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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
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

NOTICE OF EX PARTE COMMUNICATION

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July 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
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NOTICE OF EX PARTE COMMUNICATION

Pursuant to Rule 8 of the Rules of Practice and Procedure of the California Public Utilities Commission (Commission), the Cogeneration Association of California[1] and the Energy Producers and Users Coalition[2] (jointly CAC/EPUC), submit this notice. This notice describes the following Ex Parte communication in the above-referenced consolidated proceedings.

On July 20, 2007, Michael Alcantar and Nora Sheriff, counsel to CAC/EPUC, and Donald Schoenbeck of RCS Inc., consultant to CAC/EPUC, met with Matthew Deal,

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[1] CAC represents the power generation, power marketing and cogeneration operation interests of the following entities: Coalinga Cogeneration Company, Mid-Set Cogeneration Company, Kern River Cogeneration Company, Sycamore Cogeneration Company, Sargent Canyon Cogeneration Company, Salinas River Cogeneration Company, Midway Sunset Cogeneration Company and Watson Cogeneration Company.

[2] EPUC is an ad hoc group representing the electric end use and customer generation interests of the following companies: BP America Inc. (including Atlantic Richfield Company), Chevron U.S.A. Inc., ConocoPhillips Company, Shell Oil Products US, THUMS Long Beach Company, Occidental Elk Hills, Inc., and Valero Refining Company - California.

advisor to President Peevey. The meeting was initiated by counsel for CAC/EPUC and was held from approximately 11:00 to 11:30 AM at the Commission's office in San Francisco. Mr. Alcantar referred to the attached documents regarding the proposed decision; these were the only written materials used during the meeting.

During the meeting, Mr. Alcantar, Mr. Schoenbeck and Ms. Sheriff discussed the importance of resolving the Qualifying Facilities' (QF) pricing and policy issues.

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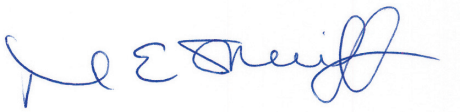
Dated: July 24, 2007

Respectfully submitted,



Michael Alcantar
Rod Aoki

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Evelyn Kahl
Nora Sheriff

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Discussion Points for R.04-04-025 and R.04-04-003

1. **Specific Standard Offer Contract Option** is needed and essential – non-price terms and conditions of the EEI-based SCE-Mountainview contract; no "gold rush" under CPUC pre-approval and fixing reasonable commercial milestones.

2. Conceptual agreements from CAC/EPUC and TURN comments:

   - **New Small QFs and Contract Eligibility** -- new "small" QFs (*i.e.*, capacity of 20 MW or an annual energy delivery equivalent) eligible for standard offer contracts; bilateral contracting or RFO process will not work for these resources.

   - **Fixed pricing option for LRAC** – TURN conceptually agrees with using the full MPR for a CCGT with a fixed heat rate as proposed by CAC/EPUC; full MPR capacity price is $154 including <u>all</u> fixed costs; heat rate is 6,918 Btu/kWh; O&M adder brings heat rate to CAC/EPUC's recommended 7,500 Btu/kWh.

   - **Bandwidth Ceiling and Floor for "Market" Heat Rates** – have rational ceiling and floor for "market" heat rates that reflect actual gas fired generator operations for California projects; 10,000 Btu/kWh High Heating Value TURN recommended ceiling and 7,000- 7,210 Btu/kWh HHV CAC/EPUC recommended floor reflecting Mountainview terms.

3. **Long Term (not 8 month) QF Policy** – resolve issues for long term planning and do not start over again with MRTU implementation; uncertainty in procurement must be solved.

4. **Establish Decision on State Law** – rely on state law for CPUC directive on procurement, and not at-risk federal law PURPA provisions; blunt utility appellate challenge.

5. **No Piecemeal Implementation** – assure no price changes under "bridge" SO1s until new contracts are available and implemented.

6. **CPUC versus CAISO Jurisdiction for CHP** – Do not make private CHP companies CAISO utility-like market participants or scheduling coordinators. Harmonize inconsistency in proposed decision regarding CAISO jurisdiction over CHP (*see* page 130 requiring compliance with CAISO tariff versus page 87 – CAISO "*will have to accept [QF Power] as must-take and focus on refining and shaping IOU power portfolios through the use of other resource options*.").

7. **Technical Issues**
   - Clarify designation of burner tip gas prices for energy pricing calculation.
   - Re-establish existing rulings on Resource Adequacy Tariff compliance for CHP.
   - Correct As-available capacity pricing:
     - Escalate 2004 CT costs to 2007 dollars,
     - Annual inflation adjustment to variable O&M,
     - Remove ancillary services reduction as inconsistent with TOU factor applications.
   - **New QFs** (greater than 20 MW) eligible for standard QF contracts through PRG process; no oversubscription if new QF replaces baseload service provided by expiring or terminated DWR or QF contracts; or percent of new load growth reserved for CHP.

Table 1 Qualifying Facility (QF) Programs Adopted and Existing					
No.	Provision	**Prospective QF Program** (Adopted) (For any future contract for expiring and expired QFs; and for New QFs as described)		**Existing QF Program** (Will phase out with QF Contract Expiration)	
		One- to Five-Year <u>As-Available</u> Energy Contract	One- to Ten-Year <u>Unit Firm</u> Capacity Contract	**Adopted**	**Current**
<u>Recommendation</u>: Non-price terms and conditions for must-take QF resources must be non-discriminatory to ensure an effective, secure, and commercially viable QF Program. Terms and conditions should be on par with those applicable to utility resources (*e.g.*, Mountainview) and implemented simultaneously with adopted avoided cost pricing.					
1	Energy Price	<u>Market Index Formula (MIF)</u> For PG&E, SCE, and SDG&E: Same as SCE's current SRAC formula as adopted in D.01-03-067, with the exception that the heat rate, or Incremental Energy Rate (IER), component will instead be calculated from a twelve-month rolling average* of historical NP-15 or SP-15 Day Ahead market price data with a "collar" around the possible IER values to provide a cap and a floor to mitigate excessive volatility.		Market Index Formula (MIF) Same as in the Prospective QF Program, or as contractually based, *e.g.*, fixed price agreement or SRAC energy variant.	SRAC Transition Formula for PG&E and SDG&E; and the Modified Transition Formula for SCE.
<u>Recommendation</u>: The Energy Price "Cap and Floor" should reflect real operating resource higher heating value (HHV) heat rates (*i.e.*, TURN's 10,000 Btu/kWh CT; Mountainview's 7,000 Target Full Load Heat Rate at a "new and clean" condition). A firm and fixed 7.4¢/kWh "All In" price option (at an assumed $7.50/MMBtu gas price) should be offered to QFs. IOU burner-tip gas prices for SCE and SDG&E should be the sum of: (1) the bid-week Topock-CA Border natural gas price; and (2) the intrastate natural gas transportation cost. For PG&E the burner-tip natural gas price should be the sum of: (1) the simple average (*i.e.*, 50%/50% weighting) of the bid-week Malin and Topock-CA Border natural gas prices and (2) the intrastate natural gas transportation cost.					
2	Capacity Price	As-available capacity payments will not fall below the first-year capacity price for the duration of the contract.	The capacity payment will be fixed for the duration of the contract.	Existing contractually-based capacity payments remain unchanged. ---------- Eligibility: If as-available capacity counts for purposes of Resource Adequacy (RA), QFs will receive a	Posted Price for As-Available Capacity. ---------- -------- Contractually-Based Capacity Prices.
2a	Calculation of Capacity Price	Based on the fixed cost of a Combustion Turbine (CT) as proposed by TURN, less the estimated value of	Based on the MPR capacity cost in E-4049 of $980/kW which results in an annual cost of $104/kW-yr.		

		Ancillary Services (A/S) as generally proposed by SDG&E.		capacity payment.	
Recommendation: The beneficial term and duration of the adopted capacity pricing should be matched by sound capacity price calculations. The as-available calculation's flaws should be corrected through escalation of the 2004 CT costs ($60.94/kW-yr) to 2007 ($66.92/kW-yr), an annual inflation adjustment to the variable O&M, and removal of the A/S credit adjustment as inconsistent with TOU Factor applications.. The MPR firm capacity calculation should be corrected to include (1) all fixed CCGT cost components (*i.e.*, return costs, depreciation costs, and income and property taxes, insurance costs and fixed O&M),and (2) local QF benefits.					
3	Daily Scheduling	Standard CAISO Timetables and Protocols for Day-Ahead Schedules for QFs greater than 1MW**		No Change	None
Recommendation: Retention of the utilities' traditional role of Scheduling Coordinator for QF power deliveries and interface with the ISO maintains a critical component for the success the Prospective QF Program. State jurisdiction (*e.g.*, Rule 21 interconnection oversight) over QF resources should be maintained in a manner that is consistent with the ISO Tariff but does not subject these resources to unnecessary ISO Tariff obligations.					
4	Forecasting	Weekly, Monthly and Annual Forecasts**		No Change	None
Recommendation: Forecasting issues – See comment to Provision 3 above.					
5	Deliveries	SC-SC Trade (where SC = Scheduling Coordinator for QFs greater than 1MW)**		No Change	None. Utility is now the Scheduling Coordinator.
Recommendation: Delivery issues – See comment to Provision 3 above.					
6	Emergency Response	Standard ISO Emergency Response Provisions**		No Change	None
Recommendation: Emergency Response issues – See comment to Provision 3 above.					
7	CPUC Performance Requirements	Day-Ahead Scheduling**	Penalties to Capacity Payment for Failure to Deliver 95% during on-peak months and 90% during off-peak months (no counting scheduled outages).** This is a Qualifying Capacity provision.	No Change	None
Recommendation: Monthly peak and off-peak period QF delivery requirements, consistent with traditional QF operations, should be established.					
8	Credit	None**	None**	No Change	None
Recommendation: The credit support policy for QFs with expiring contracts must be maintained to ensure retention of the utilities' QF supplies.					

9	Termination Rights	QF has the ability to terminate if selected in native utility solicitation**	No Change	QF has the unilateral right to terminate on 30-days notice. ------ IOU termination rights are tied to QF non-performance, and QFs can also be derated.
Recommendation: Provisions regarding termination rights, similar to other standard terms and conditions, must be addressed expeditiously and implemented in concert with changes in avoided cost pricing calculations.				
10	New QFs	New QFs may seek a contract under the Prospective QF Program. 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 complaint with the Commission.	--	--
Recommendation: A simple 20 MW capacity or annual GWH equivalent (164.25 GWH annual delivery) measure should be established to exempt from the PRG process "small" QFs with no significant impact on the respective utility's portfolio. New QFs not meeting the above measure should obtain standard contracts through the PRG process. The PRG process must, however, recognize the lack of risk of oversubscription where: (1) new QFs would serve a specified percentage of the baseload portfolio historically served by expiring or terminated CDWR contracts; or (2) new QFs would serve load equivalent to or less than the percentage of load served by existing QFs multiplied by the new load growth.				
11	CAISO Resource Adequacy (RA) Tariff	QFs with a dependable capacity of greater than 1 MW shall comply with the CAISO RA tariff.	--	--
Recommendation: QFs should comply with applicable tariff provisions that support Resource Adequacy requirements, but should not be needlessly subject to CAISO Tariff jurisdiction or requirements which do not appropriately account for the unique operating characteristics of these resources.				

APPENDIX

PROPOSED MODIFICATIONS (Additions, ~~deletions~~)

Page 2

Specifically, we adopt:

- **The Market Index Formula (MIF),** which is an updated short-run avoided cost (SRAC) formula for pricing SRAC energy. The MIF is based on the formulistic method adopted in 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);

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- **Prospective QF Program Contract Provisions**

  - SRAC Energy Payments: Market Index Formula (MIF). Existing QF contracts with energy pricing provisions specifically stating that the Commission determined ~~providing~~ SRAC is the basis for energy payment will also be priced pursuant to the MIF.

  - ~~o~~ Payments for As-Available Capacity: Based on the full fixed cost of a Combustion Turbine (CT) and the economic carrying charge 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)~~.

Page 3

  - Payments for Firm Capacity: 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 $1540~~4~~/kW-year.

***

An Entry Procedure for New QFs. New QFs may seek either of the aforementioned contracts as follows:

- New QFs may seek a standard contract under the Prospective QF Program just as existing QFs may. ~~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.~~ The Commission will allow new QFs to obtain a standard contract under the Prospective QF Program where: (1) the new QF will serve a portion of the baseload portfolio that was historically served by CDWR contracts as those contracts expire or are terminated, and (2) the new QF will serve load equivalent to or less than the percentage of load served by existing QFs multiplied by new load growth.
- New, as available QFs may also receive a standard contract under the Prospective QF Program. Projects that are 219,000 GWh (25 MW X 8760) or less in size and that consume at least 25% of their power internally and sell all of their additional output to the utility are eligible for a contract. The 25% requirement includes any increments of new capacity added to the project.
- Where the new QF sells all of its output to the interconnected utility it's interconnection shall be governed by state Rule 21.

Page 4

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.

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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 employs the formulistic approach ~~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 consistent with actual operational generation resource heat rate to mitigate excessive pricing uncertainty ~~volatility~~.

Page 7

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. These QF should continue to have available standard offers, albeit at market-based prices.

Page 7-8

For these reasons, we adopt two flexible market-based contract options in addition to the competitive solicitation and bilateral contracting options already 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.~~ QF resources acquired under the prospective QF program per se benefit ratepayers.

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 full 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 $154~~0~~4/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.

Page 9

We also continue to require the utilities to make available CAISO scheduling services to all 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.~~

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PG&E further asserts that e~~E~~xisting 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, according to PG&E, the utility's avoided cost for a given hour becomes the market price. The market price that PG&E contends that it 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~~ states that its 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.)

Page 59-60

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 incur in the short run ~~to replace QF power~~. QF parties contend that the NP15/SP15 prices are below utility avoided cost, yet the power products at NP15/SP15 are for firmer power products than the as-available energy provided by QFs.

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~~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~~.

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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 the ~~this~~ approach of relying on the Market Price Referent CCGT variable O&M component and adopt it for use in the SRAC energy formulae for the three utilities.

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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.~~ Therefore, we will ~~We also~~ require the IOUs to provide updated TOU/TOD factors and periods when they file their next long-term procurement plans for approval.

Page 85-86

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 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 $154~~04~~/kW-year.

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Once a full CT capacity value is determined, adjustments to that value may ~~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 may ~~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.

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We agree with TURN, SCE, and SDG&E that the avoided CT annual 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 annual 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 nonperformance 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 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.~~

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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~~. Based on the assumptions presented in Exhibit 149, Appendix B, 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).~~

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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%
$**9**80.00	8.5%	20	$154~~04~~	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

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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.

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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, fF~~or purpose of determining short-run energy payment to QF in this proceeding, we find that the SRAC 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.

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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, to the extent those tariffs are applicable to the QF. 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.

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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. Future standard ~~New~~ contracts will be subject to any changes in capacity payments resulting from future modifications to the RA counting rules, however, no existing contracts will ~~not~~ be affected. The utilities ~~QFs larger than one megawatt in dependable capacity~~ will be responsible for scheduling coordination with the CAISO, however, QFs have the option of acting as their own scheduling coordinators. To the extent the utility is not acting as the scheduling coordinator, it must offer scheduling coordinator services to the QF ~~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 standard 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 $154~~04~~/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. Locational benefits, if provided by these QFs, will also be compensated. The all-in payments, excluding the QF-specific locational benefits, associated with the two prospective QF Program options are shown in Table 4a, attached to this order, at an illustrative gas price. QFs may also elect an LRAC firm pricing option consistent with CAC/EPUC's recommendation summarized in Table 7 for the term of the contract.

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We adopt PG&E's recommendation to use the EEI Master Contract as a starting point for new QF contracts, as described herein. Non-price terms and conditions under our Prospective QF Program must be non-discriminatory; i.e., at least equal to utility-owned procured resource provisions. Accordingly, standard offer contracts under the Prospective QF Program shall specifically provide for the pass through of future "regulatory legal risk conditions" (e.g., Greenhouse Gas costs, regulatory compliance required capital additions, Electric Reliability Organization costs.

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The new standard 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. The utilities will continue to be ~~QFs larger than one megawatt are~~ responsible for scheduling coordination, although the QF has the option to act as its own scheduling coordinator. To the extent the utility does not act as a scheduling coordinator, it ~~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.

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… we expect that as old QF contracts expire, new or renewed QF contracts will replace them. All QF resources acquired under the prospective QF program constitute per se ratepayer benefits. Also, increases in QF contractual capacity that are consistent with increases permitted by Public Utilities Code § 371 will be accommodated by the standard contracts in the prospective QF program.

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A ~~If a~~ new QF may have ~~seeks~~ access to ~~one of~~ the standard contract options described above just as an existing QF has.~~, and the IOU contends it would be inconsistent with the existing need determination from the Long-Term Procurement Plan (LTPP) proceeding, the 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.~~ The Commission will allow new QFs to obtain a standard contract under the Prospective QF Program where: (1) the new QF will serve a portion of the baseload portfolio that was historically served by CDWR contracts as those contracts expire or are terminated, and (2) the new QF will serve load equivalent to or less than the percentage of load served by existing QFs multiplied by new load growth. New, as available QFs may also receive a contract under the Prospective QF Program. Projects that export 164,250 MWh (25 MW X 8760 X 0.75) or less and consume at least 25% of their power internally and sell all of their additional output to the utility are eligible for a contract. The 25% requirement includes any increments of new capacity added to the project. Where the new QF sells all of its output to the interconnected utility it's interconnection shall be governed by state Rule 21. 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.

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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.~~

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We find that QFs should generally be required to comply with applicable 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 reject ~~adopt~~ PG&E's recommendation that QFs one MW or greater should be required to comply with the CAISO tariffs. We also reject ~~adopt~~ PG&E's recommendation that QFs serve as their own scheduling coordinators. The CAISO must accept QF power as a "must-take" resource and QFs greater than one MW should only be required to comply with CAISO Tariff provisions to the extent the provisions are directly applicable to QF operations. Moreover, t~~T~~he utility should continue to serve as the scheduling coordinator for QFs, however, the QF should have ~~has~~ the option of serving as its own scheduling

coordinator. The QF has the ~~, with the~~ option of purchasing these services from the utility at cost.

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The Assigned Commissioner may convene a workshop to begin no later than 14 days from the final decision's mailing date to address implementation issues left unresolved by the final decision. Interested parties shall file proposed standard offer contract forms no later than June 7, 2007, with reply comments on the proposals no later than June 21, 2007. If there are unresolved issues pertaining to the standard offers provide that those issues may be addressed at the post-final decision workshop on implementation issues. Alternatively, if the issues have been sufficiently addressed in written comments the Assigned Commissioner should issue a ruling on the provisions of the standard offer contract no later than 21 days after the conclusion of the Assigned Commissioner's workshop following the final decision. An Assigned Commissioner's Ruling on any outstanding implementation or standard offer contract issues will be issued no later than 21 days after the conclusion of the Assigned Commissioner's workshop following the final decision. ~~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~~. The pricing determinations in this decision will not become effective until final standard offer contracts are available to QFs as discussed in this decision.

PROPOSED MODIFICATIONS TO FOF AND COL

Findings of Fact

~~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~~. 8. 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~~. 9. The PX is no longer operational.

~~11~~. 10. 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~~. 11. Each of the utilities has demonstrated that market prices play a key role in achieving least cost dispatch.

~~14.~~ 12. SRAC energy prices should reflect power prices consistent with the utilities' avoided costs. ~~as reported the NP 15 trading point for PG&E and the SP 15 for SCE and SDGE.~~

~~15.~~ 13. 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.~~ 14. SDG&E's energy pricing proposal is ~~consistent with § 390 (b) and~~ linked to market prices.

~~17.~~ 15. 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 currently ~~would~~ purchases ~~in the absence of QF generation~~.

~~18.~~ 16. A Market Index Formula based on day-ahead market prices best reflects the utilities' short-run energy purchases~~avoided cost~~.

~~19~~. 17. There is no compelling reason not to adopt the same variable O&M adder for all three utilities.

~~20.~~ 18. 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~~. 19. The Legislature did not adopt a specific formula or specific factors for use in implementing § 390(b).

~~22~~. 20. It is reasonable to update the TOU factors used to calculate SRAC ~~to be~~ consistent with TOU factors adopted in future ~~other~~ Commission proceedings.

~~23~~. 21. 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~~. 22. Pursuant to D.04-10-035, QF as-available capacity currently “counts” for purposes of meeting RA requirements.

~~25~~. 23. 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~~. 24. 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~~. 25. 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~~. 26. 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~~. 27. 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~~. 28. 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~~. 29. For purposes of calculating payments for as-available capacity, it is reasonable to adopt the full 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~~. 30. It is not reasonable to reduce CT annual capacity cost by 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.~~ 31. 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~~

34. A new QF may have access to the standard contract options provided by the Prospective QF Program just as an existing QF has. The Commission will allow new QFs to obtain a contract under the Prospective QF Program where: (1) the

new QF will serve a portion of the baseload portfolio that was historically served by CDWR contracts as those contracts expire or are terminated, and (2) the new QF will serve load equivalent to or less than the percentage of load served by existing QFs multiplied by new load growth. New, as available QFs may also receive a contract under the Prospective QF Program. Projects that export 164,250 MWh (25 MW X 8760 X 0.75) or less and consume at least 25% of their power internally and sell all of their additional output to the utility are eligible for a contract. The 25% requirement includes any increments of new capacity added to the project. Where the new QF sells all of its output to the interconnected utility it's interconnection shall be governed by state Rule 21.

~~35.~~ 33. Long-term QF policy choices will continue to affect ratepayers for 10 to 20 years.

~~36.~~ 34. 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.

35. QF resources acquired under the prospective QF program per se constitute ratepayer benefit.

36. Pricing terms must be predictable and secure for the entire term of any contract.

37. It is reasonable that our Prospective QF Program should accommodate increases in contractual capacity to the extent that such increases are consistent with Section 371 of the Public Utilities Code.

38. It is reasonable for the Commission to take into account the local benefits provided by QFs in the LRAC determination.

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.~~ 3. The Commission should assure ~~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.~~ 4. 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.~~ 5. 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.~~ 6. 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.~~ 7. IOUs should modify their monthly SRAC energy prices using the MIF adopted in this order. No pricing determinations under this decision shall go into effect until the Commission has approved the Prospective QF Program's standard offer contracts and those contracts are available to QFs.

~~11~~. 8. 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.~~ 9. PURPA does not require that the Commission make available long-term standard offer contracts.

~~13.~~ 10. A solicitation process wherein the IOUs would issue requests for offers from QF generators to meet specific, identified resource needs, ~~is~~ may be insufficient 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.~~

11. A new QF may have access to the standard contract options provided by the Prospective QF Program just as an existing QF has. The Commission will allow new QFs to obtain a contract under the Prospective QF Program where: (1) the new QF will serve a portion of the baseload portfolio that was historically served

by CDWR contracts as those contracts expire or are terminated, and (2) the new QF will serve load equivalent to or less than the percentage of load served by existing QFs multiplied by new load growth. New, as available QFs may also receive a contract under the Prospective QF Program. Projects that export 164,250 MWh (25 MW X 8760 X 0.75) or less and consume at least 25% of their power internally and sell all of their additional output to the utility are eligible for a contract. The 25% requirement includes any increments of new capacity added to the project. Where the new QF sells all of its output to the interconnected utility it's interconnection shall be governed by state Rule 21.

12. Non-price terms and conditions under our Prospective QF Program must be non-discriminatory; i.e., at least equal to utility-owned procured resource provisions. Accordingly, standard offer contracts under the Prospective QF Program shall specifically provide for the pass through of future "regulatory legal risk conditions" (e.g., Greenhouse Gas costs, regulatory compliance required capital additions, Electric Reliability Organization costs.

13. The CAISO must accept QF power as a must-take resource; QFs greater than one MW should only be required to comply with CAISO Tariff provisions to the extent the provisions are directly applicable to QF operations.

14. The utility should continue to serve as the scheduling coordinator for QFs, however, the QF should have the option of serving as its own scheduling coordinator. In such a case, the QF has the option of purchasing these services from the utility at cost.

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.

16. The prospective QF program should include an LRAC firm pricing option that reflects CAC/EPUC's recommended values for capacity and a fixed heat rate of 7,500 Btu/kWh and an established O&M adder for the term of the contract.

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. The pricing determinations in this decision will not become effective until final standard offer contracts are available to QFs as discussed in this decision.

~~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~~.

2. If implementation issues remain unresolved in the final decision the Assigned Commissioner shall convene a workshop to begin no later than 14 days from the final decision. The implementation workshop is to be strictly monitored process with the Assigned Commissioner presiding over issues identified and left unresolved by the final decision.

3. Parties shall file proposed standard offer contract forms no later than June 7, 2007. Reply comments on the proposals may be filed no later than June 21, 2007. If there are unresolved issues pertaining to the standard offers those issues may be addressed at the post-final decision workshop on implementation issues.

4. The Assigned Commissioner's Ruling on any outstanding implementation

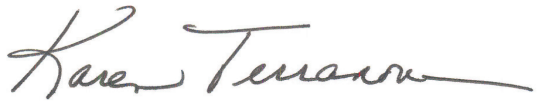
or standard offer contract issues shall be issued no later than 21 days after the conclusion of the Assigned Commissioner's workshop following the final decision.

5. ~~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.

CERTIFICATE OF SERVICE

I, Karen Terranova hereby certify that I have on this date caused the attached **Notice of Ex Parte Communication** in R.04-04-003/R04-04-025 to be served to all known parties by either United States mail or electronic mail, to each party named in the official attached service list obtained from the Commission's website, attached hereto, and pursuant to the Commission's Rules of Practice and Procedure.

Dated July 24, 2007 at San Francisco, California.



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