BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking into Implementation of Pub. Util. Code § 390.	Rulemaking 99-11-022

FINAL REPORT ON

WORKSHOP TO DISCUSS ALTERNATIVE GAS INDICES

Prepared by:

James Loewen

Energy Division

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Introduction

Pursuant to Decision 01-03-067, Energy Division held a workshop on April 19, 2001 regarding the gas index which is to be used in calculating short-run avoided cost (SRAC) payments to Qualifying Facilities (QFs). Prior to the workshop, parties were invited to file pre-workshop comments. The intent of the workshop and of this report is to provide information for the Commission to help it decide upon an appropriate way to implement Public Utilities Code Section 390 (b), to comply with the Public Utilities Regulatory Policy Act (PURPA), and provide a gas index that reflects gas supply arrangements at the California border that are physically and financially available to the QFs. This workshop report summarizes the written comments which were filed prior to the workshop, as well as the facts and discussion which came out of the workshop.

Background

The world of QFs was created in 1978 by Congress when it enacted PURPA. PURPA mandated that QFs receive payments that are just and reasonable, that do not discriminate against QFs, and that do not exceed the utilities' avoided costs (18 CFR 292.304 (a)(1 and 2). QF contracts in California are constructed to include an energy payment component as well as a capacity component. The energy component for most QF contracts has been set equal to the SRAC. Up until 1996, the SRAC was established pursuant to an annual proceeding in which the Commission conducted a detailed examination of the utilities' avoided cost. In Assembly Bill (AB) 1890, the process for determining the SRAC was automated and simplified. This is embodied in P.U. Code Section 390.

Section 390 (c) envisioned that SRAC energy payments paid to QFs would eventually be based upon the clearing price paid by the California Power Exchange (PX) once certain criteria had been met. Determining whether those criteria had been met was one of the tasks of this proceeding. The demise of the PX has rendered Section 390 (c) moot. Pending implementation of a PX-based SRAC, Section 390 (b) provided for a "transition" formula for determining the SRAC. Section 390 (b), therefore, is the code to which the CPUC's SRAC methodology currently must conform.

> Until the requirements of subdivision (c) have been satisfied, short run avoided cost energy payments paid to nonutility power generators by an electrical corporation shall be based on a formula that reflects a starting energy price, adjusted monthly to reflect changes in a starting gas index price in relation to an average of current California natural gas border price indices. The starting energy price shall be based on 12-month averages of recent, pre-January 1, 1996, short-run avoided energy prices paid by each public utility electrical corporation to nonutility power generators. The starting gas index price shall be established as an average of index gas prices for the same annual periods. (P.U. Code Section 390 (b))

The Commission worked out the implementation details of this mandate in D.96-12-028. For each utility, the SRAC varied from month to month, based on changes in the average spot price for natural gas as traded at the California border and reported in several trade publications. For Pacific Gas and Electric (PG&E), the border price was weighted between two different border points – 50% at Malin and 50% at Topock. For San Diego Gas & Electric (SDG&E) and Southern California Edison (Edison) the border price was set entirely at the Topock border price.

On July 28, 2000 Edison filed a motion to modify D.96-12-028 to revise the transition formula. Responding to this motion, ORA filed comments referencing a complaint filed by the CPUC at the Federal Energy Regulatory Commission (FERC) alleging that suppliers of natural gas and their affiliates have increased gas prices by withholding capacity. The Assigned ALJ in this proceeding issued a ruling on September 1, 2000 adding the question of the reliability and validity of the border indices to the issues raised in Edison's motion. Several rounds of comments and replies followed.

On March 27, 2001 the Commission issued D.01-03-067. Among other things, that decision replaced the Topock price with the Malin-plus-tariffed transport price. That decision also summarized many of the facts and arguments concerning the border gas indices. That discussion will not be reprised here. The decision directed "Energy Division to conduct a workshop on the various gas cost options to replace Topock -- Malin plus intrastate transport to Southern California, basin price plus tariffed interstate transport, continued use of indices at Topock or some other location or some combination of these – and report to the Commission within thirty five days. The primary guidance that we give the Energy Division is that the proposals to be considered should reflect gas supply arrangements at the California border that are physically and financially available to QFs." (p.19)

On April 3, 2001 parties were notified of the upcoming workshop. In the workshop notice, parties were invited to file pre-workshop comments no later than April 10. In response to a request for a delay, the deadline for comments was postponed to April 12.

Summaries of Pre-Workshop Written Comments

Nine parties submitted pre-workshop comments[1]. Their comments, ordered alphabetically, are summarized below.

California Cogeneration Council (CCC):

CCC maintains that the March 27 decision violates PURPA because it bases SRAC on the Malin price plus transport, and electric generators in neither northern California nor southern California are able to obtain gas at this price. As a short-term solution, CCC advocates returning to an SRAC based on Topock prices for SDG&E and Edison, and 50/50 of Malin/Topock for PG&E. As a long-term solution, CCC advocates a negotiated solution incorporating features such as hedging instruments, or long-term gas supply options.

CCC devoted a considerable portion of its filing to a discussion of the physical gas delivery system in California as well as the contractual and financial hurdles facing a generator seeking to procure gas for its plant. CCC explained that PG&E's Redwood Path pipeline runs the length of PG&E service territory, connecting Malin in the north at the California-Oregon border with Kern River Station in the south. Kern River Station is at the service territory border with Southern California Gas Company (SoCalGas). CCC explained that the Redwood Path pipeline can carry only 350 million cubic feet of gas per day (350

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[1] The comments of the Departmant of the Navy (DON) were accompanied by a motion to intervene.

MMcf/d). This amount is further restricted during times when significant volumes of California gas are concurrently being injected into the SoCalGas system. CCC states that according to PG&E's "Pipe Ranger" web site, for the year ending January 2001 deliveries from Malin over the PG&E system into the SoCalGas system were 244 MMcf/d. CCC states that according to the 2000 California Gas Report[2], the total demand by electric generators in southern California (in Edison and SDG&E territories) in 1999 was 1,037 MMcf/d. CCC maintains that the demand for gas by generators is now considerably higher.

As for northern California, CCC explains that much of the gas consumed by electric generators comes from southern California at Topock or from the Rocky Mountains via the Kern River pipeline (Daggett is the border point). In 1999, PG&E's noncore market received 63% of its supplies from Malin, 27% from Topock/Kern River, and 10% from California production. CCC maintains that the percentage of gas arriving from Topock will be higher now, as a result of the pipeline from Malin being congested and because of higher gas demand.

CCC argues that the very existence of a price differential between Malin and Topock indicates that the Redwood Path pipeline is congested. CCC explains that were there no congestion, prices would equalize between the two trading points.

CCC explains that if a generator located in southern California wants to buy Malin gas, he has to buy it at Kern River Station from a holder of firm capacity rights on the PG&E system. CCC notes that the trading price for gas at Kern River Station is very close to the Topock price. In other words, Malin gas ends up getting delivered at the Topock price. CCC argues that even a generator located in northern California has difficulty obtaining gas at the Malin price, since gas consumers face a similar situation of congestion on PG&E's

[2] The 2000 California Gas Report (2000 CGR) is prepared by California gas utilities, with oversight by the CPUC and the California Energy Commission.

system. CCC notes that even the PG&E's city-gate market rate[3] is higher than the Malin price plus the tariffed transport rate. CCC's comments include two graphs showing various gas indices over the last 12 months. Topock and Malin tracked closely up until January 2001, when a sizeable gap opened up. For the first four months of 2001, PG&E's city-gate is shown to run approximately half-way between the prices at Malin and those at Topock.

CCC goes on to discuss some of the legal aspects of QF pricing. "Avoided costs must be set to reflect the actual costs that are avoided by QF power, not the Commission's or Edison's beliefs and wishes for lower costs." (p.9) CCC notes that the FERC, in its March 9, 2001 order reviewing the rates charged for sales during January 2001 Stage 3 alerts, set $273 per MWh as a reasonable price threshold in these circumstances.

CCC then reviews various alternative SRAC options.

Production basin plus interstate transportation: CCC maintains that this approach does not comply with Section 390 (b). In addition, CCC argues that since the pipelines are fully subscribed, it is impossible to buy gas on a short-run basis, and therefore this also violates PURPA.

Other southern California border trading points: CCC notes that alternative trading points include North Needles (TransWestern), Wheeler Ridge (Kern River and Mojave), Kern River Station (PG&E). CCC explains that all of these trading points show prices virtually identical to those at Topock – there is only one southern California trading price – and that it has no objection to the Commission's using these other trading points instead of Topock for the SRAC.

SRAC based on long-term gas purchase agreements: The defunct Battin bill proposal (SB 47X) incorporated long-term contracts. CCC still supports these, as well as the concept of utility hedging arrangements, in which utilities purchase long-term gas supplies, sell to QFs at spot rates, and purchase QF power at an SRAC based on spot gas rates. Meanwhile,

[3] The city-gate price is the market price of gas delivered to customers in PG&E's service territory that is unloaded off of PG&E's backbone pipeline system.

ratepayers' liability would be based on long-term gas contracts. CCC notes that long-term deals require that the parties be credit-worthy – and the credit-worthiness of both the utilities and the QFs has been seriously degraded in recent months.

Repeal of P.U. Code Section 390: CCC discourages this option, as it would add uncertainty to QF pricing.

Phase in of new methodology: CCC encourages the Commission to return to an SRAC reflecting gas physically and financially available to QFs. CCC maintains that this will bring QFs back on line, and help to provide power through the difficult summer months.

CCC also attached to its comments a copy of the April 5, 2001 filing it had submitted to the FERC in which CCC requested that FERC initiate an enforcement action against the CPUC for alleged violations of PURPA resulting from the March 27 decision.

Calpine Corporation (Calpine):

Calpine argues that D.01-03-067 underestimates the cost of gas, and by so doing is forcing a great deal of QF power off the grid. An April 9, 2001 ISO news release is cited in which 3,000 MW of QF power are said to be offline due to financial concerns[4]. Calpine argues that Malin gas is unavailable except to those who secured long term capacity several years ago. Calpine notes that no shipper has been able to obtain firm capacity on PG&E's pipeline from Malin since 1998. Calpine maintains that there is no evidence which shows that any generator is able to meet its gas requirements solely through Malin. Calpine states that more than 50% of northern California gas comes from Topock, and so does almost all of southern California gas. Calpine explains that "because supplies at Malin are less expensive than at Topock, PG&E's pipelines that move gas south from Malin operate at full capacity."

[4] In response to data requests to the utilities, Energy Division has been provided a much smaller estimate of QF generation that is currently offline for economic or financial reasons: approximately 620 MW for PG&E, 320 MW for Edison, and 150 MW for SDG&E – totaling approximately 1,090 MW. In addition to QFs who are shut down, there may be other QFs who are producing at reduced levels.

Calpine cautions that the California Department of Water Resources (DWR) is purchasing power on the margin at rates far higher than prices paid to QFs. Calpine argues that by substituting gas prices from Malin simply because it is lower not only results in inaccurate avoided costs, but also ensures that gas-fired QFs cannot operate. Calpine also argues that alleging market abuse at Topock does not disqualify this index for avoided cost purposes.

Calpine strongly urges that the Commission return to an index based upon the Topock gas prices, arguing that this complies with P.U. Code Section 390 (b), comports with utility avoided cost principles of PURPA, and realistically represents the gas prices available to gas QFs operating in California.

<u>County of Los Angeles (Los Angeles):</u>

Los Angeles urges a return to an index based on Topock prices, claiming that other prices do not reflect prices that are actually physically and financially available to the county. Los Angeles explains that it currently has a firm contract with Williams Natural Gas to take all of its gas needs at the Topock index. This contract extends until November 2001. Los Angeles expects to lose $3.5 million as a result of D.01-03-067. Even after the County is freed of this contractual obligation, it believes the Topock index reflects prices it will be able to secure.

Los Angeles also criticizes the alternative of basing SRAC on a production basin price plus interstate transportation. With a San Juan basin price of $4.60 / MMBtu and interstate firm transportation cost of about $0.50 / MMBtu, the result would be even more disadvantageous than Malin.

<u>Department of the Navy (DON):</u>

DON's comments were accompanied by a Motion to Intervene in R.99-11-022. In its comments, DON explains that its facilities in the San Diego area purchase steam energy under a contract with Sithe Energies, Inc. Normally, DON obtains steam from several QFs who also sell their electricity to SDG&E under SO4 contracts. Following March 27, 2001, Sithe has notified DON that it is discontinuing the production of steam and electricity at the QFs that are affected by D.01-03-067. For the time being, Sithe is producing steam for DON from fossil fuel-fired boilers. DON explains that for environmental reasons these boilers are constrained to operate only 10% of the hours of the year (i.e., 876 hours). Since the boilers commenced operation on April 1, they will no longer be permitted to operate after early May. DON believes that with its QF-based steam supply unavailable as a result of the March 27 decision's SRAC policy, and the boilers constrained by environmental regulations, the steam supply to critical defense facilities in San Diego will be jeopardized.

Office of Ratepayer Advocates (ORA):

ORA maintains that the three criteria which should guide the Commission's thinking as it determines the SRAC are: (1) PURPA's requirement that it reflect the utilities' short run avoided cost, be just and reasonable, and not discriminate against QFs; (2) the requirement in P.U. Code Section 390 (b) that SRAC be based upon a current average California border price; and (3) the need for any gas index to reflect a robust market, as ordered in D.96-12-028.[5]

ORA notes that QFs are, for the most part, base load power. For this reason, various potential indexes which would meet PURPA's avoided cost criteria are the DWR long-term (five or ten year) power contracts, the utilities' long term bilateral power deals, and the forward contracts from the PX's Block Forward Market (BFM). ORA suggests that the Commission could offer QFs an alternative pricing option based on the utilities' purchases from other sources.

ORA examines the language of P.U. Code Section 390 (b) which requires that SRAC be based on "current California natural gas border price indices." ORA opines that this can be read narrowly (gas purchased at the border) or liberally (gas delivered to the border).

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[5] D.96-12-028 emphasized the importance of robustness in choosing gas indices (sections 5.2 and 5.4).

Favoring a liberal reading of the statute language, ORA proposes several options for consideration, including the Southern California Gas Company (SoCalGas) Weighted Average Cost of Gas[6] (WACOG), and several production basin possibilities.

ORA concludes by arguing that the QFs are in the best position to determine the actual physical and financial availability of gas arrangements to them. The onus lies on the QFs to file declarations (confidential, if desired) as to their individual gas arrangements.

Pacific Gas and Electric (PG&E):

PG&E notes in its preliminary comments that proposed legislation in Sacramento (ABX 66, introduced by Assemblyman Fred Keeley) could soon result in the repeal of P.U. Code Section 390. PG&E suggested that perhaps the workshop could be postponed until more was known of the future of Section 390.[7]

In the short run, PG&E supports replacing Topock indices with Malin, but with the caveat that the intrastate transport rate should be removed from the SRAC calculation. PG&E argues that the use of this tariff implies transporting gas from Malin, down to the SoCalGas border, and then back.[8]

PG&E considers that use of any border index, be it Topock or Malin, is in the long run imprudent, given their exposure to market conditions which may render them unsuitable for SRAC purposes. PG&E recommends, for the circumstance in which Section 390 does not hold, the use of DWR average purchase price, provided these are adjusted to arrive at an energy-only price.

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[6] This is the cost of gas which SoCalGas buys for its customers.

[7] As of April 26, 2001, the status of this bill was inactive.

[8] A reading of PG&E's tariff G-AAOFF shows that this tariff covers the transport cost for gas taken at one of several entry points, among which is Malin, and delivered to customers located along PG&E's main "backbone" pipeline system.

San Diego Gas & Electric (SDG&E):

SDG&E agrees with D.01-03-067 that "Topock indices no longer reflect a 'robust market'… as evidenced by the increase in the price of natural gas delivered at Topock, and a growing differential between that price and the wellhead price of gas."[9] However, SDG&E is concerned by how San Diego QFs have reacted to the decision. SDG&E believes that many QFs have gas contracts that tie their gas costs to the Topock indices, and therefore cannot cover their operating costs if SRAC is based on the Malin indices.

SDG&E reports that two of its largest QFs have shut down and informed the utility they will not return to service until further notice. These QFs have stated that their shutdowns are due to the differential in gas prices between Malin and their cost of gas, which is based on Topock. "Both Sithe Energy (three plants totaling 101.5 MW of firm capacity) and Goal Line (one plant for 49.9 MW firm capacity) have shut down for 'economic reasons', resulting in a loss of more than 151 MW of firm capacity to California." (p.2) SDG&E indicates that this represents about 6% percent of SDG&E's current peak load. The QFs have indicated to SDG&E that they cannot purchase gas at Malin due to transportation constraints on the gas, and that their gas costs are based on Topock prices.

SDG&E is extremely concerned about its QF outages, and encourages the Commission to arrive quickly at a new and equitable long-term gas index, while keeping in mind that any prices for power, to the degree those prices are above the 6.5 cent/kWh rate cap, further expose SDG&E customers to undercollections. SDG&E believes that any solutions must address both concerns.

Southern California Edison Company (Edison):

Edison notes that the essential legal analysis mandated by PURPA requires that the CPUC focus on the utility's avoided cost, not the QFs' variable operating cost. Edison

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[9] The Enerfax energy news service report for May 1, 2001 showed an El Paso San Juan price of $4.62/MMBtu while the California Border price (southern California) was $14.50.

therefore agrees with D.01-03-067 that "QFs have never been absolutely entitled to a payment to cover their operating costs." (p.3) Edison also notes that there is little record evidence that QFs actually buy gas at Topock. Edison maintains that the use of Malin indices are preferable to those at Topock, but agrees with the decision's caution that reliance upon any spot market can lead to volatility in prices.

Edison notes that previous recommendations to the Commission with respect to SRAC – for example, production basin plus tariffed transport rate, or SoCalGas's WACOG – were rejected for reasons that they violated Section 390 (b). Edison suggests that a liberal reading of Section 390 (b) would allow these alternatives.

Edison lists several policy guidelines which it believes should inform Commission policy with respect to SRAC. These principles include: utility avoided cost principles as mandated by PURPA, recognition that where a legal conflict exists Federal law supercedes state law (i.e., PURPA supercedes Section 390 (b)), legal irrelevancy of QF operating costs, skepticism that spot gas prices are representative of utility avoided costs, and belief that a prudent gas buyer would contract for long-term transportation. Edison also holds that the WACAG is a reasonable substitute for Edison's avoided fuel costs, being both consistent with the company's historical practice, and subject to on-going reasonableness review. Finally, Edison suggests that as an expedient mechanism to ensure that gas-fired QFs stay on line the Commission authorize a "parity adjustment". This would be made available on an interim basis and subject to substantiation by the QF of need.

<u>Tractebel Power, Inc. and Tractebel Energy Marketing, Inc. (Tractebel):</u>

Tractebel maintains that Malin gas is not reasonably available to southern California QFs. Tractebel says that this prevents QFs from recovering operating costs, and discourages QF production. "In view of the current level of demand on the PG&E backbone gas transportation system, and in view of the fact that upstream PGT interstate pipeline capacity is fully subscribed, it is not possible for QFs in southern California physically – or financially – to deliver gas to southern California, through Malin, at a Malin border price plus tariffed PG&E transportation." (p.2)

Tractebel requests the Commission not undertake a review of what kind of gas procurement arrangements – such as entering into long term gas transport contracts – the QFs should have entered in years past.

Tractebel criticizes the Malin-based SRAC, as well as the proposal to base SRAC on production basin indices plus interstate transport, as being unavailable and unattainable to QFs as well as to Edison. Tractebel maintains that the Topock index is the most reliable measure of the market price of gas at delivery points into SoCalGas's system. Tractebel notes that the FERC used the Topock price in calculating a "just and reasonable marginal production cost for energy sellers bidding into the ISO market." Tractebel argues that, regardless of whether parties have engaged in market manipulation with respect to interstate transportation, QFs and other noncore end-users are paying the prices reflected at the Topock border.

Tractebel intends to remain open to alternative approaches to the SRAC gas index, but maintains that one key criterion must be that QFs should have a practical opportunity to purchase gas at the price that is included in the SRAC formula. For example, if a new SRAC is to be based upon a forward gas price, Tractebel advocates that the Commission must provide QFs with a reasonable opportunity to enter into similar long-term contracts. Commission policy should also recognize that QFs may currently be under long-term contractual constraints. Consequently, Tractebel urges that any change to SRAC provide a sufficient notice or phase-in period.

The Workshop

The workshop was held on April 19, 2001 in the Training Room at the CPUC at 505 Van Ness Avenue in San Francisco. It began at 9:30 a.m. and ended at 4 p.m. Approximately 40 persons participated. Following introductory remarks by the moderator, Energy Division's James Loewen, Cogeneration Association of California (CAC) representative Michael Alcantar expressed CAC's position that by participating in this workshop, CAC in no way waived its right to challenge the legality of D.01-03-067. Following a short discussion, it was agreed that all participants retained their right to challenge this proceeding, notwithstanding their presence at the workshop; indeed no participant's right to take any position was to be affected by their presence.

Gas Transportation Logistics:

CCC's pre-workshop comments had been particularly detailed and helpful in describing the network of pipelines in California as well as the difficulties it believed QFs were faced with in procuring gas. Consequently, CCC witness Tom Beach had been invited to make a presentation to the group. Since Mr. Beach had fallen ill and was not available, his colleague, Patrick McGuire made the presentation. Essentially, the presentation followed the lines of CCC's comments. Mr. McGuire related that PG&E's Redwood Path pipeline, which connects Malin (California / Oregon border) in the north to Kern River Station (PG&E / SoCalGas border) in the south, had been fully subscribed as of 1998 and would remain so until 2002 (one participant later noted that this should be until 2003). In response to a question asking clarification about Kern River and Kern River Station, Mr. McGuire explained that the former is an interstate pipeline, whereas the latter is a trading point located inside California.

Mr. McGuire's presentation next addressed the historical behavior of various gas indices. In addition to the price data distributed by Mr. McGuire (see Appendix E for copies of his presentation), data which had been compiled by Edison's Eric Lavik for Energy Division the day before the workshop (see Appendix F) were also handed out. From these data several observations were made. First, the various southern California indices – Topock (El Paso), North Needles (Transwestern), Kern River Station (PG&E), Blythe (El Paso) have historically and even now continue to track each other very closely. Second, Malin often has tracked the southern California indices closely, but in recent months has been significantly cheaper than Topock. Third, PG&E's city-gate price in recent months has been approximately half-way between Malin and the southern California price.

There was some discussion as to why the Malin price should recently have diverged from the Topock price. Mr. McGuire opined that this was due to congestion on the

Redwood Path pipeline, as well as to increased price differentials between the production basins which respectively feed Malin and Topock (e.g., Alberta and the San Juan basin).

Mr. McGuire was asked to explain how consumers located in, say, southern California, would go about procuring transportation for gas which they bought at Malin. He explained that there is a secondary transportation market – those parties who secured firm transportation rights in 1998 now are in a position to charge other parties for the right to transport gas through the pipeline. The amount which they can charge for transportation is effectively set by the price differential in the gas market between Malin and southern California. In this way, even if a customer succeeds in buying gas at Malin, once he has paid for transportation to southern California, the effective price would be the Topock price. This of course assumes that the customer has no pre-existing arrangements to procure or transport gas.

Mr. McGuire also asserted that the same difficulty arose for customers located in PG&E's territory. Transporting gas from Malin to any location in PG&E territory still requires use of PG&E's congested backbone pipeline system, and hence will cost more than the Malin plus tariffed transport rate.

Richard Myers of Energy Division pointed out that there is a substantial price difference between the Topock price index for PG&E and the Topock price index for SoCalGas. In other words, customers in PG&E territory who are buying gas at Topock are able to secure cheaper gas than customers in SoCalGas territory who are buying gas at Topock.[10] This observation does cast the PG&E QF situation in a different light. One element of uncertainty here regards liquidity – how big are the volumes being moved out of Topock into PG&E territory at this lower price?

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[10] Data compiled by Energy Division for the past several months shows the PG&E-Topock price averaging close to the PG&E city-gate price, i.e., higher than Malin and lower than SoCalGas-Topock.

Seeking to get some consensus regarding at least one factual matter, the moderator asked if any of the participants were willing to assert that a southern California QF (or any electric generator, or any non-core customer for that matter) who did not have pre-existing gas procurement and transportation arrangements could buy and transport gas at a Malin plus tariffed transportation price. No one was willing to make this assertion. Next, participants were asked about generators located in northern California, with the same response.[11]

[11] Parties have not objected to the 50% Malin portion of the pre-March 27 SRAC for PG&E's QFs. One reason may be that since that SRAC was established in 1996, generators have had ample time to secure long-term transportation arrangements.

QF Operating Costs:

Seeing as the SRAC level is only one of the factors determining the economics of QF operations, the moderator listed several other factors which come into play – previous gas arrangements, capacity payment levels, heat rates, and, for cogenerators, the commercial value of byproduct heat. Participants were asked for their thoughts about these factors. CAC's Alcantar argued that consideration of these factors is illegal since doing so would violate PURPA's mandate to focus on the utility's avoided costs instead of on the QFs operating costs. Lars Bergmann of Edison supported Mr. Alcantar's contention, saying that QF operating costs are not relevant to this proceeding. He stated that he is not seeking declarations from QFs regarding their operating costs. Indeed, no QF volunteered to declare its operating costs.

Mr. Alcantar offered that his clients would be happy to have the state, or the utility, supply gas to them. Other QFs expressed common sentiments. Mr. Bergmann responded that Edison did not have the obligation to purchase gas for the QFs.

Aside: Importance of Back Payments in QF Non-Performance:

Part of the context for this workshop is the fact that some QFs are currently offline for economic reasons. QFs have stated in other forums that low SRAC payments are not the only factor in the decision to shut down. In addition, the fact that most had not been paid for several months prior to March 27, 2001 was said to jeopardize their own cash flow and credit status, making it difficult to buy fuel. Participants were asked which factor was more important in their decision not to generate – the back payments or the SRAC.

Responses to this question were mixed. Some QFs said the matter of back payments was more important, while others said that the going-forward SRAC payments were more important. Edison said that prior to D.01-03-067 (which ordered the utilities to resume QF payments and altered the SRAC) it had about 700 MW of QFs offline for economic reasons; since the decision, it has had only 225 MW offline (of these, 145 MW are paid the Malin-based SRAC, while 80 MW have special contracts with energy payments based on Topock).

Tractebel explained that it generated until March 27, so clearly its determining factor was the SRAC level. CCC and CAC say that for them the back payments are a stronger factor.

<u>Alternatives – Given Section 390 (b):</u>

Participants were asked to list all of the possible ways that a gas index for SRAC could be obtained. Below are listed the alternatives mentioned by participants, along with their comments.

Status quo (post-March 27): Since reactions to and analyses of D.01-03-067 were fairly fully articulated in pre-workshop comments, it was decided not to spend too much workshop time further discussing this approach. In the short discussion of this approach that did take place, CAC mentioned its several objections to the March 27 decision, among which is the gas index determination. Edison acknowledged that under the current SRAC, QFs who do not have prior arrangements for transport are unable to supply gas at the Malin price. And SDG&E stated that it is not in favor of the current SRAC mechanism.

Pre-March 27 SRAC: Several features of the pre-March 27 SRAC were noted. First, QFs were able to cover their gas purchase costs, as there existed a real linkage between gas spot prices which generators faced and the SRAC payment level. Second, it eliminated / managed the risk faced by QFs with respect to purchasing gas. Third, as Topock prices rose much higher than Malin in recent months, the pre-March 27 methodology resulted in significantly higher SRAC payment levels than SRACs based on Malin. Fourth, if SRAC were based on Topock then the SRAC would reflect the market distortions which are alleged to be occurring on the interstate transportation market which feeds into Topock.

Production basin plus tariffed interstate transport rate: Participants noted that this proposal is probably in conflict with Section 390 (b). One participant said that this proposal has the advantage that it avoids the interstate pipeline problem. CAC responded that it simply ignores the problem. One participant said this approach would result in a mismatch, since California buyers cannot obtain basin gas to the extent that they do not hold interstate transportation rights. The issue of credit was also raised here, inasmuch as long term firm rights purchases require credit-worthiness.

Basing SRAC on multiple indices from southern and northern California: It was pointed out that if, for example for Edison, multiple indices from southern California were used, this would result in an SRAC very close to a Topock-based SRAC, since all of the southern California gas prices historically have tracked closely. One participant argued that instead of the average of various indices, marginal cost pricing should properly be set at the highest index.

Incremental cost in the electric market: It was pointed out that this approach was difficult to reconcile with Section 390 (b). On the plus side, it did present itself as a good candidate with respect to PURPA's avoided cost criteria.

Edison's previously proposed mix of 90% WACOG and 10% border: Again, the difficulty of allowing this proposal under Section 390 (b) was noted. QFs complained that the WACOG is not available to them, but Edison argued that this is irrelevant for SRAC purposes. One participant said that the WACOG has the favorable quality of reflecting the buying behavior of an intelligent, self-interested buyer.

Topock, as justified by recent FERC order: In 94 FERC 61,245, FERC describes the Topock, Daggett, Blythe, Needles, and Ehrenberg as the most liquid trading points in southern California. The FERC consequently used the Topock price in its calculation of a "just and reasonable" marginal production cost. Various parties have pointed toward the FERC's opinion in bolstering their support for Topock.

Edison's bridging proposal for differential payments: In its written comments, Edison had proposed that the Commission allow a short-term differential in SRAC payments between gas-fired and non-gas-fired QFs. CCC noted that this idea runs counter to the economic ideal of having one market price. At least one participant pointed out that this might conflict with PURPA, which does not provide for differential payments, except when based upon differential of supply characteristics. Some participants responded to this argument with the observation that QF contracts already displayed considerable variation, including firm and fixed capacity options, and various energy payment and capacity payment options. It was further observed that to the degree that the parties to the purchased power agreements (PPAs), namely the QF generators and the utilities, agreed mutually on contract modifications, PURPA restrictions would be avoided.

Use of forward prices associated with border points: One weakness of this approach is the lack of published indices.

<u>Alternatives – If Section 390 (b) Were Repealed:</u>

Participants were asked to list all of the alternatives for an SRAC, should Section 390 (b) no longer constrain the Commission. It should be noted that all of the proposals listed in the previous section fit under this section as well. Below are listed the additional alternatives mentioned by participants, along with their comments.

DWR spot electricity purchases: The main advantage of this approach is that it arguably represents the incremental price of electricity in California (see Finding of Fact #9 of D.01-03-067). One drawback of this approach is that there is a lack of transparency, and thus a lack of knowledge, regarding DWR's power procurement process. The moderator mentioned that, for practical purposes, this number, reportedly in the range of $300/MWh, is extremely high.

DWR long term power purchases: As with the DWR spot purchase proposal, a weakness in this approach is a lack of transparency in DWR's process, including uncertainty about the length of the contract term and uncertainty about how cost averaging was conducted, i.e., whether the numbers provided to the public are simple or weighted averages. Another criticism is that, as a long-term purchase, it is difficult to see how this fits the description of "short run avoided cost."

ISO real-time power purchases: As with the DWR spot electricity proposal, an advantage here is that it arguably represents the incremental power price faced by California utilities. And it, too, suffers the practical drawback of being extremely expensive. Another criticism leveled against this proposal is that, because of price caps in the real-time market, the price signal is distorted. In addition, there may be some inconsistency with respect to FERC market mitigation policies.

Edison pointed out that for the previous three proposals, it would be necessary to remove their embedded capacity component in order to arrive at an SRAC. Douglas Kerner of the Independent Energy Producers Association (IEP) suggested that the removed capacity component could then be used for the as-available capacity payments to QFs. SDG&E's Vince Bartolomucci qualified this, pointing out that the DWR long-term contracts represent firm deliveries.

Forward gas prices: As with the other long-term proposals, this one is problematical for an application to short-run avoided costs. Also, the over-the-counter market is not published. And, when a QF chooses to buy long-term, then credit comes into play (admittedly, this is a practical consideration, and not strictly related to PURPA compliance).

Utility forward electricity prices: As with other electricity market options, a complication associated with this one involves the need to identify and remove the part of the electric price associated with capacity in order to arrive at an SRAC. As with other long-term proposals, a practical consideration is the fact that the QF would need to be in a solid credit-worthy position. Another implementation consideration is that there would need to be a standard procedure to quantify, for purposes of determining SRAC, the variable features of forward contracts, such as performance requirements and tolling agreements.

Utilities purchase gas and sell it to QFs at cost: From the QF perspective, an advantage of this approach is that it removes the risk associated with fuel procurement. The utilities responded that they might be interested in this approach if there were included some kind of reward-and-penalty mechanism that would encourage utilities to buy gas cheaply. One participant noted that if all the utilities were to go out and try to enter into long-term gas deals for their QFs, it could cause a bump in the price, and therefore a phase-in period was indicated.

QFs' actual gas purchase costs: One QF participant advocated this approach, with the understanding that QFs act jointly and pool resources in their purchases. From the QFs' perspective, an advantage of this approach is that it eliminates their gas purchase risk, but a disadvantage is that QFs are not eager to have their business expenses audited. From the ratepayer perspective, a drawback here is the apparent lack of any cost control incentive.

Key Findings

The workshop resulted in consensus that electric generators located in southern California who have not previously made procurement and transportation arrangements cannot buy and transport gas at a price equal to the Malin spot price plus the intrastate firm transport rate.[12] While the problem is decidedly less severe for generators in PG&E service territory, the same holds true for electric generators located in northern California.

At the same time, whether a given QF does or does not have in place such prior arrangements is largely a matter of conjecture. However, several parties, Edison included, stated that examining QFs' operating costs is irrelevant to the proper determination of the SRAC.

To assist gas-burning QFs cover operating costs, Edison supports the use of a payment scheme in which gas-fired QFs will be paid more than non-gas-fired QFs on an interim basis. While PURPA prohibits differential QF payments, participants pointed out that when both contract parties are in agreement, PURPA no longer constrains.

SDG&E believes that the use of the Malin index is responsible for the decision of two of its QFs to shut down. These total over 150 MW of firm capacity.

Data compiled by different participants and distributed at the workshop seem to indicate that very little price differential exists or has existed historically among the various southern California trading points, including Topock.

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[12] The Enerfax energy news service report for May 1, 2001 showed a significant gap between the southern California border price ($14.50 / MMBtu) and the border price at Malin ($7.80 / MMBtu). PG&E's gas transportation tariff G-AAOFF is $0.42 / MMBtu.

CERTIFICATE OF SERVICE

I certify that I have by mail this day served a true copy of the original attached Final Report on Workshop to Discuss Alternative Gas Indices on all parties of record in this proceeding or their attorneys of record. In addition, service was also performed by electronic mail.

Dated May 1, 2001, at San Francisco, California.

James Loewen

N O T I C E

Parties should notify the Process Office, Public Utilities Commission, 505 Van Ness Avenue, Room 2000, San Francisco, CA 94102, of any change of address to insure that they continue to receive documents. You must indicate the proceeding number on the service list on which your name appears.

List of Appendices