

**BEFORE THE PUBLIC UTILITIES COMMISSION  
OF THE STATE OF CALIFORNIA**

Order Instituting Rulemaking to Establish Policies and  
Cost Recovery Mechanisms for Generation Procurement  
and Renewable Resource Development.

Rulemaking 01-10-024  
(Filed October 25, 2001)

**REPLY BRIEF OF THE CALIFORNIA WIND ENERGY ASSOCIATION**  
**ON THE IMPLEMENTATION OF THE**  
**CALIFORNIA RENEWABLES PORTFOLIO STANDARD PROGRAM**

Joseph M. Karp  
Enoch H. Chang  
White & Case LLP  
Three Embarcadero Center, Suite 2210  
San Francisco, California 94111  
Telephone: (415) 544-1100  
Facsimile: (415) 544-0202  
*jkarp@whitecase.com*  
*echang@whitecase.com*

Attorneys for the California Wind Energy  
Association

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**I. INTRODUCTION AND OVERVIEW**

Pursuant to Rule 75 of the California Public Utilities Commission's ("Commission") Rules of Practice and Procedure, the California Wind Energy Association ("CalWEA") submits its reply brief on the implementation of the California Renewables Portfolio Standard ("RPS") program. In this reply brief, CalWEA responds to the positions of other parties that would materially affect the successful implementation of the RPS program.

From the opening briefs, it is perfectly clear that Southern California Edison Company ("Edison") and Pacific Gas and Electric Company ("PG&E") desire to limit as much as possible their requirements to purchase renewable power under the RPS program and to increase as much as possible their flexibility in complying (or not complying) with the requirements. It is apparent that, if their proposals are adopted, the RPS program will be a mere shadow of what the Legislature intended.

## II. DISCUSSION

### A. COMPLIANCE FLEXIBILITY

#### 1. **The Utilities Should Be Required To (i) Achieve A Net Increase Of At Least One Percent Each Year, Making Up For Any Reductions In Prior Years, And (ii) Reach 20 Percent By No Later Than 2017.**

In its opening brief, TURN proposes that the Commission clarify that the utilities are obligated to increase their purchases of renewable power by at least one percent each year, net of any reductions in prior periods. *TURN Opening Brief at 2-3*. In other words, the Commission should set the annual procurement targets (“APT”) at no less than one percent of the current year’s retail sales plus any reductions in renewable purchases from the prior year. Looked at another way, TURN proposes simply that if a utility is required to purchase five percent of its sales from renewables in one year, it should be required to purchase 6 percent of its sales from renewables in the next year. CalWEA strongly supports TURN’s proposal. Under any reasonable interpretation of the RPS legislation, no other outcome is possible.

In its testimony, however, Edison took the position that the APT should be set at (and no greater than) one percent of the most recent prior year’s sales, without considering potential reductions in renewables purchases during the prior year.<sup>1</sup> *Edison/Bergmann, Tr. at 2648:25-2649:25*. PG&E has taken the same position in its opening brief at pages 10-11. This position is fundamentally at odds with the clear intention that the utilities achieve an overall level of 20% renewables purchases by 2017 and make steady progress towards that goal through annual increases of at least one percent per year. As stated in § 399.15(b)(1), a utility must “increase its *total* procurement of eligible renewable energy resources by at least an *additional* 1 percent of retail sales per year so that 20 percent of its retail sales are procured from eligible renewable energy resources no later than December 31, 2017.” (Emphasis added.) *See also* § 399.11(a).

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<sup>1</sup> The Commission also should clarify that the APT for a given year must be set by reference to that year’s retail sales, and not the prior year’s sales as Edison proposes. § 399.15(a).

If the Commission were to accept Edison's and PG&E's interpretations and not require the utilities to make up for reductions in renewable purchases, the total amount of renewable generation could actually *decline* steadily from year to year.<sup>2</sup> In fact, while PG&E would nevertheless enforce the 20% by 2017 requirement and, presumably, risk a scramble to meet the 20% target in the later years,<sup>3</sup> Edison proposes that the utility's obligation to reach 20% simply be voided if, as a result of backsliding, 1% increases are insufficient to reach 20% by 2017. As Edison's witness Bergmann testified under cross-examination:

Q. By the end of 2017, is the utility [that is at 18 percent by the end of 2016 due to a decline in renewable purchases from a prior year] obligated to purchase 2 percent from renewables to make 20 percent, or is it only obligated to purchase 1 percent from renewables?

A. As I testified yesterday, there is no last minute makeup to get to the 20 percent that I see in the statute, so you have a 1 percent requirement. And assuming in your hypothetical that there were no other renewable or contract terminations, then you would get 19 percent.

*Edison/Bergmann, Tr. at 2809:13-20.*<sup>4</sup> The prospect of backsliding and a scramble to make up for reductions in prior years under the PG&E approach is bad enough;<sup>5</sup> the waiver that Edison seeks from the clear and unambiguous 20% by 2017 requirement is directly contrary to the legislation.

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<sup>2</sup> Taken to its logical extreme, PG&E, which proposes that it be permitted to execute one year contracts until it is creditworthy, could simply sign one year contracts for one percent of its retail load and comply by extending the same contracts year after year.

<sup>3</sup> PG&E expressly acknowledges in its opening brief that the utility will have to "meet the 20% requirement by 2017" notwithstanding reductions in purchases from renewables. *PG&E Opening Brief at 11.*

<sup>4</sup> Mr. Bergmann's failure to see a provision in the statute for a last minute make-up may be attributed to the statute's requirement that the utilities achieve a steady net increase each year of at least one percent and not backslide during their progress to the 20 percent by 2017 requirement. It is also possible that Mr. Bergmann overlooked the language requiring the utilities to procure "at least" one percent per year so as to achieve 20 percent by 2017.

<sup>5</sup> Given that the primary driver of reductions in purchases from renewables will be the expiration of existing renewables contracts, and that the utilities should know when their existing contracts will expire, the utilities should not be unduly burdened by the net increase requirement and should have the wherewithal to comply fully in light of the other flexible compliance mechanisms.

In order to avoid any uncertainty on this critical issue, the Commission should, consistent with TURN's recommendation and as SDG&E has accepted (*see SDG&E Opening Brief at 27*), clarify that the utilities are required to increase their net purchases from renewables each year by at least one percent until they reach 20 % (which must be no later than the end of 2017, subject to adopted compliance flexibility measures).

**2. Failure To Identify A Specific Need for Power In The Long-Term Plan Should Not Excuse A Utility From Its RPS Obligations.**

PG&E argues that a utility's RPS obligations to purchase from renewables are conditioned upon an identification of need in its long-term resource plan. *PG&E Opening Brief at 6-7*. In support of its argument, PG&E points to § 399.14(a), which requires the Commission to coordinate RPS procurement, to the extent feasible, with general procurement activities, and to § 399.15(a), which begins with the phrase "In order to fulfill unmet long-term resource needs". *Id.* PG&E's arguments are contrary to the statute, extremely dangerous with respect to the success of the RPS program and should be rejected.

Contrary to PG&E's arguments, the RPS legislation does not specify that a Commission finding of a long-term resource need is a prerequisite to the utilities' obligation to procure power from renewable resources. As TURN correctly pointed out, the reference to long-term resource needs appears only once in the RPS legislation in an extremely general prefatory context.<sup>6</sup> *TURN Opening Brief at 7*. Although the Commission should interpret the statute to give meaning to each and every word, each word of the statute must also be interpreted in the context of the entire statute. *58 Cal. Jur. 3d Statutes § 122 (in interpreting the statute, courts "may ascertain the meaning of words by their context")*. Here, the reference to long-term resource needs is in the context of the Legislature's declaration of intention and purpose for the Commission to establish the RPS program. The reference merely creates a context for the creation of the RPS program, and is not intended as a specific limit on the procurement obligations of the utilities. At most, the reference to need in § 399.15(a) should be viewed as a foreshadowing of the requirement that renewable

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<sup>6</sup> §399.15 states that: "In order to fulfill unmet long-term resource needs, the Commission shall establish a renewables portfolio standard . . ."

procurement incorporate both least-cost and best-fit considerations. By requiring that the renewables be evaluated with respect to “best fit,” the Legislature is tying renewable procurement to the utilities’ actual needs.

Moreover, as TURN pointed out in its opening brief, where the Legislature has intended to limit the utilities’ RPS obligations, it has clearly stated its intention. *TURN Opening Brief at 7*. For example, in the very same section cited by PG&E, the Legislature conditioned the utilities’ obligations to purchase renewable output on the sufficiency of PGC funds. This limitation is expressly stated in a subsequent section of the statute. § 399.15(a)(2). Had the Legislature intended that a demonstration of “need” serve as a precondition to the utilities’ procurement obligations (in a manner akin to the sufficiency of PGC funds), it would have written § 399.15(a) very differently. For example, rather than place the “need” language at the beginning of the sentence, disjoining it from the other parts of the sentence, the Legislature would have either (i) called out “need” as a limit on the utilities’ obligations as it did with respect to PGC funds in § 399.15(a), or (ii) stated elsewhere in the statute that need serves as a limit, as was done with respect to utility creditworthiness. *See 399.14(a)(1)*. In the absence of such an express limitation based upon need, the Commission should construe the language cited by PG&E as what it is, preamble and context for the remainder of the section.

In addition, PG&E simply overlooks that the language it cites from § 399.14(a) requires the Commission to coordinate RPS procurement with general procurement “to the extent feasible.” As such, the Legislature clearly recognized that annual renewables procurement obligations under the RPS program might not match perfectly with the general procurement plans of the utilities. Rather than establishing legislative intent to limit the utilities’ RPS obligations, this portion of the statute actually reinforces the contrary position, that RPS obligations are not conditioned upon identified “need” in the utilities’ general procurement process. Similarly, the Legislation specifically anticipates the “sale of excess energy” as one of the potential indirect costs associated with the purchase of renewable energy, evincing awareness that short-term displacement of energy might occur as a result of meeting the long-term goals of the RPS Program. § 399.15(a)(2).

Aside from the statutory construction arguments, PG&E's interpretation of the statute is simply not logical. As PG&E interprets the statute, the utilities would be obligated to purchase at least one percent of annual retail sales from renewables as long as there is any need identified in the long-term plan, even if the need is dramatically lower than such one percent threshold. If the Legislature intended that renewable purchases be tied strictly to utility "need," it would have made much more sense to tie the APTs to the identified need and not to a simple one percent minimum requirement. As such, PG&E's interpretation should be rejected.

Further, if the RPS program is to have any credibility with the renewables community, the Commission must reject PG&E's argument. Given that the specific information in PG&E's long-term plan that goes to a need determination is confidential, renewables advocates have no basis for participating in this part of the debate. Although CalWEA has high regard for the ratepayer advocates that will have access to the confidential data, direct participation in matters of the magnitude presented here is absolutely critical.<sup>7</sup>

Nevertheless, if the Commission believes that it should determine the existence of a long-term resource need before requiring RPS procurement, the Commission should still not limit RPS procurement obligations merely to fill holes in the utilities' long-term procurement plans as PG&E appears to suggest. Such a construction would effectively negate the value of the APTs as a mechanism to increase in an orderly fashion utility procurement of renewables, and would be inconsistent with the 20% by 2017 requirement, which PG&E believes is the paramount component of the RPS program. *PG&E Opening Brief at 3* ("The primary objective of the RPS legislation is to realize 20% procurement from renewable energy sources by 2017"). According to PG&E's logic, if the utility does not identify a need for 20% more power resources, it would not need to meet the 20% by 2017 requirement.

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<sup>7</sup> If PG&E's position were to be contemplated, CalWEA would strongly support TURN's call for a Commission order requiring PG&E to release the portions of its long-term plan concerning need. *TURN Opening Brief at 56*. It is particularly outrageous for PG&E to take this position while it shields from participants in this proceeding its data pertaining to need, thus preventing participants from knowing the impacts on the RPS program if the Commission is to adopt PG&E's position.

On the contrary, if the Commission believes that it must find that the utilities need power in order to mandate RPS procurement, the Commission should follow the recommendation of CalWEA's witness R. Thomas Beach and simply (i) make a finding as to whether there is a long-term need for new resources and (ii) assuming that there is such a need, implement the RPS program as the legislation provides (i.e., with full APTs and the 20% by 2017 requirement). As Mr. Beach explained during cross-examination: "there are unmet long-term resource needs and so long as there are those needs today, then it's appropriate for the Commission to go forward and establish the RPS Program." *CalWEA/Beach, Tr. at 3060:10-13.*

**3. The Commission Has The Authority To, And Should, Adopt Up-Front Penalties For Utility Non-Compliance.**

Not surprisingly, each of the utilities argues that the Commission should not adopt up-front penalties for utility failures to comply with the RPS requirements. *PG&E Opening Brief at 5; Edison Opening Brief at 11; SDG&E Opening Brief at 52.* PG&E and Edison argue that, by removing from the final statute a detailed and self-effectuating penalty mechanism contained in an earlier draft, and by replacing this detailed mechanism with the contents of § 399.14(d), the Legislature intended that the Commission be precluded from adopting up-front penalties. *Edison Opening Brief at 11; PG&E Brief at 5.* They also argue that up-front penalties are unnecessary and not appropriate for a variety of reasons. *PG&E Opening Brief at 5-6; Edison Opening Brief at 12; SDG&E Opening Brief at 52.* Contrary to the utilities' interpretation of the legislative history and their limited view of the Commission's power under the Public Utilities Code, the Commission has the authority to impose specific and substantial up-front penalties for a utility's non-compliance with the RPS program. Also, contrary to their pleas of "trust me," clearly articulated up-front penalties protects all parties, including the utilities, and should be adopted.

First, it is simply wrong to infer that, because an express up-front penalty provision was removed from the first version of the statute, the Legislature determined that the Commission should not impose such a requirement. There are several possible reasons why the Legislature removed the specific penalty provisions that do not lead to the utilities'

conclusion. Most likely, the Legislature was not convinced that the specific penalty mechanism contained in the earlier draft should be mandated by statute and decided to leave it to the Commission to evaluate the need for and specifics of any penalty mechanism, including an up-front mechanism. Obviously, if the Legislature decided that the Commission should not impose an up-front penalty mechanism, the Legislature could have and, in light of the Commission's broad authority to regulate the utilities and its specific authority to impose penalties for non-compliance with Commission orders (as discussed below), would have expressly so stated.

Second, even though no up-front penalty mechanism is expressly endorsed under the RPS legislation, the Commission has broad authority under the Public Utilities Code to adopt up-front penalties for violation of the Public Utilities Act. Under § 701, for example, the Commission "may do all things, whether specifically designated in this part or in addition thereto, which are necessary and convenient in the exercise of [its] power and jurisdiction".

Third, the utilities' arguments that § 399.14(d) divests the Commission of authority to adopt up-front penalties are erroneous and should be rejected. § 399.14(d) provides that, in the event of utility noncompliance, the Commission shall exercise its authority under § 2113 to require compliance. § 2113 allows the Commission to impose fines and imprisonment for noncompliance with the Commission's orders to the same extent as a court may punish contempt; in no way does it proscribe the Commission from adopting an up-front mechanism to implement the contempt penalties. In addition, § 2113 specifically states that it "does not bar or affect any other remedy prescribed in [the Public Utilities Act], but is cumulative and in addition thereto." The plain text of the statute makes clear that the Commission's exercise of its authority under § 2113 does not preclude the Commission from imposing penalties under the provisions of § 701 or other authority in the Public Utilities Code. *See, e.g., § 2101-2119.* Again, had the Legislature intended to divest the Commission of the authority to impose up-front penalties, it would have so stated such intent.

Fourth, the Commission has already specifically rejected SDG&E's argument that § 2104 precludes the Commission from imposing penalties on the utilities. *SDG&E Opening Brief at 52-53.* § 2104 requires the Commission (except in the case of penalties against

common carriers) to bring actions to recover penalties before the superior court and that provides fines and penalties be deposited in the State's General Fund. The Commission has held that the requirement under § 2104 to bring an action to recover penalties before the superior court does not apply to penalties levied under § 2113. *Decision 82-03-070, 8 CPUC 2d 356, 1982 WL 196895, at 3*. In addition, aside from penalties levied under § 2113, the Commission has consistently construed § 2104 "to apply to the recovery of penalties, rather than the imposition of penalties." *Decision 03-01-087, mimeo. at 5 (also noting that several utilities have brought this argument before the state appellate court, and the courts have all denied review)*. See also, *Decision 99-04-028, 85 CPUC 2d 667; and Decision 99-03-025, 85 CPUC 2d 295 (noting that the Commission has interpreted §§ 2104 and 701 to allow it to impose penalties but to require action in superior court if the penalties are not paid voluntarily)*. The Commission has insisted, correctly, that the authority to impose penalties "is critical to [the Commission's] ability to regulate public utilities and to protect the public interest. If [the Commission] could not penalize utilities for violating [the Commission's] rules and orders, utilities would have little or no incentive to comply with them." *Id.* at 12-13.

Fifth, the Commission should not merely rely on the amorphous threat of after-the-fact penalties and the good faith of the utilities to ensure compliance with RPS requirements. Utilities have a history of obstructing Commission policy on independent (including renewable) generation, even with the guaranteed pass-through that PG&E cites as obviating the need for Commission concern. See e.g., *Decision 82-12-055 at 200-209, and Decision 91109, 3 CPUC 2d 1, 1979 WL 50929, mimeo. at 21 (criticizing PG&E's effort in developing cogeneration)*. Edison's reference to the results of the recent interim renewables solicitation as evidence that penalties are not necessary to ensure utility compliance (*Edison's Opening Brief at 12*) is actually rather comical and, notwithstanding its comic value, should be rejected. Edison had to be found in non-compliance with the earlier Commission decision and threatened with penalties before it executed (in the 13<sup>th</sup> hour) contracts with renewables as required with the Commission's interim procurement requirements. *Decision 02-12-074, at 26*.

Sixth, the utilities' contention that adopting up-front penalties would confer undue bargaining power on renewable bidders should be rejected outright. *PG&E Opening Brief at 5; Edison Opening Brief at 12*. It is completely ridiculous to assert that renewable suppliers will have undue bargaining power when there are expected to be only three real buyers (and in some cases only one in the event of transmission constraints), each of whom will have an array of compliance flexibility measures and multiple potential suppliers. Indeed, in light of the secrecy that will undoubtedly surround the utilities' RPS purchase obligations, there is no way for renewables to utilize any theoretical advantage conferred by up front penalties. Finally, if, as the utilities argue, the threat of after-the-fact penalties will have much the same impact on utilities as up-front penalties, no additional bargaining power will be conferred on renewables by up-front penalties.

Seventh, if the utilities' arguments are to be taken at face value, CalWEA cannot understand how they prefer uncertain, after-the-fact penalties as opposed to clearly articulated up-front penalties. In the earlier phase of this proceeding, the utilities made very plain that after-the-fact penalties for utility procurement activities was anathema to restoring utility creditworthiness. *Edison Rebuttal Testimony (June 2002), Ex. 7, at I-17*. The only rational way to reconcile the utilities' disdain for after-the-fact reasonableness reviews in the earlier phase with their position in this phase is that the utilities expect that they will be better able to avoid the after-the-fact penalties in the event of non-compliance with RPS requirements than up-front penalties.

#### **4. The Utilities' APT Obligations Should Not Be Extinguished By Any Lack Of PGC Funds; The APT Obligations Should Only Be Deferred.**

Edison argues that § 399.15(b)(4) extinguishes the obligation of the utilities to procure from renewables in a given year if there are insufficient PGC funds for the utilities to meet the APTs. In other words, Edison proposes that a procurement shortfall resulting from a lack of PGC funds in any year is not deferred to a subsequent year. *Edison Opening Brief at 5*. Even if PGC funds subsequently become available, Edison believes that it is under no obligation to meet the 20% requirement. *SCE/Bergmann, Tr. at 2728:23-2729:9*. In support of its position Edison relies on the following language from § 399.15(b)(4): "If [payments

from the PGC funds] are insufficient to cover the above-market costs of eligible renewable energy resources, the commission shall allow an electrical corporation to limit its annual procurement obligation to the quantity of eligible renewable energy resources that can be procured with available supplemental energy payments.” Edison’s interpretation of § 399.15(b)(4) should be rejected; if there are insufficient PGC funds to permit purchases in a given year, the unmet portion of the APT should be deferred into the next compliance year.

§ 399.15(b) directs the Commission to establish annual procurement targets in four steps. First, the statute directs the Commission to establish a specific annual “target” for the utilities, i.e., the annual procurement target of at least one percent. § 399.15(b)(1). Second, for the purpose of establishing the annual “targets,” the Commission is to include power sold by DWR in the calculation of the total retail sales of each utility. § 399.15(b)(2). Third, the statute provides that if the utility fails to meet its annual “target” in one year, it must make up the shortfall in subsequent years. § 399.15(b)(3). Lastly, the statute addresses the impact of the lack of PGC funds on the annual “procurement obligation” in § 399.15(b)(4).

A logical reading of the entirety of subdivision (b) provides a better interpretation of the Legislature’s intent – that subdivision (b)(4) is intended to be a specific instance in which the utility is allowed to defer part of its annual procurement target to the next year. First, in § 399.15(b)(4), the Legislature uses the phrase “annual procurement obligation” instead of “annual target” in discussing the limited amount of renewable energy that the utility must procure. Throughout the other parts of § 399.14(b), the Legislature has used the term “annual target” consistently to mean the at-least-one-percent requirement that the Commission establishes. Thus, in § 399.15(b)(4), when the Legislature uses the term “annual procurement obligation,” it is not limiting the utility’s “annual target” to the amount of renewable energy that the utility is able to procure with the available PGC fund, only its obligation to meet that target in the current compliance year.

Second, if the Legislature had intended the statute to mean what Edison asserts, it easily could have so provided. For example, the statute could easily have been revised as follows: If [payments from the PGC fund] are insufficient to cover the above-market costs of eligible renewable energy resources, the commission shall **reduce the annual target** ~~allow~~

~~an electrical corporation to limit its annual procurement obligation~~ to the quantity of eligible renewable energy resources that can be procured with available supplemental energy payments.” In fact, where the Legislature has intended to limit the utilities’ obligations to meet an annual procurement target in any specific year, it has clearly so indicated. For example, in § 399.15(b)(1), the Legislature stated that a utility with 20% of renewables in one year is exempt from an obligation to increase purchases in the following year. If the Legislature had intended to obviate the annual targets based on the unavailability of PGC funds, it would have so stated.

Third, Edison’s argument that “as a practical matter, rolling forward a compliance requirement from a year in which PGC funding is inadequate will merely result in insufficient PGC funds in a later year” (*Edison’s Opening Brief at 6*) should be rejected. There are a number of factors that would enable shortfalls to be made up in future years – additional PGC funds could become available, the market price benchmarks could rise (due to natural gas price increases or other factors) allowing renewable power to be procured at or below the benchmark, or the cost of renewable generation could fall. The Commission should not allow the lack of PGC funds (or a temporary drop in the benchmark) to eliminate the utilities’ procurement requirements.

Finally, although it could be stated that extended deferrals may result in a stacking problem for the utilities, the Legislature has provided measures to ease those difficulties with flexible compliance rules. For example, if there were a big shortfall to make up in any given year, CalWEA’s proposed flexibility measures would allow the utility to seek a deferral of some or all of the annual obligation to future periods.

**5. The Utilities’ APT Obligations Should Not Be Extinguished By Any Lack Of Utility Creditworthiness; The APT Obligations Should Only Be Deferred.**

Similar to Edison’s arguments concerning the impact of lack of PGC funds on the APT discussed above, PG&E argues that, based upon § 399.14(a)(1), if the utility is not creditworthy, there should be no APT. *PG&E Testimony, Chapter 2, p. 3.* (“An IOU should not incur or accrue any APT obligations until after it is deemed creditworthy by the Commission upon the IOU having attained an investment grade rating as an entity as

*determined by at least two major rating agencies*”). For much the same reasons as discussed above, PG&E’s arguments should be rejected.

In particular, the language relied upon by PG&E states that the utility shall not be obligated “to conduct procurement to fulfill” the RPS until is deemed creditworthy. This does not say that the RPS or APTs should not be established and are inapplicable; this only says that the Commission shall not obligate the utilities to procure the power needed to meet the RPS or APT requirements while the utility is not creditworthy. In fact, by including the term “fulfill,” the Legislature presumed the existence of the requirements. As such, the only fair reading of the statute is that, to the extent that the utilities are not creditworthy, they do not have to meet the APTs; such obligations will be deferred to the future when the utilities are creditworthy.

**6. The Commission Should Clarify That Merely Signing Contracts Does Not Constitute Compliance; Actual Procurement Of Power Is Required.**

PG&E asserts that the utility may comply with APTs simply by signing contracts with renewables, whether or not any power is ever delivered to them under the contracts. *PG&E Opening Brief at 8. See also PG&E/Papas, Tr. at 3381:18-28 (stating that to satisfy the APT for a particular year, PG&E only has to sign contracts for delivery of power in that year, and that if for some reason, the contract is terminated and power is not delivered, the utility will get to defer the APT for another three years).* This position must be rejected. For one thing, the statute requires the utilities “to procure a minimum quantity of output” from renewables, not “enter into contracts for the procurement of output” with renewables. § 399.14(a). *See also § 399.14 (g) “For purposes of this article, “procure” means that a utility may acquire the renewable output of electric generation facilities that it owns or for which it has contracted”*). For another thing, if PG&E’s proposal were adopted, the utilities would have no incentive to design an RPS program or enter into contracts with renewable projects that will ultimately succeed. All the utility would have to do is sign contracts, however unlikely they are to result in development. This cannot be what the Legislature intended.

**7. The Commission Should Adopt Reasonable Limits On The Utilities Ability To Defer Compliance With The APTs.**

Both Edison and PG&E assert that they should be given unrestricted discretion to defer compliance with the APTs. *PG&E Opening Brief at 9; Edison Opening Brief at 6-7.* Although SDG&E has agreed with TURN upon what appears to be limits on their flexibility, SDG&E in reality will have too much discretion under its proposed mechanisms. *SDG&E Opening Brief at 20-22.* As discussed in its opening brief, CalWEA believes that, consistent with the requirements of § 399.14(a)(2)(C), the utilities should be given reasonable flexibility to defer compliance with an APT for up to three years. *CalWEA Opening Brief at 21-22.* Contrary to the utilities arguments, the Commission should ensure that if there is a deferral, it is for legitimate reasons and not simply out of a desire to obstruct or delay compliance. CalWEA's proposed compliance flexibility mechanisms would accomplish this objection while the utilities' proposals would not.

For example, as Edison admitted, its compliance flexibility proposal would allow the utility, for any reason, perpetually to lag three years behind in compliance with the APTs, even beyond 2017. *Edison/Bergmann, Tr. at 2729:18-2730:17.* PG&E's proposal would also allow the utility to defer compliance for any reason whatsoever. *PG&E Opening Brief at 9.* SDG&E's proposal would allow the utilities to avoid compliance as a result of inadequate bidding by renewables or failure of renewables to come on line, even if these events occurred as a result of the utility imposing onerous bid terms or contractual requirements. *SDG&E/Bartolomucci, Tr. at 3286:6-3287:7.* These proposals are consistent with the utilities' overall approach to RPS compliance rules: no rules are good rules.

As discussed in CalWEA's opening brief, the Commission should adopt a set of flexible compliance rules, including (i) an automatic five percent safe harbor each year, no questions asked, for minor variations, (ii) a three-month reconciliation period to allow the utilities a chance to make up for unintended shortfalls, (iii) unlimited forwarded banking to encourage early compliance (provided that the Commission clarifies that the 20% by 2017 obligation extends beyond 2017), and (iv) deferrals of up to three years, provided that the utility articulates a reasonable justification and obtains Commission approval. *CalWEA Opening Brief at 19-21.* Arguments against CalWEA's proposals are without merit.

For example, Edison argues that CalWEA's proposal will result in a "prescription for litigation." *Edison Opening Brief at 9*. Under cross-examination, however, Edison's witness agreed that the amount of litigation would depend on the criteria adopted, and that it would be possible for the Commission to develop criteria that would allow quick and decisive decisions on deferral requests. *Edison/Bergman, Tr. at 2732:28-1234:14*. Edison also agreed that litigation only would follow if the utilities were unable to comply timely with the APTs. That Edison views limits on deferrals as a prescription for litigation does not bode well for the prospect of timely compliance by the utilities and, if anything, is even more justification for curbing their desire for unlimited flexibility. PG&E's criticism that CalWEA's proposal will result in micromanagement by the Commission (*PG&E's Opening Brief at 11-12*) should be rejected for the same reasons.

The Commission should also reject Edison's baseless criticism that CalWEA's compliance flexibility scheme will unduly favor wind (and implicitly discriminate against other renewable generators). *Edison's Opening Brief at 9, n. 8*. Edison's accusation ignores the other elements of CalWEA's proposed flexibility mechanisms, particularly the rule that allows a utility to defer compliance for up to three years beyond the compliance year where: (i) the results of the least-cost/best-fit evaluation of bids demonstrate that substantial benefits can be captured through a deferral; and; (ii) contracts are being signed for future deliveries that will bring the utility into compliance as planned. *CalWEA/Rader Ex. RPS-12, Ch.3, at 3-4, and CalWEA Opening Brief at 21*.

In addition, Edison's claim that CalWEA's three-month reconciliation period collapses the three-year period permitted by statute into three months (*Edison Opening Brief at 8*) is patently false. As discussed above CalWEA proposes that the utilities have three full years to make up shortfalls, so long as they obtain Commission approval for shortfalls beyond five percent. The three-month reconciliation period is another element of flexibility, not referenced in the statute, that should be available to the utilities.

Finally, SDG&E's claim that CalWEA's proposed mechanism will create undue market power for renewable bidders (*SDG&E Opening Brief at 23*) should be rejected out of hand. As discussed above, given their monopsony power and confidentiality restrictions, the utilities possess huge amount of leverage over renewables in negotiations. Requiring the

utilities to justify significant deviations from annual procurement targets, as SDG&E itself proposes, will not turn the tables on the utilities, whatever they might claim.

In concept, CalWEA's proposed flexible compliance mechanisms are not unlike those proposed by SDG&E and TURN. The differences are more in degree. While SDG&E and TURN assert that the utilities should have a 25% safe harbor, for example, CalWEA proposes that the safe harbor be limited to a more modest five percent. Given that the utilities have for years been matching generation to load, CalWEA sees no reason why they would need the wide berth proposed by SDG&E and TURN. In addition, while both SDG&E and TURN envision, as does CalWEA, Commission approval for deviations beyond the safe harbor limit, CalWEA limits the excuses to the results of the least-cost/best-fit evaluation (as well as PGC insufficiency and lack of creditworthiness) in order to ensure that the utilities have the proper incentive to develop reasonable solicitations and contracts and are not able to take advantage of the failure of a renewable to survive unreasonable terms imposed by the utilities as a legitimate ground for utility deferral.

## **B. MARKET PRICE REFERENTS**

### **1. The Commission Should Not Use Unaccepted Bids Or Broker Quotes As The Basis For Adopting A Market Price Referent Under § 399.15(c)(1).**

Both Edison and PG&E assert that the Commission should employ binding bids and broker quotes in setting the market price benchmarks under § 399.15(c)(1). *Edison Opening Brief at 22-25; PG&E Opening Brief at 18-19*. Their proposal is opposed by every other party to the proceeding and should be rejected.

§ 399.15(c)(1) directs the Commission to consider “the long-term market price of electricity for fixed price contracts . . . .” A plain reading of the statute does not permit the use of bids or broker quotes, only contract price information. Edison's argument that the statute used the phrase “price... **for** fixed price contracts” instead of “price . . . **of** fixed price contracts” as the basis for justifying the use of quotes or bids in lieu contract prices is without merit. Until a contract is entered into, there is neither a price “for” or “of” the contract. Once the contract is entered into, the price for or of the contract is the agreed upon contract price. Broker quotes and binding bids are, at best, offers that the utilities may or may not

accept, depending upon many variables that could affect the value of the offer, including the reputation or creditworthiness of the bidder, conditions placed on bids or other factors. As such, they do not reflect market prices and should not be used to determine the benchmark.

Some of the practical problems with using broker quotes and bids were further demonstrated during the hearings. For example, Edison's witness Mr. Bergmann admitted that he did not know the performance requirements associated with products reported on in published indices, such as a NYMEX futures contract. *Edison/Bergman, Tr. at 2818:13-2819:13*. Without knowing the performance requirements, it is impossible to know if the product covered by the quote is at all comparable to the product covered by the benchmark.<sup>8</sup> In addition, Edison's proposal does not require any minimum number of bids to be used as the benchmark; relying on too few bids could unduly sway the benchmark calculation, particularly as Edison proposes to rely 75% on the bid or other market price information. *Id., at 2818:6-12*.<sup>9</sup> Finally, Edison will not publicly reveal the bids or broker quotes, shrouding in secrecy one of the most important aspects of RPS program implementation. For these reasons, the use of broker quotes and binding bids should be rejected.

## **2. The Commission Should Adopt CalWEA's Proposed Market Price Benchmark For Both Energy And Capacity**

CalWEA, Edison and ORA all proposed that the Commission adopt separate energy and capacity benchmarks. The three proposals, however, differ from one another in certain critical respects. For the reasons discussed below, the Commission should adopt CalWEA's approach.

Before comparing the merits of the three bifurcated proposals, it is important first to address TURN's objections to developing separate energy and capacity benchmarks. TURN proposes to establish only an all-in benchmark and objects to Edison's proposal to separate energy and capacity benchmarks. *TURN Opening Brief at 30-31*. Specifically, TURN argues that Edison's approach (i) will overvalue firm capacity to the detriment of intermittent

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<sup>8</sup> Pursuant to § 399.15(c)(3), the benchmarks must correspond to the value of individual products.

<sup>9</sup> Edison's proposal to rely on market price information for 75% of the benchmark is completely arbitrary and should be rejected.

renewable generators, (ii) will be contentious and delay the process, (iii) will confuse bidding protocols, and (iv) could lead to double penalizing intermittent renewable generators. CalWEA agrees with TURN's criticism of Edison's approach. CalWEA's proposal, on the other hand, effectively addresses TURN's concerns over a separate energy and capacity approach.

First, whereas Edison proposed to establish capacity benchmarks only for dispatchable and non-dispatchable firm capacity, CalWEA's approach would establish a value for firm, unit-contingent and as-available capacity from a consistent set of assumptions and integrated with performance requirements under the standard contract terms. CalWEA's approach will properly value as-available capacity, the most likely product offered by intermittent generators.

Second, Edison failed to describe how the value of capacity would actually be determined. CalWEA's approach, however, would employ the costs of a combustion turbine as a proxy for capacity value. As CalWEA pointed out in its direct testimony and its opening brief, the Commission has used this approach since the 1980s. *CalWEA Opening Brief at 8-9 (and Commission decisions cited therein); CalWEA/Beach, Ex. RPS-12, Ch. 1, at 6.* This long-standing approach is not contentious and will not unduly delay the process.

Third, CalWEA's approach is transparent and easy to follow. Because, under CalWEA's proposal, the predetermined capacity value will be a standardized capacity payment depending upon the product being sold, bidders will not bid a capacity price, only an energy price. As such, there is no likelihood of bidder confusion. The process is not any more complicated than using an all-in benchmark price, as TURN advocates.

Fourth, CalWEA's approach, unlike Edison's and an all-in benchmark price approach, properly recognizes the capacity value of intermittent generators and ensures that the determination of the capacity payment is not left in the hands of the utilities, an invitation to introduce unfair bias into the process. While CalWEA certainly appreciates TURN's concern that the utilities will not give due credit to the capacity value of intermittent resources, the worst way to mitigate this would be to leave the capacity component of the benchmark determination and least cost evaluation, and the determination of as-available

capacity payments, to the utilities' discretion, as would TURN's approach.<sup>10</sup> This, not separating energy and capacity, is a recipe for utility bias. For example, adopting TURN's proposed benchmark methodology, SDG&E indicates its intention not to make any capacity payments to intermittent resources. *SDG&E Supp. Testimony, Ex. RPS-24 at 8; SDG&E's Opening Brief at 6-8*. Edison has also demonstrated an unfounded bias against intermittent generators receiving any capacity value. *Edison/Bergmann, Tr. at 2825:17-2827:6*.

As CalWEA has established in its testimony and during cross-examination of the utilities' witnesses, as-available resources can and do provide capacity value to the utilities. As CalWEA witness Mr. Beach testified, the Commission should develop a benchmark price with a capacity component that "recognizes the capacity characteristics of each of the [firm, unit-contingent, and as-available] electricity products. *CalWEA/Beach, Ex. RPS-12, Ch. 1, at 6*. The Commission has long recognized that as-available QFs qualify for capacity payments, even though they are under no firm obligation to deliver power. *See Decision 82-01-103, 1982 WL 196903, at 22 (recognizing that QFs are to be paid as-available capacity payments under standard offer contracts), Decision 82-04-071, and Decision 82-12-120*. Moreover, as Edison's witness Mr. Bergmann admitted on cross-examination, as-available capacity does have some value depending on the time of delivery and the delivery characteristics of the intermittent generator. *Edison/Bergmann, Tr. at 2827:7-2829:27, and SDG&E/Thomas and Bartolomucci, Tr. at 3306:19-3307:28; see also, Decision 82-12-120, 1982 WL 196691, at 40; and Decision 82-04-071, 1982 WL 196883, at 2*. The best way to protect against undue bias is, as CalWEA has proposed, to adopt an integrated capacity valuation methodology that is employed in the benchmark, the least-cost / best-fit evaluation process and the standard contract terms and conditions.

Finally, ORA's approach to determining capacity value is very similar to CalWEA's except that ORA's approach overvalues the costs of a combustion turbine and assumes that it will only be available in 85% of the hours. *ORA Opening Brief at 6*. These assumptions,

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<sup>10</sup> Although TURN would have an as-available benchmark determined from independent sources, and CalWEA does not necessarily object to TURN's approach in this regard, TURN's all-in approach would leave it to the utility to convert any capacity price bid by a generator into an energy value for the purpose of the benchmark and least-cost / best-fit analysis.

unsupported by the record, overstate the value of capacity and should be rejected. In contrast, CalWEA's proposed capacity value of \$72 per kW-year should be adopted.

**3. The Commission Should Adopt CalWEA's Combined Cycle Plant Input Values In Calculating The Benchmark Instead Of Picking Any One Particular "Real Life" Plant As Edison Has Proposed.**

A number of the parties in this proceeding propose illustrative benchmark values. Recognizing that SDG&E is currently creditworthy and subject to RPS requirements following approval of its renewables procurement plan, and recognizing that all parties are presently engaged in this proceeding, CalWEA's witness Mr. Beach has proposed a series of input values that are ripe for Commission adoption.<sup>11</sup> Edison's argument that because PG&E and Edison are not creditworthy there is no need to establish the market price methodology (*Edison Opening Brief at 15*) simply ignores SDG&E and should be rejected.

CalWEA's proposed input values are consistently derived to establish the benchmark based on the average cost of a new generating facility. Contrary to Edison's argument, CalWEA's approach does not "pick and choose" the highest values from different sources; rather, it picks a reasonable set of assumptions for the kind of new generating facility that will meet the utilities' long-term needs. As Mr. Beach states, CalWEA's proposal is to "come up with a reasonable average overall market benchmark." *CalWEA/Beach, Tr. at 3092:18-3093:14*. As Mr. Beach pointed out "there is adequate information [that has] been culled by the Energy Commission and others from a whole range of [actual] combined-cycle projects at a variety of sites in California," and that it is "that kind of more generic, more average data that the Commission should rely on." *Id. at 3093:9-14; see also, id. at 2996:6-9 (using a "number in the middle of [the] range" for heat rates that is "typical number for the gas-fired cogeneration or combined-cycle plants") and 3077:4-3078:11*. Similarly, TURN's witness Mr. Marcus also takes the same approach, arguing that the Commission should be "seeking a number that is at or slightly above the average." *TURN/Marcus, Tr. at 3158:6-11 ("we shouldn't be looking at the Cadillac, but we shouldn't be looking at the stripped-down Geo Metro, either")*. In addition, as Mr. Beach explains in

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<sup>11</sup> Of course, in certain instances, e.g., gas prices, it makes sense to wait until actual utility procurement to adopt input values, as Mr. Beach testified. *CalWEA/Beach, Tr. at 2993:21-25*.

his cross-examination, the differences that Edison tries to emphasize between its “real-world” plant and CalWEA’s proposal concern parameters that are very small components of the benchmark.

“Well, one thing I want to point out on this last line of cross [covering heat rate, line losses, and emissions costs] is that, you know, you focused on a couple of the parameters for my combined-cycle benchmark . . . that are some of the smallest pieces of my benchmark. I mean, if you look at the NOX emissions, . . . the NOX adds 10 cents per megawatt-hour to the benchmark in northern California, and 20 cents per megawatt-hour in southern California. In a benchmark that's . . . \$50 to \$60 per megawatt-hour, it's a very small component, mainly because . . . new combined cycles with SCR have very low emissions. And so the emission costs are a very small component of the benchmark. Similarly, the line losses. . ., obviously whether we're talking about a .97 or a .98, it's only a 1-percent difference in the benchmark. So frankly I don't think that it's worth -- it would be worth the time and effort, for example, for the Commission to hold a whole other phase of this case, with hearings and testimony, et cetera, and so forth, in order to iron out differences like this. Frankly, I think the testimony that Mr. Marcus and Mr. Monsen and myself have presented in this case is – has all the necessary pieces for the Commission to adopt a pretty solid combined-cycle benchmark.”

*CalWEA/Beach, Tr. at 3002:4-26.*

The Commission has all the necessary pieces it needs in CalWEA’s proposal to adopt a solid, workable combined-cycle benchmark, and it should do so.

#### **4. Gas-Hedging Costs Should Be Part Of The Benchmark Price.**

As several parties pointed out, the Commission should incorporate gas-hedging costs as part of the benchmark under § 399.15(c)(2). Edison argues that if a gas-fired generator has a fixed-price gas contract, then there is no need for the generator to hedge against fuel price risk. *Edison’s Opening Brief at 29 (quoting TURN/Marcus, Tr. at 3180:25-3181:11).* To the extent that the Commission can obtain a reliable estimate of the cost of a fixed price gas contract over a 10-year, 15-year and 20-year term, CalWEA does not disagree with Edison. However, if the Commission relies on such things as futures prices or long-term price forecasts, which are really forward projections of the spot market, then it is necessary to add a hedge value to reflect the cost of the added risk that the seller accepts for fixing the price of gas over a long term.

Edison's second criticism of proposed hedge values is that hedging costs proposed by the parties are incorrect, criticizing a Lawrence Berkeley National Laboratory report used by many parties. Although CalWEA's witness Mr. Beach did utilize the particular report criticized by Edison to develop his proposed hedge costs, it is not the exclusive source of Mr. Beach's information on this point. Instead, CalWEA proposes that "the Commission . . . not just rely on one single data point, but to take a look at, if possible, several or all of these approaches, and . . . put together a [benchmark from a] market basket of different approaches." *CalWEA/Beach, Tr. at 3045:26-3046:4; see also, id. at 3040:18-28.*

## **5. Edison's PURPA Argument Is Not Relevant To The RPS Program**

Just as it did in connection with the interim renewables solicitation adopted in Decision 02-08-071, Edison argues that in implementing the RPS legislation, the Commission must conform its market price benchmark to the avoided cost standard of the Public Utility Regulatory Policies Act of 1978 ("PURPA"). *Edison Opening Brief at 18-19.* Edison argues that, in setting the market price benchmark and ordering the utilities to increase their purchases from renewables at a price no higher than the benchmark, the Commission is in effect setting wholesale rates. *Id.* Since the only authority the Commission has to set wholesale rates, ordinarily the province of FERC, is under PURPA, Edison concluded that the Commission must conform the benchmarks to PURPA's requirements. *Id.* Magically, Edison then conjures up the avoided cost standard under PURPA to mean that the Commission cannot set the benchmark in excess of the price of alternatives available to Edison in the market. *Id.* Edison's argument is without merit.

First, establishing market price benchmarks under the RPS program is not establishing wholesale rates. Consider, for example, what would happen if the Legislature adopted an RPS program without a benchmark price mechanism, as many other state legislatures have done. In this scenario, the Commission would require the utility to procure a certain amount of renewable power pursuant to an auction, and pay the price that results from the auction irrespective of the amount. In this case, there could be no claim that the Commission is establishing a wholesale rate simply by requiring the utility to procure power from renewables pursuant to an auction; the Commission is simply implementing its right to oversee the utility's procurement activities. The fact that the Commission in California is

charged with supplementing the basic RPS program with a market price benchmark that defines the maximum price at which the utility can be required to purchase power from renewables under the auction does not change the fundamental character of the Commission's actions. The Commission is simply placing an outer limit on the amount that the utility can be required to spend in the auction; this is not the establishment of a wholesale rate, any more than requiring the utility to pay the unlimited price that results from an auction is establishing a wholesale rate.

Second, the RPS program, similar to the renewables procurement programs implemented in many other states, is not designed pursuant to PURPA, and the Commission's authority to adopt the RPS program is completely independent of PURPA. PURPA was designed, among other things, to encourage qualifying facilities ("QFs"), and authorizes the Commission to set avoided-cost rates at which the utilities will purchase power from QFs. The RPS program, on the other hand, is applicable to all renewable generators (both QFs and non-QFs), with no preference for QFs. The Commission derives its authority to implement the RPS program from state law, not from PURPA. In fact, §399.15(d) provides that the "establishment of a renewables portfolio standard shall not constitute implementation of [PURPA]." Under the RPS program, the utilities are not obligated to purchase power from renewables at the utilities' avoided costs; rather, the utilities are required to increase their purchases of renewable power in accordance with solicitations that will establish the prices paid.<sup>12</sup>

Third, Edison's argument that the Commission should apply the same principle of indifference as that used to set avoided costs should be rejected. The concept of avoided costs in the context of PURPA bears no relationship to the concept of the market price referent in the context of the RPS legislation. Avoided costs prices set by the Commission as part of the state's implementation of PURPA is the price that the utilities must pay to QFs. The market price referent is a per se reasonableness benchmark. The utility under the RPS

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<sup>12</sup> If Edison is correct that the PURPA avoided cost standard applies to the RPS program, then it also follows that the Commission must limit the RPS program to participation by QFs only. Under PURPA, the Commission only has the authority to set rates for purchases from QFs. Limiting participation to QFs only clearly was not envisioned by the Legislature; the Commission should avoid any such construction of the RPS program.

program is free to contract with renewable generators at prices below or above the market price referent (although the utility cannot be required to pay more than the market price referent under § 399.15(a)(1)). Edison fails to recognize and reconcile the difference (in both form and purpose) between the market price referent and avoided costs.

Finally, even if PURPA is deemed to apply to the market price referents, Edison's assertions are without merit. The avoided cost standard, as implemented in California, has never been limited to the price that is available for purchases of a given product in the market, as Edison now appears to assert. While the Commission at one point was clearly headed in that direction under the requirements of § 390(c), the Commission has considerable latitude in setting avoided cost prices and can certainly employ the method proposed by CalWEA or other parties.

Like the child that threatens to take home its marbles if it does not like the way the game turns out, Edison's position on PURPA should be seen as nothing more than a threat to sue the Commission if Edison does not like the benchmarks adopted by the Commission. In fact, Edison does not even attempt to veil this threat, referring to "a prescription for litigation" and the BRPU, which Edison successfully stopped through litigation. *Edison Opening Brief at 19*. The Commission should reject Edison's blatant attempt to bully its position through the RPS implementation process.

**C. LEAST-COST / BEST-FIT**

**1. The Commission Must Evaluate Bids Based On Total Cost, Not Just Energy Cost.**

Although Edison and CalWEA agree that the Commission should establish separate energy and capacity benchmarks, and that capacity payments to renewable generators should be based upon the adopted capacity value employed in the benchmark assessment, CalWEA disagrees with Edison as to how energy and capacity values should be incorporated into the least-cost / best-fit process. In particular, Edison proposes that bids be scored based upon the energy only price. *Edison Opening Brief at 36*. CalWEA believes that bids should be

evaluated, and pursuant to § 399.14(a)(2)(B) must be evaluated, based upon total costs, including expected energy and capacity payments.<sup>13</sup>

As discussed in CalWEA’s opening brief, § 399.14(a)(2)(B) expressly requires the Commission to adopt a least-cost / best-fit process that compares bids “on a total cost basis.” To ignore expected capacity payments would fail to comply with the express statutory requirement. It also would not make good sense. As demonstrated through cross-examination of Edison’s witness, ignoring capacity costs in bid evaluation could lead to the acceptance of a more expensive product that provides a higher, yet unnecessary, level of service simply because the bidder is able to offer a lower energy price than another bidder that has a higher energy price but a lower overall cost. *Edison/Bergmann, Tr. at 2833:20-2835-11*. In essence, if capacity costs are ignored, California may fill its portfolio with expensive firm resources, when a mix of firm and as-available resources would provide the needed energy and capacity at a lower overall cost.

Moreover, ignoring capacity costs will certainly lead to the bias against intermittent resources about which TURN is concerned. *TURN Opening Brief at 30-31*. Because intermittent resources are not likely to provide firm capacity products that carry with them higher capacity payments, they are more likely to seek capital-cost recovery in their energy payments. Ignoring capacity payments in bid evaluation will provide a distinct, and unwarranted, advantage to firm bidders that can include capital cost recovery in their capacity payments. In essence, Edison’s proposal will allow firm bidders to hide costs from the bid evaluation that intermittent bidders cannot hide.

For these reasons, the Commission should include both capacity and energy costs in the least-cost / best-fit bid evaluation process.

## **2. The Commission Should Adopt Realistic Assumptions For Imbalance Costs.**

Edison’s proposal for incorporating imbalance costs as bid adders are in a number of respects flawed. First, there is no basis for adopting Edison’s proposal to add to a bid any

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<sup>13</sup> Edison is wrong in claiming that CalWEA supports using energy only values in scoring bids. *Edison Opening Brief at 36*.

scheduling and imbalance costs in excess of those that the utility would incur if a dispatchable firm capacity bidder were providing power. *Edison Opening Brief at 36-37.* Edison offers no rationale for relying generically on the cost of a dispatchable firm capacity bidder to determine the excess integration costs of all renewable generators. If anything, integration costs associated with a given bid should be determined by reference to non-renewable providers of comparable products. It makes no sense to assume that a dispatchable firm capacity bidder will be selected to provide all possible products.

Second, Edison argues that the Commission should ignore ISO Tariff Amendment No. 42 in calculating imbalance costs. *Edison Opening Brief at 35-36, n. 39.* Edison asserts that Amendment 42 hides costs that are actually borne by the system. Edison is wrong.

Under the current California market structure, imbalance service is provided by the ISO and the costs thereof are assessed to loads and generators under the ISO tariff. To the extent that the tariff permits generators or their scheduling coordinators to aggregate imbalances over a portfolio of resources or a period of time, these mechanisms are real world drivers of costs that simply cannot be ignored. Edison's attempt to develop some form of underlying imbalance cost that does not in reality exist should be rejected. In fact, Edison's concern that there is some underlying hidden imbalance cost is contradicted by FERC and the ISO, both of whom concluded that Amendment No. 42 will not result in subsidization of intermittent resources. *California Independent System Operator Corp. 98 FERC ¶ 61,327, mimeo. at 9.*

Edison's attempt to add phantom integration costs to renewable bidders, most notably to intermittent renewable bidders, should be rejected.

### **3. The Commission Should Not Foreclose Participation By Hybrid Resources.**

In a footnote to its opening brief, Edison asserts that hybrid resources should not be permitted to participate in the RPS process. *Edison Opening Brief at 35-36, n. 38.* CalWEA believes that hybrid resources are in actuality a microcosm of the least-cost / best-fit process. In particular, hybrid resources represent the combination of renewable and non-renewable resources in such a way as to provide a high value energy product and renewable attributes at

the lowest possible cost. CalWEA recognizes that there may be unique issues associated with incorporating hybrid projects into the RPS process. Nevertheless, the Commission should not, at this time, foreclose such form of participation. Rather, the Commission should include, in a subsequent phase of this proceeding, consideration of how hybrid resources can be incorporated into the RPS program.

**4. PG&E’s “Relative To The Benchmark” Approach Should Be Rejected.**

PG&E proposes that bids be ranked based upon their savings relative to the applicable benchmark. *PG&E Opening Brief at 24*. This approach ignores the fact that some bidders may propose great discounts relative to a high-cost benchmark and yet be more expensive on an absolute basis than others that provide a smaller discount relative to a lower-cost benchmark. *PG&E/Hatton, Tr. at 3435:10-3437:21*. One is reminded of a happy but misguided shopper that is delighted to receive a great price on a lawnmower only to be reminded upon returning home that they do not have a lawn. This is clearly not what is meant by least-cost / best-fit.

**5. The Commission Should Reject Certain Aspects of PG&E’s Transmission Cost Proposal.**

One of the more complex components of the least-cost / best-fit process is the determination of indirect transmission costs, which are to be added to bids to determine total bid costs. While PG&E presents a fairly comprehensive approach, two particular aspects of PG&E’s proposal should be rejected.

First, PG&E’s proposal that transmission costs be allocated in accordance with a given bidder’s place in the ISO’s transmission queue (*PG&E Opening Brief at 26*) should be rejected. While the actual costs to be assessed to a bidder may very well be determined by reference to its place in the queue, the mere fact that a bidder submitted an application before (possibly mere moments before) another bidder should not serve as the determining factor for the Commission’s allocation of potentially significant indirect costs to a given bidder’s bid. Rather, as proposed by CalWEA’s witness Mr. Beach, the Commission should assess a proportionate share of all upgrade costs to the resources that will be accommodated by the

upgrade (whether bid in a particular solicitation or not), regardless of whether or when they entered the ISO transmission queue. *CalWEA/Beach, Ex. RPS-12, Ch. 2, at 5-6.*

Second, PG&E's refusal to offset transmission costs with transmission benefits (*PG&E Opening Brief at 29-32*) should be rejected. This issue is not limited, as PG&E appears to believe, to locating generation within load pockets and attempting to quantify the benefits thereof. To the contrary, this issue goes to the fundamental notion of whether, and to what extent, bidders with upgrades that provide significant network benefits get penalized by considering only the costs of the upgrades. It is without question that certain transmission upgrades will yield benefits primarily to renewable generators. To the extent that a given upgrade, however, significantly improves the reliability or performance of the transmission system, its benefits may outweigh some or all of its costs. If these benefits are ignored, perverse price signals may be sent to developers to seek transmission solutions that appear cheaper but in reality (after offsetting costs with benefits) are not. As such, the Commission should require the utilities, when evaluating transmission costs for the purposes of least-cost / best-fit, to include as an offset to transmission costs any material benefits to the network conferred by a proposed project.

#### **D. STANDARD CONTRACT TERMS AND CONDITIONS**

##### **1. The Commission Must Adopt Standard Contract Terms and Conditions, Including Performance Requirements.**

Perhaps the most incredible aspect of the utilities' opening briefs is their apparent willingness to ignore the express statutory requirement that the Commission adopt standard contract terms and conditions, including performance requirements. § 399.14(a)(2)(D). Edison, for example, simply proposes that the Commission identify the terms that must be standardized and adopt a process for doing so in advance of the first solicitations. *Edison Opening Brief at 39.* PG&E proposes that the Commission adopt the EEI Master Agreement (an enabling agreement that fails to contain product-specific terms and conditions, including performance requirements) as the standard contract, including a handful of often self-serving terms and conditions. *PG&E Opening Brief at 34-37.* SDG&E also suggests that the Commission adopt the EEI Master Agreement and proposes a number of illustrative terms

and conditions. *SDG&E Opening Brief at 31-45*.<sup>14</sup> Paranoid that the Commission might adopt a “standard offer” contract, the utilities expend considerable effort lambasting the standard offers.<sup>15</sup>

Under CalWEA’s proposal, the Commission would comply with the statutory requirement by adopting specific standard terms and conditions, including performance requirements. These provisions, based on the EEI Master Agreement, form all the essentials of a standard contract (other than terms that must be bid by developers) and were included as an attachment to CalWEA’s supplement to its direct testimony. *Ex. RPS-12*.

CalWEA recognizes that relatively scant attention has been given to the specific contract proposals made thus far. As such, in order to comply with the statute’s requirement in a realistic fashion, CalWEA recommends that the Commission adopt on a preliminary basis (i) the EEI Master Agreement, (ii) CalWEA’s proposed EEI Cover Sheet, and (iii) CalWEA’s proposed confirmation letter as the standard contract terms and conditions, including performance requirements required by the statute. At the same time, the Commission should direct the utilities to convene a stakeholder process to negotiate any desired changes to the preliminary terms. Unresolved issues would then be submitted to the Commission for final resolution.

## **2. SDG&E’s Proposed Process For Protestng Its Standard Contract Should Be Rejected.**

SDG&E’s proposal with respect to standardizing contract terms and conditions is, in many important respects, identical to CalWEA’s approach.<sup>16</sup> Both parties envision the

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<sup>14</sup> It is important to note that, while the utilities oppose the adoption of a standard contract, each utility believes that terms that it considers to be important should be standardized.

<sup>15</sup> The historical “standard offers” are not, of course, what CalWEA proposes; the standard contracts must be won through competition. Moreover, CalWEA’s proposal does not preclude the negotiation of terms with a utility; it just prevents a utility from unilaterally imposing changes to the standard form. Finally, standard contracts that define products are essential to the benchmark and the least-cost / best-fit process, as explained in CalWEA’s opening brief.

<sup>16</sup> Although SDG&E proposes to standardize only certain terms and conditions and CalWEA proposes to standardize as many terms and conditions as possible, CalWEA believes that the parties’ differences here is really one of degree and not principle.

development of a standard base contract, developed from EEI documentation, to be used in RPS solicitations. *SDG&E Opening Brief at 30*. Both parties would have a dialogue concerning the contract terms and conditions before the RPS solicitations. *Id. at 27, 29-30*. Both envision a role for the Commission in approving the standard terms and conditions. *Id.* There is, however, one major difference. While CalWEA would have the Commission rule on disputed terms and conditions to be utilized in the standard contract before solicitations are conducted (in effect, CalWEA proposes that the Commission adopt the standard terms and conditions in advance of the solicitations), SDG&E would only allow renewable advocates to protest offensive contract terms after the solicitation has been concluded. *Id. at 29-30*. In the event that the Commission agrees with the protesting party, SDG&E proposes that the Commission direct the utility to enter into good faith negotiations with the protesting party. *Id. (incorporating the SDG&E and TURN Joint Principles)*.

CalWEA objects to SDG&E's proposal primarily because its remedy is likely to be empty. Once a solicitation process is concluded, it will very difficult for renewable developers to sustain the need for Commission intervention. There will be a tendency to declare success, as was done in the interim renewables solicitation, and either defer or reject protests to specific contract terms as unnecessary. Developers that lose a bid, or refrain from bidding, will have a difficult time justifying the cost of raising and pursuing a protest, when the outcome of the process is completely uncertain and may provide no value, even if the developer succeeds in its claims. Sustaining a claim that a given contract term is inappropriate will also be an uphill evidentiary battle, as some developers inevitably will simply accept unfavorable terms and factor the impacts into their pricing; the utility will then be able to point to the fact that other suppliers are not complaining as evidence of the reasonableness of the terms and conditions.

Then, even if by some miracle the renewable supplier succeeds in convincing the Commission that intervention is needed, the prospect of good faith negotiations with the utility after the solicitation is completed is fraught with uncertainty and likely to be wholly inadequate. For example, will the utility be expected to enter into brand new contracts with bidders that failed to bid or lost in the bid process because of the erroneous contract terms? Will these contracts qualify for PGC funds? Can the developer or the utility re-open negotiations on terms (e.g., price) that were not the subject of the dispute but that are

impacted by the outcome? What happens if the developer and the utility are unable to agree? How will changes in the contracts affect the least-cost / best-fit bid evaluation process and benchmark analysis, which presumably are to be based upon the particular products offered by renewable suppliers?

Although CalWEA accepts that SDG&E's proposal is motivated by its good intentions and a good faith belief that the mechanism will work, CalWEA has no such confidence. The best way to ensure that reasonable standard contract terms and conditions, provisions that meet the legitimate needs of both utilities and renewable generators and promote least-cost bids, are developed is through pre-approval of a basic form by the Commission followed by individual negotiations based upon such form after the fact if necessary or desirable. This is CalWEA's proposal.

**3. The Commission Should Only Allow The Utilities To Offer Five-Year Term Contracts In Limited Circumstances.**

§ 399.14(a)(4) states that each utility "shall offer contracts of no less than 10 years in duration" in soliciting and procuring eligible renewable resources, unless the Commission otherwise approves shorter-term contracts. As TURN correctly points out, short-term contracts (such as the five-year contract suggested by Edison or the one-year contract suggested by PG&E) do not provide enough financial incentives for a developer to build a new renewable facility. *TURN Opening Brief* at 49-50. Even if the utilities are able to find new renewable generators that are willing to enter into five-year contracts, the Commission should not encourage such behavior.

If the Commission allows for five-year contracts for new renewable resources, the result is likely to be an inflation of prices and a quicker drain on the PGC fund because the developers will be forced to recover all of the initial investment costs over the first five years of operation (instead of spreading them over 10 to 20 years). The utilities will have no incentive to seek a longer-term contract because any amount above the market benchmark is to be recovered through the PGC, instead of being paid by the utilities. This would lead to an unfavorable result for the ratepayers as the ratepayers (through the PGC fund) will be bearing

the additional costs of the renewable development, but without the benefit of long-term price stability.

CalWEA does recognize, however, as a practical matter, that the utilities may legitimately seek to enter into contracts of less than ten years with existing renewable projects (instead of new ones). Because existing projects are not eligible for PGC funds under the RPS program, there is no concern about the potential drain on the PGC funds as discussed above.<sup>17</sup> CalWEA supports the recommendation of TURN that the Commission establish a standard contract for use in connection with existing projects; to the extent that a simple extension of the existing contract is not acceptable to the parties, the parties should employ the standard contract terms and conditions developed in this proceeding. Such a contract could have a term of five years. The utilities should be free to use this contract outside of the specific RPS auctions in light of the benefits of preserving existing resources and the fact that no PGC funds are available in connection with existing projects. In no case, however, should existing renewable generators be denied the opportunity of bidding on longer-term contracts in RPS auctions, as these projects often require major capital investments and can offer consumers long-term fixed prices.

**4. Bilateral Contracts Outside Of The RPS Auction Process Should Not Receive PGC Funds.**

SDG&E and PG&E propose that they be permitted to enter into bilateral agreements with renewable suppliers outside of the RPS auction process. *SDG&E Opening Brief at 48-50; PG&E Opening Brief at 15.* CalWEA does not oppose allowing utility flexibility to enter into contracts with renewable suppliers outside of the RPS auction process. Renewable attributes purchased under those contracts should qualify against the APT and the 20% by 2017 requirement. Because such contracts were not subject to the least-cost / best-fit evaluation process, however, it would be inappropriate to permit the allocation of PGC funds

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<sup>17</sup> Although the procurement process may seem to be “outside” the RPS Program, if the Commission does allow the utilities to enter into five-year contracts, it is reasonable for the utilities to count procurement under short-term contracts toward their annual procurement targets.

to these renewable suppliers.<sup>18</sup> In order to ensure that scarce PGC funds are allocated appropriately, the Commission should require that bidders seeking PGC funds qualify under the utilities' least-cost / best-fit process.

## 5. Confidentiality

As TURN argues in its opening brief, excessive confidentiality is inappropriate for renewable procurement activities. *TURN Opening Brief at 52*. CalWEA concurs with TURN's assessment of the impact of excess confidentiality on the parties' ability to have meaningful participation in the renewable solicitation process. Specifically, CalWEA agrees with TURN's criticism of PG&E's confidentiality proposal, which includes virtually all information related to its RPS compliance. *Id. at 55*. This level of confidentiality severely impairs oversight, accountability and the viability of the RPS program, and is not necessary to ensure the ability of the utilities to engage in competitive procurement of renewable resources. In general, CalWEA supports the additional level of transparency provided by TURN/SDG&E's joint principle on confidentiality.

Further, the Commission should adopt a confidentiality policy beyond the TURN/SDG&E joint principles. Specifically, the Commission should allow parties access to important contract terms (other than price and the identity of the supplier). The Commission should have more comfort in doing so if it adopts CalWEA's proposal of standardized contract terms. This will minimize the need for confidentiality protections, reduce the potential for the utilities' abuse of confidential terms, and provide the public better oversight and accountability over the utilities' behavior in the renewable solicitation process. The success of the RPS program depends in part on the level of transparency in the implementation process, and the Commission should not allow the utilities to use the cloak of confidentiality to shield themselves from public scrutiny and criticism.

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<sup>18</sup> For example, SDG&E's contention that a demonstration project should be able to fail the least-cost / best-fit test and then be selected under a bilateral deal and draw PGC funds should be rejected. *SDG&E/Bartolomucci, Tr. at 3298-99*.

### **III. CONCLUSION**

CalWEA urges the Commission to consider and adopt the proposals as discussed above.

Respectfully submitted,

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Joseph M. Karp  
Enoch H. Chang  
White & Case LLP

Attorneys for the California Wind Energy  
Association

May 5, 2003

**CERTIFICATE OF SERVICE**

I hereby certify that I have this day served a copy of the

**REPLY BRIEF OF THE CALIFORNIA WIND ENERGY ASSOCIATION ON THE  
IMPLEMENTATION OF THE CALIFORNIA RENEWABLES PORTFOLIO  
STANDARD PROGRAM**

on all known parties to R.01-10-024 named in the official service list by electronic mail for all parties providing an email address, and by mailing a properly addressed copy by first-class mail with postage prepaid to each of the parties not providing an email address.

Executed on May 5, 2003, at San Francisco, California.

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Ruby F. Wheeler