and an AMI smart meter is not installed before the next meter read cycle, load profiles will be used for settlement purposes, trued up by actual meter reads, as is done for customers with loads less than 50kW, until an AMI smart meter is installed. All customers with service accounts having a demand of 200 kW or greater are required to have interval metering. Therefore, a waiver shall not apply to these accounts.

Utility Tariff Rule 22 requires that service accounts with demands greater than 50 kW have interval meters prior to being placed on DA service.[17] Therefore, a revision to the Utility Tariff Rule 22 will be necessary to authorize this waiver. The utilities shall incorporate this revision in their advice letter filings implementing the requirements of this order.

8. Compliance with Procurement and Resource Planning Rules

SB 695 requires the Commission to ensure that other providers of electricity in California are subject to the same procurement-related requirements that apply to the IOUs, including resource adequacy requirements, renewables portfolio standards, and greenhouse gas emission reductions.

Pursuant to SB 695, once the Commission has authorized additional DA transactions, it is required to ensure that other providers are subject to the same requirements that apply to the three largest California electric utilities under:

1. Commission-adopted programs to implement the resource adequacy provisions of Public Utilities Code Section 380;

[17] *See* Utility Tariff Rule 22, Section A.2.

2. Renewable portfolio standards of the Public Utilities Code, Article 16; and
3. Electricity sector requirements adopted by the California Air Resources Board pursuant to the California Global Warming Solutions Act of 2006.

8.1. Parties' Positions

Various parties affirm the importance of enforcing uniform procurement and resource planning rules on all load serving entities (LSEs). SCE, in its comments, identified a number of issues that remain to be addressed by the Commission to ensure that these requirements are imposed in a uniform manner among all LSEs. As noted in the Assigned Commissioner's Ruling dated November 18, 2009, specific additional procurement-related requirements will be considered in the appropriate proceedings. SCE asks that in the final decision in this sub-phase we order the immediate opening of a separate sub-phase here, or in other existing proceedings, to address any and all remaining issues regarding procurement-related obligations of ESPs under SB 695.

TURN identifies the potential problem with the allocation of RA resources in this regard. Under current rules, a customer's new ESP is not required to obtain its proportionate share of Local RA resources until the 2011 RA compliance year, because Local RA is subject to only an annual compliance obligation, with no monthly true-up. At the same time, the IOU that loses the load will have no market for the Local RA resources that it had previously procured to serve that load. TURN argues that while a longer-term solution to this problem may be developed in Rulemaking (R.) 09-10-032, the new RA OIR, that proceeding cannot be expected to produce a resolution of the issue by April 11, 2010. As a result, TURN expresses concern that bundled service customers may be left with a disproportionate share of Local RA obligations and costs for the remainder of 2010, including the critical summer peak period when RA is particularly valuable and costly.

TURN initially proposed as an interim solution – pending longer-term resolution of the issue in R.09-10-032 – that ESPs obtaining additional load as a result of the DA reopening in April 2010 be required to purchase the proportional amount of Local RA capacity from the host IOU at an RA "waiver trigger" price of $40 per kW-year, pro rated as appropriate for the remainder of the current year. TURN argued that this interim measure will help to prevent inappropriate gaming and avoid creating a perverse incentive for customers to switch providers simply to avoid their fair share of Local RA costs.

TURN argues that new ESPs entering the market should not be treated any differently from existing ESPs or IOUs with respect to RPS requirements. TURN notes that the rules require all LSEs to procure 20% of their energy from eligible renewable projects by 2010, subject to the applicable flexible compliance rules.

PG&E also recommends that resolution is needed on how DA customers and ESPs could make IOUs whole for the local RA that has already been procured in 2010, thereby effectuating the transfer of local RA from the IOUs to ESPs at a price certain. PG&E believes that TURN's January 11, 2010 filing in R.09-10-012 is simple and can be adapted for this purpose. PG&E states that this approach would not have precedence on the long-term proceeding under R.09-10-012, or the RA proceeding R. 09-10-032, but would only apply for 2010.

A proposal for an interim solution to Local RA obligations was further developed in the comments of the Joint Parties. As noted by the Joint Parties, the reopening of DA in April 2010 comes in the middle of the RA program compliance year, which is administered on a calendar year basis. While system RA obligations are adjusted on a monthly basis to reflect migration of customers between LSEs under current procedures, no similar adjustment exists for Local RA. Proposals to adopt a formal Local RA load migration adjustment are under consideration in R.09-10-032 for compliance year 2011. In view of the increase in load migration that may occur as early as April 2010, however, a more immediate temporary solution to deal with this issue is needed. This interim solution is described in Appendix 3 hereto.

The proposed temporary solution, as set forth in the Joint Parties' comments, provides a means of establishing a value for a "Customer Local RA Obligation" when a customer seeks to migrate between LSEs after the effective date of DA reopening. This value will be based upon the customers' actual 2009 Coincident Peak Demand multiplied by a "Local-to-Peak Ratio" that will be calculated for each IOU service territory, as set forth in Appendix 3. The resulting figure (expressed in MW) will constitute the Local RA Obligation of that customer. The LSE gaining the additional load will have the option to obtain an allocation of RA "credits" from the LSE losing the load without the need for an actual sale of physical capacity to occur between the two LSEs. The LSE gaining the load would make a payment to the LSE losing the load equal to the customer's Local RA Obligation multiplied by a default transfer price of $24 per kW-year. This payment would be deemed to satisfy the acquiring LSE's Local RA Obligation for the remainder of the 2010 compliance year.

8.2. Discussion

We recognize the need for timely action on resolving any remaining issues relating to procurement-related obligations of ESPs under SB 695. We conclude, however, that as a general matter, the adoption of a specific timetable and the scope of the relevant issues is best addressed in the separate proceedings where the relevant specialized expertise already exists. As an exception to this general approach, however, we conclude that the one specific issue relating to RA obligations, as discussed in the Joint Parties' comments, requires an interim resolution in this proceeding. We agree that the Joint Proposal offers a reasonable short-term solution to deal with the issue of Local RA Obligations and we adopt it on that basis. The proposed temporary solution is set forth in Appendix 3 of this decision, based upon the Joint Proposal. This interim solution is adopted for implementation as part of the initial phase-in of new DA load in order to allow DA transactions to proceed in a timely manner while accounting for the impacts on RA obligations.

The adopted solution will provide an expedient means of establishing a value for a Customer Local RA Obligation for use when a customer transfers from one LSE to another during the initial DA open enrollment period. The temporary solution will avoid the potential for cost shifting or undue competitive advantage associated with the Local RA Obligation. After 2010, this temporary solution would be superseded as a result of whatever solution (if any) is adopted in R.09-10-032 for the 2010 compliance year.

This temporary solution shall explicitly apply only for calendar year 2010, and shall either continue or be replaced as a result of whatever solution (if any) is adopted in R.09-01-032 for the 2011 RA compliance year. To facilitate a smoother synchronization between the phased increase in DA load and the annual RA schedule, the next step in the DA phase-in schedule would occur on January 1, 2011, rather than on April 11, 2011. The use of the January date would allow LSEs' year-ahead Local RA showings for 2011 to reflect any load migration that is expected to occur at the start of the next DA reopening phase-in. The ESPs will remain subject to the previously adopted RA showing process which starts in July 2010 for 2011 showings.

We make certain revisions to Appendix 3 based upon comments on the proposed decision. For example, we revise the previous references in the proposed decision to Local RA obligations being "aggregated by NP-26 and SP-26," and instead specify the local areas for which LSEs must procure Local RA. We also incorporate Joint Parties' proposed modifications to the formulas for calculating the Local-to-Peak ratio and the Customer Local RA obligation, as set forth in Appendix 3.

The Joint Parties propose that all LSEs that intend to serve load during 2011 refile load forecasts for the 2011 RA compliance year on July 15, 2010

We shall adopt the due date of May 26, 2010 (instead of July 15, 2010), for LSEs to provide Energy Division with revised load forecasts for the 2011 RA compliance year. Based on the timing for the IOUs to respond to NOIs, a suitable compromise is to have forecasts due from LSEs on May 26, 2010. This will be the only forecast due for 2011 year-ahead compliance.

9. Categorization and Assignment of Proceeding

This proceeding is categorized as Ratesetting. The assigned Commissioner is Michael R. Peevey and the assigned ALJ is Thomas R. Pulsifer.

10. Comments on Proposed Decision

The proposed decision of ALJ Pulsifer in this matter was mailed to the parties in accordance with Section 311 of the Public Utilities Code and comments were allowed under Rule 14.3 of the Commission's Rules of Practice and Procedure. Comments were filed on March 1, 2010, and reply comments were filed on March 8, 2010. The proposed decision was also mailed to the service lists of R.08-01-025 and R.09-10-032 so that all affected LSEs could comment on the proposed decision. We have incorporated parties' comments, as appropriate, in finalizing this decision.

Findings of Fact

1. On October 11, 2009, SB 695 was signed into law as an urgency statute, adding Section 365.1 (b) to the Public Utilities Code.

2. Public Utilities Code Section 365.1(b) requires the Commission to allow individual retail nonresidential end-use customers to acquire electric service from other providers in each electrical corporation's distribution service territory, up to a maximum allowable total annual limit.

3. The amounts of DA load as set forth in Appendix 1 of this decision constitute the incremental amount of transactions that are allowed in conformance with implementation of Public Utilities Code Section 365.1(b).

4. The statute allows for a phase-in period for new DA of not less than three years and not more than five years, subject to Commission determination.

5. A four-year phase-in period with annual caps as set forth in Appendix 2 will reasonably accommodate the utilities' long-term procurement and resource planning needs, while providing for timely implementation of new DA load consistent with the provisions of SB 695.

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

7. Under current rules, any customer with a peak load that is greater than 50 kW is required to install an approved interval meter. Interval meters allow customers better access and control to their load consumption, and are a step toward a smarter, more efficient electric grid.

8. Rule 22 requires that service accounts with demands greater than 50 kW have interval meters prior to being placed on DA service.

9. SB 695 requires that other providers of electricity in California are to be subject to the same procurement-related requirements that apply to the IOUs, including resource adequacy requirements, renewable portfolio standards, and greenhouse gas emission reductions.

10. The interim measures set forth in Appendix 3 for the treatment of Local RA obligations during the enrollment period for new DA will provide a reasonable way to satisfy an LSE's RA obligations in connection with customer migration pursuant to SB 695, subject to any further disposition in R.09-10-032.

11. The enrollment procedures for new Direct Access Load as set forth in Appendix 2 of this decision provides for an orderly process that will be manageable by the utilities while providing for timely processing of new enrollments.

12. The Proposed Decision (PD) was served on parties in R.08-01-025 and R.09-10-032 so that all affected Load Serving Entities could comment on the PD.

Conclusions of Law

1. The Commission is required by the provisions of Pub. Util. Code § 365.1(b) to allow individual retail non-residential end-use customers to acquire electric service from other providers in each electrical corporation's distribution service territory, up to a maximum allowable total annual limit.

2. The authorizations for increased DA transactions, as set forth below in the ordering paragraphs of this decision, reasonably satisfy the requirements of Section 365.1(b) for increased limits in DA transactions.

3. The investor-owned utilities should proceed with implementation of the processing of new DA service requests in accordance with the revised limits adopted below.

4. A temporary one-time waiver of the current three-year minimum bundled service commitment for customers now on BPS customers should be granted covering the initial open enrollment period, starting on the effective date of this decision and extending through June 30, 2010.

5. Any commercial/industrial customers whose peak load is between 50 kW and 200 kW should have the choice of whether to install an interval meter.

6. The procedures for enrollment of new DA load pursuant to SB 695, as set forth in Appendix 2 of this decision, are reasonable and should be adopted.

7. The procedures for the treatment of Local Resource Adequacy Obligations pursuant to SB 695, as set forth in Appendix 3 of this decision are reasonable and should be adopted.

8. The next phase of this proceeding should expeditiously address the remaining issues to be resolved relating to the phase-in of additional limits on direct access transactions.

9. The provisions for new enrollments of DA customers under SB 695 should be based upon a first-come, first-served principle, without special set-asides for DA-eligible customers who have exercised the right to take DA previously.

10. In order to establish an orderly process for enrolling new DA customers pursuant to SB 695, a Notice of Intent (NOI) to subscribe to DA should be submitted by customers. The NOI should be subject to utility review and notification of space availability to the customer and the ESP in accordance with the procedures set forth in Appendix 2 of this decision.

11. SB 695 contains no language granting any preference or special rights to DA-eligible customers who have exercised the right to take DA previously, and there is no basis for the Commission to impose special preferential treatment for such DA-eligible customers in implementing SB 695.

12. For purposes of determining if the authorized cap has been reached in relation to the total requests for new DA service, a daily NOI batching process, as proposed by the Joint Parties, provides for a more streamlined implementation.

13. The right to acquire new DA pursuant to SB 695 excludes residential customers who are not already taking DA service o otherwise eligible per D.05-03-034.

O R D E R

IT IS ORDERED that:

1. Revised limits are hereby adopted in the cap on direct access transactions within the service territories of each of California's three major investor-owned utilities, Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company, as set forth in Appendix 1 of this decision. The authorized increases in direct access transactions shall be incorporated into the utilities' tariffs pursuant to Ordering Paragraph 8. Adjustments to each utility's baseline amount of direct access load as set forth in Appendix 1 shall be based on the same method used by the utilities to calculate direct access load in their Direct Access Implementation Activities Reports submitted to the Commission on a monthly basis. The Energy Division is authorized to post each utility's monthly baseline amount of direct access load,

as reported in their Direct Access Implementation Activities Reports, on the Commission's public website.

2. The increased limits on direct access transactions set forth in Appendix 1 hereof shall be phased in over a four-year period beginning on the effective date of April 11, 2010, in accordance with the enrollment procedures set forth in Appendix 2.

3. A one-time waiver of the current three-year minimum bundled service commitment for customers now on bundled portfolio service is hereby granted for any bundled portfolio service commitments in existence as of April 11, 2010, the direct access reopening effective date. This one-time waiver will effectively eliminate those bundled portfolio service commitments in existence on the Effective Date of the direct access reopening, even if those customers do not elect to take direct access service during the Open Enrollment Window, to allow these customers to elect Direct Access service at any time with the required 6-month advance notice, assuming there is room under the annual limits or overall cap. The three-year bundled portfolio service commitment period will continue to apply anytime a Direct Access customer returns to bundled portfolio service after the Effective Date of the direct access reopening.

4. The increased authorizations in the level of direct access transactions as set forth in Appendix 1 of this decision shall take effect beginning April 11, 2010, and continue for four calendar years, with annual limits as set forth in Appendix 2.

5. The procedures for enrollment of new direct access load pursuant to SB 695, as set forth in Appendix 2 of this decision, are hereby adopted. The IOUs shall file advice letters within 20 days of the issuance of this decision proposing modifications to their direct access tariffs in compliance with this decision. The

advice filings shall be effective upon filing, and any modifications subsequently requested by the Energy Division based on its review of the advice filings shall not alter their effectiveness as of their filing dates. The advice letters shall include the form NOI to be used during the Open Enrollment Window authorized in this decision.

6. A temporary waiver is hereby granted of Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company's direct access interval meter installation requirement applicable to service accounts with demand between 50 kilowatts (kW) and 199 kW, pending the scheduled installation of an Advanced Metering Infrastructure Smart Meter by the utility, unless an interval meter is specifically required by the customer's electric service provider.

7. A methodology for local Resource Adequacy obligations, based on the Joint Proposal and set forth in Appendix 3, is hereby adopted. The methodology shall be in effect for 2010 only, unless otherwise specified by a future ruling. We delegate authority to the Energy Division to make minor refinements or clarifications to the adopted methodology in the course of implementation.

8. Investor-owned utilities subject to the provisions of this decision are directed to file advice letters to modify their tariff rules in compliance with this decision, due 20 days after the issuance of the decision, and effective upon filing.

9. This proceeding shall remain open to address the remaining implementation issues relating to the increased phase-in of direct access and other pending issues to be addressed in this rulemaking.

This order is effective today.

Dated ____________________ in San Francisco, California

Appendix 1

Authorized Increases in Caps on Direct Access Transactions

By Service Territory

Authorized Direct Access Cap Increase (in GWh)

Within Service Territories of the Electric Utilities

	Southern California Edison Company	Pacific Gas and Electric Company	San Diego Gas & Electric Company
Load Cap	11,710	9,520	3,562
Existing Base Line DA	7,764	5,574	3,100
New DA Load Allowance	3,946	3,946	462
Peak Load			

(End of Appendix 1)

APPENDIX 2

Adopted Enrollment Procedures for the Phase-In Period

1. As described more fully below, the phase-in period will begin on April 11, 2010 (the "Effective Date"), and continue for four calendar years, with the annual limits on direct access (DA) load increases over the phase-in period as described in step 2 below, up to the maximum DA cap for each investor-owned utility's ("IOU") service territory (the DA cap). Any kilowatt-hours (kWh) not used in one year will be rolled over to the subsequent years as part of the cumulative increasing annual limits.

2. The annual kWh limits are as follows:

   - Y1 (2010): 35% of the current room available under the DA cap.
   - Y2 (2011): An additional 35% of the current room available under the cap (or70% of the available room under the DA cap).
   - Y3 (2012): An additional 20% of the current room available under the cap (or 90% of the available room under the DA cap).
   - Y4 (2013): An additional 10% of the current room available under the cap (or 100% of the available room under the DA cap).

3. The same switching rules will apply to all customers eligible to switch to DA service under SB 695 ("DA-eligible customers").

4. To facilitate implementation as of the Effective Date, the IOU will notify all DA-eligible customers prior to the Effective Date of the terms and conditions for participation in the partial DA reopening under SB 695. Specifically, the IOU will use a bill insert or onsert[1] to notify all DA-eligible customers as early as March 2010 to visit the IOU's website for details on the partial DA reopening. The website will be updated to ensure accurate information based on the Commission's final decision implementing the DA reopening.

5. To facilitate implementation as of the Effective Date, an Open Enrollment Window ("OEW") will be established as of the Effective Date, during which all DA-eligible customers will be allowed to submit a notice of intent ("NOI")[2] to transfer to DA service.

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[1] A bill onsert is a message imprinted on the customer's bill, as distinguished from a bill insert, which is a separate insertion included in the bill's envelope. The bill onsert may be a more cost-effective way to provide customers notice of the partial DA reopening, because it can be included only on DA-eligible customers' bills, and does not increase the weight of the bills (and thereby should not increase bill mailing costs).

[2] The parties will work together cooperatively in advance of the Open Enrollment Window to develop a uniform NOI in a timely fashion, which shall be filed as part of the IOUs' advice letters implementing

Footnote continued on next page

6. The OEW will begin on the fifth business day after the Effective Date and end ninety (90) calendar days thereafter or on June 30, 2010, whichever comes first. The OEW will occur in Y1 of the phase-in period only.

7. Enrollment during the OEW:

   a. A temporary, one-time waiver of the 6-month advance notice requirement for all DA-eligible customers will be granted so that all DA-eligible customers may begin to enroll in DA service as of the Effective Date if they wish to do so, pursuant to the process described herein.

   b. A one-time waiver of the current Bundled Portfolio Service ("BPS") commitment periods (per Rule 25.1) will be granted so that all DA-eligible customers may begin to enroll in DA service as of the Effective Date if they wish to do so, pursuant to the process described herein.[3]

   c. All LSEs (those that currently serve load and those that do not) will file forecasts of new customers that they expect to gain from via the OEW and other periods for RA compliance years 2010 and 2011 according to the rule set forth by Energy Division for the RA process. Energy Division will issue an amended RA Guide and reporting template for 2010 compliance year as well as an RA Guide and reporting template for 2011 compliance year.

   d. The IOU will begin accepting NOIs up to the Y1 limit as of 9:00 a.m. PST on the fifth business day after the Effective Date. The methods for submitting NOIs will be specified by each utility on its website, provided that all methods shall allow for a time and date stamping to determine precedence. The daily batch process for accepting NOIs during the OEW (described in 7.d below) will allow for up to a 10 percent (10%) threshold above the Y1 limit.

   e. The IOU will process NOIs in daily (12:00 a.m. to 11:59 p.m.) batches. Each daily batch of NOIs will, within 20 days of its receipt, be accepted unless and until the Y1 limit is reached. A daily batch that causes the Y1 limit to be exceeded will nevertheless be accepted provided that such daily batch does

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changes to their direct access tariffs in compliance with this decision. Customers wishing to authorize their ESP or other third party to submit the NOI on their behalf may do so by providing the IOU with a signed "Authorization to Receive Customer Information or Act on a Customer's Behalf" (CISR) form, indicating that the ESP or other third party is authorized to "Request Rate Changes" for the customer.

[3] The one-time waiver will apply to all non-residential customers under current BPS commitments, even if they do not elect to take DA service during the OEW. After the end of the OEW, these customers may elect DA service at any time with the required 6-month advance notice, assuming there is room under the annual limits or overall cap. However, the 3-year BPS commitment period will continue to apply anytime a DA customer returns to BPS.

not exceed the Y1 limit by more than 10%. Should a daily batch cause the Y1 limit to be exceeded by more than 10%, NOIs in that particular daily batch will be accepted on a first-come, first-served basis (based on the date/time stamp of the NOI) up to the Y1 limit plus a threshold of no more than 10%. All other NOIs in that particular daily batch will be rejected.4[4]

f. NOIs submitted during the OEW will be rejected only if the Y1 limit has been reached. Any NOI that is found to have a deficiency (e.g., incorrect service account number) will be accepted on the condition that it is corrected by the customer within two business days after the IOU notifies the customer of such deficiency. NOIs will be void in the event a Direct Access Service Request (DASR) is not timely submitted, as described in 7.h below, or in the event a deficiency in the NOI is not corrected by the customer within two business days.

g. For any NOI accepted during the OEW, the IOU will notify the customer of NOI acceptance within 20 days of NOI receipt, and will instruct the customer to notify its Electric Service Provider (ESP) that a DASR to switch customer's service account(s) to DA service must be submitted to the IOU within 60 calendar days of the date the IOU's notice of NOI acceptance is sent to the customer.

h. The customer will have 60 calendar days from the IOU's notice of NOI acceptance to cause its ESP to submit a DASR.[5] DASRs will be processed using existing processes and timelines in accordance with Rule 22 (or equivalent rule),[6] and eligible service accounts will be switched to DA service on their next scheduled meter read date, or the date specified on the DASR, if different from the next meter read date, depending on when the IOU receives the DASR. Although Rule 22 (at Section E.18) allows the IOU, the customer and the ESP to mutually agree to a different service change date for the service changes requested in a DASR, the IOUs may be unable to accommodate special service change dates during the OEW.

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[4] The threshold is only used for purposes of processing daily batches of NOIs. It is not intended as an increase in the annual limits.

[5] In accordance with the IOUs' current procedures, rejected DASRs must be corrected and resubmitted by the ESP and be acceptable to the IOU no later than 20 days following the conclusion of the 60-day period. DASRs not corrected by the ESP within this time period w ill be cancelled by the IOU.

[6] The DA Rules for SDG&E are Rules 25 and 25.1. The IOUs' DA Rules generally require that DASRs received by the OIU on or before the 15th of the month will be switched over no later than the next month's scheduled meter reading date for that service account. Under SCE and SDG&E's current DASR process, DASRs that are received by SCE or SDG&E five (5) business days before the customer service account's next scheduled meter reading date will be switched over on its next scheduled meter reading date.

Nothing in this Appendix 2 is intended to rescind Section E.18 of Rule 22; however, it may not be operable during the OEW.

i. If a DASR is not received by the IOU for an accepted NOI by the end of the 60-day period, the customer's NOI will be void.

j. Any NOIs voided for failure to submit a DASR within the 60-day period will not be subject to a three-year minimum BPS commitment period as a result such failure. This exception will apply only to NOIs accepted during the OEW.

k. If the Y1 limit is reached during the OEW, the IOU will stop accepting NOIs, and will begin placing submitted NOIs on a wait-list on a first-come, first-served basis. The wait-list shall have a maximum capacity equal to 25% of the Y1 limit, and will be maintained until the last day of the OEW. Should any room under the Y1 limit become available during the OEW as a result of any voided NOIs, within one (1) business day of any room becoming available, the IOU will notify eligible customers on the wait-list by email of the acceptance of their NOIs. The IOU will continue to issue such email notices, on a 1-business day basis as room becomes available during the OEW, through the last day of the OEW. A customer coming off the OEW wait-list will have 60 days after the IOU's notice of the NOI acceptance to cause its ESP to submit a DASR to the IOU. If a DASR is not received by the IOU by the end of the 60-day period, the customer's NOI will be void, and the exception under Section 7.k for the three-year BPS commitment will apply. The wait-list will end on the last day of the OEW. Any NOIs on the wait-list that were not accepted during the OEW will be void, and customers will be notified that they can begin submitting 6-month advance NOIs as early as July 1, 2010 to switch to DA in 2011. No wait-list will be used after the OEW.

l. The OEW will close 90 calendar days after the Effective Date, or on June 30, 2010, whichever comes first. There will be no OEW in subsequent years of the phase-in period.

m. All LSEs that intend to serve load during 2011 will refile load forecasts for 2011 RA compliance year by May 26, 2010. This revised forecast shall account both for customer migration up to that date, but also to forecast expected customer migration during the second phase of DA access that commences in January of 2011. The updated load forecasts due by May 26, 2010 will be used by the Energy Division and CEC to develop Local RA obligations, inclusive of adjustments, as accurately as possible within the constraints of the 2011 RA filing cycle.

8. Enrollment after the OEW closes:

    a. In 2010:

        - Customers may submit 6-month advance NOIs starting July 1, 2010 to switch to DA in 2011 (Y2). The IOU will accept 6-month advance NOIs up to the Y2 limit. The daily batch process for accepting NOIs (described in 7.d above) will allow for up to a 10 percent (10%) threshold above the Y2 limit.
        - A customer with an accepted NOI will be switched to DA starting in January 2011, provided the customer's 6-month advance notice period has been satisfied and a DASR has been timely received.
        - DASRs will be processed using existing processes and timelines in accordance with Rules 22 and 22.1 (or equivalent rules), and eligible service accounts will be switched to DA service on their next scheduled meter read date, or the date specified on the DASR, if different from the next meter read date, depending on when the IOU receives the DASR. Customers who fail to meet the time limitations and DASR requirements set forth in Rules 22 and 22.1 will be subject to a three-year minimum BPS period as provided for in Rule 22.1 (or equivalent IOU rules).
        - Once the Y2 limit is reached, the IOU will stop accepting 6-month advance notices.
        - If room under the Y2 limit subsequently becomes available, the IOU will update its website to notify customers that it is accepting 6-month advance notices. The IOU will use the same daily batch process described above for accepting NOIs for any room under the Y2 limit.

    b. In 2011:

        - Customers may continue to submit 6-month advance notices after January 1, 2011 to switch to DA in 2011 or 2012, depending on whether there is room available under the Y2 limit. The IOU will accept 6-month advance notices up to the Y3 limit. The daily batch process for accepting NOIs (described in 7.d above) will allow for up to a 10 percent (10%) threshold above the Y3 limit.
        - A customer with an accepted NOI will be switched to DA as soon as possible (depending on whether there is room under the Y2 limit), but in any event starting in January 2012, provided the customer's 6-month advance notice period has been satisfied and a DASR has been timely received. If there is no room available under the Y2 limit, customers who submit 6-month advance NOIs prior to July 2011 may need to remain on bundled service for up to twelve months before being able to switch to DA. In other words, they may have to wait for the Y3 allotment to open up in January 2012 before they can switch to DA. If room under the Y2

limit subsequently becomes available in 2011, some customers may be able to switch to DA prior to 2012, provided the 6-month advance notice period has been satisfied and a DASR has been timely received.

- DASRs will be processed using existing processes and timelines in accordance with Rules 22 and 22.1 (or equivalent rules), and eligible service accounts will be switched to DA service on their next scheduled meter read date, depending on when the IOU receives the DASR. A customer failing to meet the time limitations and DASR requirements set forth in Rules 22 and 22.1 will be subject to a three-year minimum BPS period as provided for in Rules 22 and 22.1 (or equivalent rules).[7]
- Once the Y3 limit is reached, the IOU will stop accepting 6-month advance NOIs.
- If room under the Y3 limit subsequently becomes available, the IOU will update its website to notify customers that it is accepting 6-month advance NOIs. The IOU will use the same daily batch process described above for accepting NOIs for any room under the Y3 limit.

c. In 2012 and 2013:

- The IOU will use the same enrollment process as described above for 2011, using the applicable annual limits, except that a threshold for daily batch processing will not apply to the Y4 limit (because it represents the overall cap).

9. During the phase-in period, the IOU will indicate on its public website whether NOIs (during OEW) or 6-month advance NOIs are being accepted, and update this information regularly, as reasonably necessary, but in no event less frequently than monthly. This information

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[7] With the exception that customers who submit 6-month advance NOIs prior to July 2011 may be required to remain on bundled service for longer than 6 months (but not more than 12 months) before switching to DA service, if there is no room under the Y2 limit. In other words, they may have to wait for the Y3 allotment to open up in January 2012 before they can switch to DA.

should be sufficient to inform customers and ESPs whether there is room available under the annual limits during the phase-in or the overall cap after the phase-in. The IOU will provide notice on its public website when the level of annualized sales for customers electing DA service approaches a certain percentage of the annual limit or overall cap (e.g., 95%).

10. Changes in the 12-month usage of DA accounts will be reflected in order to determine the room available under the cap. No customer taking DA service while room was available under the cap will be removed from DA service as a result of growth in DA load.

(End of Appendix 2)

APPENDIX 3

Adopted Temporary Treatment for Local Resource Adequacy Obligations During Direct Access Reopening

We hereby adopt the methodology set forth below in order to fairly allocate local RA costs among LSEs during RA compliance year 2010:

The first step in the methodology is to determine the size of the Local RA obligation associated with a migrating customer. The following calculation is suggested:

Calculate a "Local to Peak Ratio" (LPR) for each IOU service territory. This ratio would be determined by taking the total Local RA obligation in the service area in MW, as adopted by the CPUC decision that established Local RA obligations for 2010, and then subtracting the Local MW that were allocated among all LSEs for Demand Response (DR), Cost Allocation Mechanism (CAM) resources, and RMR Condition 1 (RMR-1) resources. That number is then divided by the total forecasted 2010 coincident peak load in MW of that same IOU service territory (Service Area CPD) that was developed by the California Energy Commission for purposes of establishing 2010 RA obligations. This LPR would be expressed as a percentage. The LPR will be calculated by the CPUC Energy Division and posted to the CPUC website for each service territory alongside the amended 2010 RA Guide and Templates in April of 2010[1].

When a customer seeks to migrate between LSEs after the date of DA reopening, a Customer Local (RA) Obligation (CLO) would be established for that customer, based on the customer's actual recorded Coincident Peak Demand (COPD) in MW at the time of the IOU service territory's 2009 coincident system peak, grossed up by the appropriate Distribution Loss Factor (DLF) for the service area and multiplied by the LPR for the service territory in which the customer is located. The resulting figure would be the Local RA obligation of that customer in MW, the CLO. The LSE losing the load and the LSE receiving the load would stipulate to this figure, which would require only the data establishing the customer's 2009 CPD at the time of the CAISO system peak.

In mathematical terms:

> LPR = Total 2010 Service Area LCR in MW (less Local MW from DR, CAM, and RMR1 & 2)/ Forecasted Service Area 2010 CPD.
>
> CLO = LPR ***x*** Customer 2009 CPD.

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[1] RA compliance materials for 2008 through 2010 are posted to the CPUC website here: http://www.cpuc.ca.gov/PUC/energy/Procurement/RA/ra_guides_2008-09.htm

In order to simplify the process for this temporary and interim solution, the LSE gaining the additional load would have the option[2] to obtain an allocation of Local RA "credits" from the LSE losing the load, without the need for any actual commercial sale of physical capacity to occur between the two LSEs. Rather, the LSE gaining the load would make a payment to the LSE losing the load, equal to the customer's CLO times an administratively determined price in dollars per kilowatt-year (kW-yr) or kilowatt-month (kW-mo). This payment would be deemed to satisfy the acquiring LSE's Local RA obligation for the remainder of the 2010 compliance year. LSE RA filings from both the LSE that lost the customer and the LSE that gained the customer would need to clearly indicate and highlight the exchange of customer MW and RA capacity if any transferred or sold directly to the other LSE. These rules and implementation procedures will be described in an amended RA Guide and Template for 2010 compliance year, and LSEs will be notified in April of 2010 of the new procedures and rules.

No changes to the current RA compliance process would be required, except that both LSEs would report in their System RA monthly true-ups to Energy Division the amount of the Local RA obligation (the CLO) that was being transferred, and the acquiring LSE would also report the amount of the CLO being satisfied through the default transfer payment, as well as the amount of CLO that was being otherwise satisfied.[3] The capacity that is transferred via the default mechanism would still be obligated by the RA Must-Offer Obligation (MOO) throughout the period in which it was originally shown in the year ahead filing, and the SC for the capacity would be required to demonstrate that in each monthly supply plan. Additionally, in the event that Local RA capacity is not sold to another LSE but is now in excess of the Local RA obligations of the original LSE, the original LSE would still be required to list the capacity to on its RA filing and that capacity would still be subject to the RA MOO via requirement to submit supply plans. LSEs are still under the obligation to demonstrate all Local RA capacity that they have under contract via RA Filings. The current process for monthly true-ups to LSEs' System RA obligations would continue without change. All LSEs that expect to serve load during any month(s) are required to submit a monthly load forecast and System RA filing for each month that the LSE will serve load. Failure of an LSE to demonstrate that it has satisfied the CLO through a timely default transfer payment to the transferring LSE and/or through other means will result in a deficiency in the Local RA obligation of such LSE.

Consistent with proposals in the current RA proceeding (R.09-10-032), in order to reduce administrative complexity, local true-ups shall be completed twice during 2010: once for August

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[2] If the LSE that was gaining the load (the acquiring LSE) can show that it already met some or all of its Local RA obligation with excess Local RA capacity or was able to obtain it from another source, the acquiring LSE would not be required to use this "default" option for some or all of its Local RA obligation. For purposes of these mid-year load migration adjustments only, LSEs gaining load may meet increased Local RA obligations in the PG&E service territory via procurement in either the Other PG&E Areas or in the Greater Bay Area, or any combination of the two. Similarly, the SCE service territory, procurement may be in either the LA Basin or in the Big Creek/Ventura area. Procurement adjustments in the SDG&E service territory must be in the San Diego Area.

[3] *See* fn. 1, above.

and September, and a second time for October-December. For 2010 compliance year, the Local RA true-ups will be performed as follows: On May 31, LSEs (both LSEs that currently serve load and LSEs that assume load during the OEW) shall file their monthly load forecast adjustments for August compliance month pursuant to the current RA schedule. This filing for August will be used to establish adjusted Local RA obligations for LSEs for August and September, 2010. LSEs that do not currently serve load will be required to file with the CPUC and demonstrate RA capacity sufficient to meet their Local RA obligations gained from new customers. On August 2, LSEs will file load migration adjustments to establish Local RA obligations for the months of October, November, and December 2010.

The default transfer payment would provide an administrative price for the transfer of Local RA credits of $24 per kW-year. This amount is intended to reflect only the "premium" value of Local RA capacity over System RA capacity, since the LSEs acquiring new load would still be purchasing any increased amount of System RA capacity required to be shown in its monthly System RA filing under the current RA load migration rules. Rather than a flat $2.00 per kW-month, the monthly prices would be "shaped" to reflect the fact that RA capacity is most valuable during the peak summer months. This shaping would spread the $24 over the months of the year based on the same factors (shown below) that were used to allocate capacity payments under the CAISO's former Reliability Capacity Services Tariff program across the 12 months of the year. In mathematical terms, the transfer payment would be determined as follows:

CLO ***x*** $24/kW-yr ***x*** Shaping Factor for remaining months of 2010.

If, during the course of 2010, the new DA load subsequently switched to another LSE, the same process would be repeated again, and the new LSE would meet the CLO for the new DA load by either making a transfer payment to the prior LSE under the default mechanism or showing that it has obtained Local RA from another source.

This temporary and interim solution shall explicitly apply ***only*** for calendar year 2010, and shall continue or be replaced as a result of whatever solution (if any) is adopted in R.09-10- 032 for the 2011 RA compliance year. If the LSE that was gaining the load already held excess Local RA capacity or was able to obtain it from another source, the acquiring LSE shall not be required to use this temporary and interim option, but shall still be required to make a true-up filing, even if there is no change. To facilitate a smoother synchronization between the phased reopening of DA and the annual RA schedule, the next step in the DA phase-in schedule shall occur on January 1, 2011 rather than April 11, 2011. The use of the January date would allow LSEs' year-ahead Local RA showings for 2011 to reflect any load migration that is expected to occur at the start of the next step of the DA reopening phase-in.

In order to provide Energy Division and California Energy Commission with all necessary documentation for a transfer of local RA obligation, both the losing and gaining LSE shall provide the following information to the California Energy Commission and Energy Division at the time of the local true-ups: CLO for each customer gained and lost, documentation of customer transfer, default transfer payment amount (if a transfer payment has been made), identity (CAISO scheduling resource ID and MW amount) of any local RA capacity transferred, and any other information that may be required by Energy Division and California Energy

Commission to implement this methodology. Energy Division shall publish a template to facilitate this documentation.

Monthly Shaping Factors

	SP-15	NP-15/ZP-26
Jan	6.7%	4.9%
Feb	5.0%	4.9%
Mar	5.0%	5.6%
Apr	5.8%	4.6%
May	6.3%	4.8%
Jun	8.3%	5.1%
Jul	15.8%	13.7%
Aug	17.5%	15.3%
Sep	11.7%	13.8%
Oct	5.8%	8.7%
Nov	6.3%	8.8%
Dec	5.8%	9.8%

(End of Appendix 3)