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ORIGINAL

Decision No. 83127

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of PACIFIC GAS AND ELECTRIC COMPANY for authority to revise its gas service tariff to offset the effect of increases in the price of gas from CALIFORNIA SOURCES. (Gas)	Application No. 54616 (Filed January 31, 1974)
Application of PACIFIC GAS AND ELECTRIC COMPANY for authority to revise its gas service tariff to offset the effect of increases in the price of gas from EL PASO NATURAL GAS COMPANY. (Gas)	Application No. 54617 (Filed January 31, 1974)
Application of PACIFIC GAS AND ELECTRIC COMPANY for authority to revise its gas service tariff to offset the effect of increases in the price of gas from PACIFIC GAS TRANSMISSION COMPANY. (Gas)	Application No. 54618 (Filed January 31, 1974)

(Appearances are listed in Appendix A)

O P I N I O N

Nature of Proceeding

On January 31, 1974, Pacific Gas and Electric Company (PG&E) filed a series of three applications requesting authority to increase its rates and charges for natural gas service to offset increases in expense caused by increases in the price of gas delivered to PG&E from its three sources of supply, California gas producers, the El Paso Natural Gas Company (El Paso), and from Canadian sources delivered by the Pacific Gas Transmission Company (PGT).

The matters were assigned to Commissioner David W. Holmes and referred to Examiner Parke L. Boneysteele for hearing.

In the applications, PG&E states that the increases of price of gas obtained from California sources and PGT will become effective July 1, 1974, and from El Paso on July 10, 1974. PG&E therefore proposes to increase its gas rates to its customers for service after those dates to offset the increased cost of gas and related franchise payments and uncollectibles on a uniform cents per therm basis as follows:

Source	Cents Per Therm	Effective
California Producers	0.042	July 1, 1974
El Paso	0.354	July 10, 1974
Canadian Gas (PGT)	1.427	July 1, 1974
Total	1.823	

PG&E estimated, in the three applications, that the offset rates would increase annual revenues, based on an estimated 1974 test year, $156,263,000, broken down as follows:

Class of Service	A.54616 California Sources Dollars	Percent	A.54617 El Paso Dollars	Percent	A.54618 Canadian Sources (PGT) Dollars	Percent	Total Dollars	Percent
General Service	1,546,000	0.4	13,056,000	3.5	52,593,000	14.0	67,195,000	17.9
Firm Industrial	115,000	0.5	973,000	4.4	3,918,000	17.6	5,006,000	22.5
Resale	43,000	0.6	366,000	5.2	1,476,000	20.8	1,885,000	26.6
Interruptible								
Regular	1,503,000	0.7	12,697,000	6.2	51,146,000	24.8	65,346,000	31.7
Steam electric	387,000	0.8	3,270,000	7.0	13,174,000	28.1	16,831,000	35.9
Total	3,594,000	0.5	30,362,000	4.6	122,307,000	18.6	156,263,000	23.7

PG&E claims that, unless it is to be permitted to make the proposed offset rates effective on the dates requested, it will suffer an irreparable daily loss of approximately the following amounts:

To Offset Cost Of Gas From:	Daily Amount
California Producers	$10,000
El Paso	83,000
Canadian Sources (PGT)	335,000
Total	$428,000

The rate of return, according to PG&E, would drop by:

Effect of Increases From:	
California Producers	0.16%
El Paso	1.34
Canadian Sources (PGT)	5.39
Total	6.89%

PG&E claims that, should the offsets be granted as proposed, during the year 1974, as estimated, it would only earn a 6.50 percent rate of return on its Gas Department rate base, which return is below the 8.0 percent last found to be fair and reasonable for the Gas Department by the Commission in Decision No. 80878 dated December 19, 1972 in Application No. 53188.

Stated Reasons for Proposed Increases

California Sources

In its Application No. 54616, PG&E explained that it obtains approximately 20 percent of its natural gas from California gas producers. Under the terms of PG&E's contracts with these producers the base price for the gas was subject to renegotiation in 1973. The last price redetermination which occurred that year provided for new base price levels of 43¢ per Mcf effective

July 1, 1973 and 45¢ per Mcf effective July 1, 1974, was the subject of review by the Commission in its consideration of Application No. 53866. The Commission, in its Decision No. 82224 dated December 4, 1973, authorized an increase in PG&E's rates to offset the increase in the cost of California gas to the 43¢ per Mcf price level. PG&E claims that when the new price level of 45¢ per Mcf becomes effective on July 1, 1974, it must pay 2¢ per Mcf more for 1,000 Btu heating value California gas delivered on a 33-1/3 percent load factor basis.

PG&E expects that, as a result of the July 1, 1974 base price increase for California gas, its annual expense will increase $3,594,000, effective July 1, 1974, based on a 1974 test year.

El Paso

In Application No. 54617, PG&E said that it obtains approximately 40 percent of its natural gas from El Paso, which obtains its gas from out-of-state sources (primarily New Mexico and West Texas). On January 11, 1974 El Paso filed increased rates with the Federal Power Commission (FPC) amounting to 7.09¢ per Mcf for gas purchased by PG&E (FPC Docket No. RP 74-57). It was anticipated that the FPC would suspend the effective date of El Paso's filing until July 10, 1974, at which time this increase will become effective. Further, an amendment to El Paso's filing was anticipated. This amendment was expected to increase the requested increase to 9.21¢ per Mcf to be effective after FPC suspension on July 10, 1974. Approximately 2¢ of the 7.09¢ per Mcf of the presently requested increase and the 2.12¢ of the anticipated amended increase of 9.21¢ represent disputed costs which El Paso would be forced to pay if overriding royalty payments of 40¢ per Mcf of production should be determined by the courts to be owed by El Paso to Sun Oil Company. The disputed costs were the subject of an arbitration award, effective January 5, 1973, which is now on review before the courts.

The anticipated amendment seeking to increase the filed rates by 2.12¢, to be effective July 10, 1974 through September 30, 1975, was expected to be designed to recover the disputed costs from the effective date of the arbitration award, January 5, 1973, until the effective date of the filed increase should the arbitration award be determined by the courts to be valid; however, approximately 2¢ of the presently filed increased rates are sought for prospective recovery of the same disputed costs.

As a result of the El Paso rate increases, PG&E expects annual expenses to increase $30,362,000, effective July 10, 1974, based on a 1974 test year.

The El Paso rate filing will become effective subject to reduction and refund under provisions of the Natural Gas Act if the FPC should ultimately determine in the proceeding before it that El Paso's rates exceed just and reasonable levels. PG&E states that it proposes to make appropriate rate reductions and refunds to correspond with any rate reductions and refunds ordered by the FPC.

Canadian Sources

PG&E explains in Application No. 54618 that it obtains approximately 40 percent of its natural gas from PGT, which obtains its gas from Canada. PG&E expects its cost of gas from this source to increase 33.10¢ per Mcf effective July 1, 1974, or some earlier date.

The bulk of the gas is purchased under existing contracts with producers which provide for the price to be renegotiated effective July 1, 1974. The gas is purchased in Alberta by Alberta and Southern Gas Co., Ltd. (Alberta and Southern) a wholly owned subsidiary of PG&E. Its cost of service is flowed through to PG&E via PGT which purchases the gas at the Canadian border and sells it to PG&E at the California-Oregon line. PG&E states that, in general, the prices of all fuels have increased markedly since the field price of the gas was last agreed upon, the costs of producing gas have increased, and the governmental authorities in Canada have taken steps to assure "a fair value for the natural gas being removed" for shipment abroad. Alberta and Southern has agreed to a new increased field price of gas which is claimed to be the minimum the Alberta governmental authorities believe to be appropriate at this time. PG&E believes that for these reasons, and because alternate less expensive supplies of gas are not available as a substitute, PG&E must pay the resulting increased cost of PGT gas to meet the demands of PG&E's gas customers for continued service.

As a part of the consideration for the producers agreeing to the new increased field price, Alberta and Southern has agreed that it will become effective on the earlier of July 1, 1974, or the date on which the border price is increased by Canadian federal authority under Regulation 11A of the National Energy Board Act regulations. Consequently, if under Regulation 11A the Canadian federal authority takes such action which itself were to become effective before July 1, 1974, PG&E's cost of gas from PGT would increase before July 1, 1974. Whenever the price increase occurs the increase in the field price of Canadian gas together with Alberta and Southern's increased costs of service will be passed along to PG&E by PGT under PGT's tariff on file with and authorized by the FPC.

PG&E expects that if the PGT increase becomes effective July 1, 1974, PG&E's annual expense will increase $122,307,000 effective July 1, 1974 based on a 1974 test year.

Other Rate Increase Applications Pending

In addition to the applications being considered herein, PG&E has pending three so-called "general rate increase" applications as filed on August 30, 1973, for its Electric, Gas, and Steam Departments. According to these applications, of which we take official notice, PG&E is requesting additional increases in revenues, based on an estimated 1975 test year, as follows:

Application No.	Department	Estimated Increase 1975 Basis Amount	Percent
54279	Electric	$158,446,000	16.1
54280	Gas	73,475,000	13.3
54281	Steam	754,700	43.0

By Application No. 54199 filed July 23, 1973, PG&E has requested rate increases that would increase water revenues from its Tuolumne Water System by $267,760 based on the year 1973 estimated, an increase of approximately 105 percent.

Also, by Application No. 54025 filed May 11, 1973, PG&E has requested an "offset" increase in rates for its Steam Department that would increase estimated 1973 revenues by $211,500 or 15.0 percent.

Public Hearing

The three applications, Nos. 54616, 54617, and 54618 were consolidated for hearing, and after due notice, including a notice included with customers' bills for service, 11 days of hearing were held in San Francisco during the period April 15, 1974 through May 8, 1974 before Examiner Boneysteele. Statements were taken from four representatives of the parties and from six members of the public. Evidence was given by the following witnesses:

For PG&E

John F. Roberts, Jr.
Vice President - Rates and Valuation

Douglas L. Mc Leod
Manager - Gas Purchase Department

C. Kennedy Orr
Executive Vice President
Alberta and Southern Gas Company Ltd.,
Alberta Natural Gas Company, Ltd.

Harry Booth
President and Chief Executive Officer
Alberta and Southern Gas Company Ltd.
Alberta Natural Gas Company, Ltd.

Robert Lyall Winton
Consulting Canadian Attorney

For the Commission Staff

Donald L. King
Associate Utilities Engineer

For the California Gas Producers Association

Henry F. Lippitt, 2nd
Secretary

Thirty-five exhibits were received and the appearances made in the related proceedings, Applications Nos. 54279, 54280, and 54281 were incorporated into these proceedings by reference.

Motions

The following motions were made during the course of the hearings:

By William M. Bennett on behalf of himself and Consumers Arise Now:

1. That PG&E be directed to present its case in support of its applications before any member of the public presents any statement, testimony, or whatsoever.

2. That the three subject applications be consolidated with Application No. 54280, and if that not be done, that the three offset applications be dismissed because of the failure of PG&E to provide supporting data, because of PG&E's keeping of data from his group by keeping the data at the utility's offices in a very restricted setting in terms of examination, and the failure of PG&E to put on a showing as to rate of return, depreciation, materials and supplies, wage expense, and the charting of revenues to see whether they are going ahead of, keeping pace, or following behind expenses.

By Mrs. Sylvia M. Siegel, representing herself, Towards Utility Rate Normalization, and other consumer groups:

> To eliminate from the record all evidence based on the showing PG&E intends to present based on PG&E's yet untested showing in Application No. 54280, or in the alternative, to submit evidence supporting the foundation data taken from the showing in Application No. 54280 and test them in this proceeding.

By staff counsel, R.T. Baer, that evidence relating to rates of exchange for United States and Canadian currencies be stricken from the record.

The motion by Mrs. Siegel relating to Application No. 54280 was granted by the examiner. The other motions were denied.

Concept of an Offset Proceeding

The traditional public utility rate setting procedure as followed in California is based on the authorization of rates designed to produce revenues sufficient: (a) to recover proper operating expenses, depreciation expense, and taxes other than those based on income; (b) to provide a reasonable return on the utility's net investment, or "rate base"; and (c) to cover the taxes based on income that would be payable if the authorized return were earned.

Stated more concisely, the revenue requirement is determined so as to equal the cost of service. In order to meet the requirements of due process, each element of the cost of service is usually thoroughly examined and a "general rate case" involving a major utility is usually a lengthy and time consuming process, often requiring upwards to a year.

Absent any major changes in price level, taxes, or technology, rates prescribed after a general rate case may be appropriate for many years. Occasionally, a specific element of the cost of service can undergo a sudden and significant change. The adjustment of rates to reflect the effect of a change in specific definable elements, independent of the changes that may have occurred to other elements, is known as an offset, and a rate proceeding involving such a change is known as an offset proceeding. The offset procedure has an obvious advantage from a time standpoint, but, in order to be valid, a relatively recent adopted cost of service, or results of operations as it is known in California, must be available as a foundation upon which to base the offset.

PG&E's requests for increases to cover only increased costs of gas generally meet the above-described criterion for offsets, however, PG&E, in its prepared testimony and in its exhibits accompanying the applications, based its showing on an estimate of the results of operations for test year 1974, as contained in its showing in Application No. 54280. At the time of the hearings in these applications there had been no hearings relating to PG&E's showing in Application No. 54280, and a motion to consolidate was denied, as reported above.

A motion to eliminate references to PG&E's Application No. 54280 was granted, however. Any other ruling would have converted these proceedings into a general rate case. PG&E, then, at the suggestion of the examiner, recast its showing of results of operations to base them on the results adopted by the Commission for the test year 1973 estimated in the last general rate increase for the Gas Department, as contained in Decision No. 80878 dated December 19, 1972 in Application No. 53188. The staff, in its showing, also followed this procedure. The Commission thus has two showings which illustrate what the effect would have been to 1973's operations had the increased costs of gas been in effect for that year. The applications, therefore can be considered in an offset basis.

Results of Operations

In presenting their adjusted year 1973 results, both PG&E's witness Roberts and staff's witness King used the current estimates of the gas to be available from the various sources, the cost of gas effective January 1, 1974, and the rate tariffs in effect in 1974.

PG&E's and the staff's results are shown in the following tabulation:

Results of Operations
Adopted in Decision No. 80878 - Test Year 1973 and as Adjusted
For Reduced Gas Supply and to Gas Costs and
Rate Tariffs Effective January 1, 1974

Item	PG&E	Staff	PG&E Exceeds Staff: Amount	PG&E Exceeds Staff: Percent
	(Dollars in Thousands)			
Gross Operating Revenues	$ 650,432	$ 652,100	$(1,668)	(0.3)
Operating Expenses				
Cost of Gas	396,803	396,803	-	-
Other Expenses Excluding Taxes Based on Income	170,944	170,944	-	-
Taxes Based on Income	9,860	10,727	(867)	(8.1)
Total Operating Expenses	577,607	578,474	(867)	(.1)
Net for Return	72,825	73,626	(801)	(1.1)
Rate Base	1,022,547	1,022,547	-	-
Rate of Return	7.12%	7.20%	(.08)%	

(Red Figure)

The only difference between the two showings is in estimates of the heating value of gas. PG&E estimated that gas purchased from Canadian sources would have a heating value of 1,060 Btu per cubic foot, whereas the staff's appraisal indicated that the heating value would be 1,075 Btu. Conversely, the staff adjusted the heating value of California gas from a utility estimated 997 Btu per cubic foot to 982 Btu. The result of the staff's adjustments was to make more revenue available from steam electric sales, and increase PG&E's rate of return by 0.08 percent.

Both results of operations studies indicated that, on a Decision No. 80878 basis, PG&E was earning below the 8.0 percent that we authorized, and any rate increase designed to compensate for increased costs of gas would not result in PG&E's earning a rate of return in excess of that we last found reasonable.

For the purposes of this decision we will adopt the staff's estimate of 7.20 percent.

California Gas Purchase Arrangements

PG&E has been purchasing natural gas from California sources since 1929. It presently buys gas from 82 fields in California. There are 232 contracts with 77 producers. It normally enters into a 20-year contract with a producer giving PG&E the right to purchase all of the producer's gas underlying the lands set forth in the contract. The utility estimates that a 20-year term will more than cover the normal life of the average gas field in California. PG&E purchases the gas at the wellhead and is responsible for the collection, dehydration, transmission, and distribution of the gas to its point of use.

The contracts with the producers specify that PG&E is obligated to purchase a certain amount of gas under each contract on an annual basis. This annual obligation is usually the lesser of 5 percent of the estimated recoverable reserves of gas attributable to the contract, or 33-1/3 percent of the daily deliverability under the contract times 365. This 33-1/3 percent figure is known as a load factor.

Load factor, as defined by PG&E, is the quotient of the average daily volume that PG&E is obligated to buy gas divided by the maximum rate at which the supplier is willing and able to deliver. Gas is purchased from El Paso and PGT at very nearly 100 percent load factor.

A 33-1/3 percent load factor means that the producer must be willing and able to deliver, at PG&E's request, a daily amount of gas equal to at least 3 times PG&E's average annual daily purchase obligation. This permits the flexibility necessary to adjust to customers' seasonal and daily demands for gas.

Cost of California Gas

PG&E's witness Roberts and staff's witness King agreed that the base price for 1,000 Btu California gas delivered at a 33-1/3 percent load factor basis would increase from 43¢ per Mcf to 45¢ per Mcf effective July 1, 1974. They agreed that the effective price as of July 1, 1974 would be 43.77¢ per Mcf. (The staff rounded this to 43.8¢ per Mcf.) They also agreed that estimated 1974 California purchase volumes would be 144,580,000 Mcf.

PG&E claimed that the effective price increase over the average price of gas used in the last offset as authorized by Decision No. 82224 dated December 4, 1973 in Application No. 53866 would be 2.47¢ per Mcf but the staff argued that the 0.47¢ was attributable to variations in the mix of gas as purchased from the various California producers. The staff witness, Mr. King, testified that there is always a possibility that rates based on estimates made for one test year would over or under recover expenses in the following test year because of changes in the mix from the various fields and also in the mix of the total gas supply as between the three sources. Mr. King urged that only the 2¢ escalation was a proper subject for an offset and differences in mix were more properly considered in a general rate proceeding.

The staff spread its recommended increase over a slightly higher system sales estimate because of its slightly higher appraised of average heating value of all gas sold, as explained under the heading "Results of Operations".

The two showings resulted in a required increase as determined by PG&E of 0.042¢ per therm and, as recommended by the staff 0.034¢ per therm. The details of the derivations are shown in the following tabulation:

		PG&E 1/	Staff 1/
1.	Effective Price 7/1/74	43.77¢/Mcf	-
2.	Avg. Price 1/1/74	41.30¢/Mcf	41.30¢/Mcf
3.	Price Increase	2.47¢/Mcf	2.00¢/Mcf
4.	Est. 1974 Purchase Volumes	144,580,000 Mcf	144,580,000 Mcf
5.	Increase in Cost of Gas	$3,571,000/Yr.	$2,891,600/Yr.
6.	Net of Gas Injected into Storage, Franchise Fees, and Uncollectibles	$23,000/Yr.	$19,000/Yr.
7.	Increase to be Recovered in Sales	$3,594,000/Yr.	$2,910,600/Yr.
8.	Total Estimated 1974 System Sales Subject to Increase	856,949,000 dkt/Yr. 1/	860,238,000 dkt/Yr. 1/
9.	Required Increase	0.042¢/therm	0.034¢/therm

1/ The abbreviation for "dekatherm" or 10 therms is dkt - the energy equivalent of 1 Mcf of 1,000 Btu gas.

California Gas Availability

The witness for the California Gas Producers Association, Mr. Lippitt, presented a series of exhibits to show that in the past five years PG&E's estimated purchases of California gas had fallen behind actual purchases. He testified that purchases of California gas over the period 1963-1972 varied from a low of 207,200,000 Mcf in 1967 to a high of 249,000,000 in 1971, with an average take over the period of 233,100,000 Mcf. Mr. Lippitt urged that the Commission should consider this last figure as the available supply of California gas for 1974. He felt that PG&E's estimate of 144,580,000 Mcf did not give consideration to the probability that additional California suppliers would become available as a result of continuing exploration and development. He stated that PG&E's March 5, 1974 fuel report indicates a substantially increased availability of California gas supply.

Mr. Lippitt also recommended that the Commission should indicate to PG&E that financial incentives should be provided to California producers similar to those afforded PG&E's Canadian producers.

In response to Mr. Lippitt's proposals Mr. Mc Leod, manager of PG&E's Gas Purchase Department, testified that the availability of California gas has declined 32 percent in the period between 1967 and 1974. The annual take of California gas at over 200,000,000 Mcf has been maintained by exceeding PG&E's purchase obligations. To produce California gas greatly in excess of purchase obligations would reduce the gas deliverable in future years and amplify supply problems in the future.

Other California Gas Issues

Mr. Bennett argued that there appeared to be price fixing with California producers. He stated that he tried to go into PG&E's expenses and revenues, but could not get the documents, as they were located at PG&E's office in downtown San Francisco.

Mrs. Siegel also raised the antitrust issue but seemed to relate it more to PG&E's relationships between itself, PGT, and the Canadian subsidiaries.

Discussion of California Gas Issues

In appraising the record as outlined above, we are satisfied that the staff's recommendations are the most reasonable. We will accept the staff's recommendations that the offset be limited to the 2¢ per Mcf escalation as provided by the gas purchase contracts. Reflection of changes in mix, changes which can be expected to occur each year, are on-going changes and are, in our opinion, outside the scope of specific definable changes that are the proper subject of an offset proceeding.

We will accept PG&E and the staff's estimated 1974 California purchase volumes of 144,580,000 Mcf. We recognize that should purchases of 45¢ per Mcf California gas be higher than this estimate, a windfall to PG&E might result. We therefore will require PG&E to file quarterly reports of its California purchases for a period ending ninety days after the effective date of our decision in the PG&E Gas Department general rate increase Application No. 54280.

The staff's other recommendations appear to be reasonable and will be accepted. We find that on July 1, 1974, PG&E will be exposed to an additional $2,891,600, annualized, in the cost of natural gas as a result of a 2¢ per Mcf escalation in the base price of gas purchased from California producers. Such increased costs can be offset by a revenue increase of $2,910,600, based on total estimated 1974 system sales subject to increase, an increase of 0.034¢ per therm in PG&E's present rates will offset the increased cost of gas purchased from California sources.

We will not require PG&E to initiate financial incentives for California producers. This issue is not a proper one to be considered in context of an offset proceeding.

We have considered the issues of price fixing and anti-trust at length only recently in Decision No. 53866 dated December 4, 1973 in Application No. 53866. No new evidence was presented in this proceeding to cause us to change our findings and conclusions respecting California gas purchasing arrangements as set forth in that decision.

<u>Cost of El Paso Gas</u>

PG&E has been purchasing gas from El Paso since 1950. Deliveries are made at the Arizona-California border at Topock on the Colorado River, south of Needles, San Bernardino County. On November 1, 1972, with the sanction of the FPC, El Paso began to curtail its deliveries of gas to PG&E and to other customers of El Paso's Southern Division. Since that date, daily deliveries to PG&E have usually been less than the 1,140,000 Mcf that PG&E is entitled to receive under its contract with El Paso.

Subsequent to the filing of Application No. 54617, the FPC suspended El Paso's filing of a proposed increase of 7.09¢ per Mcf until July 10, 1974 (Docket No. RP 74-57). On April 22, 1974, it rejected El Paso's request for the additional 2.12¢ increase to become effective the same day.

The staff is recommending that only the 7.09¢ be allowed in PG&E's rates whereas PG&E's counsel, in his closing statement requested that the full 9.21¢ requested be granted, subject to refund. He also stated however, that should the 2.12¢ not be allowed, that amount or such equivalent surcharge as the FPC might grant, be authorized subject to such granting.

PG&E's request for a 9.21¢ per Mcf offset would require an increase of 0.354¢ per therm, whereas the staff's recommendation would result in 0.272¢ per therm.

The staff's determination reflects its judgment as to gas injected into storage, franchise fees, uncollectibles, and total estimated system sales, as discussed under cost of California gas.

The details are shown in the following tabulation:

		PG&E	Staff
1.	Effective Price 7/10/74	58.81¢/Mcf	-
2.	Avg. Price 1/7/74	50.60¢/Mcf	50.60¢/Mcf
3.	Price Increase	9.21¢/Mcf	7.09¢/Mcf
4.	Est. 1974 Purchase Volumes	327,513,000 Mcf	327,513,000 Mcf
5.	Increase in Cost of Gas	$30,165,000/Yr.	$23,220,000/Yr.
6.	Net of Gas Injected into Storage, Franchise Fees, and Uncollectibles	$197,000/Yr.	$152,000/Yr.
7.	Increase to be Recovered in Sales	$30,362,000/Yr.	$23,372,700/Yr.
8.	Total Estimated 1974 System Sales Subject to Increase	856,949,000 dkt/Yr.	860,230,000 dkt/Yr.
9.	Required Increase	0.354¢/therm	0.272¢/therm

The staff's determination of the amount of increase needed to offset, subject to refund, the 7.09¢ per Mcf increase in cost of El Paso gas appears to be the most reasonable and the recommended amount of 0.272¢ per therm will be adopted. We do not believe it fair, however, to require PG&E to be exposed to this further increase merely because of the procedural aspects of El Paso's request for the additional 2.12¢. In the order which follows we will authorize PG&E to recover this increase, subject to refund, based on estimated 1974 system sales of 860,238,000 therms, whenever such increase becomes effective.

Canadian Gas Purchases

PG&E's purchases of Canadian gas are handled by its wholly owned subsidiary, Alberta and Southern, an Alberta corporation. Gas is purchased from producers in the Province of Alberta, by Alberta and Southern, principally for ultimate delivery to PG&E in California. (Approximately 7 percent of Alberta and Southern's purchases are resold to Montana Power Company, one percent to Canadian distributors, and the remaining 92 percent to PG&E.)

Alberta and Southern has no physical plant except for its office facilities. Ownership of the gas is acquired by Alberta and Southern at the outlet of the producers processing plant or at the end of his gathering system if the gas does not require processing. At that point the gas flows directly into facilities of the Alberta Gas Trunk Line Company, Limited (Trunk Line) for transportation within the Province of Alberta to two delivery points. One point, for PG&E destined gas is located a mile inside Alberta at the British Columbia border, just east of the summit of the Rocky Mountains in Crows' Nest Pass near Coleman, Alberta. The other point, for Montana Power gas, is located at the Alberta-Montana border near Carway, Alberta, east of Glacier and Waterton Lakes National Parks.

Alberta and Southern's gas export permit from the Province of Alberta contains a condition that all gas removed from the Province under the authority of the permit must be delivered through the facilities of Trunk Line which has the right to transport all Alberta gas destined for extra-provincial markets. Trunk Line is a contract carrier. It operates under an act of the Alberta Legislature and its shares are publicly traded. The transportation service rendered by Trunk Line is on a cost of service basis providing for reasonable and necessary operating expenses, depreciation, taxes, including taxes on income, and return on net investment base.

On January 1, 1974, Trunk Line was operating 1,398 miles of pipeline (ranging in diameter from 4" to 42") and 8 compressor stations with 93,310 installed horsepower for the purpose of providing gas transmission service to Alberta and Southern. Trunk Line's net investment base, applicable to Alberta and Southern, on January 1, 1974, was $149 million, Canadian.

Trunk Line is subject to the jurisdiction of the Alberta Energy Resources Conservation Board as to construction and operation, and the Alberta Public Utilities Board as to rates.

Since January 1, 1973, the gas transportation contract of Trunk Line has provided for a rate of return of 9 percent per annum. PG&E has no direct or indirect interest in Trunk Line, except for 15 of Trunk Line's 1,699 shares Class B stock that Alberta and Southern is eligible to hold by virtue of its status as a gas exporter.

Alberta Natural Gas Company, Ltd. (Alberta Natural) transmits gas for Alberta and Southern from the interconnection with the Trunk Line system in Crows' Nest Pass to Kingsgate on the British Columbia-Idaho border. The service is rendered on a cost of service basis, providing for the same four categories of cost detailed for Trunk Line.

Alberta Natural's shares are owned 45 percent by PGT and the remainder by the investing public (PGT's shares are in turn 51 percent owned by PG&E). The shares of Alberta Natural are listed on the principal Canadian stock exchanges. The Alberta Natural system consists of 106-miles of 36" diameter pipeline and 3 compressor stations with 88,600 installed horsepower.

Alberta Natural's rate base, applicable to Alberta and Southern on January 1, 1974, was $35.2 million, Canadian. Effective April 1, 1973 Alberta Natural's rate of return on transmission rate base has been 9 percent per annum.

Alberta Natural is a "special-act-of Parliament company" chartered by the Parliament of Canada with express authority to engage in the interprovincial transportation of gas. As an interprovincial carrier, Alberta Natural is regulated by the National Energy Board of Canada.

Alberta and Southern and Alberta Natural share the same officers.

The price charged for gas sold by Alberta and Southern to PGT at the Canada-United States border delivery point is determined under the provisions of a gas sale contract entered into by the two companies. According to the contract, the amount to be charged for gas delivered each month shall be the greater of the specified price in the contract multiplied by the volume of gas delivered during the month, or Alberta and Southern's actual cost of service for the month as defined in the gas sale contract.

Alberta and Southern's cost of service is defined as the sum of the following items:

> The cost of Alberta and Southern of gas purchased from producers and delivered to PGT.
>
> The cost of transportation within Canada of the gas delivered to PGT.
>
> Alberta and Southern's reasonable and necessary operating expenses.

Depreciation.

Taxes, including taxes on income.

Return on investment represented by interest expenses on funds borrowed for gas operations and acquisition activities and a return at an annual rate of 12 percent on equity investment.

The specified price has been 31¢, U.S., per Mcf since October 1, 1972. On July 1, 1973, however, the price under the cost of service tariff was 38.30¢, Canadian.

According to PG&E's Mr. Roberts and Alberta and Southern's Mr. Orr, the cost of gas at the international border is expected to increase by 31.8¢ to 70.1¢ per Mcf, Canadian. Mr. Orr, a chartered public accountant, explained that of the 31.8¢ per Mcf increase in price, 28.8¢ per Mcf is attributable to the increase in the field price of gas. The remaining 3.0¢ per Mcf of the increase is attributable to the following factors:

(a) .6¢ results from increases in cost of gas used for compressor fuel in the Alberta Natural, .3¢, and the Trunk Line, .3¢, transmission systems.

(b) 1.5¢ results from a change in the calculation of depreciation, from straight-line at 2-1/2 percent per annum on original cost to a "unit of throughput" basis, in the Trunk Line system. This method of depreciation calculation conforms to the method being utilized in both the Alberta Natural and PGT systems.

(c) 1.0¢ results from increased interest expense on funds borrowed for gas operation and acquisition activities by Alberta and Southern. Alberta and Southern has made advance payments of approximately $25 million for established reserves. To date, as a result of this activity, 2.2 trillion cubic feet of reserves has been committed by gas purchase contracts to Alberta and Southern and gas from these reserves is now flowing to PGT. Alberta and Southern is also providing loans to producers to finance exploration in the Mackenzie Delta area of the Canadian Arctic. Alberta and Southern has agreements to buy up to 11 Tcf from gas reserves that are being explored for and developed in this area.

(d) A negative amount of .1¢ is the net impact of the remaining cost of service components of the three companies, Alberta Natural, Trunk Line, and Alberta and Southern.

The gas sale contract between PGT and Alberta and Southern provides that when the price for gas sold to PGT is determined on the basis of Alberta and Southern's cost of service, payment must be made in Canadian dollars, except for a provision that requires PGT to substitute United States dollars for Canadian dollars to the extent that Alberta and Southern's Canadian transporters, Alberta Natural, and Trunk Line require United States dollars for the servicing of certain United States dollar debt financings effected in 1961 (Alberta Natural Gas Series A Bonds, Trunk Line Series B Bonds).

Although, at the time of submission, the Canadian dollar was trading at 103-1/8, PG&E was claiming no exchange differential in these proceedings.

After the Canadian gas is sold to PGT, it is transported to the California-Oregon line at a point in Modoc County east of the city of Tule Lake, where it is resold to PG&E under a cost of service tariff filed with the FPC.

The reasonableness of the cost of service of PG&E's affiliates has been a subject of concern to the Commission in recent gas offset cases and one general rate case. We particularly have in mind our comments in the following decisions:

Decision No. 80794 dated December 5, 1972 in Application No. 53552, page 10 (mimeo.).

Decision No. 80878 dated December 19, 1972 in Application No. 53188, page 21 (mimeo.).

Decision No. 81590 dated July 10, 1973 in Application No. 53866, page 8 (mimeo.).

Decision No. 82224 dated December 4, 1973 in Application No. 53866, page 4 (mimeo.).

We will not reproduce the phraseology here; our concern now is that, because of the exigencies of the offset situations, and because of the prima facie indications that the offset would not produce the rate of return that we last found reasonable, that the cost of service tariffs and affiliate relationships had not received detailed exposition.

Canadian Gas Renegotiations

The circumstances behind the drastic increase in the field price of gas were explained in detail by Alberta and Southern's President, Mr. Booth. (Mr. Booth is also president of Alberta Natural and a director of PGT) Mr. Winton, a member of the Alberta bar and former vice president and director of both Alberta and Southern and Alberta Natural, testified to recent developments in Canadian legislation, both federal and provincial, affecting gas prices.

Mr. Booth described how, in 1970, the Government of Canada assumed new powers over the "border price" of natural gas by adding a regulation under the National Energy Board Act. That Act empowers the National Energy Board to regulate the export of gas and oil from Canada and the construction and operation of interprovincial and international gas and oil pipe lines. The new "Regulation 11A" is designed to keep the border price of Canadian gas in line with prices of competing gas supplies or alternative energy sources in the market area to which the gas is destined. The regulation empowers the Governor in Council, in effect the Canadian Cabinet, after having received a report of the National Energy Board on the subject, to fix the price below which gas may not be exported under a particular gas export license. In 1971 and 1972 administration of this regulation was reflected by the introduction into the gas sale contract between Alberta and Southern and PGT of a specified price per Mcf with minimum price calculated in accordance with cost of service provisions.

In November 1973 the National Energy Board requested each Canadian gas exporter to provide information on its international price by January 22, 1974 and the Board called a hearing on that subject which commenced on March 26, 1974. The hearings have been concluded but no decision has been issued.

Mr. Winton explained that, at the provincial level, the Province of Alberta is the owner of more than 80 percent of the estimated volume of Alberta gas reserves, having retained, as the "Crown in the right of the province", mineral rights to almost 85 percent the "Crown" or public lands as the Province was settled and the land passed into private ownership.

The contracts between Alberta and Southern generally have a term of 25 years, subject to earlier termination should Alberta and Southern lose its permit to export gas from Alberta. The price was originally subject to renegotiations at five-year intervals, but in the 1973 renegotiations the period was reduced to two years. The contracts provide for arbitration should the parties fail to agree on a suitable price.

According to Mr. Booth, in 1971 a new provincial government came into power in Alberta and announced a policy intended to assure the realization of the "fair value" of the province's depleting and nonrenewable natural resources. New legislation was enacted at the 1973 session of the legislature to place the announced policy into effect.

The Premier of Alberta, in November of 1973, met with Mr. Booth and discussed the field price of gas, and in December the Premier sent the following letter:

"THE PREMIER OF ALBERTA

403/425-1610

Legislative Building
Edmonton, Alberta, Canada T5K 2B6

17 December 1973

Mr. Harry Booth
President
Alberta and Southern Gas Co. Ltd.
3rd Floor
240 - 4th Avenue SW
Calgary, Alberta

Dear Mr. Booth:

I have your letter of November 26, 1973 with regard to our meeting of November 21 where we exchanged views on the matter of pricing of natural gas purchased by your Company within Alberta. I noted further the attachment entitled "Memorandum of Discussion, dated October 31, 1973 regarding Prospective Price Adjustments".

I have discussed the matters raised with the Members of the Executive Council of the Government of Alberta and would like to inform you of our reaction.

In view of the rapid changes in energy prices in the California market area served by Alberta natural gas, we would like to inform you of our position on these matters.

"Mr. Harry Booth 17 December 1973

We recognize that you have responded to our policy statement regarding field prices of natural gas dated November 16, 1972 as reflected in the redetermined field prices for Alberta and Southern purchases as set forth in the July 1973 progress report of the Alberta Energy Resources Conservation Board.

However, the rapid changes in energy prices in the last few weeks are of such a nature that the Executive Council has come to the conclusion that we should advise you that we expect your Company to further negotiate with all of the producing companies your present gas supply contracts to ensure that there are appropriate increases in the field price of Alberta natural gas which would be passed back to the producers of Alberta and through our royalty system to the Government of Alberta. As you are aware, we are planning a new natural gas royalty system to be implemented by regulation in the early months of 1974.

It is our considered view that your actions should involve a minimum of a doubling of the present field price of natural gas purchased in Alberta by your Company. We believe that such action would be beneficial to the people of Alberta through increased revenues from the royalty system, but in addition, it would provide a reasonable field price to Alberta explorers and producers which would create an incentive for drilling for additional supplies of natural gas in Alberta, particularly in the deeper zones of the foothills of our Province. This will of course strengthen the supply position of your Company.

We recognize that such a major adjustment in the cost of your natural gas supply will require you to take the necessary steps before the California Public Utilities Commission, but such contract price revisions are essential under the circumstances and must be accomplished expeditiously.

"Mr. Harry Booth 17 December 1973

It is the view of the Executive Council of the Government of Alberta that this action should take place prior to the opening of the Third Session of the Alberta Legislature on March the 7th, 1974 unless some unanticipated circumstances arise which we consider justified an extension. In the event you fail to comply with this request, we want you to know that it will be our intention to take the necessary legislative or government action to ensure that Albertans receive fair value for the sale of the depleting resource of natural gas owned by Albertans and leased to the producers.

We would appreciate your response and planned course of action arising out of the matters raised in this letter.

Yours truly,

/s/ PETER LOUGHEED

Peter Lougheed

PL/ww

cc. Hon. D. R. Getty
Minister of Federal &
Intergovernmental Affairs

Dr. G. W. Govier
Chairman
Energy Resources Conservation Board"

As a result of these legislative and administrative developments, Alberta and Southern, on January 2, 1974 opened renegotiation of prices that would become payable to producers leasing the Crown and privately owned gas fields effective July 1, 1974. At the same time some producers gave Alberta and Southern similar notice. For the initial negotiations, Alberta and Southern selected ten of its major gas suppliers, who together account for about 78 percent of the total gas supply.

Mr. Booth said that, under the price renegotiation provisions of the gas purchase contracts, it was not open to Alberta and Southern to refuse to negotiate promptly on receiving notice to negotiate from a producer, and it was evident from the notices received from some producers that, had Alberta and Southern not moved on January 2, 1974 to commence negotiations, producers would have done so. The only alternative course would have been to refuse to conclude price agreements with producers. To have adopted that course would have involved the risk that there would be a call to arbitration by one or more producers under the price renegotiation provisions of the gas purchase contracts, in which case the arbitrators would be bound by the provisions of the 1973 amendment to The Alberta Arbitration Act. These new provisions could be used by the producers to contend that the field prices should be directly related to the comparable price of fuel oil in northern California related back to the field plus a premium for the special qualities of natural gas, Mr. Booth calculated the comparable northern California price to be $1.25 per Mcf without any provision for the premium. In addition there would have been risks of other governmental action.

It was evident that, with the knowledge of the hearing to be called by the National Energy Board to consider international gas prices under Regulation 11A and the recent enactment of the 1973 amendment to the Alberta Arbitration Act, producers expected the renegotiation of the field price to move to the standards prescribed in those enactments.

The field prices as negotiated at the time of the hearing ranged from a low of 45.75¢ per MMBtu for gas at the northern extremity of the Alberta Gas Trunk Line to 59.75¢ per MMBtu for gas at the southern extremity. Assuming all producers accept the offered prices, the overall weighted average, based on forecasts of deliveries and after heating value adjustment, would be 56.8¢ per Mcf, Canadian. The differences in prices are accounted for by differences in transportation costs as between the several fields and a difference in load factor in the case of casinghead gas purchases. In terms of volume, Alberta and Southern had, at the time of the hearings, achieved agreement on prices for about 91 percent of its gas supply.

Mr. Booth testified that it became apparent during the course of negotiations that Alberta and Southern's price offering would be unacceptable to the producers for a pricing period extending to June 1976, and it became obvious that they needed either to introduce a significant escalation at the midpoint of the two-year pricing period or else, as they decided to do, have these prices effective only for the period ending June 30, 1975. The renegotiated contracts include a mechanism whereby any excess of the border price, as fixed by a Government of Canada Order under Regulation 11A, over Alberta and Southern's cost of service would be paid to the producer.

Mr. Booth was requested, during his cross-examination to supply for the record a copy of Alberta and Southern's letter to the Premier dated November 26, 1973, and the attached "Memorandum of Discussion" dated October 31, 1973. From the memorandum it appears that the management of PG&E was interested in "coordinating field price and international border price increases in time and amount and in avoiding diversion of increases by producers". Mr. Booth explained that the PG&E interests were concerned that an inadequate price for gas being exported might cause the Government of Canada to impose an export tax on gas leaving Canada. Such an export tax was not likely to lead to the generation of additional supply, whereas a higher field price would.

During the cross-examination of Mr. Booth it was discovered that he had recommended to PG&E that, concerning the hearings before the National Energy Board pursuant to Regulation 11A, PG&E suggest to the U.S. State Department that the Department have discussions with its counterpart, the Department of External Affairs in Canada, concerning pricing matters. Mr. Roberts when asked about the disposition of this recommendation, testified that PG&E had not acted on Mr. Booth's advice, and that, in his opinion, PG&E and its subsidiary were in as good a position as anyone to negotiate in behalf of the people of northern California over the price of fuel.

Staff Evaluation of Canadian Gas Costs

The staff analyzed PG&E's presentation and, although there were minor differences in derivation, agreed with the overall concept. The staff recommended, however, that interest charges on funds borrowed by Alberta and Southern for gas exploration and development activities should not be flowed through to the customer without prior regulatory approval. The staff also recommended that additional depreciation expense attributable to the expected adoption of the unit of throughput method not be included since such increases are "tentative". The difference between PG&E and staff showings were summarized at page 1127 of the transcript and are shown, in less detail, below:

		PG&E[1]	Staff[1]
1.	Effective Price 7/1/74	70.10¢/Mcf	-
2.	Average Price 1/1/74	38.30¢/Mcf	38.30¢/Mcf
3.	Average Increase in Field Price of Gas	28.8¢/Mcf	28.4¢/Mcf
4.	Increase in Compressor Fuel to International Border	0.6¢/Mcf	0.6¢/Mcf
5.	Increase Resulting from Operation of Cost of Service Tariffs	2.4¢/Mcf	2.8¢/Mcf
6.	Price Increase	31.8¢/Mcf	31.8¢/Mcf
	Est. 1974 Purchase Volumes at International Border	382,108,000 Mcf/Yr	382,108,000 Mcf/Yr.
7.	Increase in Cost of Gas at International Border	$121,511,000/Yr.	$121,510,300/Yr.
8.	Net of Gas Injected into Storage, Franchise Fees, And Uncollectibles	$796,000/Yr.	$795,600/Yr.
9.	Gross Increase	$122,307,000/Yr.	$122,305,900/Yr.
	Alberta and Southern Interest	-	$(6,578,700)/Yr.
	Trunk Line Throughput Depr.	-	$(5,384,500)/Yr.
10.	Net Increase to be Recovered in Sales	$122,307,000/Yr.	$110,342,700/Yr.
11.	Sales Subject to Increase	856,949,000 $\frac{\text{dkt}}{\text{Yr.}}$[2]	860,238,000 $\frac{\text{dkt}}{\text{Yr.}}$[2]
12.	Required Increase	1.427¢/therm	1.283¢/therm

1/ Both showings ignore exchange differential between U.S. and Canadian currency.

The main difference in derivation, as mentioned above, is that PG&E based its determination at sales at the international border, whereas the staff used sales at the Oregon-California state line. The difference is accounted by 15,000,000 Mcf/Yr. of gas consumed by PGT as compressor fuel. The staff made appropriate allowance for this so the staff and PG&E results were comparable. For the comparison above we have selected PG&E's method and made appropriate adjustments to the staff's showing to place it on a border price basis.

Although the staff and utility both arrived at a 31.8¢ per Mcf increase at the border, the staff started with a 28.4¢ increase in field cost of gas, to which it added 0.6¢ for compressor fuel to the international border and 2.8¢ for the operation of the cost of service tariffs.

It is interesting to note that the staff's increase of 28.4¢ per Mcf is exactly 100 percent of the present 28.4¢ per Mcf average field price of Canadian gas determined by the staff.

Discussion of Field Price of Canadian Gas

We have before us, as part of an offset case, an exceedingly complex situation. In addition to the more familiar regulatory problems involving affiliated relationships and negotiations with gas producers, we must recognize that, when PG&E reached, with our blessing, across the international border into Canada for a source of natural gas to supply the northern California market, it subjected itself and its customers, insofar as the cost of gas is concerned, to the jurisdiction of two levels of a foreign sovereignty, and to the vicissitudes of the foreign currency market.

In our discussion of the cost of Canadian gas we will dispose of the unfamiliar question of the field price of gas imported from a foreign country, and then take up more routine cost of service and regulatory issues.

In Decision No. 82224 dated December 4, 1973 in Application No. 53866, we noted, on page 3 (mimeo.), concerning Canadian gas, that "the California consumer could not realistically ask for more effective bargaining in his behalf, or expect a lower price". Now, in this case we are faced with an almost doubling of the field price of gas. We also have an indication that the circumstances behind the determination of the new field price involved some degree of rivalry between the provincial and federal levels of the Canadian government over who should benefit from a higher cost of gas to the ultimate consumer.

The bargaining for the gas involved in Application No. 54618 is virtually complete and the contracts will be effective July 1, 1974. We have had no evidence presented that the contracts with the producers are not the best that could be obtained under the unusual circumstances nor that they were not the results of arm's length bargaining with the gas producers.

We have been advised by the California Supreme Court that:

> "Almost every contract a utility makes is bound to affect its rates and services. Moreover, the question whether a contract or practice is reasonable is one on which, except in clear cases, there is bound to be conflicting evidence and considerable leeway for conflicting opinions. The determination of what is reasonable in conducting the business of the utility is the primary responsibility of management. If the Commission is empowered to prescribe the terms of contracts and the practices of utilities and thus substitute its judgment as to what is reasonable for that of the management, it is empowered to undertake the management of all utilities subject to its jurisdiction. It has been repeatedly held, however, that the Commission does not have such power". (The Pacific Tel. & Tel. Co. v PUC (1950) 34 Cal 2d 822, 828.)

In our opinion the contracts negotiated with the Alberta producers fall within these guidelines.

Keeping in mind our responsibilities insofar as the negotiation of contracts is concerned, we note that the fact that Alberta and Southern, following the admonition of the Premier of Alberta, has negotiated higher prices from the producers, might not preclude the National Energy Board from taking further action under Regulation 11A. The Canadian government could still decide to impose an export tax on natural gas and, finally, the prices we are considering are only effective until June 30, 1975. Every engineering witness in this case agreed that there was no practical alternative to natural gas for space and water heating for most northern California residential and commercial customers.

Northern California is irrevocably committed to Canadian sources for 40 percent of its natural gas supply. This commitment was made without the benefit of a treaty or other international agreement. The customers of PG&E must pay, in their rates, whatever field prices may result from the operation of the Canadian political structure. That structure, built on a parliamentary base and different constitutional concepts, is one in which an American utility corporation may not be the most effective arm to negotiate on behalf of an important segment of the American public.

Negotiation with foreign governments is the sole prerogative of the President of the United States. (United States v Curtis-Wright Export Corp. (1936) 299 US 304, 319, 81 L ed 255, 262.)

The people of northern California, both by their taxes and through payment of utility bills, contribute significant sums towards the support of the United States. We therefore feel no reluctance in calling, on their behalf, for the assistance of the United States in dealing with Canadian authorities. Pursuant to Sections 307 and 701 of the Public Utilities Code, we shall direct the General Counsel of the Commission to meet with the representatives of the United States Department of State, and such other Federal agencies as may be appropriate, and to enlist their advice and aid for the purpose of securing effective representation before the various Canadian federal and provincial agencies in future executive, legislative, judicial, and regulatory proceedings involving the cost of gas. Such action would be consistent with the long record of representation by our attorney in Federal proceedings concerning utility costs ultimately paid by California consumers.

Since we have no reason to conclude that the field price as negotiated by PG&E was not the best that could be obtained under the circumstances, we will find reasonable, and allow in our adopted cost of service, the increased cost of gas attributable to the increased field price of 28.4¢ per Mcf, and the associated increase in compressor fuel to the international border of 0.6¢ per Mcf for a total of 29.0¢ per Mcf. Based on deliveries at the international border of 382,108,000 Mcf/Yr. the increased cost of gas will be $110,811,000 in Canadian currency. The cost attributable to the 28.4¢ doubling of the field price alone is $108,519,000.

<u>Affiliates' Cost of Service Tariffs</u>

We have expressed above our concern over the inclusion of purported cost increases arising from the operation of the cost of service tariffs of PG&E's affiliates. The troublesome question of affiliate costs and profits has been a concern of the Commission since its inception. In Southern Sierras Company, Decision No. 224 dated September 16, 1912 in Application No. 220 (1 CRC 556, 558), we said, "The construction of a utility's plant by a subsidiary construction company consisting of the same people will always call for the most careful scrutiny of this Commission in a rate case or in an application to issue stocks, bonds, or other securities."

At the last day for testimony PG&E presented several exhibits showing components of Alberta and Southern's and Alberta Natural's increases in cost of service for the year ended June 30, 1975 over that ended June 30, 1974. These exhibits were in a different test period from that used in the remainder of PG&E's showing and the staff's results. They covered all elements of results of operations and did not fall within the scope of our concept of an offset proceeding, that is, to consider the change of one, or at the most, a few definable elements. The rates of return used were also higher than the 8 percent last found reasonable for PG&E by this Commission.

The staff engineer's showing in this proceeding was of exceptionally high quality. His exhibits were laid out in sufficient detail so it was possible to perceive the exact basis on which he arrived at his results and conclusions. On the witness stand he appeared to be knowledgeable, fully informed on the subject, and most responsive in answering questions. A complete results of operations study of the affiliates was outside of the scope of his assignment, however, and he made no field investigation in Canada. He also did not make a detailed review of the results of operations such as is normally made by the staff in a general rate case. He concentrated, as time permitted, on the specific major issues of interest, field price of gas, funding of Alberta and Southern's exploration and development activities, and an anticipated increase in Trunk Line's depreciation expenses.

We now have before us, in Application No. 54280, a general rate case for PG&E's Gas Department where we are considering all aspects of results of operations. We also have the most unusual circumstance of also having, in Applications Nos. 54278 and 54281, general rate cases for the Electric and Steam Departments. In these proceedings, which are consolidated for hearing, we are considering all aspects of PG&E's operations (except for PG&E's water utility systems, a very minor portion of the total PG&E system). These proceedings, as consolidated, provide a most appropriate vehicle for consideration of the affiliates' cost of service tariffs and other matters not properly encompassed within our concept of an offset proceeding.

We will defer the affiliate question to the consolidated general rate case and will expect PG&E, the staff, and interested parties to be prepared to present appropriate showings and proposals on all elements of cost of service not considered in this decision.

In order to obviate the necessity of plowing the same ground twice, we will incorporate the record in these Applications Nos. 54616, 54617, and 54618 with that in Applications Nos. 54279, 54280, and 54281. Thus further consideration of the affiliate question, and other issues deferred to those proceedings, can commence where this case was concluded.

We agree with the staff's position that the expenses incurred by a utility or its subsidiaries in supporting gas exploration activities should not be flowed through to the customer without prior regulatory approval, and will also consider this question in the general rate case.

Adopted Canadian Gas Costs

The only specific definable element of the increased cost of service that meets our concept of a proper subject for an offset proceeding is the increase in cost of gas at the international border as determined below, expressed in Canadian currency:

Increased in Field Price	28.4¢ Mcf
Increase in Cost of Compressor Fuel to International Border	.6
	29.0¢ Mcf

Increase in Cost of Gas at Canadian Border

$$29.0¢/\text{Mcf} \times 382{,}108{,}000 \ \frac{\text{Mcf}}{\text{Yr.}} = \$110{,}811{,}000$$

As noted above, PG&E did not claim a differential for the prevailing rate of exchange. The staff objected to the very mention of the subject.

The fact remains, however, that PG&E must collect its rates for service in U.S. currency and pay the increased field price in Canadian money. We have no reason to conclude that, in the foreseeable future, the Canadian and U.S. dollars will be at parity except as the result of coincidence. We therefore will convert the costs associated with the increased field price from Canadian to U.S. currency at the rate of $1.03125 U.S. equal to $1.00 Canadian[1/] and authorize PG&E to recover through its rates for service an increase in cost of gas at the international border the sum of $115,022,000 determined as follows:

1/ On Friday, June 14, 1974, the selling price for bank transfers in the United States for payment in Canada, was, according to the June 17 issue of Wall Street Journal $1.0375 U.S. equal to $1.00 Canadian.

Increase in Cost of Gas At International Border In Canadian Currency	$110,811,000
Increase in Border Price in U.S. Currency at $1.03125	$114,274,000
Franchise Fees and Uncollectibles	$748,000
Net Increase to be Recovered in Sales	$115,022,000
Sales Subject to Increase	860,238,000 Dekatherms
Required Increase	1.337¢/therm

We recognize that exchange fluctuations also affect the base price of gas. We believe that subject, involving as it does certain fixed charges of Alberta Natural's and Trunk Line's cost of service payable in U.S. currency, is a proper issue for the general rate case. In that connection we will also expect proposals for the establishment of appropriate machinery to adjust its rates for gas service on an ongoing basis so that PG&E will neither profit, nor lose on foreign exchange transactions.

Summary of Authorized Increases

The increase in the field price of gas is an increase in the commodity component of the cost of service. There was no indication in this proceeding that the demand or customer components would be affected. The authorized increases will therefore be on the uniform cents-per-therm basis that we have used in PG&E's other recent gas offset proceedings.

In the order which follows we will authorize the following increases, on a uniform cents-per-therm basis:

For Increased Cost of California Gas	$ 2,911,000/Yr.	0.034¢/therm
For Increased Cost of El Paso Gas	23,373,000	0.272
For Increased Cost of Canadian Gas	115,022,000	1.337
Total	$141,306,000/Yr.	1.643¢/therm

Of this increase 1.371¢ per therm is to offset increases in the price of California and Canadian gas, effective July 1, 1974, and the remaining 0.272¢ per therm for El Paso gas effective July 10, 1974.

The various classes of service will be increased by the following amounts and percentages:

Class of Service	A.54616 California Sources Dollars	Percent	A. 54617 El Paso Dollars	Percent	A. 54618 Canadian Sources (PGT) Dollars	Percent	Total Dollars	Percent
General Service	1,205,000	0.3	9,673,000	2.7	47,602,000	13.1	58,480,000	16.1
Firm Industrial	88,000	0.4	706,000	3.4	3,476,000	16.5	4,270,000	20.3
Resale	34,000	0.5	275,000	4.0	1,354,000	19.7	1,663,000	24.2
Interruptible								
Regular	1,282,000	0.6	10,295,000	4.8	50,661,000	23.6	62,238,000	29.0
Steam - Electric	302,000	0.7	2,424,000	5.3	11,929,000	26.3	14,655,000	32.3
Total	2,911,000	0.5	23,373,000	3.6	115,022,000	17.6	141,306,000	21.7

Note: Base revenues by class are as adopted in Decision No. 80878, and as adjusted as shown in Exhibit 28.

Findings

1. PG&E has requested authority to offset the effect of increases in the price of gas from its various sources of supply.

2. An offset proceeding as differentiated from a general rate increase proceeding is designed to provide prompt timely relief of limited issues susceptible to abbreviated review processes.

3. Such issues should be limited to specific definable changes.

4. It is appropriate in this offset proceeding to consider only increases in the cost of purchased gas authorized by the Federal Power Commission or attributable to direct contract changes with the producers. Increases in the cost to serve not directly related to such increases should appropriately be determined in a general rate increase proceeding.

5. On July 1, 1974, PG&E will be exposed to an additional $2,891,600, annualized, in the cost of natural gas as a result of a 2¢ per Mcf escalation in the base price of gas purchased from California producers. Such increased costs can be offset by a revenue increase of $2,911,000.

6. The 2¢ per Mcf escalation in the base price of California source gas effective July 1, 1974, was provided for in the contracts negotiated prior to July 1, 1973. The increase in the base price will essentially increase the average price PG&E pays for 1974 estimated volumes by 2¢ per Mcf over the price that would have been paid had no escalation been included in the 1973 price negotiations. The additional 0.47¢ per Mcf that PG&E seeks to offset results not from the increase in price that is to become effective July 1, 1974, but from a change in the mix of purchases.

7. PG&E should be required to file quarterly reports on the gas taken from California sources. The report should be by load factor class and include the following detail: (1) amount of gas produced by months for the prior three months, (2) for the prior

12 months, the amount produced, the amount available, the minimum required take, and annual contract obligation. The filing of these reports should terminate with the quarter ending within ninety days after the effective date of our final decision in Application No. 54280.

8. On July 10, 1974, PG&E will be exposed to increases in the cost of natural gas purchased from El Paso Natural Gas Company. Such increases result from El Paso's rate increase application before the Federal Power Commission in Docket No. RP 74-57. The increase currently scheduled to go into effect on July 10, 1974, is 7.09¢ per Mcf. The 7.09¢ per Mcf increase in the price of gas results in $23,220,700, annualized, in PG&E's cost of gas which can be offset by a revenue increase of $23,373,000. Additionally, PG&E is potentially exposed to further increases in the cost of gas purchased from El Paso under FPC Docket No. RP 74-22. It is reasonable that PG&E be authorized to recover increases resulting from FPC Docket No. RP 74-22 whether such increases become effective on July 10, 1974, or some later date provided such later date is not beyond December 31, 1974.

9. The El Paso increase effective July 10, 1974, under FPC Docket No. RP 74-57 is subject to possible reduction and refund. Any increase under FPC Docket No. RP 74-22 would, under the National Gas Act, also be subject to possible reduction and refund. Any rate increase by PG&E for the purpose of recovering these increases in cost of gas should be subject to refund and rate reduction to offset the effect of any refunds and rate reductions ordered by the FPC.

10. As of July 1, 1974, the cost of natural gas purchased from Canadian producers will increase by 28.4¢ per Mcf (Canadian) or an annual increase of $108,519,000 (Canadian) which can be offset by a revenue increase of $115,022,000 (U.S.).

11. The new field prices negotiated by PG&E's Canadian subsidiary effectively doubles the average price currently being flowed through to the rates applicable to PG&E's Gas Department customers and are considered by the Alberta government to be the minimum acceptable levels.

12. Gas purchased in Canada must be paid for in Canadian currency, whereas PG&E's revenues are collected in lawful money of the United States.

13. Foreign exchange differentials are an unavoidable factor in the cost of gas purchased in Canada and are properly reflected in rates.

14. An exchange rate of $1.03125 Canadian equal to $1.00 U.S. is reasonable for the purpose of this proceeding.

15. The Commission has not previously authorized rates designed to provide funds to pay interest charges on money advanced by Alberta and Southern to support gas exploration and development activities. Consistent with Finding 4 no allowance for the flow through of such interest will be made in the rates authorized herein.

16. The General Counsel of the Commission should be directed to confer with representatives of the United States Department of State, and such other federal agencies as may be appropriate and enlist their advice and aid for the purpose of securing effective representation before the appropriate Canadian federal and provincial governmental bodies and agencies in future executive, legislative, judicial, and regulatory proceedings involving the cost of natural gas imported into the United States from Canada.

17. The record in Applications Nos. 54616, 54617, and 54618 should be incorporated into the record of Applications Nos. 54279, 54280, and 54281 now pending before the Commission.

18. All reports required by previous decisions of the Commission affecting the Gas Department of PG&E should continue to be filed.

19. PG&E should be authorized to increase rates to its customers, by a uniform 1.643¢ per therm, to provide increased revenues of $141,306,000 per year to offset increased costs of natural gas.

20. The increased rates will merely offset increase in the cost of gas and PG&E's rate of return for the adjusted year 1973 will not exceed 7.20 percent, which is less than that last found reasonable in Decision No. 80878.

<u>Conclusion</u>

Based on the foregoing findings PG&E should be granted the authority sought in Applications Nos. 54616, 54617, and 54618 to the extent set forth in the order which follows.

<u>O R D E R</u>

IT IS ORDERED that:

1. Pacific Gas and Electric Company (PG&E) is authorized to increase its gas rates by 1.371¢ per therm to offset increases in the price paid for gas purchased from Canadian and California producers effective July 1, 1974.

2. PG&E is further authorized to increase its gas rates to offset increases in the price paid for gas purchased from El Paso Natural Gas Company, as follows:

a. FPC Docket No. RP 74-57: .272¢ per therm effective July 10, 1974, or a lesser amount consistent with any reduction in the 7.09¢ per Mcf increase that might be ordered by the FPC.

b. FPC Docket No. RP 74-22: Increased rates to offset increases ordered by the FPC effective July 10, 1974, or at a later date provided such later date does not extend beyond December 31, 1974.

c. Calculation of rate increases offsetting actual increases authorized by the Federal Power Commission shall be consistent with Table C of Exhibit 26.

PG&E shall pass on to its customers any reduced rates, and refund to its customers any refund from El Paso Natural Gas Company pursuant to order of the Federal Power Commission in Dockets Nos. RP 74-57 and RP 74-22.

3. Tariff filings to reflect the authorized increases shall be made in accordance with General Order No. 96-A and shall include consistent revisions to the contingent offset provisions contained in the preliminary statement. The revised tariff schedules shall become effective one day after the date of filing and shall apply only to service rendered on and after the effective date thereof.

4. PG&E shall file, commencing within thirty days after the effective date of this order and every ninety days thereafter, quarterly reports on the gas taken from California sources. Such reports should be for calendar quarters, be by load factor class, and include the following data:

a. The amount produced by months for the prior three months.

b. For the prior 12 months, the amount produced, the amount available, the minimum required take, and annual contract obligation.

The filing of these reports shall terminate with the quarter ending within ninety days after the effective date of our final decision in Application No. 54280.

5. The General Counsel of the Commission is hereby directed to confer with representatives of the United States Department of State, and such other federal agencies as may be appropriate, and enlist their advice and aid for the purpose of securing effective representation before the appropriate Canadian federal and provincial governmental bodies and agencies in future executive, legislative, judicial,

and regulatory proceedings involving the cost of natural gas imported into the United States from Canada.

6. The record in Applications Nos. 54616, 54617, and 54618 is hereby incorporated into the record of Applications Nos. 54279, 54280, and 54281 now pending before the Commission.

7. All reports required by previous decisions of the Commission affecting the Gas Department of PG&E shall continue to be filed.

The effective date of this order is the date hereof.

Dated at San Francisco, California, this 9th day of JULY 9, 1974.

Vernon L. Sturgeon
President

William Symons Jr.

D W Holmes

Commissioners

APPENDIX A
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LIST OF APPEARANCES

Applicant: John C. Morrissey, Malcolm H. Furbush, Robert Ohlbach, Joseph S. Englert, by Malcolm H. Furbush, Robert Ohlbach, and Donald L. Freitas, Attorneys at Law, for Pacific Gas and Electric Company.

Protestants: Mrs. Sylvia M. Siegel, for herself, Toward Utility Rate Normalization, Consumer Federation of California, Consumers Cooperative of Berkeley, Consumers United, Inc., Diablo Valley Consumer Action, and Alameda County Consumer Action; Robert L. Gnaizda, Attorney at Law, for American G.I. Forum, League of United Latin American Citizens, National Organization for Women, Black Women Organized for Action, NAACP Western Region, Mexican-American Political Association, and Coalition for Utility Reform; Thomas J. Graff, Attorney at Law, and Richard E. Gutting, Jr., for Environmental Defense Fund; James J. Cherry, Attorney at Law, for San Francisco Consumer Action; Donald P. McCullum, Attorney at Law, for City of Berkeley; and Wayne A. McFadden, City Attorney, for City Council, City of Foster City.

Protestant and Intervenor: William M. Bennett, Attorney at Law, for Consumers Arise Now and for himself.

Interested Parties: Brobeck, Phleger & Harrison, by Gordon E. Davis, Attorney at Law, and Robert E. Burt, for California Manufacturers Association; Overton, Lyman & Prince, by Donald H. Ford, Attorney at Law, for Southwestern Portland Cement Company; John R. Phillips, Attorney at Law, for Planning and Conservation League; J. Randolph Elliott, Attorney at Law, for California Portland Cement Co.; William Knecht and William H. Edwards, Attorneys at Law, for California Farm Bureau Federation; Curtis L. Wagner, Jr., and Colonel Frank J. Dorsey, Attorneys at Law, for The Secretary of Defense on behalf of the Consumers Interests of the Executive Agencies of the United States; Warren L. Williams, Attorney at Law, for Valley Nitrogen Producers, Inc.; Edward A. Boehler, for California Ammonia Company; Thomas M. O'Connor, City Attorney, by Robert R. Laughead, for City and County of San Francisco; Michael W. McFunk, for McFunk Enterprises - The Electronic and Construction Divisions; Donald F. X. Finn, for himself; Silver, Rosen, Fischer & Stecher, by John Paul Fischer, Attorney at Law, for the City of Palo Alto; Robert Salter, David B. Follett, and E. A. Tharpe, III, Attorneys at Law, for Southern California Gas Company; Charles J. Mackres, Attorney at Law, for Department of Defense; Farrow, Cahill, Kaswell & Shieldhouse, by Larry B. Dent, Attorney at Law, for California Community Television Association; James F. Sorensen, for Friant Water Users Association, Alpaugh Irrigation District, No. San Joaquin Water Conservation District;

Robert Nykodym, Attorney at Law, for City of San Pablo; George T. Lenehan, Attorney at Law, for The Executive Agencies of the United States Government; Fred Bray and Dennis Woodruff, Attorneys at Law, for California Public Interest Law Center; Henry F. Lippitt, 2nd, Attorney at Law, for California Gas Producers Association; and Edward V. Sherry, for Air Products & Chemicals Inc.

Commission staff: Richard D. Gravelle and Robert T. Baer, Attorneys at Law, Tedd F. Marvin, and K. C. Chew.