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Decision 91-12-049 December 18, 1991

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

ORIGINAL

In the Matter of the Application of SOUTHWEST GAS CORPORATION for Authority to Change Natural Gas Rates in San Bernardino and Placer Counties, California. (U 905 G)	Application 91-01-027 (Filed January 23, 1991)

Edward C. McMurtrie, Attorney at Law, for Southwest Gas Corporation, applicant.
Messrs. Brady & Berliner, Attorneys at Law, for LUZ Partnership Management, and Donald Clary, Assistant General Counsel, for LUZ International, interested parties.
Philip Weismehl, Attorney at Law, and Maurice Monson, for Division of Ratepayer Advocates.

OPINION

I. Summary

This decision adopts test year 1992 revenues, revenue allocation, and rates for Southwest Gas Corporation (Southwest) in accordance with the stipulations reached by the three parties to this general rate case proceeding - Southwest, LUZ Partnership Management (LUZ), and the Commission's Division of Ratepayer Advocates (DRA).

For the Southern California Division of Southwest, an increase of $2.57 million over present revenues of $61.00 million, or a 4.2% increase in average rates, is approved. For the Northern California Division, a decrease of $0.90 million from present revenues of $6.70 million, or a 13.4% decrease in average rates, is approved.

The only contested issue in this general rate case was the availability and level of a cogeneration parity rate for LUZ. That issue is resolved as follows: The Schedule No. G-COG rate of Pacific Gas and Electric Company (PG&E) is adopted as the basis of Southwest's cogeneration parity rate; Southwest will continue to collect all of its margin from its cogeneration service customer (LUZ); and the cogeneration service rate will be credited with the increment necessary to maintain its parity with PG&E's utility electric generation (UEG) rate.

We provide that future revenue allocation and rate design issues with respect to Southwest's rates for its Southern California Division will be addressed in a biennial cost allocation proceeding (BCAP). The stipulation between Southwest and DRA on results of operations for the test year and attrition years is adopted. The supplemental stipulation between Southwest, LUZ, and DRA concerning revenue allocation and rate design is also adopted.

II. Statement of the Case

A. Application of Southwest Gas

On January 23, 1991, Southwest filed the instant application for a general rate increase based on a 1992 test year and including 1993 and 1994 as attrition years. Southwest owns and operates natural gas distribution systems in two discrete service areas in California. They are the "Southern California Division," which is located in San Bernardino County, and the "Northern California Division," which is located in Placer County. These two service areas are operated as separate areas for ratemaking purposes.

Southwest requested a $4,296,552 increase for its Southern California Division and a $656,088 decrease for its Northern California Division for its 1992 test year annual gross revenues.[1] These changes represent an average 6.72% increase in Southern California Division rates and an average 9.99% decrease in Northern California Division rates. Southwest states that rapid growth in its Southern California Division service area, along with increases in the cost of materials, wages, O&M, and taxes necessitate the requested increase. In its Northern California Division, slow growth and depreciation of existing plant produce an overall reduction in revenue requirement. Without rate relief in test year 1992, Southwest claims it will earn a rate of return of

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1 Attrition year revenue increases were also requested as follows: 1993 - Southern California Division $1.75 million, Northern California Division ($50,000) and 1994 - Southern California Division $1.96 million, Northern California Division ($40,000).

(Edison).[4] LUZ claimed it is entitled to a rate no higher than that paid by Edison to Southern California Gas Company (SoCalGas) under the latter's Schedule GT-5 tariff for gas used in the generation of electricity.[5] LUZ also claimed that Southwest should not directly pass through the demand charge component of PG&E's wholesale transportation rate as allocated by PG&E to core and noncore customers.[6]

C. <u>Section 311 Comment Process</u>

The proposed decision of the assigned Administrative Law Judge (ALJ) was mailed and served pursuant to Public Utilities (PU) Code Section 311 and Rule 77.1 of the Commission's Rules of Practice and Procedure (Rules) on November 18, 1991. Comments on the proposed decision were received from Southwest, LUZ, and DRA. The comments of Southwest and DRA addressed the need to revise Appendix A to reflect the 1992 cost of capital authorized for Southwest in Decision (D.) 91-11-059. The version of Appendix A attached to this final order does list costs and revenues based on Southwest's authorized rate of return and return on common equity for 1991 of 11.73% and 13.05%, respectively. The comments of LUZ support the proposed decision.

On November 22, 1991, Southwest filed its Advice Letter No. 436. The purpose of this advice letter filing was to:

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4 All of LUZ' SEGS projects are qualifying facilities which sell their electric power output to Edison.

5 Edison's gas-fired powerplants receive natural gas service from SoCalGas and PG&E; Edison does not take service from Southwest.

6 Southwest had proposed to assign core and non-core upstream costs directly to the respective groups. The assignment would be based on PG&E's Advice Letter No. 1624-G B, which specifically assigned costs to Southwest's core and noncore customers. Since this proceeding was submitted, PG&E has withdrawn that portion of the advice letter.

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8.04% on its Southern California Division operations. The proposed rates would yield a rate of return of 11.73% for test year 1992.[2]

B. Participation by DRA and LUZ

DRA and LUZ, an industrial customer engaged in the solar generation of electricity in Southwest's Southern California Division, were the only other parties to enter appearances.

DRA recommended that Southwest's rates for the Southern California Division be established to produce an annual revenue increase of $1,708,801. According to DRA, revenues for the Northern California Division should be decreased by $934,614. DRA's recommendations would result in an average 6.26% increase in Southern California Division rates and an average 13.65% decrease in Northern California Division rates.

LUZ is Southwest's largest customer in its Southern California Division service area, accounting for 25.6% of all Southern California Division therms forecast for 1992.[3] It purchases gas from Southwest for its SEGS units and sells the resultant electric output to Southern California Edison Company

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2 In Decision (D.) 89-11-057, the Commission authorized for Southwest a rate of return of 11.73%, based upon a 13.05% return on common equity. The rates authorized by this proceeding are based on Southwest's cost of capital adopted for 1992 in Application (A.) 91-05-018. The attrition adjustments will be modified to be consistent with the cost of capital adopted for Southwest during 1993 and 1994.

3 In test year 1992, LUZ expects to accept delivery of 5.3 million therms (MMth) of gas at its solar electric generating station (SEGS) projects located near Daggett and 23.1 MMth of gas at its Harper Lake SEGS projects. Southwest provides service to the Daggett SEGS units under its Schedule GN-2 tariff. Service to the Harper Lake SEGS units is provided pursuant to a negotiated contract between Southwest and LUZ that was signed on May 18, 1989 and amended on December 14, 1990 (special contract).

(Edison).[4] LUZ claimed it is entitled to a rate no higher than that paid by Edison to Southern California Gas Company (SoCalGas) under the latter's Schedule GT-5 tariff for gas used in the generation of electricity.[5] LUZ also claimed that Southwest should not directly pass through the demand charge component of PG&E's wholesale transportation rate as allocated by PG&E to core and noncore customers.[6]

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5 Edison's gas-fired powerplants receive natural gas service from SoCalGas and PG&E; Edison does not take service from Southwest.

6 Southwest had proposed to assign core and non-core upstream costs directly to the respective groups. The assignment would be based on PG&E's Advice Letter No. 1624-G B, which specifically assigned costs to Southwest's core and noncore customers. Since this proceeding was submitted, PG&E has withdrawn that portion of the advice letter.

1) update the balancing account surcharges applicable to the purchased gas cost, supply adjustment mechanism, and low income ratepayer assistance provisions of Southwest's tariffs and 2) to withdraw certain advice letter filings. Advice Letter No. 436 would establish revised surcharge rates which would amortize Southwest's balancing accounts as of September 30, 1991 and merge certain funds consistent with a Commission resolution.

At the same meeting at which we issued this decision, we approved Southwest Advice Letter No. 436. Since the terms of Advice Letter No. 436 are to become effective on January 1, 1992, it is reasonable to amortize the approved balancing account balances in the adopted rates for Southwest. The ALJ had requested Southwest to recalculate the relevant schedules in Appendix A so that the balances will be amortized in test year 1992 rates. Southwest provided the schedules as late-filed Exhibit 24. Exhibit 24 reflects Southwest's approved rate of return for 1992 and the terms of approved Advice Letter No. 436. No objection to Exhibit 24 has been received. Appendix A to the ALJ's proposed decision has been replaced by Exhibit 24.

III. The Parties' Settlements

A. Settlement of Results of Operations Issues

1. Procedural Background

A prehearing conference was held on March 15, 1991 at which the ALJ established a procedural schedule for the proceeding. Public participation hearings were held on July 1 and July 8, 1991 at Kings Beach and Victorville, respectively.

Southwest's rate filing was accompanied by a full set of workpapers supporting the utility's cost estimates. On June 24, 1991, DRA distributed proposed exhibits, including its report on the results of operations of Southwest's two operating divisions.

On July 15, 1991, LUZ filed its testimony concerning Southwest's proposed rates for the Southern California Division.

During July of 1991, the parties began to explore the settlement of some or all of the issues in this proceeding. On July 30, 1991, in conformance with Rule 51.1(b), Southwest served a written notice of settlement conference upon LUZ and DRA. The settlement conference was attended by representatives of all three parties on August 7, 1991.

2. Stipulation on Results of Operations

On August 16, 1991, the "Joint Motion for Adoption of Stipulation and Settlement Agreement and for Waiver" (Motion) was jointly filed by Southwest and DRA. The Motion was accompanied by a Stipulation and Settlement Agreement (Stipulation) signed by representatives of Southwest and DRA (settling parties). The settling parties urge the Commission to find that the costs and noncost elements contained in the Stipulation are just and reasonable for Southwest's operations during test year 1992 and attrition years 1993 and 1994.

The Stipulation governs operating revenues and margin, O&M expenses, depreciation and amortization expenses, taxes, rate base, and demand-side management programs. Summaries of the agreed-upon results of operations for test year 1992 and attrition years 1993 and 1994, comparisons of numbers initially proposed by Southwest and DRA with the stipulated amounts, and a cost summary for demand-side management programs are all attached as Appendix A of this decision.

For the Southern California Division, the parties have agreed to an increase in present revenues of $61.00 million by $2.57 million, resulting in a 4.2% increase in system average rates. For the Northern California Division, the parties have agreed to a decrease in present revenues of $6.70 million by $0.90 million, yielding a 13.4% decrease in revenues.

The stipulated revenue levels were calculated using Southwest's authorized rate of return and return on common equity for 1991 of 11.73% and 13.05%, respectively. This decision incorporates the cost of capital authorized for Southwest by D.91-11-059 in A.91-05-018, the generic cost of capital proceeding. The Summary of Southwest/DRA's Comparison Exhibit which was submitted as Appendix A of the Stipulation has been modified to reflect the adopted cost of capital and is attached to this decision as Appendix A. The authorized revenues for attrition years 1993 and 1994 will be amended annually to reflect the Commission's annual adoption of a reasonable cost of capital for Southwest. Also, the escalation rates which determine the increase in authorized O&M and administrative and general expenses during attrition years will be subject to adjustment when Southwest makes its annual operational attrition filing.

In their Motion, the settling parties request the Commission to waive the comment requirements of Rules 51.4 and 51.5. They propose that any hearings on the Stipulation that may be required by Rule 51.6 be held at the same time and place as set for evidentiary hearing. LUZ was the only other party to this proceeding, but it was not concerned with the subject of the Stipulation and did not request a hearing on the Stipulation. LUZ did not object to the request for waiver of the Rules. The waiver is granted.

B. <u>Settlement of Rate Design Issues</u>

At the time the settlement agreement on results of operations issues was reached, Southwest, DRA, and LUZ were unable to reach agreement on revenue allocation and rate design. Hearings were held on August 21 and 22, 1991 to receive evidence on these issues. Witnesses representing Southwest, DRA, and LUZ offered testimony on the issues of rate design and revenue allocation.

1. Cogeneration Parity Rate

The primary issue for evidentiary hearing was the availability of a cogeneration parity rate to LUZ. A cogeneration parity rate is required under Public Utilities (PU) Code Sections 454.4 and 454.6.

PU Code $ 454.4 states, in relevant part:

> "The commission shall establish rates for gas which is utilized in cogeneration technology projects not higher than the rates established for gas utilized as a fuel by an electric plant in the generation of electricity, except that this rate shall apply only to that quantity of gas which an electrical 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 ...."

Section 454.6 contains identical language describing the rate which is to be provided to SEGS projects.

This issue arose because Southwest has no utility electric generation (UEG) customers and thus no UEG rate that could be used to establish a cogeneration parity rate. A cogeneration parity rate could be based on the UEG rate of PG&E, from whom Southwest purchases all the gas used to serve its Southern California Division. LUZ, however, claimed its rate should not exceed SoCalGas UEG gas rate paid by Edison, the utility that purchases its electric output.

When the Commission unbundled and established separate rates for gas utility procurement and transportation service, it interpreted the parity statutes to require utilities to set the transportation component of the rate for service to cogenerators "at parity with" the transportation rate for UEG gas usage.

There is no operational basis for Southwest to establish a UEG transportation rate because Southwest's rates are established on the basis of usage. This particular utility does not have any

UEG customers. The transportation rates offered by Southwest to LUZ under Schedule GN-2 and under the special contract rate exceed the UEG rate paid by Edison, which purchases LUZ' electric output.

If Southwest's GN-2 rate were set at the UEG rate of either SoCalGas or PG&E, the difference between revenues to be collected under Southwest's cold year allocation and the UEG parity rate would create a "cogeneration shortfall." That revenue amount would have to be collected from Southwest's noncogeneration customers so that Southwest could earn its authorized rate of return.

Changing circumstances also complicated this issue. At the time of the hearings on the issue of Southwest's rate design, PG&E had proposed to assign separate gas transportation rates and charges to Southwest's core and noncore customers. Southwest intended to allocate directly to the respective groups those costs identified by its upstream supplier as core and noncore costs. Approximately two months after the close of evidentiary hearing, however, PG&E deleted its proposed distinction between core and noncore users. This removed from the record any rational basis besides cold year throughput for allocating revenues.

On October 18, 1991, the ALJ convened a meeting of the parties and ordered them to jointly file an updated exhibit on revenue allocation and rate design to reflect the current state of the record. Accordingly, an updated calculation of the cogeneration shortfall, revenue allocation, and rate design was filed on October 28, 1991.

2. <u>Motion for Adoption of Supplemental Stipulation</u>

On November 6, 1991, Southwest, LUZ, and DRA (moving parties) jointly filed their "Joint Motion for Adoption of Supplemental Stipulation and Settlement Agreement and for Waiver" (Motion). The Supplemental Stipulation adopts PG&E's Schedule G-COG rate as the cogeneration parity rate available to cogenerators served by Southwest, revises Southwest's rates to separately state a transport rate and a gas cost rate, and coordinates Southwest's participation in the gas industry restructuring program with that of its supplier, PG&E. Approval and adoption of the Supplemental Stipulation, along with the Stipulation on results of operations filed by Southwest and DRA, will completely resolve all issues in this proceeding.

The moving parties state that they realized the potential for reaching settlement only after PG&E revised its wholesale rates to Southwest and the ALJ required a recalculation of the cogeneration shortfall. The process of developing the late-filed exhibit enabled the parties to reach compromise on the remaining contested issues.

All of the parties to the proceeding have joined in the Supplemental Stipulation. No party, as defined in Rule 51(a), will be filing comments upon the settlement or contesting the settlement agreement. The moving parties request a waiver of the Commission's settlement rules requiring a noticed conference prior to execution of the stipulation (Rule 51.1) and a comment period (Rule 51.4). Waiver of Rule 51.2, which authorizes parties to propose a stipulation or settlement within 30 days after the last day of hearing, is also requested.

We find it reasonable to waive the settlement rules as requested because all parties to the proceeding are jointly sponsoring the Supplemental Stipulation, no party will file comments or contest the stipulation, and the stipulation was made possible by events over which no party could exercise control and that occurred more than two months after the close of evidentiary hearing.

3. Terms of Supplemental Settlement

The Supplemental Stipulation is intended to complement the original Stipulation. It resolves the revenue allocation and rate design issues that were contested at hearing. It also proposes a means by which Southwest will unbundle its gas and transportation rates, revise its cost allocation procedures and otherwise participate in the Commission's restructuring of the gas industry.

Under the Supplemental Stipulation, PG&E's Schedule No. G-COG rate is adopted as the basis of Southwest's cogeneration parity rate. While Southwest will continue to collect all of its margin from its cogeneration service customer (LUZ), the cogeneration service rate will be credited with the increment necessary to maintain its parity with PG&E's UEG rate. That credit constitutes the cogeneration shortfall, which will be collected in a balancing account and then allocated among non-cogeneration customer classes based on their percentage of revenues compared to total Southern California Division revenues.

The parties offer "Revenue Allocation and Rate Design Procedures" to implement the Stipulation. Under the allocation methodology, 75% of the incremental revenues will be allocated based upon the relative cost of service to each class, and 25% of the incremental revenues will be allocated based upon the system average change. A rate cap will be imposed to ensure gradual movement in rates. Under this cap, the increase above the system average increase will be limited to 10% and 5% for the Southern and Northern California Divisions, respectively.

According to the Supplemental Stipulation, Southwest's noncore customers will be removed from Southwest's Gas Cost Balancing Account; their gas rates will be adjusted each month to account for the prior month's actual gas cost. Future revenue allocation and rate design issues with respect to Southwest's rates for its Southern California Division will be addressed in BCAP.

C. Standard of Review for Settlements

"The Commission will not approve stipulations or settlements, whether contested or uncontested, unless the stipulation or settlement is reasonable in light of the whole record, consistent with law, and in the public interest." (Rule 51.1(e).)

The Commission has also reviewed settlements on the same grounds as those employed by federal courts in their review of class action settlements. We have evaluated the fairness of a settlement on the basis of the relationship of the amount agreed upon to the risk of obtaining the desired result.

"In a proceeding under the Rate Case Plan... (such as this one), the settlement must be supported by a comparison exhibit indicating the impact of the settlement in relation to the utility's application. If the participating staff supports the settlement, it must prepare a similar exhibit indicating the impact of the proposal in relation to the issues it contested, or would have contested, in a hearing." (Rule 51.1(c).)

The Stipulation on results of operations proposed by Southwest and DRA comprehensively resolves all issues presented by Southwest's general rate case application, except for revenue allocation and rate design. That remaining issue was examined in evidentiary hearing and extensively briefed by all three parties. The independently prepared testimonies of Southwest, LUZ, and DRA were received in the record. In these testimonies, all of the parties fully advocated the merits of their positions. Southwest, LUZ, and DRA were represented by experienced attorneys and witnesses with proven ability. No settlement was proposed until after the parties had undertaken a thorough review of the issues and had had sufficient time and resources to present their positions.

The Southwest/DRA comparison exhibit attached to the August stipulation on results of operations reveals that the stipulated amounts represent a fair compromise of the parties' positions. On the issue of rate design, the joint exhibit required by the ALJ in October compared the parties' litigation positions with their ultimate stipulation. That exhibit illustrated the change in cogeneration shortfall from an estimated $1.2 million, based on the testimony of Southwest and DRA, to an estimated $379,674, based on the Supplemental Stipulation.

At hearing and in the briefs, the major issue was whether certain LUZ facilities were entitled to a cogeneration parity rate because they are being served under a special contract. The load represented by those facilities contributes only 27% of the cogeneration shortfall; 73% of the shortfall is attributed to facilities the parties agreed were entitled to the parity rate. Thus, the Supplemental Stipulation results in only $105,603 of incremental revenue allocation to non-cogeneration customer classes. We find that the incremental burden on non-cogeneration customers is offset by the potential benefits to all ratepayers resulting from Southwest's prompt integration into our gas industry restructuring program.

The Stipulation and the Supplemental Stipulation were reached through a process whereby all of the settling parties had a fair opportunity to develop their positions and to advocate their interests. This tends to ensure that the result is fair to the parties and their constituents. The Stipulation and the Supplemental Stipulation should be approved.

The appendices to the Stipulation should be adopted as the results of operations for Southwest's test year 1992 and attrition years 1993 and 1994. They are attached as Appendix A of this decision. The Supplemental Stipulation provides the gas costs, class cost of service, class revenue allocation, and statement of rates necessary to conform Southwest's tariff sheets with this decision. The "Supplemental Stipulation and Settlement Agreement" dated November 6, 1991 is attached as Appendix B. The rates, revenue allocation, class cost of service, and other attachments to the Supplemental Stipulation are attached as Appendix C. We also adopt the proposed BCAP schedule; the proposed coordination with PG&E's BCAP should enable Southwest to better match its costs and revenues.

IV. Conclusion

Base rates for Southwest should be revised to implement the results of operations contained in the Stipulation between Southwest and DRA filed on August 16, 1991. Base rate revenues for test year 1992 as well as attrition years 1993 and 1994 are adopted based on the attached Appendix A. Revenues should be allocated and rates should be designed according to the Supplemental Stipulation attached as Appendix B. Southwest should revise its rate schedules and tariff sheets to implement Appendix C. Southwest should also file an application for a BCAP as provided in the Supplemental Stipulation.

Findings of Fact

1. Southwest owns and operates natural gas distribution systems in two discrete service areas in California. The "Southern California Division" is located in San Bernardino County; the "Northern California Division" is located in Placer County.

2. On January 23, 1991, Southwest filed the instant application for a general rate increase based on a 1992 test year and including 1993 and 1994 as attrition years.

3. Southwest requested a $4,296,552 increase for its Southern California Division and a $656,088 decrease for its Northern California Division for its test year 1992 annual gross revenues.

4. DRA and LUZ, an industrial customer engaged in the solar generation of electricity in Southwest's Southern California Division, were the only other parties in this case.

5. DRA recommended that Southwest's rates for the Southern California Division be established to produce an annual revenue

increase of $1,708,801; for the Northern California Division, a revenue decrease of $934,614.

6. Southwest's rate filing was accompanied by a full set of workpapers supporting the utility's cost estimates. On June 24, 1991, DRA distributed proposed exhibits, including its report on the results of operations of Southwest's two operating divisions. On July 15, 1991, LUZ filed its testimony concerning Southwest's proposed rates for the Southern California Division.

7. On July 30, 1991, Southwest served a written notice of settlement conference upon LUZ and DRA. The settlement conference was attended by representatives of all three parties on August 7, 1991.

8. On August 16, 1991, the "Joint Motion for Adoption of Stipulation and Settlement Agreement and for Waiver" (Motion) was jointly filed by Southwest and DRA.

9. The Motion was accompanied by a Stipulation signed by representatives of Southwest and DRA. The Stipulation governs operating revenues and margin, O&M expenses, depreciation and amortization expenses, taxes, rate base, and demand-side management programs for Southwest's operations during test year 1992 and attrition years 1993 and 1994.

10. The Stipulation increases present revenues of $61.00 million by $2.57 million, resulting in a 4.2% increase in Southern California Division revenues. The Stipulation decreases present revenues of $6.70 million by $0.90 million, resulting in a 13.4% decrease in Northern California Division revenues.

11. The stipulated revenue levels were calculated using Southwest's authorized rate of return and return on common equity for 1991 of 11.73% and 13.05%, respectively.

12. Since the time of the stipulation the Commission has issued D.91-11-059, which authorized a rate of return and return on common equity for Southwest for 1992 of 11.26% and 12.75%,

respectively. The adopted revenue requirement should reflect this latest decision on Southwest's cost of capital.

13. The authorized revenues for attrition years 1993/1994 and the escalation rates which determine the increase in authorized O&M and administrative and general expenses during attrition years will be amended annually to reflect annual cost of capital and operational attrition changes.

14. Evidentiary hearings were held on August 21 and 22, 1991 to receive evidence and testimony from witnesses representing Southwest, LUZ, and DRA on the issues of revenue allocation and rate design.

15. The settlement rules should be waived with respect to the August 16, 1991 Stipulation because LUZ is the only other party to the proceeding, LUZ was not concerned with the issues addressed by the settlement, and LUZ attended the evidentiary hearing.

16. The parity statutes require utilities to set the transportation component of the rate for service to cogenerators "at parity with" the transportation rate for UEG gas usage.

17. There is no operational basis for Southwest to establish a UEG rate because Southwest does not have any UEG customers and rates are established on the basis of usage, among other things.

18. All of the gas used in Southwest's Southern California Division is purchased from PG&E.

19. If Southwest's GN-2 rate were set at the UEG rate of either PG&E or SoCalGas, the difference between revenues to be collected under Southwest's cold year allocation and the UEG parity rate would create a "cogeneration shortfall."

20. When PG&E filed a rate change two months after evidentiary hearing, the assigned ALJ required the moving parties to jointly file an updated exhibit to recalculate the cogeneration shortfall.

21. An updated calculation of the cogeneration shortfall, revenue allocation, and rate design was filed on October 28, 1991.

22. On November 6, 1991, Southwest, LUZ, and DRA (moving parties) jointly filed their "Joint Motion for Adoption of Supplemental Stipulation and Settlement Agreement and for Waiver" (Motion).

23. All of the parties to the proceeding have joined in the Supplemental Stipulation.

24. We find it reasonable to waive the settlement rules because all parties to the proceeding are jointly sponsoring the Supplemental Stipulation, no party will file comments or contest the stipulation, and the stipulation was made possible by events over which no party could exercise control and that occurred more than two months after the close of evidentiary hearing.

25. The Supplemental Stipulation resolves the cogeneration parity issue as follows: PG&E's Schedule No. G-COG rate is adopted as the basis of Southwest's cogeneration parity rate; Southwest will continue to collect all of its margin from its cogeneration service customer (LUZ); and the cogeneration service rate will be credited with the increment necessary to maintain its parity with PG&E's UEG rate.

26. The Supplemental Stipulation provides that future revenue allocation and rate design issues with respect to Southwest's rates for its Southern California Division will be addressed in BCAP.

27. The proposed BCAP schedule should enable Southwest to better serve its customers by matching its costs and revenues.

28. The incremental burden on non-cogeneration customers due to the cogeneration shortfall is offset by the potential benefits to all ratepayers resulting from Southwest's prompt integration into our gas industry restructuring program.

29. The Stipulation and the Supplemental Stipulation were reached through a process whereby all of the settling parties had a fair opportunity to develop their positions and to advocate their interests.

30. The Stipulation and the Supplemental Stipulation, taken as a whole, constitute a resolution that is in the best interests of ratepayers and utility shareholders.

31. Advice Letter No. 436, filed on November 22, 1991, calculates the balances in Southwest's purchased gas account, supply adjustment mechanism, and low income ratepayer assistance balancing accounts as of September 30, 1991.

32. On December 12, 1991, pursuant to direction from the ALJ, Southwest served its late-filed Exhibit 24 on all parties. Exhibit 24 reflects Southwest's approved rate of return for 1992 and includes the balances shown in Advice Letter No. 436 in revenues and rates. No objection to Exhibit 24 has been received.

33. On December 18, 1991, the Commission approved Southwest Advice Letter No. 436. Appendix A of this decision incorporates the terms of the advice letter.

34. This order should be effective today to enable Southwest to promptly revise its rate schedules and tariff sheets to implement the approved rates and revenues on January 1, 1992.

<u>Conclusions of Law</u>

1. The "Joint Motion for Adoption of Stipulation and Settlement Agreement and for Waiver" filed by Southwest and DRA on August 16, 1991 should be granted.

2. The "Stipulation and Settlement Agreement" attached to the August 16, 1991 motion is reasonable.

3. The "Joint Motion for Adoption of Supplemental Stipulation and Settlement Agreement and for Waiver" filed by Southwest, LUZ, and DRA, on November 6, 1991, should be granted.

4. The "Supplemental Stipulation and Settlement Agreement" attached to the November 6, 1991 motion is reasonable.

O R D E R

IT IS ORDERED that:

1. The "Joint Motion for Adoption of Stipulation and Settlement Agreement and for Waiver" filed by Southwest Gas Corporation (Southwest) and Division of Ratepayer Advocates (DRA) on August 16, 1991 is granted.

2. The "Stipulation and Settlement Agreement" (Stipulation) attached to the August 16, 1991 motion is approved and adopted.

3. The "Joint Motion for Adoption of Supplemental Stipulation and Settlement Agreement and for Waiver" filed by Southwest, LUZ Partnership Management (LUZ), and DRA, on November 6, 1991, is granted.

4. The "Supplemental Stipulation and Settlement Agreement" attached to the November 6, 1991 motion is approved and adopted.

5. Effective on January 1, 1992, base rates for Southwest shall implement the results of operations contained in the Stipulation between Southwest and DRA filed on August 16, 1991, D.91-11-059 which adopted Southwest's 1992 rate of return, and Southwest Advice Letter No. 436. Base rate revenues for test year 1992 as well as attrition years 1993 and 1994 are adopted based on the results of operations tables that are attached to this decision as Appendix A.

6. Effective on January 1, 1992, revenues shall be allocated and rates shall be designed according to the Supplemental Stipulation between Southwest, LUZ, and DRA filed on November 6, 1991. Southwest shall revise its rate schedules and tariff sheets to implement the Supplemental Stipulation which is attached as Appendix B.

7. Southwest is authorized and directed to file with this Commission on or after the effective date of this order, and at least three days prior to their effective date, revised tariff schedules complying with this decision.

8. The revised tariff schedules shall become effective on or after January 1, 1992 and shall comply with General Order 96-A. The revised tariffs shall apply to service rendered on or after their effective date.

9. Southwest is authorized to file attrition adjustments for 1993 and 1994 based on the results of operations adopted in Appendix A.

10. Southwest shall file an application for biennial cost allocation proceeding (BCAP) as provided in the Supplemental Stipulation.

11. This proceeding is closed.

This order is effective today.

Dated December 18, 1991, at San Francisco, California.

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

I CERTIFY THAT THIS DECISION
WAS APPROVED BY THE ABOVE
COMMISSIONERS TODAY

Neal J. Shulman

NEAL J. SHULMAN, Executive Director

APPENDIX A

SOUTHWEST GAS CORPORATION
SOUTHERN CALIFORNIA DIVISION
COMPARISON EXHIBIT
SUMMARY

Line No.	Description (a)	Stipulated Amounts at Present Rates (b)	Revenue Increase (c)	Stipulated Amounts at Proposed Rates (d)	Line No.
	Operating Revenues				
1	Revenues [1]	$ 59,921,563	$ 2,341,149	$ 62,262,712	1
2	Less: Gas Cost	29,833,154	0	29,833,154	2
3	Net Operating Margin	$ 30,088,409	$ 2,341,149	$ 32,429,558 [2]	3
	Operating Expenses				
4	Other Gas Supply	$ 11,600	$ 0	$ 11,600	4
5	Transmission	6,866	0	6,866	5
6	Distribution	6,713,516	0	6,713,516	6
7	Customer Accounts	4,195,730	0	4,195,730	7
8	Uncollectibles	166,050	8,967	175,017	8
9	Customer Service	393,375	0	393,375	9
10	Sales	22,218	0	22,218	10
11	Administrative & General	2,819,357	0	2,819,357	11
12	Depreciation	5,999,141	0	5,999,141	12
13	Taxes Other Than Income	1,869,079	25,927	1,895,006	13
14	State Income Taxes	438,042	234,613	672,655	14
15	Federal Income Tax	1,407,546	779,691	2,187,237	15
16	Total Operating Expense	$ 24,042,520	$ 1,049,198	$ 25,091,718	16
17	Net Operating Income	$ 6,045,889	$ 1,291,951	$ 7,337,840	17
18	Rate Base	$ 65,167,193		$ 65,167,193	18
19	Rate Of Return	9.28%		11.26%	19

[1] Revenues per Advice Letter No. 436, excluding $2,758,255 and $ 2,399,348 of balancing account surcharges in revenues at present and proposed rates respectively.

[2]

Net Operating Margin	$ 32,429,558
Less: Franchise & Uncollectibles on Gas Cost	404,522
Annual Base Cost Amount	$ 32,025,036

The Annual Base Cost Amount differs from the Revised Annual Base Cost Amount in Appendix A attached to Southwest's December 6, 1991 comments due to Franchises and Uncollectibles on the balancing account surcharge revenue.

Exhibit No. 24
Appendix A (2nd Revised)
A. 91-01-027
Sheet 2 OF 4

SOUTHWEST GAS CORPORATION
SOUTHERN CALIFORNIA DIVISION
COMPARISON EXHIBIT
SUMMARY

Line No.	Description (a)	SWG As Filed (b)	DRA As Filed (c)	Stipulated Adjustments (d)	Stipulated Amounts at Proposed Rates (e)	Line No.
	Operating Revenues					
1	Revenues	$ 68,193,799	$ 59,540,230	$ 2,722,482	$ 62,262,712 [1]	1
2	Less: Gas Cost	33,795,697	27,692,659	2,140,495	29,833,154	2
3	Net Operating Margin	$ 34,398,102	$ 31,847,571	$ 581,987	$ 32,429,558	3
	Operating Expenses					
4	Other Gas Supply	$ 14,120	$ 11,478	$ 122	$ 11,600	4
5	Transmission	6,722	6,802	64	6,866	5
6	Distribution	7,364,667	6,186,201	527,315	6,713,516	6
7	Customer Accounts	4,489,974	4,165,523	30,207	4,195,730	7
8	Uncollectibles	235,948	164,722	10,295	175,017	8
9	Customer Service	238,155	210,144	183,231	393,375	9
10	Sales	23,061	22,139	79	22,218	10
11	Administrative & General	2,999,113	2,819,227	130	2,819,357	11
12	Depreciation	5,986,658	5,952,198	46,943	5,999,141	12
13	Taxes Other Than Income	1,950,594	1,852,787	42,219	1,895,006	13
14	State Income Taxes	718,031	671,634	1,021	672,655	14
15	Federal Income Tax	2,319,279	2,200,561	(13,324)	2,187,237	15
16	Total Operating Expense	$ 26,346,322	$ 24,263,417	$ 828,301	$ 25,091,718	16
17	Net Operating Income	$ 8,051,780	$ 7,584,154	$ (246,314)	$ 7,337,840	17
18	Rate Base	$ 68,642,603	$ 64,656,052	$ 511,141	$ 65,167,193	18
19	Rate Of Return	11.73%	11.73%		11.26%	19

[1] Revenues per Advice Letter No. 436, excluding $2,758,255 and $ 2,399,348 of balancing account surcharges in revenues at present and proposed rates respectively.

SOUTHWEST GAS CORPORATION
NORTHERN CALIFORNIA DIVISION
COMPARISON EXHIBIT
SUMMARY

Line No.	Description (a)	Stipulated Amounts at Present Rates (b)	Revenue Increase (c)	Stipulated Amounts at Proposed Rates (d)	Line No.
	Operating Revenues				
1	Revenues [1]	$ 6,696,998	$ (892,407)	$ 5,804,591	1
2	Less: Gas Cost	3,157,753	0	3,157,753	2
3	Net Operating Margin	$ 3,539,245	$ (892,407)	$ 2,646,838 [2]	3
	Operating Expenses				
4	Other Gas Supply	$ 0	$ 0	$ 0	4
5	Transmission	0	0	0	5
6	Distribution	316,833	0	316,833	6
7	Customer Accounts	280,076	0	280,076	7
8	Uncollectibles	8,134	(1,098)	7,036	8
9	Customer Service	115,853	0	115,853	9
10	Sales	2,925	0	2,925	10
11	Administrative & General	337,587	0	337,587	11
12	Depreciation	460,611	0	460,611	12
13	Taxes Other Than Income	146,829	(7,615)	139,214	13
14	State Income Taxes	154,436	(80,374)	74,062	14
15	Federal Income Tax	518,718	(266,350)	252,368	15
16	Total Operating Expense	$ 2,342,002	$ (355,437)	$ 1,986,565	16
17	Net Operating Income	$ 1,197,243	$ (536,970)	$ 660,273	17
18	Rate Base	$ 5,863,980		$ 5,863,980	18
19	Rate Of Return	20.42%		11.26%	19

[1] Revenues per Advice Letter No. 436, excluding <$256,188> and <$120,213> of balancing account surcharges in revenues at present and proposed rates respectively.

[2]

Net Operating Margin	$ 2,646,838
Less: Franchise & Uncollectibles on Gas Cost	31,055
Annual Base Cost Amount	$ 2,615,783

The Annual Base Cost Amount differs from the Revised Annual Base Cost Amount in Appendix A attached to Southwest's December 6, 1991 comments due to Franchises and Uncollectibles on the balancing account surcharge revenue.

Exhibit No. 24
Appendix A (2nd Revised)
A. 91-01-027
Sheet 4 OF 4

SOUTHWEST GAS CORPORATION
NORTHERN CALIFORNIA DIVISION
COMPARISON EXHIBIT
SUMMARY

Line No.	Description (a)	SWG As Filed (b)	DRA As Filed (c)	Stipulated Adjustments (d)	Stipulated Amounts at Proposed Rates (e)	Line No.
	Operating Revenues					
1	Revenues	$ 5,910,789	$ 5,761,705	$ 42,886	$ 5,804,591 [1]	1
2	Less: Gas Cost	3,114,938	3,114,938	42,815	3,157,753	2
3	Net Operating Margin	$ 2,795,851	$ 2,646,767	$ 71	$ 2,646,838	3
	Operating Expenses					
4	Other Gas Supply	$ 4,510	$ 0	$ 0	$ 0	4
5	Transmission	0	0	0	0	5
6	Distribution	353,605	316,833	0	316,833	6
7	Customer Accounts	297,015	280,076	0	280,076	7
8	Uncollectibles	15,264	6,985	51	7,036	8
9	Customer Service	82,037	79,337	36,516	115,853	9
10	Sales	3,020	2,925	0	2,925	10
11	Administrative & General	363,349	337,587	0	337,587	11
12	Depreciation	471,442	460,611	0	460,611	12
13	Taxes Other Than Income	132,706	138,860	354	139,214	13
14	State Income Taxes	78,596	74,981	(919)	74,062	14
15	Federal Income Tax	267,239	260,940	(8,572)	252,368	15
16	Total Operating Expense	$ 2,068,783	$ 1,959,135	$ 27,430	$ 1,986,565	16
17	Net Operating Income	$ 727,068	$ 687,632	$ (27,359)	$ 660,273	17
18	Rate Base	$ 6,198,385	$ 5,862,172	$ 1,808	$ 5,863,980	18
19	Rate Of Return	11.73%	11.73%		11.26%	19

[1] Revenues per Advice Letter No. 436, excluding <$256,188> and <$120,213> of balancing account surcharges in revenues at present and proposed rates respectively.

Exhibit No. 24
Appendix B (2nd Revised)
A. 91-01-027
Sheet 1 OF 4

SOUTHWEST GAS CORPORATION
SOUTHERN CALIFORNIA DIVISION
1993 ATTRITION
$000

Line No.	Description (a)	Test Year 1992 (b)	Escalation Rates (c)	Escalation Amounts (d)	Non-Escalation Amounts (e)	Volumes (f)	Total (g)	Estimated 1993 (h)	Revenue Increase Attrition (i)	Attrition 1993 (j)	Line No.
1	Operating Revenues	$ 62,263				5,031	$ 5,031	$ 67,294	$ 229	$ 67,523	1
2	Gas Cost	29,833				2,731	2,731	32,564		32,564	2
3	Franchise & Uncollectibles	0				0	0	0		0	3
4	Operating Margin	$ 32,430				2,300	$ 2,300	$ 34,730	$ 229	$ 34,959	4
	O & M Expenses										
5	Labor	$ 5,309	3.60%	$ 191	$ 0		$ 191	$ 5,501	$	$ 5,501	5
6	Labor Loading	2,500	3.60%	90	0		90	2,590		2,590	6
7	Materials & Supplies	3,534	4.10%	145	0		145	3,679		3,679	7
8	Other	175			0		0	175	1	176	8
9	Total O & M	$ 11,518		$ 426	$ 0	$ 0	$ 426	$ 11,944	$ 1	$ 11,945	9
	A & G Expenses										
10	Labor	$ 1,343	3.60%	$ 48	$ 0		$ 48	$ 1,392	$	$ 1,392	10
11	Labor Loading	633	3.60%	23	0		23	655		655	11
12	Materials & Supplies	843	4.10%	35	0		35	878		878	12
13	Other	0		0			0	0		0	13
14	Total A & G	$ 2,819		$ 106	$ 0	$ 0	$ 106	$ 2,925	$ 0	$ 2,925	14
	Other Expenses										
15	Franchises	$ 702			$ 56		$ 56	$ 758	$ 3	$ 761	15
16	Taxes Other Than Income Tax	1,193			232		232	1,425		1,425	16
17	Depreciation & Amortization	5,999			573		573	6,572		6,572	17
18	Total Other Expenses	$ 7,894		$ 0	$ 861	$ 0	$ 861	$ 8,755	$ 3	$ 8,758	18
19	Total Operating Expenses	$ 22,231		$ 532	$ 861	$ 0	$ 1,393	$ 23,624	$ 4	$ 23,628	19
20	Taxable Income Before Interest	$ 10,199					$ 907	$ 11,106	$ 225	$ 11,331	20
21	Income Tax Adjustment	3,209			$ 370		370	3,579		3,579	21
22	State Taxable Income	$ 6,990					$ 537	$ 7,527	$ 225	$ 7,752	22
23	State Income Tax @ 9.3%	$ 650					$ 50	$ 700	$ 21	$ 721	23
24	Add: South Georgia	23			$ 0		0	23		23	24
25	Total State Income Tax	$ 673					50	723	21	744	25
26	Taxable Income Before Interest	$ 10,199					$ 907	$ 11,106	$ 225	$ 11,331	26
27	Income Tax Adjustment	3,284			$ 370		370	3,655		3,655	27
28	Federal Taxable Income	$ 6,915					$ 537	$ 7,451	$ 225	$ 7,676	28
29	Less: State Income Tax	673					50	723	21	744	29
30	Federal Taxable Income	$ 6,242					$ 487	$ 6,729	$ 204	$ 6,933	30
31	Federal Inc Tax @ 34%	$ 2,122					$ 166	$ 2,288	$ 69	$ 2,357	31
32	Add: South Georgia	126			$ 0		0	126		126	32
33	Less: ITC	(60)			0		0	(60)		(60)	33
34	Total Federal Income Tax	$ 2,187					$ 166	$ 2,353	$ 69	$ 2,422	34
35	Total Operating Expense	$ 25,091					$ 1,609	$ 26,700	$ 94	$ 26,794	35
36	Net Operating Income	$ 7,339					$ 691	$ 8,030	$ 135	$ 8,165	36
37	Rate Base	$ 65,167			$ 7,344		$ 7,344	$ 72,512		$ 72,512	37
38	Return	11.26%						11.07%		11.26%	38

Exhibit No. 24
Appendix B (2nd Revised)
A. 91-01-027
Sheet 2 OF 4

SOUTHWEST GAS CORPORATION
SOUTHERN CALIFORNIA DIVISION
1994 ATTRITION
$000

Line No.	Description (a)	Attrition 1993 (b)	Escalation Rates (c)	Escalation Amounts (d)	Non-Escalation Amounts (e)	Volumes (f)	Total (g)	Estimated 1994 (h)	Revenue Increase Attrition (i)	Attrition 1994 (j)	Line No.
1	Operating Revenues	$ 67,523				4,961	$ 4,961	$ 72,504	$ 216	$ 72,720	1
2	Gas Cost	32,564				2,748	2,748	35,312		35,312	2
3	Franchise & Uncollectibles	0				0	0	0		0	3
4	Operating Margin	$ 34,959				2,233	$ 2,233	$ 37,192	$ 216	$ 37,407	4
	O & M Expenses										
5	Labor	$ 5,501	3.60%	$ 198	$ 0		$ 198	$ 5,699	$	$ 5,699	5
6	Labor Loading	2,590	3.60%	93	0		93	2,683		2,683	6
7	Materials & Supplies	3,679	4.00%	147	0		147	3,826		3,826	7
8	Other	176			0		0	176	2	178	8
9	Total O & M	$ 11,945		$ 438	$ 0	$ 0	$ 438	$ 12,384	$ 2	$ 12,385	9
	A & G Expenses										
10	Labor	$ 1,392	3.60%	$ 50	$ 0		$ 50	$ 1,442	$	$ 1,442	10
11	Labor Loading	655	3.60%	24	0		24	679		679	11
12	Materials & Supplies	878	4.00%	35	0		35	913		913	12
13	Other	0		0			0	0		0	13
14	Total A & G	$ 2,925		$ 109	$ 0	$ 0	$ 109	$ 3,034	$ 0	$ 3,034	14
	Other Expenses										
15	Franchises	$ 761			$ 47		$ 47	$ 808	$ 3	$ 811	15
16	Taxes Other Than Income Tax	1,425			184		184	1,609		1,609	16
17	Depreciation & Amortization	6,572			742		742	7,314		7,314	17
18	Total Other Expenses	$ 8,758		$ 0	$ 973	$ 0	$ 973	$ 9,731	$ 3	$ 9,733	18
19	Total Operating Expenses	$ 23,628		$ 547	$ 973	$ 0	$ 1,520	$ 25,148	$ 5	$ 25,153	19
20	Taxable Income Before Interest	$ 11,331					$ 713	$ 12,044	$ 211	$ 12,254	20
21	Income Tax Adjustment	3,579			$ 302		302	3,881		3,881	21
22	State Taxable Income	$ 7,752					$ 411	$ 8,162	$ 211	$ 8,373	22
23	State Income Tax @ 9.3%	$ 721					$ 38	$ 759	$ 20	$ 779	23
24	Add: South Georgia	23			$ 0		0	23		23	24
25	Total State Income Tax	$ 744					38	782	20	802	25
26	Taxable Income Before Interest	$ 11,331					$ 713	$ 12,044	$ 211	$ 12,254	26
27	Income Tax Adjustment	3,655			$ 302		302	3,967		3,967	27
28	Federal Taxable Income	$ 7,676					$ 411	$ 8,087	$ 211	$ 8,298	28
29	Less: State Income Tax	744					38	782	20	802	29
30	Federal Taxable Income	$ 6,933					$ 373	$ 7,305	$ 191	$ 7,496	30
31	Federal Inc Tax @ 34%	$ 2,357					$ 127	$ 2,484	$ 65	$ 2,549	31
32	Add: South Georgia	126			$ 0		0	126		126	32
33	Less: ITC	(60)			0		0	(60)		(60)	33
34	Total Federal Income Tax	$ 2,422					$ 127	$ 2,549	$ 65	$ 2,614	34
35	Total Operating Expense	$ 26,794					$ 1,685	$ 28,479	$ 90	$ 28,569	35
36	Net Operating Income	$ 8,165					$ 548	$ 8,713	$ 126	$ 8,838	36
37	Rate Base	$ 72,512			$ 5,995		$ 5,995	$ 78,506		$ 78,506	37
38	Return	11.26%						11.10%		11.26%	38

Exhibit No. 24
Appendix B (2nd Revised)
A. 91-01-027
Sheet 3 OF 4

SOUTHWEST GAS CORPORATION
NORTHERN CALIFORNIA DIVISION
1993 ATTRITION
$000

Line No.	Description (a)	Test Year 1992 (b)	Escalation Rates (c)	Escalation Amounts (d)	Non-Escalation Amounts (e)	Volumes (f)	Total (g)	Estimated 1993 (h)	Revenue Increase Attrition (i)	Attrition 1993 (j)
1	Operating Revenues	$ 5,805				179	$ 179	$ 5,984	$ (41)	$ 5,942
2	Gas Cost	3,158				61	61	3,219		3,219
3	Franchise & Uncollectibles	0				0	0	0		0
4	Operating Margin	$ 2,647				118	$ 118	$ 2,765	$ (41)	$ 2,724
	O & M Expenses									
5	Labor	$ 321	3.60%	$ 12	$ 0		$ 12	$ 332	$	$ 332
6	Labor Loading	150	3.60%	5	0		5	156		156
7	Materials & Supplies	245	4.10%	10	0		10	255		255
8	Other	7		0	0		0	7	(0)	7
9	Total O & M	$ 723		$ 27	$ 0	$ 0	$ 27	$ 750	$ (0)	$ 750
	A & G Expenses									
10	Labor	$ 116	3.60%	$ 4	$ 0		$ 4	$ 120	$	$ 120
11	Labor Loading	55	3.60%	2	0		2	57		57
12	Materials & Supplies	167	4.10%	7	0		7	173		173
13	Other	0		0			0	0		0
14	Total A & G	$ 338		$ 13	$ 0	$ 0	$ 13	$ 351	$ 0	$ 351
	Other Expenses									
15	Franchises	$ 49			$ 2		$ 2	$ 51	$ (0)	$ 51
16	Taxes Other Than Income Tax	90			2		2	92		92
17	Depreciation & Amortization	461			18		18	479		479
18	Total Other Expenses	$ 599		$ 0	$ 22	$ 0	$ 22	$ 621	$ (0)	$ 621
19	Total Operating Expenses	$ 1,660		$ 40	$ 22	$ 0	$ 62	$ 1,722	$ (0)	$ 1,721
20	Taxable Income Before Interest	$ 987					$ 56	$ 1,043	$ (41)	$ 1,002
21	Income Tax Adjustment	288			$ 5		5	294		294
22	State Taxable Income	$ 699					$ 51	$ 749	$ (41)	$ 709
23	State Income Tax @ 9.3%	$ 65					$ 5	$ 70	$ (4)	$ 66
24	Add: South Georgia	9			$ 0		0	9		9
25	Total State Income Tax	$ 74					5	79	(4)	75
26	Taxable Income Before Interest	$ 987					$ 56	$ 1,043	$ (41)	$ 1,002
27	Income Tax Adjustment	296			$ 5		5	301		301
28	Federal Taxable Income	$ 692					$ 51	$ 742	$ (41)	$ 702
29	Less: State Income Tax	74					5	79	(4)	75
30	Federal Taxable Income	$ 617					$ 46	$ 664	$ (37)	$ 626
31	Federal Inc Tax @ 34%	$ 210					$ 16	$ 226	$ (13)	$ 213
32	Add: South Georgia	51			$ 0		0	51		51
33	Less: ITC	(8)			0		0	(8)		(8)
34	Total Federal Income Tax	$ 252					$ 16	$ 268	$ (13)	$ 256
35	Total Operating Expense	$ 1,986					$ 82	$ 2,069	$ (16)	$ 2,052
36	Net Operating Income	$ 661					$ 36	$ 696	$ (25)	$ 672
37	Rate Base	$ 5,864			$ 104		$ 104	$ 5,968		$ 5,968
38	Return	11.26%						11.66%		11.26%

Exhibit No. 24
Appendix B (2nd Revised)
A. 91-01-027
Sheet 4 OF 4

SOUTHWEST GAS CORPORATION
NORTHERN CALIFORNIA DIVISION
1994 ATTRITION
$000

Line No.	Description (a)	Attrition 1993 (b)	Escalation Rates (c)	Escalation Amounts (d)	Non-Escalation Amounts (e)	Volumes (f)	Total (g)	Estimated 1994 (h)	Revenue Increase Attrition (i)	Attrition 1994 (j)	Line No.
1	Operating Revenues	$ 5,942				176	$ 176	$ 6,118	$ (57)	$ 6,061	1
2	Gas Cost	3,219				61	61	3,280		3,280	2
3	Franchise & Uncollectibles	0				0	0	0		0	3
4	Operating Margin	$ 2,724				115	$ 115	$ 2,839	$ (57)	$ 2,782	4
	O & M Expenses										
5	Labor	$ 332	3.60%	$ 12	$ 0		$ 12	$ 344	$	$ 344	5
6	Labor Loading	156	3.60%	6	0		6	161		161	6
7	Materials & Supplies	255	4.00%	10	0		10	265		265	7
8	Other	7		0	0		0	7	(0)	7	8
9	Total O & M	$ 750		$ 28	$ 0	$ 0	$ 28	$ 777	$ (0)	$ 777	9
	A & G Expenses										
10	Labor	$ 120	3.60%	$ 4	$ 0		$ 4	$ 125	$	$ 125	10
11	Labor Loading	57	3.60%	2	0		2	59		59	11
12	Materials & Supplies	173	4.00%	7	0		7	180		180	12
13	Other	0		0			0	0		0	13
14	Total A & G	$ 351		$ 13	$ 0	$ 0	$ 13	$ 364	$ 0	$ 364	14
	Other Expenses										
15	Franchises	$ 51			$ 1		$ 1	$ 52	$ (0)	$ 51	15
16	Taxes Other Than Income Tax	92			2		2	94		94	16
17	Depreciation & Amortization	479			19		19	498		498	17
18	Total Other Expenses	$ 621		$ 0	$ 22	$ 0	$ 22	$ 643	$ (0)	$ 643	18
19	Total Operating Expenses	$ 1,721		$ 41	$ 22	$ 0	$ 63	$ 1,784	$ (1)	$ 1,784	19
20	Taxable Income Before Interest	$ 1,002					$ 52	$ 1,054	$ (57)	$ 998	20
21	Income Tax Adjustment	294			$ (1)		(1)	292		292	21
22	State Taxable Income	$ 709					$ 53	$ 762	$ (57)	$ 706	22
23	State Income Tax @ 9.3%	$ 66					$ 5	$ 71	$ (5)	$ 66	23
24	Add: South Georgia	9			$ 0		0	9		9	24
25	Total State Income Tax	$ 75					5	80	(5)	75	25
26	Taxable Income Before Interest	$ 1,002					$ 52	$ 1,054	$ (57)	$ 998	26
27	Income Tax Adjustment	301			$ (1)		(1)	299		299	27
28	Federal Taxable Income	$ 702					$ 53	$ 755	$ (57)	$ 698	28
29	Less: State Income Tax	75					5	80	(5)	75	29
30	Federal Taxable Income	$ 626					$ 48	$ 675	$ (51)	$ 624	30
31	Federal Inc Tax @ 34%	$ 213					$ 16	$ 229	$ (17)	$ 212	31
32	Add: South Georgia	51			$ 0		0	51		51	32
33	Less: ITC	(8)			0		0	(8)		(8)	33
34	Total Federal Income Tax	$ 256					$ 16	$ 272	$ (17)	$ 254	34
35	Total Operating Expense	$ 2,052					$ 85	$ 2,136	$ (23)	$ 2,113	35
36	Net Operating Income	$ 672					$ 31	$ 703	$ (34)	$ 669	36
37	Rate Base	$ 5,968			$ (29)		$ (29)	$ 5,939		$ 5,939	37
38	Return	11.26%						11.83%		11.26%	38

SOUTHWEST GAS CORPORATION
DEPRECIATION RATES
FOR THE TEST YEAR 1992

Description	FERC Account Number	Depreciation Rate Southern California	Depreciation Rate Northern California	Depreciation Rate System Allocable
Intangible Plant				
Organization	301	–	–	–
Franchise and Consents	302	–	–	–
Miscellaneous Intangible Plant	303	–	–	15.00%
Transmission Plant				
Land and Land Rights	365.1	–	–	–
Rights of Way	365.2	2.11%	1.96%	–
Structures and Improvements	366.2	1.32%	–	–
Mains	367	3.00%	2.46%	–
Measuring & Reg. Station Equipment	369	3.22%	6.16%	–
Communication Equipment	370	10.02%	6.98%	–
Distribution Plant				
Land and Land Rights	374	–	–	–
Structures and Improvements	375	0.17%	2.51%	–
Mains	376	4.47%	3.12%	–
Measuring & Reg. Station Equipment	378	6.03%	7.19%	–
Measuring & Reg. Station Equipment – City Gate	379	0.00%	–	–
Services	380	7.53%	3.57%	–
Meters	381	2.92%	2.39%	–
Other Equipment	387	7.14%	–	–
General Plant				
Land and Land Rights	389	–	–	–
Structures and Improvements	390	2.28%	–	–
Structures and Improvements – General	390.1	–	–	2.33%
Structures and Improvements – Leasehold	390.2	–	–	10.31%
Office Furniture and Equipment	391	5.01%	–	6.52%
Computer Equipment	391.1	17.91%	–	13.57%
Transportation Equipment – Vehicles	392	11.54%	–	22.12%
Transportation Equipment – Airplane – Frame	392.2	–	–	8.45%
Transportation Equipment – Airplane – Eng.	392.3	–	–	10.83%
Stores Equipment	393	1.90%	–	3.40%
Tools, Shop and Garage Equipment	394	4.33%	–	3.76%
Laboratory Equipment	395	4.91%	–	4.24%
Power Operated Equipment	396	5.68%	–	–
Communication Equipment	397	6.77%	–	9.42%
Miscellaneous Equipment	398	0.16%	–	4.90%

DEMAND SIDE MANAGEMENT PROGRAMS

For purposes of this Stipulation, it is agreed that ratepayer funding for Southwest's existing low income weatherization program and general conservation programs shall be continued for the 1992 Test Year, as well as for 1993 and 1994. It is agreed that these programs shall be funded at $205,020 annually, $145,693 of which shall be included in Southwest's Southern California Division rates and $59,327 of which shall be included in Southwest's Northern California Division rates.

In Chapters 11B and 23B of its Report, DRA recognizes that additional Demand Side Management (DSM) measures may be cost effective in Southwest's California service areas. Southwest agrees with DRA that there is potential for additional DSM programs due to continuing growth in its California service areas.

However, because Southwest has not yet developed a sufficient customer database or marginal cost analysis for its California service areas, a specific analysis could not be performed. As an alternative, Southwest suggested using a study recently conducted by Synergic Resources Corporation (SRC) for its Southern Nevada service area. This study includes an extensive analysis of DSM programs. SRC evaluated more than 50 programs, from which it selected 13 to include in Southwest's Gas Resource Plan filing to the Nevada Public Service Commission. Because the scope of analysis and activity conducted for Nevada exceeds that expected for Southwest's California service areas and because marginal costs in California are likely to be higher than in Nevada, DRA and Southwest agree that the SRC analysis can be used as a basis for determining those DSM programs which are most likely to be cost-beneficial in California.

Southwest also recognizes the need for appropriate customer and appliance saturation data and intends to conduct such surveys and analyses for use in future program planning. Southwest intends to spend up to $30,000 in addition to DSM program costs to acquire such information for its residential and commercial markets during 1992.

In its Measurement and Evaluation Program, Southwest agrees to maintain sufficient data to measure the ongoing results of all DSM programs conducted and to keep records on all activities, including customer participation, information on equipment replaced, new equipment installed, and weatherization measures provided. Further, Southwest will provide an overall evaluation of the DSM programs at their conclusion.

Thus, it is agreed that Southwest shall implement three new DSM programs, with annual contributions from ratepayers, as follows:

(1) Residential Weather Retrofit Incentives - This program will include caulking, weather stripping, water heater wraps, and attic insulation up to R-30 (if less than R-19 with a central heating or air conditioning system), and will be designed for other than low income customers. Inspections will be conducted to confirm customer qualification for this program, and spot checks will be provided to assure satisfactory installation. An amount of $75,000 per annum shall be included in Southwest's rates for this program, $60,000 of which shall be included in Southwest's Southern California Division rates and $15,000 of which shall be included in Southwest's Northern California Division rates.

(2) Residential Appliance Efficiency Incentive Program - This program will be aimed at existing customers and will encourage the replacement of older equipment with newer, higher efficiency equipment, with the principal focus on furnaces and water heaters. An amount of $50,000 per annum shall be included in Southwest's rates for this program, $40,000 of which shall be included in Southwest's Southern California Division rates and $10,000 of which shall be included in Southwest's Northern California Division rates.

(3) Residential New Construction Program - This program will encourage builders to upgrade housing shells and to install appliances which exceed current minimum energy efficiency requirements. These appliances include gas water heating, gas heating and high efficiency cooling (in conjunction with Southern California Edison). An amount of $55,000 per annum shall be included in Southwest's rates for this program, $50,000 of which shall be included in Southwest's Southern California Division rates and $5,000 of which shall be included in Southwest's Northern California Division rates.

The total amount to be funded by ratepayers for these new DSM programs shall be $180,000 annually, $150,000 of which shall be included in Southwest's Southern California Division rates, and $30,000 of which shall be included in Southwest's Northern California Division rates. In addition, up to

$30,000 will be spent to acquire customer and appliance saturation data. This amount shall also be funded by ratepayers, with $25,000 being included in Southwest's Southern California Division rates, and $5,000 being included in Southwest's Northern California Division rates. It is further agreed that Southwest shall commence the Residential Weather Retrofit Incentives program immediately upon receiving approval of this Stipulation in this proceeding.

With respect to the Residential Appliance Efficiency Incentive Program and the Residential New Construction Program, prior to their implementation Southwest shall file an advice letter with the Commission. The advice letter, which is to be filed no later than February 1, 1992, will set forth details of the design of each program, the requirements for customer eligibility, the expected participation levels, the incentives or rebates to be provided, the evaluation studies to be performed, and any other matters which shall define the programs. Southwest shall implement these programs upon Commission approval of its advice letter filing.

The Commission will determine the disposition of any unspent funds, collected through rates for conducting these programs, in Southwest's next general rate case proceeding.

COST SUMMARY FOR DEMAND SIDE MANAGEMENT PROGRAMS

EXISTING PROGRAMS	Total	So. CA	No. CA
Low Income Weatherization	$145,943	$ 95,935	$50,008
General Conservation	59,077	49,758	9,319
Total	$205,020	$145,693	$59,327
NEW PROGRAMS			
Residential Weather Retrofit Incentives	$ 75,000	$ 60,000	$15,000
Residential Appliance Efficiency Incentive Program	50,000	40,000	10,000
Residential New Construction Program	55,000	50,000	5,000
Total	$180,000	$150,000	$30,000
MEASUREMENT AND EVALUATION			
Residential and Commercial	$30,000	$25,000	$5,000
TOTAL COSTS	$415,020	$320,693	$94,327

Note: Table reflects 1992 Test Year (1990 dollars).

(END OF APPENDIX A)

APPENDIX B

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

In the Matter of the Application of SOUTHWEST GAS CORPORATION (U 905 G) for Authority to Change Natural Gas Rates in San Bernardino and Placor Counties, California

Application No. 91-01-027

SUPPLEMENTAL STIPULATION AND SETTLEMENT AGREEMENT

I

INTRODUCTION

Pursuant to Article 13.5 of the Rules of Practice and Procedure of the California Public Utilities Commission (Commission), Southwest Gas Corporation (Southwest), the Commission's Division of Ratepayer Advocates (DRA), and Luz Partnership Management (Luz), collectively referred to as "the Parties," have entered into this Supplemental Stipulation and Settlement Agreement (Stipulation) for the purpose of providing to the Commission a recommended resolution of the remaining, heretofore contested issues in this proceeding. The Stipulation includes this text and the appendices attached hereto. Accompanying this Stipulation is a Joint Motion of the Parties requesting that the Commission adopt the terms of this Stipulation in its decision on Application No. 91-01-027.

The Parties urge the Commission to find that the matters agreed to in this Stipulation, when coupled with the stipulations set forth in the "Stipulation and Settlement Agreement" filed by Southwest and DRA in this proceeding on August 16, 1991 (Original Stipulation), result in rates that are just and reasonable for Southwest's operations in its Southern California (San Bernardino County) and Northern California (Placer County) Divisions for the Test Year 1992 and for the Attrition Years 1993 and 1994.[1]

II

BACKGROUND

This proceeding is Southwest's triennial general rate case filed in accordance with the Commission's General Rate Case Plan. On January 23, 1991, Southwest filed its application in this proceeding to effect general rate changes for its Southern California and Northern California Divisions for a 1992 Test Year and for Attrition Years of 1993 and 1994. The filing gave notice of Southwest's intent to request authority to recover the revenue requirement resulting from Southwest's costs of owning and operating the facilities necessary to provide natural gas service in Southwest's certificated service areas.

On June 24, 1991, following extensive discovery and on-site review of Southwest's records, DRA distributed proposed exhibits, consisting of its reports analyzing Southwest's rate filing, including its "Report on the Results of Operations" for Southwest's Southern California and Northern California Divisions. Luz also conducted discovery of Southwest, and on

1 Aside from Southwest and DRA, Luz is the only other party to have entered an appearance in this proceeding. This Stipulation, therefore, is sponsored by all of the parties to this proceeding.

July 15, 1991, filed testimony concerning Southwest's proposed rates for the Southern California Division.

On August 16, 1991, just prior to the scheduled commencement of an evidentiary hearing in this proceeding, Southwest and DRA jointly filed a settlement proposal in this proceeding. The settlement filing consisted of the Original Stipulation, including accompanying appendices, and a joint motion for adoption.

The Original Stipulation proposes to resolve all matters in this proceeding except for revenue allocation and rate design issues. For the Test Year 1992, the Original Stipulation provides for an annual revenue requirement increase of $2,567,717 for Southwest's Southern California Division service area, and an annual revenue requirement decrease of $896,659 for Southwest's Northern California Division service area. The Original Stipulation also specifies the methodology to be employed when determining the attrition adjustments to be made for the Attrition Years 1993 and 1994 for both the Southern California and Northern California Divisions. In addition, the Original Stipulation addresses certain other rate adjustments to be made during the three-year rate case cycle as well as other issues, including demand-side management and accounting matters.

On August 21-22, 1991, a formal hearing was held in this proceeding to address primarily revenue allocation and rate design issues. The formal hearing record in this proceeding, which includes Southwest's application, the testimony and exhibits of the Parties, and the Original Stipulation, are incorporated herein by reference. The Parties submitted opening briefs to the Administrative Law Judge (ALJ) on October 7, 1991.

However, by Resolution G-2961, dated October 11, 1991, the Commission made certain findings with respect to the wholesale transportation rates charged by Pacific Gas and Electric Company (PG&E), the upstream supplier of gas to Southwest's Southern California Division service area. These findings significantly affected the evidentiary presentations made by the Parties in the litigation of the contested issues in this proceeding. As a result, the ALJ convened a meeting of the Parties on October 18, 1991 to discuss supplementing the record, and thereafter issued a ruling on October 22, 1991 (Ruling). In the Ruling, the ALJ, among other things, directed the Parties to submit a joint late-filed exhibit and to discuss in their reply briefs how the Commission's restructuring of the natural gas industry in California should apply to Southwest, including an identification of issues to be addressed in a future Southwest cost allocation proceeding.

As a result of the Commission's findings with respect to PG&E's wholesale transportation rates, the Parties' meeting with the ALJ, and the Parties' preparation of the late-filed exhibit in response to the ALJ's Ruling, the Parties then engaged in discussions regarding a possible settlement of the litigated issues in this proceeding. Those discussions have resulted in an agreement upon the terms set forth in this Stipulation.

The Parties hereto urge that this Stipulation, along with the Original Stipulation, be adopted by the Commission. The Parties believe such action to be clearly in the public interest. Approval of this Stipulation, in conjunction with approval of the Original Stipulation, represents a resolution that is fair and reasonable for both Southwest and its customers.

III

STIPULATIONS

It is understood and agreed by the Parties hereto that this Stipulation is made for the purpose of achieving a fair and reasonable resolution of the issues in this proceeding. None of the Parties expressly concedes the validity of the other Parties' positions expressed in their testimonies or briefs where such positions differ. Each of the Parties, however, supports this settlement of the issues. The Parties agree that this Stipulation, either in whole or in part, shall have no express or implied precedential effect in any future proceeding, except as specifically agreed to by the Parties.

A. ORIGINAL STIPULATION

This Stipulation is not intended by the Parties to alter or amend the Original Stipulation filed by Southwest and DRA in this proceeding, but rather to supplement and complement the Original Stipulation. Although Luz is not a sponsoring party to the Original Stipulation, Luz does not object to the Original Stipulation, and joins with Southwest and DRA in urging the Commission to approve the Original Stipulation in conjunction with its approval of this Stipulation. The Parties intend that this Stipulation, coupled with the Original Stipulation, will resolve all issues in this proceeding.

B. PARITY RATE

For purposes of this Stipulation, it is agreed that all of Southwest's Schedule No. GN-2 cogeneration customers and all of Luz' solar electric generation station units served by Southwest shall be eligible to receive service from Southwest at a "parity" rate whose transportation component, including Southwest's margin and allocable PG&E transportation charges, shall be equal to the PG&E gas cogeneration rate prescribed in PG&E's tariff Schedule No. G-COG. This "parity" rate eligibility shall not apply to quantities of gas or to customer facilities that fail to meet the qualifying criteria in either of Sections 454.4 or 454.6 of the California Public Utilities Code.

C. REVENUE ALLOCATION AND RATE DESIGN

For purposes of this Stipulation, it is agreed that Southwest shall use the revenue allocation and rate design procedures described in Appendix A attached hereto. The rates set forth in the accompanying schedules are based upon the use of these procedures. It is specifically agreed that the total amount of the "cogeneration shortfall" that results from Southwest's providing service to Luz and Schedule No. GN-2 customers at a "parity" rate shall be allocated among Southwest's non-cogeneration customers (i.e., all customers except for Southwest's Schedule No. GN-2 and Special Contract customers), using the allocation method described in Appendix A attached hereto.

D. GAS COST TREATMENT FOR NON-CORE CUSTOMERS

For purposes of this Stipulation, it is agreed that Southwest's non-core customers will be removed from Southwest's Gas Cost Balancing Account, and instead will receive gas cost adjustments by means of monthly billing adjustments, as described in Appendix A attached hereto.

E. STATEMENT OF RATES TARIFF SHEETS

For purposes of this Stipulation, it is agreed that Southwest will redesign its Statement of Rates tariff sheets in the manner presented in Appendix A attached hereto.

F. FUTURE COST ALLOCATION PROCEEDINGS

It is agreed that in the future, revenue allocation and rate design issues with respect to Southwest's rates for its Southern California Division service area will be addressed in biennial cost allocation proceedings (BCAPs). Southwest's BCAPs will be conducted on a schedule in which Southwest lags the filing of PG&E's BCAP (as established by D.89-01-040 and D.90-09-089) in such a fashion as to permit the assignment of the same administrative law judge to the Southwest BCAP as is assigned to the PG&E BCAP and to allow the Commission to render concurrent decisions in the two proceedings. Southwest will file its initial BCAP application on March 2, 1992, in recognition of the delay in the filing of PG&E's scheduled BCAP filing from the normal date of August 15 to November 1, 1991. All subsequent BCAP applications by Southwest will be filed no later than 30 days after PG&E files its future BCAP applications. A time line illustrating the relative timing of Southwest's future BCAP and general rate case proceedings is set forth in Appendix B attached hereto.

It is further agreed that the issues to be addressed in Southwest's initial BCAP shall include, but not be limited to, the following:

(1) The further unbundling of Southwest's rates, over and above that accomplished by this Stipulation, including the design of three-part, seasonal, and non-core service level rates.

(2) The appropriate rate treatment of Southwest's system shrinkage (i.e., lost and unaccounted for gas).

(3) Whether other balancing accounts would be appropriate for Southwest, including 75% balancing account treatment of non-core transportation revenues.

(4) The allocation methodology to be applied to costs incurred from PG&E, particularly PG&E's storage costs.

(5) Whether PG&E's transportation charges to Southwest

under its Schedule No. G-WRT should be treated in Southwest's SAM account or as gas costs.

IV

TERMS AND CONDITIONS

A. PRECEDENTIAL EFFECT.

The Parties agree, as provided in Rule 51.8 of the Commission's Rules of Practice and Procedure, that adoption of this Stipulation by the Commission shall not constitute approval of, or precedent regarding, any principle or issue in this proceeding or in any future proceeding, except as specifically provided herein. Furthermore, no agreement by Southwest, DRA, or Luz to stipulate to any matter in this Stipulation shall imply any agreement by any of the Parties to any principle, methodology, or fact other than for purposes of this Stipulation.

B. INDIVISIBILITY OF STIPULATION.

This Stipulation represents a compromise of many positions and interests of the Parties hereto, and no individual term is assented to by any party except in consideration of the other parties' assents to all of the other terms of this Stipulation. The Stipulation is accordingly indivisible, and each part is interdependent on each and all of the other parts. Any party may withdraw from this Stipulation if the Commission modifies, deletes or adds any term. The Parties agree, however, that they will negotiate in good faith with regard to any Commission-ordered changes in order to restore the balance of benefits and burdens, and will exercise the right to withdraw only if such negotiations are unsuccessful.

C. EVIDENTIARY EFFECT OF STIPULATION

The Parties agree, as provided in Rule 51.9 of the Commission's Rules of Practice and Procedure, that no discussion, admission, concession, or offer to stipulate or settle, whether oral or written, made during any negotiation leading to this Stipulation shall be subject to discovery, or admissible in any evidentiary hearing against any participant who objects to its admission. Furthermore, if this Stipulation is not adopted by the Commission, then the Parties agree that no portion of this Stipulation, or any of its terms or conditions, or any of the discussions leading to it, may be subject to discovery or used in hearings in support of or in opposition to any party or position without the prior express written consent of the Parties hereto.

D. STIPULATION IN THE PUBLIC INTEREST.

The Parties agree by jointly executing and submitting this Stipulation that the Commission's approval and adoption of the Stipulation is in the public interest and will result in a resolution of this proceeding that is just, fair, and reasonable; that it will resolve in a fair manner the alternative positions presented in this proceeding; that, coupled with approval and adoption of the Original Stipulation, it will result in rates that are fair and reasonable for Southwest and its customers; and that it will establish a future regulatory process that will ensure that innovations and developments in the Commission's regulation of the larger California gas utilities will be applied to Southwest's system where appropriate.

E. EFFECTUATION OF STIPULATION.

The Parties agree to perform diligently and in good faith all actions required or implied hereunder in order to obtain the approval and adoption of this Stipulation by the Commission. It is understood by the Parties that time is of the essence in obtaining the Commission's approval of this Stipulation.

F. ENTIRETY OF STIPULATION

This Stipulation contains the entire agreement of the Parties hereto. The terms and conditions of the Stipulation may only be modified by a writing subscribed by the Parties.

G. APPENDICES

The appendices attached to this Stipulation are a part of this Stipulation and are incorporated herein by reference.

Dated this 6th day of November, 1991.

SOUTHWEST GAS CORPORATION

By Edward C. McMurtrie
Edward C. McMurtrie

DIVISION OF RATEPAYER ADVOCATES

By Philip S. Weismehl
Philip Scott Weismehl

LUZ PARTNERSHIP MANAGEMENT

By R. Thomas Beach
R. Thomas Beach

(END OF APPENDIX B)

APPENDIX C

REVENUE ALLOCATION AND RATE DESIGN PROCEDURES

These procedures reflect the settlement agreement between DRA, Luz, and Southwest regarding the class revenue allocation and rate design methods to be employed for the purposes of implementing the Original Stipulation filed on August 16, 1991, in this proceeding, which resolved revenue requirement issues. The revenue allocation adopts the SAM base cost revenue requirements included in Appendix A to the Original Stipulation. The amounts in Appendix A to the Original Stipulation represent an increase above present rates in Southwest's Southern California Division and a decrease below present rates in Southwest's Northern California Division. The allocation of revenues among the customer classes is derived on the basis of 75 percent of the increase or decrease being spread based upon cost of service and 25 percent of the increase or decrease being spread based upon the system average increase or decrease. To ensure gradual movement in rates, a rate cap (allowable increase above the average system increase) of 10 percent and 5 percent is applicable to the Southern California and Northern California Divisions, respectively.

For Southwest's Southern California Division, the allocation of revenues also takes into consideration several factors discussed below,[1] including the allocation of upstream PG&E demand charges based on cold year throughput, parity with PG&E's Schedule G-COG transportation rates for Southwest's cogeneration customers served under Schedule No. GN-2 and its Special Contract cogeneration customers, establishment of a rate design applicable to non-core industrial customers served under proposed Schedule No. GN-4, and special revenue allocation for core and non-core industrial gas service.

Storage costs included in the demand charge under PG&E's Schedule G-WRT have been assigned to the winter peak season and allocated based on peak season throughput. The remaining fixed demand charges under Schedule G-WRT have been seasonalized and allocated based on cold year throughput volumes. The effect of utilizing cold year throughput to allocate upstream PG&E demand charges will be reflected in revisions to Part 7G, Average Cost of Purchased Gas, the Preliminary Statements of Southwest's California Gas Tariff, which will be submitted as part of the compliance filing in response to a final Commission order in this proceeding.

The effect of providing transportation service to Schedule No. GN-2 and Special Contract cogeneration customers at a rate equal to PG&E's Schedule G-COG transportation rate versus Southwest's fully allocated transportation rate has

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1 The class revenue allocation and underlying procedures used for Southwest's Southern California Division are identical to those presented in Schedule 1 of Exhibit No. 23 of this proceeding. The class revenue allocation and underlying procedures used for Southwest's Northern California Division are identical to those presented in Exhibit No. (ABC-1) of Exhibit No. 22. The schedules originally presented in Exhibit No. (ABC-1) of Exhibit No. 22 for the Northern California Division have been adjusted to correct an error in the annual purchased gas cost amount.

been quantified. The resulting difference in revenue recovery is referred to as the Cogeneration Shortfall. The Cogeneration Shortfall is allocated to each customer class, except Cogeneration and Special Contract customer classes, on the basis of each class' proportionate share of total revenues allocated to such classes (other than the Cogeneration and Special Contract classes). In order to maintain parity, the Cogeneration Shortfall will be calculated and reallocated each time Southwest files to revise its rates.

To allow proper allocation of costs and rate design between core and non-core customer classes, Southwest will establish a new Schedule No. GN-4, Non-Core Industrial Gas Service, and will revise its existing Schedule No. GN-3 to restrict its applicability to core industrial customers only.

The base margin rate applicable to industrial customers has been established by increasing the allocated present revenues by the system average increase percentage. The Cogeneration Shortfall and all applicable surcharges then apply.

Once the revenues for the Industrial, Cogeneration, and Special Contract customer classes are established as outlined above, the revenue allocation for both the Southern California and the Northern California Divisions is performed in accordance with the 75/25 split and rate caps as described above. Revenues will be reallocated each time Southwest files to revise its purchased gas costs, to reflect attrition year adjustments, to recognize changes in upstream supplier costs, and to respond to regulatory directives.

In addition to the class revenue allocation and rate design procedures described above, non-core customers will be removed from the Gas Cost Balancing Account on January 1, 1992. Such customers will remain responsible for the balance in the account at the time of their removal and will be subject to the Balancing Account Adjustment surcharge until such customers have paid their share of the December 31, 1991, account balance. Rather than participate in the Gas Cost Balancing Account, non-core customers will receive gas cost adjustments by means of monthly billing adjustments. These monthly billing adjustments will reflect Southwest's actual cost of gas on a monthly basis such that the customers will be charged or credited for the differential between the base gas cost and the actual gas cost. This accounting treatment will be reflected in Part 7H, Monthly Non-Core Gas Cost Adjustment, contained in the Preliminary Statements of Southwest's California Gas Tariffs, which will be submitted as part of the compliance filing in response to a final Commission order in this proceeding. All core customers will continue to participate in the Gas Cost Balancing Account.

Attached are schedules illustrating the stipulated revenue allocation and rate design procedures, development of the present and proposed revenues assuming an overall rate of return of 11.73 percent, and a Cogeneration Shortfall of $379,674 based on PG&E's Schedule G-COG rate which is proposed in Advice Letter No. 1624-G-D. These schedules will be revised pursuant to the Commission's decision addressing cost of capital issues, effective January 1, 1992.

STATEMENT OF RATES
EFFECTIVE RATES APPLICABLE TO SOUTHERN CALIFORNIA DIVISION SCHEDULES

Schedule No. and Type of Charge (a)	Southwest Margin (b)	Upstream Transport Charge (c)	Southwest Shrinkage Charge (d)	Balancing Account Surcharges [1] (e)	CPUC Surcharge (f)	LIRA Surcharge (g)	Total Transport Charge (h)	Gas Cost [2] (i)	Currently Effective Tariff Rates (j)
G-1 Residential Gas Service									
Basic Service Charge	$ 4.25								$ 4.25
Cost per Therm									
Baseline Quantities	0.30977	$ 0.08762	$ 0.00580	$ 0.00559	$ 0.00000	$ 0.00000	$ 0.40878	$ 0.20892	$ 0.61770
Tier II	0.54876	0.08762	0.00580	0.00559	0.00000	0.00000	0.64777	0.20892	0.85669
G-1-LI - Low Income Residential Gas Service									
Basic Service Charge	$ 3.60								$ 3.60
Cost per Therm									
Baseline Quantities	0.21712	$ 0.08762	$ 0.00580	$ 0.00559	$ 0.00000	$ 0.00000	$ 0.31613	$ 0.20892	$ 0.52505
Tier II	0.42026	0.08762	0.00580	0.00559	0.00000	0.00000	0.51927	0.20892	0.72819
G-1N Residential Gas Service									
Basic Service Charge	$ 4.25								$ 4.25
Cost per Therm	$ 0.52087	$ 0.09456	$ 0.00580	$ 0.00691	$ 0.00000	$ 0.00000	$ 0.62814	$ 0.20892	$ 0.83706
GN-1 Commercial Gas Service									
Basic Service Charge	$ 10.00								$ 10.00
Cost per Therm									
Summer	$ 0.25326	$ 0.07327	$ 0.00580	$ 0.00441	$ 0.00000	$ 0.00000	$ 0.33673	$ 0.20892	$ 0.54566
Winter	0.25326	0.09319	0.00580	0.00441	0.00000	0.00000	0.35665	0.20892	0.56557
GN-2 Cogeneration Gas Service									
Basic Service Charge	$ 75.00								$ 75.00
Cost per Therm									
Summer	$ 0.07503	$ 0.06753	$ 0.00578	$ (0.05138)	$ 0.00000	$ 0.00000	$ 0.09396	$ 0.20817	$ 0.30213
Winter	0.07503	0.07606	0.00578	(0.05138)	0.00000	0.00000	0.10771	0.20817	0.31588
GN-3 Core Industrial Gas Service									
Basic Service Charge	$ 75.00								$ 75.00
Cost per Therm									
Summer	$ 0.03870	$ 0.06753	$ 0.00578	$ 0.00095	$ 0.00000	$ 0.00000	$ 0.11296	$ 0.20817	$ 0.32113
Winter	0.03870	0.07606	0.00578	0.00095	0.00000	0.00000	0.12149	0.20817	0.32966
GN-4 Non-Core Industrial Gas Service									
Basic Service Charge	$ 75.00								$ 75.00
Cost per Therm									
Summer	$ 0.04625	$ 0.06753	$ 0.00578	$ 0.00243	$ 0.00000	$ 0.00000	$ 0.12198	$ 0.20817	$ 0.33015
Winter	0.04625	0.07606	0.00578	0.00243	0.00000	0.00000	0.13051	0.20817	0.33868
GN-6 Internal Combustion Engine Gas Service									
Basic Service Charge	$ 25.00								$ 25.00
Cost per Therm									
Summer	$ 0.10622	$ 0.06753	$ 0.00578	$ 0.00292	$ 0.00000	$ 0.00000	$ 0.18244	$ 0.20817	$ 0.39061
Winter	0.10622	0.07609	0.00578	0.00292	0.00000	0.00000	0.19100	0.20817	0.39917
GM Multi Family Master Metered Gas Service									
Basic Service Charge	$ 25.00								$ 25.00
Cost per Therm									
Baseline Quantities	$ 0.30767	$ 0.09039	$ 0.00580	$ 0.00491	$ 0.00000	$ 0.00000	$ 0.40878	$ 0.20892	$ 0.61770
Tier II	0.54666	0.09039	0.00580	0.00491	0.00000	0.00000	0.64777	0.20892	0.85669
Special Contract									
Basic Service Charge	$ 75.00								$ 75.00
Cost per Therm									
Summer	$ 0.02665	$ 0.06753	$ 0.00578	$ (0.00457)	$ 0.00000	$ 0.00000	$ 0.09396	$ 0.20817	$ 0.30213
Winter	0.02665	0.07606	0.00578	(0.00457)	0.00000	0.00000	0.10771	0.20817	0.31588

[1] Balancing Account Surcharges include the following:

	PGA	SAM	Cogeneration Shortfall
	$ 0.00000	$ 0.00000	Varies

[2] Cost of gas equal to PG&E wholesale procurement rate effective August 1, 1991 including Franchises and Uncollectables on Southwest's system.

SOUTHWEST GAS CORPORATION
SOUTHERN CALIFORNIA DIVISION
CLASS REVENUE ALLOCATION

Line No.	Description (a)	Total Division (b)	Residential Primary (c)	Secondary (d)	Commercial (e)	Industrial Core (f)	Industrial Non-core (g)	Gas Engines (h)	Cogeneration (i)	Master Metered (j)	Special Contract (k)	Other Revenue G8 Discount (l)	Line No.
	Summary of Allocated Cost of Service												
1	Cost Of Gas [1]	$ 30,237,675 $	14,351,685 $	1,208,055 $	3,930,710 $	1,186,425 $	570,549 $	258,537 $	1,528,275 $	645,625 $	6,555,815 $	0	1
2	Amortization of PGA Balancing Account [2]	0	0	0	0	0	0	0	0	0	0	0	2
3	Amortization of SAM Balancing Account [2]	0	0	0	0	0	0	0	0	0	0	0	3
4	Allocated Fixed Cost	32,395,699	19,802,755	2,186,898	5,496,311	728,538	140,345	58,230	271,146	710,148	1,655,664	1,347,663	4
5	Total Cost of Service	$ 62,633,374 $	34,154,440 $	3,394,953 $	9,427,022 $	1,914,963 $	710,894 $	316,767 $	1,799,421 $	1,355,773 $	8,211,479 $	1,347,663	5
	Comparison of Revenues At Present Rates to Cost of Service												
6	Revenue at Present Rates [3]	$ 60,307,375 $	35,131,703 $	3,815,273 $	6,921,763 $	1,631,897 $	638,642 $	419,846 $	1,893,216 $	1,328,577 $	7,174,130 $	1,352,326	6
7	Cost Based Allocation Of Proposed Rates	62,633,374	34,154,440	3,394,953	9,427,022	1,914,963	710,894	316,767	1,799,421	1,355,773	8,211,479	1,347,663	7
8	Percent Change From Present Revenues	3.86%	-2.78%	-11.02%	36.19%	17.35%	11.31%	-24.55%	-4.95%	2.05%	14.46%	-0.34%	8
	Weighting Factors												
9	Cost of Service 75%	$ 1,747,997 $	(732,947)$	(315,240)$	1,876,944 $	212,300 $	54,169 $	(77,311)$	(70,346)$	20,397 $	778,012		9
10	System Average Increase 25%	582,666	347,214	37,707	68,409	16,126	6,312	4,149	18,711	13,131	70,803		10
11	Weighted Allocation	$ 62,633,374 $	34,745,970 $	3,537,740 $	8,869,116 $	1,860,325 $	699,143 $	346,887 $	1,841,581 $	1,362,105 $	8,023,045 $	1,347,663	11
12	Maximum Allowed Above System Average 10%		39,999,870	4,343,952	7,880,905	1,694,636	663,274	476,026	1,966,236	1,512,677	7,174,130	1,347,663	12
13	Proposed Revenue Allocation	$ 62,633,374 $	36,439,064 $	3,710,126 $	7,880,905 $	1,694,636 $	663,274 $	363,560 $	1,931,317 $	1,426,477 $	7,174,130 $	1,347,663	13
14	Allocation of Cogeneration Shortfall [4]	0	265,138	26,996	57,343	12,332	4,826	2,645	(274,044)	10,394	(105,630)	0	14
15	Proposed Revenue	$ 62,633,374 $	36,704,202 $	3,737,122 $	7,938,248 $	1,707,170 $	668,100 $	366,225 $	1,657,273 $	1,436,871 $	7,068,500 $	1,347,663	15
16	Percentage Change From Present Rates	3.86 %	4.48 %	(2.05)%	14.69 %	4.61 %	4.61 %	(12.77)%	(12.46)%	8.30 %	(1.47)%	(0.34)%	16
17	Proposed Fixed Cost Revenue Allocation	$ 32,395,699 $	22,067,379 $	2,502,071 $	3,950,195 $	506,413 $	92,725 $	105,040 $	403,042 $	782,853 $	618,215 $	1,347,663	17
18	Total Rate - $/Therm	$ 0.56541 $	0.77324 $	0.95676 $	0.61012 $	0.13187 $	0.33647 $	0.40376 $	0.31056 $	0.68000 $	0.30600		18
19	Gas Cost Rate - $/Therm	0.27296	0.30234	0.30928	0.30211	0.09180	0.28734	0.28505	0.28641	0.30512	0.28380		19
20	Cogeneration Shortfall - $/Therm	0.00000	0.00559	0.00691	0.00441	0.00095	0.00243	0.00292	(0.05136)	0.00491	(0.00457)		20
21	Total Gas Cost - $/Therm	0.27296	0.30793	0.31619	0.30651	0.09276	0.28977	0.28796	0.23505	0.31003	0.27923		21
22	Amortization Rate - $/Therm	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000		22
23	Fixed Cost (Margin) Rate - $/Therm	0.29245	0.46531	0.64057	0.30360	0.03912	0.04670	0.11581	0.07553	0.36997	0.02677		23
24	Estimated Deliveries	110,774,998	47,467,099	3,906,000	13,011,000	12,945,403	1,985,597	907,000	5,336,000	2,115,999	23,100,000		24
25	Number of Customers	92,279	77,424	9,168	5,549	6	1	29	3	96	3		25

[1] Cost of gas at PG&E's G-WRT and procurement rates proposed in Advice Letter No. 1624-G-D.
[2] Account balance excluded from this filing.
[3] Rates proposed in Advice Letter No. 420-B excluding amounts to amortize balancing accounts with gas cost adjusted as described in Note 1.
[4] Cogeneration Shortfall based on PG&E's G-COG rate per Advice Letter No. 1624-G-D.

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Appendix A
Sheet 4 of 11

SOUTHWEST GAS CORPORATION
SOUTHERN CALIFORNIA DIVISION
CALCULATION OF COGENERATION SHORTFALL

Line No.	Description (a)	Annual Deliveries (b)	Proposed Rates (c)	Amount (d)	Line No.
	Southwest Margin & Transportation Cost				
	Cogeneration Customers (Schedule GN-2)				
1	Summer	2,250,068 $	0.14834 $	333,767	1
2	Winter	3,085,932	0.15687	484,079	2
3	Total Cogeneration	5,336,000 $	0.15327 $	817,846	3
	Special Contract Customers				
4	Summer	16,800,000 $	0.09996 $	1,679,267	4
5	Winter	6,300,000	0.10849	683,465	5
6	Total Special Contract	23,100,000 $	0.10228 $	2,362,731	6
7	Total Southwest Margin and Transportation Cost (Line 3 + Line 6)	28,436,000	$	3,180,578	7
	Maximum Revenue Recovery at PG&E G-COG Rate [1]				
	Cogeneration Customers (Schedule GN-2)				
8	Summer	2,250,068 $	0.09396 $	211,416	8
9	Winter	3,085,932	0.10771	332,386	9
10	Maximum Revenue Recovery	5,336,000 $	0.10191 $	543,802	10
	Special Contract Customers				
11	Summer	16,800,000 $	0.09396 $	1,578,528	11
12	Winter	6,300,000	0.10771	678,573	12
13	Maximum Revenue Recovery	23,100,000 $	0.09771 $	2,257,101	14
14	Total Maximum Revenue Recovery at PG&E G-COG Rate (Line 10 + Line 13)	28,436,000	$	2,800,903	
15	Total Cogeneration Shortfall (Line 7 - Line 14)		$	379,674	15

[1] Recovery at the PG&E G-COG rate per Advice Letter No. 1624-G-D.

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SOUTHWEST GAS CORPORATION
SOUTHERN CALIFORNIA DIVISION
SUMMARY OF PRESENT AND PROPOSED RATES AND REVENUES BY RATE SCHEDULE

Line No.	Description (a)	Rate Schedule (b)	Annual Number of Bills (c)	Sales Volumes (Therms) Present (d)	Sales Volumes (Therms) Proposed (e)	Present Rates [1] Rates (f)	Present Rates [1] Revenues (g)	Proposed Rates [2] Rates (h)	Proposed Rates [2] Revenues (i)	Increase/(Decrease) Dollars (j)	Increase/(Decrease) Percent (k)	Line No.
	Residential Gas Service											
	Primary											
1	Basic Service Charge	G-1	929,082			$ 4.25	$ 3,948,599	$ 4.25	$ 3,948,599	$ 0	0.00 %	1
2	Basic Service Charge	GS & GM	1,152			25.00	28,800	25.00	28,800	0	0.00	2
	Commodity Charge per Therm											
3	Baseline			34,780,770	34,780,770	0.58376	20,303,513	0.61770	21,484,082	1,180,569	5.81	3
4	Tier II			14,803,228	14,803,228	0.82275	12,179,368	0.85669	12,681,777	502,409	4.13	4
5	Total Primary		930,234	49,583,998	49,583,998		$ 36,460,280		$ 38,143,258	$ 1,682,978	4.62 %	5
	Secondary	G-1N										
6	Basic Service Charge		110,016			$ 4.25	$ 467,568	$ 4.25	$ 467,568	$ 0	0.00 %	6
	Commodity Charge											
7	All Usage per Therm			3,906,000	3,906,000	0.85707	3,347,705	0.83706	3,269,556	(78,149)	(2.33)	7
8	Total Secondary		110,016	3,906,000	3,906,000		$ 3,815,273		$ 3,737,124	$ (78,149)	(2.05)%	8
9	Total Residential		1,040,250	53,489,998	53,489,998	$ 0.75295	$ 40,275,553	$ 0.78296	$ 41,880,382	$ 1,604,829	3.98 %	9
	Commercial Gas Service	GN-1										
10	Basic Service Charge		65,504			$ 10.00	$ 655,040	$ 10.00	$ 655,040	$ 0	0.00 %	10
	Commodity Charge											
11	Summer			3,791,212	3,791,212	0.48165	1,826,030	0.54566	$ 2,068,695	$ 242,665	13.29 %	11
12	Winter			9,219,788	9,219,788	0.48165	4,440,693	0.56557	5,214,472	773,779	17.42	12
13	Total Commercial		65,504	13,011,000	13,011,000		$ 6,921,763		$ 7,938,207	$ 1,016,444	14.68 %	13
	Cogeneration Gas Service	GN-2										
14	Basic Service Charge		36			$ 75.00	$ 2,700	$ 75.00	$ 2,700	$ 0	0.00 %	14
	Commodity Charge											
15	Summer			2,250,068	2,250,068	0.35429	797,187	0.30213	$ 679,810	$ (117,377)	(14.72)%	15
16	Winter			3,085,932	3,085,932	0.35429	1,093,329	0.31588	974,780	(118,549)	(10.84)	16
	Total Cogeneration		36	5,336,000	5,336,000		1,893,216		$ 1,657,290	$ (235,926)	(12.46)%	
	Special Contract											
17	Basic Service Charge		36			75.00	2,700	75.00	2,700	0	0.00 %	17
	Commodity Charge											
18	Summer			16,800,000	16,800,000	0.31045	5,215,585	0.30213	$ 5,075,763	$ (139,822)	(2.68)%	18
19	Winter			6,300,000	6,300,000	0.31045	1,955,845	0.31588	1,990,036	34,191	1.75	19
20	Total Special Contract		36	23,100,000	23,100,000		$ 7,174,130		$ 7,068,499	$ (105,631)	(1.47)%	20
21	Total This Sheet		1,105,826	94,936,998	94,936,998		$ 56,264,662		$ 58,544,378	$ 2,279,716	4.05 %	21

[1] Rates proposed in Advice Letter No. 420-B excluding amounts to amortize balancing accounts with gas cost adjusted to reflect PG&E rates proposed in Advice Letter No. 1624-G-D.
[2] Rates to recover settlement revenue.

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SOUTHWEST GAS CORPORATION
SOUTHERN CALIFORNIA DIVISION
SUMMARY OF PRESENT AND PROPOSED RATES AND REVENUES BY RATE SCHEDULE

Line No.	Description	Rate Schedule	Annual Number of Bills	Sales Volumes (Therms) Present	Sales Volumes (Therms) Proposed	Present Rates [1] Rates	Present Rates [1] Revenues	Proposed Rates [2] Rates	Proposed Rates [2] Revenues	Increase/(Decrease) Dollars	Increase/(Decrease) Percent	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	
	Industrial Gas Service	GN-3										
1	Basic Service Charge		60			$ 75.00	$ 4,500	$ 75.00	$ 4,500	$ 0	0.00 %	1
	Commodity Charge											
2	Summer			446,292	446,292	0.12564	56,073	0.32113	$ 143,319	$ 87,246	155.59 %	2
3	Winter			436,437	436,437	0.12564	54,835	0.32966	143,877	89,042	162.38	3
4	Total Core Industrial Sales		60	882,729	882,729		$ 115,408		$ 291,696	$ 176,288	152.75 %	4
5	Basic Service Charge		12			$ 75.00	$ 900	$ 75.00	$ 900	$ 0	0.00 %	5
	Commodity Charge											
6	Summer			5,970,688	5,970,688	0.12564	750,174	0.11296	$ 674,470	$ (75,704)	(10.09)%	6
7	Winter			6,091,986	6,091,986	0.12564	765,415	0.12149	740,137	(25,278)	(3.30)	7
8	Total Core Industrial Transportation		12	12,062,674	12,062,674		$ 1,516,489		$ 1,415,507	$ (100,982)	(6.66)%	8
9	Total Core Industrial		72	12,945,403	12,945,403		1,631,897		1,707,203	75,306		9
	Non-Core Industrial Gas Service	GN-4										
10	Basic Service Charge		12			$ 75.00	$ 900	$ 75.00	$ 900	$ 0	0.00 %	10
	Commodity Charge											
11	Summer			619,554	619,554	0.32118	198,991	0.33015	$ 204,547	$ 5,556	2.79 %	11
12	Winter			1,366,043	1,366,043	0.32118	438,751	0.33868	462,654	23,903	5.45	12
13	Total Non-Core Industrial		12	1,985,597	1,985,597		$ 638,642		$ 668,101	$ 29,459	4.61 %	13
	Internal Combustion Engine Gas Service	GN-6										
14	Basic Service Charge		348			$ 25.00	$ 8,700	$ 25.00	$ 8,700	$ 0	0.00 %	14
	Commodity Charge											
15	Summer			528,524	528,524	0.45331	239,583	0.39061	$ 206,446	$ (33,137)	(13.83)%	15
16	Winter			378,476	378,476	0.45331	171,565	0.39917	151,075	(20,490)	(11.94)	16
17	Total Internal Combustion Engine		348	907,000	907,000		$ 419,848		$ 366,221	$ (53,627)	(12.77)%	17
	Standby Gas Service	GN-7										
18	Basic Service Charge		0			$ 10.00	$ 0	$ 10.00	$ 0	$ 0	0.00 %	18
	Commodity Charge											
19	All Usage per Therm		0	0	0	0.53308	0	0.55842	0	0	0.00	19
20	Total Standby Service		0	0	0		$ 0		$ 0	$ 0	0.00 %	20
	Street Lighting Gas Service	G-5										
	Charge per Lamp per Month											
21	1.99 cfh or Less (Lamps X 12)		0	0	0	$ 3.49	$ 0	$ 11.61	$ 0	$ 0	0.00 %	21
22	2.00 – 2.49 cfh (Lamps X 12)			0	0	6.40	0	14.61	0	0	0.00	22
23	Total Street Lighting		0	0	0		$ 0		$ 0	$ 0	0.00 %	23
24	Total This Sheet		432	15,838,000	15,838,000		$ 2,690,387		$ 2,741,525	$ 51,138	1.90 %	24
25	Total All Schedules		1,106,258	110,774,998	110,774,998		$ 58,955,049		$ 61,285,903	$ 2,330,854	3.95 %	25
26	Other Operating Revenues						1,432,538		1,432,538	0	0.00	26
27	GS & GM Discount						(80,212)		(84,875)	(4,664)	5.81	27
28	Total Operating Revenue / SAR						$ 60,307,375	$ 0.56541	$ 62,633,566	$ 2,326,190	3.86 %	28
29	Total Settlement Revenue Requirement								$ 62,633,374			29
30	Over / (Under)								$ 191			30

[1] Rates proposed in Advice Letter No. 420-B excluding amounts to amortize balancing accounts with gas cost adjusted to reflect PG&E rates proposed in Advice Letter No. 1624-G-D.
[2] Rates to recover settlement revenue.

STATEMENT OF EFFECTIVE RATES
APPLICABLE TO NORTHERN CALIFORNIA

Schedule No. And Type Of Charge (a)	Southwest Margin (b)	Upstream Transport Charge (c)	Southwest Shrinkage Charge (d)	Balancing Account Surcharges[1] (e)	CPUC Surcharge (f)	URA Surcharge (g)	Total Transport Charge (h)	Gas Cost [2] (i)	Currently Effective Tariff Rates (j)
G-10 Residential Gas Service									
Basic Service Charge	$ 4.25								$ 4.25
Commodity Charge per Therm									
Baseline	$ 0.20267	$ 0.09640	$ 0.01117	$ 0.00000	$ 0.00000	$ 0.00000	$ 0.31025	0.24990	$ 0.56015
Tier II	0.25318	0.09640	0.01117	0.00000	0.00000	0.00000	0.36076	0.24990	0.61066
G-10 Residential Low Income Gas Service									
Basic Service Charge	$ 3.60								$ 3.60
Commodity Charge per Therm									
Baseline	$ 0.11865	$ 0.09640	$ 0.01117	$ 0.00000	$ 0.00000	$ 0.00000	$ 0.22623	0.24990	$ 0.47613
Tier II	0.16158	0.09640	0.01117	0.00000	0.00000	0.00000	0.26916	0.24990	0.51906
G-10N Residential Gas Service									
Basic Service Charge	$ 4.25								$ 4.25
Commodity Charge per Therm									
All Usage	$ 0.29366	$ 0.09640	$ 0.01117	$ 0.00000	$ 0.00000	$ 0.00000	$ 0.40124	0.24990	$ 0.65114
GN-10 Commercial Gas Service									
Basic Service Charge	$ 7.75								$ 7.75
Commodity Charge per Therm									
All Usage	$ 0.10846	$ 0.09640	$ 0.01117	$ 0.00000	$ 0.00000	$ 0.00000	$ 0.21604	0.24990	$ 0.46594
G-16 Street and Outdoor Lighting Gas Service									
Charge per Lamp per Month									
Rate "X" 1.99 cu.ft./hr. or Less [3]	$ 3.04	$ 1.49	$ 0.17	$ 0.00	$ 0.00	$ 0.00	$ 4.70	3.87	$ 8.57
GS & GM Multi-Family Master Metered Gas Service									
Basic Service Charge	$ 7.75								$ 7.75
Commodity Charge per Therm									
Baseline	$ 0.20267	$ 0.09640	$ 0.01117	$ 0.00000	$ 0.00000	$ 0.00000	$ 0.31025	0.24990	$ 0.56015
Tier II	0.25318	0.09640	0.01117	0.00000	0.00000	0.00000	0.36076	0.24990	0.61066

[1] Balancing Account Surcharge include the following: PGA $ 0.00000 ; SAM $ 0.00000 ; CFA $ 0.00000

[2] Cost of gas equal to average procurement rate including Franchises and Uncollectables on Southwest's system.

[3] Average monthly use in therms 15.50

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SOUTHWEST GAS CORPORATION
NORTHERN CALIFORNIA DIVISION
CLASS REVENUE ALLOCATION

Line No.	Description (a)	Total Division (b)	Residential Primary (c)	Residential Secondary (d)	Commercial (e)	Master Metered (f)	Street Lighting (g)	Other Revenue (h)	Line No.
	Summary of Allocated Cost of Service								
1	Cost Of Gas [1]	$ 3,188,808	$ 1,033,838	$ 1,517,154	$ 632,028	$ 5,720	$ 69	$ 0	1
2	Amortization of Balancing Accounts [2]	0	0	0	0	0	0	0	2
3	Allocated Fixed Cost	2,653,666	784,623	1,535,717	236,828	1,682	10	94,806	3
4	Total Cost of Service	$ 5,842,475	$ 1,818,461	$ 3,052,871	$ 868,856	$ 7,402	$ 79	$ 94,806	4
	Comparison of Revenues At Present Rates to Cost of Service								
5	Revenue at Present Rates [3]	$ 6,696,998	$ 2,085,764	$ 3,483,019	$ 1,022,731	$ 10,652	$ 125	$ 94,687	5
6	Cost Based Allocation Of Proposed Rates	5,842,475	1,818,461	3,052,871	868,856	7,402	79	94,806	6
7	Percent Change From Present Rates	-12.76 %	-12.82 %	-12.35 %	-15.05 %	-30.51 %	-36.79 %	0.13 %	7
	Development of Proposed Revenue Allocation Weighting Factors								
8	Cost of Service @ 75%	$ (640,982)	$ (200,493)	$ (322,611)	$ (115,406)	$ (2,437)	$ (34)		8
9	System Average Decrease @ 25%	(213,657)	(67,499)	(112,716)	(33,097)	(345)	(4)		9
10	Weighted Allocation	$ 5,842,475	$ 1,817,792	$ 3,047,692	$ 874,228	$ 7,870	$ 86	$ 94,806	10
	Minimum Class Revenue Allowed								
11	System Average Decrease Minus 5%		1,715,353	2,864,442	841,098	8,760	103	94,806	11
12	Proposed Revenue Allocation	$ 5,842,475	$ 1,817,505	$ 3,047,211	$ 874,090	$ 8,760	$ 103	$ 94,806	12
13	Percentage Change From Present Rates	(12.76)	(12.86)	(12.51)	(14.53)	(17.76)	(17.76)	0.13	13
14	Proposed Fixed Cost Revenue Allocation	$ 2,653,666	$ 783,667	$ 1,530,057	$ 242,061	$ 3,040	$ 34	$ 94,806	14
15	Total Cost – $/Therm	$ 0.65497	$ 0.62846	$ 0.71800	$ 0.49439	$ 0.54749	$ 0.53542		15
16	Gas Cost Rate – $/Therm	0.35748	0.35748	0.35748	0.35748	0.35748	0.35704		16
17	Amortization Rate – $/Therm	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000		17
18	Fixed Cost(Trans) Rate – $/Therm	0.29749	0.27098	0.36052	0.13691	0.19001	0.17837		18
19	1992 Test Year Sales	8,920,192	2,892,000	4,244,000	1,768,000	16,000	192		19
20	1992 Test Year Number of Customers	8,985	2,878	5,564	541	1	1		20

[1] Cost of Gas at rates effective per Advice Letter No. 414.
[2] Account balance excluded from this filing.
[3] Present Revenues reflect rates effective January 1, 1990, per Advice Letter No. 414 excluding amounts to amortize balancing accounts.

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SOUTHWEST GAS CORPORATION
NORTHERN CALIFORNIA DIVISION
SUMMARY OF PRESENT AND PROPOSED RATES AND REVENUES BY RATE SCHEDULE

Line No.	Description	Rate Schedule	Annual Number of Bills	Sales Volumes (Therms) Present	Sales Volumes (Therms) Proposed	Present Rates [1] Rates	Present Rates [1] Revenues	Proposed Rates [2] Rates	Proposed Rates [2] Revenues	Increase/(Decrease) Dollars	Increase/(Decrease) Percent	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	
	Residential Gas Service											
	Primary	G-10										
1	Basic Service Charge	GS & GM	34,536			$ 4.25	$ 146,778	$ 4.25	$ 146,778	$ 0	0.00 %	1
2	Basic Service Charge		12			7.75	93	7.75	93	0	0.00	2
	Commodity Charge per Therm											
3	Baseline			1,908,733	1,908,733	$ 0.65002	$ 1,240,715	$ 0.56015	$ 1,069,177	$ (171,538)	(13.83)%	3
4	Tier II			999,267	999,267	0.70937	708,850	0.61066	610,212	(98,638)	(13.92)	4
5	Total Primary		34,548	2,908,000	2,908,000		$ 2,096,436		$ 1,826,260	$ (270,176)	(12.89)%	5
	Secondary	G-10N										
6	Basic Service Charge		66,768			$ 4.25	$ 283,764	$ 4.25	$ 283,764	$ 0	0.00 %	6
	Commodity Charge											
7	All Usage per Therm			4,244,000	4,244,000	0.75383	3,199,255	0.65114	2,763,438	(435,817)	(13.62)	7
8	Total Secondary		66,768	4,244,000	4,244,000		$ 3,483,019		$ 3,047,202	$ (435,817)	(12.51)%	8
9	Total Residential		101,316	7,152,000	7,152,000		$ 5,579,455		$ 4,873,462	$ (705,993)	(12.65)%	9
	Commercial Gas Service	GN-10										
10	Basic Service Charge		6,492			$ 7.75	$ 50,313	$ 7.75	$ 50,313	$ 0	0.00 %	10
	Commodity Charge per Therm											
11	All Usage per Therm			1,768,000	1,768,000	0.55001	972,418	0.46594	823,782	(148,636)	(15.29)	11
12	Total Commercial		6,492	1,768,000	1,768,000		$ 1,022,731		$ 874,095	$ (148,636)	(14.53)%	12
	Street Lighting Gas Service	G-16										
	Charge per Lamp per Month											
13	1.99 cfh or Less (Lamps X 12)		12	192	192	$ 10.39	$ 125	$ 8.57	$ 103	$ (22)	(17.60)%	13
14	Total All Schedules		107,820	8,920,192	8,920,192	$ 0.74015	$ 6,602,311	$ 0.64434	$ 5,747,660	$ (854,651)	(12.94)%	14
15	Other Operating Revenues						$ 95,723		$ 95,723	$ 0	0.00 %	15
16	GS & GM Discount						(1,036)		(902)	134	(12.92)	16
17	Total Operating Revenue						$ 6,696,998		$ 5,842,481	$ (854,517)	(12.76)%	17
18	Total Revenue Requirement								$ 5,842,475			18
19	Over / (Under)								$ 5			19

[1] Rates effective per Advice Letter No. 414 excluding amounts to amortize balancing accounts.
[2] Rates required to recover settlement revenue requirement.

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SOUTHWEST GAS CORPORATION
NORTHERN CALIFORNIA DIVISION
WEIGHTED AVERAGE COST OF GAS

Line No.	Description (a)		Billing Units (b)	Paiute Rates [1] (c)	Annual Purchased Gas Cost (d)	Average Cost per Therm Sales (e)	Average Cost per Therm Purchases (f)	Line No.
	Transmission Line Purchases Paiute Rate Scheddule G-1							
1	Total Core Throughput		9,319,047					1
2	LAUF Gas At	4.2800%	398,855					2
3	Sales in Therms		8,920,192					3
	Paiute Annual Demand Charges							
4	Annual Demand Charge Excluding F&U's			$ 70,964	$ 851,568	$ 0.09547	$ 0.09138	4
5	Average Demand Charge Including F&U's					$ 0.09640	$ 0.09228	5
	Paiute Commodity Charge							
6	Procurement Rate Excluding F&U's			$ 0.24747	$ 2,306,185	$ 0.25854	$ 0.24747	6
7	Procurement Rate Including F&U's					$ 0.26108	$ 0.24990	7
8	Total Gas Cost Excluding F&U's				$ 3,157,753	$ 0.35400	$ 0.33885	8
9	Total Gas Cost Including F&U's				$ 3,188,808	$ 0.35748	$ 0.34218	9

[1] Paiute rates effective November 1, 1988.

SOUTHWEST GAS CORPORATION
SOUTHERN CALIFORNIA DIVISION
CLASS COST OF SERVICE BASED ON CPUC METHODOLOGY

Description (a)	Allocators (b)	Total Division (c)	Residential Primary (d)	Residential Secondary (e)	Commercial (f)	Industrial Core (g)	Industrial Non-Core (h)	Gas Engines (i)	Cogeneration (j)	Master Metered (k)	Special Contract (l)
Cost of Gas From PG&E											
Total Throughput		113,848,919	48,785,199	4,014,388	13,372,045	13,304,628	2,040,696	932,169	5,484,070	2,174,716	23,741,007
Core Purchases		70,185,742	48,785,199	4,014,388	13,372,045	907,224	0	932,169	0	2,174,716	0
Non-Core Purchases		31,265,773	0	0	0	0	2,040,696	0	5,484,070	0	23,741,007
LAUF Transport		334,730	0	0	0	334,730	0	0	0	0	0
Purchased Revenue $											
Demand - Fixed											
Summer	10	$2,768,908	$783,088	$37,720	$256,355	$399,159	$38,538	$32,876	$139,962	$36,189	$1,045,020
Winter	11	5,600,728	3,097,962	308,342	804,394	461,167	96,497	26,746	217,990	142,597	445,032
Demand - Volumetric	5	507,766	217,582	17,904	59,639	59,339	9,102	4,157	24,459	9,699	105,865
Commodity	3	20,886,838	10,043,897	826,482	2,753,037	186,779	420,138	191,915	1,129,060	447,731	4,887,799
LAUF Transport	4	68,914	0	0	0	68,914	0	0	0	0	0
Total Cost of Gas Purchase	$0.42506	$29,833,154	$14,142,529	$1,190,449	$3,873,425	$1,175,359	$504,276	$255,695	$1,511,472	$636,215	$6,483,735
F&U Rate			0.014789	0.014789	0.014789	0.011117	0.011117	0.011117	0.011117	0.014789	0.011117
Demand - Fixed											
Summer		$2,803,778	$794,669	$38,278	$260,146	$403,597	$38,967	$33,242	$141,518	$36,724	$1,056,638
Winter		5,678,977	3,143,778	312,903	816,291	466,294	97,570	27,044	220,413	144,706	449,979
Demand - Volumetric		514,530	220,800	18,169	60,521	59,998	9,203	4,204	24,731	9,843	107,062
Commodity		21,170,709	10,192,438	838,705	2,793,752	188,856	424,809	194,048	1,141,612	454,352	4,942,136
LAUF Transportation		69,680	0	0	0	69,680	0	0	0	0	0
System Revenue $		$30,237,675	$14,351,665	$1,208,055	$3,930,710	$1,188,425	$570,549	$258,537	$1,528,275	$645,625	$6,555,815
ADJUSTED FOR AMORTIZATION		$30,237,675	$14,351,665	$1,208,055	$3,930,710	$1,110,745	$570,549	$258,537	$1,528,275	$645,625	$6,555,815
F&U's on Gas Cost		$404,521	$209,157	$17,606	$57,285	$13,066	$6,273	$2,843	$16,803	$9,409	$72,080
Commodity Cost - Shrinkage $/Thm											
Commodity $/Therm - Sales			$0.21472	$0.21472	$0.21472	$0.21395	$0.21395	$0.21395	$0.21395	$0.21472	$0.21395
Commodity $/Therm - Purchases			0.20892	0.20892	0.20892	0.20817	0.20817	0.20817	0.20817	0.20892	0.20817
Shrinkage			0.00580	0.00580	0.00580	0.00578	0.00578	0.00578	0.00578	0.00580	0.00578
Allocated Demand Costs $/Thm Based on Sales Including F&U's											
Transport $/Therm - Average			$0.08297	$0.08921	$0.08273	$0.06720	$0.06876	$0.06647	$0.06783	$0.08574	$0.06522
Fixed - Summer			0.07520	0.06966	0.06862	0.06290	0.06290	0.06290	0.06290	0.07095	0.06290
Fixed - Winter			0.08520	0.09322	0.08854	0.07143	0.07143	0.07145	0.07143	0.09053	0.07143
Volumetric			0.00405	0.00405	0.00405	0.00403	0.00403	0.00403	0.00403	0.00405	0.00403

SOUTHWEST [illegible] CORPORATION
SOUTHERN CALIFORNIA DIVISION
CLASS COST OF SERVICE BASED ON CPUC METHODOLOGY

Description (a)	Allocators (b)	Total Division (c)	Residential Primary (d)	Residential Secondary (e)	Commercial (f)	Industrial Core (g)	Industrial Non-Core (h)	Gas Engines (i)	Cogeneration (j)	Master Metered (k)	Special Contract (l)
Fixed Costs											
Production Revenue $	5	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Transmission Revenue $	7	699,449	318,905	28,088	87,621	73,140	11,218	5,125	30,148	14,692	130,512
Transmission (Interutility) Rev	7	0	0	0	0	0	0	0	0	0	0
Storage Revenue $	8	0	0	0	0	0	0	0	0	0	0
Distribution Revenue $	9	10,389,597	6,042,504	586,113	1,504,418	450,258	94,210	21,762	168,856	283,618	1,237,858
Customer Revenue $	12	19,298,820	13,334,142	1,578,945	3,876,737	47,541	11,832	20,639	7,240	402,394	19,352
50% of A&G Revenue $	5	1,499,557	642,572	52,875	176,129	175,241	26,879	12,278	72,233	28,644	312,704
F & U Revenue $, Chap 6, Sh	1.478919%	471,589	300,784	33,217	83,484	11,035	2,132	884	4,118	10,786	25,148
Margin Revenue $		$32,359,012	$20,638,908	$2,279,238	$5,728,388	$757,216	$146,271	$60,688	$282,595	$740,134	$1,725,573
Pipeline Revenue $		0	0	0	0	0	0	0	0	0	0
Total Revenue $		$32,359,012	$20,638,908	$2,279,238	$5,728,388	$757,216	$146,271	$60,688	$282,595	$740,134	$1,725,573
SAM Margin $/Therm		$0.29211	$0.43480	$0.58352	$0.44027	$0.05842	$0.07367	$0.06691	$0.05296	$0.34978	$0.07470

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Appendix A
Workpapers
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SOUTHWEST GAS CORPORATION
SOUTHERN CALIFORNIA DIVISION
CLASS COST OF SERVICE BASED ON CPUC METHODOLOGY

Description	Allocators	Total	Residential			Industrial	Industrial	Gas		Master	Special
		Division	Primary	Secondary	Commercial	Core	Non-Core	Engines	Cogeneration	Metered	Contract
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
Allocation Factors											
Average Year Sales											
Core		68,290,727	47,467,999	3,906,000	13,011,000	882,729	0	907,000	0	2,115,999	0
Allocation Fraction	1	100.0000%	69.5087%	5.7197%	19.0524%	1.2926%	0.0000%	1.3281%	0.0000%	3.0985%	0.0000%
Non-Core		30,421,597	0	0	0	0	1,985,597	0	5,336,000	0	23,100,000
Allocation Fraction	2	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	6.5269%	0.0000%	17.5402%	0.0000%	75.9329%
Total Sales		98,712,324	47,467,999	3,906,000	13,011,000	882,729	1,985,597	907,000	5,336,000	2,115,999	23,100,000
Allocation Fraction	3	100.0000%	48.0872%	3.9570%	13.1807%	0.8942%	2.0115%	0.9188%	5.4056%	2.1436%	23.4013%
Transportation		12,062,674	0	0	0	12,062,674	0	0	0	0	0
Allocation Fraction	4	100.0000%	0.0000%	0.0000%	0.0000%	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
Total System Thru-Put		110,774,998	47,467,999	3,906,000	13,011,000	12,945,403	1,985,597	907,000	5,336,000	2,115,999	23,100,000
Allocation Fraction	5	100.0000%	42.8508%	3.5261%	11.7454%	11.6862%	1.7925%	0.8188%	4.8170%	1.9102%	20.8531%
System Thru-Put Less LUZ		82,338,998	47,467,999	3,906,000	13,011,000	12,945,403	1,985,597	907,000	0	2,115,999	0
Allocation Fraction	6	100.0000%	57.6495%	4.7438%	15.8017%	15.7221%	2.4115%	1.1015%	0.0000%	2.5699%	0.0000%
Cold Year											
Annual Thru-Put		123,799,228	56,444,791	4,971,385	15,508,474	12,945,403	1,985,597	907,165	5,336,000	2,600,423	23,100,000
Allocation Fraction	7	100.0000%	45.5938%	4.0157%	12.5271%	10.4568%	1.6039%	0.7328%	4.3102%	2.1005%	18.6592%
Peak Season Thru-Put		79,286,632	43,855,680	4,364,989	11,387,246	6,528,763	1,366,043	378,631	3,086,615	2,018,645	6,300,000
Allocation Fraction	8	100.0000%	55.3128%	5.5053%	14.3621%	8.2344%	1.7229%	0.4775%	3.8930%	2.5460%	7.9459%
NCP Distribution		839,321	488,142	47,349	121,534	36,374	7,611	1,758	13,641	22,912	100,000
Allocation Fraction	9	100.0000%	58.1592%	5.6413%	14.4800%	4.3337%	0.9068%	0.2095%	1.6252%	2.7298%	11.9144%
Cold Year - Summer		44,513,639	12,589,111	606,396	4,121,228	6,416,980	619,554	528,524	2,250,068	581,778	16,800,000
Allocation Fraction	10	100.0000%	28.2815%	1.3623%	9.2583%	14.4158%	1.3918%	1.1873%	5.0548%	1.3070%	37.7412%
Cold Year - Winter		79,285,589	43,855,680	4,364,989	11,387,246	6,528,423	1,366,043	378,631	3,085,932	2,018,645	6,300,000
Allocation Fraction	11	100.0000%	55.3136%	5.5054%	14.3623%	8.2341%	1.7229%	0.4776%	3.8922%	2.5460%	7.9460%
Weighted Customer Factor											
302 - Customer Services		60,282,897	52,137,759	6,173,623	1,812,567	39,716	9,722	12,841	2,657	64,647	29,165
Weighting Factor	0.323084	19,476,410	16,844,850	1,994,560	585,611	12,832	3,141	4,149	858	20,886	9,423
Weighted Percent		32.3084%	27.9430%	3.3088%	0.9714%	0.0213%	0.0052%	0.0069%	0.0014%	0.0346%	0.0156%
303 - Meters		19,088,084	7,979,266	944,854	8,878,400	114,400	28,600	46,400	18,000	1,035,264	42,900
Weighting Factor	0.372204	7,104,658	2,969,913	351,678	3,304,574	42,580	10,645	17,270	6,700	385,329	15,968
Weighted Percent		37.2204%	15.5590%	1.8424%	17.3122%	0.2231%	0.0558%	0.0905%	0.0351%	2.0187%	0.0837%
309 - Customer Accounts		4,705,643	3,951,997	467,970	278,632	306	51	1,480	153	4,900	153
Weighting Factor	0.304713	1,433,869	1,204,224	142,597	84,903	93	16	451	47	1,493	47
Weighted Percent		30.4713%	25.5911%	3.0303%	1.8043%	0.0020%	0.0003%	0.0096%	0.0010%	0.0317%	0.0010%
Weighted Allocator	12	100.0000%	69.0930%	8.1816%	20.0879%	0.2463%	0.0613%	0.1069%	0.0375%	2.0851%	0.1003%

SOUTHWES[illegible]S CORPORATION
SOUTHERN CALIFORNIA DIVISION
CLASS COST OF SERVICE BASED ON CPUC METHODOLOGY

Description (a)	Allocators (b)	Total Division (c)	Residential Primary (d)	Residential Secondary (e)	Commercial (f)	Industrial Core (g)	Industrial Non-Core (h)	Gas Engines (i)	Cogeneration (j)	Master Metered (k)	Special Contract (l)
Test Year Projections											
Total Sales		110,774,998	47,467,999	3,906,000	13,011,000	12,945,403	1,985,597	907,000	5,336,000	2,115,999	23,100,000
Summer Sales		42,041,150	10,567,702	549,528	3,791,212	6,416,980	619,554	528,524	2,250,068	517,582	16,800,000
Winter Sales		68,733,848	36,900,297	3,356,472	9,219,788	6,528,423	1,366,043	378,476	3,085,932	1,598,417	6,300,000
Number of Bills		1,106,258	929,082	110,016	65,504	72	12	348	36	1,152	36
Avg Customers		92,279	77,424	9,168	5,549	6	1	29	3	96	3
Estimated Deliveries Baseline		Present Volume	33,055,360			5,970,688 <---Ind. Transport Volumes				1,725,410	
TIER II			14,412,639			6,091,986				390,589	
		Proposed Volum	33,055,360	30,813,295 <------		formulas for proposed baseline not used ----			1,620,878	1,725,410	
			14,412,639	(26,907,295)					21,479,122	390,589	

Allocation Factors

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Appendix A
Workpapers
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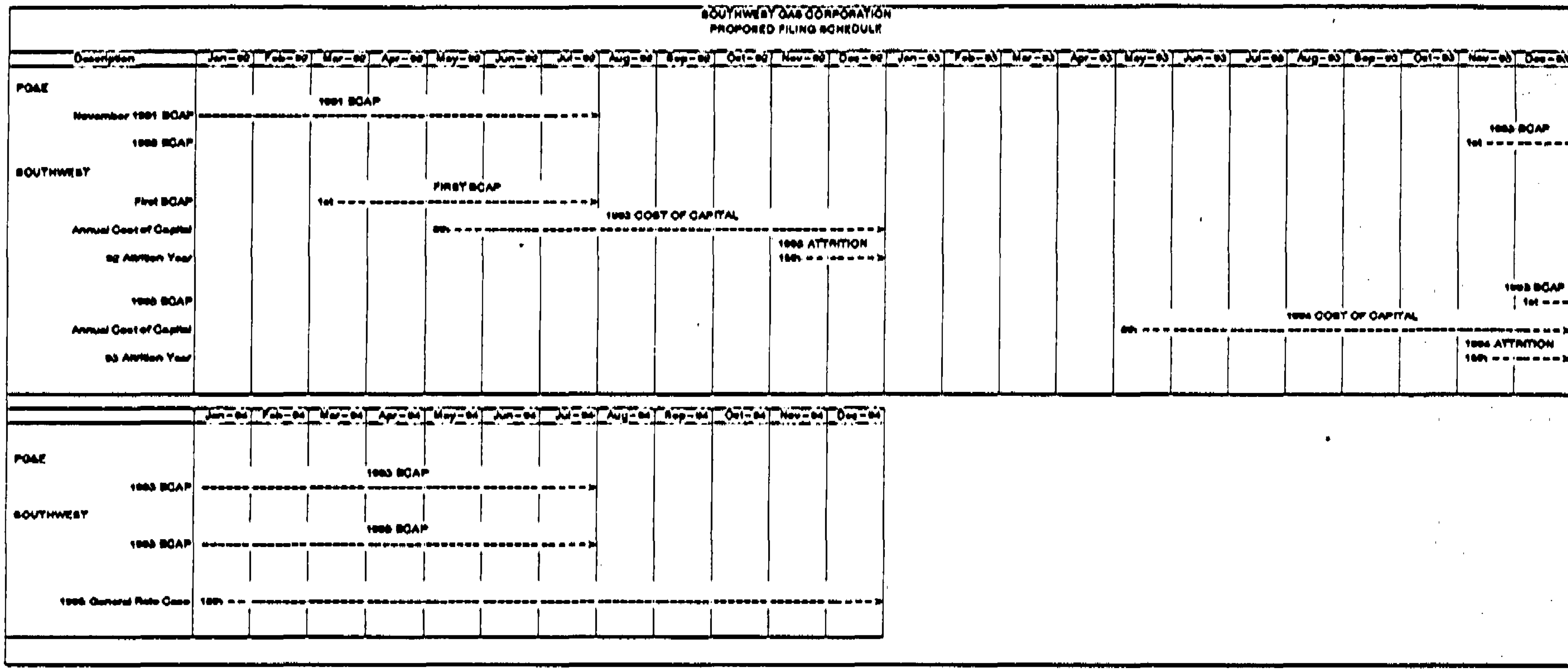

(END OF APPENDIX C)