Decision **PROPOSED DECISION OF ALJ HALLIGAN (Mailed 4/24/2007)**

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Promote Policy and Program Coordination and Integration in Electric Utility Resource Planning.	Rulemaking 04-04-003 (Filed April 1, 2004) (QF Issues)
Order Instituting Rulemaking to Promote Consistency in Methodology and Input Assumptions in Commission Applications of Short-Run And Long-Run Avoided Costs, Including Pricing for Qualifying Facilities.	Rulemaking 04-04-025 (Filed April 22, 2004) (QF Issues)

(See Appendix C for List of Appearances.)

OPINION ON FUTURE POLICY AND PRICING FOR QUALIFYING FACILITIES

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OPINION ON FUTURE POLICY AND PRICING FOR QUALIFYING FACILITIES

1. Summary

In this order, we adopt specific policies and pricing mechanisms applicable to the electric utilities' purchase of energy and capacity from qualifying facilities (QFs) pursuant to the Public Utilities Regulatory Policy Act of 1978 (PURPA).[1]

Specifically, we adopt:

- **<u>The Market Index Formula (MIF)</u>**, which is an updated short-run avoided cost (SRAC) formula for pricing SRAC energy. The MIF is based on the Decision (D.) 01-03-067 Modified Transition Formula but contains a market-based heat rate component, instead of an administratively determined incremental energy rate (IER);
- **<u>Two Standard Contract Options for Expiring or Expired QF Contracts and New QFs – Our Prospective QF Program</u>**:
  - o One- to Five-Year As-Available Power Contract.
  - o One- to Ten-Year Firm, Unit-Contingent Power Contract.
  - o QFs will also continue to have the option of either participating in Investor-Owned Utilities (IOU) power solicitations, or negotiating bilateral contracts with the IOUs.
- **<u>Prospective QF Program Contract Provisions</u>**
  - o <u>SRAC Energy Payments</u>: Market Index Formula (MIF). Existing QF contracts providing SRAC energy will also be priced pursuant to the MIF.
  - o <u>Payments for As-Available Capacity</u>: Based on the fixed cost of a Combustion Turbine (CT) as proposed by The Utility Reform Network (TURN), less the estimated value

[1] The United States Congress passed PURPA in 1978, as codified in the United States Codes (USC) at 16 U.S.C. § 824a-3, and 18 Code Federal Regulations (CFR) §§ 292.301 et seq.

of Ancillary Services (A/S) as generally proposed by San Diego Gas & Electric Company (SDG&E).

- Payments for Firm Capacity: Based on the market price referent (MPR) capacity cost adopted in Resolution E-4049[2] of $980/kW, annualized over a 20-year term at a Weighted-Average Cost of Capital (WACC) rate of 8.5%,which results in an annual amortized cost of $104/kW-year.
- The EEI contract[3] will be the basis for our Prospective QF Program contract options, however, a simplified version of the EEI contract shall be utilized for Small QFs.
- The adopted Prospective QF Program contract options are available to QFs that are, or were, on contract extensions set forth in D.02-08-071, D.03-12-062, D.04-01-050, and D.05-12-009.

Additional provisions are outlined in Table 1.

- **An Entry Procedure for New QFs**. New QFs may seek either of the aforementioned contracts as follows:
  - New QFs may seek a contract under the Prospective QF Program. However, if an IOU claims a new QF contract will result in over-subscription, the IOU shall meet and confer with its Procurement Review Group (PRG) within 20 days of receiving such a request from a new QF. The Commission's Energy Division will prepare a brief summary of the PRG meeting regarding the IOU's ability to enter into the new QF contract. If the PRG feedback is unfavorable toward the new QF, the new QF may opt to file a formal compliant with the Commission.
  - A The new QF should make its request for a new QF contract to the IOU in writing. The new QF may send a

[2] MPR Resolution, E-4049, December 2006, http://www.cpuc.ca.gov/Published/Final_resolution/63132.htm

[3] Electric Edison Institute (EEI) contract, http://www.eei.org/industry_issues/legal_and_business_practices/master_contract/OptionalProvisions.htm

copy of its request to Commission's Executive Director, Energy Division Director, and the Division of Ratepayer Advocates (DRA).

1.1. Recent Developments and Scope of this Order

Two recent developments limit the effect of this order on energy prices and capacity prices over the next five years because (1) a large number of QFs have entered into contractually based energy pricing agreements, and (2) many existing QFs are on contractually based capacity pricing.

With regard to energy, in D.06-07-032, we adopted the Pacific Gas and Electric Company (PG&E)/Independent Energy Producers (IEP) Settlement Agreement, in which 121 power projects entered into either a fixed or variable energy price agreement with PG&E. The power deliveries associated with the PG&E/IEP Settlement Agreement "represent almost 52.04% of generation deliveries from all QFs currently under contract with PG&E" (D.06-07-032, pp. 4-5). On October 19, 2006, in Resolution E-4026, we approved Southern California Edison Company's (SCE) request for approval of 61 fixed price energy agreements with existing renewable QFs for a five-year period commencing on May 1, 2007, and ending on April 30, 2012. The 61 contracts represent 1,840 MW of May 2006 on-line capacity for SCE. With regard to capacity payments, many QFs are on contractually-based capacity pricing. Thus, our determination here on updated as-available capacity prices will have a limited impact on the utilities and on the entire pool of QFs.

Since the early 1980s, this Commission's goal in implementing PURPA has been to encourage the development of cost-effective alternative and renewable generation[4], while protecting California's utility ratepayers by ensuring that utilities pay rates that do not exceed what they would have incurred but for purchasing QF power. Today's decision is consistent with this goal, but reflects the fact that the electricity procurement market has changed significantly since the initial standard offer contracts were approved by this Commission.

PURPA requires that QFs be compensated for power deliveries at a level equal to, but not higher than, "the incremental costs to an electric utility of electric energy or capacity or both, which, but for the purchase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source."[5] Thus a primary goal and guidepost in this proceeding is the need to accurately estimate the costs a utility would incur to obtain an amount of power that it purchases from a QF, either by the utility's self-generation or by purchase from a third party, on a short-term and long-term basis.

In addition to evaluating which QF policy approach is the best fit for California at this time, we must consider which proposals are consistent with state and federal law. Today's decision provides utilities and QFs with two flexible contracting options that reflect the requirements of PURPA and the realities of California's energy markets. The policies adopted are consistent with and implement federal and state law regarding QFs, and existing Commission decisions as well as the policy goals articulated in our Energy Action Plan (EAP

[4] "One of PURPA's stated goals is to encourage the development of alternative and renewable generation of electricity in the United States. To serve this end, PURPA sets forth two major provisions. First, PURPA requires utilities to interconnect with and purchase power from QFs at prices up to a utility's avoided cost. Second, PURPA exempts QFs from standard utility cost-of-service regulation." (D.01-05-085, *mimeo.*, p. 2.)

[5] 18 CFR § 292.101(b)(6).

II). In the EAP we adopted "a long-term policy for existing and new qualifying facility resources, including better integration of these resources into California Independent System Operator (CAISO) tariffs and deliverability standards" (EAP II, Section 4 and 7).[6]

With respect to the short-run avoided cost of energy, or SRAC, we have been presented with proposals that range from shifting SRAC directly to market prices, modifying the current formula to link SRAC to market prices, or retaining the current formula. While solely using power market prices to determine SRAC sounds simple and appealing, it would require legislation to eliminate Pub. Util. Code § 390(b), which requires SRAC to be tied to natural gas prices. However, revising the Transition Formulas adopted in D.96-12-028, as modified by D.01-03-067 will not require statutory changes and will permit us to tie SRAC to market prices, and still comply with Section 390(b).

Accordingly for PG&E, SCE, and SDG&E, we define and adopt the Market Index Formula or "MIF" to calculate SRAC energy payments to QFs. The MIF equation is similar to the Modified Transition Formula we adopted for SCE in D.01-03-067, with the exception that the market-based heat rate component, formerly the Incremental Energy Rate (IER), will be calculated from a 12-month rolling average of historical North of Path 15 (NP15) or South of Path 15 (SP15) Day-Ahead (DA) market price data with a "collar" around the possible IER values to provide a cap and a floor to mitigate excessive volatility.

For long term QF policies, we have been presented with several proposals from the investor-owned utilities (IOUs) and consumer advocacy groups that

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[6] EAP II was adopted by this Commission in October 2005 and is a joint policy plan by the California Public Utilities Commission (CPUC) and the California Energy Commission.

would allow QFs to compete in utility resource solicitations, with their price based on the competitive bidding process and provide a one-year market-based contract for QFs who are either unwilling or unable to participate in IOU solicitations.

We have also been presented with proposals from the QF community requesting that the Commission reinstate a series of long term (10 to 20-year) standard offers available to all QFs with expiring contracts as well as new QFs, at prices based on the estimated cost of a combined cycle generating plant. As we discuss below, our experiences with long-term QF contracts have left us unwilling to exactly replicate past practices. Instead, after extensive review, we conclude that the QF procurement process should include power product differentiation and increased flexible performance requirements to better reflect the fact that competition to serve new demand in California exists among utilities, QFs and other non-utility independent power producers. This reality, and the resulting market pricing mechanisms it offers, suggests that QFs should be given reasonable options and incentives to compete with other power providers.

However, we are persuaded that there are currently few options to utility purchases, particularly for Small QFs, whose size prevents them from participation in the CAISO markets.[7] These QF should continue to have available standard offers, albeit at market prices.

For these reasons, we adopt two flexible market-based contract options in addition to the competitive solicitation and bilateral contracting options already

[7] Generators may not participate in CAISO markets, including the upcoming Market Redesign and Technology Upgrade (MRTU) market, unless the generator is capable of providing at least one MW of dependable capacity.

available to QFs. To safeguard against oversubscription in the future, we adopt a process by which the utilities can request relief from the requirement to enter into the standard offers.

First, QFs who choose only to provide non-firm, as-available power will have access to a one- to five-year as-available contract with energy prices based on the MIF formula and posted as-available capacity payments based on the cost of a combustion turbine less the estimated value of Ancillary Services.

Second, we will make available a one-to-ten-year contract for firm unit-contingent power, with energy prices based on the MIF formula, and capacity payments based on the market price referent (MPR) capacity cost adopted in Resolution E-4049 of $980/kW, annualized over a 20-year term at a Weighted Average Cost of Capital (WACC) rate of 8.5%, which results in an annual amortized cost of $104/kW-year. This longer-term contract option is intended to provide sufficient contract and pricing certainty to allow QFs to make decisions on capital expenditures for facilities and upgrades.

Our prior PURPA implementation policies reflected a time when the QF industry was in its infancy, and standard offers were deemed the fastest, most efficient way to spur new technology and investment. However, this is no longer a nascent industry. QF generation is currently well established and constitutes 20-30% of the utilities' resource portfolios.

We also recognize that utilities are reluctant to keep QFs in their portfolios because they do not contain the performance guarantees that utilities would otherwise need to include in power contracts and that are commonly available in the market. For example, the frequently touted benefits that QFs offer the state, (i.e., that they are in or near utility load centers or load pockets, utilize existing interconnections and transmission access, facilitate peak power deliveries, and provide environmental benefits) may not be characteristic of all QFs. However, QFs which are able to offer these benefits should be uniquely situated to compete in utility solicitations at prices that reflect the cost that the utilities would otherwise have to pay for an equivalent resource, consistent with PURPA.

The contract terms and pricing in this decision apply specifically to expired, expiring and new QF contracts. Other than updating the SRAC formula and posted capacity prices, we do not change existing QF contracts. Furthermore, this decision updates the methodology for calculating SRAC energy prices on a prospective basis only, to ensure that SRAC prices continue to reflect utility avoided cost in the changing electricity markets in California.

We also continue to require the utilities to make available CAISO scheduling services to QFs. QFs whose size prevents them from participation in the CAISO markets should not have to establish scheduling operations staff to interact with the CAISO.

2. Procedural History

On April 1, 2004, we issued an Order Instituting Rulemaking (OIR) to Promote Policy and Program Coordination and Integration in Electric Utility Resource Planning. Among other procurement issues, Rulemaking (R.) 04-04-003 indicated that the development of a long term policy for handling QFs with expiring contracts and procurement policies for new QFs would be among the key issues to be addressed (OIR, p. 4, pp. 18-19). R.04-04-003 also indicated the Commission's intent to issue a separate rulemaking to address avoided cost issues, including the need for a complete review of the pricing methodology applicable to QFs.

On April 22, 2004, the Commission issued R.04-04-025 to develop avoided costs in a consistent and coordinated manner across Commission proceedings, including QF pricing issues. In this rulemaking, we reiterated certain goals that were adopted in both D.03-12-062 and D.04-01-050, issued in our initial procurement rulemaking (R.01-10-024):

> … [I]n our view, there is a pressing need to revisit the SRAC pricing system, which will accurately and fairly set utility avoided cost prices both under current and expected future market conditions and with an eye toward diverse utility resource portfolios.
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> As the foregoing discussion demonstrates, the SRAC energy pricing formula is now out of date. The capacity pricing component of the SRAC formula is also problematic, because the QFs receive capacity payments in addition to energy payments. With SRAC energy prices that can now be above market prices, the additional capacity payments that QFs receive could compound any inequity to the utilities and their ratepayers of the current SRAC pricing formula.
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> We have a two-year window until most existing QF contracts begin to expire, and we should craft a remedy in the new OIR that better matches QF contracts with the actual needs and economic alternatives of the IOUs. Because it is so important that the current methodologies to establish SRAC be modified, we are directing the Commission staff to immediately begin work on a draft Instituting Rulemaking (OIR) that will examine and propose appropriate modifications to the SRAC methodology.[8]

The initial prehearing conference (PHC) was held on November 9, 2004. On January 4, 2005, the Assigned Commissioner issued the first Assigned Commissioner's Ruling and Scoping Memo (ACR) in R.04-04-025 that separated the various issues to be addressed in R.04-04-025 into three phases: (1) Phase I of this rulemaking was to address an immediate need to adopt avoided costs for use in evaluating potential energy efficiency programs; (2) Phase II was to

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[8] D.03-12-062, pp. 58-59. *See* also D.04-01-050, pp. 155-156.

address all SRAC issues; and (3) Phase III would consider long run avoided costs (LRAC) issues.

The January 4, 2005 ACR also noted that the QF pricing issues in R.04-04-025 must be carefully coordinated with the QF policy issues to be addressed in R.04-04-003[9] and scheduled a joint PHC. In response to concerns expressed by many of the parties at the January 24, 2005 PHC, a second ACR was issued on February 18, 2005, combining the two rulemakings for purposes of testimony and evidentiary hearings on QF policy and pricing issues. The second ACR also modified the January 4, 2005 scoping memo such that all QF pricing issues would be addressed in Phase II of R.04-04-025.

The two dockets have been combined for evidentiary hearings to reduce duplication and for the efficiencies that one round of evidentiary hearings can provide to the parties and the Commission.[10] In addition, a joint Administrative Law Judge (ALJ) ruling in R.99-11-022 and R.04-04-025 transferred certain SRAC issues from R.99-11-022 to R.04-04-025, including the determination of an IER and an Operation & Maintenance (O&M) adder, but excluded other issues that remain in R.99-11-022.

Testimony was served on August 31, 2005. Rebuttal testimony was served on October 28, 2005. Evidentiary hearings were conducted from January 18, 2006 through February 2, 2006.

Concurrent opening and reply briefs were filed on March 3, 2006, and March 17, 2006. Opening Briefs were filed by Davis Hydro, CAISO, PG&E, TURN, the Cogeneration Association of California and the Energy Producers and

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[9] The September 30, 2004, ACR in R.04-04-003 designated R.04-04-003 as the forum for considering long-term policies for new QFs and QFs with expiring contracts.

[10] The two proceedings are not consolidated.

Users Coalition (CAC/EPUC), the IEP, the California Biomass Energy Alliance, L.L.C., the California Landfill Gas Coalition and the California Wind Energy Association (jointly, the "Renewables Coalition"), DRA, the County of Los Angeles, SCE, RCM Biothane (RCM), SDG&E, Californians for Renewable Energy (CARE), and the California Cogeneration Council (CCC). Reply Briefs were filed by Davis Hydro, the County of Los Angeles, CAC/EPUC, TURN, IEP, PG&E, CCC, SCE, RCM, and SDG&E.

3. PURPA and Other Legal Requirements

3.1. Federal Law

Sections 201 and 210 of PURPA encourage resource competition and the development of cogeneration and renewable energy technologies by non-utility power producers called qualifying facilities, or QFs. PURPA requires the Federal Energy Regulatory Commission (FERC) to prescribe and periodically revise rules that "require electric utilities to offer to . . . purchase electric power[11] from [QFs]."[12] "PURPA does not permit either FERC, or the States in their implementation of PURPA, to require a purchase rate that exceeds avoided cost."[13] Rates paid by utilities for purchases of electric energy may not exceed "the incremental cost to the electric utility of alternative electric energy."[14] PURPA defines avoided cost with respect to electric energy purchased from a QF as "the cost to the electric utility of the electric energy which, but for the

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[11] The term electric power, as used in this decision refers to electric energy, electric capacity, or both.

[12] 16 U.S.C. § 824a-3(a).

[13] *Southern California Edison v. Pub. Util. Comm'n*,101 Cal. App. 4th 982, 998 (2002); reh'g denied, 2002 Cal. App. LEXIS 4728 (2002), review denied, 2002 Cal. LEXIS 8129 (2002). (*Edison II*.)

[14] 16 U.S.C. § 824a-3(b).

purchases from such [QF] such utility would generate or purchase from another source."[15]

The FERC CFR regulations implementing PURPA provide in pertinent part that: "each electric utility shall purchase, in accordance with [18 CFR] § 292.304, any energy and capacity which is made available from a [QF]. . . "[16] Section 292.304, entitled "rates for purchases," establishes a pricing regime for purchases by IOUs from QFs. Consistent with 18 U.S.C. § 824a-3, § 292.304(a)(1) requires first that "rates for purchases shall: (i) [b]e just and reasonable to the electric consumer of the electric utility and in the public interest. . ."[17] While rates may not exceed avoided costs,[18] rates will satisfy the "just and reasonable" and non-discrimination requirements of § 292.304(a) "if the rate equals the avoided costs determined after consideration of the factors set forth in paragraph (e) of this section."[19] Paragraph (e) provides a list of factors to be taken into account in determining avoided costs, "to the extent practicable."

The FERC's rules require that standard rates for purchases be put into effect only "for purchases from qualifying facilities with a design capacity of 100 kilowatts or less."[20] Whether to implement standard rates for qualifying facilities "with a design capacity of more than 100 kilowatts" is discretionary.[21]

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[15] 16 U.S.C. § 824a-3(d). PURPA also requires that the cost to the utility be "just and reasonable" to electric consumers while not discriminating against QFs. (16 U.S.C. § 824a-3(b)(1) and (2).)

[16] 18 CFR § 292.303(a).

[17] 18 CFR § 292.304(a)(1).

[18] 18 CFR § 392.304(a)(2).

[19] 18 CFR § 392.304(b)(2).

[20] 18 CFR § 392.304(c).

[21] 18 CFR § 392.304(c)(2).

Purchases from "as-available" QFs are subject to special pricing rules. QFs may provide energy as it is available, "in which case the rates for such purchases shall be based on the purchasing utility's avoided costs calculated at the time of delivery."[22] QFs providing electric energy or capacity under a contract are to be paid either avoided costs at the time of delivery, or avoided costs calculated at the time the QF entered the contract, whichever the QF chooses at the time it enters the contract.[23]

3.2. State Law and the Commission's Implementation of PURPA

PURPA, and related FERC regulations, delegate the implementation of the pricing provisions to the states.[24]

In response, this Commission developed a series of standard offers[25] which required the IOUs to purchase alternative sources of power from QFs by entering into contracts with QFs pursuant to the terms and conditions contained in the standard offers. While the standard offers were extremely successful in terms of the amount of QF capacity developed in California, they were much less successful in accurately reflecting the IOUs avoided cost as the electricity market evolved and large numbers of QFs came on line. As a result, in the mid-1980s,

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[22] 18 CFR § 392.304(d)(1).

[23] 18 CFR § 392.304(d)(2).

[24] 16 U.S.C. § 824a-3(f)(1).

[25] The Commission approved four standard offers. SO1 and SO3 are "as-available" contracts in which QFs are paid SRAC energy and capacity in the time periods they deliver energy. SO3 is only applicable to QFs less than 100 kW. SO1 and SO3 provide for termination upon notification by the QF only. SO2 and ISO4 are "fixed" price contracts. SO2 offered a fixed capacity price and SRAC energy prices and was available for a term of up to 30 years. ISO4 QFs could select several payment options, including fixed capacity prices, and a period of fixed energy prices. ISO4 contracts were also available for a term of up to 30 years.

the Commission was forced to suspend all of its fixed forecast standard offers due to oversubscription and forecast errors.[26]

In D.95-12-063, as modified by D.96-01-069, the Commission envisioned a major shift in the Commission's mechanisms used to price and acquire QF power. In particular, the restructuring decision directed that short-run QF prices would be based on the market clearing prices developed through the Power Exchange, or PX.

Consistent with this new direction, D.96-10-036 terminated as of January 1, 1998 any requirement that utilities enter into the remaining standard offers. For "grandfathered" QFs, i.e., those with contracts entered into prior to December 20, 1995, pricing would continue to be based on the contract terms, which almost universally set price at SRAC for energy. The bulk of the remaining SO contracts are now due to expire over the next decade. Attachment A to this decision summarizes the various standard offer types.

In September 1996, as part of the legislation for restructuring California's electric industry, the Legislature enacted Pub. Util. Code § 390. Pub. Util. Code § 390 sets forth specific components to use in setting SRAC, pending a shift to the use of California Power Exchange (PX) prices to establish SRAC. Section 390(b) requires the Commission to calculate SRAC energy prices using a formula that links SRAC energy prices to California border natural gas prices. Pursuant to the requirements of § 390(b), the Commission issued D.96-12-028, which adopted a "Transition Formula" for each utility to calculate SRAC energy payments to QFs. In response to the energy crisis of 2000 and 2001 and the associated rise in natural gas prices, on March 27, 2001, the Commission adopted D.01-03-067, which, among other things, revised SCE's Transition Formula by replacing the

[26] See, D.85-07-021, 18 CPUC2d 315, and D.86-05-024, 21 CPUC2d 124.

fixed factor with a dynamic factor. D.01-03-067 also replaced the Topock[27] gas index used in the SRAC Transition Formula with a gas index based on Malin,[28] plus intrastate gas transportation. No changes were adopted for the factors used to calculate SRAC for PG&E or SDG&E. The revised Transition Formula for SCE is more commonly known as the Modified Formula.[29]

In addition, on June 13, 2001, the Commission adopted D.01-06-015, which pre-approved three voluntary QF contract amendments, including the 5.37 cents per kilowatt (kW) five-year, fixed energy price amendment. Subsequently, numerous contract amendments were approved by the Commission between IOUs and QFs, primarily adopting the fixed energy price amendment, and in some instances, different values for the IER and O&M adder.[30]

Beginning in 2002, the Commission issued a series of decisions directing the IOUs to resume responsibility for procuring energy resources. An interim procurement policy for expiring QF contracts was part of that effort, as adopted in D.02-08-071[31] and D.03-12-062 and modified and extended in D.04-01-050, and D.05-12-009. During interim procurement, D.02-08-071 and D.03-12-062 required utilities to enter into SO1 contracts of one year in length. Pricing for these contracts would be at posted SRAC, pursuant to the Modified Formula in D.01-03-067.

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[27] Topock is located at the California/Arizona border and is an entry point for gas into Southern California Gas Company's system.

[28] Malin is located at the California/Oregon border and is an entry point for gas into PG&E's gas system.

[29] *See* D.02-02-028.

[30] *See for example*, D.01-07-031 in R.99-11-022 and D.03-04-001 in A.02-01-035.

[31] *See* D.02-08-071, *mimeo.*, p. 32.

Under the revised interim policy adopted in D.04-01-050, the IOUs were required to offer five-year contract extensions to QFs that wished to provide power at posted SRAC prices as an incentive to encourage existing QFs to continue providing power and to make efficiency upgrades. D.04-01-050 also put parties on notice that certain renewed contracts would be subject to subsequent changes in pricing methodologies that may result from this rulemaking.

Effective January 1, 2006, D.05-12-009, continued the interim relief provided in D.04-01-050 for QFs with expired or expiring contracts until the Commission issues a final decision in the combined dockets, R.04-04-003 and R.04-04-025. We issue that final decision today. In part because the development of our prospective QF Program has taken longer than we anticipated, we opt to make it available to QFs that are, or were, on contract extensions approved in D.02-08-071, D.03-12-062, D.04-01-050, and D.05-12-009.

3.3. Energy Policy Act of 2005

On August 5, 2005, Congress enacted the Energy Policy Act of 2005 (EPAct 2005). Section 1253 of EPAct 2005 added Section 210(m) to PURPA. Under Section 210(m)(1), FERC will exempt a utility from entering into *new* QF contracts or obligations if it finds that QFs have non-discriminatory access to one of three market conditions. (16 U.S.C. §824a-3, subd. (m)(1).)

On January 19, 2006, FERC issued a Notice of Proposed Rulemaking (NOPR)[32] regarding PURPA Section 210(m) which "provides for termination of an electric utility's obligation to purchase energy and capacity from qualifying

[32] FERC Notice of Proposed Rulemaking, New PURPA Section 210(m) Regulations Applicable to Small Power Production and Cogeneration Facilities Docket No. RM06-10-000. (71 Fed. Reg. 4532 (January 27, 2006).)

cogeneration facilities and qualifying small power production facilities (QFs), if FERC finds that certain market conditions are met."[33] This rulemaking, also referred to as the Obligation NOPR, proposed a framework for FERC's determination of whether electric utilities will be exempt from the PURPA mandatory purchase obligation as otherwise provided in PURPA Section 210.[34]

In response to the Obligation NOPR, the IOUs argued that the potential end of the PURPA mandatory purchase obligation under EPAct 2005 should cause the Commission to be very cautious and limit any new contracts to very short duration (e.g. one year). In contrast, the QF parties suggest that the Commission should do the opposite, noting that the only jurisdiction that the Commission has to set wholesale power prices is the jurisdiction that the Commission derives from PURPA. As such, the CCC argues that the Commission should view the continuing purchase obligation as a "window of opportunity" within which to secure the benefits of cogeneration by making long-term contracts with avoided cost pricing available to cogenerators whose contracts expire and to new cogenerators.

On October 20, 2006, FERC issued *New PURPA Section 210(m) Regulations Applicable to Small Power Production and Cogeneration Facilities* (Order 688)[35] to amend its regulations governing small power production and cogeneration in response to Section 1253 of EPAct 2005 and Section 210(m). In Order 688, FERC

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[33] 71 Fed. Reg. 4532.

[34] The Obligation NOPR is procedurally separate from the NOPR concerning Revised Regulations Governing Small Power Production and Cogeneration Facilities, RM05-36-000 (Criteria NOPR). (70 Fed. Reg. 60456 (October 18, 2005).) The Criteria NOPR concerns new Section 210(n) and addresses the requirement that no new qualifying cogeneration facility can enter into a contract with an electric utility unless the cogeneration facility satisfies criteria for new qualifying cogeneration facilities.

[35] 18 C.F.R § 292, 71 Fed. Reg. 64342 (December 1, 2006).

provided for, among other things, the termination of the requirement that an electric utility enter into a new contract or obligation to purchase electric energy from QFs if the FERC finds that the QF has nondiscriminatory access to:

> (1)(i) Independently administered, auction-based day ahead and real time wholesale markets for the sale of electric energy; and
>
> (ii) Wholesale markets for long-term sales of capacity and electric energy; or
>
> (2)(i) Transmission and interconnection services that are provided by a Commission-approved regional transmission entity and administered pursuant to an open access transmission tariff that affords nondiscriminatory treatment to all customers; and
>
> (ii) Competitive wholesale markets that provide a meaningful opportunity to sell capacity, including long-term and short-term sales, and electric energy, including long-term, short-term and real-time sales, to buyers other than the utility to which the qualifying facility is interconnected. In determining whether a meaningful opportunity to sell exists, the Commission shall consider, among other factors, evidence of transactions within the relevant market; or
>
> (3) Wholesale markets for the sale of capacity and electric energy that are, at a minimum, of comparable competitive quality as markets described in paragraphs (a)(1) and (a)(2) of this section.[36]

With respect to the California market, FERC determined that it would be premature to find that the CAISO had met the criteria of Section 210(m)(1)(A)[37] once its ongoing market redesign becomes effective.[38] Further, while FERC determined that CASIO was a "regional transmission entity" and thus, met the

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[36] 18 CFR § 292.309, subd. (a) (emphasis added).

[37] This requirement is adopted as 18 CFR § 292.309(a)(1).

[38] Order 688, 71 Fed. Reg. 64363.

requirements of Section 210(m)(1)(B)(i), it did not make any determinations with regard to Section 210(m)(1)(B)(ii).[39] Thus, FERC determined that:

> electric utilities that are members of the CAISO seeking relief from the mandatory purchase requirement will need to file an application pursuant to section 210(m)(3) and § 292.310 of the Commission's regulations with the Commission and make the showings required by section 210(m)(1)(B)(ii) in order to be relieved of the PURPA purchase obligation.[40]

Order 688 further establishes a "rebuttable presumption that the requirement that an electric utility enter into new contracts or obligations to purchase from a QF remains in effect, *in all markets*, for QFs sized 20 MW net capacity or smaller."[41] This presumption, however, could be rebutted upon demonstration by the electric utility "with regard to each small QF that it, in fact, has nondiscriminatory access to the market."[42]

Today's decision addresses the QF Program as it exists today, in accordance with the modified mandatory purchase obligation. Therefore, our policy determinations must ensure that QFs continue to have opportunities to provide power to the utilities under terms and conditions that offer mutual benefit to utilities, consumers and QFs. Nevertheless, we cannot ignore the changes that have occurred in the PURPA program and must keep in mind that federal regulations reflect an industry that is becoming increasingly competitive.

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[39] This requirement is adopted as 18 CFR § 292.309(a)(2).

[40] Order 688, 71 Fed. Reg. 64363.

[41] Order 688, 71 Fed. Reg. 64352 (emphasis in original; footnotes omitted).

[42] Order 688, 71 Fed. Reg. 64352.

4. History of SRAC Energy Pricing

4.1. Background of the Formula

The Commission has set SRAC energy prices using a variation of the following formula for 25 years:

SRAC Energy Price = Fuel Price x IER Heat Rate + O&M Adder

Since the outset of the QF Program, SRAC energy prices have always been set on a prospective basis. With respect to retroactive adjustments of these prices, the Commission has generally declined to make retroactive downward adjustments.[43] Each element of the formula has a lengthy history of CPUC proceedings and decisions. The formula reflects the fact that a fossil fuel - oil or natural gas - has always been the predominant marginal resource for producing electricity in California. The components of the SRAC formula reflect costs averaged over periods from one month, at a minimum, to as long as several years. Thus, SRAC prices will likely not equal IOU avoided costs on a day-to-day basis.

4.1.1. Fuel Price

Until the mid-1980s, fuel oil was the predominant marginal fuel. Avoided fuel costs were revised quarterly, based on the IOUs' actual costs. When natural gas largely displaced fuel oil in the mid-1980s, the avoided fuel cost was based on the fully bundled tariffed rate that the electric IOUs paid to the gas utilities for natural gas supplied for electric generation.

With restructuring of the natural gas industry in the late 1980s, the electric IOUs began to buy their own gas supplies, with the gas IOUs providing only transportation and storage services. Unbundled gas commodity markets opened

[43] See, e.g., *Biennial Resource Update Plan* [D.96-07-026] (1996) 66 CPUC2d 780; *Order Instituting Ratemaking No. 2* [D.82-12-120] (1982) 10 CPUC2d 553.

first in the producing basins and later at natural hubs along the major interstate pipelines, such as Topock, Arizona and Malin, Oregon. The natural gas trade press began to report price indices for these markets.

In 1991, the Commission approved an "index methodology" to determine the avoided fuel cost, using published producing basin indices to track the electric IOUs' actual natural gas costs on a timely basis. SRAC postings changed from quarterly to monthly, to coincide with the reporting of monthly “bid week” gas prices.

From 1991 - 1996, the Commission adjudicated numerous issues concerning the index method, as gas markets continued to develop and the electric IOUs' gas purchases became more diversified and complex. The electric IOUs began to buy significant volumes in the border markets to take advantage of low border prices that resulted from the then-present excess pipeline capacity to California.

In 1995 and early 1996, it became clear that the California electric industry would be restructured. In an effort to simplify the transition to a restructured market in which electric market prices would set SRAC, and to reduce the contentiousness of the index method, the IOUs and QF parties agreed in early 1996 to move to simplified SRAC “transition formulas” to set SRAC prices until the PX market was functioning properly.

The Commission-adopted SRAC “Transition Formula” for each utility, pursuant to Pub. Util. Code § 390(b), prescribes the basic elements for determining energy prices to be paid to QFs. D.96-12-028 adopted specific formula values for each of the IOUs. Each IOU’s Transition Formula includes a starting energy price, a starting gas price, a utility-specific gas factor (or factor), California border gas price, and intrastate gas transportation costs to approximate a burnertip gas price.[44] The Transition Formula provides for the starting energy price to be adjusted monthly to reflect changes in assumed fuel costs, as reflected in percentage changes to certain border gas price indices. The specific 'factor' for each utility was "necessary to yield a fair representation of the historical values required by AB 1890." (D.96-12-028, *mimeo.*, p. 14.)

The original transition formula values adopted in D.96-12-028 were based on regressions of 1994 - 1995 SRAC prices versus border gas prices, and were driven entirely by changes in border gas prices. The SCE and SDG&E formulas used 100% Topock border prices; the PG&E formula reflected a 50/50 mix of Malin and Topock border prices.

The Transition Formula was expected to be used for a relatively short "transition period" until energy payments could be based on California PX prices. (See Pub. Util. Code, § 390 (c).) The PX ceased market operations at the end of January 2001, so the Transition Formula remains in use. At the time of the PX demise, the Transition Formula for each utility had remained unchanged for four years.

In the wake of the 2000-2001 energy crisis, and in response to numerous SCE requests, the Commission modified the Transition Formula for SCE in D.01-03-067, although PG&E and SDG&E remained on the original Transition Formula approved in D.96-12-028. D.01-03-067 also replaced the Topock gas price index in the SRAC energy formula for each utility with a Malin index plus

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[44] The Transition Formula does not contain a variable O&M adder, but SCE's Modified Formula does contain an O&M adder.

and off-system transportation rate.[45] The SRAC energy Transition Formula adopted in D.96-12-028 is shown here:

Original SRAC Transition Formula

$$Pn = \left[\, Pb + Pb \times [(GPn-GPb)/\ GPb] \times (\text{utility factor}) \,\right] \times TOU$$

Pn = calculated SRAC energy price, cents/kWh
Pb = starting energy price (as required by Section 390), cents/kWh
GPn = current gas price, $/MMBtu
GPb = starting gas border price (as required by Section 390), $/MMBtu
Utility Factor for SCE = .7067 (unitless -- all units cancel out)
TOU = time of use multiplier (no units)

In D.01-03-067, the Commission modified SCE's Transition Formula by replacing SCE's fixed factor of 0.7067 with a 'floating' factor that changes in value from month to month. The 'floating' factor is actually a formula unto itself, employing an updated burnertip gas price, an IER, and an O&M adder. Shown below, first, is the 'floating' factor adopted in D.01-03-067 at page 6 (with the omitted division line now included). Note that all the units cancel out rendering the factor unitless:

$$\text{SCE Factor} = \frac{[IER \times (GPn + GTn)/10{,}000] + O\&M - Pb}{Pb \times (GPn - GPb)/GPb}$$

Sample Factor Calculation for November 2001 for SCE

$$0.4932 = \frac{[9140\ (3.3439 + 0.2777)/10{,}000] + 0.2 - 2.0808}{2.0808\ (3.3439 - 1.3975)/1.3975}$$

GTn = intrastate transportation costs, $/MMBtu
IER = Incremental Energy Rate (utility heat rate) Btu/kWh
O&M = operations and maintenance costs, Cents/kWh

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45 The change from Topock to Malin was made due to concerns that the Topock gas prices were being manipulated and were no longer robust for purposes of pricing SRAC energy.

10,000 = [$1/100 Cents] x [1,000,000 Btu/MMBtu]

SCE's Modified Formula

$$Pn = Pb + [Pb \times \underline{(GPn - GPb)/GPb]} \times \frac{\overbrace{[IER \times (GPn + GTn)/10{,}000\,] + O\&M - Pb}^{\text{=============utility factor===========}}}{[Pb \times (GPn - GPb)/GPb]}$$

When the floating factor is inserted into the Transition Formula, a number of the components algebraically cancel out, resulting in the following:

$$Pn = (IER \times (GPn + GTn)/10{,}000) + O\&M$$

Sample Calculation for April 2006 for SCE
$P_{April\text{-}2006}$ = 6 .4597 cents/kWh = (9140 (6.3205 + 0.5282)/10,000) + 0.2

4.1.2. The Incremental Energy Rate (IER)

The IER, a heat rate in British thermal unit (Btu) per kWh, is intended to reflect the efficiency with which the IOUs could obtain the energy that they would have to produce (or purchase) "but for" QF production. IERs reflect the fact that fossil generation is not always on the margin. IERs increase as demand increases, as less efficient plants are needed to supply the marginal kWhs.

Traditionally, IERs have been calculated through complex production cost computer modeling of the IOU systems both with and without QFs, and have generated issues that have been difficult, at best, for the Commission to adjudicate.

The general formula for the IER has been:

IER = [(QFOUT Costs - QFIN Costs) / QF Energy] / Avoided Fuel Cost

The IER is expressed in units of Btu per kWh, as follows:

IER = [(Costs in $) / (QF Energy in kWh)] / Fuel Costs in $ per Btu

= [($ / kWh) / ($ / Btu)] = Btu / kWh

IERs were originally determined in general rate cases. In the late 1980s, the Commission moved IER issues to annual Energy Cost Adjustment Clause (ECAC) cases. Due to the complexity of IER issues, the IOUs, Office of Ratepayer Advocates (ORA), and QF parties tended to settle IER issues outside of the hearing room, with the Commission reviewing and approving those agreements.

Commission-adopted IERs have been in the range of 9,000 to 10,000 Btu per kWh over the two decades of the California QF Program. The SRAC transition formula factors approved in D.96-12-028 are based on regressions of 1994 - 1995 SRAC prices, and thus reflect 1994 - 1995 IERs.

4.1.3. The O&M Adder

The Operation and Maintenance (O&M) component of the Transition Formula is designed to capture the IOUs' generating costs (except for fuel and capital costs) that vary with the amount of power purchased from QFs. Historically, these costs have been limited to consumables such as chemicals and lubricants and to O&M costs that vary with the amount of power produced in IOU-owned gas-fired power plants (such as the costs of certain maintenance activities that are scheduled based on plants' production or operating hours, as well as the O&M costs avoided if QF power allows an IOU to place older units on standby). Variable generating costs today also include air emission credit costs and periodic costs to replace expensive catalysts in air emission control equipment.

Commission-adopted O&M adders have ranged from $1 to $3 per megawatt hour (MWh). D.01-03-067 adopted an O&M adder of $2 per MWh for SCE.

4.2. Proposals for SRAC Energy Pricing

Five parties (PG&E, SCE, SDG&E, TURN, and CCC) have proposed SRAC energy pricing methodologies that utilize implied market heat rate (IMHR) figures derived from Day-Ahead power price indices at NP15/SP15 and spot bid week natural gas indices at border trading points or at the burner-tip. For example, the IMHR for $56.00/MWh power at NP15 or SP15, and $7.00/MMBtu gas at the border is $56.00/MWh ÷ $7.00/MMBtu = 8,000 Btu/kWh. While the respective PG&E, SCE, SDG&E and TURN proposals differ in overall mechanics, they all use unadjusted IMHRs. The CCC's proposal derives IMHRs in a manner similar to SDG&E and SCE, except that CCC uses forward prices as opposed to historical prices. CCC then grosses up the result with a proposed adjustment factor to reflect an estimated aggregate value of QF generation.

In contrast, two parties (CAC/EPUC and IEP) recommend keeping PG&E's existing Transition Formula. IEP also recommends keeping SCE's existing Modified Formula. However, CAC/EPUC recommends moving SCE from the Modified Formula adopted in D.01-03-067, back to the original Transition Formula approved in D.96-12-028. The QF parties generally argue that there are many problems with the existing Day-Ahead market that prevent Day-Ahead prices from accurately reflecting the utility avoided cost. In particular, the QF parties explain that the Day-Ahead market is very small and the utilities' transactions in the market represent only about 4% of their load. The QF Parties also complain that the Day-Ahead market price doesn't reflect the cost of higher priced units that are dispatched through reliability-must-run (RMR) contracts or CAISO must-offer waiver denial (MOWD) provisions. The QF parties are also concerned that, since the utilities are the dominant participant in the markets, they have the ability to artificially depress market prices.

It should be noted that most parties recommend the use of burner-tip gas prices in their proposed SRAC energy equations, while PG&E recommends the use of a border gas price, and TURN recommends the use of the PG&E City Gate trading point price. An illustration of these gas price differences appears in Table 2, Party Positions on SRAC Energy Pricing.[46] Although these prices, and their relative differences, will fluctuate over time, it is imperative to clearly identify the proposed price inputs for comparison purposes.

4.2.1. SCE

SCE proposes that "the Commission abandon the [Transition Formula] methodology adopted in D.96-12-028 in favor of an approach that compares monthly electricity prices in the wholesale electricity markets to natural gas prices to compute an implied market heat rate…" (Exhibit 1, p. 61.) It also recommends that we adopt a heat rate pricing methodology that compares SP15 Day-Ahead prices to natural gas prices to compute an implied market heat rate and multiplies that IMHR by a monthly bid week natural gas price. SCE's SRAC energy pricing proposal functions essentially the same as the Modified Formula. SCE proposes that the Commission calculate SRAC energy each month using the following formula:

[46] Table 2 is a modified version of a table that appears in Exhibit 104. "Table ES-1 summarizes the principal SRAC recommendations of the parties to this case, and expresses those recommendations as a "spark spread" between natural gas and SRAC prices" (Exhibit 103, p. ii). However, the actual table was not included but was submitted with the errata in Exhibit 104.

SCE's Proposed SRAC Energy Formula

$$\textbf{SRAC (cents/kWh)} = \left(\textbf{IER} \times \frac{\textbf{1 MMbtu}}{\textbf{1,000,000 btu}} \times \textbf{E} \times \frac{\textbf{100 cents}}{\textbf{\$1}}\right) + \left(\textbf{B} \times \frac{\textbf{100 cents}}{\textbf{\$1}} \times \frac{\textbf{1 MWh}}{\textbf{1,000 kWh}}\right)$$

Where:

A = Monthly average of daily Day-Ahead SP15 prices (DJ / ICE / MWD), where DJ = Dow Jones, ICE = Intercontinental Exchange, and MWD = Megawatt Daily.

B = Variable O&M ($2.00/MWh)

C = Topock bid week gas price average (NGI, NGW, Btu Daily Gas Wire)

D = So Cal Gas Intrastate Transportation[47]

E = Burnertip Gas Price (C + D) in $/MMBtu

HR_m = Monthly Heat Rate [(A – B) / E] * 1,000 Btu/kWh

HR_{Cap} = 9,864 Btu/kWh

HR_{Floor} = 5,864 Btu/kWh

HR_c = Collared Monthly Heat Rate ($HR_{Floor} <= HR_m <= HR_{Cap}$)

$HR_{12mthMAvg}$ = 12 month Moving Average of Capped Monthly Heat Rates

= [Σ ($HR_{c1} \ldots HR_{c12}$)] / 12 months]

IER = $HR_{12mthMAvg}$

According to SCE, "using this approach, the IER for December 2004 would have been 7,837 Btu/kWh, as shown in Table 3.[48] Over the three-year period from August 2002 through July 2005, the average implied market heat rate was 7,864 Btu/kWh. (*Id.*).

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[47] This rate is calculated in the same manner as in SCE's Short Run Avoided Cost Energy Price Update for Qualifying Facilities (SRAC posting). In SCE's SRAC posting, the Intrastate Transportation is referred to as GTn and is currently derived from applicable So Cal Gas rates from tariffs GT-F5, ITCS, G-MSUR and G-CPA.

[48] Exhibit 1, Figure 10.

Table 3
Sample Derivation of IER

	A	B	C	D	E =	HR_m =	HR_{Floor} =	HR_{Cap} =	HR_c =	$HR_{12mthMAvg}$ =
					C + D	(A-B)/E*1000	3-yr Avg HR_m - 2000	3-yr Avg HR_m + 2000	HR_{Floor}<=HR_c<=HR_{Cap}	[∑(HR_{c1}..HR_{c12})]/12mth
	SP-15 Monthly Avg of DJ, ICE & MWDaily	VO&M	Topock CA Bidweek Border Gas Price	SoCalGas Intrastate Transportation	Burnertip Gas Price	Implicit Heat Rate (Net of VO&M)	Heat Rate Floor	Heat Rate Cap	Collared Heat Rate	Collared Heat Rate (12mthMAvg)
	$/MWh	$/MWh	$/MMBtu	$/MMBtu	$/MMBtu	Btu/KWh	Btu/KWh	Btu/KWh	Btu/KWh	Btu/KWh
Aug-02	$26.82	$2.00	$2.91	$0.21	$3.12	**7,959**	5,864	9,864	7,959	
Sep-02	$30.23	$2.00	$3.09	$0.23	$3.32	**8,500**	5,864	9,864	8,500	
Oct-02	$32.10	$2.00	$3.31	$0.23	$3.54	**8,497**	5,864	9,864	8,497	
Nov-02	$35.79	$2.00	$4.11	$0.23	$4.34	**7,778**	5,864	9,864	7,778	
Dec-02	$39.91	$2.00	$4.04	$0.26	$4.29	**8,832**	5,864	9,864	8,832	
Jan-03	$38.78	$2.00	$4.69	$0.34	$5.03	**7,312**	5,864	9,864	7,312	
Feb-03	$53.20	$2.00	$4.92	$0.35	$5.27	**9,715**	5,864	9,864	9,715	
Mar-03	$52.86	$2.00	$6.98	$0.39	$7.37	**6,904**	5,864	9,864	6,904	
Apr-03	$41.80	$2.00	$4.92	$0.35	$5.27	**7,556**	5,864	9,864	7,556	
May-03	$39.87	$2.00	$4.95	$0.33	$5.28	**7,176**	5,864	9,864	7,176	
Jun-03	$42.69	$2.00	$5.73	$0.36	$6.09	**6,680**	5,864	9,864	6,680	
Jul-03	$51.58	$2.00	$5.42	$0.35	$5.77	**8,588**	5,864	9,864	8,588	
Aug-03	$47.09	$2.00	$4.56	$0.34	$4.90	**9,208**	5,864	9,864	9,208	**7,958**
Sep-03	$44.05	$2.00	$4.84	$0.35	$5.19	**8,103**	5,864	9,864	8,103	**8,062**
Oct-03	$42.20	$2.00	$4.37	$0.34	$4.70	**8,547**	5,864	9,864	8,547	**8,029**
Nov-03	$37.87	$2.00	$4.29	$0.34	$4.62	**7,757**	5,864	9,864	7,757	**8,033**
Dec-03	$44.12	$2.00	$4.56	$0.34	$4.90	**8,588**	5,864	9,864	8,588	**8,032**
Jan-04	$45.64	$2.00	$5.42	$0.39	$5.81	**7,506**	5,864	9,864	7,506	**8,011**
Feb-04	$43.99	$2.00	$5.29	$0.38	$5.67	**7,405**	5,864	9,864	7,405	**8,027**
Mar-04	$41.84	$2.00	$4.75	$0.38	$5.13	**7,773**	5,864	9,864	7,773	**7,835**
Apr-04	$45.19	$2.00	$4.88	$0.39	$5.27	**8,195**	5,864	9,864	8,195	**7,907**
May-04	$51.31	$2.00	$5.50	$0.40	$5.91	**8,350**	5,864	9,864	8,350	**7,961**
Jun-04	$46.91	$2.00	$6.31	$0.41	$6.72	**6,680**	5,864	9,864	6,680	**8,058**
Jul-04	$54.71	$2.00	$5.82	$0.41	$6.23	**8,460**	5,864	9,864	8,460	**8,058**
Aug-04	$50.41	$2.00	$5.81	$0.40	$6.21	**7,792**	5,864	9,864	7,792	**8,048**
Sep-04	$42.05	$2.00	$4.89	$0.39	$5.28	**7,584**	5,864	9,864	7,584	**7,930**
Oct-04	$48.46	$2.00	$4.80	$0.39	$5.19	**8,947**	5,864	9,864	8,947	**7,886**
Nov-04	$53.78	$2.00	$7.23	$0.43	$7.66	**6,758**	5,864	9,864	6,758	**7,920**
Dec-04	$57.52	$2.00	$6.43	$0.41	$6.84	**8,112**	5,864	9,864	8,112	**7,837**
Jan-05	$49.97	$2.00	$6.00	$0.46	$6.46	**7,425**	5,864	9,864	7,425	**7,797**
Feb-05	$48.51	$2.00	$5.73	$0.45	$6.19	**7,517**	5,864	9,864	7,517	**7,790**
Mar-05	$51.00	$2.00	$5.64	$0.45	$6.09	**8,049**	5,864	9,864	8,049	**7,799**
Apr-05	$53.54	$2.00	$6.75	$0.47	$7.22	**7,140**	5,864	9,864	7,140	**7,822**
May-05	$43.86	$2.00	$6.60	$0.47	$7.07	**5,920**	5,864	9,864	5,920	**7,735**
Jun-05	$45.22	$2.00	$5.65	$0.46	$6.11	**7,073**	5,864	9,864	7,073	**7,532**
Jul-05	$62.06	$2.00	$6.42	$0.47	$6.89	**8,711**	5,864	9,864	8,711	**7,565**
8/02' - 7/05' Avg	$45.4707	$2.00	$5.21	$0.37	$5.58	**7,864**				

Given the fact that SCE's Modified Formula will yield the same SRAC energy result as SCE's Proposed SRAC Energy Formula (when the same inputs are used), the actual difference between the two is in the development of the IER heat rate. The IER in SCE's Modified Formula is a heat rate that is tied to the 1994-1995 time period and was adopted in D.96-12-028, whereas the heat rate in SCE's Proposed SRAC energy formula is derived from a twelve-month rolling average of historical Day-Ahead market price data with a "collar" around the possible IER values to provide a cap and a floor for possible IER values. SCE states that its proposed SRAC energy formula is designed "to reflect wholesale market conditions…, includes a 'trigger' that provides for expedited review of the methodology in the event of persistent and significant changes in the SP15 market relative to gas prices, and … in order to mute volatility and to account for seasonality, SCE's proposal employs rolling averages of market data and collars on permissible monthly data points." (Exhibit 1, pp. 60-61.)

SCE states that it developed the "collar" for the implied market heat rate by reviewing the monthly implied market heat rates in SP15 from August 2002 through July 2005. According to SCE, during this period, 100% of the implied market heat rates in SP15 fell within the range of 5,864 to 9,864 Btu/kWh, therefore, SCE recommends that "collars" of these numbers be adopted and if the implied market heat rate hits or exceeds the collars in four successive months, any stakeholder may seek modification of the SRAC formula.

With regard to the gas component in the SRAC formula, SCE "proposes that the Commission adopt a Topock burnertip price for natural gas in lieu of the Malin burnertip price currently used in the transition formula." (*Id.,* p. 64.) According to SCE, adopting a Topock burnertip price would result in SRAC energy prices that are "approximately 17% lower than the price produced using SCE's current SRAC transition formula:

> Using the December 2004 IER of 7,837 Btu/kWh shown in Figure 10 and replacing Malin with Topock yields an illustrative SRAC price in December 2004 of 5.5640 cents/kWh as compared to SCE's posted SRAC of 6.6827 cents/kWh. In this example, SCE's formula results in a price approximately 17 percent lower than the price produced using SCE's current SRAC transition formula. (*Id*., p. 66.)

4.2.2. PG&E

PG&E proposes to update its original SRAC Transition Formula to account for current market conditions. More specifically, PG&E proposes to "update the 'factor' in the SRAC energy formula so that SRAC energy prices for existing QFs approximate NP15 day-ahead prices" (Exhibit 28, p. ES-2).

PG&E proposes to revise the factors such that when the current natural gas border index price is put into the Transition Formula, the resulting SRAC energy price will reflect the monthly NP15 Day-Ahead price.

To derive the revised factors, PG&E performed a regression analysis using bid-week border gas index prices[49] and monthly NP15 Day-Ahead prices. PG&E provides this overview and other observations:

> …the transition formula includes gas "factors" that reflects the relationship between the historical border gas and SRAC prices. The Commission initially derived the factors from a regression analysis.[50] The Commission has previously confirmed that it has authority to modify a utility's transition formula factor to arrive at a price that better reflects a utility's avoided cost and complies with PURPA. Four years after originally adopting a factor in Southern California Edison's (SCE) transition formula, the Commission modified the factor, at SCE's request, to lower SCE's SRAC prices.[51] QF groups petitioned for review of Decision 01-03-067, claiming that revising SCE's factor violated Section 390(b). The California Court of Appeal affirmed the Commission's decision to adjust the SCE's transition formula factor to comply with PURPA's avoided cost cap.[52] The Court of Appeal expressly rejected the QFs' contentions that the Commission lacked authority to revise the factor to adjust to changes in the market. (Exhibit 28, p. 3-2.)

[49] PG&E used a 50/50 mix of Malin and Topock border prices.

[50] Decision 96-12-028, *mimeo.*, p. 14. For PG&E, the CPUC adopted two factors, one for summer, one for winter.

[51] Decision 01-03-067, *mimeo.*, p. 11.

[52] *Southern California Edison* v. *Pub. Util. Comm'n*, 101 Cal. App. 4th 982, 992-93 (2002).

PG&E further notes that "under PG&E's proposal, the starting energy and border gas prices used in the formula remain unchanged.[53] The transition formula factors would be modified, however, to yield energy prices that reflect PG&E's avoided costs." (Exhibit 28, p. 3-5.) Thus, PG&E's formula would continue to be the original Transition Formula:

> Pn = Pb + Pb x [(GPn-GPb)/ GPb] x (utility factor) x TOU, as already described in detail above.

As stated, it is PG&E's goal to calibrate its SRAC Transition Formula using revised utility factors (one for summer and one for winter) so that "SRAC energy prices for existing QFs approximate NP15 day-ahead prices." PG&E derived its proposed factors through regression analysis, the same method used to compute the original Transition Formula factors in D.96-12-028, however, PG&E's proposal would base its new factor on the correlation between NP15 Day-Ahead prices and border gas prices instead of the original correlation between pre-1996 SRAC energy prices and border gas prices. PG&E compared factors from several different time periods and compared the revenues earned under the SRAC Transition Formula with each set of revised factors with the revenues that would have been earned using monthly NP15 Day-Ahead prices. PG&E then selected the factors which most closely matched the total revenues that would have been earned by a QF with a price based on monthly NP15 Day-Ahead prices. To ensure that the revised factors continue to yield SRAC energy prices that closely track NP15 Day-Ahead prices, PG&E notes that the Commission must establish a process to periodically compare SRAC energy prices with corresponding NP15

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[53] Section 390(b) mandates the use of the starting energy and border gas prices. These starting values were derived using a 24-month average of pre-January 1, 1996 values as originally adopted in D.96-12-028.

Day-Ahead prices and provide for further updates of the revised factors as needed, either monthly, yearly, or seasonally.

PG&E states that the NP15 Day-Ahead price is very transparent, because there are at least three different providers of NP15 indices approved by FERC. PG&E also notes that the Day-Ahead price is used as the benchmark price for settling financial and physical contracts for trading hubs across the United States, including NP15 energy. As an example, PG&E states that the New York Mercantile Exchange (NYMEX) Dow Jones NP15 Electricity Price Index Swap Contract (on-peak) is settled by cash payment based on the contract price and the so-called "Floating Price" which is the arithmetic average of the Dow Jones NP15 Day-Ahead on-peak indices for the contract month.[54]

4.2.3. SDG&E

In this rulemaking, SDG&E has requested that the Commission approve "the same formulation of the variable factor as the Commission adopted for SCE in D.01-03-067." More precisely, SDG&E has requested to be put on the Modified Formula:

> "Since the Commission stated in D.01-03-067 that all elements of the transition formula should be updated, SDG&E is proposing to use the same formulation of the variable factor as the Commission adopted for SCE in order to update the IER, intrastate gas transportation rate, and the variable O&M in this proceeding." (Exhibit 85, pp. 6-7.)

SDG&E's proposal for SRAC pricing is based on the Transition Formula, as required by § 390(b), but converts the fixed factor to a formula, consistent with

[54] Exhibit 28, at p. 3-17, citing the "New York Mercantile Exchange Inc. Online Rulebook," Chapter 644, NYMEX Dow Jones NP15 Electricity Price Index Swap Contract.

Commission precedent and policy. SDG&E recommends determining an O&M adder and then deriving an IER from two years of historical Day-Ahead market prices using the O&M adder and historical natural gas prices. SDG&E proposes to use daily market prices at SP15 less O&M divided by burnertip priced gas for the day. The daily values would be averaged over two years to create a forecast market IER for the year. SDG&E suggests updating the various components of the SRAC formula for 2006 along with an automatic recalculation process for subsequent years. SDG&E's proposed 2006 IER would be 7,782 with a $2.60 /MWh variable O&M adder. The variable O&M adder would be updated annually for inflation while the IER would be updated based on the most recent two-year average of historical information on gas prices and SP15 prices. SDG&E recommends an as-available capacity price of $68.93 in 2006, to be adjusted in subsequent years, depending on resource adequacy and already acquired reserves.

4.2.4. TURN

TURN recommends basing SRAC payments on actual electricity market prices, using publicly available on-peak and off-peak pricing date from the Intercontinental Exchange (ICE) or Dow Jones until the CAISO's MRTU project becomes operational, at which point hourly prices from the CAISO's day-ahead electricity market should be used. TURN believes that this approach would ensure that SRAC payments would be equal to the price of energy in the market, ratepayers would not be subject to systematic overpayments, and the Commission would be relieved of the responsibility to adjudicate an administratively determined cost.

In its reply brief, TURN provides us with another option in which we would retain, as a temporary measure, the SRAC Transition Formula with a new heat rate developed from real electricity market price data, until CAISO's MRTU reforms are implemented. This approach relies on forward market prices for electricity and natural gas, as suggested by CCC witness Beach, but would look no more than one year forward. According to TURN, on a yearly basis, the utilities would compile publicly reported forward market prices for electricity and natural gas for the upcoming year. The average forward price of electricity would be divided by the average forward price of gas to derive the incremental heat rate, which would be fixed for the following year (with appropriate peak/off-peak and seasonal differentiation.) The SRAC would be set prior to the beginning of each month, using the month-ahead price of gas. No O&M or other adders should be used, because the forward market price already reflects all the underlying components of the price of electricity. TURN recommends this alternative approach as a temporary measure until MRTU is implemented and robust locational day-ahead market prices are available from the CAISO. The use of forward market prices would eliminate the concerns that QFs raise regarding the use of day-ahead market prices to determine SRAC.

4.2.5. DRA

For short-term purchases, DRA recommends a one-year contract similar to an SO1 contract, but with updated terms and conditions. DRA recommends basing SRAC on market prices and supports PG&E's proposal to replace its Transition Formula by revising the fixed factor. DRA notes, however, that setting SRAC prices to market prices would expose ratepayers to price fluctuations of the market, should the market fail to function correctly, but suggests that the Commission could mitigate this risk exposure by placing a cap on SRAC prices as recommended by TURN.

4.2.6. CCC

Alone among the QF parties, CCC recommends that the Commission revise SRAC energy prices for all three utilities using the Modified Transition Formula adopted in D.01-03-067, updated to reflect current market conditions. CCC states that updating the Modified Transition Formula is reasonable because it complies with § 390(b), it can be updated periodically as necessary to keep pace with changing market conditions, and it is flexible enough to accommodate all of the SRAC energy pricing proposals.

CCC recommends updating the IER as well as gas prices and the variable O&M adder. CCC states that IERs for 2006 -2010 can be estimated using the market heat rates, or spark spreads, reflected in forward market prices for natural gas and electricity in the California market, dividing the forward electric prices (in $ per MWh) by the forward gas price (in $ per MMBtu) to yield a heat rate (in Btu/KWh). However, CCC states that because forward heat rates do not include the least efficient generators, they do not reflect the utilities' full avoided cost and must be adjusted to meet PURPA requirements. CCC states that market heat rates must be adjusted to reflect the absence of many of the least efficient generators as well as the price elasticity benefits of QFs in lowering market-clearing prices.

In support of its position, the CCC compared SRAC energy prices to CAISO Competitive Market Clearing Price (CMCP) values for the years 2002 through 2004. CCC states that the CAISO's CMCP represents "an estimate of the market-clearing price in a perfectly competitive market for California's energy."[55] CCC explains that the CAISO uses all in-state thermal generation priced at each unit's full lead heat rate times the daily burnertip gas prices, plus a variable

[55] Exhibit 102, p. 29.

O&M adder. The CCC reports that the CMCP values were very close to SRAC values in 2002 through 2004. The CCC also compared the heat rates implicit in the CMCP data, using daily burnertip gas prices and an assumed variable O&M adder of $2.50 per MWh to the heat rates implicit in a weighted average of posted SRAC energy prices, using bid-week delivered natural gas price indices and an O&M adder of $3.00 per MWh.

CCC's proposal derives an updated implied market heat rate using forward day-ahead electricity market prices, divided by forward gas prices. The forward electricity prices are developed using publicly-available NYMEX data for monthly on-and off-peak NP15 and SP15 electric forward prices for 2006-2007 and annual broker quotes for 2008-1011. The forward gas prices would use NYMEX gas futures prices, NYMEX Clearport basis differentials for the PG&E city-gate and the southern California border, plus intrastate transportation costs on the PG&E and Southern California Gas Company (SoCalGas) systems. CCC then applies an elasticity factor to the forward market heat rates to develop IERs that reflect the aggregate value of QF generation. The elasticity factor used by CCC is similar to the elasticity factor developed and used by Energy and Environmental Economics, Inc. (E3)[56] for use in avoided cost in Phase 1 of R.04-04-025. The CCC's formula for the IER is as follows:

$IER = FMHR \times (1 + \Sigma \times RNS\%)$ where FMHR is the Full Market Heat Rate, Σ represents price elasticity, and RNS is the utility's residual net short.

CCC believes that using forward market prices is superior to using historical prices because forward prices reflect actual transactions and

[56] "Methodology and Forecast of Long Term Avoided Costs for the Evaluation of California Energy Efficiency Programs," prepared for the California Public Utilities Commission's Energy Division, dated October 25, 2004.

anticipated market conditions during the time the QFs will actually deliver energy to the utilities. According to CCC, the use of forward market prices is especially important when market prices are trending upwards and historical markets have been affected by the market flaws and gaming behavior that the QF parties argue has existed and currently exists.

4.2.7. CAC/EPUC and the IEP

CAC/EPUC and IEP are opposed to pricing SRAC energy at market levels and support a continued reliance on a largely administratively determined formula that requires periodic adjustment via protracted litigation. They argue that the Commission should reject the utilities' SRAC energy pricing proposals and continue to set monthly SRAC energy prices using the Section 390 (b) formula. They advocate changes to the capacity payments, as well as a change to SCE's factor, but no change to the SRAC energy pricing formula for SDG&E and PG&E. Their primary objections are summarized briefly below.

First, CAC/EPUC and IEP argue that the current SRAC energy price formula fairly reflects the short-run avoided costs of the utilities and should be retained. In their opinion, not only is there no basis in the record on which to find that the current SRAC formula should be replaced, but they contend that it is impossible to verify the proposed market price proxies without actual utility data, and conclude that the current SRAC energy price formula should not be changed.

Second, CAC/EPUC and IEP argue that the utility proposals are unlawful, both because they do not accurately reflect the price "at the time of delivery" and because they do not represent the market clearing price that would result in the absence of QF generation. Each of the QF parties argues that a fundamental flaw in the assumption that market prices reflect full avoided costs for utilities is the assumption that the market price remains unchanged with or without the QF capacity. The CCC agrees with the other QF parties in this respect, and includes an "elasticity adder" in its long-run proposal to reflect the aggregate impacts of QF generation. CAC/EPUC testified that prices in a well-functioning market can reveal the value of the marginal unit of electricity, but note that to the extent energy payments to QFs depend on the cost of energy avoided as a result of the aggregate value of energy provided by multiple QFs, the market price in even a well-functioning market will not reflect this higher cost necessary to replace QF-provided energy in the face of an upward-sloping energy supply curve. (Exhibit 42, p. 7, fn. 8.)

Third, CAC/EPUC/IEP argue that the use of a day-ahead market price cannot represent the costs a utility would incur "but for" QF purchases because it does not include utility costs incurred outside that market. They argue that the market price benchmarks proposed by the utilities are not liquid, do not reflect all sources available in the market, are artificially depressed, and are extremely subject to market manipulation due to the monopsony power of the utilities.

In particular, CAC/EPUC and IEP argue that the day-ahead market price is "artificially depressed" because it does not account for the impact of the CAISO dispatches of energy from RMR contracts and FERC MOWD units "out-of-market," meaning the cost of power from those units is not reflected in the price of energy that actually trades in the NP15 and SP15 day-ahead markets. IEP testifies that "…as a result of these out-of market dispatch actions, the CAISO adds a significant supply to the market place that is generally not eligible to set market clearing prices. This results in observed prices that do not accurately reflect the actual generation supply resources that are dispatched to meet demand. The exclusion of the resources from the price-setting process significantly lowers the market-clearing prices." (Exhibit 42, pp. 17-18.)

They point out that underscheduling and infeasible scheduling can result in significant volumes of out-of-market energy to replace or make up for energy not purchased and scheduled by the scheduling coordinators. IEP suggests that the utilities would have a huge incentive to manipulate the market if QF energy payments were tied to day-ahead prices. "Suppression of the day-ahead price of only $1 per MWh… would result in $48.5 million dollars of savings to the utilities if SRAC payments to QFs were based on this price." (Exhibit 42, p. 34.) In addition IEP notes that "strategic generation or dispatch would entail the production of energy at times either to replace energy that would be purchased in the short-run energy market, or to add supply to short-run market to suppress prices. Strategic behavior could take the form of substituting higher cost retained generation or purchased energy for energy that would otherwise be purchased in the market."

CAC/EPUC agrees, and claims that the utilities chronically underschedule in the NP15 and SP15 day-ahead markets. They note that SCE witness Silsbee acknowledges that "Some parties may have been underscheduling in order to take advantage of the lower prices in the real time market … [and] amendment 72 was designed to prevent that kind of gaming opportunity by requiring accurate scheduling in the day-ahead market." (RT 19, p. 2698.) According to IEP, SCE's purchases from the SP15 Day-Ahead market are never more than 3% of its total supplies, while SCE's QF purchases are typically 28% to 35% of SCE's total supplies.

The QF parties state that the current design of the California electric market provides the opportunity and economic incentive for utilities to submit day-ahead schedules with inadequate quantities of energy and infeasible energy, resulting in load that cannot be effectively served by day-ahead scheduled energy even if it were balanced when scheduled. The CAISO has been forced to procure contracts for thousands of megawatts of higher-cost generation capacity, out of market on a day-ahead, hour-ahead , and real-time basis to make up for shortfalls of usable scheduled energy. The cost of these out-of-market energy purchases is socialized and allocated in various ways by the CAISO among multiple parties. The QF parties note that anticipated changes by the CAISO to move to a system of locational prices with balanced and feasible day-ahead commitments may correct some of these problems and provide usable signals of marginal energy costs. However, at this point, they maintain, the day-ahead market prices of SP15 and NP15 will not reflect marginal costs.

According to CAC/EPUC, to the extent high-cost energy (through the RMR or MOWD) is effectively prepaid through a long-term contract or converted into a non-energy charge through the socialization of cost through a central purchasing entity, the true marginal price of energy may never actually be observed. Under this theory, all existing utility contracts and agreements must be participating in the market in order to determine the true marginal price of energy. Indeed, IEP argues that unless and until the CAISO and other California electricity markets can and do meet all demand and supply with energy that is in the market, California energy markets cannot be used to establish prices reflective of utilities' marginal costs of generation, or SRAC.

CAC/EPUC explains that they have analyzed SRAC energy prices using four approaches:

(a) QF-in/QF-out computer simulation similar to those performed in past ECAC proceedings, but without some confidential data provided by the utilities on loads and resources,

(b) an analysis of forward market energy prices (without some confidential utility data),

(c) an analysis of CAISO FERC Form 714 data, and

(d) an examination of CAISO Market Surveillance data.

CAC/EPUC report that prospective IERs resulting from the four analyses range from 9,067 Btu/kWh to 10,689 for SCE and 9,177 Btu/kWh to 10,730 Btu/kWh for PG&E. CAC/EPUC maintain that the results of these analyses demonstrate that a continuation of the current § 390(b) Transition Formula is reasonable.

4.2.8. The Renewables Coalition

The Renewables Coalition recommends that the Commission adopt an as-available contract option for QFs. According to the Renewables Coalition, the contract term should be for up to 15 years and should be terminable by the QF upon 30 days prior notice by the QF. The Commission should update the utilities' as-available capacity prices to equal the full cost of a combustion turbine, or $110 per kW-year[57] and escalate this price annually to reflect changes in the Consumer Price Index.

The Renewables Coalition maintains that capacity is very tight on SCE's system and the Energy Reliability Index (ERI) should be higher than 10%, at which it is currently set. Furthermore, the Renewables Coalition argues that updating as-available capacity prices is necessary to ensure that QFs with expired or expiring long-term contracts stay online.

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[57] Exhibit 90, p. 5.

4.3. Should the SRAC Energy Formula be Updated?

As a threshold issue in this proceeding, we must first determine whether it is necessary to update or revise SRAC pricing to ensure that it continues to represent the utilities' short-run avoided cost. The current SRAC formulae are dated, which is not inherently problematic; nonetheless, certain components of the formulae contain hard-wired values that are based on pre-electric restructuring markets and utility portfolios. For example, PG&E and SDG&E have been on the SRAC energy Transition Formula since it was originally established in 1996 per D.96-12-028, and include unchanged IERs and SRAC factors. The latter SRAC factors are a result of "regression [analysis] describing the historical relationship between changes in border gas costs and … [an IOU's] calculated avoided cost" (D.01-03-067, p. 5). The regressions were based on 1994-1995 data. With regard to SCE, the utility was on the Transition Formula until 2001 when it was effectively replaced by the Modified Transition Formula per D.01-03-067. Although SCE's fixed SRAC factor was replaced by a dynamic factor that changes monthly, the SCE SRAC formula still contains an original 1996 IER.

In D.04-07-037, we clarified our observations and intent on the issue of SRAC in Ordering Paragraph 1:

> 1. The discussion under heading (2) "Revision of SRAC Prices" on pages 56 to 58 of D.03-12-062 is deleted and replaced with the following discussion:
>
> All three utilities contend that revision of the current SRAC methodologies for determining QF energy and capacity payments is needed. For many years now, SRAC has been approximated through time-differentiated energy prices (set once a month) and time differentiated capacity prices (set annually). There is evidence on the record in this proceeding

> for some time periods the current SRAC energy pricing methodology has yielded prices in excess of spot market prices.
>
> Although, the evidence presented here raises questions and supports the need to revisit SRAC pricing system, the utilities' have not demonstrated the SRAC formula is inadequate or that it exceeds avoided costs in violation of PURPA. Moreover, this procurement proceeding is not the appropriate forum to review the SRAC pricing formula. The current SRAC formula was considered and adopted in D.01-03-067 and D.02-02-028, and this formula was upheld on appeal. (*Southern California Edison Co.* v. *Public Utilities Comm.* (2002) 101 Cal. App. 4th 982.)
>
> The concern exists, however, that the SRAC pricing formula may need to be revised in light of the current energy market. Therefore, the Commission should carefully consider how to modify the SRAC methodology and whether to seek legislative changes to Pub. Util. Code § 390. Because it is important that current methodologies to establish SRAC be critically evaluated and modified where necessary, we are directing Commission staff to immediately begin work on a draft OIR that will examine and propose appropriate modifications to the SRAC methodology." (D.04-07-037, *mimeo*., Ordering Paragraph 1.)

Energy pricing, under both existing long-term QF standard offer contracts and the revised Standard Offer 1 (RSO1) five-year contract extensions mandated by the Commission, is based on the current SRAC Transition Formula (unless a different pricing term is provided in the contract between the utility and the QF, such as the five-year fixed energy price amendments entered into by many QFs during 2001). Currently, as noted above, the SRAC Transition Formula is based in large part on the current cost of gas times an assumed heat rate or IER. Under the formula, if the assumed heat rate (existing IER) is greater than the utility's incremental heat rate, then the SRAC formula results in a price that exceeds avoided cost (all other factors being equal).

PG&E, SCE, SDG&E, ORA, and TURN argue that the IERs adopted in D.96-12-028, for PG&E and SDG&E, and D.01-03-067 for SCE, currently exceed actual market heat rates, resulting in SRAC energy payments that exceed the utilities' short-run avoided cost of energy. PG&E, SCE, SDG&E, ORA, and TURN assert that day-ahead market prices more accurately reflect the utilities' avoided cost and should be used to determine SRAC energy payments.

4.3.1. Market Prices and Avoided Cost

All parties seem to agree that generally, in a well-functioning market, the price of energy established in the market is equal to the marginal cost of the incremental unit of energy where the quantity of energy supplied and the quantity of energy demanded at that price are equal. The market-clearing price for energy is then determined by the bid for and marginal cost of the last unit of energy in the market. They disagree, however, on whether the market clearing price accurately reflects the utilities' avoided cost and whether the market-clearing prices that are available are the result of a well-functioning market.

As argued by the QF parties, SRAC energy prices should exceed current wholesale market prices. Specifically, they maintain that market prices must be adjusted to reflect the estimated increase in the market clearing price that would result from removal of a block of QF generation and that the market price indices recommended by the utilities are not sufficiently liquid or competitive enough to represent the utilities' avoided cost. In addition, the QF parties claim that the utilities have not provided sufficient data to assess whether SRAC prices exceed actual avoided costs.

In support of their argument, the QF parties state that they analyzed SRAC energy prices using several approaches and that each demonstrated that the SRAC Transition Formula results in SRAC energy payments that are in line with, or lower than, current avoided costs. CCC, CAC/EPUC, and IEP each present comparisons of SRAC energy prices to the CMCP. First, CCC, CAC/EPUC, and IEP maintain that the heat rates implicit in the CAISO CMCP values demonstrate that the SRAC Transition Formula continues to reflect avoided cost "when viewed from the perspective of a broad, competitive market that includes the thermal generation that is operated outside of today's limited wholesale market." (Exhibit 102, p. 31.) The CCC estimates a 2002 through 2004 average CMCP implied heat rate of 9,449 Btu/kWh and compares it to a statewide average SRAC heat rate of 9,776 Btu/kWh. CAC/EPUC performed a similar calculation, then extrapolated the CAISO 2003 and 2004 CMCPs to calculate QF-out heat rates using the price differential between QF-in and QF-out electricity prices using the AURORA production cost model. CAC/EPUC calculates that PG&E's current SRAC energy price understates avoided costs by approximately 1.3% in 2003 and by 17% in 2004. (Exhibit 134, pp. 71-74.) IEP also compares the CMCP with SRAC energy prices from 2002 and 2003. IEP contends that SRAC energy prices in these years were about 6.8 % higher than the CMCP. (Exhibit 95, pp. 58-62.)

Thus, all three QF parties maintain that the current SRAC energy prices accurately reflect avoided costs for this period. However, there are several problems with the various QF analyses. For example, according to the CAISO Department of Market Analysis, the resources used to establish the real-time CMCP:

> [c]ompares real-time market prices to estimates of system marginal costs. The analysis only includes resources that were actually dispatched for real time energy by the CAISO, therefore it excludes resources or certain portions of resources that were unable to respond to dispatch instructions for reasons such as physical operating constraints.[58]

Moreover, the CCC and IEP did not state that the CAISO, in its 2004 report to FERC, itself noted that the CMCP or "system lambda" data reported to FERC was not actually system lambda data:

> The CAISO operates its control area through forward energy scheduled and operation of an imbalance energy market, plus reserve/ancillary service markets (to cover generation and transmission contingencies). Suppliers provide the CAISO real-time energy bids that are used by the CAISO to match supply and demand every 5 minutes in a least cost manner. Because energy bids do not necessarily reflect system marginal costs, the CAISO does not have true system lambda information. Therefore, the CAISO will not be submitting system lambda data as part of this FERC 714 filing. (In previous years, the CAISO had provided a formulated estimation of system lambda data; upon closer review of Form 714 instructions, this was not appropriate.) Though not a true system lambda, historical real-time energy price information is available on the CAISO's OASIS website at http://oasis.caiso.com, under Real Time Information.[59]

In addition, as explained by SCE witness Silsbee, the competitive market clearing price data utilized by QF parties is only for purchases by the CAISO (the incremental, or "INC" market) and does not include sales by the CAISO (the decremental, or "DEC" market). The incremental CMCP represents the cost of

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[58] CAISO Department of Market Analysis, 2004 Annual Report on Market Issues and Performances, at p. 2-17 and p. 2-18.

[59] CAISO 2004 FERC Form 714 Filing, Part IV, Notes to Page No. 43.

increasing generation from thermal units designated by the CAISO. The incremental CMCP does not include units that were asked to reduce generation by the CAISO in the "DEC" market. PG&E reports that the incremental market is roughly 2.5 times that of the decremental CMCP.[60] As an example, SCE calculates that market performance based on a weighted average of the two markets resulted in an average IER of less than 6,000, well below the IER of 9,140 currently embedded in the SRAC Transition Formula.[61]

4.3.2. QF-in/QF-out

According to CAC/EPUC, the only way to accurately estimate utility avoided cost is to perform a QF-in/QF-out production cost simulation to calculate the cost that would have been incurred by the utility in lieu of QF generation. (Exhibit 134, p. 48.) This complex computer simulation would calculate the system costs based on the economic dispatch of the available generating resources. Two production cost simulations (or runs) would be performed: (1) with the QFs included in the utility's portfolio (QF-in) and (2) without the QFs (QF-out). The difference in cost between these two production costs simulations provides an estimate of the utilities production costs avoided by QFs' provisions of short run energy. The difference is then divided by the incremental fuel cost resulting in an IER.[62] In other words, in the

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[60] Exhibit 29, p. 3-18.

[61] Exhibit 2, p. 41.

[62] The QF in/QF out IER calculation can be illustrated as follows:

IER = **{** [(QF-out Market Costs) – (QF-in Market Costs)] ÷ Gas Market Price **}** ÷ QF Volumes

Alternatively, the equation can be stated in terms of net market costs as follows:

IER = **{** [Net Market Costs to the utility when QFs are out] ÷ Gas Market Price **}** ÷ QF Volumes

QF-out run, the utility would have to either generate more power or buy more power from the market. The cost of this incremental amount of power and the amount of this incremental power can be expressed in $/kWh. Dividing this $/kWh by the gas price in $/MMBtu leaves a heat rate figure in Btu/kWh. Under the QF-in/QF-out approach, the IER is a measure of the thermal efficiency for the entire system that would have been required to serve the load absent the block of QF resources. The O&M cost is then independently determined and added to the IER for an SRAC energy payment.

CAC/EPUC claim that a market price does not reflect a utility avoided cost of energy unless "the QF capacity normally supplied to the utility is assumed to be unavailable." (Exhibit 134, p. 41.) The QF parties rely on FERC's regulations referring to the "aggregate value of energy and capacity from qualifying facilities on the electric utility's system" to support their argument that QFs should be treated as a block in determining a utility's avoided cost. (See Exhibit 102, p. 4.) The language cited by CCC and others appears in a subsection of the regulations entitled "Factors affecting rates for purchases" (18 CFR 304(e)). This subsection lists a number of factors that should be taken into consideration "to the extent practicable." One such factor is "The individual and aggregate value of energy and capacity from qualifying facilities on the electric utility's system. (18 CFR 304(e)(2) (vi).)

Given that the majority of the utilities' resource procurement efforts involve competitive solicitations, we agree with the utilities and TURN that it is neither reasonable nor practical to base avoided costs on a "QF-out," or "aggregate value" methodology. The "aggregate value" is only one of several factors that FERC suggests should be considered and is not determinative. One of the other factors to be considered is the "individual" value of QFs.

Furthermore, as PG&E points out, to read this section as supporting the treatment of QFs in the aggregate is inconsistent with many of the other factors listed in the section, which refer to the characteristics and capabilities of an individual QF. (PG&E Opening Brief, p. 20.)[63]

The utilities point out that in comparing the QF-in or marginal cost pricing approach, and the QF-in/QF-out or incremental approach, the Commission found that while "the QF-in/QF-out, method meets the PURPA requirements for QF pricing, to the extent that changes in ECAC and possibly other developments create a more competitive environment and move this industry closer to a true spot market, it is appropriate and consistent with PURPA to reconsider marginal cost energy cost pricing for short-run QFs." (27 CPUC 2d p. 576, D.88-03-079.)

As we stated in D.92-01-018, using QF-in/QF-out methodology involves hundreds of modeling assumptions and forecasts.[64] We concluded at that time that the IER is not just a "somewhat" artificial concept, but a "totally" artificial

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[63] 18 CFR § 292.304(e) lists the following factors, among others:

(1) The utility's system cost data;

(2) The availability of capacity or energy from a QF during the system daily and seasonal peak periods, including: (i) the ability of the utility to dispatch the qualifying facility; (ii) the expected or demonstrated reliability of the qualifying facility; (iii) the terms of any contract or other legally enforceable obligation, including the duration of the obligation, termination notice requirement and sanctions for noncompliance; (iv) the extent to which scheduled outages of the qualifying facility can be usefully coordinated with scheduled outages of the utility's facilities; (v) the usefulness of energy and capacity supplied from a qualifying facility during system emergencies; including its ability to separate its load from its generation; (vi) the individual and aggregate value of energy and capacity from qualifying facilities on the electric utility's system; and (vii) the smaller capacity increments and the shorter lead times available with additions of capacity from qualifying facilities.

[64] D.92-01-018, *mimeo*. at pp. 8-9.

concept.[65] This conclusion has become even more-true as QF generation has become a larger percentage of the utilities' resource portfolios. The continuing long-term obligations to thousands of megawatts of QF power mean that QFs as a block will never be "out."

Furthermore, we find no right through any contract term or fair market expectation that the Commission must adopt the QF-in/QF-out approach. As TURN points out, "[N]o supplier anywhere can expect to capture the higher price that would have prevailed had that supplier not offered its product to the market." (TURN Opening Brief, p. 2.) Even CAC/EPUC admit that, in light of electric restructuring, the utilities and QF parties developed a simplified SRAC energy pricing approach that was ultimately adopted by the Commission in D.96-12-028. Although this simplified method initially utilized IERs that were based on 1994-1995 data developed using a QF-in/QF-out method, a revision to this method that does not rely on the pre-1996 IERs was adopted for SCE by this Commission in D.01-03-067 and approved by the Court. As CAC/EPUC correctly note, changing from a fixed factor to a dynamic factor through the use of an algebraic expression in D.01-03-067 results in a formula without a "starting energy price" or "starting gas index price" and therefore does not utilize pre-1996 results of a production cost simulation. Although CAC/EPUC assert that the formula is inconsistent with § 390(b), the Court upheld our revision in *Edison II*.

The QF parties' primary objection to revising SRAC energy prices is that in the current market, the Commission cannot find that the SRAC energy prices exceed the utilities' avoided cost and as a result, cannot make a finding supporting modifying SRAC. They claim that since the IERs embedded in the

[65] *Id*. at pp. 11-12.

current SRAC energy formula have been shown to be lower than the IERs calculated using certain market data on occasion, the SRAC formula should not be revised. We disagree.

4.3.3. IOU Dispatch, Day-Ahead Markets, and SRAC

The utilities contend that the since their dispatch decisions are based on the prices in the day-ahead markets, these day-ahead markets represent a reasonable proxy for SRAC. Standard of Conduct (SOC) 4 was adopted in D.02-10-062 and modified in D.02-12-069, D.02-12-074, D.03-06-076 and D.05-01-054. SOC 4 requires an IOU to dispatch its portfolio of existing resources, allocated California Department of Water Resources (CDWR) contracts, and new purchases to meet its electric load obligations in a least-cost manner. D.04-07-028 requires system reliability and deliverability of power to be included as part of least-cost dispatch. For example, PG&E states that "the wholesale power market, and in particular, the NP-15 Day-Ahead market, is PG&E's short-run avoided cost and guides PG&E's dispatch decisions." (Exhibit 28, page 1-3.)

Existing resources in PG&E's portfolio (i.e., utility retained generation, CDWR, and those contractual obligations which allow economic dispatch) are regularly compared to the market price, with power being either bought or sold at that price. Regardless of the resource stack, the utility's avoided cost for a given hour becomes the market price. The market price that PG&E uses to determine what resources are dispatched in northern California is the NP15 price. If the dispatch decision is made day-ahead, then the price is the day-ahead NP15 price. If the dispatch decision is made hour-ahead, then the price is the hour-ahead NP15 price. PG&E's traders are active in the market and are keenly aware of current prices at which sellers are offering, buyers are bidding and the price at which the most recent transaction was executed. Price discovery is available through voice brokers, electronic trading platforms, such as the ICE, and direct contact with trading counterparties. (*Id.*, p. 3-10.)

According to PG&E, the Day-Ahead spot market is both an obvious and conservative (*i.e.*, erring on the side of overpayment) measure of PG&E's true short-run avoided costs. PURPA's definition of avoided cost clearly and correctly envisions that utilities may satisfy their short-run incremental energy needs either through spot purchases or by increasing generation under their control. Since the divestiture of most of its fossil plants around 1998, PG&E has been a net buyer of power, meaning that the main sources of additional power in both the long and short run have been purchases, not self-owned generation. For short-run spot market purchases in NP15, there are three common product types: bilateral Day-Ahead, bilateral Hour-Ahead (HA) and the real time imbalance energy from the market run by the CAISO. While the markets for these products are linked to a substantial degree by the arbitrage activities of participants, the attributes of these products do differ and market prices do differ from day to day. (*Id.*, p. 3-14.)

PG&E further contends that the NP15 Day-Ahead price is very transparent, based on the fact that there are at least three different providers of an NP15 Day-Ahead index approved by FERC, including the ICE and Dow Jones indexes that PG&E is using. (*Id.*, p. 3-16.)

The utilities further argue that the day-ahead markets are "workably competitive," claiming that they meet the FERC liquidity criteria set forth in FERC's November 19, 2004 Order Regarding Future Monitoring of Voluntary Price Formation. PG&E analyzed price levels in the NP15 Day-Ahead power market, as reported by ICE from 2002 to 2005 and compared them to other Day-Ahead power prices delivered in related markets or trading hubs: South-of-Path 15 (SP-15), the California-Oregon Border (COB), and Palo Verde (PV).

> My analysis, presented in more detail in Appendix A, concludes that the NP-15 DA hub is within a larger market that is workably competitive. I find that DA prices are nearly identical across the CAISO control area and also close in the other two nearby trading hubs during the vast majority of all hours. Thus, NP-15 is almost always part of a larger market, either SP-15, COB or PV, depending upon season. Historical prices of these hubs during the 2002 to 2005 period are at levels that show that the market is sufficiently robust and well-functioning. There have been few "price separations" within the CAISO control area and also few price spikes across the Western U.S. The CAISO's automatic mitigation program, designed to capture and mitigate excessively high sales bids in the RT market, has not been triggered once in the last three and a half years. (*Id.*, p. 3-17.)

The QF parties disagree, stating that day-ahead market prices cannot serve as a proxy for avoided costs because they are thinly traded, and are used infrequently by the utilities. IEP reports that SCE purchases from the SP15 market are never more than 3-4% of their total supplies, while SCE's QF purchases are typically 28% to 35% of their total supplies. IEP also notes that the current trading volumes of 33,500 MWh per day in the NP15 market and 44,600 MWh per day in the SP15 market are less than total QF deliveries.

TURN compared the northern California NP15 daily electricity prices and PG&E natural gas prices from the ICE to calculate market heat rates for the summer and winter on-peak and off-peak periods during the one-year period from August 1, 2004, through July 31, 2005. TURN also reports that the actual market heat rate averaged approximately 8,300 Btu/kWh during that period (TURN notes that the results using burnertip gas prices would be somewhat lower). TURN compared those prices with PG&E's current SRAC formula, which yielded an implicit heat rate of approximately 10, 840 Btu per kWh averaged across the same period (9,360 in summer and 12,324 in winter), resulting in SRAC payments that were approximately 30% greater than market prices. TURN notes that since many QFs are continuing to operate under the fixed price amendments, SRAC payments did not exceed market prices to the same degree, but with those fixed price amendments due to expire in 2006 and 2007, there will be a substantial increase in cost if the SRAC formula is not revised to reflect actual market prices. (TURN Opening Brief, p. 6.)

SCE provided a similar example, comparing posted SRAC energy prices to monthly average prices reported by Dow Jones, Megawatt Daily (MWD), and ICE for day-ahead electricity in SP15 from August 2002 through July, 2005. During this period, SCE states that the monthly average day-ahead price in SP15 was $45.47/MWh, while the average posted SRAC energy price was $55.76/MWh, 23% higher than SP15 prices.[66]

SCE also compared the embedded IER in the Modified Formula with an implied market heat rate calculated by taking a monthly average of SP15 day-ahead electricity prices expressed in $/MWh, subtracted $2/MWh for variable O&M, and divided this result by a Malin-based burnertip price for natural gas for the same period.[67] SCE states that implied market heat rates in SP15 were consistently below the 9,140 Btu/kWh heat rate in the Transition Formula.

PG&E states that not only do QFs receive SRAC energy prices that are approximately 30% above prices in the NP15 Day-Ahead wholesale power

[66] Exhibit 1, p. 57.

[67] *Id.*, p. 58.

market, but many QFs also receive capacity payments pursuant to the standard offer contracts, resulting in all-in SRAC payments that are well above the utilities' actual avoided cost**.**

All parties acknowledge that, from its inception in D.96-12-028, the Transition Formula was intended as a temporary measure, to be used to calculate utility avoided costs until energy payments could be based on California PX prices pursuant to § 390(c). D.96-12-028 adopted factors, consistent with § 390(b) designed to "yield a fair representation of the historical values required by AB 1890." (D.96-12-028 [69 CPUC 2d 546, 553].) Those factors were derived from a regression analysis and were based on pre-1996 data, a time when the utilities owned their own generation resources or purchased from QFs, and there was no market mechanism available for use as an avoided cost benchmark. Since then, electric restructuring, the energy crisis, and the resulting shift in the utilities' procurement practices have made the determination of avoided costs much more dependent on market activity.

As we are all aware, the PX will never be fully operational because it is defunct, yet we continue to calculate avoided costs pursuant to § 390(b). Although the PX ceased market operations at the end of January 2001, Day-Ahead markets for electricity continue to exist.

The evidence suggests that over time, SRAC prices under the Transition Formula have exceeded market prices, and potentially, avoided costs on occasion. Therefore, we find that it is time to update the SRAC methodology to ensure that it continues to reflect utility avoided costs. Moreover, we find that the variable factor formulation of the transition formula and updates to the formula are legal and permitted by § 390(b). This belief was upheld in *Edison II*, which affirmed the Commission's finding, stating, "to the extent that CCC is arguing that the Commission is forever wedded to the pre-1996 figures and cannot take current prices into account, CCC is in error."[68] Even CCC does not dispute that SCE's proposal can be implemented through the MIF consistent with § 390(b). (CCC Opening Brief, p. 9.)

In upholding our discretion to modify the factors, as needed, to reflect changing conditions in the market, the Court, in *Edison II*, stated that the Commission not only has the power to alter the factors, but has the duty to do so in appropriate circumstances, finding:

> The Legislature did not prescribe a specific formula. Rather, it prescribed a general formula to be transitional until such time as the PX was up and running properly…[I]t is now becoming obvious that the PX will never properly function. Thus it was up to the Commission to arrive at a formula that met the requirements of section 390 and also complied with PURPA.[69]

Although some QF parties may view certain proposed SRAC revisions as too extreme, our goal is to price QF energy at avoided cost, not based on QF economics. The primary difference between the Transition Formulas adopted in D.96-12-028 and D.01-03-067 and the formulas proposed in this proceeding is the IER. The IER used in the existing formula has remained unchanged for almost ten years, and is based on data that is 11-12 years old. In D.01-03-067, we found that an update of both the IER and the O&M adders were necessary, but would require additional information. A proceeding to update these factors was held, but a decision was never issued as the testimony in that proceeding quickly became outdated as a result of the ongoing energy crisis and its aftermath.

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[68] *Southern California Edison* v. *Pub. Util. Comm'n*,101 Cal. App. 4th 982, 993 (2002).

[69] *Southern California Edison* v. *Pub. Util. Comm'n*,101 Cal. App. 4th 982, 991-992 (2002).

The evidence in this case demonstrates that the Commission should adjust the factors in the Transition Formula such that the SRAC energy prices resulting from the formula continue to appropriately reflect the utilities' short-run avoided cost.

4.4. The Market Index Formula

All of the proposals to update SRAC energy prices recognize that current market prices, whether historical or forecast, should be taken into account when setting avoided cost. As discussed above, PG&E, SCE, SDG&E, TURN, and CCC have each proposed SRAC energy pricing methodologies that utilize IMHR figures derived from day-ahead power price indices at NP15/SP15 and spot bid-week natural gas indices at border trading points or at the burner-tip.

Each of the utilities has demonstrated that market prices play a key role in achieving least cost dispatch. D.02-12-074 and other Commission orders require the utilities to "prudently administer all contracts and generation resources and dispatch energy in a least cost manner."[70] Therefore, the short-run cost of energy will either reflect the cost of increasing production of one of the utility-controlled resources or the cost of procuring energy in the market, whichever is least-cost. In this environment, these day-ahead markets represent a reasonable proxy for SRAC energy prices.

We agree that SRAC energy prices should reflect power prices as reported at the NP15 trading point for PG&E, and the SP15 trading point for SCE and SDG&E. Although the Day-Ahead market prices may not include all of the types of contracts that exist in the electricity industry today, these are the energy costs that would otherwise be incurred by the utilities in the short run to replace QF power. QF parties contend that the NP15/SP15 prices are below utility avoided

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[70] D.02-12-074, *mimeo.*, p. 54.

cost, yet the power products at NP15/SP15 are for firmer power products than the as-available energy provided by QFs.

The difference between the proposals lies in the derivation of the IER. Conceptually, we find PG&E's proposal appealing, because it preserves the D.96-12-028 Transition Formula. However, the PG&E proposal simply updates the pre-1996 factor in the Transition Formula which would likely require future, administratively determined updates.

Specifically, PG&E's proposal would link the SRAC energy prices to the Day-Ahead trading points. However, if the market conditions underlying the data used in the regression analysis differ from current market conditions, the resulting SRAC price may not accurately reflect a utility's avoided cost. Moreover, PG&E's proposal would require formal Commission update immediately and on an ongoing basis. PG&E agrees that its factors require revision before they can be used and would continue to require continuous updates. (RT, p. 3567.)

CCC's proposal presents similar problems. CCC's proposal uses forward market prices, along with an "elasticity adder" to adjust the forward prices to reflect the price increase if the "aggregate" amount of QF energy production on the utility's system is withheld. As discussed above, a price that is based on an assumption that a large block of generation has disappeared is not reasonable. The forward market data in CCC's proposal were also not well supported by CCC. The proposal uses two years of futures prices, followed by a period of three years where prices were determined using arguably transparent broker quotes. Updating these assumptions would be required as frequently as every other year. In addition, CCC's proposal relies on statewide numbers, contrary to the PURPA requirement that we develop utility-specific avoided costs.

SDG&E's proposal uses a two-year average of daily Day-Ahead market prices at SP15 for SDG&E, less the proposed O&M divided by the burnertip price of gas. This average would be updated automatically on an annual basis. SDG&E's proposal is consistent with § 390(b) and linked to market prices; however, SCE's proposal is preferable to SDG&E's, because it uses a twelve-month rolling average of historical market prices, resulting in SRAC prices that reflect more current avoided costs. SCE's proposal is also preferable to CCC's because the use of historical values will significantly reduce the controversy associated with forecasts of market prices.

The CCC expresses concern that SCE's backward-looking proposal tends to result in IERs that are lower than appropriate when costs are rising. However, data from the last 12 months represents an improvement over data from 1995 that is embedded in the Transition Formula. This finding is consistent with our prior findings that the components of the SRAC Transition Formula reflect costs averaged over periods from one month, at a minimum, to as long as several years. Thus, SRAC prices do not track utility avoided costs on a real time or day-to-day basis. SRAC prices are designed to reflect the utilities' avoided costs over the forecast periods for which they are developed. During particular time periods SRAC prices may be higher or lower than actual, real-time avoided costs, but, as the Commission has recognized, such differences balance out over time. (D.04-07-037.)

We find that it is to the benefit of all interested parties to adopt a more transparent, market-based solution, namely, the Market Index Formula (MIF) shown below and in Table 4. The MIF is based on the Modified Formula adopted in D.01-03-067. This formula complies with § 390(b). The IER or heat rate in the MIF shall be calculated in the manner proposed by SCE, but using NP15 power prices and a burner-tip gas price for PG&E.

Market Index Formula (MIF)

$$Pn = (MHR \times (GPn + GTn)/10{,}000) + O\&M$$

Sample Calculation for SCE
$P_{April\text{-}2006}$ = 6 .4597 cents/kWh = (9140 (6.3205 + 0.5282)/10,000) + 0.2

Pn = calculated SRAC energy price, cents/kWh
GPn = current gas price, $/MMBtu
GTn = intrastate transportation costs, $/MMBtu
MHR = Market Heat Rate Btu/kWh
O&M = operations and maintenance costs, Cents/kWh
10,000 = [$1/100 Cents] x [1,000,000 Btu / MMBtu]

Finally, while we find that a MIF based on Day-Ahead prices best reflects the utilities' avoided cost, we expect that a further update will be required when the CAISO's MRTU is operational, at which point the CAISO's day-ahead market will likely be the appropriate benchmark for pricing SRAC energy.

4.4.1. Variable O&M in SRAC Energy Formulas

The MIF has a Variable O&M component. The O&M adder accounts for the variable O&M expenses incurred by the utility to produce energy and is a relatively small component of costs in the SRAC formula. SCE has proposed $2.00/MWh (see Figure 1 above), and IEP concurs. SDG&E's proposed "$2.50/MWh in 2004 dollars was adopted in D.05-04-024 and implemented for Energy Efficiency by SDG&E Advice Letter 1687-E. Escalated to 2006 at 2% per year, this value would be $2.60 in 2006."[71] (Exhibit 85, p. 7.) For purposes of establishing SRAC energy prices, TURN does not recommend the use of a

[71] The 2% escalation was also adopted in Advice Letter 1687-E.

Variable O&M adder.[72] Likewise, PG&E does not propose a variable O&M adder value because the Transition Formula does not contain that component.[73] CCC recommends a Variable O&M adder of $3.00/MWh, and also recommends an automatic adjustment in future years.

Given the uncertainty in formulating such estimates, all three utilities will now be on the MIF as described herein. With regard to our consistency goal in this avoided cost rulemaking, there is no compelling reason to not adopt the same variable O&M adder for all three utilities. As SDG&E notes in its direct testimony, the Commission has adopted variable O&M figures for other purposes:

> SDG&E proposes the variable O&M component be based on the variable O&M of a Combined Cycle Gas Turbine (CCGT). This level of variable O&M is consistent with the type of power that would replace QF power, baseloaded power supplies as provided by a CCGT. In the decision in phase 1 of this proceeding, D.05-04-024, the Commission recommended using the data developed in R.04-04-026 for the costs of operating a CCGT. For consistency, SDG&E proposes to use the 2004 value for the variable cost of a CCGT adopted in Phase 1. (Exhibit 85.)

We concur with this approach and adopt it for use in the SRAC energy formulae for the three utilities.

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[72] With regard to variable O&M, TURN does present recommendations on variable O&M, not for the purpose of calculating SRAC energy but, instead, for the purpose of "capping market energy prices at the costs of generating energy from such a new CT." (Exhibit 149, p.1.)

[73] CCC (in Exhibit 104) impute a variable O&M adder value for PG&E based on its proposed factors and is useful for illustration, but it is not a value recommended by either PG&E or CCC.

4.4.2. Gas Prices in the SRAC Formulas

Overall, as is shown in Table 2, eight parties in this rulemaking are recommending the use of three different gas prices: border, burner-tip, and the trading point at PG&E City Gate. For this illustration, the respective prices in Table 1 are $6.33, $6.53, and $7.00/MMBtu.

Border prices are recommended by PG&E and CAC/EPUC, while burner-tip gas prices are recommended by SCE, SDG&E, and CCC. IEP supports the status quo, which for PG&E is border, and for SCE and SDG&E is burner-tip. As noted, TURN recommends the use of the PG&E City Gate trading point. All parties advocate the use of the Topock border point in lieu of the Malin border point adopted in D.01-03-067.

For PG&E in its May 2006 SRAC posting, the utility takes (1) the average of three Malin bidweek gas indices as reported in Gas Daily, Natural Gas Intelligence, and Natural Gas Weekly which is $6.1167 per MMBtu, (2) then PG&E adds $0.377 per MMBtu for intra-state transportation and $0.0551 for shrinkage to the Malin average to get $6.5488/MMBtu to approximate the formerly unrobust Topock border point per D.01-03-067, and (3) then PG&E averages the $6.1167 and $6.5488 to get $6.3328 per MMBtu. For SCE in its May 2006 SRAC posting, the utility takes (1) the average of three Malin bidweek gas indices as reported in Gas Daily, Natural Gas Intelligence, and Natural Gas Weekly which is $6.1167 per MMBtu, and (2) then SCE adds $0.377 per MMBtu for intra-state transportation and $0.0555 for shrinkage[74] to the Malin average to

[74] It's not clear why the shrinkage rates are reported differently by PG&E and SCE.

get $6.5492 to approximate the formerly unrobust Topock border point per D.01-03-067. SDG&E makes the same calculation as SCE.[75]

SDG&E proposes to update its intrastate gas transportation rate based on the current Schedule EG tariffs for electric generators using more than 3 million therms. According to SDG&E, this rate is the intrastate transportation rate for most electric generators in SDG&E's service area; the value is presently 36.98 cents per decatherm.

CCC summarizes the burner-tip gas price in the proposed MIF as the sum of: (i) the bidweek Topock gas prices as published in the three publications currently being used in SCE's postings, (ii) the tariffed SoCalGas Schedule GT-F5 "Sempra-wide transportation rate for large electricity generators, including Interstate Transition Cost Surchage (ITCS), and (iii) SoCalGas' tariffed schedule G-MSUR, the transported gas municipal surcharge." CCC explains that this is essentially the same approach adopted in D.01-03-067, with the exception of the use of Topock border gas prices instead of Malin gas prices.

Because burner-tip gas prices include intra-state transportation costs, on top of border gas prices, burner-tip gas prices are necessarily higher. With regard to avoided cost, whether the utility bought the gas to run its own plant or whether the utility bought the power from a merchant plant fueled by natural gas, burner-tip gas would be required. Therefore, we adopt a burnertip gas price for use in calculating SRAC. We also agree with the parties that the Topock border point is now sufficiently robust and should be utilized in lieu of the Malin border point. SCE provides a succinct description of the changes that have occurred with respect to the Topock border point since D.01-03-067 was issued.

[75] SDG&E reports the same shrinkage rate as PG&E which results in a slightly lower gas price than SCE.

(See Exhibit 1, pp. 64-65.) We will allow SDG&E and the other utilities to annually update the intrastate transportation rate to the most recent value in their gas tariffs, as necessary.

For example, if border gas at Malin is $6.00/MMBtu and intra-state transportation is $0.50/MMBtu, the burner-tip gas price is $6.50/MMBtu which, in this example, is 8% higher than border gas.

4.4.3. Time-of-Use Periods and Factors

In accordance with D.96-12-028, SRAC energy prices are time differentiated to reflect the different value of power on the utilities' systems throughout a given day. Time-of-Use (TOU) or Time of Delivery (TOD) factors convert annual or seasonal prices into intra-day, time-period specific prices.

SDG&E proposes to change both the TOD factors and the TOD periods. SDG&E proposes to use the current TOD hourly time periods going forward but to change the current May through September summer period to a summer season of June through October. TURN recommends changing the summer period for capacity to exclude May and October.

Since existing QF contracts have incentives tied to performance during different TOD periods, keeping the hourly time period definitions roughly the same will reduce problems related to changing the terms of existing contracts. However, SDG&E proposes that the energy price be the same for the on-peak and the semi peak periods going forward. Similarly, SDG&E proposes that the prices for off-peak and super off-peak be the same. Under SDG&E's proposal, the four TOD period definitions would remain the same (with the exception of the summer period change described above), but there would be only two prices.

SDG&E would update the existing summer and winter price differentials and on-peak and off-peak price differentials using the same two years of recent historical data used to forecast the IER. However, SDG&E notes that if the Commission decides that the capacity payment derived from the transition formula should constitute the entire payment to a QF, no added adjustments to the TOD factors are necessary. If the Commission continues to provide a separate capacity payment, there would be potential double-counting since the market price includes some contribution to fixed costs. SDG&E therefore proposes two sets of TOD factors, for use with and without a separate capacity payment.

CCC believes that the PG&E and SDG&E factors are "quite 'flat' across TOU periods, and thus do not value on-peak generation substantially more than off-peak power." (Exhibit 102, p. 54.) CCC notes that both PG&E and SDG&E use significantly "peakier" TOU factors in their RPS solicitations. CCC recommends that the Commission update PG&E's and SDG&E's TOU factors to reflect either the allocations in their recent RPS solicitations or those contained in PX price data from the 1998-2000 period when the PX market functioned well. The CCC notes that this PX data was used by PG&E witness Strauss and by E3 in the development of avoided costs for energy efficiency programs adopted in D.05-04-024. CCC remains silent regarding SCE's TOU factors.

The CCC proposes that the Commission adopt updated TOU factors based on the E3 TOU price profile utilized and adopted in D.05-04-024 for the development of avoided costs for energy efficiency programs.

DRA also recommends an update of the utilities' TOU factors given the length of time since the factors have been examined, but does not provide a specific proposal and instead suggests that the Commission convene workshops to update the IOUs TOU/TOD factors and periods using more recent load profile data.

PG&E argues that it is constrained by Section 390(b) and cannot change TOU factors.

As noted above, the Legislature did not adopt a specific formula, nor did it adopt specific TOUs factors. Therefore, it is appropriate to update the TOU or TOD factors periodically. The evidence in this proceeding clearly demonstrates that the TOU/TOD data is outdated. Unfortunately, the parties recommending specific changes to the TOU/TOD factors and periods did not provide a sufficient showing to support their recommendations. Nevertheless, we believe that updating the IOUs TOU/TOD factors and periods to be consistent with the TOU factors adopted in other procurement proceedings is reasonable and will require the IOUs to include the TOU/TOD factors and periods utilized as part of their most recent RFOs. We also require the IOUs to provide updated TOU/TOD factors and periods when they file their next long-term procurement plans for approval.

4.4.4. Line Loss Factors

FERC's regulations require the Commission to take line losses into account in determining avoided cost.[76] Line loss adjustments to QF prices are currently determined in accordance with the methodology adopted in D.01-01-007, which is based on the CAISO generator meter multipliers (GMMs). PG&E recommends that the Commission modify the GMM that is used to estimate line losses associated with QF power and replace the current formula of (GMMqf-GMMsys) with GMMqf.

Since the MIF we adopt today is based on the Transition Formula, we decline to modify the GMM calculation at this time.

[76] 18 CFR § 292.304(e)(4).

5. As-Available Capacity Pricing

5.1. Scope of this Decision

A Commission determination on the price for as-available capacity will only affect about 20% of QFs currently delivering power to the utilities, because many QFs have contractually specified (fixed) capacity payments. These fixed capacity payments were provisions in two of the original standard offer contracts (SO): SO2 and Interim SO4 (ISO4) contracts.

Table 5
QF Capacity Payments
As-Available vs. Fixed Nameplate Capacity (MW)

Type	PG&E	SCE	SDG&E	Total QF Nameplate Capacity	Illustrative Estimate of Total QF Dependable Capacity
As-Available (MW)	824	1615	21	2,460	1,260
Fixed (MW)	3,429	2,547	219	6,195	5,040
Total (MW)	4,253	4,162	240	8,655	6,300
As-Available %	19%	39%	9%	28%	20%
Fixed %	81%	61%	91%	72%	80%
Total %	100%	100%	100%	100%	100%

5.2. Background

While QFs with SO2 or ISO4 long-term firm capacity contracts are paid a capacity price that is fixed by the terms of their contracts, SO1 QFs and Revised

SO1 (RSO1)[77] QFs are paid the "as-available" prices that were set almost ten years ago for all three utilities. These payments are based on the annualized cost of a peaker plant (typically a combustion turbine, or "CT"), adjusted in some cases by an Energy Reliability Index (ERI) that reflects the lower value of capacity in periods when the individual IOUs were long on capacity. The ERI varies between a minimum of 0.1 and a maximum of 1.0. The annualized costs of a CT (in $ per kW-year) are allocated to time-of-use periods using capacity allocation factors, then converted to as-available capacity prices (in $ per kWh) by dividing by the hours in each TOU period.

The bulk of the capacity value is allocated to the summer on-peak period. If an as-available QF delivers a steady flow of power throughout this time period, the QF is given credit for displacing the purchase of a full CT (assuming the ERI is equal to 1.0).

The 2007 as-available capacity prices for the utilities are as follows: PG&E[78] at $69.93 kW-year; SCE[79] at $4.93 kW-year; and SDG&E[80] at $70.34 kW-

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[77] RSO1 contracts entered into pursuant to D.02-08-071, D.03-12-062, D.04-01-050, and D.05-12-009, are priced as directed in D.01-03-067.

[78] PG&E's avoided cost posting states: "This Capacity Value is the combustion turbine proxy capacity value effective beginning April 1, 1997, as approved in CPUC D.97-03-017 on March 7, 1997. This value has been adjusted for use in 2006 to reflect inflation. A weighted average of the capacity value is used for meters without time-of-delivery metering." The value adopted in D.97-03-017 was $64.77/kW-year. http://www.pge.com/docs/pdfs/suppliers_purchasing/qualifying_facilities/prices/2006_asdelcap.pdf.

[79] SCE's avoided cost posting states: "Pursuant to D.96-12-051, the Capacity Schedule for As-Available Capacity for Standard Offer Nos. 1 and 3 reflects SCE's shortage cost of $4.93/kW-year, which is based on an Energy Reliability Index of 0.1. Shortage costs are determined by adjusting the costs avoided by deferral of combustion turbines using an Energy Reliability Index and will remain in effect until revised pursuant to the Commission's directions. The schedule includes future escalations of capital costs and operation and maintenance costs. Per D.82-01-103, capacity payments are reduced 50%

year. Although the SCE value of $4.93/kW-year was much lower than that for the other utilities, it was uncontested and memorialized in a Joint Recommendation signed by CCC, CAC, DRA, IEP, Watson Cogeneration Company (WCC), and SCE, and the value of $4.93/kW-year had been adopted in each of SCE's last five ECAC proceedings, 1992-1996 (D.96-12-051, pp. 4-5).

Under Electric Restructuring, the plan was to pay QFs the PX price for as-available power, an all-in payment for energy and capacity. This all-in payment to QFs would have commenced only after a Commission determination that the PX was, indeed, fully operational under the terms and conditions of Pub. Util. Code § 390(c). Of course, such a determination was never made because the PX never achieved this level of operation and ceased market operations in January 2001 during the 2000-2001 energy crisis.

Since the energy crisis and its aftermath, the utilities resumed procurement on January 1, 2003 and have received increasing levels of authority to transact for various power products on a forward basis:

> In R.01-10-024, the Commission worked to give the IOUs procurement authority, often referred to as 'AB57 authority,' including the authority to sign contracts for up to five years' duration. Utilities resumed procurement on January 1, 2003, and undertook power procurement in 2003 in accordance with Commission approved 2003 short-term plans. In D.03-12-062, the Commission approved the utilities' 2004 short-term procurement plans. In D.04-01-050, the Commission established that each load serving entity has an obligation to acquire sufficient reserves for its customer loads, endorsed a hybrid market structure, and extended utilities' procurement authority into 2005. In

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for projects under Standard Offer No. 3 with no time of delivery meters." http://www.sce.com/NR/rdonlyres/83102058-F6B9-4A6B-8255-1358C66F1A89/0/QF_SRAC.pdf.

[80] SDG&E as-available capacity price of $70.34/kW-year was adopted in D.96-06-033.

> R.04-04-003 (especially D.04-12-048), the Commission approved the IOUs' long-term procurement plans and gave the IOUs procurement authority for short, medium, and long term contracts for the planning period 2005 through 2014. (R.06-02-013, pp. 7-8.)
>
> In D.02-10-062, Section VI, the Commission adopted a list of authorized products, specified authorized procurement transaction processes, and established upfront reasonableness guidelines for transactions. (D.03-12-062, *mimeo.*, p. 20.)

The vast majority of the time, capacity payments made for general procurement purposes are for power products that have dispatchability (optionality) and/or firmness (delivered at specific times and recourse for non-delivery). With the exception of QF contracts, resource adequacy (RA) resources must generally be firm power products in order to be counted to meet RA requirements. Table 6 (below) shows some key power contract components and component types.

Table 6 Power Contract Components	
Components	Types
Time-of-Delivery	7x24 Baseload; 6x16 peak; 6x8 super-peak; 5x8 critical peak.
Price Structure	Fixed; Indexed; Tolling.
Firmness	Unit-Contingent; Firm
Availability	All hours and months, or as specified.
Dispatchability	Dispatchable, non-dispatchable, or intermittent.
Efficiency	Heat rate, sometimes including periodic heat rate tests for unit contingent contracts.
Delivery Point	NP15, SP15, or as agreed.
Recourse for Non-Delivery	Payment for replacement energy at a specified price, or as agreed.

5.3. Proposals on As-Available Capacity Pricing

Four parties (DRA, TURN, SCE, and SDG&E) recommend that no additional capacity payments be made to QFs for as-available power because Day-Ahead energy sold at the NP15 and SP15 trading points already implicitly has capacity value embedded in the energy price. PG&E proposed an as-available capacity payment that would recover only the current cost of an existing generator, resulting in a significantly lower capacity payment of $10.42/kW-year, relative to its existing payment.

In contrast, the QF parties recommend significantly increased capacity payments for as-available power. The QF parties generally recommend that the SRAC capacity value should be the fully annualized fixed cost of a simple cycle combustion turbine (CT) for each utility. CCC recommends $100.50/kW-year in 2006 (Exhibit 102, p. 51). CAC/EPUC recommends $83.50/kW-year for PG&E,

and $86.59/kW-year for SCE in 2008 dollars (Exhibit 134, pp. 5, 75-76), or about $80.20/kW-year for PG&E, and $83.20/kW-year for SCE in 2006 dollars. IEP recommends $78.68/kW-yr for 2006 (Exhibit 95, p. 71).

DRA, SCE, SDG&E, and TURN contend that there is some capacity value in the Day-Ahead power indices at NP15 and SP15 because Day-Ahead power is a firm delivery product for which there are contractual consequences for non-delivery. This is in contrast to the relative lack of performance obligations in the existing standard offer QF contracts.

> QFs must be paid a price not to exceed the utilities' avoided cost. ORA recommends replacing the SRAC transition formula price with a market-based SRAC price that does not exceed the utilities' avoided cost. If QFs are to be paid a market-based SRAC price, the capacity value in the market price must not be paid in the market-based SRAC price (Exhibit 154, p. 48).
>
> …. One can also consider separating energy and capacity by determining the maximum capacity value portion in the market-based price. But data for determining a "capacity value subtractor" for as-available capacity may not be readily available. ORA understands that utilities recently conducted capacity RFOs in connection with their respective procurement activities. For future reference, the Commission should also look into the possibility of using some of the data from such capacity RFOs to develop a capacity value subtractor for purposes of backing out capacity value from market-based prices. Depending on the utilities bid offer specifications, bids for as-available capacity might indicate separate prices for capacity and energy. (DRA, *supra*, p. 51.)
>
> While ORA recognizes that it can be difficult to isolate capacity from energy in market prices, the above recommended methodology to determine the energy portion of the market price, may yet be the only viable solution to keep the SRAC reflective of the utilities' avoided cost. (DRA, *id.*, p. 51.)
>
> SCE has developed a heat rate pricing methodology for existing QFs that: (1) compares SP15 DA prices to natural gas prices to

> compute an implied market heat rate; and (2) multiplies the implied market heat rate by a monthly bidweek natural gas price to produce an 'all-in' SRAC price. This approach requires no separate calculation of or payment for as-available capacity because any capacity value is more than adequately reflected in the 'all in' SP15 DA prices used to compute the implied market heat rate. (Exhibit 1, p. 4.)
>
> The … energy price … based on the electric market for firm deliveries, contains both an energy component and a capacity component. If the Commission determines that the payment derived from the transition formula should constitute the entire payment to a QF, no added adjustments to the TOD factors are required. However, if the Commission continues to provide a separate as-available capacity payment, there would be double counting since the market price for firm energy contains both energy and capacity components. In that event, SDG&E proposes to remove the capacity value contained in market prices through the simple decomposition described in the E3 report. (Exhibit 85, p. 12.)
>
> The first and most basic appropriate payment to QFs consistent with PURPA 'avoided costs' would be an unhedged market price contract, which could be based on ISO imbalance prices,[81] on-peak and off-peak prices reported by a publicly available service such as the Intercontinental Exchange (ICE) or Dow Jones, or hourly prices from a future day-ahead market when and if developed.[82] These market prices are for firm energy, which includes both energy and capacity, and represent utilities' 'avoided costs' as specified by PURPA. (Exhibit 149, p. 2.)

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[81] TURN footnote: The use of Independent System Operator (ISO) imbalance prices is not our preferred option, because ISO imbalance prices truly represent the last few megawatts and can swing dramatically based on minute-to-minute imbalances between load and generation rather than day-to-day loads and resources.

[82] TURN's preferred option.

TURN also notes that

> with the issuance of D.05-10-042 Firm Liquidated Damages (LD) contracts will no longer 'count' for RA purposes after a transitional 'phase-out' period that runs through 2008. After that, all Load Serving Entities, including the utilities will be required to purchase a 'resource adequacy capacity product' to meet their load plus reserves, in addition to firm energy. This RA capacity product could be purchased as a bundled product that includes energy or separately as an unbundled 'RA capacity product.' An unbundled capacity product would meet the RA requirement, even if it doesn't include a fixed 'strike price,' or fixed heat rate for the associated energy production. (D.05-10-042, *mimeo.*, pp. 25-28.)

TURN further notes that any such capacity product will be less valuable than a capacity contract that includes a fixed price or heat rate for the associated energy.

According to TURN, "full, annualized fixed cost of a peaker plant no longer represents the avoided cost of as-available capacity because if the utility built or purchased a peaker plant, such as a modern CT, it would obtain not only the pure capacity for RA purposes, but also the ability to receive energy at a price equal to the peaker's heat rate times the cost of gas. As a result, an as-available capacity price set equal to the annualized cost of a new CT would, when combined with a market-based SRAC energy price, provide QFs with a total payment that exceeds the utility's actual avoided cost." (Exhibit 149, p. 3.)

TURN argues that the RA program does not require the utilities to purchase "capacity" in the traditional sense of a peaking plant. Rather, utilities are only required to obtain a resource adequacy capacity product that obligates a generator to make its energy available to the CAISO at any price it chooses, constrained only by the applicable energy price cap. In contrast, a new CT provides a known price for energy based on the plant's heat rate, typically, 10,000 Btu per kWh or less. Thus, at a $7 gas price, the energy from the new peaking plant would cost 7 cents per kWh or less, plus variable O&M. Using a taxi cab example raised in hearings, contracting for a new peaking plant would be the equivalent of paying a cab driver a set fee for standing by and waiting for the passenger, and then an additional seven cents per mile. In contrast, the RA capacity product provides a fixed charge for standing by, but would allow the driver to quote a rate of up to 40 cents per mile once the passenger gets in the cab. Clearly, the product (standing by) is much more valuable when the per mile or per kWh charge is fixed in advance.

TURN notes in its testimony that the sum of unhedged market energy prices and CT capacity costs is greater than the total avoided costs. TURN also notes that

> the theory that the capacity value is based on the cost of a combustion turbine was established in the late 1970s when CTs were far less efficient than they are today. Heat rates of 15,000 Btu/kWh were common… A CT therefore had little or no energy value and would be the cheapest cost of pure capacity at that time. Technology has rendered this old theory obsolete. Modern CTs are very different. They have a heat rate in the range of 10,000 Btu/kWh, which is considerably less than many older steam plants, while offering more flexible operations than steam plants that must run overnight to meet peak on two consecutive days. Therefore, we can no longer just claim that marginal energy costs – or market prices – plus a CT equals marginal generation costs, because the CT produces significant fuel savings relative to older steam plants and even more savings when compared to market prices. (Exhibit 149, pp. 4-5, footnote 8.)

SCE compares as available power in relation to modern options theory as follows: "an SO1 [as-available power] contract essentially gives the QF a special seller's 'put' option with the following basic features:

- It allows the seller to deliver (*i.e.*, "put") a flow of power (up to a contractually specified maximum rate of flow) to the utility for up to 30 years and receive the as-available energy and as-available capacity prices as periodically approved by the Commission.
- The seller also has a one-way option to terminate the contract on 30-days' notice.
- Under the SO1 contract, the utility has no option that it can exercise but instead must simply accept the power as delivered." (Exhibit 1, p. 88.)

SCE states that

> by way of comparison, the 'gold standard' of commercial value in the electricity market is the buyer's 'call' option…. A unit-contingent call option allows the buyer to make a periodic payment to the seller in order to secure the right to call on a specific facility to deliver electricity at a stated per-kWh price. Frequently, these call options are structured as tolling agreements allowing for the buyer to purchase the fuel, thereby placing the risk of variability in the fuel price directly on the buyer. Ultimately, all power in the system comes from power plants and ownership of a physical power plant can itself be considered to approximate the value of a unit-contingent call option structured as a tolling agreement. (*Id.*)

Further, SCE states that,

> in contrast to this classic buyer's 'call' option, the as-available SO1 contract is a kind of special seller's 'put' option. The first problem encountered in trying to evaluate the utility's avoided cost of undertaking the purchase obligation associated with this special seller's 'put option' under an SO1 contract is that the utility would not normally seek to purchase such a one-sided product in the market. In short, the as-available contract is simply not a 'natural' [or transactable] commercial product. Otherwise, one would actually observe this product being voluntarily transacted in the market at least occasionally. Thus, there are no readily available commercial reference points that are exactly appropriate; instead, there are only synthetic and conceptual constructs to guide our thinking about the issues. (*Id.*)

SCE recommends that if the Commission disagrees with its position on as-available capacity, the maximum payment authorized for-as available capacity should be considerably less than the full CT value. SCE admits that the state is currently short on capacity and the ERI values are likely to be above the minimum level of 10%. However, as the ERI values become larger, as-available prices under the current methodology get larger and may exceed the actual avoided costs for as-available capacity. As SCE notes, firm performance obligations are preferable to as-available contracts because the utility cannot avoid resource commitments based on the historical delivery performance of a QF and the avoided cost should accurately reflect this.

Therefore, SCE recommends that if the Commission is inclined to require as-available capacity payments, the traditional calculation of capacity value (CT * ERI) should be modified. In this case, SCE recommends that an additional element be added to the formula to reflect the fact that as-available capacity is not a perfect substitute for a physical CT. The new formula would be CT*AA*

ERI, where AA is a fraction less than 1.0 but no greater than 0.2. SCE maintains that this modified calculation would ensure that the as-available capacity payment option reflects the fact that as-available is less valuable to the utilities than firm performance. SCE's description of the proposal is incomplete and does not present a clear method of implementation. SCE also suggests another approach which would cap a QF's actual as-available capacity payments to no more than the class average performance of all as-available QFs.

The utilities also contend that, unlike as-available standard offer contracts which have voluntary performance requirements (i.e., the financial incentive to receive the full capacity payment during certain delivery times), and are terminable by the QF on 30 days notice, recent as-available contracts, such as Renewable Portfolio Standard (RPS) contracts, do include more stringent performance requirements and are generally not terminable by the seller. In addition, SCE points out that the capacity price for as-available wind generators in the RPS is discounted by 76% in the least-cost, best fit evaluation process, in a manner similar to SCE's proposal to discount as-available capacity prices to reflect their relative value to the utility.

In response to these arguments, the QF parties urge the Commission to maintain the current capacity pricing mechanism and simply modify the ERI values to reflect that each utility is currently seeking additional capacity to meet its RA requirements. They contend that the levelized cost of a CT best represents the cost the utilities would incur to procure a new capacity resource and thus represents the cost that the utilities avoid through the purchase of QF capacity. They note that the Commission has recently adopted the levelized capacity cost of a new CT as the MPR for as-available capacity and that all three utilities and TURN supported the use of the SCE cash flow model and levelization over a period of 20 years to determine the MPR for as-available capacity. While the QF parties have each proposed different input assumptions, they have each utilized the MPR model to calculate as-available capacity prices. The QF parties also argue that the lower short-term capacity values resulting from the real economic carrying charge method will not reflect the cost that the utility would pay when procuring a capacity product.

The QF parties further argue that because QFs providing as-available capacity do not receive the full capacity price unless they deliver during all of the hours in which capacity has value (i.e., in all but the off-peak hours), it is appropriate to set the price for both firm and as-available capacity payments using the same CT proxy method. The QF parties also note that, under the standard offers, QFs are obligated to deliver any energy they produce in excess of their on-site needs to the utilities. Therefore, while as-available contracts lack firm performance requirements, they are obligated to provide power to the utilities in the event that they are operating, unlike other generators in the market that may withhold or remove their power from the market to sell elsewhere.

Nine of the eleven active parties contend that a CT proxy should be used to establish as-available capacity payments made to QFs. Three non-QF parties (SCE, SDG&E, and TURN) state that as-available capacity prices should be expressed in real dollars, whereas the six QF parties have proposed the use of nominal dollars.[83] TURN notes that the Commission has never used nominal

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[83] SDG&E qualifies its recommendation on this point: "The levelized cost of a combustion turbine has been used in numerous recent proceedings by the Commission and various parties as the marginal generation capacity cost including demand response programs in R.02-06-001. From a theoretical perspective, however, for a short-term program like QF as-available capacity, a real economic carrying charge may be the

pricing for this purpose but has, instead, established "marginal capacity costs and single-year avoided capacity costs" in real dollars from the inception of the QF Program in California in the early 1980s.

> The Commission has calculated marginal capacity costs and single-year avoided capacity costs in real terms for over 20 years, since the OIR 2 decision (D.82-12-120) and 1983 Test Year Edison General Rate Case (D.82-12-055). Levelized nominal dollar capacity costs have never been used before for either marginal or avoided costs since then. (Exhibit 149, Appendix B, p. 1.)

TURN provided a detailed calculation of the real economic carrying charge in real dollars for a CT in Exhibit 149, Table B-2, p. B-4). According to TURN, the CT capacity cost in a given year is equal to the capital cost of the CT times the real economic carrying charge rate, which in TURN's analysis is 9.94%, plus fixed O&M and insurance. This equals the total marginal CT cost, which is shown in Exhibit 149, Table B-2, Column 18. TURN shows this value for 2004 as $60.95 per kW-year, and notes that the corresponding levelized nominal dollar cost would have been $76.75 per kW in 2004. For 2006, the total marginal CT cost shown in column 18 of the table is $64.13/kW-year.

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more appropriate measure of marginal generation capacity cost. Real economic carrying charge reflects the short term cost savings from delaying investment in new generation plant; the effect of the QF if it can be counted under the resource adequacy counting rules has the same effect. Real economic carrying charge escalates annually with inflation over the life of the marginal resource unlike the levelized annual cost that is constant. Over a long period of time, the present value of the real economic carrying charge is the same as the present value of the levelized cost over the life of the marginal resource, but in the first year has a lower value. If the Commission shifts to using a real economic carrying charge approach in other ratemaking such as rate design and demand response avoided costs, SDG&E would recommend using the real economic carrying charge approach for QF as-available capacity in this proceeding." (Exhibit 85, p. 15, fn. 15.)

SDG&E makes similar note of the Commission's use of real dollars for this purpose:

> In the past, the QF as-available capacity payments were set based on an annual avoided capacity cost, calculated as the Real Economic Carrying Charge (RECC) factor multiplied by the capital cost of a combustion turbine (CT), and the energy reliability index (ERI). (Exhibit 85, p. 14.)

In addition, SDG&E recommends that the value for full as-available capacity should net out the expected ancillary services value of the CT so as not to exceed avoided cost.

For 2006, SDG&E recommends a "full avoided generation cost [of] $83.75 per kW-year less the ancillary value of $14.82 per kW-year, so the proposed value for full as-available capacity is $68.93/kW-year" (Exhibit 85, p. 15).

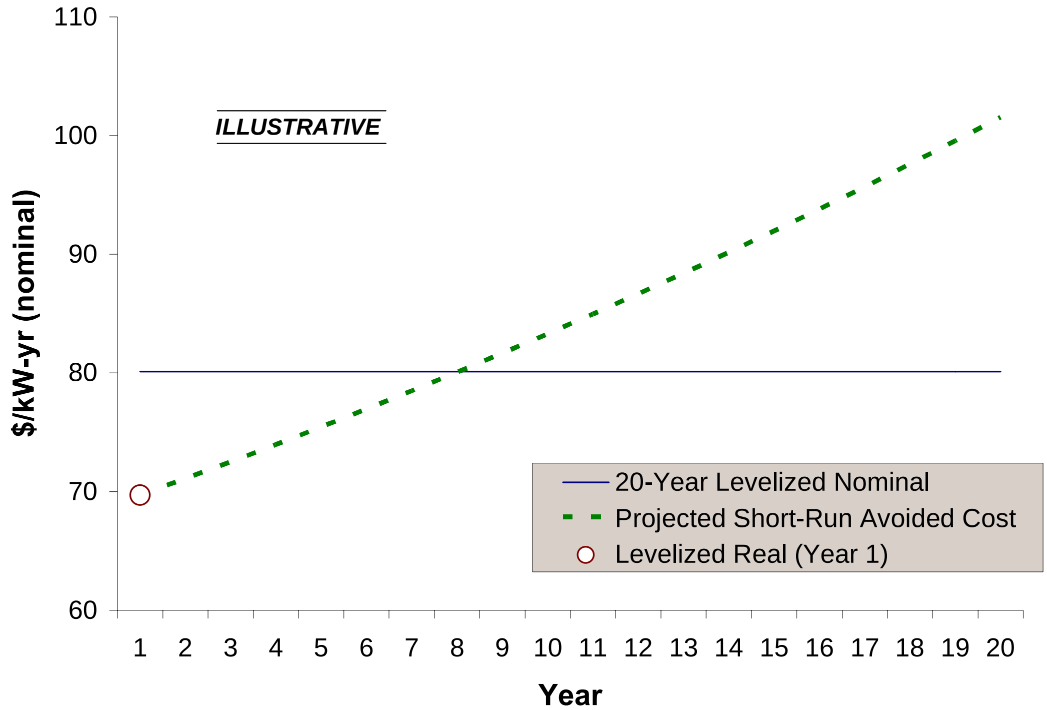
"DRA recommends that the Commission modify the method for calculating as-available capacity prices for existing contracts to reflect the actual value that those contracts provide." (Exhibit 154: pp. 52-54, DRA Opening Brief, March 3, 2006, p. 10.) Although DRA recommends that the Commission modify the method (presumably based on the carrying cost of CT), DRA provides no specific alternative.

PG&E proposes to base "QF capacity prices [on] the resource's going-forward fixed costs." (Exhibit 28, pp. 3-42 to 3-43.) PG&E would define going-forward fixed costs as "...costs that do not vary with the resource's output, but which are needed to maintain an existing resource in operation [including] insurance, property taxes, and fixed operations and maintenance costs [but that] do not include depreciation of sunk capital, such as the cost of construction for the resource." (*Id.*) PG&E claims that the going-forward fixed cost for resource alternatives in 2006 and 2007 is approximately $23/kW-year.

CCC, IEP and the Renewables Coalition recommend calculating as-available capacity prices using levelized-nominal values. CCC and IEP use the Market Price Referent (MPR) methodology to calculate 20-year levelized-nominal values, and CCC cites a 2003 CEC estimate also based on a 20-year nominal levelization.[84] SCE contends that it is inappropriate to use a 20-year levelized-nominal value to assess SRAC. SCE's Figure 5-1 (shown below) illustrates this concept by showing the difference between a 20-year levelized pricing stream and a SRAC pricing stream, as described here:

> In Figure 5-1, the levelized-nominal stream represents a fixed price over the 20-year term that is equal (on a present value basis) to the annual stream that escalates at the rate of forecast inflation. However, the levelized-nominal stream overstates the capacity price in the early years and understates the capacity price in the later years. This is appropriate for the limited purpose of evaluating a firm capacity product for a 20-year term. One should be indifferent to these pricing streams, and the levelization of payments merely establishes a convenient payment methodology. In the context of developing an avoided firm capacity cost estimate for an unspecified time period less than the full 20 years, however, only the escalating curve appropriately represents the short-run price of firm capacity. Otherwise, payments made in the early years are overburdened by expected inflation that occurs throughout the entire 20 years. (Exhibit 2, p. 69.)

[84] Exhibit 102, pp. 51-52; Exhibit 95, p. 70.



SCE Figure 5-1 (Exhibit 2)

5.4. Adopted Capacity Payment Calculation

Today, we adopt two contract options for expiring or expired QF contracts and new QFs – Our Prospective QF Program. The first option is a one- to five-year as-available power contract. The second is a one- to ten-year firm, unit-contingent power contract. Payments for as-available capacity will be based on the fixed cost of a Combustion Turbine (CT) as proposed by The Utility Reform Network (TURN), less the estimated value of Ancillary Services (A/S) as generally proposed by San Diego Gas & Electric Company (SDG&E). Payments for firm, unit-contingent capacity will be based on the market price referent (MPR) capacity cost adopted in Resolution E-4049[85] of $980/kW, annualized over

[85] MPR Resolution, E-4049, December 2006, http://www.cpuc.ca.gov/Published/Final_resolution/63132.htm.

a 20-year term at a Weighted-Average Cost of Capital (WACC) rate of 8.5%,which results in an annual amortized cost of $104/kW-year.

Our reasons for these determinations are described as follows. First, firm, unit-contingent capacity is more valuable than as-available capacity because, it is much more predictable and, therefore, much more reliable. Thus, firm power and as-available power cannot be priced identically. Historically, as-available QF power has been priced based on the real economic carrying charge of a combustion-turbine (CT) power plant. We will continue that practice as described herein because as-available QF power, as a block, does allow an IOU to avoid the procurement of additional capacity albeit without the same precision as that associated with a block of firm power. Second, the firm, unit-contingent power product from our prospective QF Program will allow an IOU to more precisely avoid the procurement of additional capacity.

Of course, we must take into account the Resource Adequacy requirements developed in R.04-04-003. (See, i.e., D.04-10-035 and D.05-10-042 et seq.) In D.04-10-035, the Commission found that QF as-available capacity should be "counted" for RA purposes at the historical level of deliveries. Due to the magnitude of QFs in the IOU portfolios, this approach is prudent. However, QFs under existing contracts are not under the same "must-offer obligation" required of other RA resources. However, these previous RA orders were issued prior to the development of our Prospective QF Program. The firm, unit-contingent power product should count for purposes of resource adequacy because it will be very similar to other modern power products that contain similar performance requirements. With regard to the as-available power product in our prospective QF Program, it should also count as a block of QF power. The issue of whether any of this QF power counts for purposes of RA is now moot with respect to the capacity payments because the capacity payments will no longer be contingent on RA counting rules. This follows from the fact that we cannot reasonably institute a meaningful long-term policy for expiring QF contracts, nor a policy for the entry of new QFs unless there is a capacity payment commitment.

It is true that QFs under existing contracts are not available to the CAISO as an RA resource. However, it is also true that all QFs with a dependable capacity under one MW are not capable of participating in CAISO markets, in terms of bidding and scheduling. Further, many as-available QFs are under one MW. Any generator under one MW, whether as-available or firm, does not have access to CAISO markets, nor does the CAISO have control access over sub-MW generators, including QFs. Thus, for example, even if QFs under one MW were fully dispatchable, CAISO systems are not currently set up to accommodate these sub-MW resources, nor will they be under the MRTU.

At this point, further consideration of any 'disparity' between the adopted RA counting rules and the reality of resource needs of the CAISO can be ended by acknowledging that capacity payments under the prospective QF Program will not be contingent upon future determinations on the RA counting rules. Instead, the RA counting rules can count or not count QF power, depending upon how the RA portfolios will be conceptualized in the future. Prospectively, we are committing ourselves to this next era of QF power through the provision of reasonable capacity payments for the power products provided. The CAISO and the RA counting rules will have to accept this power as must-take and focus on refining and shaping IOU power portfolios through the use of other resource options.

Once a full CT capacity value is determined, adjustments to that value should be considered. For example, we agree that the value of additional (ancillary services) revenue streams associated with the physical ownership of an actual CT should be accounted for in our estimate of capacity value. In its rebuttal testimony, CCC recommended the use of the full cost of a CT as the avoided value of as-delivered capacity, but also acknowledged that an adjustment to as-delivered capacity prices would be warranted given certain substantial evidence. (Exhibit 103, pp. 59-60.) CCC explored TURN's evaluation of the potential for such an adjustment based on an assessment of energy profits where an adjustment hinged on an accurate estimate of the number of hours of annual CT operation.

SDG&E recommends that:

> the value of the CT in the ancillary service market would be deducted from proposed annual avoided capacity cost. As the name "as-available" implies, the as-available capacity of a QF does not have the same characteristics as a CT that can be dispatched as needed. If the utility owned a CT, it could capture added value by offering the unit in the CAISO ancillary services market as non-spinning reserve, while the utility cannot obtain that value from an as-available QF. It is estimated that this ancillary services value over June, 2003 - May, 2005 was $14.78/kW-year. The full avoided generation cost is projected to be $83.75 per kW-year less the ancillary value of $14.82 per kW-year, so the proposed value for full as-available capacity is $68.93/kW-year in 2006. (Exhibit 85, p. 15.)

SDG&E proposes a methodology for estimating its recommended ancillary services value adjustment of $14.82 per kW-year, to account for revenue received from the CAISO for the provision of non-spinning reserves. The CAISO defines this product as follows:

> Non-Spinning Reserve is off-line generation capacity that can be ramped to capacity and synchronized to the grid within 10 minutes of a dispatch instruction by the ISO, and that is capable of maintaining that output for at least two hours. Non-Spinning Reserve is needed to maintain system frequency stability during emergency conditions.[86]

SDG&E assumed a 5% maintenance outage rate (438 hours/year), and that the CT would actually be operating (e.g., to serve native load) for 634 hours/year or about 7.2% of the year. During the remainder of the year (8,760 – 438 - 634 = 7,688 hours), the CT would be available to the CAISO to provide non-spin ancillary services. SDG&E obtained monthly non-spin prices from the CAISO for the period of June 2003 through May 2005 with a simple average of $1.93 per MW. Thus, the capacity value for non-spin reserves is estimated to equal 7,688 hours times $1.93 per MW = $14,815/MW or $14.82/kW-year.

We agree with TURN, SCE, and SDG&E on this issue. The avoided CT cost should be based on an economic carrying charge rate, escalated for inflation over the life of the contract. Using a levelized nominal dollar value to compute the CT cost would overstate the avoided capacity cost as well as present additional cost and risk for utilities and ratepayers. A primary concern is that the use of a levelized nominal value would require higher capacity payments in early years, exposing the utilities and their ratepayers to the risk of non-performance if the QF went off-line or simply failed to perform. While termination penalties or the posting of security could mitigate some of the concern, calculating a CT cost based on an economic carrying charge rate and escalating for inflation would eliminate this concern. In addition, as pointed out

[86] CAISO Settlements Guide, Ancillary Services, Spinning Reserve and Non Spinning Reserve, Draft Revised, 01/31/2006) http://www.caiso.com/clientserv/settlements/SettlementsGuide/index.html.

by SCE and TURN, it would be inappropriate to use a 20-year levelized value for a contract of less than 20 years in length. Using an economic carrying charge rate, escalated for inflation over the life of the contract, allows us to provide more flexibility in contract terms, from one year up to five years with the same CT cost estimate. As-available capacity prices should be expressed in real dollars.

For the as-available contract option, we adopt the CT cost and real economic carrying charge rate calculations proposed by TURN as presented in Exhibit 149, Appendix B, with an ancillary services adjustment subtracted from the adopted value as suggested by SDG&E. The estimated ancillary services value proposed by SDG&E is an annual average value; however, we believe this is an over-estimate and should be adjusted downward to reflect the fact that SDG&E's value of $14.82/kW-year is more indicative of a peak value. Accordingly, we reduce it by two-thirds to $4.94/kW-year. TURN calculates a total marginal CT cost of $64.13/kW-year in 2006. Using the adopted TURN value for $64.13, the resulting capacity value would be $59.19/kW-year ($64.13/kW-year - $4.94/kW-year).

6. Firm Capacity Pricing

In this rulemaking, CAC/EPUC, CCC, and IEP each respectively submitted long-run avoided cost (LRAC) contract and pricing proposals. The respective proposals are described in Party Positions, Section 6.2 of this decision. Although the QF parties proposed long-term contracting options, none of the QF parties proposed additional performance requirements beyond that in the existing standard offer contracts. For example, CCC recommends that "QFs should have the option to elect to extend their original firm capacity contracts on the same operating terms and conditions as specified therein, but subject to the contract lengths and LRAC contract prices that are approved for the new contract" (Testimony, 8/31/2005, p. 72). In contrast, the firm power contact option adopted in this decision establishes a higher level of performance by imposing penalties to the capacity payment for failure to deliver 95% of the contract power during on-peak months and 90% of the contract power during off-peak months (not counting scheduled outages).

Notwithstanding the fact that the QF parties have not proposed an increase in contract performance requirements, the LRAC contract pricing information, including capacity prices, proposed by CAC/EPUC, CCC, and IEP is shown in Table 8 below, along with the adopted firm capacity price and MIF heat rate figure issued today (CCC, p.5) , (CAC/EPUC, p.v), and (IEP, p.85) (Testimony, August 31, 2005). In addition, the pricing provisions for the PG&E/IEP Settlement are also shown for comparative purposes.[87] Although the capacity prices and heat rates vary, the all-in power prices under the CAC/EPUC and IEP proposals are essentially the same as the adopted value.

[87] Note that CCC based its capacity price on a combustion turbine (CT), whereas CAC/EPUC and IEP each based their proposed pricing on combined-cycle gas turbines.

Table 7 QF LRAC Pricing Proposals And All-In Payments					
Pricing Provisions	**CAC/EPUC**	**CCC**	**IEP**	**PG&E/IEP Settlement**	**Adopted**
Capacity Price $/kW-year	$142	$110	$129	$50	$104
Based On	CT	CCGT	CCGT	CCGT	CCGT
Heat Rate (Btu/kWh)	7,500	8,895	7,400	8,700	7,903
VOM ($/MWh)	$2.00	$2.70	$2.50	$2.00	$2.47
Illustrative Gas Price ($/MMBtu)	$7.50	$7.50	$7.50	$7.50	$7.50
All-In Power Price (cents/kWh)	7.4	8.2	7.3	7.3	7.4

Further, as illustrated in Table 8 above, four of the five all-in power price outcomes are essentially the same at 7.3 and 7.4 cents/kWh. This is in spite of the fact that the four similar price outcomes have capacity prices that range from $50 to $142/kW-year, and heat rates that range from 7,400 to 8,700 Btu/kWh. While the respective energy and capacity prices must each have their own basis in fact, the combination of the two prices in the form of the all-in power price represents the actual payment for the power delivered.

With regard to the capacity price calculation, the CAC/EPUC and IEP base their respective price proposals on the cost of a CCGT, whereas CCC bases its capacity cost proposal on the cost of a CT. IEP states that it used "used the model adopted by the Commission to determine the MPR" to calculate its capacity price (Testimony, p. 85). CAC/EPUC briefly describe their use of a CCGT proxy plant calculation to arrive at a capacity price (Testimony, p.5). The

CCC capacity value based on a CT is significantly above our as-available capacity price of $65.78/kW-year, due in part to the fact that it is in levelized nominal dollars (see SCE Figure 5-1 above).

The adopted method is similar to that proposed by IEP, but simply uses a short form of the more detailed MPR calculation of the annualized capacity payment, as shown in the figure below.

Figure 2
Simple Interest Annual Payment for Capacity
Given the Baseload MPR Capacity Price

$/kW	Rate %	years	$/kW-year	E-4049, Appendix E 2006 MPR Non-Gas Inputs
$ 980.00	7.13%	20	$93	Cost of Long-Term Debt is 7.13%
$ 80.00	8.5%	20	$104	WACC: Weighted-Average Cost of Capital = (Cost of Equity x Equity %) + (Cost of Debt x (1-tax rate) x Debt %)
$ 980.00	12.78%	20	$138	The Cost of Equity is 12.78% in the latest MPR Resolution E-4049

7. Policy Proposals for QFs with Expiring Contracts and New QFs

7.1. Overview

The parties fundamentally disagree on the future role of QFs in the provision of power to the utilities. The QF parties assert that PURPA requirements, as well as California's procurement policies, require that the Commission make available standard offers as a means of implementing PURPA, while the utilities and consumer advocates maintain that the Commission's policy for new QFs and QFs with expiring contracts should be to require such resources to participate in open solicitations with prices to be determined by the outcome of the competitive process.

The IOUs and consumer advocates' long term policy proposals for QFs are essentially a continuation of the interim approach established by the Commission in D.04-01-050 with the exception of the elimination of the five-year Revised Standard Offer 1 (RSO1) contract availability approved in D.04-01-050, and D.05-12-009. The IOUs propose three ways for QFs to obtain new power purchase agreements (PPAs). The first is participation in one of the utilities' all-source or renewable competitive solicitations. The second is bilateral contract negotiations. For both of these options, the pricing and terms would be set by the final negotiated PPA. The third option is a one-year market-based standard offer. Each utility's one-year market-based proposal is slightly different, but essentially, the QFs would have access to a one-year market-based standard offer as long as the PURPA mandatory purchase obligation remains in effect. The IOUs believe that these three options comply with PURPA, meet the Commission's EAP II loading order preferences, and are consistent with the Commission decisions D.04-01-050, and D.04-12-048. TURN and DRA support the IOUs' recommendations.

The IOU and consumer advocates also argue that QF contracts should include all up-to-date terms and reflect current electricity procurement requirements, including integration of QF resources into the CAISO tariffs. They note that this recommendation is consistent with the policy enunciated in the EAP II, specifically, Key Action Item 7 of Section 4, which states "adopt a long-term policy for existing and new qualifying facility resources, including better integration of these resources into CAISO tariffs and deliverability standards." These parties maintain that any future power purchase contracts should be consistent with CAISO tariffs, rules, regulations and protocols and utilities should not have to act as scheduling coordinators for QF power purchase contracts. The CAISO agrees.

The QF parties strenuously object to the IOUs' proposals. The QF parties believe that absent a Commission order to contract with cogeneration QFs on a "must-take" basis, the utilities could essentially eliminate these resources from their portfolios. The QF parties argue that despite repeated urging from the Commission in D.03-12-062 and D.04-01-050, and several rounds of utility power solicitations, QFs have not be able to compete successfully in the solicitations. The QF parties maintain that QFs have been unsuccessful because the terms of the utility solicitations, including requiring new facilities, dispatchable facilities, or certain minimum size restrictions, are not compatible with certain existing QF operations.

The QF Parties recommend that the Commission should provide the following options to QFs with expiring contracts and new QFs: (1) A QF could choose to be paid SRAC and as-available capacity payments (similar to the existing SO1 contracts); (2) If the QF is willing to enter into a PPA of at least 10 years but no more than 20 years, the QF should receive a PPA based on the all-in cost of a new combined cycle power plant, using updated assumptions and the Commission's MPR pricing model; and (3) negotiated agreements. CAC/EPUC and CCC also recommend that the Commission adopt, as a goal, a cogeneration portfolio standard. The cogeneration portfolio standard would require the utilities to continue to make available long-term standard offer contracts until they achieve a 25% increase in the amount of cogeneration in California over and above January 1, 2005 levels by the end of 2010.

7.2. Parties' Positions

7.2.1. PG&E

PG&E proposes that the Commission require QFs to compete in utility resource solicitations on an equal basis with other resources. PG&E contends that the record and the relevant law establish that the results of competitive solicitations would more closely reflect the utilities' avoided costs than an estimate of the cost of a CT. PG&E notes that each of the QF proposals for an administratively–determined long-run avoided cost (LRAC) price contains different values for long-term energy, capacity, and O&M, thereby demonstrating that any estimate selected by the Commission is highly likely to be incorrect. Moreover, PG&E maintains that each of the proposals is too high because they do not reflect the dispatchability benefit inherent in a CT that is not present in a QF contract.

PG&E also argues that the QF parties' proposals violate PURPA in that they do not reflect the many types of facilities available to sell power to the utilities, as required by FERC. PG&E notes that the proposed prices are higher than the prices paid for renewable power in recent RPS solicitations. PG&E states that it has conducted twelve solicitations since it resumed procurement in 2003 and argues that if QFs have not been successful in these solicitations, it is because they have elected not to compete due to the option of a higher-priced SO1 contract.

PG&E proposes that QFs with existing contracts may sell energy to PG&E at market-based prices under a one-year contract based on the Edison Electric Institute (EEI) Master Agreement. PG&E states that the EEI Master Agreement is widely recognized in the industry and has been approved by the Commission for use in the RPS program. PG&E argues that using the EEI Master Agreement for

QF power purchases going forward would make QF contracts consistent with those of other wholesale providers and would eliminate the contract provision advantages QFs currently have over their non-QF competitors. Specific contract modifications proposed by PG&E are listed in Table 4-3 of Exhibit 28.

PG&E emphasizes that the Commission should not adopt the QF proposals to allow QFs capable of committing to the delivery of firm capacity the option to sign as-available SO1 contracts. PG&E also maintains that federal policy favors moving QFs to wholesale competition, citing the August 8, 2005, Energy Policy Act of 2005.

Finally, PG&E argues that if any of the QF proposals are adopted, there will be a rush for the new contracts because the proposed prices are above market rates and the contract terms impose virtually no performance obligations outside of the three summer months.

7.2.2. SCE

SCE states that the Commission should adopt policies that support cost-effective cogeneration that benefits retail electricity customers. In particular, SCE emphasizes that the Commission must adopt long-term QF policies that are consistent with the other resource planning decisions adopted by the Commission as well as PURPA requirements. According to SCE, mandating a priority position for QFs and requiring that the utilities make available long-term standard offers to all existing cogenerators upon expiration of their current contracts does nothing to support cost-effective cogeneration. Instead, such a policy will support inefficient cogeneration.

SCE objects to the QF parties' proposal to determine LRAC pricing based on a Combined Cycle Gas Turbine (CCGT) proxy. SCE believes that "only if a QF were willing and able to operate in a dispatchable manner, so that the utility could curtail its output when less expensive baseload energy is available, would it be appropriate to use a CCGT proxy." (Exhibit 2, p.78.) SCE also points out that although certain QF parties have attempted to use SCE's Mountainview contract to justify CCGT proxy prices, the Mountainview contract contains many beneficial features that QF contracts do not, including a provision for the Mountainview project to be transferred to SCE at the end of the 30-year agreement term.

SCE recommends that the Commission require QFs to participate in utility resource solicitations, and if they choose not to, or are unsuccessful, provide a one-year market-based contract that would remain available as long as the PURPA mandatory purchase obligation is in effect.

7.2.3. SDG&E

SDG&E generally agrees with PG&E and SCE and recommends that the Commission require new QFs and QFs with expiring contracts to participate in utility solicitations. SDG&E also recommends that for existing QF contracts, a multi-year (one-to-five year) fixed price energy option, mutually agreed to via bilateral negotiations, should be permitted as discussed below. The pricing terms would be for one to five years and would be arranged by mutual agreement based on border gas forward prices and SRAC energy price transition formula as determined in this proceeding. PG&E and SCE are not opposed to a five-year fixed contract as long as the contract is voluntary on the part of the utility.

7.2.4. TURN

TURN states that the QF industry has embarked on an aggressive public relations campaign, in which they assert that the very existence of QF power in California is at risk if the Commission fails to accede to their pricing and contracting demands. TURN maintains that the Commission must recognize this campaign as an attempt to blackmail policymakers into authorizing another generation of above-market long-term QF contracts.

TURN would also support making five-to-ten year contracts available for certain existing QFs with expiring contracts and certain new QFs as long as those contracts were based on market prices. TURN states that it supports the IOUs' approach if SRAC pricing is not reformed as TURN recommends. However, if the Commission adopts the TURN reforms for SRAC pricing, TURN could support making five- to ten-year contracts available for QFs with expiring contracts and certain new QFs who might otherwise find it difficult to participate in the wholesale market and/or in utility solicitations.

7.2.5. CAC/EPUC

CAC/EPUC believes that the proposals presented by the utilities and the CAISO are contrary to the state's stated preference for cogeneration and do nothing to either preserve existing resources or to encourage new resources to be built. CAC/EPUC claims that cogeneration provides substantial benefits to the state, including (1) reduction in natural gas consumption, (2) reduction in emissions, (3) increased thermal efficiency, (4) capacity located within California, (5) increased electric system reliability, and (6) reduced impacts on the transmission grid.

CAC/EPUC describes cogeneration as the "sequential production of both useful thermal energy (such as heat or steam) used for industrial, commercial, heating or cooling purposes, and electric energy, from a single source of fuel." They jointly argue that the unique dual use of that fuel results in a reduction in the overall consumption of that fuel thereby providing both energy efficiency and environmental benefits. For cogenerators that produce more electrical energy than is consumed on site, the option to employ cogeneration technology is tied to the ability to harmonize the operation of the cogeneration facility with the production requirements of the thermal host and the electrical needs of the utility. CAC/EPUC also note that the types of companies which rely on thermal energy output of a cogeneration facility for their core operations will only continue to operate under a cogeneration configuration for as long a such a configuration continues to be economic, provides a reasonable certainty of operational longevity and does not jeopardize their ability to produce their core business product. (CAC/EPUC Opening Brief, pp. 36-36.) CAC/EPUC states that cogeneration resources are not and never will be fully dispatchable merchant facilities, since they are designed to serve thermal energy load and the right to dispatch or curtail would adversely impact the industrial obligations. CAC/EPUC asserts that because of cogeneration's unique operating characteristic (i.e., the need to harmonize both the electrical and thermal output) the only viable purchaser of electric power from a cogeneration facility is the utility. This is because of the utility's inherent long-term baseload requirements and the relatively large resource portfolio that allows cogeneration to be operated in a baseload mode consistent with cogeneration thermal output requirements.

CAC/EPUC argues that absent a long-term commitment, the continued operation of existing cogeneration facilities and the electrical energy supplied by these projects would be jeopardized. CAC/EPUC emphasizes the importance of state law, as set forth in Pub. Util. Code § 372, in encouraging the Commission to support the continued development, installation, and interconnection of clean and efficient self-generation and cogeneration resources, and to improve system reliability for consumers by retaining existing generation and encouraging new generation to connect to the electric grid.

CAC/EPUC also cites the EAP II:

> In furtherance of this important goal, EAP II sets forth the following key actions related to the preservation of existing CHP resources and the encouragement of new resources: (1) provide for the continued operation of existing generation need to meet current reliability needs, including combined heat and power generation; (2) adopt a long-term policy for existing and new qualifying facility resources, including better integration of these resources into CAISO tariffs; and (3) encourage development of environmentally sound distributed generation projects, including combined heat and power resources.

CAC/EPUC argues that the CEC has also recognized cogeneration as a critical loading order resource through its 2005 Integrated Energy Policy Report (IEPR) process, stating "cogeneration, combined heat and power" (CHP) is the most efficient and cost-effective form of DG [distributed generation], providing numerous benefits to California including reduced energy costs; more efficient fuel use; fewer environmental impacts; improved reliability and power quality; locations near load centers; and support of utility transmission and distribution systems. (2005 IEPR at p. 74.)

CAC/EPUC also point out that the Commission has expressed its support for the preservation of existing QFs in D.04-01-050, finding that "QF power provides numerous benefits to California, including environmental attributes, local power production, and economic development" (D.04-01-050, Finding of Fact (FOF) 71) and that "It is in the State's interest for QFs to continue to provide those benefits over the long term, especially when they are already in existence." (*Id.*, p. 151.)

CAC/EPUC believes that long-term contract price should be based on the actual LRAC from utility specific resource plans, e.g., the specific cost of resources in these plans should be the costs paid to QFs. They explain that since they did not have access to this level of cost information from the utilities' resource plans, an alternative surrogate resource, or combined cycle generating turbine, or CCGT, should be used as a proxy for the utilities' long-run avoided costs. CAC/EPUC maintains that the most reasonable LRAC pricing proxy is the CCGT proxy approved for the RPS. They argue that the MPR model can be readily employed to perform the necessary calculation based on recent long-term baseload resource proposals of the utilities. For an illustrative 20-year agreement beginning in 2008, the LRAC energy and capacity would be as follows, with the gas price input for each utility the same as that used for calculating their SRAC:

Capacity Payment ($/kW-Year) = $142
Variable O&M ($/MWh) = $2
Heat Rate (BTU/kWh) = 7,500
Capacity Factor = 92%.

CAC/EPUC argues that the IOUs' one-year as-available contract is unacceptable, but, given the problematic nature of participation in the utility resource solicitations, this option may be the only option that is executable. However, without a long-term contract, there is no guarantee that an industrial customer will have an outlet for the electrical energy that is produced in the cogeneration process. The one-year contract is also in conflict with the IEPR, according to CAC/EPUC, because a one-year contract at market-based prices is contrary to the IEPR's desire for the utilities to engage in long-term commitment to cogeneration. CAC/EPUC also claims a one-year contract violates PURPA because it is offered at prices which have not been demonstrated to reflect avoided cost.

CAC/EPUC also opposes the CAISO proposal to require QFs executing new contracts to comply with CAISO tariff requirements. According to CAC/EPUC, the CAISO's proposal would reduce California's ability to implement EAP II and IEPR cogeneration objectives, by subjecting cogeneration operation to federal jurisdiction and because it lacks any priority for cogeneration. CAC/EPUC cites Pub. Util. Code § 372 (f) in support of its position that California should not accede to this request. Section 372(f) states, in part, "If the commission and EOB [Electricity Oversight Board] find that any policy or action of the CAISO unreasonably discourages the connection of existing self-generation or cogeneration or new self-generation or cogeneration to the grid, the commission and the Electricity Oversight Board (EOB) shall undertake all necessary efforts to revise, mitigate, or eliminate that policy or action."

7.2.6. DRA

DRA recommends that new long term contracts for QFs be obtained by either participation in the IOU's general and renewable resource solicitations or by negotiating bilateral contracts with IOUs. As a backstop, DRA recommends that a one-year contract similar to SO1 be available for QFs who do not obtain contracts through other means.

DRA also recommends that the Commission adopt the standard terms and conditions of EEI model contracts, such as the EEI Master Agreement, in any future QF contracts authorized under this order. (Exhibit 154, p. 29.) DRA states that such contract standardization would promote: (1) full competition between QFs and non-QFs (2) provide the IOUs with an "apples-to-apples" comparison of competing resources, and (3) provide a closer fit between IOU portfolio need and contracted projects.

7.2.7. IEP

The IEP recommends that existing QFs should have the right to obtain a long-term contract based on the IOUs' long-run avoided costs. IEP states that the QFs should receive three payments: (1) a fixed capacity payment based on the levelized value of the fixed costs associated with a long-run avoided resource; (2) a fuel payment equal to the heat rate associated with the avoided resource multiplied by the cost of fuel; and (3) a variable O&M payment based on the variable O&M associated with the avoided resources multiplied by the QF's generation. IEP recommends using the 2004 MPR model and input assumptions to calculate the levelized fixed capacity payment, updated to reflect recent values for costs of construction, financing, and operation of new combined cycle facilities.

IEP argues that the adopted capital costs in the 2004 MPR did not include the cost of transmission interconnection, project laterals, environmental mitigation, emissions offsets, and cooling equipments, and is therefore too low. IEP recommends that the capital costs be updated to equal the mean value of the capital costs for Mountainview, Palomar, and Contra Costa 8. However, IEP recommends adjusting the capital costs for Mountainview and Contra Costa 8 to reflect the fact that these plants were acquired after a distressed sale and partial development, respectively. IEP recommends the average of the $740, $1017, and $850 capital costs for Mountainview, Palomar and Contra Costa 8, or $869/kWh.

IEP also states that the assumed capacity factor for the current MPR's combined cycle is too high. IEP believes that the capacity factor for determining LRAC should be lowered to reflect periods when it is uneconomic to operate the plant. IEP believes that a reasonable value is an 80% capacity factor. IEP also states that the heat rate for the combined cycle is too low, and an appropriate heat rate is 7,400 Btu/kWh reflecting a new heat rate of 6,950, a heat rate degradation factor of 3.5% and a 200 Btu/kWh increase in heat rate due to dry cooling. IEP's recommendations result in a fixed capacity payment of $129/kW-year, a heat rate of 7,400, and a variable O&M payment of $2.50/MWh.

IEP states that new QFs should have to participate in the utilities' solicitation process, to prevent over-subscription of the standard offers.

7.2.8. CCC

CCC recommends that the Commission approve a long-term firm capacity contract for QFs, and specify the minimum terms and conditions that such contracts must contain. Existing QFs should have the option to sign the new long-term firm capacity contract once their original contracts expire. Alternatively, CCC believes that QFs should have the option to extend their original firm capacity contracts on the same terms and conditions as specified therein, but subject to the contract lengths and LRAC prices that are approved for the new contract.

CCC also recommends that the Commission should continue to offer an as-available contract option priced at SRAC energy and as-delivered capacity prices with the same terms and conditions as the existing SO1, including the termination provisions, which give the QFs the ability to terminate the contract upon 30 days' notice to the utility. CCC states that this 30-day termination right is consistent with the as-available nature of the SO1 contract (i.e., the QF is under no obligation to deliver energy).[88] CCC believes that the as-available pricing option should be available to QFs for a contract term of up to 15 years.

CCC emphasizes that the approval of minimum contract terms and conditions is essential to ensure that QF contracts can be developed on a timely basis, without the need for negotiations between the utilities and QFs. CCC recommends the following terms and conditions:

> Term – The contract should be available for terms of 10, 20, or 25 years, to be selected by the QF.
>
> Purchase Obligation – The utility would be obligated to purchase, and the QF would be obligated to deliver, firm capacity at a level that is selected by the QF and specified in the contract (Contract Capacity). The utility would also be obligated to purchase any capacity made available in excess of the Contract Capacity ("As-Available Capacity"). The utility would be obligated to purchase all energy made available by the QF, which would be measured as either (1) the QF's gross output in kilowatt hours, less station use and transformation and transmission losses to the point of delivery (i.e., the QFs net energy output) or (2) the QF's gross output in kilowatt hours less station use, any other use by the QF (such as the sale of power to its onsite host facility) and transformation and transmission losses to the point of delivery (i.e., the QF's surplus energy output). The QF would be entitled to specify how energy is sold.
>
> Creditworthiness – The contract should not require the QF to post collateral or provide any form of credit support.
>
> Performance Standard – The QF would be entitled to receive, and the utility would be obligated to pay, the full firm capacity payment specified in the contract as long as the QF delivers the Contract Capacity during the peak hours of the peak months as defined in the contract ("Peak Period"), subject to a 20 percent allowance for forced outages at the QF. In other words, the QF would be entitled to the full firm capacity payment as long as the

[88] Exhibit 102, p. 74.

QF delivers 80 percent of the Contract Capacity during the Peak Period. This performance standard is the same one that appears in existing firm standard offer contracts.

Bonus Capacity Payments – The QF would be entitled to receive, and the utility would be obligated to pay, increased capacity payments when the QF exceeds the performance standard required for payment of the full firm capacity payment.

Scheduling Requirements – The utility should continue to be the scheduling coordinator for QF generation supplied under the contract, unless the QF chooses to schedule its own power.

Curtailment – The utility would be entitled to refuse deliveries from the QF only (1) when reasonably necessary to conduct repairs on its system, (2) when reasonably necessary because of emergencies or forced outages on its system, or (3) during other periods when FERC's regulation implementing PURPA allow the utilities to curtail QF deliveries.

Dedication of the Facility – The QFs output would be deemed to be dedicated to the utility up to the amount of Contract Capacity. The QF would retain the right and ability to use or sell elsewhere any and all capacity and energy generated in excess of the Contract Capacity.

Interconnection – For QFs supplying power under an existing utility contract that has expired, or that is set to expire, the contract should provide for an extension of the existing interconnection arrangements that is commensurate with the term of the new contract.

CCC states that the LRAC prices for energy and capacity should be based on an all-in CCGT proxy similar to that used to develop the MPR. However, CCC notes that "one can find CCGT cost estimates that span a wide range," and "[F]or the purpose of setting LRAC prices for QFs, the Commission should use

CCGT cost data that meets a higher standard than the CCGT data that has been used for other purposes."[89]

CCC recommends that the Commission consider SCE's Mountainview project and SDG&E's Palomar project as potential CCGT proxies. However, for Mountainview, CCC notes that the capital costs should be adjusted upwards by at least 11% to reflect the discount that SCE received for this distressed project. CCC argues that the EAP II identifies CHP as a preferred loading order resource and establishes the continued operation of existing cogeneration resources and new cogeneration resources. CCC argues that new long-term contracts are essential if California is to retain existing generation resources, to encourage existing cogenerators to invest new capital to improve their resources and to attract new cogenerators.

7.2.9. The Renewables Coalition

The Renewables Coalition recommends that the Commission adopt both a long-term firm capacity contract and a long-term as-available capacity contract for QFs whose contracts expire and for new QFs. According to the Renewables Coalition, the firm capacity contract should be available to existing QFs upon expiration of their existing contracts and to new renewable QFs in each utility's service territory until the utility has met its RPS program goals.

The Renewables Coalition also recommends that the Commission should adopt an as-available capacity contract based upon the current SO1 contract for renewable QFs. The Renewables Coalition states that the contract should contain as-available capacity and SRAC energy prices, should be available for up to at least 15 years, and should be terminable by the QF upon 30 days prior notice by

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[89] *Id.*, p. 76.

the QF. The Renewables Coalition recommends that the Commission adopt the terms proposed by the CCC.

The Renewables Coalition argues that each of their proposals is supported by the record, as well as by existing law and policy favoring the increased procurement of renewable power. Specifically, the Renewables Coalition maintains that its long-term QF procurement policy will support the Commission's RPS goals and is in fact necessary as a backstop to the RPS program to ensure that the benefits of existing renewables are fully captured by California ratepayers. The Renewables Coalition states that the RPS solicitations themselves do not ensure that renewable QFs will have purchasers for their power upon expiration of their existing contracts. They note that the utilities are only required to meet their annual procurement targets through solicitations if there are adequate Public Goods Charge funds available to support payments in excess of the MPR. They also note that the utilities are not obligated to procure from renewables in excess of the 20% goal established by the RPS program.

The Renewables Coalition also argues that the RPS program is structured such that existing renewables risk exclusion. Existing renewables are not eligible to obtain Supplemental Energy Payments (SEPs) as part of the RPS program. Small renewable QFs are prohibited from bidding in RPS solicitation because they cannot offer a product that is one MW or greater in size and/or cannot comply with certain terms and condition in the RPS solicitations such as credit guarantees. The Renewable Coalition states that existing biomass facilities are unable to compete with more modern wind or geothermal facilities, therefore the RPS program is not likely to be viable option for these less cost-effective renewables. The Renewables Coalition argues that by adopting long-term LRAC contracts as a complement to the RPS program solicitations, the Commission will ensure that all renewable resources, both existing and new, are encouraged.

7.3. PURPA Purchase Obligation

Before addressing the merits of the parties' long-term recommendations, we believe it is useful to discuss our PURPA obligations. The Commission has found it necessary to adjust its implementation of PURPA periodically over the years. Prior to electric restructuring, Standard Offer contracts allowed QFs to unilaterally choose a contract term of up to 30 years, and some Small QFs obtained evergreen contracts which may only be terminated by the QF. SO2, SO3, and ISO4 offers were also available, some with fixed energy prices and/or fixed capacity prices for terms of up to 30 years.[90] Over the years, the Commission eventually suspended the availability of virtually all of the standard offers, first due to oversubscription and inaccurate pricing, and then due to electric restructuring. The bulk of the remaining QF contracts are now due to expire over the next decade.

In several recent procurement orders, we have articulated our interpretation of PURPA requirements. In D.02-08-071, we noted that PURPA gives us considerable discretion in its implementation and does not obligate us to continue standard offer contracts.[91] At that time, no new SO1 contracts were available and we offered a limited extension of certain contracts to ensure reliability of supply as the utilities resumed procurement following the electricity crisis. We next considered this issue in D.03-12-062, again offering a limited extension of certain expiring QF contracts. However, in D.03-12-062 we also noted that while "QF participation in such solicitations is the best way for the

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[90] See Appendix A for a brief description of the various standard offers.

[91] See, D.02-08-071, p. 31, addressing a QF request to continue SO1 contracts.

IOUs to match their need for new capacity with the range of potentially available resources, including QFs… we do not believe that such participation should be mandatory for existing QFs seeking to renew their contracts." (D.03-12-062, p. 5.)

In D.04-01-050 we addressed our PURPA obligations as we considered whether to grant further extensions of SO1 or offer contracts to new QFs. In that case, we found that FERC's *Ketchikan* order and Order No. 69, provide more specific guidance on this question of whether we are obligated to offer contracts to new QFs as follows:

> …we find that compliance with the utility purchase obligation, by means of a purchase that would displace power from the Four Dam Pool Initial Project, is not necessary to encourage cogeneration and small power production and is not otherwise required under section 210 of PURPA. We make this finding because, as we have stated previously, there is no obligation under PURPA for a utility to pay for capacity that would displace its existing capacity arrangements. Moreover, there is no obligation under PURPA for a utility to enter contracts to make purchases which would result in rates which are not 'just and reasonable to electric consumers of the electric utility and in the public interest' or which exceed 'the incremental cost to the electric utility of alternative electric energy.' 16 U.S.C. § 824a-3(b) (1994). (footnotes omitted, emphasis added) *City of Ketchikan (2001) 94 FERC 61,293,* pages 15-16.

Thus, as FERC itself has recognized, we must balance the PURPA mandate that utilities are to purchase energy and capacity from QFs with the overarching requirement that electric utilities may only charge just and reasonable rates for the power they supply to their customers. In this order, we continue to find that PURPA does not require us to create new standard offers that do not reflect the utilities' resource needs or market conditions.

When the Commission began implementing PURPA, QFs were the only viable alternative to utility generation. Today, the wholesale power marketplace has changed significantly, due in part to FERC regulations requiring open, non-discriminatory access to transmission, non-utility power marketers that are licensed to buy and sell power in the wholesale market at market-based rates, utility divestiture, the CAISO, and the various trading markets and financial instruments that have developed and evolved. As a result, there are several wholesale market participants available to sell power to the utilities, and/or construct new generation facilities. It is simply inaccurate to assume that "but for" a block of QFs, the utilities would replace the QF generation with the same generation that is in their resource portfolio. It is more reasonable to look to resources available in the market as a benchmark.

We agree with TURN in part, that what the IOUs "avoid" by purchasing QF energy is the price that they would otherwise pay in the wholesale market for replacement energy. Thus, for short-run energy, that price should reflect the Day-Ahead market prices. For longer-term contracts, the IOUs generally avoid procurement of baseload capacity. We find that, aside from the QF contract options presented in this order, the price should be the result of a competitive process.

Proponents of long-run standard offers argue that standard offers are the best, if not the only effective mechanism to encourage QF generation in the state. In their view, the unique operation characteristics of cogeneration resources, combined with IOU reluctance to sign contracts with QFs, will force QFs with expiring contracts off-line. They argue that a standard offer approach is the only way to effectively comply with the EAP II directives to encourage cogeneration. These parties maintain that the benefits of QFs overshadow and outweigh the potential concerns regarding high prices of excessive supply associated with prior standard offers. They calculate benefits of QFs such as gas savings, locational benefits, reduced emissions, and job creation, that are not quantified or included in avoided cost but that should be considered by the Commission. They also argue that they should continue to be treated as must-take generation and should not be subject to CAISO tariff requirements.

As noted by the QF Parties, the EAP II sets forth a list of joint goals and an implementation plan for California's energy future. EAP II identifies as its "overarching goal" a desire for California's energy to be adequate, affordable, technologically advanced and environmentally-sound. EAP II contains explicit direction, in the form of a "loading order" (EAP loading order) that describes the priority sequence for actions to address increasing energy needs.

The EAP loading order identifies energy efficiency (EE) and demand response (DR) as the State's preferred means of meeting increasing energy needs. After cost-effective EE and DR, the loading order provides that the State should rely on renewable sources of power and distributed generation (DG), such as CHP operations. To the extent these resources are unable to satisfy increasing energy and capacity needs, EAP II supports clean and efficient fossil-fired generation.

Notwithstanding the fact that the term cogeneration does not appear in either EAP I or EAP II, the QF Parties assert that the EAP loading order identified CHP resources, as a priority resource in the order of policy preferences adopted for the California's electric utilities. CCC and CAC/EPUC claim that under the EAP loading order, cogeneration, as a CHP resource, is second in priority only to EE and DR and equal in priority to renewable resources.

The parties disagree as to whether all CHP resources, particularly large cogeneration projects, should qualify for second-priority status in the loading order. The QF Parties maintain that all CHP resources, including large cogeneration, are to be considered along with DG in the loading order. They assert that the EAP loading order simply does not differentiate between small and larger cogeneration projects, therefore all cogeneration projects necessarily fall into the second priority. The IOUs and DRA maintain that the agencies did not intend to include large cogeneration projects with renewable resources or other DG projects, and therefore, such projects do not have loading order priority.

EAP II does not include a specific definition of either DG or CHP resources; however, we find no reason not to encourage cost-effective, environmentally-sound CHP resources, regardless of their size. At the same time, we find no evidence to support the position that all cogeneration should be second in the loading order, regardless of efficiency.

To be clear, neither EAP I or EAP II include a specific definition of either DG or CHP resources, nor has the CEC specifically defined these terms elsewhere. We have, however, adopted policies to encourage specific types of CHP and DG in our Self Generation Incentive Program (SGIP).

California's SGIP contains both renewable and non-renewable CHP technologies, depending upon the fuel source. In March 2001, we issued D.01-03-073 authorizing the Self Generation Incentive Program, and allocated $125 million per year through 2004 for program administration and customer incentives. In October 2003, Assembly Bill (AB) 1685 (Stats. 2003, Ch. 984) extended the program to 2008.

Only certain technologies are eligible to receive SGIP incentive payments: photovoltaics, wind turbines, fuel cells, internal combustion engines, small gas turbines, and microturbines. These last four technologies can be considered CHP.

In its 2005 IEPR and associated Transmittal Report, the CEC equates cogeneration with CHP. On a technological basis, to simply equate cogeneration with CHP is over-simplification. Consider that the U.S. Combined Heat and Power Association (USCHPA) in its November 8, 2005 comments filed at FERC in the QF criteria NOPR stated that,

> "CHP is effectively a synonym to the term 'cogeneration,' but has come into wider use in recent years because it more clearly allows for the increasing number of facilities with multiple useful thermal energy outputs rather than simply steam…."

On a policy basis, we are reluctant to group 20-year old cogeneration technology in with state-of-the-art fuel cells, small gas turbines, and micro turbines because such an approach would not allow us to differentiate among technologies.

In discussing the loading order in D.04-12-048, we identified the order of resources as follows: EE and DR, renewables (including renewable DG), clean fossil-fired DG, and clean central station DG. For purposes of implementing the EAP II loading order in this proceeding, the order of resources should be the same as that adopted in D.04-12-048. We recognize however, that the utilities' implementation of the loading order cannot result in payments to QFs that exceed the utilities' avoided costs.

On the other hand, we are troubled by the QFs' assertions that there are significant barriers to entry in IOU power solicitations. The QF Parties are concerned that solicitations may shut them out of future procurement opportunities because the utilities have each indicated in one form or another that they prefer dispatchable resources to baseload, or that they have no need for additional as-available capacity. The QFs complain that, to date, IOU solicitations have imposed conditions on bidders that are unworkable for most cogeneration QFs. Furthermore, the QFs assert that the IOUs have emphasized that for the foreseeable future, they are only willing to purchase firm, dispatchable resources, even if this limitation would eliminate most cogeneration projects from the range of potential suppliers. The QFs also note that for many QFs, their only option is to sell to the utilities.

As we previously stated:

> To the greatest extent possible, the utilities should conduct power solicitations for the specific power products needed to meet their load-serving obligations. The utilities should avoid the exercise of monopsony power through arbitrary segmentations of potential bidders. The utilities should spend much more time signaling their power product needs to the market so as to encourage all qualified bidders to participate.
>
> While we did not give any specific instructions in D.04-12-048 to the IOUs for including or excluding bidders from RFOs, we encourage the IOUs to be as inclusive as possible in their RFOs. We will refine the directives for RFOs, as needed, in the 2006 LTPP decision. (D.05-12-022, *mimeo.*, pp. 16-17.)

This point was reiterated when we issued our Rulemaking to Promote Policy and Program Coordination and Integration in Electric Utility Resource Planning, R.06-02-013 (*See* R.06-02-013, p. 11) and we stress these points here. Based on all of these considerations, we provide the following three options for QFs in the next section of this decision.

7.4. Prospective QF Program

First, for existing QFs, the utilities shall offer new one- to five-year, as-available standard offer contracts to QFs. The contracts shall be updated to require compliance with CAISO tariffs, including the Resource Adequacy (RA) tariff. However, QFs with expiring contracts seeking to sign new, one- to five-year as-available contract shall not be required to provide new credit support provisions nor new interconnection studies.

QFs under the one- to five-year as-available contracts shall receive SRAC energy payments as discussed herein along with the as-available capacity payment described herein. New contracts will be subject to any changes in capacity payments resulting from future modifications to the RA counting rules; existing contracts will not be affected. QFs larger than one megawatt in dependable capacity will be responsible for scheduling coordination with the CAISO, however, the utilities must provide that service for a reasonable cost. We adopt PG&E's recommendation to use the EEI Master Contract as a starting point for new QF contracts, as described herein.

Second, the utilities will offer a one- to ten-year contract term to those QFs with expiring contracts that are willing to provide unit firm capacity and that desire a longer-term contract. As with the as-available contracts, QFs under the one- to ten-year fixed capacity contracts will receive the revised SRAC energy payments as discussed herein. Long-term firm capacity payments will be based on the MPR capacity cost of $980/kW adopted in Resolution E-4049 which results in an annual cost of $104/kW-year. The higher capacity payments associated with the firm capacity contracts will appropriately compensate the QFs for the increased hedge value of assuring firm capacity for a longer term. These contracts will only be available to those QFs willing to offer unit-firm capacity. The all-in payments associated with the two prospective QF Program options are shown in Table 4a, attached to this order, at an illustrative gas price.

The new contracts will also have updated performance requirements to reflect the firm capacity, but QFs with expiring contracts seeking to sign new unit-firm contracts shall not have to provide additional credit support, nor should they be required to perform additional interconnection studies. QFs larger than one megawatt are responsible for scheduling coordination, although the utilities must offer scheduling service to QFs at a reasonable cost. QFs who are not able to offer unit firm capacity will be able to either continue on a one- to five-year as-available contract from year to year or may participate in utility resource solicitations and bilateral negotiations.

The third option, available to QFs desiring longer-term contracts or more flexible contract options, is to participate in utility resource solicitations or bilateral negotiations. We do not expect or desire all QFs to continue on SRAC-based pricing. The prices paid to winning bidders in competitive solicitations can best reflect the utility's long-run avoided cost for the specific type of product needed and provided. As we stated in D.96-10-036, "[N]o preference for QF power justifies payment above levels arrived at by all source bidding, as such above market prices would violate PURPA's standard of ratepayer indifference."[92] We uphold the same principle today. Contrary to the QF representatives claims, we are under no PURPA obligation to require long-term standard offers, and we find no mandated minimum term for PURPA required purchases. Looking to FERC regulations, we similarly find no mandated minimum term.[93] We do not want to see erosion of the utilities' QF supplies, therefore we expect that as old QF contracts expire, new or renewed QF contracts will replace them.

If a new QF seeks access to one of the contract options described above, and the IOU contends it would be inconsistent with the existing need determination from the Long-Term Procurement Plan (LTPP) proceeding, the

[92] D.96-10-036, *mimeo.*, p. 40.

[93] *Id.*

utility must consult with its Procurement Review Group (PRG) within 20 days of receiving a contract request from a QF. The PRG consultation period shall be initiated within 20 days of receiving a contract offer from a QF. If a QF believes that a contract is being unreasonably withheld, it may file a complaint with the Commission. Utilities and QFs will also have the opportunity to address the need for new contracts as part of the utilities' long-term procurement plan filings in R.06-02-013 or its successor.

The cogenerators point to the fact that the QFs have not obtained contracts with utilities through competitive solicitations as evidence that they will not be successful if required to compete against non-QF generators. (CCC Opening Brief, pp. 63-64.) On the other hand, the utilities argue that the QFs have chosen not to participate in these solicitations because SO1 PPAs have been available as a result of Commission direction in D.02-08-071, D.03-12-062, D.04-01-050 (five-year), and D.05-12-009 and the QFs have not been required to participate. We have a chicken and egg problem. Utilities state that the prices paid for energy and as-delivered capacity under the SO1 agreements averaged $87.44 in 2005 and exceed the spot market prices for firm energy and capacity, even though they have no performance requirements.

Despite the utilities' assertions that their RFOs are open to QFs, it is clear that more needs to be done to ensure that QFs are able to compete. For example, PG&E witness La Flash testified that baseload QFs were able to bid a baseload product in PG&E's 2004 solicitation even though PG&E needed only dispatchable and shaping resources. (RT 3444.) In this case, while the RFO is "open" to baseload QFs, it may not be useful to submit a bid. Clearly, then, if we are to encourage QFs to remain on line but be active in RFOs, the RFOs need to be more open to QFs. As QF contracts, expire, utilities should be soliciting new

QFs, especially those in local load pockets. For example, with the advent of local RA requirements in D.06-06-064, we expect the IOUs to seek to retain existing local RA generation that counts towards local RA requirements.

FERC has approved the use of solicitations for complying with PURPA. As SCE points out, FERC determined that a QF that unsuccessfully bid to supply capacity and energy to a utility had its complaint dismissed by FERC, with FERC holding that PURPA did not obligate the utility to purchase from the QF. In that decision, FERC stated:

> [a]voided costs are determined, in the first instance, by all alternatives available to the purchasing utility. Those alternatives, as we have explained in a number of recent orders, include all supply alternatives. Here the [utility's] supply alternatives included the power sale agreement offered by the [winning bidder]. If the QF… could not match the rate offered by a competing supplier of power to the [utility], regardless of whether the competitor was or was not a QF, then the QF demonstrably was not offering a rate at the [utility's] avoided cost – and the [utility] had no obligation under PURPA to purchase power offered at a higher price than the lowest bid.[94]

In conclusion, we find that a combination of market-based offers along with the ability to compete for longer-term contracts best reflects the utilities' avoided cost and meets California's goals for acquiring and retaining cost-effective, environmentally sound generation. First, it provides both short and longer-term options for market-based contracts. Second, for each procurement cycle, the IOU must propose a portfolio of resources that reflects the continuation of QF capacity. The IOU must demonstrate that their solicitations encourage the participation of QFs whose contracts are expiring.

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[94] SCE Brief, p.8., citing *N. Little Rock Cogeneration, L.P.* 72 FERC at 62, 170-172.

Furthermore, requiring the utilities to make available one to ten-year unit firm capacity contracts, as well as optional one- to five-year as-available contracts is consistent with and supports one of the key actions in the EAP II. Our prospective QF Program process will ensure that the amount of QF power under contract is consistent with the utilities' need. If a utility currently does not need additional QF power, for example, the utility is only required to renew existing contracts if it chooses, and will not be required to purchase new QF capacity if the utility can demonstrate that it no longer needs capacity.

As noted above, the Commission has stated its intent to encourage cogeneration and DG, however we cannot do so in manner that results in payments to QFs that exceed the IOU's avoided cost. CAC/EPUC accurately comment that "one of the more effective ways to encourage cogeneration is to enhance payments for delivered electric power."[95] However, we are prevented from "enhancing" QF payments if that would exceed avoided cost. Moreover, we are precluded from paying different avoided costs rates for different QFs or different technologies; any standard offer we provide is open to all QFs, regardless of size, location, efficiency, as long as they are certified as a qualifying facility under PURPA.

Our decision in D.04-01-050, relying on *City of Ketchican*, explicitly recognized that the PURPA purchase obligation is not absolute. D.04-01-050 also refers to FERC's Order No. 69, which states, among other things:

> A qualifying facility may seek to have a utility purchase more energy or capacity than the utility requires to meet its total system load. In such a case, while the utility is legally obligated to purchase any energy or capacity provided by a qualifying facility, the purchase rate should only include payment for

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[95] Exhibit 134, p. 43.

> energy or capacity which the utility can use to meet its total system load. These rules imply no requirement on the purchasing utility to deliver unusable energy or capacity to another utility for subsequent sale.[96]

FERC has therefore recognized that we must balance the PURPA mandate that utilities purchase energy and capacity from QFs with the overarching requirement that electric utilities may only charge just and reasonable rates for the power they supply to their customers.

7.4.1. Small QF Contract Option

RCM Biothane (RCM), Davis Hydro (DH), CARE, and TURN each expressed concern regarding the one MW minimum bid requirement for participation in utility RPS procurement RFOs and request that the Commission adopt a standard offer contract for small generators. (TURN Opening Brief. p. 12; DH Opening Brief, p. 11; RCM Opening Brief, p. 2.)

RCM designs anaerobic digesters for waste-to-energy projects on hog and dairy farms, such that the farms also function as small renewable DG facilities. RCM states that currently, net-metering is the only avenue available for the farms to interconnect to a utility in California, and the net-metering laws do not allow for compensation of excess generation. Under the net metering statutes, the dairy farms can only net-meter against the generation component of the utility bill, and any excess is zeroed out. Because of this, anaerobic digesters are not cost-effective and relatively few farms have chosen to build digesters.

To cure this problem, RCM proposes that the Commission require the IOUs to purchase power from all renewable DGs that are less than one MW in size under standard offer contracts. RCM explains that only a "large scale

[96] 45 Fed Reg 12219 (1980).

developer or merchant generator" can meet a one MW requirement in many utility RPS solicitations.

PG&E points out that the net metering program provides credit to certain renewable generators for their exports that offsets the generation portion on the retail amount that would otherwise apply for energy purchased from PG&E. PG&E suggests that generators choosing to install large systems might be better off choosing to sell power rather than participating in net metering.

PG&E also notes that it modified the one MW requirement for its RFOs in 2005 and allows systems smaller than one MW to combine bids to meet the minimum. PG&E encourages dairy farms to pursue this option as an alternative to net metering where, for example, the optimal size of a generator would be larger than the limitations required by the net metering legislation.

PG&E also points out that it is proposing a simplified as-delivered contract form for use with QFs and eligible renewable resources smaller than one MW in dependable capacity. PG&E would pay the QFs at market-based rates for up to a term of five years, therefore, all generators are guaranteed a buyer. The proposed agreement, which PG&E would file for Commission approval, would pay the QFs at market-based rates and contain a term of up to five years.

TURN recommends a maximum size cutoff for this category of 10 MW or the minimum size limit established for the utility's RFOs, whichever is greater. TURN also recommends that QF projects of 25 MW or less that consumes at least 25% of their power internally and sell all of their additional output to the utility should be eligible for longer-term contracts. TURN recommends this option because such QFs cannot sell their surplus directly to the CAISO under its current rules. (Exhibit 149, p. 6, fn. 10.)

We agree with PG&E and TURN that Small QFs that do not qualify to participate in utility RFOs, or for whom the transaction costs of RFO participation and or individual contract negotiation would be prohibitive (for the QF and perhaps for the utility as well) should be provided with a market priced standard offer. We note that avoided cost payments are not dependent on the type of QF, instead, the avoided cost is are based on the cost to the utility of the next increment of generation, and are intended to put the utility in the same position when purchasing QF capacity and energy as if the utility generated the energy itself or purchased the energy from another source.

Therefore, Small QFs will have the same contracting options as larger QFs, with one exception. As recommended by TURN and PG&E, for Small QFs with one MW or less in dependable capacity we will approve a five-year as-available standard offer contract. We find this additional option reasonable for Small QFs because they may have more difficulty participating in utility solicitations.

7.4.2. Five-Year Fixed Price Proposals

As already noted, we recently approved two five-year, fixed energy price agreements in D.06-07-032 (PG&E/IEP Settlement) and in Resolution E-4026 (SCE and Renewables). Last year, prior to the announcement of either of these agreements, each of the major QF parties participating in this proceeding (CAC/EPUC, CCC, IEP, and the Renewables Coalition) as well as SDG&E, had recommended that the Commission make available five-year, fixed price standard offers, either as an extension of the existing five-year fixed price mechanism adopted in D.01-03-067, or as a new option for QFs with expiring contracts or new QFs. We observe here that the two recently approved five-year, fixed energy price agreements were a result of bilateral negotiations. The prior five-year, fixed-price contract option at 5.37 cents per kWh, adopted in D.01-06-015, was also largely the result of a bilateral negotiation process.

The QF parties maintain that the 5.37 cents/kWh fixed price has been below posted SRAC prices and the amendments have resulted in substantial ratepayer savings. CCC and the Renewables Coalition point out that the fixed price amendment was "so widely perceived as a good thing, especially for renewable QFs whose economics are not premised on the varying price of natural gas, that the California Legislature codified that right of renewable QFs to negotiate a fixed price, upon expiration of the existing contract amendments, as a price to be set by the Commission. The statute, PU Code Section 390.1 was enacted in SB 1078."[97]

The Renewables Coalition suggests that the five-year fixed price should be a five-year forecast of SRAC prices based on the adopted SRAC formula. Eligible QFs would be given a 12-month period in which to elect the fixed price, with the election period commencing either with the expiration of each QFs' existing five-year amendment or, for QFs that do not have five-year amendments, with a month to be assigned that falls within the period during which the existing five-year amendments expire. The Renewables Coalition also recommends that the Commission update as-available capacity and energy pricing terms consistent with CCC's proposal. The Renewables Coalition maintains that Pub. Util. Code § 390.1 requires the Commission to adopt a five-year fixed price option.[98]

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[97] CCC Opening Brief, p. 43.

[98] Section 390.1 states "[A]ny nonutility power generator using renewable fuels that has entered into a contract with an electrical corporation prior to December 31, 2001, specifying fixed energy prices for five years of output may negotiate a contract for an

The Renewables Coalition also maintains that adoption of a five-year fixed price contract will not result in oversubscription because the contract would only be offered to QFs that are already built and have operated reliably for many years. The Renewables Coalition further states that utilities' concerns regarding gas price arbitrage do not apply to the renewables QFs and that the IOU can incorporate provisions into the fixed price contract that prevent such gas price arbitrage.

CAC/EPUC recommends that the Commission require the utilities to offer PPAs of five years with a variable or optional fixed energy price and as-available capacity payments. CAC/EPUC recommends pricing the five-year fixed option on the implicit IER in the SRAC energy price and the latest available forward market gas prices at the relevant gas hub. In response to utility concerns that gas-fired QFs executing these contract amendments would sell their gas rather than providing as-available energy under the contract could be addressed through contract provisions stating that during on-peak periods when the power is needed, such activity would be prohibited.

CCC proposes that the renewed fixed price be set using the MIF, with the extended five years of IERs and O&M adders and a five-year forecast of gas prices.

SDG&E also recommends that for existing QF contracts, a multi-year (one-to-five year) fixed price energy option, mutually agreed to via bilateral negotiations, should be permitted. The pricing terms would be for one to five years and would be arranged by mutual agreement based on border gas forward

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additional five years of fixed energy payments upon expiration of the initial five-year term, at a price to be determined by the commission."

prices and SRAC energy price transition formula as determined in this proceeding.

SCE and PG&E both oppose the adoption of a mandatory new fixed price option based on a five-year forecast of SRAC. In support of their position, SCE and PG&E maintain that PURPA does not allow state regulatory authorities to revise binding contractual agreements in QF contracts; therefore, any mandated substitution of the fixed price for SRAC in existing contracts would be unlawful. In addition, they note that the five-year fixed price option is not required by statute. Instead, § 390.1 provides:

> Any nonutility power generator using renewable fuels that has entered into a contract with an electrical corporation prior to December 31, 2001, specifying fixed energy prices for five years of output may negotiate a contract for an additional five years of fixed energy payments upon expiration of the initial five-year term, at a price to be determined by the Commission.

PG&E does not oppose negotiating a fixed price with QFs, but opposes any mandated fixed price. We agree that the option provided under § 390.1 does not undermine the RPS program because the generators who have access to this program are existing renewable generators. Therefore, while a contract extension would ensure that the utilities' baseline RPS resources did not disappear, it would not bring new renewable resources on line, a key objective of the RPS program. Moreover, although these resources would then be removed from the RPS solicitations, that result may allow new resources to compete more effectively, possibly bringing new renewable resources on line in California.

Moreover, the statute does not require the Commission to make available a standard offer with five-year fixed prices, it merely requires the Commission to approve the pricing terms agreed upon in the negotiation of the contract. Many QF contracts were originally modified to provide energy payments based on fixed prices, rather than SRAC as a result of contract amendments approved in D.01-07-031. Recently, many more QF contracts were modified to provide an additional fixed price period in D.06-07-032 and Resolution E-4026. We adopted both these contract amendments recognizing that they were the result of negotiations involving many factors in addition to the SRAC formula. These amendments are not precedential.

At this point, we are not in a position to adopt a mandatory five-year fixed price based on contract terms that have yet to be negotiated. We encourage any renewable resources to negotiate and bring before us applications for such five-year, fixed price amendments, wherever possible, and will consider such applications as we have other negotiated agreements in prior decisions, keeping in mind the direction provided by § 390.1.

7.4.3. Applicability CAISO Tariffs

The CAISO requests that the Commission require QFs executing new PURPA contracts to comply with CAISO tariff requirements. The CAISO also requests that the Commission specify that QFs seeking to interconnect or modify an existing interconnection at the transmission level should be required to comply with the CAISO's interconnection process.[99]

The IOUs agree and also request that the Commission relieve the IOUs from the obligation to act as scheduling coordinators for QF power purchase contracts. SDG&E notes that existing QFs, already interconnected with the utility under an expiring contract, should not require additional interconnection studies, but PG&E maintains that QFs who have substantially modified their

[99] CAISO, August 17, 2005 Comments, p. 2.

facilities as well as QFs with new PPAs should comply with the procedures and standards of the CAISO.

The QF parties believe that subjecting QFs to the CAISO tariffs would be an unreasonable burden for QFs, especially for cogenerators that have host thermal obligations and smaller QFs that may not be able to afford the various additional costs required for tariff compliance. They argue that neither the CAISO nor the utilities have argued that they will incur significant additional costs in handling the scheduling for QFs with new or renewed contracts. They also argue that there is no evidence that continuing to exempt QFs from the CAISO tariffs causes any problems.

The CAISO submits that if regulatory must-take status is removed, it will respect the QFs preexisting status and not subject them to burdensome tariff requirements but noted, that such treatment "may require action by the CAISO in conjunction with the California Commission's action." (RT 4127:27-4128:6.)

On this issue, we are guided by Key Action Item 7 of Section 4 of EAP II, which provides: "Adopt a long-term policy for existing and new qualifying facility resources, including better integration of these resources into CAISO tariffs and deliverability standards."

For Small QFs whose size prevents them from participating in CAISO markets, it is clear that the utilities should continue to be obligated to act as scheduling coordinators. It is less clear for larger QFs, who may or may not have the capability to perform these functions. A more critical question, however, is whether or not the costs of scheduling and imbalance charges are avoided by the utility through its purchases from the QF. PG&E claims that these are not avoided costs and that any power purchased, whether from QFs or other market participants would need to be scheduled. It is possible that in the case of purchased power, the seller would perform the scheduling function, but in that case, the cost would be built in to the cost of the energy.

We find that QFs should generally be required to comply with CAISO tariff requirements, however, as recommended by the CAISO and SDG&E, we do not expect existing QFs to be required to complete new interconnection studies. As observed by several parties, neither the CAISO nor the utilities have described what type of disruption would be caused by retaining QFs' existing arrangements, and in fact, CCC points out that the Kern River Cogeneration Company (KRCC) contract would extend KRCC's existing interconnection agreements for the term of that contract, five years. The current "CAISO exempt" and "must-take" status of the QF contracts stems from the fact that the CAISO did not exist when the contracts were signed. New contracts must explicitly take the existence of the CAISO and its tariff requirements into account. We adopt PG&E's recommendation that QFs one MW or greater should be required to comply with the CAISO tariffs. We also adopt PG&E's recommendation that QFs serve as their own scheduling coordinators, with the option of purchasing these services from the utility.

7.4.4. Standby Power

CAC/EPUC maintains that IOUs must continue to provide standby power and recommend that the Commission adopt standby power policies that reflect certain CEC and FERC policies regarding the location of metering and telemetry for QF projects. CAC/EPUC are opposed to the CAISO's preferred approach which would require gross metering or net generation metering. CAC/EPUC note that FERC found that the CAISO need only meter the direct impact on its system; "changes in load and generation behind the meter will be captured at this point." (CAC/EPUC Opening Brief, p. 39.) The IOUs do not disagree, but note that issues of standby policies and rate design are outside of the scope of this proceeding.

For purposes of our prospective QF Program, we will continue to require the IOUs to provide backup or standby power at reasonable rates to QFs. Standby rate design issues have been considered and adopted as part of the Commission's Distributed Generation Rulemaking and are not further considered in this proceeding.

8. The Record is Sufficient Despite Confidentiality Concerns

IEP and CAC/EPUC ague that we cannot make a finding on the utilities' avoided costs without certain of the utility cost, load, and supply information that has not been made available to all the parties. IEP and CAC/EPUC claim that the Commission cannot use as a basis for its decisions information that is not disclosed to all parties. They claim that if they do not have access to all of the information they deem necessary to determine avoided costs, their due process rights will be violated. CAC/EPUC complain that without full access to IOU planning and procurement data, QFs cannot meaningfully evaluate rates offered by the IOUs for QF power. CAC/EPUC argue that in order to establish avoided cost rates for energy and capacity payments, we must consider the actual costs that would have been incurred by the IOU "but for" purchasing the power from the QF. Therefore, they argue, detailed information on actual procured resources and actual resources available to replace QFs is required. In support of its position, CAC/EPUC states that the FERC order in *Tennessee Power Co.*, (77 FERC ¶61125) "entrusts State regulatory authorities…with the responsibility to compile the necessary data for the purpose of calculating avoided cost rates for QF purchases." (1996 WL 636527 (F.E.R.C. 1996.)) CAC/EPUC asserts that the lack of "granular" data in the record strongly supports the position that no changes may be lawfully made to the SRAC formula and leaves the IOUs' proposals unsubstantiated.

We disagree. The debate over the degree of access to specific IOU load and supply information began with (a) the CAC/EPUC Motion for Order Compelling Compliance with Federal Law and Production of Complete, Non-Redacted Responses to Data Requests (December 9, 2004); (b) the IEP Motion to Compel Responses to Data Requests (January 4, 2005); (c) the CAC/EPUC's Draft Protective Order (January 21, 2005); and (d) other parties' responses to and comments on these pleadings. These issues were resolved in the ALJs May 9, 2005, Ruling on Protective Order and Remaining Discovery Disputes. In the May 9, 2005 ruling, the ALJ found that certain of the information requested by the parties during discovery in this proceeding should remain confidential, or should be released only under a protective order. As noted in the May 9, 2005 ruling, "the Commission often faces the tension between transparency of information and the potential adverse impacts the release of some information may have on markets and ultimately ratepayers." The ALJ further noted that many of the discovery requests at issue in this proceeding concern data related to the utilities' procurement of energy, therefore Pub. Util. Code § 454.5(g) governs the manner in which the issues are addressed. Pub. Util. Code § 454.5(g) provides that the Commission "shall ensure the confidentiality of any market sensitive information submitted in an electrical corporation's proposed procurement plan or resulting from or related to its approved procurement plan including, but not limited to, proposed or executed power purchase agreements, data request responses, or consultant reports, or any combination, provided that the Office of Ratepayer Advocates (ORA) and other consumer groups that are nonmarket participants shall be provided access to this information under confidentiality procedures authorized by the commission."

The May 9, 2005 Ruling resolved the discovery disputes by (a) adopting a protective order that balanced the QF parties' need for certain information to participate meaningfully in this proceeding with the utilities need (and, implicitly, the ratepayers' need) to prevent certain sensitive market information from being used by the QF parties' marketing personnel, and (b) determining the level of protection required for each type of requested data. The ruling found that, although market participating parties would not have access to certain proprietary information and would not have complete access to market sensitive information, non-market participants would have complete access to all information and would be able to provide the Commission with the information and arguments necessary to reach informed decisions on the substantive issues in this proceeding.

Subsequently, in D.06-06-066, the decision implementing SB 1499 (Stats. 2004, Ch. 690), we affirmed certain of the findings in the May 9, 2005 Ruling. In particular, D.06-06-066 found that "[T]he due process and confrontation clauses do not prohibit use of confidential data in Commission proceedings" (p. 4). The Commission further noted that "it is not a violation of due process for any agency to allow certain records to be deemed confidential where there is a statute allowing confidentiality in certain cases." D.06-06-066 goes on to direct that "[W]here we find that data are market sensitive pursuant to Pub. Util. Code § 454.5(g) or otherwise entitled to confidentiality protection, in most cases, we adopt a window of confidentiality…" (D.06-06-066, *mimeo.*, O.P. 1.)

We therefore conclude that there is no due process error involved in reaching a decision on the IOU's avoided cost and other issues on the current record, which is complete for this purpose.

9. Proceedings Closed

This Decision closes R.04-04-003 and R.04-04-025. Filings from the Mohave application, A.02-05-046 ordered by D.04-12-016 to be filed in these proceedings are no longer to be filed. Instead, D.04-12-016 compliance reports are to be submitted to the ALJ and Energy Division and served on the service list for A.02-05-046. The service list for A.02-05-046 will now be a special service list in R.06-02-013. Filings from the 2006 Update phase of R.04-04-025 ordered in D.06-06-063 should be filed in R.06-04-010. The monthly SRAC postings ordered in this decision shall be submitted to the Energy Division and posted on each IOU's web site.

10. Process for Review and Approval of Standard Offer Contracts

The respondent IOUs will have 45 days from the effective date of this decision within which to file and serve their draft standard offer contracts. There will be a comment period following the filing of the compliance contracts.

11. Assignment of Proceeding

Michael R. Peevey is the assigned Commissioner in both proceedings. ALJ Julie Halligan is the assigned ALJ in R.04-04-025 and Carol A. Brown is the assigned ALJ in R.04-04-003.

12. Comments on the Proposed Decision

The proposed decision in this matter was mailed to the parties in accordance with Section 311 of the Public Utilities Code and Rule 14.2(a) of the Commission's Rules of Practice and Procedure. Comments were filed on _______, and reply comments were filed on __________.

Findings of Fact

1. PURPA requires electric utilities to purchase electricity from QFs.

2. QF pricing must comply with both the requirements of PURPA and the Public Utilities Code.

3. Pub. Util. Code § 390 provides an interim formula for calculating short-run avoided cost energy payments to QFs.

4. Current short-run avoided cost postings are based on the Transition Formulas adopted in D.96-12-028 as modified by D.01-03-067, which incorporate various California natural gas border price indices.

5. The Transition Formula can be updated periodically.

6. Power is traded on a Day-Ahead basis at various trading points (a.k.a., hubs or markets) throughout the country, the West, and in California, including North-of-Path 15 (NP15) and South-of-Path 15 (SP15).

7. Bilateral power traded at the NP15 and SP15 trading points are voluntarily reported through a number of indices, including indices published by Dow Jones and Platts. Power traded through the ICE is actually brokered through the exchange as a commodity.

8. It is neither reasonable nor practical to base short-run avoided costs on a "QF-out" or "aggregate value" pricing methodology because the continuing long-term obligations to thousands of megawatts of QF power mean that QF power cannot be "out".

9. The Transition Formula was intended as a temporary measure, to be used to calculate SRAC energy payments until energy payments could be based on PX market-clearing prices pursuant to § 390(c).

10. The PX is no longer operational.

11. SRAC energy payments under the Transition Formula have exceeded market prices, and potentially avoided costs, on occasion.

12. Given the amount of QF generation currently under contract to the IOUs, an energy price that is based on an assumption that a large block of that generation has disappeared is not reasonable.

13. Each of the utilities has demonstrated that market prices play a key role in achieving least cost dispatch.

14. SRAC energy prices should reflect power prices as reported at the NP15 trading point for PG&E, and at the SP15 trading point for SCE and SDG&E.

15. PG&E's energy pricing proposal links the SRAC energy prices to day-ahead trading points, but would require formal Commission updates immediately and on an ongoing basis.

16. SDG&E's energy pricing proposal is consistent with § 390 (b) and linked to market prices.

17. SCE's energy pricing proposal is preferable to SDG&E's because it uses a twelve-month rolling average of historical market prices as opposed to a two-year average, resulting in SRAC energy prices that reflect more current market prices. SCE's method of calculating SRAC is reasonable. SCE uses a twelve-month rolling index of historical Day-Ahead market prices in lieu of pre-1996 Incremental Energy Rate (IER) values. This method yields a SRAC that more closely reflects the short-run resources the utility would purchase in the absence of QF generation.

18. A Market Index Formula based on day-ahead market prices best reflects the utilities' short-run avoided cost.

19. There is no compelling reason not to adopt the same variable O&M adder for all three utilities.

20. With regard to avoided cost, whether the utility bought the gas to run its own plant, or bought the power from a merchant plant fueled by natural gas, burner-tip gas would be required.

21. The Legislature did not adopt a specific formula or specific factors for use in implementing § 390(b).

22. It is reasonable to update the TOU factors used to calculate SRAC to be consistent with TOU factors adopted in other Commission proceedings.

23. The MIF is based in part on day-ahead market prices, but is not a direct market price proxy as envisioned in D.01-01-007.

24. Pursuant to D.04-10-035, QF as-available capacity currently "counts" for purposes of meeting RA requirements.

25. The firmness of bilateral power may vary by trade, whereas the power products traded on ICE are clearly defined. Power contracts traded on ICE are liquidated damages (LD) contracts that are not unit contingent.

26. Power indices are also published for the long-term forward market where power is sold by the month, quarter, and year. These forward prices, along with day-ahead power, represent firm power products priced on an all-in basis, with no separate capacity payment. Delivery is certain and subject to recourse.

27. NP15/SP15 day-ahead contracts are significantly firmer than QF as-available power contracts which have no penalties for non-delivery, no forecasting requirements, no performance requirements, and a unilateral right to terminate on 30-days notice.

28. As-available power priced using NP15/SP15 implied market heat rates will provide a clear, market-based default contract for QFs that do not opt to provide power under one of the unit-firm contract options, negotiated bilaterals, or as-bid in an IOU power solicitation.

29. Using a levelized nominal dollar value to compute the CT cost would overstate the avoided capacity cost as well as present additional cost and risk for utilities and ratepayers.

30. Using an economic carrying charge rate, escalated for inflation over the life of the contract, allows us to provide more flexibility in contract terms, from one year up to ten years with the same CT cost estimate.

31. For purposes of calculating payments for as-available capacity, it is reasonable to adopt the CT cost and real economic carrying charge rate calculations proposed by TURN as presented in Exhibit 149, Appendix B, with an ancillary services adjustment subtracted from the adopted value as suggested by SDG&E.

32. It is reasonable to reduce the estimated ancillary services value proposed by SDG&E by two-thirds to reflect the fact that SDG&E's value is an annual average value and ancillary services needs occur primarily in peak periods. Accordingly, we reduce SDG&E's suggested ancillary services value by two-thirds to $4.94/kW-year.

33. A simplified version of the Edison Electric Institute Master Agreement will be the basis for our prospective QF Program contract options. The simplified version should contain, at a minimum, the contract features presented in Table 1 of this decision.

34. Potential over-subscription due to new QF contracts can be evaluated, first, through and IOU's Procurement Review Group (PRG) within 20 days of receiving such a request from a new QF. The Commission's Energy Division can prepare a brief summary of the PRG meeting regarding the IOU's ability to enter into the new QF contract. If the PRG feedback is unfavorable toward the new QF, the new QF may opt to file a formal compliant with the Commission.

35. Long-term QF policy choices will continue to affect ratepayers for 10 to 20 years.

36. It is reasonable to extend our prospective QF Program contract options to QFs that are, or were, on contract extensions approved in D.02-08-071, D.03-12-062, D.04-01-050, and D.05-12-009.

Conclusions of Law

1. Pursuant to Pub. Util. Code § 390(b), SRAC energy payments shall be based on a Transition Formula until the requirements of § 390(c) are met.

2. As set forth in PURPA, avoided costs are the cost of energy, which, in the absence of QF generation, the utility would otherwise generate itself or purchase from another source.

3. No right, contract term, or fair market expectation exists that the Commission must adopt the QF-in/QF-out approach to developing short-run avoided costs.

4. The variable factor formulation of the Transition Formula, as established in D.01-03-067, and updates to the formula are legal and permitted by § 390(b).

5. The Commission should adjust the factors in the Transition Formula such that the SRAC energy prices resulting from the formula continue to accurately reflect the utilities' avoided costs.

6. Separate capacity payments should generally only be made for unit-contingent power products that are either dispatchable, or that are significantly firmer than the non-unit contingent, Liquidated Damages (LD) contracts (i) bought and sold at NP15/SP15, and/or (ii) scheduled for phase-out for Resource Adequacy (RA) purposes, per D.06-10-035.

7. The Unit-Firm one-to-ten year QF contracts should count toward RA requirements because these contracts are unit-contingent contracts with performance obligations and recourse for non-delivery.

8. Payments to QFs under PURPA must reflect the avoided cost of the utility purchasing the energy and capacity.

9. Failure to consider utility resource needs in our long-term QF policy options would prevent us from achieving our goal of environmentally-sensitive, least-cost electric service.

10. IOUs should modify their monthly SRAC energy prices using the MIF adopted in this order.

11. IOUs should post the monthly SRAC energy prices and annual capacity prices on their websites and file the prices with the Commission's Energy Division and DRA.

12. PURPA does not require that the Commission make available long-term standard offer contracts.

13. A solicitation process wherein the IOUs would issue requests for offers from QF generators to meet specific, identified resource needs, is sufficient to meet the must purchase obligations in PURPA.

14. Potential over-subscription due to new QF contracts should be evaluated, first, through and IOU's Procurement Review Group (PRG) within 20 days of receiving such a request from a new QF. The Commission's Energy Division should prepare a brief summary of the PRG meeting regarding the IOU's ability to enter into the new QF contract. If the PRG feedback is unfavorable toward the new QF, the new QF may opt to file a formal compliant with the Commission.

15. The prospective QF Program contract options should be extended to QFs that are, or were, on contract extensions set forth in D.02-08-071, D.03-12-062, D.04-01-050, and D.05-12-009.

O R D E R

IT IS ORDERED that:

1. Pacific Gas and Electric Company (PG&E), San Diego Gas & Electric Company (SDG&E), and Southern California Edison Company (SCE) shall revise their short-run avoided cost (SRAC) calculations in conformance with the discussion, findings, and conclusions set forth in this decision as summarized in Table 1.

2. PG&E, SDG&E, and SCE shall file and serve their respective compliance draft Qualifying Facility contracts as directed by this decision within 45 days of the effective date of this decision. Parties may file comments on the draft contracts 21 days thereafter.

3. Rulemaking (R.) 04-04-003 and R.04-04-25 are closed. Filings from the Mohave application, A.02-05-046 ordered by D.04-12-016 to be filed in these proceedings are no longer to be filed. Instead, D.04-12-016 compliance reports are to be submitted to the ALJ and Energy Division and served on the service list for A.02-05-046. The service list for A.02-05-046 will now be a special service list in R.06-02-013. Filings from the 2006 Update phase of R.04-04-025 ordered in D.06-06-063 should be filed in R.06-04-010. The monthly SRAC postings ordered in this decision shall be submitted to the Energy Division and posted on each Investor Owned Utilities' web site.

This order is effective today.

Dated ______________________, at San Francisco, California.

TABLES 1 - 7

ATTACHMENT A

SUMMARY OF STANDARD OFFER CONTRACTS FOR QUALIFYING FACILITIES

Summary of Standard Offer Contracts
for Qualifying Facilities (QFs)

Standard Offer Contract	General Information	Energy Payment	Capacity Payment
Standard Offer 1 **(SO1)**	For as-available QFs, which cannot make a firm commitment to be available at peak times.	Short-run avoided cost (SRAC)	As-delivered capacity prices.
Standard Offer 2 **(SO2)**	Available for QFs who can make a firm commitment and maintain an 80% capacity factor during summer peak. Maximum contract term is 30 years. Temporarily suspended in Decision 86-05-024.	SRAC	Forecasted, fixed, and levelized capacity prices
Standard Offer 3 **(SO3)**	A simplified version of the SO1 available for QFs smaller than 100kW. Minimum contract term is one year.	SRAC	As-delivered capacity prices.
Interim Standard Offer 4 **(ISO4)**	Guarantees fixed payment rates for initial period of up to 10 years, to provide QFs with some certainty of return in their investments. Most contracts have by now reverted to SRAC. Contract term ranges from 15 to 30 years.	There are 3 energy payment options (EPO):	There are 3 capacity payment options (CPO):

Standard Offer Contract	General Information	Energy Payment	Capacity Payment
	Temporarily suspended in Decision 85-04-075. Permanently suspended in Decision 85-07-021, in anticipation of a final long-run contract.	EPO1 - Fixed, forecasted avoided energy costs for up to 10 years, after which they revert to SRAC. EPO2 - Fixed, forecasted, and levelized avoided energy costs for up to 10 years, after which they revert to SRAC. EPO3 – Based on fixed, forecasted utility Incremental Energy Rates (IERs) and current utility oil and gas costs, then reverting to SRAC.	CPO1 – Short-run capacity prices similar to those in SO1. CPO2 – Fixed, forecasted as-available capacity prices, which are not levelized, for up to 10 years, after which they revert to the higher of the as-delivered capacity price and the 10th year fixed capacity price. CPO3 – Fixed, forecasted, and levelized firm capacity prices for the term on the contract.

Standard Offer Contract	General Information	Energy Payment	Capacity Payment
Final Standard Offer 4 (FSO4) Never implemented	QFs bid against the costs of the "identifiable deferrable resources" (IDRs), rather than against existing resources. On Feb.23, 1995 the FERC invalidated the FSO4 (also known as the Biennial Resource Plan Update – BRPU), ruling that the CPUC did not consider all potential sources of power in setting avoided cost prices.	Period 1 – SRAC. Period 2 - Fixed, and ramped for inflation	Period 1 – Fixed, ramped for inflation. Period 2 – Fixed, ramped for inflation.
Non-Standard Contracts	The utilities have also negotiated QF contracts whose terms do not conform to any of the standard offers.	-	-

ATTACHMENT B

LIST OF ACRONYMS AND ABBREVIATIONS

ATTACHMENT B

LIST OF ACRONYMS AND ABBREVIATIONS

A.	Application
ACR	Assigned Commissioner Ruling
ALJ	Administrative Law Judge
A/S	Ancillary Services
Btu	British thermal unit
CAC/EPUC	Cogeneration Association of California and the Energy Producers and Users Coalition
CAISO	California Independent System Operator
CARE	Californians for Renewable Energy
CCC	California Cogeneration Council
CCGT	Combined Cycle Gas Turbine
CDWR	California Department of Water Resources
CEC	California Energy Commission
CFR	Code of Federal Regulations
CHP	Combined Heat and Power
CMCP	Competitive Market Clearing Price
COB	California-Oregon Border
CPO	Capacity Payment Options
CPUC	California Public Utilities Commission
CT	Combustion Turbine
D.	Decision
DA	Day-Ahead
DEC	Decremental
DG	distributed generation
DH	Davis Hydro
DR	demand response
DRA	Division of Ratepayer Advocates
EAP II	Energy Action Plan II
ECAC	Energy Cost Adjustment Clause
EE	Energy efficiency
EEI	Edison Electric Institute
EPAct 2005	Energy Policy Act of 2005
EPO	Energy payment options
ERI	Energy Reliability Index
E3	Energy and Environmental Economics, Inc.

ATTACHMENT B

FERC	Federal Energy Regulatory Commission
fn.	footnote
GMMs	generator meter multipliers
HA	Hour-Ahead
ICE	Intercontinental Exchange
Id.	*Idem*, meaning "the same"
IDRS	identifiable deferrable resources
i.e.	*id est,* meaning "that is"
IEP	Independent Energy Producers
IEPR	Integrated Energy Policy Report
IER	incremental energy rate
IMHR	implied market heat rate
INC	incremental
IOUs	investor-owned utilities
ISO	Independent System Operator
ITCS	Interstate Transition Cost Surcharge
KRCC	Kern River Cogeneration Company
kW	Kilowatt
kWh	kilowatt hour
LD	Liquidated Damages
LRAC	run avoided costs
LTPP	Long-Term Procurement Plan
MIF	Market Index Formula
mimeo.	mimeograph
MMBtu	Million British thermal unit
MOWD	must-offer waiver denial
MPR	market price referent
MRTU	Market Redesign and Technology Upgrade
MW	megawatt
MWD	Megawatt Daily
MWh	megawatt hour
NOPR	Notice of Proposed Rulemaking
NP15	North of Path 15
NYMEX	New York Mercantile Exchange
OIR	Order Instituting Rulemaking
O&M	Operation and Maintenance
ORA	Office of Ratepayer Advocates
p.	page
PG&E	Pacific Gas and Electric Company
PHC	prehearing conference

ATTACHMENT B
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pp.	pages
PPAs	power purchase agreements
PRG	Procurement Review Group
Pub. Util. Code	Public Utilities Code
PURPA	Public Utilities Regulatory Policy Act
PV	Palo Verde
PX	Power Exchange
QFs	Qualifying Facilities
R.	Rulemaking
RA	resource adequacy
RCM	RCM Biothane
RECC	real economic carrying charge
Renewables Coalition	California Landfill Gas Coalition and the California Wind Energy Association, jointly
RFOs	request for offers
RMR	reliability-must-run
RPS	Renewable Portfolio Standard
RSO1	Revised Standard Offer 1
RT	Reporter's Transcript
SCE	Southern California Edison Company
SDG&E	San Diego Gas & Electric Company
SEPs	Supplemental Energy Payments
SGIP	Self Generation Incentive Program
SO	Standard Offer
SOC	Standard of Conduct
SoCalGas	Southern California Gas Company
SP15	South of Path 15
SRAC	short-run avoided cost
TOD	Time of Delivery
TOU	Time-of-Use
TURN	The Utility Reform Network
USCHPA	U.S. Combined Heat and Power Association
WACC	Weighted Average Cost of Capacity
WCC	Watson Cogeneration Company

(END OF ATTACHMENT B)

APPENDIX C

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Last Update on 13-JUN-2007 by: EAP
R0404003 LISTQFISSUES
R0404025

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