attach to Resolution

STATE OF CALIFORNIA

PETE WILSON, Governor

PUBLIC UTILITIES COMMISSION
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3298

April 30, 1991

Resolution No. G-2946

Southern California Gas Company
P.O. Box 3249 Terminal Annex
Los Angeles, CA 90051

Attn: Nancy I. Day
Vice President
Regulatory Affairs

Dear Ms. Day:

An error has come to my attention regarding Resolution G-2946 concerning the revised cogeneration Rate Schedules GN-50 and GT-50. Please be advised that the following correction is now attached to the Resolution and is effective as of the resolution date, April 24, 1991.

Text on page 2, middle of paragraph four reads:

> "The difference in gas and oil consumption (in Btus) between the two runs (QFs-out minus QFs-in) is divided by the amount of cogeneration QF production (in Kwh)."

The correct language is:

> "The difference in gas and oil consumption (in Btus) between the two runs (QFs-out minus QFs-in) is divided by the change in total energy production by oil- and gas-fired plants (in Kwh)."

Copies of this correction will be forwarded to the service list attached to Advice Letter 1991, as authorized by Resolution A-4661.

Yours truly,

Neal J. Shulman

NEAL J. SHULMAN
Executive Director

PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Commission Advisory and
Compliance Division

RESOLUTION G-2946
April 24, 1991

R E S O L U T I O N

RESOLUTION G-2946. Southern California Gas Company submits revised cogeneration Rate Schedules GN-50 and GT-50 to include the average annual incremental heat rate for each of the electric utilities in SoCal's service territory.

BY ADVICE LETTER 1991, FILED ON NOVEMBER 13, 1990.

SUMMARY

1. By Advice Letter 1991, Southern California Gas Company (SoCal) submitted changes to its cogeneration Rate Schedules GN-50 and GT-50 to comply with Decision (D.) 90-09-043. That decision ordered SoCal to revise its cogeneration tariffs to reflect the use of an average annual incremental heat rate (IHR) in calculating the cogeneration gas allowance.

2. This Resolution approves Advice Letter 1991, with modifications.

BACKGROUND

1. Public Utilities Code (Code) Section 454.4 states:

> The Commission shall establish rates for gas which is utilized in cogeneration technology projects not higher than the rates established for gas utilized as fuel by an electric plant in the generation of electricity, except that this rate shall apply only to that quantity of gas which an electric corporation serving the area where a cogeneration technology project is located, or an equivalent area, would require in the generation of an equivalent amount of electricity based on the corporation's average annual incremental heat rate and reasonable transmission losses or that quantity of gas actually consumed by the cogeneration technology project in the sequential production of electricity and steam, heat, or useful work, whichever is the lower quantity.

2. Section 454.4 requires that gas utilities offer cogenerators the same gas rates offered to utility electric generation (UEG)

customers. This "parity" rate is offered to cogenerators only for that amount of gas the UEG would have required to generate the amount of electricity produced by the cogenerators. This amount is known as the cogeneration gas allowance (CGA), and provides cogenerators with a discounted rate for gas transportation only to the extent that cogenerators' productivity is superior to that of UEGs.

3. D. 90-09-043 examined two methods for calculating the CGA: the IHR and the incremental energy rate (IER). The IHR, expressed in British thermal units (Btus) per kilowatt-hour (Kwh), is a measurement of the efficiency of a UEG unit burning gas or oil. The IER, also in Btus per Kwh, is a mathematically derived expression of the efficiency of all electric resources on the margin during a forecast period. The Decision found that the IER was the more appropriate measurement of UEG fuel efficiency, but that the Code requires the use of the IHR to calculate the CGA. Therefore, the Commission ordered SoCal to submit revised cogeneration gas schedules reflecting the use of the IHR. The Decision provided no guidance on the proper method for calculating an IHR for an entire UEG system.

4. On November 13, 1990, SoCal submitted Advice Letter 1991, with revised cogeneration gas schedules reflecting the use of an annual average IHR for each of the electric utilities in SoCal's service territory. SoCal's method uses outputs from the final production cost model run in each regulated utility's Energy Cost Adjustment Clause proceeding (ECAC). First, it identifies the total amount of gas and oil consumed when all qualifying facilities (QFs) are on-line. Next, gas- and oil-fired cogeneration QFs are removed from the simulation, resulting in additional production from other resources. The difference in gas and oil consumption (in Btus) between the two runs (QFs-out minus QFs-in) is divided by the amount of cogeneration QF production (in Kwh). The IHRs were then adjusted by the average transmission line losses to arrive at the CGA, in therms per Kwh. A similar method was applied to the unregulated utilities in SoCal's territory. Since the municipal utilities are not subject to ECAC proceedings, SoCal performs the production cost model runs with and without cogeneration using a database conforming to the adopted forecast from the most recent SoCal Annual Cost Allocation Proceeding (ACAP), or from the forecast developed for each municipality in the California Gas Report in a year between ACAPs.

5. SoCal implemented the revised cogeneration tariffs on November 13, 1990, because they believed Advice Letter 1991 was a compliance filing.

NOTICE

1. Advice Letter 1991 appeared on the Commission Calendar on November 15, 1990. Copies of the Advice Letter were sent to all parties of record in A.88-12-047 and to those on SoCal's distribution list.

PROTESTS AND RESPONSES

1. Southern California Edison (Edison) and Pacific Gas and Electric (PG&E) submitted timely protests to AL 1991. Edison also submitted a supplemental protest. International Power Technology (IPT) submitted a late protest, and San Diego Gas and Electric (SDG&E) and the California Cogeneration Council (CCC) submitted comments on the advice letter. Issues raised in the protests, and SoCal's responses, are as follows:

Edison's Protest:

1. Proposed Schedule GN-50 would base cogeneration transportation rates on average UEG transportation rates lagged two months. Decision 90-01-015, from SoCal's ACAP, required the use of a forecast average UEG transportation rate to compute the cogeneration rate. Therefore, GN-50 should use a forecast UEG rate.

2. Edison claimed that SoCal's method of calculating the IHR, based on production cost model runs adopted in electric utility ECAC proceedings, is unduly complex and does not appear to be methodologically sound. Edison recommended an alternative method using "system lamdas", that is, recorded hourly IHR values from all marginal generating units. Edison's method would average the recorded IHR values over all hours in the year regardless of whether oil or gas is on the margin.

3. SoCal assumed that a barrel of fuel oil has a heat content of 6.6 thousand Btu (MMBtu). Edison stated that a value of 6.1 MMBtu would more accurately reflect the heat content of the low sulfur fuel oil purchased by Edison.

4. Edison stated that SoCal used average transmission line losses to compute the IHR. Since electricity production by cogenerators avoids incremental transmission line losses, an incremental value should be used instead of an average value.

PG&E's Protest:

1. PG&E argued that SoCal's method produced an average heat rate, rather than an incremental heat rate. According to PG&E, SoCal's IHR is actually an average because it reflects the average of a block of fuel (Btus) and a block of generation (Kwh). SoCal's approach assumes that fossil units are the marginal units at all times, but in PG&E's 1990 ECAC, fossil units were at the margin 41% of the time over the forecast period.

2. SoCal used an average line loss factor taken from the California Energy Commission's "Electricity Supply Planning Assumptions Report," April 1990. PG&E stated that this use of the line loss factor is inappropriate because the loads used in the production cost model runs already include transmission losses.

3. PG&E was concerned that this filing would result in the determination of an annual average IHR for PG&E without public notice and hearings on the correct methodology. D.90-09-043 provided no guidance on the method for calculating the IHR, but required that it be calculated using incremental values. PG&E claimed that if the production cost model runs were adjusted to reflect the time that oil and gas were actually on the margin, PG&E's IHR would be 4,100 Btu/Kwh, rather than the 11,300 Btu/Kwh submitted in SoCal's advice letter.

<u>SoCal's Response to Edison and PG&E</u>:

1. SoCal stated that its IHR method is that which Edison advocated in it's ECAC proceeding, and from the perspective of the regulated utilities, it is simple to use because the production cost modeling issues and assumptions have already been litigated in the ECAC.

2. Regarding the oil conversion factor, SoCal stated that the 6.6 MMBtu/barrel figure was used because it was appropriate to SoCal's use of PG&E as an example.

3. SoCal stated that it has used an average line loss factor for some time, and that no party raised the issue during the course of the hearings leading to D.90-09-043. SoCal referred to Code Section 454.4, which states that "reasonable line losses" should be included.

4. SoCal responded that Section 454.4 of the Code requires an <u>average</u> incremental heat rate, so some averaging must take place in calculating the IHR. According to SoCal, one could use PG&E's logic to argue that the IER is not incremental, but an average energy rate, since it is determined from an average cost per kilowatt-hour. SoCal stated that its methodology was no less incremental than the IER. In SoCal's method, the IHR is the change in the thermal requirements of the gas and oil facilities divided by the change in output of the fossil units as a result of the QF energy contribution. There is no assumption that the fossil units are on the margin at all times, as PG&E suggests.

<u>IPT's Protest</u>:

1. IPT protested changes made to Special Condition 11 of Schedule GT-50, stating that the language gives the utility direct access to proprietary information affecting the competitiveness of the QF.

<u>SoCal's Response</u>:

2. SoCal clarified that no changes were made to the special conditions in GN-50 or GT-50 that address utility access to electric meters on a customer's property. Advice Letter 1991 simply deleted old Special Condition No. 10 and renumbered the remaining special conditions. No text changes were made to the special conditions.

Edison's Supplemental Protest:

1. Edison asserted that recorded IHR values are more appropriate for calculating the IHR than SoCal's method because recorded values reflect the IHR averaged over all hours in the year regardless of whether oil or gas resources are marginal for each hour. According to Edison, SoCal's method omits those hours of the forecast period when oil or gas resources are not on the margin, and its results are potentially based on a single hour when oil or gas resources are on the margin. Edison claims that this method tends to bias the average annual IHR upward.

2. SoCal did not respond to the supplemental protest.

SDG&E's Comments:

1. SDG&E argues that SoCal's method is not a thermal heat rate, but like the IER, includes heat rates in addition to many other inputs to calculate the IHR. SDG&E states that the Commission rejected the use of production cost model estimates of system efficiency in D.90-09-043, and required the use of actual incremental heat rates, not derived factors (SDG&E's emphasis). According to SDG&E, SoCal's IHR relies on estimates of system production costs transmuted into fuel use estimates, and therefore fails to satisfy the requirements of D.90-09-043.

2. SDG&E claims that the line loss figures from the California Energy Commission's report include both distribution and transmission losses, and therefore overstate the appropriate line loss adjustment. In addition, SDG&E states that there is substantial logic to using marginal losses, because the objective of the cogeneration gas allowance is to compute the cost to produce an incremental kilowatt-hour, which is why incremental heat rates rather than average heat rates are used.

3. SDG&E proposed a method for calculating the IHR that requires creating a system-wide input-output curve for fossil generation, whose first derivative is the system IHR. The actual system IHR is taken from the system heat rate curve at the point of the average fossil plant load. SDG&E believes that actual IHRs, derived in this way from input-output curves of the system's fossil plants, are necessary to capture the letter and the spirit of the directive of D.90-09-043.

SoCal's Response to SDG&E:

1. SoCal responded that SDG&E's has misrepresented and misunderstood SoCal's method. SoCal's method measures the change in total thermal requirements of gas and oil units and the change in gas and oil generation caused by taking QF energy. It represents the incremental change in thermal requirements directly, and is not derived, as SDG&E claimed. SoCal agreed that the Commission rejected the use of estimates of system efficiency, and stated that its method does not rely on transmuted production costs to derive fuel use estimates, but instead isolates the changes in thermal requirements brought about by the QF generation.

CCC's Comments:

1. The CCC supports the use of the IHR methodology used by SoCal. According to the CCC, a correct methodology must reflect the heat rate of the oil and gas units that would operate but for the presence of the QFs, as opposed to the heat rate of the marginal resources while QFs are on the system. The QF-in/QF-out methodology is used by the Commission to estimate the price of purchased QF power. Since the price the QF receives for its power is based on the cost of power production in the absence of QFs, the CCC states that it is appropriate to limit the amount of gas the QF may transport at a discounted rate to the amount of gas the utility would use to produce the equivalent power in the absence of QFs.

DISCUSSION

1. The cogeneration gas allowance was originally established in compliance with D.92792, dated March 17, 1981. The Decision stated that the cogeneration gas rate "shall apply to that amount of natural gas which the electric utility in that service territory would require to generate an equivalent amount of electricity." The limitation was established to tie the amount of gas qualifying for the cogeneration rate to the equivalent volume of gas a utility would have consumed to produce the same Kwh, thus relating the energy savings achieved to the fuel costs avoided by the UEG. The CGA is consistent with avoided cost principles. The gas allowance requirement was subsequently codified in Section 454.4 in 1984.

2. At the time D.92792 was issued, California utilities were generally burning gas at the margin to produce electricity, and therefore, the natural gas allowance was based on the average incremental heat rate of gas plants. Since that time, utilities no longer rely solely on gas or oil at the margin, and frequently use nuclear, hydropower, and purchased power on the margin. The IHR, which applies only to fossil generation, cannot measure the efficiency of such resources.

3. Resolution G-2738, issued October 16, 1987, approved PG&E's use of the IER to calculate its CGA. That resolution found that the IER was a reasonable measure of system efficiency on which to base the CGA. Since that time, D.90-09-043 found that the statute requires the use of an IHR to reflect the efficiency of fossil fueled generation only, but the decision only applies to SoCal. PG&E continues to use the IER to calculate its CGA.

4. Because D.90-09-043 did not specify which method should be used to calculate the IHR, it is reasonable to look to avoided cost principles and methodology for useful precedents.

5. To calculate avoided costs, the Commission has adopted the IER to measure the efficiency of all marginal resources and to account for the differences in system operation due to QF production. The IER is calculated annually during each utility's ECAC. The IER is not a heat rate, but is a mathematically derived expression of the efficiency of the electric system as it

produces an incremental unit of energy. Production cost model runs generate the estimated marginal energy and fuel costs for the forecast year. When the marginal energy cost (in $/Kwh) is divided by the average cost of the marginal fuel (in $/Btu), the result is the IER, in Btu/Kwh. To account for the costs that the utilities would incur to produce the equivalent amount of energy generated by the QFs, the production cost models run two simulations: with and without QF power. The two IER results are then averaged to produce the IER that is used to calculate avoided cost energy payments to QFs.

6. As discussed above, the Commission's avoided cost methodology uses a QF-in and QF-out approach to determine the utilities' avoided cost energy payments to QFs. QFs' energy payments are based on the purchasing electric utility's system-wide IER, which takes account of the costs the utility would incur but for the energy produced by the QFs. The QF-in and QF-out approach captures costs such as start-up, no-load running time, and other costs associated with a change in resource mix. Therefore, the increment measured by the IER is not just that of producing the marginal kilowatt-hour, but is the larger and necessary increment of energy that the utilities would have to produce but for the energy produced by QFs.

7. A production cost model run generates many outputs, in addition to the IER, including total thermal requirements and total output for the different generating resources. SoCal's IHR methodology calculates the difference in total thermal requirements for gas and oil plants between the QF-in and QF-out scenarios, and divides it by the change in total energy produced by the gas and oil units under the QF-in and QF-out scenarios. The result is an estimate of the efficiency of the oil and gas units if the entire system were to compensate for the energy produced by the QFs.

8. Two issues must be resolved in this filing: 1) the appropriate interpretation of the term "<u>incremental</u> heat rate" (emphasis added), and 2) whether the IHR should include efficiencies of non-fossil units.

9. The IER approach to evaluating system efficiency includes efficiencies of non-fossil units. This is because production cost model runs simulate the system's operation over the course of the forecast year, during which time non-fossil units will be on the margin. Edison's "system lamda" approach also includes non-fossil units, since it records the marginal costs and efficiencies of all units on the margin. D.90-09-043 clearly states that the IHR is the incremental heat rate of individual utility plants and measures the efficiency of their gas and oil use (Finding of Fact No. 4, page 12). This definition excludes the use of an IHR methodology that is not limited to fossil-fueled UEG plants.

10. Regarding the term "increment," SDG&E and Edison advocate an interpretation that bases the heat rate on the efficiency of marginal resources only. In other words, their use of the term "incremental" reflects the strict economic interpretation of

"marginal:" the additional resources necessary to produce the next unit of output. SoCal and the CCC, on the other hand, favor an interpretation that includes a much larger increment. They advocate basing the heat rate on the additional resources that the utility would need to produce the equivalent total amount of energy produced by QFs.

11. Basing the IHR on the efficiency of only the marginal resources is inappropriate for several reasons. First, the Commission rejected an IER approach to calculating the CGA in D.90-09-043. The Decision found that the current language in Code Section 454.4 requires that the gas allowance be based on fossil unit, not system-wide, efficiencies. Moreover, it cannot be assumed that fossil resources would be on the margin if cogenerator power were not available. Other, more cost effective resources would be dispatched first. Gas and oil resources would not replace cogeneration on a one-for-one basis. Since non-fossil resources are marginal, a heat rate cannot be used as an efficiency measure. Finally, a strict, marginal resource interpretation would contradict the Commission's avoided cost principles and methodology, which includes start-up costs and other costs that would be incurred by the utility to replace the total block of generation provided by QFs.

12. The Commission Advisory and Compliance Division (CACD) has reviewed each of the IHR methodologies proposed by the utilities, and appreciates the utilities' hard work and assistance in resolving this complicated issue. Given the Commission's approach to calculating avoided costs on the electric side, and the concept of cogeneration parity as expressed in Section 454.4 of the Code, CACD finds that the IHR should reflect the change in oil and gas unit operation absent the QFs.

13. Both Edison and SDG&E advocated using methodologies that would consider only marginal resources and would reflect the system's efficiency in generating the marginal kilowatt-hour. Edison's use of system lamda data would include non-fossil resources. Section 454.4 specifically states that the IHR must reflect that amount of <u>gas</u> the utility would require to produce an equivalent amount of power, and therefore excludes this type of approach. SDG&E's approach limits the IHR to fossil generation only, but does not account for start-up and other costs that the utility would incur in producing an <u>equivalent</u> total amount of power. PG&E did not propose a method for calculating the IHR, although PG&E continues to use the IER for calculating its CGA.

14. CACD concludes that SoCal's IHR methodology best fulfills the requirements of Section 454.4 and D.90-09-043, and is consistent with the Commission's avoided cost principles.

15. SDG&E and Edison claimed that D.90-09-043 required the use of actual, recorded values in computing the IHR. CACD has reviewed the Decision, and found that it refers in the text to the use of an "actual" incremental heat rate on page 4. But in the findings of fact and the ordering paragraphs, there is no

other reference to actual or recorded data that would lead to the conclusion that the IHR must be based on specific recorded data.

16. Edison pointed out that SoCal used the lagged average UEG rate to calculate the cogeneration rate in GN-50. D.90-01-015 required the use of a forecast average UEG transportation rate in calculating the cogeneration rate. SoCal complied with this requirement for GT-50, and should also apply the forecast method to the GN-50 schedule.

17. SoCal deleted Special Condition 10 of the GT-50 and GN-50 tariffs, and renumbered the remaining conditions. There was no change to the special condition that permits SoCal to monitor the cogenerators' electric output.

18. SoCal used a 6.6 MMBtu/barrel oil conversion factor in its IHR calculation example. Utilities use various grades of fuel oil in their generation facilities, and each grade has a different heat content. When calculating the IHR from production cost model data, if SoCal must convert from barrels of oil to Btus, SoCal should verify the type of fuel oil generally used by the utility to ensure that the appropriate conversion factor is applied.

19. Section 454.4 requires that the IHR be adjusted for "reasonable line losses." It fails to specify whether average or incremental transmission losses should be included. D.90-09-043 is silent on the subject, and Resolution G-2738 ordered PG&E to use a "transmission line loss rate" that was adopted in PG&E's ECAC.

20. PG&E argued that the application of a line loss factor is inappropriate because line losses are already accounted for in production cost model runs performed for an ECAC. CACD confirmed that this is the case. Therefore, SoCal's method for calculating the IHR does not require an adjustment to account for line losses because this would double count the line losses.

21. PG&E's argument about double counting raised an issue that directly affects its own calculation of the CGA. Resolution G-2738 authorized PG&E to use the IER and transmission line losses, both taken from ECAC proceedings, to calculate the CGA for its customers. If PG&E is using the IER and the transmission line loss factor, it is double counting the line losses.

22. CACD attempted to determine whether PG&E is using a line loss factor. Neither PG&E or SDG&E clearly specify in their cogeneration tariffs exactly how they calculate the CGA. PG&E and SDG&E should file revised cogeneration tariffs explicitly specifying the line losses and IER or IHR figures used to calculate the CGA. SDG&E and PG&E should follow the format used by SoCal in Advice Letter 1991, and include the IER or IHR, incremental or average line losses, if any, and the CGA. Further, both utilities should document the sources of the data used to calculate the CGA. CACD recommends these tariff changes at this time because PG&E and SDG&E themselves indicate, indirectly, the possible inadequacy of their own filed tariffs by

their comments on SoCal's filing. It is only fair to require PG&E and SDG&E's tariffs to be as clear as SoCal's.

23. To avoid possible confusion over the accuracy of the CGAs in the tariffs, SoCal, PG&E, and SDG&E should update their cogeneration tariffs to reflect the results of each regulated electric utility's most recent ECAC.

24. SoCal implemented the tariffs in Advice Letter 1991 prior to receiving the approval of this Commission. In most cases, Advice Letter 1991 reduced the CGA, which in turn increases the total costs of gas to cogenerators. To the extent that Advice Letter 1991 changed cogenerators' rates, SoCal should refund or back-bill any over- or under-collections that have occurred between November 13, 1990 and the effective date of this Resolution.

FINDINGS

1. The CGA relates the energy savings realized by cogenerators to the fuel costs avoided by the UEGs, and is consistent with avoided cost principles.

2. The CGA is required by Code Section 454.4.

3. The IHR cannot measure the efficiency of non-fossil resources.

4. Although Resolution G-2738 approved PG&E's use of the IER to calculate the CGA, D.90-09-043 requires SoCal to use an IHR.

5. Because there is no obvious or approved method for calculating a system-wide IHR, it is reasonable to look to avoided cost principles and methodology for useful precedents for calculating the IHR.

6. The IER, used to determine the utilities' avoided costs, estimates the efficiency of marginal resources after taking into account the costs the utility would incur to produce the total equivalent amount of energy produced by QFs.

7. The increment measured by the IER is the additional energy that the utilities would produce but for the energy produced by QFs.

8. SoCal's IHR methodology uses production cost model outputs to estimate the efficiency of a utility's oil and gas units if the entire utility system were to compensate for the energy produced by the QFs.

9. The protestants in this filing disagreed over whether the IHR should include non-fossil resources and the proper interpretation of the term "incremental heat rate."

10. CACD finds that the IHR should reflect the change in oil and gas generating unit operation absent the QFs.

11. Basing the IHR on the efficiency of marginal resources without accounting for the system's operation in the absence of QF generation would contradict the Commission's avoided cost principles and methodology.

12. The IHR methodologies proposed by Edison and SDG&E would consider only marginal resources.

13. SoCal's IHR methodology best fulfills the requirements of Section 454.4 and is consistent with the Commission's avoided cost principles.

14. D.90-09-043 does not require that the IHR be calculated from specific recorded data.

15. SoCal should use the forecast average UEG rate to calculate the rates in both GN-50 and GT-50.

16. Advice Letter 1991 proposes no change to the Special Condition that permits SoCal to monitor the cogenerators' electric output.

17. If SoCal must convert production cost model output from barrels to Btus, it should verify the type of oil generally used by each utility, and apply the appropriate conversion factor.

18. It is not clear whether incremental or average transmission line losses should be used to calculate the CGA.

19. Line losses are already accounted for in production cost model runs used in ECACs. Therefore, no additional line loss factor should be used when calculating the CGA with ECAC data.

20. If PG&E is using the IER and a line loss factor to calculate the CGA, it is double counting the line losses.

21. PG&E and SDG&E should file revised cogeneration tariffs to clarify the figures and the method used to calculate the CGA. Both utilities should follow the format used by SoCal in Advice Letter 1991, and should document the origin of data used to calculate the CGA.

22. SoCal, PG&E, and SDG&E should update their CGAs to reflect the results of each electric utility's most recent ECAC.

23. To the extent that Advice Letter 1991 increased or reduced cogenerators' rates, SoCal should refund or back-bill any over- or under-collections that have occurred between November 13, 1990 and the effective date of this Resolution.

THEREFORE, IT IS ORDERED that:

1. Southern California Gas Company's methodology for calculating the IHR is approved.

2. Southern California Gas Company should submit, within 6 days, corrected tariff sheets to Advice Letter 1991 with the following changes:

- Exclude the use of a line loss factor;
- Use forecasted average utility electric generation rates to calculate cogeneration rates in both GN-50 and GT-50;
- Verify the type of fuel oil used by a utility if necessary to convert from barrels to Btus.

3. San Diego Gas and Electric Company and Pacific Gas and Electric Company must file advice letters, within 60 days of the effective date of this resolution, with revised cogeneration tariff sheets specifying their calculation of the cogeneration gas allowance.

4. Southern California Gas Company, San Diego Gas and Electric Company, and Pacific Gas and Electric Company each will update their cogeneration gas allowances upon the conclusion of the annual Energy Cost Adjustment Clause proceedings for Southern California Edison Company, Pacific Gas and Electric Company, and San Diego Gas and Electric Company. Revised cogeneration tariffs shall be filed within 30 days of the issuance of the final decision in each electric utility's annual Energy Cost Adjustment Clause proceeding.

5. Southern California Gas Company must refund or back-bill any over- or under-collections that may have resulted from implementing Advice Letter 1991 on November 13, 1990.

6. This Resolution is effective as of the date that Southern California Gas Company files the corrected tariff sheets required in Ordering Paragraph 2.

I hereby certify that this Resolution was adopted by the Public Utilities Commission at its regular meeting on April 24, 1991. The following Commissioners approved it:

Neal J. Shulman

Neal J. Shulman
Executive Director

PATRICIA M. ECKERT
President
G. MITCHELL WILK
JOHN B. OHANIAN
DANIEL Wm. FESSLER
NORMAN D. SHUMWAY
Commissioners