

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

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| Order Instituting Rulemaking to Promote |) | |
| Consistency in Methodology and Input |) | |
| Assumptions in Commission Applications of |) | R. 04-04-025 |
| Short-run and Long-run Avoided Costs, |) | (Issued April 22, 2004) |
| Including Pricing for Qualifying Facilities |) | |
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**Pre-Workshop Opening Comments
of the California Cogeneration Council**

Jerry R. Bloom, Esq.
Joseph M. Karp, Esq.
White & Case, LLP
Three Embarcadero Center, Suite 2210
San Francisco, CA 94111
Telephone: (415) 544-1100
Facsimile: (415) 544-0202
E-mail: jbloom@whitecase.com
jkarp@whitecase.com

R. Thomas Beach
Patrick G. McGuire
Crossborder Energy
2560 Ninth Street, Suite 316
Berkeley, California 94710
Telephone: 510-649-9790
Facsimile: 510-649-9793
E-mail: tomb@crossborderenergy.com
patrickm@crossborderenergy.com

On behalf of
CALIFORNIA COGENERATION COUNCIL

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In accordance with the procedural schedule for Order Instituting Rulemaking No. 04-04-025 (the OIR), issued April 22, 2004, the California Cogeneration Council¹ (CCC) is pleased to present its pre-workshop opening comments. This OIR focuses on issues concerning the Commission’s development of a consistent and coordinated calculation of “avoided costs.” These are the costs that the regulated California electric utilities avoid as a result of energy conservation programs, distributed generation (DG) resources, and purchases of certain electric generating resources, including new renewable generation and the power output of qualifying facilities developed in accordance with the Public Utilities Regulatory Policies Act of 1978 (PURPA).²

The CCC strongly supports the development of a consistent avoided cost methodology. Cogenerators and other QFs, renewable generation, distributed generation, and energy

¹ The CCC is an *ad hoc* association of natural gas-fired cogenerators located throughout California, in the service territories of all three of California’s major investor-owned electric utilities (IOUs)—Pacific Gas & Electric Company (PG&E), Southern California Edison Company (Edison), and San Diego Gas & Electric Company (SDG&E). CCC members are qualifying facilities (QFs) under the FERC’s rules implementing PURPA. CCC members have sold their power to the IOUs for many years, pursuant to contract terms and avoided cost prices established by this Commission. In aggregate, CCC members’ QF projects in California sell 1,845 megawatts (MWs) of generation into the California grid.

² 16 U.S.C. § 824a-3. The Federal Energy Regulatory Commission (FERC) has promulgated rules for the implementation of PURPA; *see* 18 CFR § 292 *et seq.*

conservation programs all share a common purpose – the conservation and most efficient use of limited fossil energy resources. As stated in the OIR, a consistent approach to avoided costs will ensure that the Commission correctly values all of these important resource options.

The OIR asked parties to file pre-workshop comments that focus on a study prepared by Energy and Environmental Economics (the “E3 Report”)³ that proposes a comprehensive avoided cost methodology for the purpose of evaluating the cost-effectiveness of conservation programs. The OIR also lists a series of questions for parties to address at a June 23 - 25, 2004 workshop and in subsequent post-workshop comments. In these comments, the CCC will present its analysis of the E3 Report, and will respond to the questions posed in the OIR.

I. BACKGROUND

Since the early 1980s, CCC members have operated gas-fired cogeneration projects in California. It is important to remember that the Commission’s QF program in the 1980s arose from concerns over limited and increasingly expensive fossil fuel resources, concerns that are again current today. Indeed, in the 1980s cogeneration provided a key solution to California’s first major “energy crisis.” It is important to review this history briefly, as it provides the context in which this Commission has used avoided costs for the past two decades.

In 1973, world oil prices skyrocketed during the Arab oil embargo. In the following years OPEC exercised its market power to keep oil prices high. In the electric industry, high oil prices hit ratepayers hard, particularly in states such as California where the utilities burned oil in a substantial amount of their generating capacity. The traditional alternatives to oil seemed increasingly suspect. Natural gas resources were in short supply, and gas was widely perceived to

³ “A Forecast of Cost Effectiveness of Avoided Costs and Externality Adders,” released January 8, 2004 to parties in R. 01-08-028

be a declining resource.⁴ The electric utilities responded to the crisis by seeking to build ever-larger central station coal and nuclear power plants. Their plans foundered on safety concerns and environmental opposition, as exemplified by the 1979 Three Mile Island accident and the California utilities' aborted efforts to build huge coal-fired power plants both inside and outside of California. Perhaps even more important, the utility-owned nuclear plants that were built encountered extraordinary construction cost overruns.

The nation needed a new approach to meeting its energy needs. That new paradigm emerged in PURPA, enacted in 1978 as part of a broad national energy plan. PURPA sought to reduce the country's dependence on oil through the development of new resources for electric generation, including renewable resources (solar, wind, biomass, geothermal, and small hydro) and the more efficient use of oil and gas in cogeneration projects. In fostering these new generation resources, PURPA embodied a completely new approach to the development of electric generation—a change that was as important as the new technologies that PURPA encouraged. In essence, PURPA moved beyond the electric utilities' traditional role as the sole builders of new electric generation and fostered a new industry in the independent development, ownership, and operation of such plants. PURPA broke down the barriers to entry that the utilities had erected through their refusal to negotiate with, buy power from, interconnect with, or provide reasonable back-up services to independent power producers. PURPA's key reforms included a requirement that the utilities must purchase the power output of qualifying cogeneration and other small power production facilities (referred to as “qualifying facilities” or “QFs”) – a key step designed to encourage the development of QFs by ensuring a buyer for QF power. To make certain that qualifying cogeneration facilities advanced PURPA's goals, they were required to meet certain operating and efficiency standards.⁵ PURPA also required the utilities to purchase QF power at

⁴ In fact, to conserve gas supplies, in 1978 Congress passed the Power Plant and Industrial Fuel Use Act, which limited the use of natural gas in new power plant and industrial boilers. This act was repealed in 1987 when it became clear that natural gas supplies were not dwindling.

⁵ See 18 CFR § 292.205. QFs also were exempted from the provisions of the Power Plant and Industrial Fuel Use Act.

the purchasing utility's **avoided cost**—that is, at the cost that the utilities would have incurred themselves to produce or purchase the same energy and capacity. This avoided cost standard ensured that the utilities could not use their monopsony (sole buyer) power to depress the price paid to QFs and that ratepayers would be indifferent to purchases from the QFs, as compared to traditional utility generation and procurement. Under PURPA, state commissions have the responsibility to establish the avoided cost prices that the investor-owned utilities pay to QFs.

In California, this Commission found that the utilities had erected barriers to QF development, including to the development of cogeneration projects.⁶ In response, the Commission took the further step of developing “standard offer” power purchase contracts, available to any QF, that governed the terms of QF power sales to the utilities.⁷ The standard offer contracts greatly reduced the barriers to QF entry, by providing QFs with access to reasonable power purchase agreements that did not require extensive negotiations with the utility. The standard offer contracts included fixed capacity payments over the term of the contract; these payments were based on the levelized cost of the utility's cheapest source of capacity at that time—a combustion turbine.⁸ Energy payments reflected the utility's operating costs that it avoided through its QF purchases (principally the costs of additional gas- or oil-fired thermal generation).

By the end of 1982, the key elements of PURPA had been implemented in California. At the same time, industrial and institutional customers with large energy requirements were considering cogeneration as a means to reduce their rapidly increasing electricity and natural gas costs. Most of the state's cogeneration projects were developed and built between 1982 and 1990, under 20- to 30-year contracts which provided for the sale of excess electricity to the local

⁶ See D. 91109 and D. 91107, which penalized PG&E 20 basis points on its return on equity for its failure to promote cogeneration development. In D. 82-12-055, the Commission penalized Edison \$8 million for failing to offer full avoided cost prices to QFs.

⁷ See D. 82-01-103 and D. 82-12-120.

⁸ See D. 82-12-055, at 200.

utility. These long-term power purchase contracts enabled cogeneration plants to make firm commitments to supply power and steam to their host industrial and institutional facilities. Unlike the utilities, the developers of cogeneration projects bore all of the permitting, financing, and construction risks associated with the timely completion of these plants. Also unlike the utilities, ratepayers pay cogenerators only if the power is actually produced and delivered to the purchasing utility.

Gas-fired cogeneration projects under long-term contracts to the state's three investor-owned utilities (Pacific Gas & Electric, Southern California Edison, and San Diego Gas & Electric—the "IOUs") provide 6,367 megawatts of electric generating capacity on the grid operated by the California Independent System Operator (CAISO). As shown in **Figure 1**, this amounts to 12% of the total "native" generation located within the CAISO system.⁹ Cogeneration is the third-largest source of power in the state, trailing only conventional thermal plants and hydroelectric facilities. Since cogeneration projects tend to operate around the clock in a "baseload" fashion, they produce an even larger share—about 17%—of the IOUs' annual energy (kilowatt-hour) requirements. In addition, before cogenerators sell their surplus power to the IOUs, they serve on-site manufacturing, agricultural, or other commercial loads; statewide, such self-generation serves about 5% of California's electricity requirements.¹⁰

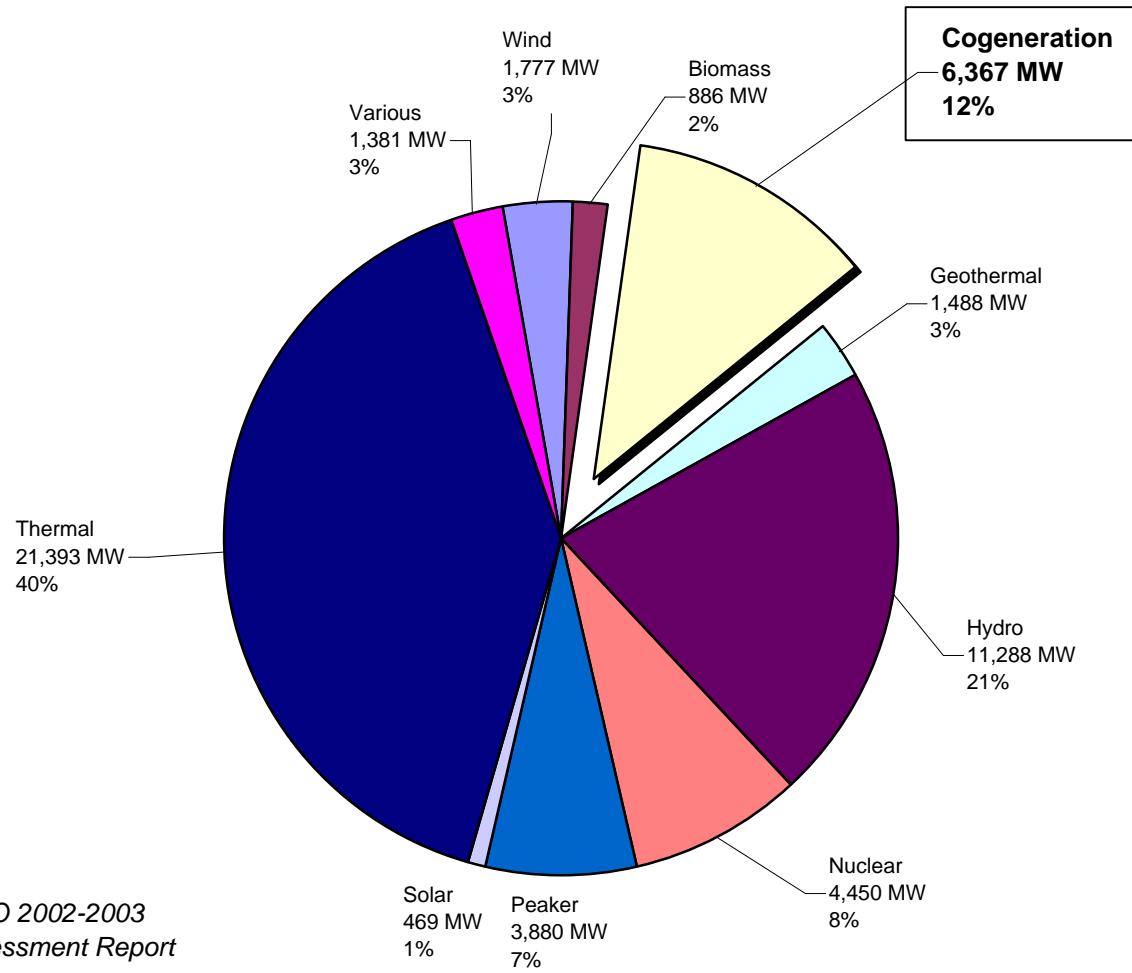
In the 1980s, a substantial number of QFs using renewable technologies also were built in California. As shown in Figure 1, these wind, solar, geothermal, biomass, and small hydro QFs now supply about 10% of the IOUs' generating resources, and form the "baseline" amount of renewable generation on which the state's new Renewables Portfolio Standard (RPS) program is building.

⁹ CAISO, "2002 - 2003 Winter Assessment" (October 7, 2002), at 12.

¹⁰ California Energy Commission, "Staff's Statewide Outlook for California Net Electricity for Generation Load: 1980 - 2007." This data is available at www.energy.ca.gov/electricity/STATEWIDE_CONSUMPTION.PDF.

Figure 1

Cogeneration Share of ISO Control Area Generation



Source: ISO 2002-2003
Winter Assessment Report

Given the importance of QF resources to California's generation portfolio, it is vital that the avoided cost prices paid to QFs in California meet the standards set by PURPA – those prices must accurately reflect the IOUs' avoided costs. If they do, they will be just and reasonable for ratepayers, and they will not discriminate against QFs in comparison to other utility resources.¹¹ Compliance with those standards has allowed the QF industry to prosper in California for the past two decades, and is critical to the viability of the state's QF resources going forward.

II. REVIEW OF THE E3 REPORT

The CPUC commissioned the E3 Report as part of its energy efficiency rulemaking, R. 01-08-028. The E3 Report presents a methodology for a long-term forecast of avoided costs and associated externality adders for use in the evaluation of energy conservation and demand-side management (DSM) programs over a 20-year forecast period. The first question posed in the OIR asks parties to evaluate the E3 Report.

Generally, the CCC believes that the E3 Report presents a complete and comprehensive avoided cost methodology. It reflects the full range of the IOUs' avoided costs and presents a comprehensive consideration of externality adders. Many of the avoided cost and externality

¹¹ The federal statute requires the Commission to balance the interests of both utility ratepayers and QFs in setting avoided cost prices. As expressed in the FERC rules implementing PURPA:

292.304 Rates for Purchases

(a) *Rates for purchases.* [1] Rates for purchases shall:

(I) Be just and reasonable to the electric consumer of the electric utility and in the public interest; and

(ii) Not discriminate against qualifying cogeneration and small power production facilities. *18 CFR Part 292.304.*

The FERC rules then state that a rate for purchases set equal to the purchasing utility's full avoided costs satisfies this standard.

components discussed in the E3 Report also should be used for QF pricing and other applications in addition to conservation and DSM programs. The CCC generally concurs with the methodology that the E3 Report proposes for calculating each component of avoided costs, with the principal exception of the E3 Report's use of a very thin and illiquid electric futures market to forecast avoided generation costs for the next several years.

The CCC discusses below each of the principal components of E3's avoided cost methodology, with an emphasis on the applicability of each component to QF pricing. The CCC notes that QF pricing can involve the use of either long-run or short-run avoided costs (LRAC or SRAC). LRAC should be applicable to new long-term QF contracts, or to long-term renewals or extensions of existing QF contracts. SRAC is used to price the energy deliveries from most existing QF projects that were developed in the 1980s, and should be used in new Standard Offer No. 1 (SO1) contracts that specify SRAC pricing (such as the five-year SO1 contracts that the Commission authorized in D. 04-01-050).

A. Generation

The E3 Report uses two distinctly different approaches to forecasting future avoided generation costs. For 2004 and 2005, E3 uses on-peak electric futures prices (SP-15) published in *Megawatt Daily* from a single day, October 15, 2003. E3 then escalates these prices to 2006 and 2007 using the observed 2004 - 2007 escalation rates in NYMEX gas futures prices on that same date. For years beginning in 2008, E3 assumes that the California market will be "in resource balance," and that electric market prices will reflect the "all-in" costs of the marginal resource, a new combined-cycle gas turbine (CCGT) plant.

The CCC strongly disagrees with two elements of the E3 Report: first, the use of published electric futures prices from *Megawatt Daily* to set avoided generation costs during the initial four years of the 20-year forecast period; and, second, the assumption that these prices include the value of both energy and capacity.

There are good reasons for the CCC's disagreement with E3's use of the over-the-counter electric futures prices reported by *Megawatt Daily*. First, the SP-15 futures market on which E3 relies is neither liquid nor deep. On many days there are no reported transactions for annual power contracts in 2004 or 2005.¹² Given the lack of transactions, the reported volumes must be very small, perhaps just a single transaction. The Commission should not allow the prices for a small number of transactions to drive the prices paid to a substantial share of California's current and future generation resources. The Commission should be concerned about the potential for gaming if the prices for a significant share of the state's power supplies depend on just a few reported transactions in a single trade publication. For the same reasons, in the June 2003 RPS decision, the Commission declined to use executed contracts, broker quotes or bids to set the long-term (10 to 20 year) RPS market price referents.¹³

The CCC also takes issue with the E3 Report's assumption that SP-15 firm energy prices include the full value of capacity. The CCC does not believe that firm energy prices reflect the full value of capacity today, because the bilateral market in California has been reduced to a small, economy energy market. This market trades limited amounts of excess energy from resources whose fixed capacity costs are covered largely by RMR contracts, DWR contracts, or an IOU or municipal utility rate base.¹⁴ Thus, published wholesale electric market prices in California do not reflect the costs or value of capacity in the market today.

¹² This is based on a review of similar prices in *BTU Weekly*, a competing trade publication.

¹³ See D. 03-06-071, at pages 17 - 18.

¹⁴ In June 2003, the California Energy Commission (CEC) published a staff study—*Aging Natural Gas Power Plants in California*—that includes essential data on the 25 largest gas-fired power plants in California, including many of the plants that can be expected to operate on the margin in California in many hours. Table 1 of this study shows that many of these plants operate under RMR contracts with the ISO. Others are operated by municipal utilities, or are merchant plants whose owners have long-term DWR contracts (for example, AES/Williams, Calpine, Constellation, Dynegy, and Sempra). See CEC Publication No. 700-03-006.

The E3 Report makes a fundamental mistake in assuming that California is long on capacity today, and thus that it is appropriate to use published bilateral market prices as the measure of avoided generation costs until the market reaches “resource balance” in 2008. If anything, California today is short on capacity. Reserve margins are below the 15 - 17% levels that the Commission adopted as a goal for 2008 in D. 04-01-050, and are expected to fall in coming years unless new resource are added.¹⁵ The California Independent System Operator’s (ISO) recently-released Summer 2004 Assessment warns that under adverse supply and demand conditions, the state could fail to serve all demand as early as this coming summer.¹⁶ The Commission recently approved Edison’s request to build the 1,054 MW Mountainview power plant in order to bridge what the utility called a “looming gap” in the electric resources available to that utility.¹⁷ Although California needs capacity today, the value of capacity is not reflected in prices in the thin wholesale electric market, for the reasons discussed above.

The E3 Report’s use of market quotes is plainly inconsistent with the Commission’s adopted approach to the calculation of the market price referents (MPR) to be used in the initial RPS auction to be conducted this summer. In D. 03-06-071, the Commission explicitly rejected the use of market quotes to set the MPRs. Instead, the CPUC adopted the use of “all-in” combined-cycle costs as the baseload MPR, and the costs of a simple-cycle combustion turbine as the peaking MPR. If generation from existing renewable QFs is lost as a result of contract expirations or other factors, under the RPS legislation and D. 03-06-071 the IOUs would have to replace that power at a cost to ratepayers of up to the all-in costs of a new CCGT. If the utilities lose gas-fired QF capacity, they will have to replace that generation with new CCGT capacity,

¹⁵ The CEC’s *2004 Energy Commission Peak Supply and Demand Balance* (January 2004), at page 5, forecasts a reserve margin of less than 15% in 2005, declining to under 6% by 2010, under normal (once-in-2 years) temperature conditions. Under more adverse one-in-10 years weather conditions, anticipated reserve margins are much lower.

¹⁶ See California Independent System Operator, *2004 Summer Assessment* (April 16, 2004), at 3-6, available at www.caiso.com/docs/09003a6080/2f/ca/09003a60802fca50.pdf.

¹⁷ See A. 03-07-032, at 16.

such as Edison's Mountainview project and SDG&E's pending purchases of the output from the Otay Mesa and Palomar plants near San Diego. Contrary to E3's assumption, these circumstances support a conclusion that the all-in costs of a CCGT are a conservative measure of long-run avoided generation costs in California today and in all years going forward, not just beginning in 2008.

As its source of CCGT costs, the E3 Report relies on an August 2003 California Energy Commission (CEC) report on the comparative costs of various electric generating technologies in California. The Commission recently conducted workshops in R. 04-04-026 on the calculation of all-in CCGT costs to serve as the baseload MPR for the RPS program. The RPS proceeding has developed substantially more detailed and updated information on CCGT costs than is available in the CEC's August 2003 study on which the E3 Report relies. A proposed decision has been issued that would adopt a methodology for calculating the MPRs, including a long-term gas price forecast¹⁸ and a model of CCGT financial costs. The Commission should draw upon the record in that case as the basis for a more detailed and sophisticated source of all-in CCGT costs for use in E3's long-run avoided cost methodology.

B. Environmental

E3's avoided cost methodology includes the costs associated with avoided emissions of NO_x, PM₁₀, and CO₂. The costs of mitigating NO_x and PM₁₀ emissions are a real cost for generators in California today, who must purchase offsets to mitigate their emissions of these criteria pollutants. The CCC agrees that these emission costs represent a real avoided cost for utility ratepayers; accordingly, the costs of controlling such emissions should become part of avoided cost prices, including the short-run avoided cost (SRAC) energy prices paid to existing QFs. The costs of necessary NO_x and PM₁₀ offsets should be incorporated into avoided costs in

¹⁸ The long-term gas price forecasting methodology developed in the MPR workshops is very similar to the approach that the E3 Report uses to estimate long-term gas prices. The MPR method draws from a more diverse array of long-term forecasts, including private consultant forecasts, while E3 relies on just the CEC and Energy Information Administration forecasts.

two ways – LRAC prices should include the costs of all necessary offsets in the capital costs for a new CCGT, and SRAC prices should include a \$ per MWh adder that reflects the emission rates of a typical electric generator using selective catalytic reduction (SCR) emission control technology¹⁹ and current emission offset costs.

Carbon dioxide emissions are a different story. Cogeneration projects do result in significant reductions in CO₂ emissions, by using the same Btus of natural gas to produce both electricity and useful thermal energy. Obviously, the output from most renewable QFs also reduces CO₂ emissions. However, CO₂ emissions are not yet regulated in the U.S.; as a result, QFs do not yet avoid the costs of CO₂ emissions. The E3 Report candidly admits that CO₂ is presently an “unpriced” externality, but argues that the regulation of CO₂ “is a matter of when, not if.”²⁰ Thus, the E3 Report includes the costs of CO₂ emissions in its 20-year, long-run forecast of avoided costs. The CCC supports the inclusion of CO₂ emission costs in a long-run avoided cost forecast. However, because CO₂ emissions are not regulated today, the CCC does not believe that they should be included in SRAC energy prices paid to existing QFs or to QFs with new SOI contracts.

C. Transmission & Distribution (T&D)

Energy efficiency programs reduce electric demand at the point of use; therefore, they avoid transmission and distribution (T&D) costs. The extent to which a generator (such as a QF or a DG project) avoids T&D costs depends on its location on the grid and the extent to which it serves on-site loads rather than exporting power to the grid. Most cogeneration QFs interconnect at sub-transmission voltages (115 kV and 66 kV) and are located in the load centers, near substantial end use loads, but upstream from the lower-voltage distribution grid. As a result, many cogeneration QFs avoid IOU costs for transmission, but not distribution. However, small cogen-

¹⁹ This is the standard emission control technology that is widely used at gas-fired power plants in California today.

²⁰ E3 Report, at 93.

eration and distributed generation facilities certainly avoid distribution costs by serving on-site or over-the-fence loads, or by delivering directly into a lower-voltage distribution system that serves a significant load center.

As discussed in the E3 Report, marginal transmission and distribution costs are adopted in the rate design phases of each electric utility's general rate case. In order to be consistent with electric rate design and to simplify implementation, the most recently-adopted marginal T&D costs should be used in the avoided cost methodology. The CCC notes that E3 recommends the use of a single method (the Present Worth approach) to calculate marginal T&D costs for all of the IOUs. The CCC supports the use of adopted marginal T&D values (irrespective of the methodology used), in order to avoid a situation in which a utility must calculate marginal T&D costs using one method for avoided cost calculations and another for electric rate design.

Transmission and distribution costs are capacity-related costs. QF contracts signed in the 1980s did not include avoided transmission or distribution costs in the fixed contractual capacity payments. However, in its BRPU process in the early 1990s the Commission recognized that some QFs will avoid transmission costs compared to the avoidable resource that the utility otherwise would build.²¹ The Commission also is now incorporating transmission costs in bid evaluation for RPS projects.²² As part of a consistent approach to avoided costs, QFs located in the load centers whose power can be delivered to load without the use of the transmission system should be paid the utility's avoided transmission costs, as an adder to capacity payments, when such QFs sign new, renewal, or extension contracts with the utility. Similarly, smaller QFs located on the distribution system should be assumed to avoid the marginal costs of the higher-voltage portions of the distribution system, and should be paid the appropriate avoided distribution costs in addition to avoided transmission costs.

²¹ See D. 92-04-045, at 40; also, D. 92-09-078, at 4-8.

²² See D. 03-06-071, at 34-37.

D. Reliability

The E3 Report computes a reliability adder based on the costs of ISO ancillary services. The IOUs' purchases from QFs do allow them to avoid certain reliability-related costs, including the costs of Reliability Must-Run (RMR) contracts.²³ In the future, the utilities will be able to count contracted QF capacity toward their resource adequacy requirements, and thus avoid the costs to acquire additional reserves. As a result, QFs signing new, renewed, or extended long-term contracts should be entitled to a reliability adder such as the one that the E3 Report computes. These reliability-related costs are re-assessed on a year-to-year basis, and the CCC understands that the on-peak production of as-available QFs under contract to the utility will be counted toward meeting resource adequacy requirements. Thus, as-available QFs operating under the 5-year Standard Offer No. 1 contracts approved in D. 04-01-050 also should be assumed to avoid reliability-related costs.

E. Price Elasticity of Demand

The E3 Study develops a "price elasticity multiplier" as an upward adjustment to the avoided cost of energy to reflect the fact that decreasing the demand for energy (through a conservation measure) will lower the market-clearing price for energy, thus reducing the price of all power bought at that market price. In effect, this multiplies the benefits of a conservation measure.

Fundamentally, QFs are similar to a conservation measure, except that QFs add to the supply of generation instead of reducing system demand. If existing QF generation was removed

²³ The ISO calculates its need for RMR power assuming that all QFs in a particular area are operating at firm contract capacity or, for as-available QFs, at historical output levels. Furthermore, the ISO treats the generation of small QFs (many of whom have SO1 / SO3 contracts with as-available capacity payments) as a reduction in the nearest load. As a result, the ISO does not consider QFs to be eligible for RMR contracts, unless the QF can show that it is not contractually obligated to be on-line absent an RMR agreement. For example, *see* the ISO's "Request for Proposals to Provide 2004 Local Area Reliability Service to California ISO," California ISO, May 21, 2003, at 2. This document is available on the ISO's website at www.caiso.com/docs/09003a6080/22/45/09003a608022450d.pdf.

from the system, the market price for power would increase to a much higher level than the observed market-clearing price with all QFs in the system. In SRAC energy pricing for QFs, the Commission has recognized this effect by using a “ QF_{In}/QF_{Out} ” approach to calculating the heat rate (incremental energy rate, or IER) used to set SRAC prices.

E3 uses this multiplier only for years until 2008, before the IOUs’ supplies and resources are predicted to be “in resource balance.” E3 drops this multiplier in 2008, when it assumes the market is in equilibrium and begins to base generation costs on all-in CCGT costs. The CCC understands that E3 stops using this multiplier on the theory that, in 2008, the long-run supply curve will be very “flat.” In other words, the long-run price will not change significantly with changes in demand. Since the CCC is recommending that the long-run avoided cost (LRAC) calculation should use all-in CCGT costs beginning today, E3’s “price elasticity multiplier” should not apply to LRAC. However, as discussed further in Section III.B.3 below, the Commission should continue to reflect the aggregate value of QF energy in SRAC pricing, as provided in the FERC rules implementing PURPA²⁴ and as the Commission has done in the past through the “ QF_{In}/QF_{Out} ” approach to calculating the SRAC IER.

F. Line Losses

The E3 Report does not discuss avoided line losses in detail, but appears to use system average loss factors. In effect, E3 assumes that a conservation measure avoids all line losses by reducing demand at the point of use. A more complex calculation is needed to determine the avoided losses resulting from a generator such as a QF that supplies power to the grid in place of some other avoided generating resource. The existing QF line loss methodology adopted in D. 01-01-007 calculates a QF’s loss factor as the ratio of the percentage of the QF’s generation which is delivered to loads divided by the percentage delivered from the system average generator. The CCC does not recommend any change in the QF line loss methodology at this time. However, this methodology may need to be revised if and when the California ISO moves

²⁴ 18 CFR § 292.304(e)(2)(vi).

to locational marginal cost pricing (LMP), because the ISO will no longer calculate the Generation Meter Multiplier loss factors used in the QF line loss factors today.

III. AVOIDED COSTS FOR QF PRICING

The second question posed in the OIR asks parties to evaluate which components of the proposed avoided cost methodology are applicable to other avoided cost applications, including SRAC pricing for QFs. The CCC presents in this section its proposal for how the Commission should price QF power in the future.

A. Long-run Avoided Cost Prices for New, Extended, or Renewed QF Contracts

The E3 long-run avoided cost (LRAC) methodology, modified as described below, should be applicable to QFs that sign new contracts to provide long-term resources to the IOUs. This includes QFs who sign new contracts pursuant to the policy on long-term QF contract renewals and extensions that the Commission will develop in R. 04-04-003. The CCC expects that such contracts will be 5 to 20 years in duration.²⁵

As discussed above, the CCC strongly recommends that long-run avoided generation costs for both energy and capacity should reflect the all-in costs of a CCGT in all years. This would be consistent with the RPS program, in which Commission has already adopted the all-in costs of a new CCGT as the MPR for new baseload renewable contracts under the RPS program. Furthermore, in its long-term procurement order the Commission has suggested the use of the RPS MPRs to price QF contract renewals or extensions.²⁶ As noted above, the Commission recently has devoted significant effort to refining the calculation of the baseload and peaking MPRs for use in the RPS program.

²⁵ These do not include the 5-year SO1 contracts adopted in D. 04-01-050.

²⁶ See D. 04-01-025, at page 156.

E3's LRAC calculation includes a number of distinct components. Consistent with the discussion of the E3 Report, the CCC believes that the following components of the E3 LRAC should be applicable to QF pricing:

- Generation, based on CCGT costs
- Environmental, including CO₂ costs
- Transmission, for QFs located in load centers
- Distribution, for small QFs located on the distribution system that avoid higher-voltage distribution costs
- Reliability, as suggested in the E3 Report
- Line losses, using the present QF line loss methodology

B. SRAC Pricing for Existing QFs

The third question posed in the OIR focuses on SRAC pricing for existing QFs. The Commission asks parties to review the existing avoided cost methodologies for SRAC energy and as-delivered capacity payments, to comment on differences between the pricing for SRAC and LRAC energy and for firm and as-delivered capacity. The OIR also asks parties to comment on the legal constraints that the Commission faces in changing the SRAC methodology, including P.U. Code Section 390.

1. Background

The CCC provides as Attachment A to these comments a brief summary of the history of SRAC pricing for QFs in California. The essential themes of this review can be summarized as follows:

- SRAC energy prices have been based on the formula:

$$\text{SRAC Energy} = \text{Gas Price} \times \text{Heat Rate (IER)} + \text{Variable O\&M} + \text{Other Adders}$$

Even the SRAC formulas adopted in 1996 pursuant to P.U. Code Section 390 have their foundations in this formula.

- Since the outset of the QF program, SRAC energy prices have always been set on a prospective basis, without retroactive downward adjustments, in order to allow QFs to make operating decisions knowing the minimum price they will be paid.
- 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 do not track IOU avoided costs on a real time or day-to-day basis.
- As required by PURPA, SRAC energy prices have reflected the aggregate value of QF power. For example, the methodology to calculate the IER heat rate has been based on system production costs both with and without QFs in the resource mix (the QF_{In}/QF_{Out} methodology).
- Prior to the 2000 - 2001 energy crisis, the natural gas price used to calculate SRAC was based on delivered gas prices actually available to generators in California.
- The Commission has used the fixed costs of a simple-cycle combustion turbine as the proxy for the value of capacity, because it represents the IOUs' least-cost source of pure capacity.
- As-delivered capacity values are allocated to time-of-use periods using capacity allocation factors and are paid on the basis of kilowatt-hours delivered.
- Firm capacity payments include performance requirements and reflect the higher value of a long-term commitment to deliver power reliably to the utility.

2. The SRAC Energy Pricing Formula

The CCC recommends that the Commission should continue to rely on its longstanding formula for SRAC energy prices:

$$\text{SRAC Energy} = \text{Gas Price} \times \text{IER} + \text{Variable O\&M} + \text{Other Adders}$$

The Commission should update all of the components of the formula to reflect today's conditions.

This approach to SRAC is well-understood by all the utilities, QFs, and the Commission, and has worked to maintain QF generation as an integral part of California's resource mix for the past two decades. Linking SRAC to natural gas prices reflects the reality that gas-fired generation is almost always on the margin in California, and allows gas-fired cogenerators to link their input and output prices, which promotes stability in QF output.

Importantly, according to existing precedent, this formula can be used and its components can be updated within the constraints of existing law (P.U. Code Section 390). The CCC observes that in D. 01-03-067 the Commission re-cast Edison's SRAC formula to this form, by adjusting the "factor" term of the Section 390 formula.²⁷ The Commission also has approved five-year SRAC pricing amendments for gas-fired QFs on the Edison system that use this formula.²⁸ Significantly, the CCC believes that the use of published wholesale electric market prices or ISO real-time electric prices would not comply with P.U. Code Section 390(b)'s requirement that SRAC energy prices must be adjusted in reference to California border natural gas prices.

3. SRAC IERs

SRAC prices represent the costs that the IOUs would incur to replace their current purchases of QF power, assuming that the only resources that the IOUs add are those that can be sited and built within the short-run period for which these SRAC prices will apply. The IERs used in the SRAC formula typically have been calculated through production cost models that

²⁷ Although the CCC opposed this change as contrary to Section 390(b), the CCC did not prevail on this issue in the appellate process.

The Commission also indicated in D. 01-03-067 that all elements of the re-cast Edison SRAC formula should be updated, in addition to the intrastate transportation rate that the Commission updated in D. 01-03-067. Although the Commission held hearings in 2001 on updating the other elements of the Edison SRAC formula, a decision on those updates has never been issued.

²⁸ See D. 01-06-015, at 8.

have calculated total costs for each IOU both with and without the block of QFs under contract to that IOU that are paid SRAC energy prices. This is the “QF-in/QF-out” methodology that incorporates the price elasticity of supply (as discussed in Section 2.7 of the E3 Report) into SRAC pricing. The CCC recognizes that challenges exist in applying the “QF-in/QF-out” method today, given the large number of QFs that are paid SRAC prices. Nonetheless, it is necessary to undertake that effort, in order for SRAC energy prices to reflect the aggregate value of QF power, as FERC rules require.²⁹ One possible simplification of the IER calculation would be to base the IER on the typical heat rate of the short-lead-time units (probably simple-cycle combustion turbines) that the IOUs would install if they had to replace existing QFs over a short-run time horizon. The CCC recommends that the Commission should examine the IER methodology in more detail in the SRAC phase of this proceeding (*see* Section IV, below).

Traditionally, SRAC prices have been time-differentiated through the use of time-differentiated IERs. SRAC prices should continue to be time-differentiated, for several reasons. First, time differentiation more closely aligns SRAC prices with the utility’s avoided costs, which can vary over a significant range throughout the day. Second, not all QFs produce baseload power; some QF projects are dispatchable or can reduce their output for significant periods of time. As a result, in order to encourage QF dispatch, QFs should receive SRAC price signals that correctly reflect when QF power is most valuable to the utility.

4. SRAC Gas Prices

SRAC prices send signals to a large block of existing gas-fired QFs that make short-term operating decisions based on whether SRAC prices allow them to recover their fuel costs. As a result, it is critical that the Commission adopt an SRAC pricing methodology that reflects the realities of changing gas costs. The CCC’s key principles concerning the gas price used in the SRAC calculation are the following:

²⁹ *See* 18 CFR Part 292.304(e)(2)(vi), emphasis added.

- the gas price must reflect a delivered price that is actually available to electric generators (including QFs) in the market place,
- the prices must be available and employed in the short-run, and
- the Commission cannot switch back and forth between different gas pricing approaches, because to do so would disrupt the market and QFs' long-term supply and transportation arrangements.

The disastrous shift from Topock to Malin border prices in March 2001 at the height of the energy crisis, a change that forced thousands of megawatts of gas-fired QFs off-line, demonstrated what can happen if the gas price in the SRAC calculation is not one which is “physically and financially available” to generators in the short-run.³⁰ This was a key conclusion of the Commission’s gas workshop in R.99-11-022 in the wake of D.01-03-067.

The CCC believes that there are three logical choices for an SRAC gas price that meets these goals. In order of the CCC’s preference, they are:

1. ***Continue To Use Border Prices.*** The set of gas prices that best meet the foregoing objectives are California border gas prices. California border gas markets reflect prices that are available to and employed by generators in the short term. They have been stable since June 2001. Substantial new gas infrastructure has been added, which should enhance stability in the border markets. As a result, the CCC believes that the state will not run a significant risk if SRAC prices remain linked to border gas prices. The CCC notes that in late 2001 all concerned parties—the IOUs, ORA, and QF parties—told the Commission that it was safe to return to the use of the Topock gas indices for SRAC pricing; nonetheless, the Commission has yet to act on those comments. The five-year pricing amendments that the CPUC approved for Edison gas-fired QFs in June 2001 also use Topock indices. As discussed below, the utilities have the ability to hedge their exposure to SRAC prices based on border gas prices. Finally, P.U. Code Section 390(b) requires the use of border gas price indices in the SRAC energy pricing methodology.
2. ***Move to the Consistent Use of Basin-forward Prices.*** The CCC is willing to consider a move away from the use of 100% California border gas prices to set

³⁰ See D. 01-03-067, at 19.

monthly SRAC prices. For example, the CCC would be willing to consider the use of basin-forward prices (i.e. published basin prices plus tariffed interstate and intrastate transportation rates to reach border or city-gate pricing points), even though such an approach might not always reflect short-term gas purchasing decisions. This would remove SRAC prices from the risk of basin-to-city-gate basis spikes, such as occurred during the energy crisis. The use of basin-forward gas prices also would allow and encourage gas-fired QFs to contract for interstate capacity – an outcome consistent with the Commission’s expressed desire in its new rulemaking on long-term gas policies, R. 04-01-025. However, it is critical that the basin choices reflect real, commercially-available procurement opportunities. Furthermore, given that the Commission wants to see long-term commitments to firm interstate capacity, it is vital that the Commission maintain the methodology for a long-term period and that changes not be made without substantial advance notice. Finally, to implement SRAC prices using basin-forward gas would require a legislative change to P.U. Code Section 390(b), which now requires that the SRAC energy pricing methodology use border gas price indices.

3. ***Provide a Tolling Option.*** The CCC also is willing to consider the development of an option to convert QF contracts to tolling agreements, whereby the IOU that purchases the QF’s electric output also would supply the natural gas used to produce that power. This could be complex, as QFs also purchase gas to support on-site loads as well as power sales to the electric utility.

The use of the traditional SRAC formula does not mean that the costs for the entire 10,000 MW of existing QFs in California must be linked directly to volatile natural gas prices. Many, if not most, renewable QFs would prefer to receive a long-term fixed price for their output, such as the five-year, fixed price of \$53.70 per MWh that most PG&E and SDG&E QFs elected in the summer of 2001. At that time, the \$53.70 per MWh price helped the state out of the energy crisis, by returning all QFs to full operation for the critical peak summer months. From today’s perspective, given the high natural gas prices that are expected to persist through 2006, the \$53.70 per MWh price appears likely to be a reasonable deal for ratepayers over the life of the contract. Furthermore, the IOUs have been able to hedge their exposure to gas-based SRAC prices using financial instruments. The Commission should direct the utilities to offer QFs a renewed 5-year fixed-price contract when the 2001 - 2002 contract amendments expire in 2006 or 2007. The new fixed price should be based on a five-year forecast of SRAC prices using the Commission’s then-current SRAC methodology.

5. SRAC Variable O&M and Environmental Adders

SRAC prices historically have included an adder for variable O&M costs, based on a comparison of each utility's variable O&M costs from operating its system both with and without the QFs that are paid SRAC prices. PG&E's SRAC prices also have included small adders to reflect the impact of QF generation on PG&E's contracts for geothermal steam and on its costs for cash working capital. The geothermal adder is no longer valid, as PG&E has divested those plants.

Going forward, modeling each IOU's short-term resource options both with and without QFs would produce that utility's avoided costs for variable O&M expenses and NOx and PM10 emission credit costs. These avoided costs should be reflected as adders to the basic SRAC energy price formula of a gas price times an IER heat rate.

6. Capacity-related Avoided Costs

QFs also may avoid certain capacity-related transmission, distribution, and reliability (RMR or capacity market) costs. These avoided costs are not captured in existing QF capacity payments, which reflect only the generation-related capacity costs that existing QFs avoided when their projects were first developed in the 1980s. Even though existing QFs now avoid these additional capacity-related costs, the Commission should not seek to alter the fixed contractual capacity payments in existing QF contracts. These avoided capacity costs represent a continuing benefit to ratepayers from existing QF resources. However, such capacity-related avoided costs should be included in as-delivered capacity payments to QFs that sign new 5-year SO1 contracts.

7. As-Delivered Capacity Prices

As-delivered or as-available capacity values should be based on the fixed costs of a new simple-cycle combustion turbine (CT). The Commission has used the costs of a CT as the proxy for the value of capacity for the past two decades, because it represents the IOUs' least-cost

source of pure capacity.³¹ The Commission also has used CT costs consistently to set marginal capacity costs for electric rate design.³² Finally, in D. 03-06-071, the Commission chose a CT as the MPR for the RPS peaking product. This traditional approach remains valid today – when the state needed additional capacity in a short time-frame during the 2000 - 2001 crisis, California sited and built hundreds of megawatts of new CTs.

At times when the electric utilities have had abundant capacity (in excess of certain target reserve margins), the Commission has applied an “energy reliability index” (ERI) of between 0.1 and 1.0 to the full CT cost, in order to reduce the value of capacity in recognition of the surplus that existed at those times. The traditional ERI formula dropped from 1.0 at a 16% reserve margin to 0.1 at just over a 22% reserve margin.³³ As discussed in Section II.A above, California’s reserve margins are well below the Commission’s adopted target reserve margins of 15% to 17%.³⁴ The value of capacity should remain at 100% of the cost of a CT at least until the state achieves its target reserve margins and a robust capacity market is established to reveal the market value of capacity alone. Capacity markets have developed in other states, and one can be expected to develop here once the state has implemented well-defined resource adequacy requirements.

As noted in Section III.B.6 above, as-delivered capacity prices for new SO1 contracts also should include avoided transmission, distribution, and reliability costs.

³¹ See, generally, D. 82-01-103, D. 82-04-071, and D. 82-12-120.

³² See, for example, D. 82-12-055, at 200.

³³ Between the floor and ceiling values, the formula for the Energy Reliability Index is $ERI = \exp(-50 * \text{Excess Reserve Margin})$, where the Excess Reserve Margin is the difference between the actual reserve margin and the 16% target.

³⁴ See Footnote 14 above.

IV. NEXT PROCEDURAL STEPS

The issues appear to divide naturally into LRAC and SRAC matters. The LRAC methodology would apply to conservation, DSM, DG, RPS contracts, and new, renewed, or extended long-term QF contracts. SRAC issues would focus on the pricing for existing, still-under-contract QFs and for those QFs that sign the new SO1 contracts authorized in D. 04-01-050. At this time the CCC suggests that the Commission should consider dividing this proceeding into two phases, which can run simultaneously. Phase 1 would develop the LRAC methodology, which would apply (with potential variances) across a number of applications. The Commission should wait until after the workshops to establish the next steps for developing the LRAC methodology. Phase 2 would address SRAC pricing issues. The Commission should establish a separate workshop and comment schedule for initial consideration of SRAC issues.

V. CONCLUSION

The CCC appreciates the opportunity to assist the Commission in the development of a consistent avoided cost methodology. The resources that are valued using avoided costs are crucial for the state to develop and maintain, if California is to conserve its limited – and

increasingly expensive – fossil fuel resources. The CCC intends to participate actively in the upcoming workshop and in subsequent phases of this important proceeding.

Respectfully submitted,

Jerry R. Bloom, Esq.
Joseph M. Karp, Esq.
White & Case, LLP
Three Embarcadero Center, Suite 2210
San Francisco, CA 94111
Telephone: (415) 544-1100
Facsimile: (415) 544-0202
E-mail: jbloom@whitecase.com
jkarp@whitecase.com

R. Thomas Beach
Patrick G. McGuire
Crossborder Energy
2560 Ninth Street, Suite 316
Berkeley, California 94710
Telephone: 510-649-9790
Facsimile: 510-649-9793
E-mail: tomb@crossborderenergy.com
patrickm@crossborderenergy.com

On behalf of
CALIFORNIA COGENERATION COUNCIL

June 4, 2004

Attachment A

A Brief History of SRAC Pricing in California

A Brief History of SRAC Pricing in California

R. Thomas Beach, Principal
Crossborder Energy

January 13, 2004

$$\text{SRAC Energy Price} = \text{Fuel Price} \times \text{IER Heat Rate} + \text{O\&M Adder}$$

I. The Formula

The above formula has been the basis for SRAC energy pricing in California since the initial implementation of PURPA in California in the early 1980s. 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.

Since the outset of the QF program, SRAC energy prices have always been set on a prospective basis, without retroactive downward adjustments, in order to allow QFs to make operating decisions knowing the minimum price they will be paid. *D. 82-12-120, at 107.*

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 do not track IOU avoided costs on a day-to-day basis.

II. 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 IOUs for natural gas supplies for electric generation.

A Brief History of SRAC Pricing
January 13, 2004

With the implementation of the 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 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 CPUC 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 “bidweek” gas prices. ***D. 91-10-039.***

From 1991 - 1996, the CPUC adjudicated numerous issues concerning the index method, as gas markets continued to develop and the electric IOUs’ gas purchases became more diversified and complex. For example, the method was revised to include indices for the rapidly-growing California border markets at Topock and Malin. ***D. 96-07-023.*** The electric IOUs began to buy significant volumes in the border markets to take advantage of low border prices that resulted from the glut of pipeline capacity to California. Edison pressed the CPUC to use 100% Topock prices as the avoided fuel cost in the SRAC posting.

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 “transition formulas” to set SRAC prices until the PX market was functioning properly. These formulas were based on regressions of 1994 - 1995 SRAC prices versus border gas prices, and were driven entirely by changes in border gas prices. The formulas were codified in P.U. Code Section 390(b); the CPUC adopted the specific, agreed-upon formula values in ***D. 96-12-018.*** The Edison and SDG&E formulas used 100% Topock prices; the PG&E formula reflected a 50/50 mix of Malin and Topock prices.

When border prices spiked during the 2000 - 2001 energy crisis, the Commission in ***D. 01-03-067*** replaced the Topock index with the Malin index plus an off-system transportation rate over the PG&E system.

III. The Incremental Energy Rate (IER) – a Heat Rate in Btu per kWh

The IER 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.

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:

$$\text{IER} = \{ (\text{QF}_{\text{OUT}} \text{ Costs} - \text{QF}_{\text{IN}} \text{ Costs}) / \text{QF Energy} \} / \text{Avoided Fuel Cost}$$

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

$$\begin{aligned} \text{IER} &= \{ (\text{Costs in } \$) / (\text{QF Energy in kWh}) \} / \text{Fuel Costs in } \$ \text{ per Btu} \\ &= \{ (\$ / \text{kWh}) / (\$ / \text{Btu}) \} = \text{Btu} / \text{kWh} \end{aligned}$$

IERs do 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. IERs also increase if production decreases from infra-marginal resources such as hydro or nuclear plants. The converse is also true.

IERs were originally determined in general rate cases. In the late 1980s, the Commission moved IER issues to annual ECAC cases. **D. 88-03-026**. Due to the complexity of IER issues, the IOUs, ORA, and QF parties tended to settle IER issues outside of the hearing room, with the Commission approving those agreements.

Commission-adopted IERs have been consistently in the range of 9,000 to 10,000 Btu per kWh over the two decades of the California QF program. IERs are time-differentiated according to each IOU’s time-of-use (TOU) periods.

The SRAC transition formulas approved in 1996 are based on regressions of 1994 - 1995 SRAC prices, and thus have 1994 - 1995 IERs implicit in them.

Historical Edison Heat Rates and O&M Adders

| <u>Year</u> | <u>Heat Rate</u> <i>Btu/kWh</i> | <u>O&M Adder</u> <i>c/kWh</i> | <u>Fuel</u> <i>\$/MMBtu</i> |
|----------------|------------------------------------|--------------------------------------|--------------------------------|
| 1981 | 10,098 | 0.20 | 6.68 |
| 1982 | 9,979 | 0.20 | 5.72 |
| 1983 | 9,972 | 0.20 | 4.69 |
| 1984 | 9,961 | 0.20 | 4.60 |
| 1985 | 9,984 | 0.20 | 4.27 |
| 1986 | 9,984 | 0.20 | 2.97 |
| 1987 | 9,984 | 0.20 | 2.67 |
| 1988 | 9,773 | 0.30 | 2.88 |
| 1989 | 9,763 | 0.30 | 3.13 |
| 1990 | 9,689 | 0.30 | 3.11 |
| 1991 | 9,549 | 0.30 | 2.70 |
| 1992 | 9,012 | 0.30 | 2.98 |
| 1993 | 9,453 | 0.30 | 3.07 |
| 1994 | 9,170 | 0.21 | 2.52 |
| 1995 | 9,140 | 0.20 | 2.03 |
| 1996 | 9,428 | 0.16 | 2.30 |
| 1997 | 9,939 | 0.23 | 3.03 |
| 1998 | 9,982 | 0.23 | 2.72 |
| 1999 | 10,205 | 0.23 | 2.76 |
| 2000 | 10,357 | 0.23 | 5.32 |
| 2001 | 9,462 | 0.21 | 7.42 |
| 2002 | 9,140 | 0.20 | 3.59 |
| 2003 | 9,140 | 0.20 | 5.68 |
| Average | 9,703 | 0.23 | 3.78 |

Source: *SCE Quarterly or Monthly SRAC Postings*

IV. The O&M Adder

This component 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).
D. 89-09-093.

Commission-adopted O&M adders have ranged from \$1 to \$3 per MWh. D. 01-03-067 adopted an O&M adder of \$2 per MWh for Edison.

Variable generating costs today also include air emission credit costs and periodic costs to replace expensive catalysts in air emission control equipment. FERC has adopted a variable O&M cost of \$6 per MWh in the California refund cases.

V. Moving SRAC to Electric Market Prices

The market-clearing price in the large PX market clearly represented the IOUs' avoided cost for QF generation, due to the requirement that the IOUs' purchase all of their power out of the PX market.

IOU avoided costs today are much less clear, given the much smaller, remnant wholesale electric markets now operating in California. There is no transparent, day-ahead electric market on which QF operating decisions could be based.

Daily electric market prices are much more volatile than gas-based, monthly SRAC prices. The IOUs can, and do, hedge their exposure to gas-based SRAC prices.

VI. As-Available Capacity Prices

Since the early 1980s, the Commission has directed the IOUs to base as-available capacity payments to QFs on the annualized costs of a combustion turbine (CT). The Commission has used the costs of a CT as the proxy for the value of capacity, because it represents the IOUs' least-cost source of pure capacity. **D. 82-01-103**, **D. 82-04-071**, and **D. 82-12-120**. For the past several decades, the Commission also has used CT costs to set marginal capacity costs for electric rate design.

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.

In the late 1980s, the Commission began to adjust CT costs downward using an Energy Reliability Index (ERI), to reflect the lower value of capacity in periods when the IOUs were long on capacity. The ERI varies between a minimum of 0.1 and a maximum of 1.0.

The Commission has not reviewed or adjusted QF as-available capacity prices since the mid-1990s. The CT costs and ERIs now in place vary widely among the IOUs.

QF As-Available Capacity Prices

| | <u>PG&E</u> | <u>Edison</u> | <u>SDG&E</u> |
|--|-----------------|---------------|------------------|
| Combustion Turbine Cost (\$/kW-yr) | \$63.90 | \$49.30 | \$70.34 |
| Energy Reliability Index (ERI) | 1.0 | 0.1 | 1.0 |
| As-Available Capacity Price (\$/kW-yr) | \$63.90 | \$4.93 | \$70.34 |

Last revised: D. 93-03-017 D. 96-12-056 1996