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DOE/SF/16343--T1

FINAL TECHNICAL REPORT
ON THE
PROVISION OF UTILITY SUPPORT SERVICES
TO THE
U.S. DEPARTMENT OF ENERGY
SAN FRANCISCO OPERATIONS OFFICE

Prepared for the
U.S. Department of Energy
San Francisco Operations Office

Under Contract
No. DE-AC03-86SF16343

April 1994

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Prepared By

MASTER

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EXETER

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- A Comments of the U.S. Department of Energy San Francisco Operations Office on the Western Area Power Administration Proposal to Establish an Energy Planning and Management Program, July 31, 1991.
- B Comments of the U.S. Department of Energy San Francisco Operations Office on the Central Valley Project 1994 Power Marketing Plan of the Western Area Power Administration Sacramento Area Office, November 20, 1989.
- C U.S. Department of Energy San Francisco Field Office Application for Central Valley Project Power Under Western's 1994 Power Marketing Plan, May 1992.
- D "Natural Gas Supply Options for the DOE/SAN Labs," March 1989.
- E "Evaluation of Natural Gas Supply Options for ETEC," March 1989.
- F "A Comparison of the PG&E Tesla Transmission Proposal with the Western Tracy Tieline Project," March 24, 1988.
- G "Phase I of a Further Evaluation of the Economic Benefits Associated with the PG&E Tesla Transmission Proposal in Comparison to the Western Tracy Tieline Project," December 6, 1988.
- H "A Summary of DOE/SAN's Involvement in and Use of the California-Oregon Transmission Project," April 1989.

- I "Proposed Strategy to Maintain Pacific Gas and Electric Company Service to the Lawrence Livermore National Laboratory with the Completion of the Tracy Tie Line." November 1980
- J "Summary Analysis of the DOE Intervention Effort in the Pacific Gas and Electric Company Cases Relating to the Tracy Tie Line Before the Federal Energy Regulatory Commission Docket No. ER91-499-000 and the California Public Utilities Commission Docket No. 91-06-060," October 1993.
- K "Analysis of Proposed Settlement Among PG&E, Western and DOE/SF Regarding Electric Power Service to LLNL," March 11, 1992.
- L Draft Language for Approval of COTP Contract, July 2, 1993.
- M Monitoring Notebook for the Department of Energy San Francisco Operations Office Laboratories (last updated February 28, 1994).
- N "A Review of the Draft Request for Proposals by San Diego Gas & Electric Company for the Purchase of the Heber Binary Geothermal Power Plant," November 1987.
- O "Lawrence Livermore National Laboratory - 115 kV Tie-Line Cost Estimates," September 1989.

I. INTRODUCTION

The U.S. Department of Energy, San Francisco Operations Office* (DOE/SAN or SAN) has oversight of the operations of three major research facilities in Northern California -- the Lawrence Berkeley Laboratory (LBL or Berkeley), the Lawrence Livermore National Laboratory (LLNL or Livermore), including the facilities referred to as "Site 300," and the Stanford Linear Accelerator Center (SLAC) -- each of which is conducting research vital to the nation's interests. In addition, other smaller research facilities are under the oversight of DOE/SAN, including two programs in Southern California -- the Doublet III fusion research project at GA Technologies, Inc. (GA), and research into energy technology applications conducted at the Energy Technology Engineering Center (ETEC).

In the summer of 1986, DOE/SAN issued a Request for Proposals (RF) for the provision of technical assistance in "(1) all facets of utility support including planning, procurement, legal support, engineering and economics which affect the acquisition and management of utility services, and (2) support of utility regulatory proceedings." The competition was won by essentially the same Exeter Team that provided these services to DOE under Contract No. DE-AC03-84SF15123. Exeter entered into a contract with DOE/SAN on September 27, 1986, for the provision of utility support services for the three-year base period, ending September 30, 1989. In addition, the contract allowed

*Now referred to as the DOE Oakland Operations Office.

DOE/SAN to exercise two additional option years to obtain further assistance through September 30, 1991. The level of effort called for under the contract was 1800 man-hours per year, for a possible total of 9,000 man-hours.

The main purpose of Contract No. DE-AC03-86SF16343 was to provide to DOE/SAN continuing, follow-up support to realize savings from a number of alternate supply arrangements that had already been and/or were expected to be identified under the original project. This expected continuation of these efforts is demonstrated by certain of the tasks that are spelled out in the Statement of Work. For example.

- Evaluate and propose alternative options and methods for improving efficiency, reducing cost, and making effective use of the energy supplies and facilities under various conditions of use.
- Provide engineering and economic analysis and recommendations for utility-related facilities and service issues, such as high voltage discounts, ownership of facilities, etc.
- Assist in developing strategy and documentation in support of negotiating utility contracts and modifications thereto.

In addition, the follow-on contract provided for monitoring and intervening in rate cases that had particular relevance to the DOE/SAN laboratories.

II. SUMMARY OF ACTIVITIES

The purpose of this Final Technical Report is to provide in one place the major reports and other deliverables that were produced under this contract. In this section we will briefly summarize these documents, which are provided as attachments.

Western Area Power Administration -- Comments and Application

DOE/SAN played an active role in all of the relevant Western public hearing processes. It regularly provided comments on proposed marketing plans and other policies. Two sets of comments are included as Tabs A and B, each of which was prepared by Exeter. The first relates to Western's Proposal to Establish an Energy Planning and Management Program, and the second relates to Western's 1994 Power Marketing Plan. DOE/SAN was successful in getting its allocations renewed, which then required an application to be submitted for the Western power. The application was prepared in draft by Exeter, which is provided under Tab C.

Evaluation of Gas Alternatives

Exeter has continued to provide analyses and recommendations regarding DOE/SAN's least cost alternatives in the procurement of natural gas, as the character of this industry has changed due, in large part, to deregulation. Two baseline reports were prepared under this contract. The first, included as Tab D, is on "Natural Gas Supply Options for the DOE/SAN Labs." The second, under Tab E, is an "Evaluation of Natural Gas Supply Options for ETEC." Both were completed in March 1989.

Transmission Service For Lawrence Livermore National Laboratory

A critical step in DOE/SAN's long-term power supply plan was to obtain a direct interconnection with Western. Funds were allocated by Congress to accomplish this, but, after PG&E applied appropriate pressure, it was granted the right to compete for the provision of the new transmission line to LLNL. Exeter conducted a number of analyses on the comparative benefits to DOE/SAN of the Western Tracy Tie Line and another PG&E transmission line. Two of these reports are provided in Tabs F and G. Both reports concluded that it was in the best interest of the Government to have Western build the line. That was done, and it opened up a number of opportunities for DOE/SAN.

The Development of the COTP Alternative

Completion of the Tracy Tie Line opened up a number of alternative ways DOE/SAN could use its entitlement in the California-Oregon Transmission Project (COTP). In April 1989 Exeter provided a report entitled, "A Summary of DOE/SAN's Involvement in and Use of the California-Oregon Transmission Project" (Tab H). This report also describes the Intra-Agency Agreement No. 90-SAO-00001 with Western, under which Western is required to act as DOE/SAN's agent in utilizing the COTP.

In Tab I is provided a report on a proposed strategy by which DOE/SAN can maintain PG&E service to LLNL with the completion of the Tracy Tie Line, which was crucial to the kind of reliability that LLNL wanted. This strategy led to litigation with PG&E at both the FERC and the CPUC. Both of these litigative actions were settled in the Settlement Agreement Among DOE/SAN, Western and PG&E, dated February 19, 1992 (Contract No. 92-SAO-10113). The intervention effort is summarized in a report in Tab J, that was provided to the Office of Organization, Resources and Facilities Management under a separate Exeter contract, because DOE Headquarters funded part of the litigation and settlement effort. Tab K provides a March 1992 report in which Exeter evaluates the relative benefits of the Settlement Agreement.

As a result of the Settlement Agreement, PG&E negotiated in good faith a 3-party contract among DOE/SAN, Western and PG&E (Contract No. 93-SAO-00018)

which the FERC is likely to accept for filing by the end of April 1994. This agreement governs the power scheduling, sale of power, and sale of other services related to DOE/SAN use of the COTP. In Tab L is provided a report on draft language requesting approval for the contract. Although this report was actually prepared under the current contract (DE-AC03-92SF19198), it does relate to some of the work that was done under Contract No. DE-AC03-86SF16343, and so it has been included.

Laboratory Monitoring Notebook

Throughout the course of Contract DE-AC03-86SF16343 Exeter has maintained an updated Laboratory Monitoring Notebook. The notebook is updated quarterly. We have included the latest version (February 28, 1994) under Tab M since we do not have the last version that was issued under the contract.

Miscellaneous Reports

Exeter has provided a number of miscellaneous reports under this contract, including a large number of less formal memo-reports. Two of the more formal reports in this category are provided in Tabs N and O. The first provides a review of a draft Request for Proposals for the purchase of geothermal power plant in which DOE had an interest. The second is a report evaluating the probable relative costs of an underground

versus overhead 115 kV tie line from the new Western substation at LLNL to LLNL's existing on-site substation.

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COMMENTS OF THE
U.S. DEPARTMENT OF ENERGY
SAN FRANCISCO OPERATIONS OFFICE
ON THE
WESTERN AREA POWER ADMINISTRATION
PROPOSAL TO ESTABLISH AN
ENERGY PLANNING AND MANAGEMENT PROGRAM

JULY 31, 1991

Following are the comments of the U.S. Department of Energy, San Francisco Operations Office (DOE/SAN) on the issues raised in the Western Area Power Administration (Western) proposed Energy Planning and Management Program (EPMP), which was noticed in the April 19, 1991 issue of the Federal Register. However, before proceeding with our specific thoughts on these issues, a few preliminary comments are in order.

Four of DOE/SAN's laboratories currently receive allocations of power from Western's Central Valley Project (CVP): Lawrence Berkeley Laboratory, Lawrence Livermore National Laboratory, Site 300 at the Lawrence Livermore Laboratory, and the Stanford Linear Accelerator Center. DOE/SAN has depended on Western power to serve the needs of the nationally critical energy and defense programs at its laboratories since the inception of the Central Valley Project. Currently the labs have a combined allocation of 78 MW of CVP power. The Western allocation met nearly two-thirds of the laboratory energy requirements in FY 1989. Other things constant, that share will fall as the labora-

tory loads are expected to rise throughout the decade, to a level of around 200 MW by the end of the century.

It is clear that the DOE laboratories have come to rely heavily on Western for their power requirements. It is also clear that the laboratories have been strong supporters of load management and energy efficiency programs, including those sponsored by Western. Each of the laboratories has developed and vigorously pursued energy-management programs to meet the requirements of the Department of Energy. Moreover, Lawrence Berkeley Laboratory is one of the nation's leaders in developing new energy management techniques and methods and procedures for implementation.

DOE/SAN's reliance on Western for more than half of the laboratory power requirements, and its commitment to efficient use of electric power, leads us to support the two basic objectives set forth in Western's EPMP: (1) Greater stability for Western customers in planning for future resources; and (2) the encouragement of efficient electric energy use by Western's customers. While DOE/SAN applauds both objectives, we have concerns about the mechanism that has been proposed to achieve these goals. In particular, we are unconvinced that linking the resource allocation process with the Energy Management Program in the manner proposed by Western will produce the desired improvements in the efficiency of energy use. DOE/SAN is also concerned that the proposal introduces a number of uncertainties regarding the future availability of Western power for those customers, such as the DOE/SAN laboratories, that place heavy reliance on Western to meet critical energy requirements.

Long-Term Resource Stability

Given the critical importance of CVP power to meeting the programmatic requirements of its laboratories, DOE/SAN endorses the concept of Western making an early commitment to extend customers' firm power allocations for a period of ten years or more. Clearly, the longer the extension period to which Western commits, the greater the degree of stability that will be afforded Western customers in their resource planning processes. However, DOE/SAN is concerned about Western's proposal to extend less than 100 percent of an existing customer's current allocation. As we understand Western's proposal, the portion of an existing customer's allocation that is not extended will be placed into a separate Resource Pool, which will subject to a separate allocation process. While energy management accomplishments may be considered as one of the criteria in the marketing of this power, Western has indicated that many other criteria will be considered, and that new customers without existing allocations will be considered.

While DOE/SAN agrees that it may be beneficial to use these non-extended amounts to reward existing customers for qualifying energy conservation and load management efforts, we do not believe Western's stated objective will be best pursued by allocating any significant portion of the unextended resources to new customers. Existing CVP customers have come to rely on CVP power as a major and stable source of supply. Using the Resource Pool as a means of redistributing that power to new customers is inconsistent with Western's stated goal of promoting long-term planning stability.

If Western pursues this course of extending less than 100 percent of a customers' allocation, DOE/SAN firmly believes that should be a very high percentage -- at least 85 percent, although 95 percent would be more appropriate. A high percentage is required for at least two reasons. First, a high percentage promotes greater planning stability. Second, and most important, a lower percentage may turn out to be patently unfair to those CVP customers that have contracts expiring in 1994. While CVP customers must await Western's decision regarding how the post-1994 allocation will proceed, there is evidence that Western contemplates reducing the allocations of these customers by some amount. If that happens, then these customers, which include all of the Federal Executive Agency facilities, will be forced to endure two "across-the-board" reductions in their contract rates of delivery -- one as a result of the post-1994 allocation, and another when their renewed contracts expire, assuming those contracts are extended to 2004, as a result of an extension policy based on less than 100 percent of the customer's allocation. Current customers with contracts expiring in 2004 would face only the second of these reductions. DOE/SAN believes this approach treats unfairly those customers with contracts expiring in 1994. The adverse impact of this inequitable treatment is larger the smaller the portion of customers' allocations that are extended early. Of course, one reasonable way to address this inequity is to extend a larger fraction of the allocations of those customers whose contracts are renewed in 1994.

The Effectiveness of Linking Resource Allocations with the Energy Management Program

Our understanding of the proposed linkage between the Power Marketing Initiative and the Energy Management Program is that qualifying, successful energy management efforts by Western customers will be rewarded in one of two ways. First, higher fractions of existing allocations may be extended for and/or some of the power in the Resource Pool may be allocated to customers that develop and implement an acceptable Integrated Resource Plan (IRP) or Performance Plan. Second, the Western proposal seems to imply that retention of an existing allocation is contingent upon the development and implementation of a qualifying IRP or Performance Plan.

Holding out the carrot of gaining additional Western power as a reward for successful energy management efforts may be effective. That is less likely if a large portion of unextended allocations is used for other purposes or is provided to new customers. Using the threat of withdrawal of existing allocations as a stick to encourage efficient energy planning and use is likely to be much less effective in DOE/SAN's opinion. We are not even certain whether Western's EPMP proposal incorporates the 10-percent power withdrawal penalty for noncompliance that is currently included as part of the C&RE Program. Without such a specific, enforceable non-compliance penalty, the threat of withdrawal is likely to provide little if any incentive for improvements in energy management. Further, DOE/SAN believes that attempts to implement such withdrawals are likely to meet with serious resistance and the most probable outcome of this approach is increased customer dissatisfaction.

As an alternative, DOE/SAN believes that Western should give serious consideration to pricing mechanisms that would provide incentives for its customers to manage their use of Western power more efficiently, and to encourage the appropriate amount of conservation and load management, especially at the times and under the conditions when the cost of providing power is highest. Reliance on prices can provide much more precise signals to Western's customers, and it has the distinct advantage of utilizing customer self-interest in undertaking socially advantageous conservation and load management efforts.

Providing differential price signals to elicit appropriate conservation and load management responses could provide a substitute for or could supplement the power allocation approach proposed by Western. It would not require any change in the way Western determines the total revenue it must recover under its repayment obligations. That is, Western's average rate level would be unaffected. Rather, the rates would be designed for different types of service and at different times that better reflect the cost of service, including the incremental costs and benefits associated with energy management activities. These rates would recover the same total revenue for each Western project. This is the same rate design process that is undertaken by regulated utilities that must recover a specified total jurisdictional revenue requirement. Moreover, at least in the case of the CVP, this approach is actually an extension of certain existing rate design practices. Rates are currently differentiated by voltage level, and incentive rates are used to encourage improvements in power factors.

Proposed Standards for IRPs or Performance Plans

Our understanding of the proposed standards for an IRP and for a Performance Plan, is that they would identify minimum acceptable criteria for integrated resource planning and for achieving acceptable levels of performance. At the same time, if allocations are to partly depend on the relative performance of customers in developing and implementing IRPs and Performance Plans, then these standards must be set forth in an acceptable, uniform manner to permit performance comparisons among customers. DOE/SAN wishes to again emphasize the importance of setting forth a standard methodology by which to calculate the energy and/or capacity benefits associated with a customer's IRP or Performance Plan. The methodology must permit the objective comparison of the benefit to the system generated by a utility customer's IRP and a large end-user customer's Performance Plan. Without some sort of objective comparative evaluation based on a common methodology, the resulting decisions to reward certain customers and not others must be highly subjective, which is likely to lead to increased customer dissatisfaction. Avoiding these kinds of subjective comparisons is, of course, one of the benefits of relying on customer responses to a uniform set of price signals set to reflect the benefits associated with reducing loads on the Western system.

DOE/SAN is also concerned about the equitable treatment of customers that have already undertaken extensive energy management programs, the energy savings of which are already reflected in their loads compared to what those loads would have been without those load management programs. Equitable treatment of these customers, such as the DOE/SAN laboratories, will require

that an appropriate historical base year be used in quantifying the continuing energy or capacity savings. This is especially necessary because the most productive investments are generally undertaken first. Thus, any method that only accounts for the savings from incremental efforts will unfairly penalize those customers that initiated programs several years ago.

COMMENTS OF THE
U.S. DEPARTMENT OF ENERGY
SAN FRANCISCO OPERATIONS OFFICE
ON THE
CENTRAL VALLEY PROJECT
1994 POWER MARKETING PLAN
OF THE
WESTERN AREA POWER ADMINISTRATION
SACRAMENTO AREA OFFICE
November 20, 1989

Following are the comments of the U.S. Department of Energy, San Francisco Operations Office ("DOE" or "DOE/SAN") on the 1994 Power Marketing Plan for the Central Valley Project. These additional comments supplement DOE/SAN's comments of February 22, 1989, and are specifically in response to the information presented by the Western Area Power Administration (Western) in the FEDERAL REGISTER notice published on August 11, 1989 (54 FR 33064), and as further supplemented in Western's September 12, 1989 brochure on the 1994 Power Marketing Plan (1994 PMP). DOE/SAN's positions on the numerous issues raised in the 1994 PMP, as initially set forth in its February 22, 1989 comments, remain unchanged. Therefore, we shall limit these comments to a summary of some of the most important points raised in our February 22, submission, and to our responses to the four draft PMP alternatives described in the September 12 brochure. We urge Western to again review our more complete February 22, 1989 comments, in addition to these comments, before preparing its next FEDERAL REGISTER notice on its proposed general allocation and contract principles, and its proposed eligibility and selection criteria.

General Comments

A Level Playing Field. DOE/SAN feels strongly that it would be fundamentally unfair to customers with 1994 contracts, and Federal Executive Agency (FEA) customers in particular, if these allocations were terminated or substantially revised as contemplated under the "Termination" and "Zero Base" alternatives. Customers with contracts that extend through 2004 would be unfairly insulated from the burdens associated with such a dramatic change in Western's power marketing practice. This inequity is further exaggerated by the fact that expiring contracts cover 80 percent of the CVP preference customers but only 26 percent of long-term firm power and only 35 percent of total CVP preference power. Moreover, all of the FEA customers have 1994 contracts, and together account for well over half of the power covered by contracts due to expire in 1994. Thus, any plan that would not extend 1994 contracts in essentially the same form and with essentially the same allocations will be especially unfair to Western's FEA preference customers.

The logical approach is to extend the 1994 contracts through 2004. That will place all of Western's existing preference customers on a level playing field, for all contracts will be expiring on the same date. Moreover, that is also the expiration date of Contract 2948A. Expiration of this contractual arrangement with the Pacific Gas & Electric Company (PG&E) may require some dramatic changes in the way Western markets power after 2004. These changes, and any reallocation among existing or to new customers, can be accomplished at that time, with the assurance that all existing CVP preference customers

will be equally at risk for the economic and power planning burdens that may accompany these changes.

The Diversity Program. DOE firmly believes that Western should make every effort to maintain and strengthen the Diversity Program. DOE supports Western's commitment to market as much power as is consistent with prudent utility practice and the constraints of the support contract 2948A with PG&E. Western has used its short-term withdrawable marketing program as the major means of accomplishing that objective, and DOE believes that the continued success of the short-term withdrawable program depends, in turn, on the maintenance and strengthening of Western's Diversity Program. Thus, DOE/SAN believes that Western should take the opportunity provided by the 1994 Marketing Plan to establish arrangements designed to support the system in staying within the marketing limitations imposed by Contract 2948A.

The Appropriate Marketing Plan Alternative. The first step to achieve these two goals of maintaining equity between customers with 1994 and 2004 contracts, and strengthening the Diversity Program, is to avoid making significant and wholesale changes to its marketing program and to its allocation of preference power. At the same time, DOE believes Western should retain sufficient flexibility to permit it to maximize the amount of power it markets by strengthening the Diversity Program. The "Termination" alternative meets neither criteria, and the "Zero-Base" alternative fails to meet the equity concerns of the first criterion. Both of the alternatives should be rejected. While the overall allocation should be essentially the same as the existing allocation, slavish adherence to the "Status Quo" alternative will

not provide Western with sufficient flexibility to make marginal adjustments that can strengthen its ability to operate within the constraints of Contract 2948A and to ensure that Western power will be used in a maximally efficient manner.

Consequently, DOE/SAN believes that some variant of Western's "Draft Plan" alternative will yield an equitable result and provide sufficient flexibility for Western to improve its marketing practices. Specifically, DOE believes Diversity Power should be retained by customers who continue to be willing to use the allocation in ways that provide revenues to the system and load shedding at times when the system nears the contract support levels. Further, DOE believes there is little system advantage in extending the Renewable Resource and Cogeneration (RRC) allocations to existing customers. DOE believes that power should be used: (1) to provide incentive for the completion of new RRC projects; (2) to add to the amount of Diversity Power available, if there are customers who can use it; and/or (3) to be marketed as long-term firm power. If converted to long-term, firm power, Western may wish to give new applicants first consideration in order to achieve its goal of increasing participation in its marketing program without making major changes to the existing allocation of power only to customers with 1994 contracts.

The Four PMP Alternatives

Following are DOE/SAN's specific comments on each of the four PMP alternatives that were presented in the September 12, 1989 brochure.

The Termination Alternative. DOE/SAN believes that any reasonable comparison of the "Pros" and "Cons" of the "Termination" alternative, as set forth on page 33 of the brochure, will result in its rejection. Of particular concern in that comparison is the fundamental inequity to 1994 contract holders that would result. Lower rates might result, but only for the remaining 17 customers with contracts that expire at the end of 2004. In a similar vein, this alternative would run counter to Western's objective of maximizing widespread use by reducing the number of CVP preference customers from 78 to 17.

The Zero-Base Alternative. Western's enumeration of the "Pros" and "Cons" of this alternative does not give proper weight to the fundamental inequity associated with the Zero-Base alternative. Western lists as an objective that this alternative will establish a "'level playing field' for those with and without Federal power." This is only partially true. More correctly stated, the "level playing field" will be established for those currently without Federal Power and those with Federal power, whose contracts expire in 1994. Customers with 2004 contracts are insulated -- they would not have to play the game and so are unconcerned that the playing field is levelized for others. This is the basic inequity of using the Zero-Base alternative before 2004, when all existing customers would be at risk of losing some of their allocations. This inequity may be what Western has in mind when it lists as the first "Con," the fact that the amount of power to be reallocated is only "40 percent of the total power marketed by Western SAO." While that is correct, the statement fails to give proper weight to the fundamental inequity of using the Zero-Base alternative in 1994. This inequity,

plus the other "Cons" listed at page 32 of the brochure, calls for rejection of the Zero-Base PMP alternative.

The Status Quo Alternative. DOE/SAN believes that extension through 2004 of the existing 1994 contracts and allocations, especially of long-term firm and short-term withdrawable allocations, is the appropriate basis for Western's 1994 PMP. In addition to the "Pros" for this alternative that are listed at page 29 of the September 12, 1989 brochure, this alternative would also maintain equity between customers with 1994 contracts and customers with 2004 contracts, which neither the "Termination" nor the "Zero-Base" alternatives would accomplish.

However, DOE/SAN believes that slavish adherence to this alternative would prevent Western from making certain marginal adjustments in its overall allocation of power, which could lead to an increase in the overall benefits associated with Western's power marketing activities. The inability to make some of these improvements is reflected in the third "Con" on page 30 of the brochure. Therefore, DOE/SAN believes that a variant of the Draft PMP alternative, which provides this needed marginal flexibility, should be used by Western in establishing the final power marketing plan.

The Draft Power Marketing Plan Alternative. DOE/SAN endorses Western's Draft PMP Alternative B. DOE/SAN believes the "Proposed Option" is best with regard to Long-Term Firm Power and Type III Withdrawable Power. This option would renew the existing allocations of these two types of power, with contracts extending through 2004. DOE/SAN believes the 89 MW of Interruptible

Power should continue to be marketed, and so "Option 1" should be rejected. We have no strong preference for the "Proposed Option" or "Option 3," except that "Option 3" would appear to make better and more complete use of system diversity, if there are customers who can meet the interruptibility conditions in ways that ensure that Western will stay within the 1,152 mW support level.

DOE/SAN opposes the treatment of Diversity Power under the "Proposed Option," which would convert all 30 mW to Type III Withdrawable Power. As we stated above, DOE/SAN believes the Diversity Program should be maintained and strengthened to continue to provide assistance to Western to stay within the contract support level, while marketing as much power as possible. DOE/SAN believes that customers with existing Diversity Power allocations should have those allocations renewed, as long as they continue to use those allocations in ways that provide revenues to the system and load shedding at times when the system peak approaches the 1,152 mW support level. If customers with existing allocations do not use those allocations, then Western should allocate that Diversity Power to other customers who can use the power in ways that help the system. DOE/SAN is unsure whether this would better be accomplished under "Option 1" or "Option 2."

DOE/SAN recommends against the "Proposed Option" for RRC allocations. As we argued in detail in our February 22, 1989 comments, these allocations were made to provide a fillip to the development of new projects. If those projects are uneconomic, no subsidies should be provided by Western. If those projects are economic, no further incentives are required. There is no basis for extending these allocations for another 10 years. Instead, DOE/SAN

believes Western can make much better use of this 30 mW of RRC power. First, Western would be better served by allocating this power to encourage new projects, which is largely accomplished by "Option 2." Second, this 30 mW could be added to the Diversity Power to be allocated, if there are customers that could efficiently use this added power subject to the load shedding requirements. Finally, Western could convert the RRC power into Long-Term Firm Power, as suggested in "Option 1." By giving new applicants first priority in the allocation of this power, this additional 30 mW could be used to meet Western's objective of widening the participation in Western's marketing program, without major disruptions in the basic power allocations of existing customers whose contracts expire in 1994.

**U. S. DEPARTMENT OF ENERGY
SAN FRANCISCO FIELD OFFICE
APPLICATION FOR
CENTRAL VALLEY PROJECT POWER
UNDER WESTERN'S
1994 POWER MARKETING PLAN**

MAY 1992

APPLICANT PROFILE DATA

Introduction

The U.S. Department of Energy San Francisco Field Office (DOE/SF) is submitting this application for the continued allocation of Western CVP power for use at Lawrence Berkeley Laboratory (LBL), Lawrence Livermore National Laboratory (LLNL), including Site 300, and Stanford Linear Accelerator Center (SLAC). Each of these facilities is a national laboratory operated for the U.S. Department of Energy. DOE/SF is responsible for the acquisition of the laboratories' electric power requirements. Therefore, this application is being made for the allocation of Western CVP power to DOE/SF.

DOE/SF is requesting in this application that the existing allocation of Western power to the DOE/SF laboratories be extended for the period covered by the 1994 Power Marketing Plan. This would result in the allocation of 77,614 kW of Western power to DOE/SF for use by the laboratories, consisting of 47,800 kW of Long-Term Firm Power, 20,814 kW of Type III Withdrawable Power and 9,000 kW of Diversity Power.

A. Applicant

- (1) Applicant's name and address:

U.S. Department of Energy
San Francisco Field Office
1333 Broadway
Oakland, California 94612

- (2) Person representing applicant:

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Special Assistant to the Assistant Manager
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San Francisco Field Office
1333 Broadway
Oakland, California 94612
(510) 273-4272

- (3) Type of organization:

DOE/SF is a Federal agency.

- (4) Parent organization:

The U.S. Department of Energy.

- (5) Names of members:

Not applicable.

- (6) Applicable law under which organization was established:

DOE was established under PL95-91 "Department of Energy Organization Act", August 4, 1977.

- (7) Organization's geographic service area:

DOE/SF is not a utility and, therefore, does not have a service area. Rather, DOE/SF is responsible for acquiring electric power for the DOE/SF laboratories, each of which is located within PG&E's service territory.

- (8) Applicant's ability to receive and use Federal power:

The DOE/SF laboratories have been receiving and using Western CVP power for many years, were receiving and using that Federal power in January 1992 and will continue to be able to receive and use Western power during the time period covered by the Western 1994 Power Marketing Plan.

B. Service Requested

DOE/SF is requesting that the existing allocation of Western CVP power to the DOE/SF laboratories be renewed. This would result in an allocation to DOE/SF of:

- 47,800 kW Long-Term Firm Power
- 20,814 kW Type III Withdrawable Power
- 9,000 kW Diversity Power

for a total CVP power allocation of 77,614 kW. The assignment of this total allocation to the individual laboratories is presented in Table I.

Table I
Assignment of CVP Power Allocation
to DOE/SF Laboratories
(kW)

	<u>LBL Bank 1</u>	<u>LLNL Main Meter</u>	<u>Site 300</u>	<u>SLAC</u>	<u>Total</u>
Long-Term Firm	0	22,300	500	25,000	47,800
Type III Withdrawable	0	5,911	0	14,903	20,814
Diversity	<u>3,000</u>	<u>0</u>	<u>0</u>	<u>6,000</u>	<u>9,000</u>
Total	3,000	28,211	500	45,903	77,614

C. Loads

- (1) Because the DOE/SF laboratories are existing Western customers, historical demand and energy data are not required.
- (2) Because the DOE/SF laboratories are existing Western customers, historical load factor data are not required.
- (3) Attachment 1 to this application provides annual load forecasts for fiscal years 1994 through 2004 for each of the DOE/SF laboratories. As shown by these load forecasts, the laboratories' power requirements are not expected to change significantly over the next several years. Factors or conditions that might affect the laboratories' peak demands or load curves are primarily tied to federal funding. If the funding of programs is either increased or decreased significantly from anticipated levels, then the power requirements at the laboratories could also change. The demand side management projects being implemented at the laboratories could also affect their peak demands and load shapes. Many of these projects are designed to reduce peak demand or shift load from peak periods to off-peak periods. A description of the DSM programs at the laboratories is contained in Section E of this Application.

D. Transmission

(1) Points of delivery:

LBL:

The point of delivery for LBL is the point at the PG&E Grizzly substation where LBL's 115 kV circuits are attached to PG&E's 115 kV circuits. Western power is delivered to PG&E's system for ultimate delivery to the Grizzly substation. The existing capacity at this delivery point is adequate to meet the laboratory's needs for the foreseeable future.

LLNL Main Meter:

The currently effective point of delivery for LLNL is LLNL's Building 424 Substation with delivery to that point via either the 115 kV transmission line from Western's Livermore Substation or PG&E's Tesla No. 1 115 kV transmission line. Effective in late 1993 or early 1994, LLNL's preferred points of delivery are anticipated to be Western's 13.8 kV switch gear at the Livermore Substation and a new substation to be built on Sandia National Laboratories property in Livermore which will be fed from a new 115 kV line from Western's Livermore Substation. The capacity at these points of delivery is adequate to meet the laboratory's needs for the foreseeable future.

LLNL Site 300:

The points of delivery at Site 300 are located at the Building 865 substation and the Building 846 substation. A single 115 kV transmission line from PG&E's Tesla substation enters Site 300. This 115 kV line connects to both Buildings 865 and 846 substations. The delivery point at Building 865 substation is metered by PG&E while the Building 846 substation delivery point is metered by Western.

The existing capacity at these delivery points is viewed as adequate to meet requirements for the foreseeable future.

SLAC:

SLAC receives power from PG&E transmission lines at 230 kV and 60 kV, which can be used interchangeably. The 230 kV line is used most of the time and has a total capacity of over 80 mW. The 60 kV line has a capacity of 17 mW and is used in cases of emergency when the 230 kV line is not available. The delivery point on the 230 kV line is at the PG&E tower (part of the Monte Vista-Jefferson line) at Bear Gulch Road. The 60 kV power is delivered over PG&E lines from the main Stanford University campus to the SLAC Master Substation near Sector 30. The existing capacity at the SLAC delivery points is viewed as adequate for the foreseeable future.

(2) Transmission arrangements:

The transmission arrangements necessary to deliver Western power to the points of delivery specified for LBL, Site 300 and SLAC are provided for in the Sales, Interchange and Transmission Contract No. 14-06-200-2948A (Contract 2948A) between Western and PG&E. This contract sets forth the terms under which PG&E's transmission system is used to deliver CVP power to Western's preference customers such as the DOE/SF laboratories.

Power is delivered to the LLNL main meter over Western's 230 kV Tracy-Livermore line and the 115 kV Livermore-LLNL line under the Intra-Agency Agreement No. 89-SA0-90001 between Western and DOE/SF. The delivery of Western power from PG&E's transmission system via the Tesla-LLNL 115 kV line No. 1 is governed by Contract 2948A and the February 19, 1992 Settlement Agreement among PG&E, Western and DOE/SF.

E. Demand Side Management Programs

DOE and its contractors have maintained active DSM programs for many years. Projects that have been implemented at the DOE/SF laboratories include:

- (a) Retrofits for: indoor and outdoor lighting; domestic and process water heating and cooling; thermal energy storage; fenestration; chiller improvements; heating, ventilation and air conditioning modifications, including air circulation turndowns; fume hood exhaust controls; motor replacements; and, insulation additions;
- (b) Addition of automated, centralized building control systems, including direct digital controls, personnel sensors and timers;
- (c) Metering and submetering aimed at load monitoring, forecasting and encouraging conservation by recharging users based on their individual consumption;
- (d) Peak shaving projects, including power factor corrections, addition of capacitor banks and time-of-use metering;
- (e) Active energy awareness programs, including posters, bulletins, suggestion programs, energy fairs, etc.; development and dissemination of high school and grade school model curriculums on energy conservation;
- (f) Research and development on conservation and renewable resources, such as windows and daylighting, aerogel insulations and energy storage;
- (g) Review of all new building designs to assure conformance to policy and compliance with federal and state requirements for energy efficiency;
- (h) Contingency plans for curtailments and load shedding; and,

- (i) Full cooperation with Western's Energy Planning and Management Program and Pacific Gas and Electric Company's DSM initiatives, incentives and rebate programs.

These DSM projects have reduced the energy requirements at the DOE/SF laboratories. The reductions in energy use are measured against the goals set in Executive Order 12759, "Federal Energy Management" of April 17, 1991 which requires federal agencies to meet the 1995 energy management goals of the National Energy Conservation Policy Act, and by the year 2000 reduce overall energy use of Btu's per gross square foot of all federal buildings. The electricity goals set by the Executive Order are a 10 percent reduction in building energy use by FY 1995 and a 20 percent reduction by FY 2000, and a 20 percent reduction in metered process energy by FY 2000. All measures use FY 1985 as a base. Contractors reporting to DOE/SF are on track to meet the goals for buildings. Due to an increase in research at LLNL and SLAC and a decrease at LBL, cumulatively, the contractors are somewhat behind in meeting the metered process goal.

The three DOE/SF laboratories will continue to actively pursue DSM projects and are projected to continue to reduce energy requirements through the implementation of these projects. Attachment 2 to this application contains information on some of the DSM projects that the laboratories have implemented and are planning to undertake.

F. Assistance in Meeting Customer Loads

The DOE/SF laboratories' participation in Western's diversity program assists Western in meeting its customers' load requirements. Specifically, LBL's ability to interrupt any or all of its 3 mW Western Diversity allocation upon Western's request means that the allocation assigned to LBL does not contribute to Western's peak. This diversity allocation allows Western to make power sales to LBL during the year but if the Western support level is being approached, the LBL load can be interrupted so that Western can meet other customers' requirements without exceeding the support limits. More importantly, SLAC's participation in Western's diversity program provides assistance in Western remaining within its support levels. In obtaining its diversity allocation, SLAC agreed to not only interrupt its 6 mW Diversity allocation but reduce its total load to 17 mW at critical times for Western. This has effectively converted SLAC's entire Type III Withdrawable allocation and 8 mW of its Long-Term Firm allocation to interruptible power. This has given Western more flexibility in staying within its support levels and, thereby, assists Western in meeting its customers' load requirements.

G. New Irrigation District Applicants

This section is not applicable to DOE/SF.

H. Other Information

The facilities for which DOE/SF is applying for the continued allocation of Western CVP power are national multi-purpose laboratories. The research and other activities undertaken at these laboratories are of national interest and are funded from the federal budget. Because of the constraints imposed by federal funding, the success of the programs of the laboratories is dependent upon efficiently managing the costs of the programs. For many of the programs, the cost of power is a critical component in the overall cost of the program. It is, therefore, essential that the cost of power be controlled in order for the programs to be successful. Without the availability of Western CVP power, the effectiveness of the programs would be seriously limited. This means that the continued allocation of Western power to DOE/SF results in a direct national benefit.

I. Signature

DOE/SF official attesting to the validity of the information submitted and authorized to submit this application.

Bobbie Vadnais
Contracting Officer

ATTACHMENT 1
ANNUAL LOAD FORECASTS
FOR 1994 THROUGH 2004

Lawrence Berkeley Laboratory
Bank No. 1
Annual Load Forecast

	<u>Demand</u> (kW)	<u>Energy</u> (mWh)	<u>Load Factor</u> (%)
FY 1994	13,000	37,000	32.5
FY 1995	16,000	45,000	32.1
FY 1996	17,000	44,000	29.5
FY 1997	17,000	40,000	26.9
FY 1998	16,000	35,000	25.0
FY 1999	15,500	35,000	25.8
FY 2000	15,000	34,000	25.9
FY 2001	14,500	32,000	25.2
FY 2002	14,000	31,000	25.3
FY 2003	13,500	30,000	25.4
FY 2004	13,000	30,000	26.3

Lawrence Livermore National Laboratory
Main Meter
Annual Load Forecast

	<u>Demand</u> (kW)	<u>Energy</u> (mWh)	<u>Load Factor</u> (%)
FY 1994	70,273	410,461	66.7
FY 1995	74,561	433,918	66.4
FY 1996	77,866	451,522	66.2
FY 1997	79,822	462,378	66.1
FY 1998	83,995	487,288	66.2
FY 1999	85,751	499,643	66.5
FY 2000	87,507	509,599	66.5
FY 2001	89,264	519,554	66.4
FY 2002	91,020	529,510	66.4
FY 2003	92,776	539,465	66.4
FY 2004	94,532	549,420	66.3

Lawrence Livermore National Laboratory
Site 300
Annual Load Forecast

	<u>Demand</u> (kW)	<u>Energy</u> (mWh)	<u>Load Factor</u> (%)
FY 1994	2,500	14,700	67.1
FY 1995	2,500	14,700	67.1
FY 1996	2,500	14,700	67.1
FY 1997	2,500	14,700	67.1
FY 1998	2,500	14,700	67.1
FY 1999	2,500	14,700	67.1
FY 2000	2,500	14,700	67.1
FY 2001	2,500	14,700	67.1
FY 2002	2,500	14,700	67.1
FY 2003	2,500	14,700	67.1
FY 2004	2,500	14,700	67.1

Stanford Linear Accelerator Center
Annual Load Forecast

	<u>Demand</u> (kW)	<u>Energy</u> (mWh)	<u>Load Factor</u> (%)
FY 1994	53,000	326,600	70.3
FY 1995	45,000	223,900	56.8
FY 1996	45,000	223,900	56.8
FY 1997	55,000	225,000	46.7
FY 1998	65,000	260,000	45.7
FY 1999	65,000	315,000	55.3
FY 2000	65,000	400,000	70.2
FY 2001	65,000	400,000	70.2
FY 2002	65,000	400,000	70.2
FY 2003	65,000	400,000	70.2
FY 2004	65,000	400,000	70.2

ATTACHMENT 2

DEMAND-SIDE MANAGEMENT ACTIVITIES
AT THE DOE/SF LABORATORIES

LAWRENCE BERKELEY LABORATORY DEMAND SIDE MANAGMT

COMPLETED PROJECT	YEAR COMPLETED	PROJECT COST K\$	PERSONNEL HOURS	POWER SOURCE	POWER kW	ENERGY kWh/Yr
1. BLDG. 51 MAGNET COOLING FAN SPEED CONTROL	1988	17	76	BANK 1	180	118,000
2. EMCS UPGRADE	1988	28	124	BANK 1&2	N/A	95,000
3. AIR COMPRESSOR REPLACEMENT	1988	(N/I)	N/A	BANK 1&2	N/A	206,000
4. BLDG. 51 COOLING TOWER FAN SPEED CONTROL	1989	23	102	BANK 1	N/A	131,000
5. BEVALAC PULSED SWITCHED MAGNET	1989	435	1,933	BANK 1	340	1,303,000
6. BLDG. 50B COMPUTER DISK DRIVE REPLACEMENT	1989	(N/I)	N/A	BANK 2	N/A	425,000
7. BLDG. 62 LCW COOLING	1989	(N/I)	N/A	BANK 2	N/A	258,000
8. BEVALAC MAIN RECTIFIER UPGRADE	1990	148	658	BANK 1	N/A	740,000
9. OUTDOOR LIGHTNG UPGRADE	1990	202	898	BANK 2	144	721,000
10. SITEWIDE PUMP AND MOTOR RETROFIT	1990	79	351	BANK 1&2	62	436,000
11. SMALL HVAC RETROFIT	1990	85	378	BANK 2	32	256,000
12. BLDG. 88 COOLING TOWER FAN SPEED CONTROL	1990	10.5	47	BANK 1	N/A	138,000

LAWRENCE BERKELEY LABORATORY DEMAND SIDE MANAGMT

COMPLETED PROJECT	YEAR COMPLETED	PROJECT COST k\$	PERSONNEL HOURS	POWER SOURCE	POWER kW	ENERGY kWh/Yr
13. BLDG. 50B COOLING TOWER FAN SPEED CONTROL	1990	11.6	52	BANK 2	40	300,000
14. MOTOR GENERATOR REPLACEMENT	1991	38	169	BANK 2	N/A	79,000
15. BLDG 37 COOLING TOWER AUTOMATION	1991	202	898	BANK 2	130	1,034,000
16. LINAC RF AMPLIFIER	1991	94	418	BANK 1	146	439,000
17. BLDG 2 CONTROL UPGRADE	1991	48	213	BANK 2	65	520,000
18. BLDG 46 & 55 CONTROLS	1991	277	1,231	BANK 2	89	711,000
19. BLDG 50 COMPLEX LIGHTING RETROFIT	1991	593	2,636	BANK 2	554	1,386,000
20. BLDG. 2 SMALL CHILLER INSTALLATION	1991	50	222	BANK 2	200	103,000
21. BLDG. 62 SMALL CHILLER INSTALLATION	1991	48	213	BANK 2	300	212,000
22. BLDG. 71 EMCS UPGRADE & MOTOR SPEED CONTROLS	1991	30	133	BANK 1	55	275,000
23. BLDG. 71 EMCS HVAC	1991	3	13	BANK 1	N/A	24,000
24. BLDG. 83 EMCS HVAC	1991	2.2	10	BANK 2	N/A	106,000
25. CONTRACT CURTAILMENT	1986-91	N/A	200	BANK 1	13000	N/A

(N/I) - Not part of IHEM

LAWRENCE BERKELEY LABORATORY DEMAND SIDE MANAGMT

PLANNED PROJECT	YEAR TO BE COMPLETED	PROJECT COST K\$	PERSONNEL HOURS	POWER SOURCE	POWER kW	ENERGY kWh/Yr	COST SAVINGS \$
1. BLDG. 74 AUTOMATION	1992	426	1704	BANK 2	88	704,000	57,024
2. BLDG. 90 AUTOMATION	1992	251	1004	BANK 2	68	540,000	43,740
3. BLDG. 70 COMPLEX LIGHTING RETROFIT	1992	214	856	BANK 2	223	558,000	45,198
4. BEVALAC DRIFT TUBE MAGNET UPGRADE	1992	61	244	BANK 1	69	261,000	14,381
5. BLDG. 90 LIGHTING RETROFIT	1993	423	1692	BANK 2	442	1,106,000	95,116
6. BLDG. 70 COMPLEX CONTROLS UPGRADE	1993	1107	4428	BANK 2	343	2,746,000	236,156
7. SITEWIDE LIGHTING RETROFIT - PHASE II	1993	946	3784	BANK 1&2	1367	3,417,000	293,862
8. BLDG. 50 COMPLEX CONTROLS UPGRADE	1993	1153	4612	BANK 2	549	2,744,000	235,984
9. SITEWIDE LIGHTING RETROFIT - PHASE III	1994	1138	4,138	BANK 2	1100	2,750,000	253,000
10. BLDGS. 54, 72, & 76 CONSERVATION UPGRADES	1994	338	1,229	BANK 2	167	501,000	46,092
11. BLDGS. 77 & 77A CONSERVATION UPGRADES	1994	413	1,502	BANK 2	185	556,000	51,152

PLANNED PROJECT	YEAR TO BE COMPLETED	PROJECT COST K\$	PERSONNEL HOURS	POWER SOURCE	POWER KW	ENERGY kWh/Yr	COST SAVINGS \$
12. SITEWIDE BLDG. CONTROL UPGRADES - PHASE I	1994	1172	4,262	BANK 2	235	1,990,000	183,080
13. SITEWIDE BLDG. CONTROL UPGRADES - PHASE II	1995	1104	3,680	BANK 2	220	1,756,000	168,576
14. BLDG. 66 CONTROL & LIGHTING UPGRADES	1996	748	2,493	BANK 2	330	1,000,000	100,000
15. SITEWIDE ELECTRIC MOTOR RETROFIT	1996	418	1,393	BANK 1&2	116	992,000	99,200
16. BLDG. 2 CONTROL SYS & ENERGY UPGRADES	1996	417	1,390	BANK 2	90	715,000	71,500
17. CONTRACT CURTAILMENT	1992-96	N/A	200	BANK 1	14000	N/A	N/A

LAWRENCE LIVERMORE NATIONAL LABORATORY:

Mike Honda
12/9/91ACTIVE PROJECTS
(\$K)

Acct#	Description	Request	Approved	Unfunded Balance
	(FY88)			
7708-70	Improve Controls B-381 & 401	266.4	199.3	67.1
	(FY89)			
7708-84	Power Factor Correction	699	699	
7708-82	(FY89) CBAS Phase III	484	484	
7708-80	Air Circ. Turndown B-391	521.4	521.4	
	(FY90)			
7708-87	Elec. Metering Sitewide	177	177	
7708-88	Hi Eff. Flourescent Lighting Inc. I	296.9	296.9	
7708-89	Hi Eff. Flourescent Lighting Inc. II	331.9	331.9	
7708-90	Add Timers HVAC Units B-491	12.8	12.8	
7708-91	Modify Control Syst. B-551	68.6	68.6	
7708-92	Repipe/Modify Chiller B-490	144.2	144.2	
7708-93	Add Timers for HVAC B-163	15.5	15.5	
7708-97	Isolated Cooling Loop B-492	950	950	
7708-98	Dedicated Cooling Tower B-490	934	934	

EMP FY'92
(\$K)

<u>Acct#</u>	<u>Description</u>	<u>Request</u>	<u>Approved</u>	<u>Unfunded Balance</u>
	<u>M & O</u>			
3902-14	Energy Awareness	40	201	20
3902-55	EMP Admin. Prop. Devel.	100	1001	
3902-56	EMP Spec. Proj./Studies			
	Proposal Devel.	50	50	
	Process Load Study	35	35	
	Prog. To Achieve 10Yr. Goal	20	20	
	Elec. Vehicle Cost Share	252		25
	Training, Travel, S&E	35		35
	Review Stand & Specs.	303		30
	Relocation Exp.	25		25
	Misc. HVAC Demo/Proto	253		25
	Misc. Lighting Demo/Proto	253		25
	Minor Energy Eff. Improv.	253		25
	Flywheel Prototype Sup.	20		20
	Subtotal M & O	430	225	205
	<u>NON-CAP</u>			
3951-46	Flywheel Energy Storage	15		15
	Low-Cost Conser. Projects	243		24
	Equipment Demo. Proj.	363		36
	EMP Study Support	48		48
	Revise Standards & Specs.	303		30
	Review V.E. Process	15		15
	Subtotal Non-Cap	168		168

<u>Acct#</u>	<u>Description</u>	<u>Request</u>	<u>Approved</u>	<u>Unfunded Balance</u>
		<u>IR&D</u>		
	Superinsulation	198		198
	Subtotal IR&D	<u>198</u>		<u>198</u>

Notes:

1. Pending budget reconcil. 11/7/91
2. Not selected for C.E.C. project may use funds for stand alone demo.
3. Both N.C. & M&O funding applied for (redundant)

SURCHARGE

3900-35	Rechage/Surcharge		
	Metering	247.2	247.2
	Recharge Rewrite	120.0	120.0
	Subtotal Surcharge	<u>367.2</u>	<u>367.2</u>

FEMP

6333-01	FEMP Travel	12.0	12.0
	Subtotal FEMP	<u>12.0</u>	<u>12.0</u>

Acct#	Description	Request	Approved	Unfunded Balance
		<u>IHEM</u>		
7708-	Retrofit Projects			
(92-202)	B361 Therm. Eng Storg.	394.3		394.3
(92-104)	B361 Retrofits	55.6		55.6
(92-210)	CNG Vehicle Conv.	147.1		147.1
(92-204)	B322 Plating Recycle Syst.	416.4		416.4
(92-205)	B492 Dye Chiller Replace	298.2		298.2
(91-02)	B391 Outside Air Reduc	54.5		54.5
(92-206)	B321 Central Plant	40.9		40.9
(92-209)	Meter Calibration Prog.	133.0		133.0
(92-211)	B113 Chiller Replacement	431.0		431.0
(91-05)	LCW Metering	112.3		112.3
(92-100)	B111 Retrofits	338.7		338.7
(92-102)	B281 Retrofits	109.5		109.5
(92-103)	B311 Retrofits	181.2		181.2
(92-200)	Bathroom Light Sensors	563.0		563.0
(92-201)	Replace Exit Signs	541.0		541.0
(92-203)	Electrical Metering	446.4		446.4
(92-207)	B222 Piping Insulation	114.5		114.5
	Subtotal Retrofits	<u>4377.6</u>		<u>4337.6</u>

<u>Acct#</u>	<u>Description</u>	<u>Request</u>	<u>Approved</u>	<u>Unfunded Balance</u>
6331-	Studies/Surveys			
	Build Energy Study	171.0		171.0
	Chiller Study	100.4		100.4
	Boiler Study	96.3		96.3
	Lighting Study	21.0		21.0
	Pumping Energy Study	31.5		31.5
	Steam Trap Study	23.5		23.5
	Wind Energy Study	45.0		45.0
	Subtotal Studies	<u>488.7</u>		<u>488.7</u>
FY'92 Budget	Totals	6041.5	604.2	5437.3

FY'93
\$K

7708-	IHEM Retrofit Projects			
	B-121 Energy Conservation Retrofits	93.2		93.2
	B-131 Energy Conservation Retrofits	227.9		227.9
	B-253 Energy Conservation Retrofits	159.0		159.0
	B-255 Energy Conservation Retrofits	204.0		204.0
	B-511 Energy Conservation Retrofits	80.8		80.8
	Subtotal Retrofits	<u>764.9</u>		<u>764.9</u>

<u>Acct#</u>	<u>Description</u>	<u>Request</u>	<u>Approved</u>	<u>Unfunded Balance</u>
	IHEM Technology Demo.			
	300 Kwh Flywheel Energy Storage	902.6		902.6
	675 Kwh Flywheel Energy Storage	1177.8		1177.8

05-Mar-92

LLNL

Accumulated Savings Due to Demand Side Management

Fiscal Year	Investment \$M	Net Savings \$M	Gross Savings \$M
=====	=====	=====	=====
1978	3.299	0.000	3.000
1980	1.665	0.000	3.000
1982	2.460	0.000	3.000
1984	4.130	0.000	3.000
1986	5.233	2.082	7.315
1988	6.011	5.900	11.910
1990	6.279	10.581	15.860
1992	6.279	16.337	22.616
1994	6.279	22.514	28.793
1996	6.279	29.067	35.346
1998	6.279	36.019	42.298
2000	6.279	43.177	49.456
2002	6.279	49.844	56.123
2004	6.279	55.453	61.732
2006	6.279	58.658	64.937
2008	6.279	60.444	66.723
2010	6.279	61.765	68.044
2012	6.279	61.924	68.204

Accumulated Savings vs. Investments for LLNL Retrofit Projects

SLAC IHEM PROJECTS

(1984-1991)

<u>COMPLETED PROJECTS:</u>	<u>YEAR OF COMPLETION</u>	<u>PROJECT COST</u> (\$1,000)	<u>EST. ANNUAL ENERGY SAVINGS</u> (000 kWh)
Electronic HVAC Timers	1984	59.4	249
High Voltage Instrument & Metering Installation	1985	42.8	383
SLAC Load/Energy Monitoring & Control System	1986	50.2	201
Local Lighting Switches for Elect. Bldg., Offices & Conf. Rm.	1986	9.3	39
Variable Speed Motor Curls Computer Building - SLAC	1988	21.3	73
SLAC 12.476 KV Distribution System	1988	133.7	715
Expansion of SLAC Load/Energy Monitor'g & Ctrl Sys (Phase I)	1989	199.0	3,624
Klystron RF Cavity & Cooling Water System Insulation	1989	132.3	4,695
Lighting Control System (A&E Bldg)	1990	17.4	42
Installation of Translucent Panels in CEH Building	1991	<u>10.8</u>	<u>81</u>
TOTAL Completed Projects		\$ 526.2	10,102

SLAC IHEM PROJECTS
(1992 - 1996)

<u>PROJECTS UNDERWAY OR DOE APPROVED</u>	<u>EXPECTED YEAR OF COMPLETION</u>	<u>PROJECT COST (\$1,000)</u>	<u>EST. ANNUAL COST SAVINGS (\$1,000)</u>
Auditorium/Cafeteria Curl Sys Upgrade	1992	16.0	3.6
Expansion of SLAC Load/Energy Monitor'g & Curl Sys (Phase II)	1992	307.0	82.3
HVAC Control Systems Upgrade	1992	192.0	38.0
Linac DeQ'ing System Upgrade	1992	302.0	272.3
Computer Bldg HVAC Control System Upgrade	1992	185.0	53.9
HVAC Control Systems Upgrade, Phase II	1992	65.0	10.4
Plating Shop Hot Water Control System	1992	29.0	16.7
Remote Monitoring and Control of Utility Systems in Sectors 14-20	1993	520.0	138.9
Capacitor Bank for Power Factor Improvement	1994	<u>233.0</u>	<u>50.6</u>
Total Projects Underway or DOE Approved		\$ 2449.0	\$ 666.7
PROJECTS PENDING DOE FUNDING AND PLANNED			
Remote Monitoring and Control of Utility Systems in Sectors 1-13	1994	950.0	235.8
Remote Monitoring and Control of Utility Systems in Sectors 21-30*	1995-1996	<u>650.0</u>	<u>160.0</u>
Total Projects Pending DOE Funding and Planned		\$ 1600.0	\$ 395.8
TOTAL PENDING AND APPROVED		\$ 4049.0	\$ 1062.5

* Plan to submit proposal to DOE for FY1994 funding.

**NATURAL GAS SUPPLY OPTIONS
FOR THE DOE/SAN LABS**

Prepared for:

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San Francisco Operations Office**

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Natural Gas Supply Options for the DOE/SAN Labs

Introduction

On May 1, 1988 Pacific Gas and Electric Company (PG&E) restructured, under the direction of the California Public Utilities Commission (CPUC), the natural gas services and tariffs offered by PG&E. Under this new structure, PG&E classified its customers as core or noncore customers. Generally, core customers include all residential users, small general service customers and large general service customers without alternative fuel capabilities. Core customers continue to be provided both gas supply and the transportation of that gas jointly by PG&E as has been done traditionally. However, the customers who do not qualify as core customers, the noncore customers, are provided transportation services by PG&E and the procurement of natural gas is provided separately either from one of PG&E's gas-supply portfolios or from third-party suppliers. PG&E currently provides two gas-supply portfolios, a core-supply portfolio and a noncore-supply portfolio. The core-supply portfolio contains gas procured largely under long-term supply and price arrangements and offers price stability to end-users; the noncore portfolio is made up largely of spot market gas.

The three DOE/SAN Laboratories (DOE/SAN Labs or Labs) in Northern California, Lawrence Berkeley Laboratory (LBL), Lawrence Livermore National Laboratory (LLNL) and Stanford Linear Accelerator Center (SLAC) use natural

gas provided by PG&E. There are currently four meters at the DOE/SAN Labs that are classified as having core usage; three at LBL and one at SLAC. The remaining meters at LBL and SLAC and the single meter at LLNL are classified as having noncore usage. The majority of the usage at the DOE/SAN Labs is through meters that are considered noncore.

In May, when the new natural gas service structure was implemented, the noncore customers were given the opportunity to select their gas procurement option. At that time, the cost of gas under PG&E's noncore-supply portfolio was lower than the cost of gas for its core-supply portfolio. In addition, the selection of the core-supply portfolio requires a commitment to remain on the core supply for a period of one year, which would have eliminated DOE/SAN's opportunities to procure third-party supplies during that period. The DOE/SAN Labs, therefore, elected to take service from PG&E's noncore-supply portfolio. However, on July 1, 1988 the cost of PG&E's noncore-supply portfolio increased so that its price was greater than the core-supply portfolio price. Insufficient notice was provided for DOE/SAN to respond to the reversal of the core and noncore gas prices by electing to receive PG&E's core gas portfolio service. PG&E's tariffs prohibit customers using its noncore-supply portfolio from switching to the core-supply portfolio when the price of the noncore portfolio is greater than the price of the core portfolio. Since the price of the noncore portfolio has remained higher than that of the core portfolio since July of 1988, DOE/SAN has not had the option to switch its gas procurement to the core-supply portfolio. Therefore, DOE/SAN's only alternative to purchasing from the noncore-supply portfolio, until the

noncore price drops below the core price, is to procure gas from third-party suppliers.

The purpose of this report is to recommend those activities which are consistent with a least-cost natural gas acquisition strategy for the DOE/SAN Labs. Current natural gas service provided by PG&E for both core usage and noncore usage is summarized. For noncore usage, a description of PG&E's transportation service is provided along with an explanation of how the Labs are currently procuring natural gas. The natural gas service alternatives available to the Labs are then presented, including a discussion of utility service and gas procurement options which are contained in PG&E's tariffs. Finally, a list of recommendations consistent with a least-cost acquisition for the Labs is presented.

Applicable PG&E Rate Schedules

Natural gas is being provided to the DOE/SAN Labs under several different PG&E rate schedules. Customers of PG&E qualify for different rate schedules based on the volume of gas consumed and the customer's priority classification. PG&E classifies its customers into priority categories for purposes of determining the order of curtailments, should curtailments be necessary. A summary of priority categories is as follows:

- P1: All residential use and all other service to customers with peak day use of 100 Mcf or less.
- P2A: Nonresidential use exceeding 100 Mcf per day where nongaseous alternate fuel is not feasible.
- P2B: Service to customers with gaseous standby fuel.

P3A: Cogeneration facilities.

P3B: Utility gas turbines and all use not included in another priority.

P4: Boiler fuel with peak day demands exceeding 750 Mcf.

P5: Utility gas-fired steam electric generation.

In addition, customers are classified as core versus noncore customers based upon their assigned priority. All customers who qualify for priorities P1 or P2A, regardless of size, and all P2B customers who's average monthly usage does not exceed 2,080 Dth are considered core customers. All other customers are considered noncore customers. Therefore, nonresidential customers with a feasible nongaseous alternative fuel and large nonresidential customers with gaseous fuel standby facilities are classified as noncore customers.

All noncore customers purchase their gas supply separately from their transportation service. A customer may arrange for its gas supplies from any of three sources: (1) PG&E's core-supply portfolio (Schedule G-PC); (2) PG&E's noncore-supply portfolio (Schedule G-PN); or (3) third-party supplies. The use of PG&E's core and noncore gas portfolios is a gas procurement service. In effect, PG&E serves as the customer's agent in assembling a supply of gas for purchase by the customer. The weighted average cost of gas (WACOG) included in PG&E's supply procurement portfolios includes the cost of gas as a commodity, and all the interstate transportation costs associated with getting that gas to the PG&E system. Transportation service is provided under PG&E transportation rates, which include the costs of moving gas over the PG&E system to the customer's location.

In order to elect the core-supply portfolio (also know as core-elect service), a customer is required to sign a natural gas supply agreement with a term of one year or longer, and the customer is required to continue to use Schedule G-PC supplies for the term of the contract. At the end of the contract term, the customer is required to renew the contract for an additional term of one year or longer in order to continue to receive gas from the core-supply portfolio. Also, a customer using the noncore-supply portfolio can switch to the core-supply portfolio only when the G-PC rate is greater than the G-PN rate. Currently, the G-PC rate of \$1.8252 per Dth is less than the March G-PN rate of \$1.9886 per Dth.

It is important to note that priority classifications of transportation customers are not dependent on whether a customer transports PG&E's gas or third-party supplies. A customer's priority classification will remain the same whether that customer purchases PG&E core gas, PG&E noncore gas, or third-party gas. The decision to elect the purchase of gas from the gas procurement alternatives is a costing decision, not an availability of supply decision. Loss of third-party gas supplies will be backed-up by PG&E's noncore portfolio gas. Presently there is no additional charge for this back-up service other than the price of the gas itself. The CPUC is considering whether an additional standby charge is appropriate.

The rate schedules under which noncore customers are billed are designed as transportation tariffs. Therefore, the cost of gas is not included in the various rates in these tariffs. The total amount billed under the transportation tariffs is the same whether the customer uses the core portfolio, the

noncore portfolio or third-party supplies because the cost of gas procurement is billed separately. Therefore, in determining the least-cost option of gas procurement the only cost comparison that is necessary is the comparison of the cost of gas delivered to the PG&E system under the different gas procurement alternatives.

The DOE/SAN Labs currently take natural gas service under the following PG&E rate schedules:

- Schedule G-NR1 -- Gas sales to small nonresidential core customers;
- Schedule G-P2B/G-PN -- Gas transportation service to noncore P2B customers using procurement of gas from the noncore supply portfolio.
- Schedule G-IND/G-PN -- Gas transportation service to noncore commercial/industrial customers using procurement of gas from the noncore-supply portfolio.

Appendix A contains the current tariffs for each of these rate schedules. Table I identifies the current rate schedule and the core versus noncore classification for each PG&E meter at the DOE/SAN Labs. Table II provides the natural gas usage by PG&E rate schedule at each of the DOE/SAN Labs for FY 1988.

Table I
PG&E Rate Schedule at Each Meter
at the DOE/SAN Labs

<u>Account No.</u>	<u>Rate Schedule</u>	<u>Classification</u>
LBL:		
BJR 64-74001	G-NR1	Core
CJR SB-92121	G-NR1	Core
BJR SB-92211	G-NR1	Core
BJR SB-92221	G-P2B/G-PN	Noncore*
BJR SB-92221	G-IND/G-PN	Noncore*
LLNL:		
YJN SB-91041	G-P2B/G-PN	Noncore*
SLAC:		
XRN 09-19201	G-NR1	Core
XRN SB-91081	G-IND/G-PN	Noncore*

*Noncore customers using the noncore-supply portfolio.

Table II
Natural Gas Usage
at the DOE/SAN Labs
in FY 1988
(therms)

	LBL				LLNL	SLAC			Total DOE/SAN
	G-NR1	G-P2B/G-PN	G-IND/G-PN	Total LBL	G-P2B/P-PN	G-NR1	G-IND/G-PN	Total SLAC	
FY 1988:									
October	18,380	37,612	25,074	81,066	264,431	724	34,273	34,997	380,494
November	24,355	61,141	40,760	126,256	421,401	3,160	54,275	57,435	605,092
December	31,843	94,503	63,002	189,348	450,615	8,668	52,100	60,768	700,731
January	28,209	77,261	51,507	156,977	463,986	12,413	48,557	60,970	681,933
February	23,474	63,888	42,592	129,954	439,867	17,008	53,184	70,192	640,013
March	22,723	56,314	37,543	116,580	370,082	12,013	54,473	66,486	553,148
April	21,730	59,437	39,624	120,791	402,005	7,592	59,339	66,931	589,727
May	24,293	57,566	38,378	120,237	360,124	5,340	36,687	42,027	522,388
June	17,705	42,523	28,349	88,577	298,726	4,636	44,785	49,421	436,724
July	16,082	33,679	22,452	72,213	199,536	1,207	41,115	42,322	314,071
August	17,229	34,009	22,672	73,910	291,513	2,619	41,400	44,019	409,442
September	18,886	33,979	22,652	75,517	284,151	1,320	49,474	50,794	410,462
Total	264,909	651,912	434,605	1,351,426	4,246,437	76,700	569,662	646,362	6,244,225

PG&E uses Schedule G-NR1 to serve its small nonresidential core customers. A customer is considered a small nonresidential customer if its average monthly usage does not exceed 2,080 Dth. The G-NR1 rate schedule contains a customer charge of \$12.12 and commodity charges differentiated by season. Currently, the winter service commodity charge is \$.58364 per therm and the summer service commodity charge is \$.43233 per therm. There are three meters at LBL and one meter at SLAC that are being billed under the G-NR1 rate schedule. During FY 1988, these accounts used 34,161 Dth. This usage constitutes approximately five percent of the DOE/SAN Labs' annual natural gas requirements.

The meters at the DOE/SAN Labs that are considered noncore customers of PG&E use Schedule G-P2B and Schedule G-IND along with the noncore-supply portfolio. Thus, all gas used at these meters is provided by PG&E at the noncore commodity rate. In addition to the commodity charge, the noncore loads are billed for PG&E transportation service under the G-P2B and G-IND rate schedules. These rate schedules have a customer charge that varies based on the customer's average monthly usage, an average demand charge (D1 demand charge) billed on the customer's average monthly use, a seasonal-peak demand charge (D2 demand charge) billed on the highest calendar month use during each season, and a volumetric charge. During FY 1988, the DOE/SAN Labs used 590,262 Dth from accounts currently billed under Schedules G-P2B and G-IND. This usage constitutes about 95 percent of the DOE/SAN Labs' total annual gas usage in FY 1988, of which 72 percent is accounted for by LLNL.

Alternatives

The alternatives for the meters at the DOE/SAN Labs that are considered core customers of PG&E are somewhat limited. These meters take service under Schedule G-NR1 because of their small monthly usage and lack of an alternative fuel. For one of the three meters at LBL (No. BJR 64-74001) and the meter at SLAC that use this rate schedule, there is no alternative but to continue to receive gas under Schedule G-NR1. For the other two meters at LBL (Nos. CJR SB-92121 and BJR SB-92211) that are currently considered core customers, it is possible to physically combine the loads served through the two meters and serve the load through a single meter. The combined loads would be large enough to qualify for Schedule G-NR2, the rate schedule for gas sales to large nonresidential core customers. The combined loads would retain their core classification because there would be no alternative fuel availability for that load. Combining these loads and taking service under Schedule G-NR2 would provide savings of approximately \$17,000 annually based on current G-NR1 and G-NR2 rates and actual natural gas usage during FY 1988.

There is also the opportunity to serve the loads of the two meters that could be combined at LBL through that Lab's main natural gas meter. The main meter at LBL is provided services under both Schedule G-P2B and Schedule G-IND. It was determined some years ago that 40 percent of the load served through the main meter at LBL had oil as an alternative fuel and that the remaining 60 percent of the load could be served by the central propane facility. Therefore, 40 percent of the main meter load is billed under Schedule G-IND and 60 percent is billed under Schedule G-P2B. If the loads of

the two meters were served through the main meter and the 40/60 billing procedure continues, the estimated annual savings to LBL of using Schedules G-PB2 and G-IND rather than Schedule G-NR1 for this load is \$37,000. These savings are based on PG&E's current rate schedules including the February price of the noncore portfolio and actual natural gas usage during FY 1988. There could be additional savings realized if the price of gas procurement for the Lab, which is currently the noncore portfolio price, falls relative to the cost of gas for core customers.

The alternatives for the meters at the DOE/SAN Labs that are considered noncore customers relate to the procurement of gas supplies. The transportation rate schedules that are used for these meters are determined based on the alternative fuel that can be used to serve the loads. If a gaseous fuel is the alternative then Schedule G-P2B is applicable and if a non-gaseous fuel is the alternative then Schedule G-IND applies. So, unless the alternative fuel can be changed, the transportation rate schedules at each of the meters cannot be altered. However, there are three alternatives for the procurement of gas supplies; specifically, PG&E's core portfolio, PG&E's noncore portfolio or third-party supplies.

Table III shows the historical behavior of PG&E's core and noncore price of gas since the inception of the new natural gas service structure in California. The core price can change twice each year, but has remained constant since May 1988. The noncore rate can change twice each month, and generally increased from May through January and has been declining since January. In July of 1988, the noncore portfolio price of gas rose above the

price of PG&E's core portfolio. This relationship continues today, with PG&E's March noncore portfolio price of gas at \$1.99 per Dth, compared to PG&E's core portfolio price at \$1.83 per Dth. The large increase in July 1988 was largely due to increased rates for the transportation of Southwest gas to the California border. The more recent changes in noncore gas prices are largely weather related. The noncore gas price increased in December and January and generally declined in February and March, with the February mid-month increase caused by a cold snap in the West. Since core gas supply is primarily composed of gas procured under long-term contract arrangements while noncore gas supply is largely composed of spot market gas purchases, the noncore price of gas is dependent on movements in the cost of spot market gas.

Table III
Comparison of Core Portfolio and
Noncore Portfolio Rates

<u>Month</u>	<u>G-PC Rate (\$/Dth)</u>	<u>G-PN Rate (\$/Dth)</u>
May 1988	1.8252	1.6050
Jun 1988	1.8252	1.6353
Jul 1988	1.8252	2.0491
Aug 1988	1.8252	2.2107
Sep 1988	1.8252	2.2107
Oct 1988	1.8252	2.2107
Nov 1988	1.8252	2.2107
Dec 1988	1.8252	2.3015*
Jan 1989	1.8252	2.4024
Feb 1989	1.8252	2.2207
Feb 1989	1.8252	2.3217**
Mar 1989	1.8252	1.9886

*Effective December 16, 1988.

**Effective February 10, 1989

In February the delivered-to-pipeline price of natural gas generally fell \$.30 to \$.40 per Dth. For example, Southern California Gas Company's anticipated border price of gas fell \$.30, from \$2.35 to \$2.05. PG&E's weighted average cost of gas of its noncore portfolio fell \$.18, from \$2.40 to \$2.22. PG&E's noncore gas costs have fallen less than the \$.30 to \$.40 decrease in gas prices apparently because PG&E has not sought out merely the cheapest gas supplies, but believes its \$2.22 average cost purchases of gas exhibit greater reliability than the lower cost gas supplies. On February 10, PG&E raised its noncore WACOG to \$2.32.¹ On March 1, PG&E's noncore portfolio price fell to \$1.99 per Dth. All of these recent changes appear, in part, to be weather-related, and illustrate the continuing volatility of natural gas prices in the California market.

Because of PG&E's prohibition that customers using the noncore portfolio may not switch to the core portfolio when the core price is lower than noncore price, core portfolio service is not currently an alternative available to DOE/SAN. However, with the additional decline in the noncore portfolio price for March, it appears that the relationship between the core price and noncore price could reverse this spring. Therefore, the relative price of the core portfolio and the noncore portfolio should be monitored. If the relative price of these two supplies reverse then DOE/SAN could elect to procure gas from the core portfolio. Electing the core portfolio requires the customer to sign an agreement with an initial and renewal term of at least 12 months.

¹The February 10 price change, coming just 10 days after the February 1 price change, marks the first occasion of PG&E changing its noncore portfolio price of gas twice within a one-month period.

This means that at the end of each 12 month period a decision to continue core gas supply locks the customer into that service for the ensuing 12-month period.

The other alternative for the procurement of gas is to purchase natural gas from third-party suppliers. Third-party supplies are available from marketers and brokers who will purchase natural gas and arrange for the transportation of that gas over the necessary interstate pipelines to PG&E's connections with those pipelines. PG&E would then transport the gas to the end-user purchasing the gas.

PG&E is directly connected to two interstate pipelines, El Paso Natural Gas Company (El Paso) which transports supplies from the Southwest and Pacific Gas Transmission Company (PGT) which transports Canadian gas into California. In addition, Transwestern Pipeline Company (Transwestern) is indirectly connected to PG&E through the Southern California Gas Company (SoCal) pipeline. El Paso and Transwestern offer open-access nondiscriminatory transportation service under Part 284 of the Federal Energy Regulatory Commission's (FERC) regulations. Both pipelines provide transportation service under Part 284 blanket certificates. An open-access blanket certificate has been granted by FERC for PGT but PGT has not accepted that certificate. Currently, a rate settlement is pending for PGT which would allow open transportation under NGPA Section 311. PGT does provide transportation services under individual certificates of public convenience and necessity issued by the FERC under Section 7(c) of the Natural Gas Act.

El Paso provides transportation service under Rate Schedule T-1 for interruptible service and Rate Schedule T-3 for firm service. However, since firm capacity is not currently available on the El Paso system, transportation service is available only under the T-1 interruptible rate schedule. The tariff rates associated with El Paso's T-1: Interruptible Transportation Service include mainline transportation charges, field transportation charges, production area charges, a San Juan Triangle facilities commodity charge, and a monthly cumulative imbalance charge. The mainline transportation charge is sub-divided by the producing basin (San Juan, Permian and Anadarko) and by the area or state of ultimate delivery. The mainline transportation charges for the San Juan, Permian and Anadarko Basins production delivered to California are \$.2556 per Dth, \$.2993 per Dth, and \$.3474 per Dth, respectively. The field transportation charges and the production area charges are also sub-divided by the producing basin. The applicability of the various charges is dependent upon the point of delivery of the gas to El Paso and the area or state of ultimate delivery. In addition to these tariff rates, the transportation customer or shipper must pay a take-or-pay throughput surcharge of \$.0198 per Dth, a Gas Research Institute (GRI) funding charge of \$.0143 per Dth, an Annual Charge Adjustment (ACA) amount of \$.0017 per Dth, all applicable taxes, and for fuel reimbursement associated with the transportation services as payment in kind. The mainline transportation fuel reimbursement percentage is equal to 5 percent of the gas delivered. The El Paso rates and terms and conditions are currently under review by the FERC.

PGT is a subsidiary of PG&E and operates a natural gas transmission system from a point near Kingsgate, British Columbia on the U.S.-Canadian

border to the California-Oregon border near Malin, Oregon. PGT is used to transport the majority of PG&E's core gas requirements from Canada to California. All of PGT's firm capacity has been committed to PG&E, Northwest Pipeline Corporation and Pacific Interstate Transmission. It is anticipated that, in the near-term, any interruptible transportation capacity over PGT will be very limited and would not provide a viable transportation service to the DOE/SAN Labs.

Transwestern provides both firm and interruptible transportation service under Rate Schedule FTS-1 and Rate Schedule ITS-1, respectively. Transwestern is in direct competition with El Paso for service to the California market. Transwestern tends to set its transportation rates somewhat less than El Paso's transportation rates, making the Transwestern system the preferred path for moving natural gas into California. With the significant increase that occurred in El Paso's transportation rates during the summer of 1988, capacity has not been available on the Transwestern system. In addition, because Transwestern is not directly connected to PG&E an additional set of transportation charges will be required to move gas over SoCal's system. Due to these additional transportation charges and the unavailability of capacity, like PGT, Transwestern would not provide a viable transportation option.

The alternative of selecting direct acquisition of third-party gas is advantageous when the price of third-party gas is acceptably below the price of the other gas procurement options. For the DOE/SAN Labs, the only alternative gas procurement option that is currently available is PG&E's noncore portfolio. However, if the price of the core portfolio should increase

sufficiently or the price of the noncore portfolio should fall sufficiently so that the relationship between these two prices reverse, then the core portfolio with its one year contract term becomes available also. Therefore, a comparison is needed between the projected price of PG&E's core portfolio, PG&E's noncore portfolio and third-party supplies. Forecasting gas prices is speculative, but several observations can be made.

- PG&E will be renegotiating their Canadian gas contract prices in March and April. It would be unreasonable to expect the Canadian price to fall below its current level in light of alternative energy prices. Sources in California generally expect PG&E's core price of gas to increase to the \$1.92 - \$1.97 per Dth range.
- Current El Paso transportation rates, which were a factor increasing delivered-to-California gas costs in July, 1988 are being collected subject to refund. These El Paso rates are currently being litigated before FERC. Settlement negotiations are being pursued which can only be expected to settle upon transportation rates somewhat lower than those currently in effect.
- Spot market prices of gas are volatile. The price history of PG&E's noncore portfolio exhibited on Table III, including the recent February 1, February 10 and March 1 price changes, reveals PG&E's spot purchase experience. The February 1 gas cost reduction resulted in the cost of gas delivered to California falling 13 percent for some California utilities. The February 10

increase in PG&E's noncore gas price was the first time since May 1988, that its noncore price changed twice in one month. The March 1 reduction shows further weakening of gas prices as spring, with its lower gas requirement, approaches. The price behavior of spot market gas in California is subject to rapid, and not altogether predictable changes.

In short, modest increases in the price of PG&E's core gas costs, and a reduction in El Paso's present transportation rates can be expected. We are entering the time of year when gas costs are normally expected to fall due to seasonal effects, ceteris paribus. While more confidence may be ascribed to an expected increase in PG&E's core cost of gas and reduced El Paso transportation rates, the cost of gas as a commodity cannot confidently be predicted.

Presently, very little third-party gas is moving on the PG&E system. The CPUC has been frustrated in its attempts to create an effective transportation program in California. The California natural gas procurement market has been characterized by price volatility since the CPUC consciously changed the gas acquisition environment in May of 1988. Continuing developments in the areas of additional pipeline capacity, the auctioning of local distribution company capacity entitlements to end-users, standby service, and the mandatory provision of certain storage service to end-users can be expected as the CPUC continues its efforts to create a viable transportation program in California. In general, each of these services presently being considered by the CPUC would increase the amount of transportation in California.

Additional capacity for the movement of gas to the California border and within the state will make it easier for marketers and brokers to access less expensive gas supplies for sale directly to end-users. PGT has recently filed with the FERC (Docket No. CP89-460) to increase its pipeline capacity to the California border from 1.0 Bcf/day to 1.6 Bcf/day. A related application for the movement of gas within California is expected to be filed by its parent, PG&E. If marketers and brokers gain access to this additional capacity end-users may gain access to Canadian and Rocky Mountain gas supplies. No immediate benefit is expected from this service that would affect the Labs near-term gas procurement strategy.

California utilities, including PG&E, are required by the CPUC to file a market-based pipeline capacity allocation program. The utilities have firm, and high priority, first-come first-served interruptible transportation on the interstate pipelines. As end-users begin to procure third-party gas, their utilities no longer need all of the capacity they had acquired in past periods. The CPUC is interested in making this capacity available to transporters. This should enhance the viability of transportation in California, as end-users, marketers and brokers gain access to firm and high-priority interruptible transportation service. Detailed programs, in the form of written testimony, were due to be filed by the California utilities in mid-February, 1989. Hearings are expected on this matter.

Increased access to storage should also encourage more transportation in California. PG&E was ordered by the CPUC to make available 5 Bcf of storage, or 15 percent of their cycling capability, as part of a pilot storage program

for 1989. End users or marketers will be able to purchase gas when it is normally cheaper, and use that supply when gas is normally more expensive. This will increase the reliability of third-party gas supplies, and lower the cost of gas to end-users across seasons, enhancing the option of acquiring and transporting third-party gas.

It is not recommended that the labs bid on capacity made available by PG&E, or that storage service be purchased by the Labs. These regulatory developments are mentioned to reveal the Commission's interest in creating a viable transportation market in California and to suggest that as marketers and brokers avail themselves of these opportunities it is expected that the California transportation market will become a more viable option for end-users than it currently is.

Closely related to access to storage is the imposition of a standby charge for back-up service. Noncore customers will have to nominate the amounts of gas they anticipate using. PG&E has proposed to charge the incremental cost of gas supplies it may have to acquire to back up any consumption of an end-user in excess of gas supplies nominated by the end-user. Also, if an end-user consumes less gas than it nominated, PG&E is proposing a storage fee for holding that gas until the end-user consumes it. Standby or storage fees would be imposed on consumption excesses or deficiencies as measured against customer nominations respectively. The CPUC's policy, as revealed in its Orders Instituting Rulemakings is to increasingly make noncore gas customers more responsible for their own gas procurement and to bear the cost consequences of their own consumption decisions. The cost

consequences of consuming more or less than nominated amounts of gas would apply equally to noncore customers buying core portfolio gas, noncore portfolio gas or third party gas. Consumption in excess of nominations, for example, requires PG&E to purchase additional spot market gas at high costs to meet customers' requirements. This is true whenever the consumption of noncore customers exceeds their nominations. Thus, noncore customers purchasing either core portfolio gas or noncore gas would be required to nominate the monthly amount of gas they want, and pay a price to cover the costs of consuming more or less than their monthly nominations. Core-elect service is not a "cradle-to-grave" service that can be expected to persist in the California gas market.

Recommendation

The procurement alternatives discussed in the preceding section of this report are alternatives available to that part of the DOE/SAN Labs' loads which are classified as noncore loads. The following discussion includes recommendations which are consistent with a least-cost natural gas acquisition strategy for the Labs' noncore loads.

The loads of the two G-NR1 meters at LBL should be combined with that lab's main meter as soon as possible. Combining these loads will produce an estimated annual saving of approximately \$37,000. There is no major impediment to implementing this recommendation, and the Lab should continue to pursue this matter with PG&E.

The Labs should continue to purchase PG&E's noncore portfolio gas until May 1989. Presently, the price advantage of core and noncore gas is narrowing. With the anticipated increase in PG&E's core price to the \$1.92-\$1.97 range, and seasonal weakening of the commodity cost of gas, it is not inconceivable that the prices of core and noncore gas could reverse before May. If this were to happen, the Labs should not leap into electing gas procurement from PG&E's core portfolio. A short wait until May will provide valuable information about any actual increase in PG&E's core portfolio gas price. This new price information, and information about the makeup of the associated producers' contracts will be valuable information to have prior to any decision by the Labs to opt for core portfolio gas supply. At risk is, perhaps, one-month's worth of potential savings if a core/noncore price reversal were to occur in April.

After May 1, one of two possibilities will exist. If the core price of gas continues to be cheaper than noncore gas, the Labs will have no choice but to continue procuring gas from PG&E's noncore portfolio of gas supply. On the other hand, if PG&E's core price should rise above their noncore price of gas, the Labs could continue to procure gas from PG&E's noncore portfolio or switch to gas procurement from PG&E's core portfolio. Should the core/noncore price reversal occur, the Labs should remain on the noncore portfolio only if the Labs can effectuate a decision to switch to core gas procurement within the five-day notification of noncore prices presently provided by PG&E. If a five-day notification period is too short for the Labs to effectuate a portfolio change, the Labs should switch to PG&E's core portfolio gas procurement option upon a reversal of core and noncore prices.

There are several reasons why the Labs should consider switching to PG&E's core portfolio of gas supply, if such an option becomes available. One reason is the market structure of gas procurement in northern California. A prime reason for the relatively low price of core gas is PGT's position as a monopsonist in the market for western Canadian gas. There are capacity constraints on getting gas from Canada to California. A more competitive market for Canadian gas would be expected to result in the cost of Canadian gas being bid upwardly to establish burner-tip costs of gas closer to the market price of alternate energy sources, including other supplies of gas. Any program to expand access to Canadian gas is, at best, several years from fruition. Thus, the market structure, and PG&E's dominance as a buyer in that market, is not expected to change over the next year. This being the case, it is expected that a relatively low price of core gas will continue to be available over the next year. Seasonal and other factors may, at times, result in a noncore price of gas below the core price, but in the winter months, when the Labs are burning most of their gas, it would be risky to base a gas procurement strategy on spot market gas prices delivered to California at prices below an expected core price of gas near the \$2.00 per Dth level.

Stability of gas procurement costs also argues for the election of core portfolio gas, if that option becomes available. PG&E's core price has remained constant for the past year, and can only change once during a year after PG&E's initial posting of its price. Stability has a market value, suggesting that core gas procurement would be preferred at some premium over the price of noncore gas.

Finally, the real choice for the Labs over the next year is whether to purchase core or noncore gas. The price of third-party gas is very close to that of PG&E's noncore price. Thus, a third-party acquisition, yielding a price close to the cost of noncore gas, would not be expected to be substantially different from PG&E's noncore price of gas. As discussed earlier, the CPUC may change the institutional framework of the gas procurement market in California, which could affect the attractiveness of third-party gas procurement as a future option available to the Labs. However, during the next year the bulk of any potential savings available to the Labs will be related to a decision of whether to purchase core or noncore portfolio gas. Thus, the one-year commitment attendant to a decision to purchase core gas, which effectively precludes the purchase of third-party gas during the next year, has only a small potential incremental effect on gas costs. Since the attractiveness of purchasing third-party gas is largely dependent on potential changes in the California regulatory arena, the acquisition of third-party gas over the next year is not recommended.

Ancillary recommendations at this time include:

- the monitoring of PG&E's core and noncore portfolio gas prices, including frequent contact with PG&E service representatives; and
- the monitoring of regulatory proceedings at both the CPUC and the FERC which could impact the costs of procuring natural gas in the California market.

Implementation of these recommendations will assist the DOE/SAN Labs in their efforts to minimize the costs of procuring gas over the next year. As indicated above, the attractiveness of a third-party gas acquisition in the future will be dependent upon changes in the California natural gas transportation market. The monitoring functions included in the recommendations will provide, over the coming year, the information necessary to reveal whether the acquisition of third-party supplies should be pursued.

APPENDIX A
PG&E Rate Schedules

SCHEDULE G-NR1--GAS SALES TO SMALL NONRESIDENTIAL CORE CUSTOMERS

APPLICABILITY: Schedule G-NR1 applies to the combined sale and transportation of natural gas. If you take service at Schedule G-NR1 rates, you must be a nonresidential customer, the uses to which you put the gas must be among those classified in PG&E's priority sequence as P1, P2A, or P2B, and your average monthly use must not have exceeded 20,800 therms in those months during the last 12 months in which you used more than 200 therms. (See Rule 14* for an exact description of these priorities.) Each March, service to all customers under this schedule will be reviewed to determine continued applicability. Such determination will be based on natural-gas use in the twelve billing months ending in the most recent calendar year. This schedule is applicable for service on and after May 1, 1988.

TERRITORY: Schedule G-NR1 applies everywhere PG&E provides natural-gas service.

RATES: You will pay the following charges under this schedule:

	<u>Per Month</u>
Customer Charge	\$12.12(1)
Delivered Commodity Charge:	<u>Per Therm</u>
Winter Service	\$0.58364(1)
Summer Service	\$0.43233(1)

SEASONS: Winter Season begins November 1 and ends on March 31.
Summer Season begins April 1 and ends on October 31.

CURTAILMENT Service under this schedule may be curtailed. Details are provided in Rule 14.
OF SERVICE:

TRANSPORTATION: If you are taking service under this schedule in conjunction with any noncore service at the same premises, you can qualify for gas transportation service. The transportation rate per therm will be the commodity rates shown above less the applicable Schedule G-PC rate. If you elect such transportation service, you will be required to sign a Natural Gas Transportation Service Agreement (Form No. 79-735) and a Natural Gas Supply Agreement (Form No. 79-736). In the event that your full requirement is not received by PG&E, any additional natural gas you require will be provided by PG&E under the terms and conditions of Schedule G-PN.

*The Rules referred to in this schedule are parts of PG&E's gas tariff schedules. Copies are available at local offices.

Advice Letter No. 1499-G-C
Decision No. 86-12-0951

Issued by
Gordon R. Smith
Vice President
Finance and Rates

Date Filed December 28, 1988
Effective January 1, 1989
Resolution No. G-2838

Pacific Gas and Electric Company
San Francisco, California

Revised Cal. P.U.C. Sheet No. 12827-G
Cancelling Original Cal. P.U.C. Sheet No. 12734,
12708-G

SCHEDULE G-NR2--GAS SALES TO LARGE NONRESIDENTIAL CORE CUSTOMER

APPLICABILITY: Schedule G-NR2 applies to the combined sale and transportation of natural gas. If you wish to purchase gas at Schedule G-NR2 rates, you must be a nonresidential customer, the uses to which you put the gas must be among those classified in PG&E's priority sequence as P1 or P2A, and your average monthly use must have exceeded 20,800 therms during those months in the last 12 months in which you used more than 200 therms. (See Rule 14* for an exact description of these priorities.) Schedule G-NR2 is closed permanently to customers who at any time choose to take service under Schedule G-NR3. Each March, service to all customers under this schedule will be reviewed to determine continued applicability. Such determination will be based on natural-gas use in the twelve billing months ending in the most recent calendar year. This schedule is applicable for service on and after May 1, 1988.

TERRITORY: Schedule G-NR2 applies everywhere PG&E provides natural-gas service.

RATES: You will pay the following charges to purchase gas under this schedule:

	<u>Per Month</u>
Customer Charge	\$138.52(1)
Delivered Commodity Charge:	<u>Per Therm</u>
Winter Service	\$0.50423(1)
Summer Service	\$0.37350(1)

SEASONS: Winter Season begins November 1 and ends on March 31.
Summer Season begins April 1 and ends on October 31.

CURTAILMENT
Rule 14.
OF SERVICE: Service under this schedule may be curtailed. Details are provided in

ALTERNATIVE
SERVICE: This schedule offers full utility natural-gas service, for which you will not be required to sign a Service Agreement. Alternatively, if you wish to purchase gas from PG&E's noncore portfolio or obtain your own gas supplies, you must take service under Schedule G-NR3 and sign a Natural Gas Transportation Service Agreement (Form No. 79-735).

*The Rules referred to in this schedule are parts of PG&E's gas tariff schedules. Copies are available at local offices.

Advice Letter No. 1499-G-C
Decision No. 86-10-1951

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Gordon R. Smith
Vice President
Finance and Rates

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Resolution No. G-2838

SCHEDULE G-NR3--GAS TRANSPORTATION SERVICE TO LARGE NONRESIDENTIAL CORE CUSTOMERS

APPLICABILITY: Schedule G-NR3 is available to customers for whom Schedule G-NR2 is applicable and applies only to the transportation of natural gas. If you wish to transport gas at Schedule G-NR3 rates, you must be a nonresidential customer, the uses to which you put the gas must be among those classified in PG&E's priority sequence as P1 or P2A, and your average monthly use must have exceeded 20,800 therms during those months in the last 12 months in which you used more than 200 therms. (See Rule 14* for an exact description of these priorities.) You may arrange for your own gas supplies and/or you may purchase gas from PG&E under Schedules G-PN and/or G-PC. Each March, service to all customers under this schedule will be reviewed to determine continued applicability. Such determination will be based on natural-gas use in the twelve billing months ending in the most recent calendar year. This schedule is applicable for service on and after May 1, 1988.

TERRITORY: Schedule G-NR3 applies everywhere PG&E provides natural-gas service.

RATES: You will pay the following two charges to transport gas under this schedule. You will also be responsible for any costs, taxes, and/or fees incurred by PG&E in taking delivery of your gas from intrastate or interstate sources.** These rates do not cover the procurement of natural gas.

	<u>Per Month</u>
Customer Charge	\$138.52(1)
Volumetric Charge:	<u>Per Therm</u>
Winter Service	\$0.32171(1)
Summer Service	\$0.19098(1)

GATHERING COSTS: If the gas that PG&E transports for you is customer-owned gas and is produced from wells located in PG&E's service area, a gathering charge of \$0.034 per therm will be added to your bill to cover PG&E's costs associated with gathering the gas for you.

STANDBY SURCHARGE: A standby surcharge may apply to gas transported via the El Paso Natural Gas Company system. For possible exceptions, refer to El Paso's Rate Schedules.

SEASONS: Winter Season begins November 1 and ends on March 31.
Summer Season begins April 1 and ends on October 31.

CURTAILMENT OF SERVICE: Service under this schedule may be curtailed. Details are provided in Rule 14.

SERVICE AGREEMENT: If you choose to take service under Schedule G-NR3, you must sign a Natural Gas Transportation Service Agreement (Form No. 79-735). Your Transportation Service Agreement will have a minimum term of one month. You may also sign a Natural Gas Supply Agreement (Form No. 79-736). If you have at any time a Natural Gas Transportation Service Agreement under Schedule GNR-3 in effect, but do not have an effective Natural Gas Supply Agreement, any natural-gas supply provided by PG&E will be subject to the terms and conditions of Schedule G-PN. Schedule G-NR2 is permanently closed to customers who at any time take service under Schedule G-NR3.

*The Rules referred to in this schedule are parts of PG&E's gas tariff schedules. Copies are available at local offices.

**Specifically, see "Gathering Costs" and "Standby Surcharge" sections of this rate schedule.

Advice Letter No. 1433-G-C
Decision No. 86-11-1351

Issued by
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Vice President
Finance and Rates

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Resolution: No. G-2838

SCHEDULE G-P2B--GAS TRANSPORTATION SERVICE TO NONCORE P2B CUSTOMERS

APPLICABILITY: Schedule G-P2B applies to the transportation of natural gas. If you wish to transport gas at Schedule G-P2B rates, your uses for the gas must be classified in PG&E's priority sequence as P2B, and your average monthly use must have exceeded 20,800 therms during those months in the last 12 months in which you used more than 200 therms. However, exceptions to the minimum average use are allowed pursuant to "CPUC Authorized Assignment," as defined below. (See Rule 14* for an exact description of service priorities.) You may arrange for your own gas supplies, and/or you may purchase gas from PG&E under Schedules G-PN and/or G-PC. Each March, service to all customers under this schedule will be reviewed to determine continued applicability. Such determination will be based natural-gas use in on the twelve billing months ending in the most recent calendar year. This schedule is applicable for service on and after May 1, 1988.

TERRITORY: Schedule G-P2B applies everywhere PG&E provides natural-gas service.

RATES: You will pay the following four charges to transport natural gas under this schedule. You will also be responsible for any applicable costs, taxes, and/or fees incurred by PG&E in taking delivery of your gas from intrastate or interstate sources.** These rates do not cover the procurement of natural gas.

1. Customer Charge:

Each month you will pay a customer charge. The amount you pay will be that shown in the table below for the range that includes your Average Monthly Use, as defined in Rule 1.

	Per Month
0 to 5,000 therms	\$ 4.00
5,001 to 10,000 therms	\$ 45.00(1)
10,001 to 50,000 therms	\$ 111.00
50,001 to 200,000 therms	\$ 267.00
200,001 to 1,000,000 therms	\$ 445.00(1)
1,000,001 therms and above	\$1,000.00

2. Average Demand Charge (D1):

Per Therm

Based on Average Monthly Use \$0.08844(2)

3. Seasonal-Peak Demand Charge (D2):

Based on Highest Seasonal Calendar Monthly Use
(as defined in Rule 1)

For billing months including: Winter Service \$0.03436(1)
Summer Service \$0.01513(1)

4. Volumetric Charge:

For gas delivered in the current billing month \$0.04353(1)

Because PG&E reads meters and issues billing statements throughout each month, your billing month may not be coincident with the calendar month. Each calendar-month use will be figured by combining the calculated use for each part of a calendar month that is included in each billing month. The demand charge in your billing statements will be based upon use in the twelve calendar months ending with the last full calendar month.

*The Rules referred to in this schedule are parts of PG&E's gas tariff schedules. Copies are available at local offices.

**Specifically, see "Gathering Costs" and "Standby Surcharge" sections of this rate schedule.

(Continued)

Advice Letter No. 1499-G-C
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Vice President
Finance and Rates

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Pacific Gas and Electric Company
San Francisco, California

Revised Cal P.U.C. Sheet No. 12737-G
Cancelling Original Cal P.U.C. Sheet No. 12648-G

SCHEDULE G-P2B--GAS TRANSPORTATION SERVICE TO NONCORE P2B CUSTOMERS

(Continued)

RATES: (Cont'd.)	PG&E will first apply your customer and demand charges when you begin to take service under Schedule G-P2B. The demand-charge components (D1 and D2) of your bill rely upon historical-use data. For use prior to May 1, 1988, only those billing months in which you were billed for natural gas use above zero (0) on a schedule that included provisions for a ratcheted demand charge are included in the calculation of demand charges under this schedule. If there was not a ratcheted demand charge component on your prior schedule(s), those months of historical use will not be considered in calculating your demand charges under this schedule. For use after May 1, 1988, all billing months and use will be included in the calculation of your demand charges.	
GATHERING COSTS:	If the gas that PG&E transports for you is customer-owned gas and is produced from wells located in PG&E's service area, a gathering charge of \$0.034 per therm will be added to your bill to cover PG&E's costs associated with gathering the gas for you.	
STANDBY SURCHARGE:	A standby surcharge may apply to gas transported via the El Paso Natural Gas Company system. For possible exceptions, refer to El Paso's Rate Schedules.	(T) (T)
SEASONS:	<u>Winter Season</u> begins on November 1 and ends on March 31. <u>Summer Season</u> begins on April 1 and ends on October 31.	
CURTAILMENT OF SERVICE:	Service under this schedule may be curtailed. Details are provided in Rule 14.	
SERVICE AGREEMENT:	You may sign a Natural Gas Transportation Service Agreement for service under Schedule G-P2B (Form No. 79-735). Except for core customers who are assigned noncore status as provided below, if you do not sign a Service Agreement, the terms and conditions of Schedules G-P2B and G-PN will apply to your service. If you sign a Natural Gas Transportation Service Agreement, you may also sign a Natural Gas Supply Agreement (Form No. 79-736), under which you may arrange for your own natural-gas supplies and/or purchase natural gas from PG&E under Schedule G-PN and/or G-PC. If you have at any time a Natural Gas Transportation Service Agreement in effect under Schedule G-P2B, but do not have an effective Natural Gas Supply Agreement, any natural gas supply provided by PG&E will be provided subject to the terms and conditions of Schedule G-PN.	
STAND-BY FUEL REQUIREMENT:	No customer shall be entitled to service under this rate schedule unless adequate standby equipment and gaseous alternative fuel is provided and is ready at all times for immediate operation in the event that natural gas transportation service is interrupted or curtailed in whole or in part, except as provided by the CPUC Authorized Assignment (see below).	
CPUC AUTHORIZED ASSIGNMENT:	In Decision No. 88-03-085, the CPUC authorized assignment of noncore status to certain core customers. These customers are reclassified to provide a competitive mechanism to meet their alternative-fuel cost. To qualify, the core customer must demonstrate the capability of using alternative fuel at a cost less than the cost of core gas service, and the customer must be willing to accept service at a lower curtailment priority. Service at this lower curtailment priority can only be provided if you have a signed Agreement for Assignment of Priority P2B (Form No. 79-737). Qualification must be demonstrated annually.	
NEGOTIABLE OPTIONS:	Rates and terms of service different than those shown on this tariff may be negotiated. Any such negotiated deviations from this tariff shall be specified in your Natural Gas Transportation Service Agreement (Form No. 79-735).	

(Continued)

Advice Letter No. 1473-G
Decision No. 87-12-039

Issued by
Gordon R. Smith
Vice President
Finance and Rates

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Resolution No. _____

SCHEDULE G-P2B--GAS TRANSPORTATION SERVICE TO NONCORE P2B CUSTOMERS

(Continued)

TERMINATION:	You may terminate service under this schedule by providing 30 days' prior written notice. If you provide at least 12 months' notice of your intent to terminate service under this schedule, you will not be responsible for any customer or demand charges after the effective termination date. If you provide less than 12 months' notice, you shall be responsible for paying all customer and demand charges for the 12 months following PG&E's receipt of the effective notice. Such charges shall be due and payable on the effective termination date. The most recent notice of termination of service shall be considered the only effective notice.	(T)
FORCE MAJEURE:	Neither PG&E nor the Customer shall be considered in default in the performance of its obligations under this Schedule, except obligations to make payments for work previously performed, to the extent that the performance of any such obligation is prevented or delayed by any cause, existing or future, which is beyond the reasonable control of the affected party. Disruption of service because of force majeure shall not exempt either party from performing its obligations prior to the disruption. The term "force majeure" specifically does not include routine maintenance and repairs of machinery and pipelines; curtailment in accordance with PG&E's gas Rule 14; or interruption of supply from an interstate pipeline supplier in accordance with the terms of an agreement between the Customer and the interstate pipeline supplier for nonfirm transportation of gas. In the event either party claims that performance of its obligations is prevented or delayed by any cause constituting force majeure, that party shall immediately notify the other party of that fact and of the circumstances preventing or delaying performance. The party claiming a cause-delayed performance shall endeavor, to the extent reasonable, to remove the obstacles which delay or preclude performance. In the event that either party claims that performance of its obligation to deliver or receive gas is not possible due to causes constituting force majeure, the parties shall promptly suspend operations under this Schedule and shall make all reasonable efforts to hasten resumption of service. Demand charges shall be prorated during periods of force majeure to the extent that the Customer establishes that the Customer's ability to accept service is prevented by force majeure.	(T)
SCHEDULED MAINTENANCE:	Demand charges shall be prorated during a period of scheduled maintenance shutdown of Customer's facilities which affects the Customer's ability to accept delivery of natural gas, provided that Customer gives PG&E 30 days' advance written notice of such scheduled shutdown. See Rule 1 for the definition of Scheduled Maintenance.	(T) (T)

SCHEDULE G-IND--GAS TRANSPORTATION SERVICE TO NONCORE COMMERCIAL/INDUSTRIAL CUSTOMERS

APPLICABILITY: Schedule G-IND applies to the transportation of natural gas. If you wish to transport gas at Schedule G-IND rates, your uses for the gas must be among the uses classified in PG&E's priority sequence as P3B, P4, or P5 (other than PG&E's electricity generating plants). (See Rule 14* for an exact description of service priorities.) You may arrange for your own gas supplies and/or you may purchase gas from PG&E under Schedules G-PN and/or G-PC. This schedule is applicable for service on and after May 1, 1988.

TERRITORY: Schedule G-IND applies everywhere PG&E provides natural-gas service.

RATES: You will pay the following four charges to transport natural gas under this schedule. You will also be responsible for any applicable costs, taxes, and/or fees incurred by PG&E in taking delivery of your gas from intrastate or interstate sources.** These rates do not cover the procurement of natural gas.

1. Customer Charge:

Each month you will pay a customer charge. The amount you pay will be that shown in the table below for the range that includes your Average Monthly Use, as defined in Rule 1.

	Per Month
0 to 5,000 therms	\$ 15.00(I)
5,001 to 10,000 therms	\$ 148.00
10,001 to 50,000 therms	\$ 354.00
50,001 to 200,000 therms	\$ 854.00
200,001 to 1,000,000 therms	\$1,217.00
1,000,001 therms and above	\$3,358.00(I)

2. Average Demand Charge (D1):

Per Therm

Based on Average Monthly Use \$0.05963(R)

3. Seasonal-Peak Demand Charge (D2):

Based on Highest Seasonal Calendar Monthly Use
(as defined in Rule 1)

For billing months including: Winter Service \$0.02238(I)
Summer Service \$0.00671

4. Volumetric Charge:

For gas delivered in the current billing month \$0.04325(I)

Because PG&E reads meters and issues billing statements throughout each month, your billing month may not be coincident with the calendar month. Each calendar-month use will be figured by combining the calculated use for each part of a calendar month that is included in each billing month. The demand charge in your billing statements will be based upon use in the twelve calendar months ending with the last full calendar month.

*The Rules referred to in this schedule are parts of PG&E's gas tariff schedules. Copies are available at local offices.

**Specifically, see "Gathering Costs" and "Standby Surcharge" sections of this rate schedule.

(Continued)

Administrative Letter No. 1439-G-C
Decision No. 85-12-1951

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Gordon R. Smith
Vice President
Finance and Rates

Date Filed December 29, 1988
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Resolution N G-2838

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2 of 6

SCHEDULE G-IND--GAS TRANSPORTATION SERVICE TO NONCORE COMMERCIAL/INDUSTRIAL CUSTOMERS

(Continued)

RATES: (Cont'd.)	PG&E will first apply your customer and demand charges when you begin to take service under Schedule G-IND. The demand-charge components (D1 and D2) of your bill rely upon historical-use data. For use prior to May 1, 1988, only those billing months in which you were billed for natural gas use above zero (0) on a schedule that included provisions for a ratcheted demand charge are included in the calculation of demand charges under this schedule. If there was not a ratcheted demand charge component on your prior schedule(s), those months of historical use will not be considered in calculating your demand charges under this schedule. For use after May 1, 1988, all billing months and use will be included in the calculation of your demand charges.	
GATHERING COSTS:	If the gas that PG&E transports for you is customer-owned gas and is produced from wells located in PG&E's service area, a gathering charge of \$0.034 per therm will be added to your bill to cover PG&E's costs associated with gathering the gas for you.	
STANDBY SURCHARGE:	A standby surcharge may apply to gas transported via the El Paso Natural Gas Company system. For possible exceptions, refer to El Paso's Rate Schedules.	(T) (T)
SEASONS:	<u>Winter Season</u> begins on November 1 and ends on March 31. <u>Summer Season</u> begins on April 1 and ends on October 31.	
CURTAILMENT OF SERVICE:	Service under this schedule may be curtailed. Details are provided in Rule 14.	
SERVICE AGREEMENT:	You may sign a Natural Gas Transportation Service Agreement for service under Schedule G-IND (Form No. 79-735). If you do not sign a Service Agreement, the terms and conditions of Schedules G-IND and G-PN will apply to your service. If you sign the Natural Gas Transportation Service Agreement, you may also sign a Natural Gas Supply Agreement (Form No. 79-736), under which you may arrange for your own natural-gas supplies and/or purchase natural gas from PG&E under Schedule G-PN and/or G-PC. If you have at any time a Natural Gas Transportation Service Agreement under Schedule G-IND in effect, but do not have an effective Natural Gas Supply Agreement, any natural gas supply provided by PG&E will be provided subject to the terms and conditions of Schedule G-PN.	
STAND-BY FUEL REQUIREMENT:	No customer shall be entitled to service under this rate schedule unless adequate standby equipment and non-gaseous alternative fuel are provided and are ready at all times for immediate operation in the event that natural-gas transportation service is interrupted or curtailed in whole or in part.	(T)
NEGOTIABLE OPTIONS:	Rates and terms of service different than those shown on this tariff may be negotiated. Any such negotiated deviations from this tariff shall be specified in your Natural Gas Transportation Service Agreement (Form No. 79-735).	
TERMINATION:	You may terminate service under this schedule by providing 30 days' prior written notice. If you provide at least 12 months' notice of your intent to terminate service under this schedule, you will not be responsible for any customer or demand charges after the effective termination date. If you provide less than 12 months' notice, you shall be responsible for paying all customer and demand charges for the 12 months following PG&E's receipt of the effective notice. Such charges shall be due and payable on the effective termination date. The most recent notice of termination of service shall be considered the only effective notice.	(T) (T)

(Continued)

Pacific Gas and Electric Company
San Francisco, California

Revised Cal. P.U.C. Sheet No. 12740-G*
Cancelling Original Cal. P.U.C. Sheet No. 12652-G

SCHEDULE G-IND--GAS TRANSPORTATION SERVICE TO NONCORE COMMERCIAL/INDUSTRIAL CUSTOMERS

(Continued)

FORCE MAJEURE: Neither PG&E nor the Customer shall be considered in default in the performance (T)
of its obligations under this Schedule, except obligations to make payments for
work previously performed, to the extent that the performance of any such
obligation is prevented or delayed by any cause, existing or future, which is
beyond the reasonable control of the affected party. Disruption of service
because of force majeure shall not exempt either party from performing its
obligations prior to the disruption. The term "force majeure" specifically
does not include routine maintenance and repairs of machinery and pipelines;
curtailment in accordance with PG&E's gas Rule 14; or interruption of supply
from an interstate pipeline supplier in accordance with the terms of an
agreement between the Customer and the interstate pipeline supplier for nonfirm
transportation of gas.

In the event either party claims that performance of its obligations is
prevented or delayed by any cause constituting force majeure, that party shall
immediately notify the other party of that fact and of the circumstances
preventing or delaying performance. The party claiming a cause-delayed
performance shall endeavor, to the extent reasonable, to remove the obstacles
which delay or preclude performance. In the event that either party claims
that performance of its obligation to deliver or receive gas is not possible
due to causes constituting force majeure, the parties shall promptly suspend
operations under this Schedule and shall make all reasonable efforts to hasten
resumption of service.

Demand charges shall be prorated during periods of force majeure to the extent
that the Customer establishes that the Customer's ability to accept service is
prevented by force majeure. (T)

SCHEDULED
MAINTENANCE:

Demand charges shall be prorated during a period of scheduled maintenance
shutdown of Customer's facilities which affects the Customer's ability to
accept delivery of natural gas, provided that Customer gives PG&E 30 days'
advance written notice of such scheduled shutdown. See Rule 1 for the
definition of Scheduled Maintenance. (T)
(T)

Advice Letter No. 1473-C
Decision No. 87-12-039

Issued by
Gordon R. Smith
Vice President
Finance and Rates

Date Filed July 13, 1988
Effective May 1, 1988
Resolution No.

SCHEDULE G-PC--PROCUREMENT OF GAS FROM THE CORE-SUPPLY PORTFOLIO

APPLICABILITY: Schedule G-PC applies to the purchase of natural gas procured by PG&E primarily from long-term supplies with pricing security. If you wish to purchase natural gas under Schedule G-PC, you must sign a Natural Gas Supply Agreement with PG&E and receive service under Schedule G-NR3, G-P2B, G-IND, G-COG, G-UEG, G-WRT or GC-2. This schedule is applicable for service on and after May 1, 1988.

TERRITORY: Schedule G-PC applies everywhere PG&E provides natural-gas service.

RATES: Commodity Charge Per Therm \$0.18252

The commodity charge under Schedule G-PC will be equal to the projected annual weighted average cost of gas (WACOG) of PG&E's core supply portfolio, plus applicable franchise fees and uncollectible expenses.* Changes may periodically occur to the Schedule G-PC rate upon CPUC approval.

CURTAILMENT: Service under this schedule may be curtailed. Details are provided in Rule 14.

SUPPLY AGREEMENT: You will be required to sign a Natural Gas Supply Agreement (Form No. 79-736) for a term of one or more years for service under Schedule G-PC.

If you do not use your full contracted quantity on a yearly basis you may be liable for unavoidable or minimum charges to reflect any costs which PG&E may incur as a result, excluding any costs allocated to transportation charges. However, no such charges are applicable at this time.

If you choose to purchase natural gas under Schedule G-PC you must elect to purchase either: 1) your full natural-gas supply requirement from Schedule G-PC or 2) a specified portion of your full natural-gas supply requirement from Schedule G-PC. If you elect to purchase a portion of your full supply requirement from Schedule G-PC, you must specify, in terms, an Annual Contract Quantity (ACQ). The ACQ that you specify may not exceed your historical annual use of natural gas on your prior account(s) as determined by PG&E, unless otherwise agreed to by PG&E. You must also designate the portion of your ACQ which will be used in each calendar month. The ratio of your highest monthly contract quantity divided by your ACQ may not be greater than the ratio of your highest monthly use in the past 12 months divided by your total use in those 12 months.

If in any calendar month during the term of the Service Agreement your natural gas use exceeds your specified monthly contract quantity, you may purchase additional natural-gas supplies from other suppliers or from PG&E's noncore supply portfolio under Schedule G-PN. In any month, if PG&E determines that it may provide additional gas supplies under this schedule without adversely affecting the cost of such supplies, PG&E at its option may permit you to purchase additional quantities of gas from this schedule above your monthly contract quantity. Such purchases will be in addition to your ACQ and will not increase your designated ACQ.

You may contract for new or additional gas supplies at any time provided that: 1) the applicable commodity charge under Schedule G-PC is greater than the applicable commodity charge under Schedule G-PN; and 2) an agreement for such new or additional supplies is executed at least four working days prior to the effective date that the commodity charge under Schedule G-PN becomes greater than that under Schedule G-PC. Notwithstanding the above, upon expiration of an existing Natural Gas Supply Agreement which specified Schedule G-PC natural-gas supply, you may elect to receive the same (i.e., specified volume or full requirements) or a lesser quantity of natural gas from Schedule G-PC. If you are (T) a noncore customer connecting gas load not previously served by PG&E, your initial election for the purchase of natural gas supplies, regardless of respective prices, may be from Schedules G-PC, G-PN or from a non-PG&E source, or any combination thereof. Service under Schedule G-PC will begin on the date specified in your (T) Supply Agreement. Such date will be either the next scheduled meter-reading date, the first day of the calendar month, or the effective date of a commodity charge change under Schedule G-PN.

The Rules applicable to this schedule are part of PG&E's tariff schedules. Copies are available at local offices.

*For sales to wholesale (resale) customers, only the franchise fee is applicable. The commodity charge for these customers is \$0.18220 per therm.

Advice Letter No. 1491-G
Decision No.

Issued by
Gordon R. Smith
Vice President
Finance and Rates

Date Filed August 31, 1988
Effective November 23, 1988
Resolution No. G-2831

Pacific Gas and Electric Company
San Francisco, California

Revised Cal. P.U.C. Sheet No. 12843-G
Cancelling Revised Cal. P.U.C. Sheet No. 12835-G

SCHEDULE G-PN--PROCUREMENT OF GAS FROM THE NONCORE-SUPPLY PORTFOLIO

APPLICABILITY: Schedule G-PN applies to the purchase of natural gas procured by PG&E primarily from short-term supply sources. If you wish to purchase natural gas under Schedule G-PN, you must receive service under Schedule G-NR3, G-P2B, G-IND, G-COG, G-UEG, G-WRT, or GC-2. This schedule is applicable for service on and after May 1, 1988.

TERRITORY: Schedule G-PN applies everywhere PG&E provides natural-gas service.

RATES: Per Therm

Commodity Charge	\$0.22207 (R)
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The commodity charge per therm under Schedule G-PN will be equal to the projected weighted average cost of gas (WACOG), plus applicable franchise fees and uncollectible expenses,* of PG&E's noncore supply portfolio, adjusted for any undercollections or overcollections from prior periods. PG&E may adjust the commodity charge on five working days' notice as often as twice per month to reflect changes in the noncore WACOG. The current applicable commodity charge for natural gas sales under this schedule may be obtained by calling PG&E's Schedule G-PN hotline at (415) 972-0461.

PG&E will provide natural gas under the terms and conditions of this rate schedule on a best-efforts basis.

CURTAILMENT: Service under this schedule may be curtailed. Details are provided in Rule 14.

NOMINATION OF USE: PG&E will set a monthly nomination of use equivalent to your use in the same month of the prior year. If this quantity does not reflect expected use, you must provide PG&E with a nomination of expected use. Nominations to PG&E must be made at least four working days prior to the start of the month in which the gas will be used.

SUPPLY AGREEMENT: You may sign a Natural Gas Supply Agreement (Form No. 79-736) for a minimum term of one month. If you do not have a Natural Gas Supply Agreement in effect, any natural gas supply provided by PG&E will be provided subject to the terms and conditions of Schedule G-PN.

The Rules applicable to this schedule are part of PG&E's tariff schedules. Copies are available at local offices.

*For sales to wholesale (resale) customers, only the franchise fee is applicable.

Advice Letter No. 1520-G
Decision No. 87-12-039

Issued by
Gordon R. Smith
Vice President
Finance and Rates

Date Filed January 26, 1988
Effective February 1, 1988
Resolution N/A

**EVALUATION OF
NATURAL GAS SUPPLY OPTIONS
FOR ETEC**

Prepared For:

**The United States Department Of Energy
San Francisco Operations Office**

**Under Contract
No. DE-AC03-86SF16343**

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EVALUATION OF
NATURAL GAS SUPPLY OPTIONS
FOR ETEC

Introduction

The Energy Technology Engineering Center (ETEC) is a government laboratory operated for the U.S. Department of Energy (DOE) by Rockwell International. ETEC is located in southern California on the DOE portion of the Santa Susana Field Laboratory. One ETEC facility, the Sodium Components Test Installation (SCTI), is currently involved in performance and endurance testing of liquid-metal steam generators to be used with nuclear reactors. A cogeneration unit, known as the Power Pak, has been added to the SCTI facility to produce electricity from the steam generated from testing activities at the SCTI facility. Natural gas or oil-fired heaters are used to provide the thermal input to the liquid sodium system.

The facility is scheduled to begin full endurance testing operations in May 1989. The facility has been using some natural gas but significantly less than is expected to be used over the next two years. In 1989 and 1990, the facility is expected to use approximately 11 million therms annually and is scheduled to operate for seven months during each year, specifically May through November. During the months the facility is operating, the average daily natural gas requirement will be about 50,000 therms. The facility also has the capability to use fuel oil as an alternative to natural gas.

Natural gas is being provided to the ETEC facility by Southern California Gas Company (SoCalGas). SoCalGas classifies its customers as core or noncore users based on the customer's usage characteristics and ability to use alternative fuels. Large customers with alternative fuel capabilities, such as the ETEC facility, are considered noncore customers. SoCalGas provides gas delivery and gas supply separately to its noncore customers. The noncore customers have three options for the procurement of gas supplies; (1) procurement from SoCalGas' core-supply portfolio; (2) procurement from SoCalGas' noncore-supply portfolio; and (3) procurement of third-party supplies. The ETEC facility is currently purchasing gas from SoCalGas' noncore-supply portfolio.

The DOE San Francisco Operations Office (DOE/SAN) is responsible for the procurement of natural gas service to the ETEC facility. This report reviews current natural gas purchasing practices at ETEC and investigates feasible alternatives to the current service. The report provides a list of recommendations consistent with a least-cost natural gas acquisition strategy for the ETEC facility.

Projected Requirements

Projections have been made of the natural gas requirements for the ETEC testing facility for 1989 and 1990, when the facility is expected to be fully operational. This natural gas usage forecast, as provided by ETEC, is contained in Appendix A. The facility is forecasted to use 10.68 million therms in 1989 and 10.89 million therms in 1990. The maximum monthly usage

during those years is projected to be 1.6 million therms. The facility is scheduled to operate from May through November with no natural gas consumption expected for December through April. During these winter months modifications to the facility are expected to occur. These natural gas usage forecasts are contingent upon DOE programmatic requirements.

During the past four years, natural gas was used at the facility while construction and testing of the Power Pak was underway. The usage during this time period was significantly less than the projected natural gas requirements for 1989 and 1990. Table I provides the annual natural gas usage for the facility from 1985 through 1988.

Table I
Historical Natural Gas Usage
(Annual therms)

1985	5,100
1986	354,000
1987	153,000
1988	3,901,000

The ETEC facility is designed to use fuel oil as an alternative to natural gas. The facility has two large fuel oil storage tanks with a combined capacity of three million gallons. The storage tanks feed directly into a pipeline which connects with the test facility through a small holding tank. A pumping station, used to refill the tanks from delivery trucks, is located on the road below the storage tanks. However, because of leakage the supply tanks required for the operation of the pumping station have been

removed. A few weeks' supply of fuel oil is available but a different pumping system would be needed to refill the storage tanks. If it is considered cost effective to use fuel oil, a new pumping system would need to be implemented in order to allow the fuel oil storage tanks to be refilled. No cost estimate was available for the repair of the pumping system.

Applicable Rate Schedules

The ETEC facility is currently receiving natural gas service under SoCalGas Schedule No. GN-30. This rate schedule is available to large commercial and industrial noncore customers, such as the ETEC facility, who use either SoCalGas' core-supply portfolio or noncore-supply portfolio. If the customer elects to use third-party gas supplies, then service would be provided under Schedule No. GT-30. The rates contained in these two rate schedules are identical except that Schedule No. GT-30 does not contain the core and noncore gas procurement charges that are included in Schedule No. GN-30. Appendix B contains the tariff pages for both Schedule No. GN-30 and Schedule No. GT-30.

The customer charge, under both the GN-30 and GT-30 rate schedules, varies based upon average monthly usage for the most recent 12-month period. For average monthly usage between 200,001 therms and 1,000,000 therms, which is the usage level projected for the ETEC facility, the customer charge is \$1,000 per month. The transmission charges, under both rate schedules, include an annual demand charge, a seasonal peak demand charge and a volumetric charge. The annual demand charge, known as the D-1 demand charge, is

based on the average monthly throughput for the most recent 12 months. Because this charge is applied to the 12-month average usage, the ETEC facility will be assessed a D-1 charge even during the months when no natural gas is used. The seasonal peak demand charges, known as the D-2 demand charges, are based on the highest monthly throughput in the same season during the most recent 12 months. The winter season is defined by SoCalGas as December 1 through March 31 and the summer season contains all remaining months. If the ETEC facility operates under its planned schedule, the facility will not be assessed a winter D-2 charge. However, if operations continue into December or begin before April 1 then a D-2 charge would be assessed in all months of the winter season for the next 11 months. For example, because the ETEC facility used some natural gas in December 1988, a winter demand charge will be assessed in January 1989 through March 1989. These potentially substantial charges can be avoided by not using natural gas during the winter season. The volumetric transmission charge is assessed on the actual throughput in the month. Table II provides the current transmission charges under both Schedule No. GN-30 and Schedule No. GT-30 which would be applicable to the ETEC facility.

Table II

Schedule No. GN-30 and Schedule No. GT-30
Transmission Charges
(Dollars per therm)

D-1	.06180
D-2 (summer)	.02000
D-2 (winter)	.04005
Volumetric	.03994

The ETEC facility, as a noncore customer, has three options for the procurement of natural gas supplies. The facility can elect to use the SoCalGas core-supply portfolio, the SoCalGas noncore-supply portfolio or to procure third-party gas supplies. Currently, the ETEC facility is using the SoCalGas noncore-supply portfolio. Customers using the noncore-supply portfolio can switch to the core-supply portfolio only when the price of the core portfolio is greater than the price of the noncore portfolio. Electing the core-supply portfolio (also known as core-elect service) requires the customer to remain on core-elect service for a minimum of one year. Core-elect customers can renew their core-elect gas procurement service at the end of that service's contract term even if the core portfolio gas price is less than the noncore portfolio gas price.

Table III shows the historical behavior of SoCalGas' core and noncore price of gas and a range of spot market prices delivered to the California border since May 1988. The core price can change twice within a one-year

Table III
Comparison of Core Portfolio,
Noncore Portfolio and Spot Market Prices

<u>Month</u>	<u>Core Price</u> (\$/Dth)	<u>Noncore Price</u> (\$/Dth)	<u>Range of Spot Market Prices</u>	
			<u>Lower</u> (\$/Dth)	<u>Upper</u> (\$/Dth)
May 1988	2.13	1.68	1.68	1.75
June 1988	2.13	1.83	1.66	1.76
July 1988	2.13	1.86	1.75	1.98
August 1988	2.13	2.18	1.96	2.38
September 1988	2.13	2.40	2.10	2.33
October 1988	2.13	2.38	2.07	2.12
November 1988	2.13	2.38	1.99	2.08
December 1988	2.13	2.38	2.03	2.33
January 1989	2.13	2.45	2.33	2.39
February 1989	2.13	2.35	1.91	2.17
March 1989	2.13	2.00	1.84	2.02

period, but has remained constant since May 1988. The noncore price can change twice each month, and generally increased from May 1988 through January 1989 and has been declining since January. In August 1988, the price of the noncore portfolio rose above the price of the core portfolio and remained above the core portfolio price through February 1989. However, in March 1989 the noncore portfolio price dropped below the core portfolio price. This reversal of the core portfolio and noncore portfolio prices makes the core portfolio option available to customers using the noncore-supply portfolio for the first time since August 1988. The core-supply portfolio consists largely of gas procured under long-term supply and price arrangements offering price stability to end-users, whereas the noncore-supply portfolio consists mainly of purchases of spot market gas.

The purchase of natural gas from third-party suppliers is the other gas procurement alternative available to SoCalGas' noncore customers. Third-party supplies are available from marketers and brokers who will purchase natural gas and arrange for the transportation of that gas over the necessary interstate pipelines to SoCalGas' connections with those pipelines. SoCalGas would then transport the gas to the end-user purchasing the gas.

SoCalGas is directly connected to two interstate pipelines, El Paso Natural Gas Company (El Paso) and Transwestern Pipeline Company (Transwestern). El Paso and Transwestern offer open-access nondiscriminatory transportation service under Part 284 of the Federal Energy Regulatory Commission's (FERC) regulations. Both pipelines provide transportation service under Part 284 blanket certificates.

El Paso provides transportation service under Rate Schedule T-1 for interruptible service and Rate Schedule T-3 for firm service. However, since firm capacity is not currently available on the El Paso system, transportation service is available only under the T-1 interruptible rate schedule. The tariff rates associated with El Paso's T-1: Interruptible Transportation Service include mainline transportation charges, field transportation charges, production area charges, a San Juan Triangle facilities commodity charge, and a monthly cumulative imbalance charge. The mainline transportation charge is sub-divided by the producing basin (San Juan, Permian and Anadarko) and by the area or state of ultimate delivery. The mainline transportation charges for the San Juan, Permian and Anadarko Basins production delivered to California are \$.2556 per Dth, \$.2993 per Dth, and \$.3474 per Dth, respectively. The field transportation charges and the production area charges are also sub-divided by the producing basin. The applicability of the various charges is dependent upon the point of delivery of the gas to El Paso and the area or state of ultimate delivery. In addition to these tariff rates, the transportation customer or shipper must pay a take-or-pay throughput surcharge of \$.0198 per Dth, a Gas Research Institute (GRI) funding charge of \$.0143 per Dth, an Annual Charge Adjustment (ACA) amount of \$.0017 per Dth, all applicable taxes, and for fuel reimbursement associated with the transportation services as payment in kind. The mainline transportation fuel reimbursement percentage is equal to 5 percent of the gas delivered to El Paso. The El Paso rates and terms and conditions are currently under review by the FERC.

Transwestern provides both firm and interruptible transportation service under Rate Schedule FTS-1 and Rate Schedule ITS-1, respectively. Transwestern is in direct competition with El Paso for service to the California market. Transwestern tends to set its transportation rates somewhat less than El Paso's transportation rates, making the Transwestern system the preferred path for moving natural gas into California. With the significant increase that occurred in El Paso's transportation rates during the summer of 1988, capacity has not been available on the Transwestern system.

Staff at ETEC have pursued the possibility of having the facility qualify as a cogeneration unit. SoCalGas, to date, has refused to classify the facility as a cogenerator and, thereby allow the facility to obtain gas from SoCalGas' preferred cogeneration rate. Efforts are continuing to obtain cogeneration status for the facility with the California Public Utilities Commission (CPUC). If successful, the facility would receive transmission service under SoCalGas Schedule No. GN-50 if one of SoCalGas' supply portfolios are used for natural gas procurement, or under Schedule No. GT-50 if third-party supplies are procured. The qualification as a cogeneration unit has no impact on the facility's gas procurement decision. The price of SoCalGas' core-supply portfolio and noncore-supply portfolio are identical under Schedules GN-30 and GN-50 and the price of third-party supplies is not impacted by the use of Schedule GT-30 or Schedule GT-50. Only the rate for transmission service over the SoCalGas system would be affected. It is expected that the transmission charges would be less if a cogeneration status was granted.

Gas Transportation Regulatory Initiatives

The California gas market is characterized by gas procurement prices at the state border that are among the lowest in the nation, while gas prices delivered at retail are among the highest. The California Commission has responded to this situation, in part, by issuing a number of Orders Instituting Rulemakings (OIRs), including:

- An OIR investigating the need for additional interstate and/or intrastate pipeline capacity;
- An OIR investigating the possibility of auctioning pipeline capacity which is unnecessary to utility operations;
- An OIR establishing a gas storage program for non-utility market participants; and,
- An OIR requiring a nominations procedure and the unbundling of standby service, including a separate charge for this service.

These regulatory initiatives are generally consistent with a policy to stimulate the natural gas transportation market in California.

The southern California natural gas market is a growing market, characterized by capacity constraints in the winter months, and quite recently, by capacity constraints in the summer months, as well. PG&E and SoCalGas, among

others, have filed their response to a CPUC directive to address the adequacy of pipeline capacity in California to meet present and growing demands for natural gas.

PG&E believes that additional capacity is appropriate to serve the southern California natural gas market. It has proposed to increase its own, and Pacific Gas Transmission's, pipeline capacity to serve the growing southern California market. SoCalGas, on the other hand, would rely, first, on providing increased access to storage and existing firm pipeline capacity. If the Commission were to require an even higher level of service, SoCalGas believes it can add incremental capacity more cheaply on its own system than the costs associated with other proposals.

Any resolution of the need for and the basis of providing additional capacity will be at least several years into the future. Competing proposals will need to be settled, or otherwise resolved. The Commission will continue its review of the adequacy of pipeline capacity through additional filings and workshops. The importance of this continuing Commission review is the revealed preference of the CPUC to ultimately stimulate additional transportation by making additional capacity available to transportation market participants. The near-term impact on California's gas transportation market structure from this regulatory initiative addressing pipeline capacity is expected to be small.

On February 17, 1989, SoCalGas submitted a proposal regarding the Commission's regulatory initiative addressing the auctioning of firm and "as

available" capacity. Capacity in excess of that necessary to provide for its core market extreme day requirements would be auctioned to the highest bidders. Long-term agreements to SoCalGas' firm capacity rights, a newly introduced concept which is a part of SoCalGas' proposal, would be deducted from the utility's capacity rights prior to the determination of excess capacity. This regulatory initiative, which allows transportation market participants access to utility capacity rights, again reveals the CPUC's preference to restructure the California transportation market environment to support greater utilization of transportation.

The CPUC, in its November 8, 1988 Decision 88-11-034, ordered SoCalGas to offer 16.7 Bcf of storage banking service to its customers on a pilot program basis, to be followed by a full-scale implementation program. SoCalGas' storage program is scheduled to commence in March or April of 1989. Participants at that time will bid for available storage service. Top bidders will receive storage service at the price bid by the lowest bidder whose demands can be accommodated within the 16.7 Bcf allotted capacity.

Storage banking will allow noncore users purchasing third-party gas to either assure more reliable supplies, and/or lower their annual gas procurement costs by purchasing and storing gas during the lower-demand summer season. Since ETEC is scheduling the test facility operations primarily in the non-winter months, the availability of storage service does not offer the facility an opportunity to significantly reduce its annual gas costs. Moreover, SoCalGas has proposed to disallow withdrawals during the injection period, while disallowing injections during the withdrawal period. This

proposed operational constraint further removes the utilization of storage from consideration at ETEC because the only scheduled operational month during which ETEC could withdraw stored gas would be in November. The Commission's regulatory initiatives in the area of storage will have their greatest impact on those noncore customers who will now opt for acquisition of third-party gas because of the greater reliability or lower cost available through the utilization of storage service.

In response to a Commission directive SoCalGas is proposing to initiate nomination procedures and standby charges to all large noncore customers. A large noncore customer is a customer which uses in excess of 10 million therms per year. Large noncore customers would be required to nominate expected monthly gas requirements and pay a standby charge or a storage charge for usage which exceeds or falls short of nominations. The charges would apply to usages which exceed or fall short of nominations by 10 percent or more, after notice and opportunity to correct. Stored gas volumes would be available in the following month. Standby volumes would be billed at one of several variants of SoCalGas' incremental cost of gas.

Importantly, noncore customers using less than 10 million therms annually would not be required to pay standby charges or storage charges for inaccurately nominating gas for their expected gas requirements. A noncore customer purchasing noncore gas simply pays the noncore WACOG for all of its gas consumption. On the other hand, a noncore customer utilizing less than 10 million therms and purchasing third-party gas would simply pay SoCalGas' noncore rate for underdeliveries (not the standby rate) and would not be

charged for the storage of excess deliveries. SoCalGas petitioned for a modification of CPUC Decision 88-11-034 (Pilot Program for Gas Storage Banking Service) so as to allow the Company to charge for the banking of gas deliveries in excess of usage, but was denied authority to charge for this unscheduled banking service pending review of the pilot storage program. Thus, noncore customers utilizing less than 10 million therms annually can avoid SoCalGas proposed standby charge, and at the present time pay no storage charge if third-party gas is purchased in amounts exceeding consumption.

The test facility is scheduled to require 10.6 million therms in 1989, slightly over the 10-million therm threshold level, above which the nomination procedures and standby charges apply. The facility has dual-fuel capability from number 2 oil. To the extent consistent with testing program objectives, it is important to keep gas consumption at the facility below the 10-million therm threshold level. Fuel oil can be used to offset natural gas consumption so that the 10 million therm annual threshold is not exceeded and thereby avoid the cost of nomination procedures and standby charges.

The importance of all these regulatory initiatives is that they reveal a regulatory interest in both stimulating the utilization of the gas transportation market in California and a preference to increasingly make large gas users responsible for the cost consequences of their gas usage decisions. The natural gas market in California continues to evolve as Commission policy is revealed in its rulemaking proceedings. It is against this changing background that current end-user strategies must be assessed.

Alternatives

Noncore customers in California, including the ETEC facility, have three choices regarding the procurement of natural gas:

- Purchase gas from their utility's core portfolio of gas supply;
- Purchase gas from their utility's noncore portfolio of gas supply;
or
- Purchase third-party gas supplies.

Since the inception of the core/noncore regulatory regime in California in May 1988, the ETEC facility has been procuring its gas supplies from SoCalGas' noncore portfolio.

Table III, above, shows SoCalGas' core and noncore monthly gas costs since May 1988. Noncore gas costs generally follow gas spot market costs, tending to be lower than core costs in summer months and higher than core costs in winter months. The expected seasonal weakening of spot market prices has already begun this year with the March 1989 cost of SoCalGas' noncore portfolio below its core portfolio WACOG. Application of the 1988 monthly noncore gas costs to the anticipated 1989 test facility gas usage provides a calculated \$24,400 savings, compared to the application of SoCalGas' core rates. Thus, had the test facility operated in 1988 as it is anticipated to

operate in 1989, the noncore gas procurement option would have produced a lower gas acquisition cost than the core gas procurement option.

Given that the test facility operating schedule is heavily weighted toward summer usage, core gas procurement would preclude the cost benefits associated with noncore gas procurement. The core gas rate reflects the average cost of assembling a gas supply portfolio providing for both summer and winter gas requirements. Since winter gas costs are routinely more expensive than summer gas costs, the average cost of core gas is expected to exceed summer gas costs. The procurement of gas from SoCalGas' core portfolio of gas supply would also eliminate the benefit of gas procurement flexibility because such an election requires a one-year commitment to purchase gas exclusively from the core portfolio. Core portfolio gas purchases would thus produce higher expected gas acquisition costs for the test facility and lock the facility into a nonflexible procurement policy for a one-year period.

A second gas acquisition alternative is the continued purchase of gas supplies from SoCalGas' noncore gas supply portfolio. This option is recommended when the noncore gas rate produces a lower gas acquisition cost of operating the ETEC test facility than does the purchase of gas from SoCalGas' core portfolio. SoCalGas was scheduled to file its new core gas rate on March 15, 1989; however, the Company has requested a delay in filing until no later than April 14. Any change in the core rate should be monitored, just as changes in SoCalGas' noncore rate should be monitored, for their impact on the costs of gas usage at the test facility.

As ETEC heads into that time of the year when the test facility is scheduled for operation, SoCalGas' noncore rate of \$2.00 per decatherm is below its \$2.13 core rate. Given southwestern U.S. field prices of gas and transportation costs to California, there is not much possible downside movement in spot gas prices in California below their current \$1.84-\$2.02 level. But this entire range of spot prices, and SoCalGas' current noncore rate are substantially below the current core gas rate. It would take unexpected events to reverse these price relationships as we approach the summer gas buying season.

A third gas acquisition alternative is the purchase of gas supplies from third-party providers. Third-party gas may be acquired in the competitive marketplace from marketers, brokers, pipelines or producers. This is the same market that SoCalGas operates in as it acquires gas supplies for its noncore gas supply portfolio. Participation by ETEC in this market would be advisable if ETEC could secure third-party gas at a cost below that of SoCalGas' noncore rate. Table III shows the history of SoCalGas' noncore rate and the range of spot gas prices delivered to California on the El Paso pipeline. Generally, the range of spot market gas prices exhibits an ability to acquire gas below the cost of gas in SoCalGas' noncore portfolio.

The California natural gas acquisition market is a market that continues to evolve. The regulatory initiatives in the areas of additional pipeline capacity, capacity bidding mechanisms, storage and standby service generally are indicative of a conscious effort to restructure the gas procurement market to more closely resemble a competitive marketplace. The Commission is

revealing its preference to stimulate more noncore-customer participation in the market for third-party gas acquisitions. Unless this policy is changed, the attractiveness of the acquisition and transportation of third-party gas can only be expected to increase.

Recommendations

The preceding section of this report discusses alternatives available to the ETEC test facility. The following recommendations are consistent with the alternatives available to ETEC and with a least-cost natural gas acquisition strategy.

The continued acquisition of natural gas from SoCalGas' noncore portfolio is recommended. This strategy is consistent with the scheduled operation of the ETEC facility during the non-winter months, and the observed seasonal pattern of spot market gas prices in California. Since SoCalGas' core WACOG is some 30 cents per decatherm higher than PG&E's, there is no great cost incentive to opt for the purchase of core gas in southern California, especially for usage in the summer months. With the March noncore gas cost already below SoCalGas' core gas cost, the coincidence of the facility's scheduled usage and favorable noncore prices is observable. While nonseasonal events can greatly influence spot market gas prices, a strategy based on an election to purchase core gas is not supported by recent spot gas prices and the onset of the summer season. The procurement of noncore gas supplies from SoCalGas' noncore portfolio is recommended for the near-term.

The DOE should commence a solicitation for the acquisition of third-party gas supplies. Table III shows that the range of spot gas prices delivered to California frequently provides the opportunity to acquire spot gas at lower costs than SoCalGas' noncore rate. The issuance of a request for proposals for the acquisition of natural gas in the competitive gas market is consistent with the acquisition of natural gas at its lowest cost.

Gas loads at the ETEC test facility are desirable loads for third-party suppliers to accommodate. The one-million decatherm annual requirement is large enough to result in an expected widespread industry response to a solicitation for proposals. Also, the high load factor during the seven-month scheduled operating period, and the seasonal scheduling of operations makes this an exceptionally attractive load for third-party providers of gas. The attractiveness of this load and observable spot market prices below SoCalGas' noncore gas rate provide the opportunity for substantial gas procurement cost savings. Each one-cent per therm difference between the cost of third-party gas and SoCalGas' noncore rate produces a \$100,000 annual cost savings.

The exact structure of a third-party gas procurement solicitation should be determined as the solicitation is developed. However, some salient features of a solicitation that are consistent with the California regulatory environment and gas market structure may include:

- A continuation of utility services (transportation, meter reading, meter and service line maintenance, etc.) from SoCalGas;

- The competitive purchase of gas as a commodity;
- The term of the procurement would be an initial year, with up to four option years;
- The price would be at the indexed spot market price of gas delivered to California, plus or minus any fixed adjustment proposed by respondents to the solicitation; and
- The purchase of gas exclusively from the successful contractor or from SoCalGas.

A solicitation for gas procurement generally structured to include these features would provide a long-term contract vehicle with the pricing flexibility to ensure that the facility would be able to continue to purchase its gas requirements at the market price for gas. Standby service is provided by SoCalGas at the noncore WACOG (as long as annual usage is less than 10 million therms). The solicitation would be designed so that if the contractor's price exceeds the SoCalGas noncore WACOG in any month natural gas would be purchased from SoCalGas' noncore portfolio that month. Therefore, the procurement of natural gas from third-party suppliers would not cost more than the purchase of SoCalGas' noncore gas supply.

It is recommended that the preparation of a request for proposal begin immediately. Before third-party gas can begin to flow, the RFP must be

prepared; DOE approval must be obtained; the RFP must be issued and advertised; responses must be received and reviewed; a contractor must be selected; a contract must be effectuated; and contract performance must commence. It is recommended that a contract be in force for even a part of this year's test facility gas usage so full advantage of a third-party procurement can be taken during future operational periods.

In short, the near-term recommendations for the ETEC facility include:

- Continuation of gas procurement from SoCalGas' noncore portfolio of gas supply, and
- Commencement of a solicitation for the acquisition of third-party gas supplies to begin flowing to the test facility as soon as possible during the upcoming testing operational cycle.

Ancillary recommendations at this time include:

- Natural gas usage at the test facility should not exceed 10 million therms annually in order to avoid standby charges and costs associated with nomination procedures;
- Natural gas should not be used between December 1 and March 31 so that D2 charges will not be paid for the entire winter period.
- SoCalGas' monthly noncore WACOG posted price should be monitored;

- DOE should obtain SoCalGas' proposed core rate contained in its Annual Cost Adjustment Proceeding, to be filed on or before April 14, 1989;
- Regulatory proceedings at both the CPUC and the FERC which could impact the costs of procuring natural gas in California should be monitored; and
- DOE contracting officers should become generally familiar with contracting procedures in the recently created competitive market for natural gas. Other governmental agency competitive acquisitions of natural gas should be reviewed.

Appendix A

Forecasted Natural Gas Requirements

Gas Usage Forecast*

Million Therms

<u>Month</u>	<u>1989</u>	<u>1990</u>
January	0	0
February	0	0
March	0	0
April	0	0
May	1.38	1.58
June	1.55	1.52
July	1.55	1.57
August	1.60	1.60
September	1.51	1.49
October	1.58	1.60
November	1.51	1.53
December	0	0
<u>Total</u>	<u>10.68</u>	<u>10.89</u>

* Subject to DOE programmatic requirements.

As provided by ETEC

Appendix B

Southern California Gas Company
Tariff Schedules

Schedule No. GN-30

NATURAL GAS NON-CORE SERVICE FOR COMMERCIAL AND INDUSTRIALAPPLICABILITY

Applicable for commercial and industrial non-core service for uses at each Facility classified in Rule 23 as Priority 3 or 4, as well as Priority 2B with usage exceeding 250,000 therms per year (or 20,800 therms per month during the season when gas is used). This schedule is also applicable to core customers who qualify in accordance with the conditions specified in their appropriate core rate schedule. Customers eligible for service under this schedule may also elect transportation service under Rate Schedule GT-30.

TERRITORY

Applicable throughout the service territory.

RATES

Monthly Customer Charge*

0 - 5,000 Therms	\$ 150
5,001 - 30,000 Therms	\$ 350
30,001 - 200,000 Therms	\$ 750
200,001 - 1,000,000 Therms	\$1,000
1,000,001 or more Therms	\$3,500

*The monthly customer charge is based on monthly average throughput for the most recent 12 months' service.

Procurement Charges

The procurement charges are the weighted average costs of gas (WACOG) of the core and noncore portfolios, plus franchise fees and uncollectible expenses. The non-core procurement charge is subject to revision not more than twice monthly upon five days' notice to reflect changes in the non-core WACOG, including recorded billing lag adjustments.

GN-30C Core, per therm	21.339¢
GN-30N Non-Core, per therm	24.498¢

(continued)

TO BE INSERTED BY UTILITY

ADVICE LETTER NO 1842

DECISION NO 88-12-010

ISSUED BY

ROY M. PAWLINGS

VICE PRESIDENT

TO BE INSERTED BY CAL P.U.C.

DATE FILED Jan 4, 1989

EFFECTIVE Jan 9, 1989

RESOLUTION NO

(Sheet 2 of 4)

Schedule No. GN-30

NATURAL GAS NON-CORE SERVICE FOR COMMERCIAL AND INDUSTRIAL
(Continued)RATES (Continued)

Transmission Charges

	Non-Core <u>P-2B</u>	<u>ETC</u> Other
D-1 Demand Charge	6.179¢ per therm	6.180¢ per therm
D-2 Demand Charge, Summer	2.221¢ per therm	2.000¢ per therm
D-2 Demand Charge, Winter	4.357¢ per therm	4.005¢ per therm
Volumetric	4.162¢ per therm	3.994¢ per therm

The D-1 demand charge is established from the average monthly throughput for the most recent 12 months' service. However, for customers initiating service with no prior usage history or who previously were on a rate schedule where no demand charges were applicable, the D-1 demand charge will be based on a moving monthly average of actual throughput until 12 month's usage is accumulated. For the D-2 demand charge, the peak month will be used based on the highest month's throughput during the same season within the most recent 12 month period.

For demand charges the winter season shall be defined as December 1 through March 31.

If the customer and/or demand charges are collected under Schedule GT-30, no duplicative charge is collected hereunder.

Minimum Charge

The minimum monthly charge shall consist of the monthly customer charge and the monthly demand charges.

Proration of demand charges shall occur only under conditions of force majeure and scheduled maintenance shutdowns with thirty days' written notice which significantly affect the customer's ability to accept delivery of natural gas. Proration will be based on the number of days gas is offered. Customers will not be excused from demand charges during any supply or capacity curtailment.

Rates may be adjusted to reflect any applicable taxes, franchise or other fees, regulatory surcharges, and interstate or intrastate pipeline demand charges that may occur.

The number of therms to be billed shall be determined in accordance with Rule No. 2.

(continued)

TO BE INSERTED BY UTILITY:

ADVICE LETTER NO. 1841DECISION NO. 88-12-094

ISSUED BY

ROY M. PAULINGS

VICE PRESIDENT

TO BE INSERTED BY CAL. P.U.C.:

DATE FILED Dec 26, 1988EFFECTIVE Jan. 01, 1989

RESOLUTION NO. _____

Schedule No. GN-30

NATURAL GAS NON-CORE SERVICE FOR COMMERCIAL AND INDUSTRIAL

(Continued)

SPECIAL CONDITIONS

1. Definitions of the principal terms used in this schedule are contained in Rule No. 1.
2. Customers may receive service under this schedule (a) separately or (b) in combination with another rate schedule(s) through a single meter installation. Where service is rendered under (b) a separate monthly customer charge may be applicable for service under each schedule.
3. As a condition precedent to service under this schedule, an executed Contract for Gas Service (Form No. 6412) is required. By mutual agreement, the contract may specify transmission charges, terms or conditions of service different than those shown herein. All rates and conditions are subject to revision and modification as a result of Commission order.
4. All contracts having terms of less than five years will be submitted to the Commission and made available for public inspection. All contracts having terms of five years or more must be filed with the Commission by advice letter for approval.
5. Customers under this schedule may purchase gas from the core portfolio (GN-30C) or the non-core portfolio (GN-30N) for all or a portion of their gas requirements. Purchases from the core portfolio are under core-elect procurement service. Customers may choose core-elect procurement initially only when the non-core procurement charge is less than the core procurement charge. Customers may not elect core procurement service when the core procurement charge is lower than the non-core procurement charge, provided that for customers connecting gas load not previously served by SoCalGas, this switching ban does not apply at the time service is initiated. Also, core-elect procurement customers may renew their core-elect contract for the same or a lesser amount of gas if their core-elect contract expires while the switching ban is in effect.
6. The Utility shall provide non-core gas procurement service on a best-efforts basis. Either the Utility or the customer may terminate the non-core procurement provisions of the Service Contract by providing a 30-day written notice of that intention, with the exception that the customer may nominate zero volume purchases for any given month following a revision to the non-core procurement portfolio WACOG.
7. Customer must provide twelve (12) months prior notification to the Utility of termination of service. At the end of the twelve (12) month period, if service is terminated, the D-1 and D-2 demand charges will no longer be due and payable. The customer charge ceases upon termination of service, even if no prior notice of termination is provided.

(continued)

TO BE INSERTED BY UTILITY

ADVICE LETTER NO. 1834

DECISION NO.

REV 1-80

ISSUED BY

ROY M. RAWLINGS

VICE PRESIDENT

TO BE INSERTED BY CAL PUC

DATE FILED NOV 10, 1983

EFFECTIVE DEC 19, 1983

RESOLUTION NO. G-2847

(Sheet 4 of 4)

Schedule No. GI-30

NATURAL GAS NON-CORE SERVICE FOR COMMERCIAL AND INDUSTRIAL
(Continued)

SPECIAL CONDITIONS (Continued)

8. The term of service for core-elect procurement under Schedule GN-30C shall be a minimum of one year. Customers who do not use their full contracted quantities on a yearly basis will be liable for unavoidable or minimum charges to reflect any costs which the Utility incurs as a result, excluding costs allocated to transmission charges. The termination fees shall be documented in the procurement contract.
9. Customers having long-term core-elect procurement contracts under GI-30C may specify in their contract lower volumes of gas each year if they do not expect their demands to be maintained at current levels.
10. Alternate fuel capability, as defined in Rule 23, is a required condition of service under this schedule, except for customers with Commission approved exemptions. It is the sole responsibility of the customer to provide and maintain adequate standby equipment and fuel at all times for immediate operation in the event that the supply of gas shall be interrupted or curtailed in whole or in part.
11. In the event of curtailment, customers under this schedule will be curtailed in accordance with Rule 23, Priority of Service. For other than an Operating Emergency, as defined in Rule 23, customers unable to curtail on request will be reassigned to the appropriate core rate schedule and subject to rebilling.
12. In the event customers make any material change, either in the amount or character of gas appliances or equipment, written notice to the Utility must be made in accordance with Rule 29, Change of Consumer's Apparatus or Equipment.

TO BE INSERTED BY UTILITY

ADVICE LETTER NO. 1167-A 3rd Suppl

DECISION NO. 87-12-039 et al

ISSUED BY

ROY M. PAWLINGS

VICE PRESIDENT

TO BE INSERTED BY CAL P.U.C.

DATE FILED APR 29, 1988

EFFECTIVE MAY 01, 1988

FILE NO. G-1787 & G-2763

(Sheet 1 of 4)

Schedule No. GT-30

TRANSPORTATION OF CUSTOMER-OWNED NATURAL GAS
FOR LARGE COMMERCIAL AND INDUSTRIAL SERVICEAPPLICABILITY

Applicable to transportation of customer-owned natural gas for commercial and industrial non-core service for uses at each Facility classified in Rule 23 as Priority 3 or 4, as well as Priority 2B with usage exceeding 250,000 therms per year (or 20,800 therms per month during the season when gas is used). This schedule is also applicable to core customers who qualify in accordance with the conditions specified in their appropriate core rate schedule.

TERRITORY

Applicable throughout the service territory.

RATES

Monthly Customer Charge*

0 - 5,000 Therms	\$ 150
5,001 - 30,000 Therms	\$ 350
30,001 - 200,000 Therms	\$ 750
200,001 - 1,000,000 Therms	\$1,000
1,000,001 or more Therms	\$3,500

*The monthly customer charge is based on monthly average throughput for the most recent 12 months' service.

Transmission Charges

	Non-Core P-2B	Other
D-1 Demand Charge	6.179¢ per therm	6.180¢ per therm
D-2 Demand Charge, Summer	2.221¢ per therm	2.000¢ per therm
D-2 Demand Charge, Winter	4.357¢ per therm	4.005¢ per therm
Volumetric	4.162¢ per therm	3.994¢ per therm

The D-1 demand charge is established from the average monthly usage for the most recent 12 months' service. However, for customers initiating service with no prior usage history or who previously were on a rate schedule where no demand charges were applicable, the D-1 demand charge will be based on a moving monthly average of actual throughput until 12 month's usage is accumulated. For the D-2 demand charge, the peak month will be used, based on the highest month's throughput during the same season within the most recent 12 month period.

(continued)

(TO BE INSERTED BY UTILITY)

ADVICE LETTER NO. 1341
DECISION NO. 88-12-094

ISSUED BY

ROY M. RAWLINGS
VICE PRESIDENT

(TO BE INSERTED BY CAL. P.U.C.)

DATE FILED Jan 26, 1988
EFFECTIVE Jan 01, 1989
RESOLUTION NO.

(Sheet 2 of 4)

Schedule No. GT-30

TRANSPORTATION OF CUSTOMER-OWNED NATURAL GAS
FOR LARGE COMMERCIAL AND INDUSTRIAL SERVICE
(Continued)

RATES (Continued)

For demand charges the winter season shall be defined as December 1 through March 31.

If the customer and/or demand charges are collected under Schedule GN-30, no duplicative charge is collected hereunder.

Billing Adjustments

Billing adjustments may be necessary to reflect changes in volumes used in developing prior periods' transportation charges.

Minimum Charge

The minimum monthly charge shall consist of the Monthly Customer Charge and the Monthly Demand Charges.

Proration of demand charges shall occur only under conditions of force majeure and scheduled maintenance shutdowns with thirty days' written notice which significantly affect the customer's ability to accept delivery of natural gas. Proration will be based on the number of days gas is offered. Customers will not be excused from demand charges during any supply or capacity curtailment.

Rates may be adjusted to reflect any applicable taxes, franchise or other fees, regulatory surcharges, and interstate or intrastate pipeline charges that may occur.

The number of therms to be billed shall be determined in accordance with Rule No. 2.

SPECIAL CONDITION

1. Definitions of the principal terms used in this schedule are contained in Rule No. 1.

(continued)

TO BE INSERTED BY UTILITY:

ADVISE LETTER NO 1313

DECISION NO

ISSUED BY

ROY M. RAWLINGS

VICE PRESIDENT

TO BE INSERTED BY CAL. P.U.C.:

DATE FILED Aug 29, 1988

EFFECTIVE July 1, 1988

RESOLUTION NO

(Sheet 3 of 4)

Schedule No. GT-30

TRANSPORTATION OF CUSTOMER-OWNED NATURAL GAS
FOR LARGE COMMERCIAL AND INDUSTRIAL SERVICE
(Continued)

SPECIAL CONDITION (Continued)

2. Customers may receive service under this schedule (a) separately or (b) in combination with another rate schedule(s) through a single meter installation. Where service is rendered under (b), a separate monthly customer charge may be applicable for service under each schedule.
3. As a condition precedent to service under this schedule, an executed Contract for Gas Service (Form No. 6412) is required. By mutual agreement, the contract may specify negotiated transmission charges, terms or conditions of service different than those shown herein. All rates and conditions are subject to revision and modification as a result of Commission order.
4. The term of service under this schedule shall be for a minimum of 30 days. All contracts having terms of less than five years will be submitted to the Commission and made available for public inspection. All contracts having terms of five years or more must be filed with the Commission by advice letter for approval.
5. After the initial term as specified in the contract, service will continue on a month-to-month basis until terminated by either party on 15 days written notice.
6. Any customer requesting a change in the quality of service (upgrading) shall be liable for the costs to the Utility associated with that change.
7. Customer must provide twelve (12) months prior notification to the Utility of termination of service. At the end of the twelve (12) month period, if service is terminated, the D-1 and D-2 demand charges will no longer be due and payable. The customer charge ceases upon termination of service, even if no prior notice of termination is provided.
8. In the event of supply shortages, customers under this schedule shall receive their transportation volumes, except during an emergency declared by the Commission requiring the use of the customer's gas to service priority 1 and 2A core procurement customers.
9. Any penalties or charges incurred by the Utility under an interstate or intrastate supplier tariff as a result of accommodating transportation service shall be paid by the responsible customer under this schedule.

(continued)

TO BE INSERTED BY UTILITY
ADVICE LETTER NO. 1317
DECISION NO. _____

ISSUED BY
ROY M. RAWLINGS
VICE PRESIDENT

TO BE INSERTED BY CAL PUC
DATE FILED APR 29, 1988
EFFECTIVE MAY 5, 1988
RESOLUTION NO. G-2810

(Sheet 4 of 4)

Schedule No. GT-30

TRANSPORTATION OF CUSTOMER-OWNED NATURAL GAS
FOR LARGE COMMERCIAL AND INDUSTRIAL SERVICE
(Continued)

SPECIAL CONDITIONS (Continued)

10. Transportation customers receiving service under this schedule shall pay any costs incurred by the Utility because of any failure by third parties to perform their obligations related to providing such service.
11. Alternate fuel capability, as defined in Rule 23, is a required condition of service under this schedule, except for customers with Commission approved exemptions. It is the sole responsibility of the customer to provide and maintain adequate standby equipment and fuel at all times for immediate operation in the event that the supply of gas shall be interrupted or curtailed in whole or in part.
12. All terms and conditions of Rule 30 apply to the transportation of customer-owned gas under this schedule.
13. Customers having existing gas exchange arrangements with the Utility must exchange the maximum amount of gas allowable under those arrangements prior to the delivery of customer-owned natural gas to the Utility for transportation, unless otherwise agreed to by the Utility.
14. In the event of curtailment, customers under this schedule will be curtailed in accordance with Rule 23 (c), Priority of Service. For other than an Operating Emergency, as defined in Rule 23, customers unable to curtail on request will be reassigned to the appropriate core rate schedule and subject to rebilling.
15. In the event customers make any material change, either in the amount or character of gas appliances or equipment, written notice to the Utility must be made in accordance with Rule 29, Change of Consumer's Apparatus or Equipment.

TO BE INSERTED BY UTILITY:

ADVISE LETTER NO. 1818

DECISION NO.

ISSUED BY

ROY M. RAWLINGS

VICE PRESIDENT

TO BE INSERTED BY CAL P.U.C.:

DATE FILED Aug 29, 1938

EFFECTIVE July 1, 1938

RESOLUTION NO.

(Sheet 1 of 4)

Schedule No. GN-50

NATURAL GAS SERVICE FOR COGENERATIONAPPLICABILITY

Applicable to natural gas service for qualifying cogeneration facilities for uses at each Facility classified in Rule 23 as Priority 3A. This schedule is also applicable to solar electric generation projects. Customers eligible for service under this schedule may qualify for transportation service under Schedule GT-50.

TERRITORY

Applicable throughout the service territory.

RATESProcurement Charges

The procurement charges are the weighted average costs of gas (WACOG) of the core and noncore portfolios, plus franchise fees and uncollectible expenses. The non-core procurement charge is subject to revision not more than twice monthly upon five days' notice to reflect changes in the non-core WACOG, including recorded billing lag adjustments.

GN-50C Core, per therm.....	21.339¢
GN-50N Non-Core, per therm.....	24.498¢

Transmission Charges

Volumetric Charge, per therm	29.826¢
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The unit volumetric charge shall be the weighted average of all the transmission charges, including demand charges, of the Utility Electric Generation customers for the preceding month, allowing for a 60 day lag for true up.

The bill for cogeneration customers shall be calculated based on the above, or the total customer charge, demand charges and volumetric transmission charge of the otherwise applicable schedule, whichever is less.

Minimum Charge

The minimum monthly transmission charge shall consist of the lower of 1) the lower of the volumetric charge shown above or the average UEG demand charge of 6.505¢ per therm multiplied by customer's average monthly cogeneration usage over the most recent 12 months' service, or 2) the monthly customer charge and the monthly demand charges of the otherwise applicable schedule.

(continued)

TO BE INSERTED BY UTILITY

ADVISE LETTER NO. 1842

DECISION NO. 86-12-010

ISSUED BY

ROY M. RAWLINGS

VICE PRESIDENT

TO BE INSERTED BY CAL. P.U.C.

DATE FILED Jan 4, 1989

EFFECTIVE Jan 9, 1989

RESOLUTION NO.

(Sheet 2 of 4)

Schedule No. GN-50

NATURAL GAS SERVICE FOR COGENERATION
(Continued)

RATES (Continued)

Rates may be adjusted to reflect any applicable taxes, franchise or other fees, regulatory surcharges, and interstate or intrastate pipeline charges that may occur.

The number of therms to be billed shall be determined in accordance with Rule 2.

SPECIAL CONDITIONS

1. Definitions of the principal terms used in this schedule are contained in Rule No. 1.
2. Customers may receive service under this schedule (a) separately or (b) in combination with another rate schedule(s) through a single meter installation. Where service is rendered under (b), a separate monthly customer charge may be applicable for service under each schedule.
3. As a condition precedent to service under this schedule, an executed Contract for Gas Service (Form No. 6412) is required. By mutual agreement, the contract may specify negotiated transmission charges, terms or conditions of service different than those shown herein. All rates and conditions are subject to revision and modification as a result of Commission order.
4. All contracts having terms of less than five years will be submitted to the Commission and made available for public inspection. All contracts having terms of five years or more must be filed with the Commission by advice letter for approval.
5. Non-core cogenerators under this schedule may purchase gas from the core portfolio (GN-50C) or the non-core portfolio (GN-50N) for all or a portion of their gas requirements. Non-core cogenerators' gas purchases from the core portfolio are under core-elect procurement service. Non-core cogenerators (and core cogenerators who have qualified for and elected non-core procurement) may choose core-elect initially only when the non-core procurement charge is less than the core procurement charge. A core-elect switching ban exists when the core procurement charge is lower than the non-core procurement charge. For customers connecting gas load not previously served by the Utility, this switching ban does not apply at the time the new or additional service is initiated. Also, core-elect procurement customers may renew their core-elect contract for the same or a lesser amount of gas if their core-elect contract expires while the switching ban is in effect.

(continued)

TO BE INSERTED BY UTILITY:

ISSUED BY

TO BE INSERTED BY CAL. P.U.C.:

ADVICE LETTER NO. 1934

ROY M. RAWLINGS

DATE FILED May 10, 1968

DECISION NO. _____

VICE PRESIDENT

EFFECTIVE Dec 19, 1968

(Sheet 3 of 4)

Schedule No. GN-50

NATURAL GAS SERVICE FOR COGENERATION

(Continued)

SPECIAL CONDITIONS (Continued)

6. The Utility shall provide non-core gas procurement service on a best-efforts basis. Either the Utility or the customer may terminate the non-core procurement provisions of the service contract by providing a 30-day written notice of that intention, with the exception that the customer may nominate zero volume purchases for any given month following a revision to the non-core procurement portfolio WACOG.
7. The term of service for core-elect procurement under Schedule GN-50C shall be a minimum of one year. Core-elect customers who do not use their full contracted quantities on a yearly basis will be liable for unavoidable or minimum charges to reflect any costs which the Utility incurs as a result, excluding costs allocated to transmission charges. The termination fees shall be documented in the procurement contract.
8. Customers having long-term core-elect procurement contracts under GN-50C may specify in their contract lower volumes of gas each year if they do not expect their demands to be maintained at current levels.
9. Core customers must purchase gas in accordance with the procurement options of their otherwise applicable rate schedule.
10. A Cogeneration Contract Addendum (Form 5058) will be required as a condition of service under this schedule in those cases where additional facilities are necessary to serve a customer who has requested service at higher than standard delivery pressure.
11. This schedule is available for only the cogeneration portion of the customer's gas purchases, which will be the lesser of:
 - a. Actual gas used by the cogenerator in the sequential production of electrical energy and heat, steam, or useful work; or
 - b. The amount of gas the local electric utility would require to generate and transmit an equivalent amount of electricity, based on the utility's average annual incremental heat rate and reasonable transmission losses.

(continued)

TO BE INSERTED BY UTILITY

ISSUED BY

TO BE INSERTED BY CAL P.U.C.

ADVISE LETTER NO 1767-A 2nd SUPPL

ROY M. RAWLINGS

DATE FILED APT 29, 1988

DECISION NO 87-10-039 et al

VICE PRESIDENT

EFFECTIVE May 01, 1988

RESOLUTION NO G-2737 & G-2

(Sheet 4 of 4)

Schedule No. GN-50

NATURAL GAS SERVICE FOR COGENERATION
(Continued)

SPECIAL CONDITIONS (Continued)

12. Customers will make available any electric meters required to directly measure the kilowatt-hours generated. The Utility shall have the right to read, inspect and/or test the measuring facilities during normal working hours. Additional gas and/or steam metering facilities required to separately determine gas usage to which Schedule GN-50 is applicable will be installed, owned and operated by the Utility at its expense; however, the Utility may, at its sole discretion, utilize estimated data to determine such gas usage.
13. Alternate fuel capability requirements will be in accordance with customer's otherwise applicable rate schedule.
14. Cogeneration facilities with standby boilers will be treated as one customer for purposes of assessing customer and demand charges, providing the cogeneration customer has signed an affidavit (Form No. 6419) to the effect that its boiler system only operates when the cogeneration system is not operating.
15. In the event of curtailment, customers under this schedule will be curtailed in accordance with Rule 23, Priority of Service.
16. In the event customers make any material change, either in the amount or character of gas appliances or equipment, written notice to the Utility must be made in accordance with Rule 29, Change of Consumer's Apparatus or Equipment.

(TO BE INSERTED BY UTILITY)

ADVICE LETTER NO. 1330

DECISION NO. _____

ISSUED BY

ROY M. RAWLINGS

VICE PRESIDENT

(TO BE INSERTED BY CAL. P.U.C.)

DATE FILED Oct 27, 1988EFFECTIVE Dec 06, 1988

RESOLUTION NO. _____

(Sheet 1 of 4)

Schedule No. GT-50

TRANSPORTATION OF CUSTOMER-OWNED NATURAL GAS
FOR COGENERATION SERVICE

APPLICABILITY

Applicable to transportation of customer-owned natural gas for qualifying cogeneration customers for uses at each Facility classified in Rule 23 as Priority 3A with usage exceeding 250,000 therms per year (or 20,800 therms per month during the season when gas is used). This schedule is also applicable to solar electric generation projects.

TERRITORY

Applicable throughout the service territory.

RATES

Transmission Charges

Volumetric Charge, per therm..... 29.826¢

The unit volumetric charge shall be the weighted average of all the transmission charges including demand charges, of the Utility Electric Generation customers for the preceding month, allowing for a 60-day lag for true-up.

The bill for cogeneration customers shall be calculated based on the above, or the total customer charge, demand charges and volumetric transmission charge of the otherwise applicable schedule, whichever is less.

Billing Adjustments

Billing adjustments may be necessary to reflect changes in volumes used in developing prior periods transportation charges.

Minimum Charge

The minimum monthly transmission charge shall consist of the lower of 1) the lower of the volumetric charge shown above or the average UEG demand charge of 6.505¢ per therm multiplied by customer's average monthly cogeneration usage over the most recent 12 month's service, or 2) the monthly customer charge and the monthly demand charge of the otherwise applicable schedule.

Rates may be adjusted to reflect any applicable taxes, franchise or other fees, regulatory surcharges, and interstate or intrastate pipeline charges that may occur.

The number of therms to be billed shall be determined in accordance with Rule No. 2.

(continued)

(TO BE INSERTED BY UTILITY)

ISSUED BY

(TO BE INSERTED BY CAL. P.U.C.)

ADVICE LETTER NO. 1841

ROY M. RAWLINGS

DATE FILED Dec 26, 1988

DECISION NO. 88-12-094

VICE PRESIDENT

EFFECTIVE Jan 01, 1989

(Sheet 2 of 4)

Schedule No. GT-50

TRANSPORTATION OF CUSTOMER-OWNED NATURAL GAS
FOR COGENERATION SERVICE
(Continued)

SPECIAL CONDITIONS

1. Definitions of the principal terms used in this schedule are contained in Rule No. 1.
2. Customers may receive service under this schedule (a) separately or (b) in combination with another rate schedule(s) through a single meter installation. Where service is rendered under (b), a separate monthly customer charge may be applicable for service under each schedule.
3. As a condition precedent to service under this schedule, an executed Contract for Gas Service (Form No. 6412) is required. By mutual agreement, a separate contract may be negotiated under this schedule that may specify transmission charges, terms or conditions of service different than those shown herein. All rates and conditions are subject to revision as a result of Commission order.
4. The minimum term of service under this schedule shall be for a period of 30 days. All contracts having terms of less than five years will be submitted to the Commission and made available for public inspection. All contracts having terms of five years or more must be filed with the Commission by advice letter for approval.
5. After the initial term as specified in the contract, service will continue on a month-to-month basis until terminated by either party on 15 days written notice.
6. Any customer requesting a change in the quality of service (upgrading) shall be liable for the costs to the Utility associated with that change.
7. In the event of supply shortages, customers under this schedule shall receive their transportation volumes, except during an emergency declared by the Commission requiring the use of the customer's gas to service priority 1 and 2A core procurement customers.
8. Any penalties or charges incurred by the Utility under an interstate or intrastate supplier contract as a result of accommodating transportation service shall be paid by customers under this schedule.

(continued)

TO BE INSERTED BY UTILITY

ISSUED BY

TO BE INSERTED BY CAL. P.U.C.

ADVICE LETTER NO. 17678-G SUPP1

ROY M. RAWLINGS

DATE FILED APR 23, 1983

DECISION NO. 87-12-033 at 21

VICE PRESIDENT

EFFECTIVE MAY 01, 1983

RESOLUTION NO. 9-2787 & 9-278

Schedule No. GT-50

(Sheet 3 of 4)

TRANSPORTATION OF CUSTOMER-OWNED NATURAL GAS
FOR COGENERATION SERVICE
(Continued)

SPECIAL CONDITION (Continued)

9. Transportation customers receiving service under this schedule shall pay any costs incurred by the Utility because of any failure by third parties to perform their obligations related to providing such service.
10. A Cogeneration Contract Addendum (Form 5058) will be required as a condition of service under this schedule in those cases where additional facilities are necessary to serve a customer who has requested service at higher than standard delivery pressure.
11. This schedule is available for only the cogeneration portion of the customer's gas deliveries to Utility, which will be the lesser of:
 - a. Actual gas used by the cogenerator in the sequential production of electrical energy and heat, steam, or useful work; or
 - b. The amount of gas the local electric utility would require to generate and transmit an equivalent amount of electricity, based on the utility's average annual incremental heat rate and reasonable transmission losses.
12. Customers will make available any electric meters required to directly measure the kilowatt-hours generated. The Utility shall have the right to read, inspect and/or test the measuring facilities during normal working hours. Additional gas and/or steam metering facilities required to separately determine gas usage to which Schedule GT-50 is applicable will be installed, owned and operated by the Utility at its expense; however, the Utility may, at its sole discretion, utilize estimated data to determine such gas usage.

(continued)

(TO BE INSERTED BY UTILITY)

ADVICE LETTER NO. 1930

DECISION NO. _____

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ROY M. RAWLINGS

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(TO BE INSERTED BY CAL. P.U.C.)

DATE FILED Oct 27, 1988EFFECTIVE Dec 5, 1988

RESOLUTION NO. _____

(Sheet 4 of 4)

Schedule No. GT-50

TRANSPORTATION OF CUSTOMER-OWNED NATURAL GAS
FOR COGENERATION SERVICE
(Continued)

SPECIAL CONDITIONS (Continued)

13. Cogeneration facilities with standby boilers will be treated as one customer for purposes of assessing customer and demand charges, providing the cogeneration customer has signed an affidavit (Form No. 6419) to the effect that its boiler system only operates when the cogeneration system is not operating.
14. All terms and conditions of Rule 30 apply to the transportation of customer-owned gas under this schedule.
15. Customers having existing gas exchange arrangements with the Utility must exchange the maximum amount of gas allowable under those arrangements prior to the delivery of customer-owned natural gas to the Utility for transportation, unless otherwise agreed to by the Utility.
16. In accordance with Section 2773.5 of the Public Utilities Code, customers shall not be required to maintain alternate fuel capability with respect to equipment which uses gas for purposes of cogeneration. However, in the event of curtailment, customers under this schedule will be curtailed in accordance with Rule 23, Priority of Service.
17. In the event customers make any material change, either in the amount or character of gas appliances or equipment, written notice to the Utility must be made in accordance with Rule 29, Change of Consumer's Apparatus or Equipment.

(TO BE INSERTED BY UTILITY)

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(Sheet 2 of 14)

Rule No. 23

SHORTAGE OF GAS SUPPLY,
INTERRUPTION OF DELIVERY AND PRIORITY OF SERVICE
(Continued)

Priority of Service

- Priority 1* All residential usage regardless of size. All other use with a peak-day demand of 100 Mcf per day or less.
- Priority 2 A Non-residential use in excess of 100 Mcf per day without alternate fuel capability. Other uses where specific Commission authorization has been granted (Decision No. 90794). Electric utility startup and igniter fuel.
- B Non-residential use in excess of 100 Mcf per day with LPG or other gaseous fuel capability. Other uses where specific Commission authorization has been granted.
- Priority 3 All Tier I usage for utility electric generating plants not included in Priority 2A.
- A** Cogeneration usage. Also, gas used in solar electric generation projects.
- B All use not included in another priority.
- C Los Angeles Department of Water and Power's Scattergood Generating Station Unit 3 (subject to provisions of Decision No. 92704).
- Priority 4 Boiler fuel use with a peak-day demand greater than 750 Mcf per day not included in another priority. All use in cement plant kilns.
- Priority 5 All use in utility electric generating plants not included in another priority. All use for enhanced oil recovery facilities.

* Any customer whose usage does not exceed 100 Mcf on a peak day for three consecutive months in the most recent fourteen contiguous month period will be classified as Priority 1. The non-residential customer who exceeds 100 Mcf on a peak-day for three consecutive months will be transferred to the appropriate lower priority.

** Existing equipment on a higher priority will not be assigned to a lower priority solely as the result of a cogeneration project. Customers in a lower priority will be reclassified for that portion of their usage associated with cogeneration only.

(continued)

(TO BE INSERTED BY UTILITY)

ISSUED BY

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A COMPARISON OF
THE PG&E TESLA TRANSMISSION PROPOSAL WITH
THE WESTERN TRACY TIELINE PROJECT

Prepared for:

The United States Department of Energy
San Francisco Operations Office

March 24, 1988

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EXECUTIVE SUMMARY

1. Background: The Department of Energy (DOE) has planned a project under which the Western Area Power Administration (Western) would build, among other facilities, a 230 kV, 325 MVA transmission line from its Tracy substation to the Lawrence Livermore National Laboratory (LLNL), thereby increasing the reliability of service to the laboratory. Subsequently, the Pacific Gas & Electric Company (PG&E) proposed to provide redundant transmission facilities from its Tesla substation to LLNL as an alternative to the DOE Tracy/LLNL Tie Line project. In addition to a redundant transmission path, economic benefits may also accrue to DOE from either proposal. Exeter Associates and C.H. Guernsey & Company were asked to evaluate the comparative reliability and economics of the Western project and the PG&E proposal to assist DOE in deciding which alternative will best serve the long term interest of DOE's mission at LLNL. This report as revised by DOE/SAN, presents the results of that evaluation.

2. The PG&E Proposal: PG&E proposes to provide a 159 MVA, 115 kV "loop" feed from their Tesla Substation with a standby feed from the Newark Substation for an annual price not to exceed \$737,000. The loop feed from Tesla is sufficient to meet DOE's redundancy requirement; thus, the standby feed from Newark was considered unnecessary. Therefore, the cost for the standby transmission facilities was not included in the economic analysis. The annual price used for analysis was \$654,000. PG&E may also provide additional transfer capability to LLNL if and when required by DOE. The total transfer capability would be 300 MVA for an annual cost not to exceed \$1,350,000 or \$1,267,000 which is less the Newark portion. PG&E would also be willing to construct desired distribution facilities at LLNL. These facilities would be owned by PG&E if paid for by DOE with an upfront contribution in aid of construction equal to the cost of construction, or by paying PG&E's annual continuing ownership cost of 20.76 percent of the capital investment. DOE could own these facilities by paying PG&E upfront an amount equal to 128 percent of the cost of construction to account for PG&E's return and resulting tax requirements.

3. The Western Project: Under the planned project, Western will construct a 230 kV line from its Tracy Substation to LLNL. The line will have a transfer capacity of 325 MVA. It will rely on PG&E's existing Tesla line for redundancy. The continuing annual cost to DOE/SAN would be \$281,600. "Loop" service using the existing PG&E line could also be accommodated by installing the required switching facilities at LLNL. Western has also proposed to construct the desired LLNL distribution facilities upgrades at no cost to DOE/SAN. The redundancy of Western's proposal depends upon the continued operation of the existing PG&E Tesla line. PG&E will be obligated to keep that line available and to provide standby wheeling for Western power as long as LLNL continues to take retail service from PG&E. Under these circumstances, no ratcheted or contract demand standby charge is expected for Western power not actually wheeled. Standby costs are expected if and when PG&E retail service is largely or wholly displaced. The cost of such standby service that would be authorized

by the FERC is estimated to fall between \$.73 and \$1.13 per kW-month, or between \$613,000 and \$949,000 a year at a 70 MW average monthly peak load. The FERC certainly would not allow PG&E to charge more for standby than the \$1.433 it charges for actually wheeling Western power to LLNL.

4. Reliability Considerations: Three regimes of reliability were considered in the analysis: instantaneous, short-term and long-term. Instantaneous reliability would allow service without interruption, even if one transmission interconnection were momentarily or permanently interrupted. Short-term reliability would allow continuous service from an alternate transmission interconnection, even if the primary interconnection is interrupted for several minutes, hours or even days. Long-term technical reliability is an extension of short-term reliability for long-term periods.

5. Comparative Reliability: PG&E's offer would provide instantaneous, short-term and long-term technical reliability. The Western proposal would provide short-term and long-term technical reliability. Instantaneous reliability could also be incorporated into Western's configuration. However, under either "looped" arrangement, voltage and current fluctuations and/or electromagnetic transients that occur during switching may still cause outages of certain critical loads, most notably computer loads.

6. Comparative Economics: The time frame used for the economic analyses was FY 1989 to FY 2001. The Western project is superior if no change is contemplated in the LLNL resource mix -- that is, the laboratory continues to take its Central Valley Project (CVP) power from Western and retail supplemental power continues to be purchased from PG&E. Under this scenario, the 1988 present value of the wheeling savings under the Western project is over \$3.1 million. The PG&E proposal shows a present value loss of \$251,000 under the same scenario due to its higher facilities charges. When allowance is made for wheeling California-Oregon Transmission Project (COTP) power to LLNL, the present value of the savings under the Western project (\$9.9 million) is greater than the present value of the savings associated with PG&E's proposal (\$8.5 million). Finally, the present value of the savings from Western's project is conservatively estimated to be \$5.6 million, when allowance is made for the potential savings associated with displacing PG&E sales with 3rd-Party power wheeled over the Tracy transmission line.

7. Planning Flexibility/Alternative Access: An important consideration in selecting either the PG&E proposal or the Western project should be access to future power supply sources. We cannot say what will happen tomorrow, but we can be sure that technical, legal and institutional changes will occur. Flexibility allows DOE to respond to the many possible changes in power supply costs and alternatives. The Western project provides DOE with significant increased future power supply planning flexibility.

8. Conclusions and Recommendation: As a result of our analyses, it is concluded that both proposals provide the necessary redundancy/reliability required by DOE. The Western proposal is superior in terms of economics. Finally, the Western proposal is superior in terms of planning flexibility. Therefore, it is recommended that the Western proposal be accepted.

9. Comparison Summary: The following matrix summarizes the two upgrade alternatives.

<u>Element</u>	<u>PG&E Proposal</u>	<u>Western Project</u>
Facilities	two 115 kV lines, 159MVA	single circuit, 230 kV line, 325 MVA, using existing Tesla line for redundancy/standby
Costs	\$654,000/year	\$281,600/year
Reliability Provided	Instantaneous reliability; short-term and long-term reliability	No instantaneous reliability; short-term and long-term reliability
Planning Flexibility/Alt Access	Not Applicable	Potential access to less expensive power
Present Value of Savings (losses):		
1 Current Source Mix	\$(0.25) million	\$3.1 million
2 COTP Wheeling	\$ 8.5 million	\$9.9 million
3 3rd Party Power	Not Applicable	\$5.6 million

* Note: The scenarios for the economic analysis are based on a time period of FY 1989 to FY 2001.

A COMPARISON OF
THE PG&E TESLA TRANSMISSION PROPOSAL WITH
THE WESTERN TRACY TIE LINE PROJECT

Introduction

The purpose of this report is to briefly review Pacific Gas and Electric Company's (PG&E) proposal to upgrade transmission connections from its Tesla Substation to the Lawrence Livermore National Laboratory (LLNL) and compare the proposal with the planned construction by the Department of Energy's Western Area Power Administration (Western) of a transmission line from its Tracy Substation to LLNL. The existing PG&E transmission interconnection is described as are the Western and PG&E transmission proposals. The comparative reliability of the two proposals is examined and other operational considerations are discussed. Additional transmission, substation and distribution facilities required under the two proposals are also discussed. The comparative economics of the two proposals is then examined in some detail. Finally, the preferred proposal is identified and recommended with some discussion of possible contingencies affecting reliability and operations. The criterion used for the selection recommendation is based on an evaluation of what was determined to be in the best long term interest of DOE's mission at LLNL and the DOE.

Explanation of Proposals

In order to properly understand the discussion of comparative reliability and operational considerations, it is helpful to consider the basic features of each of three possible transmission interconnections as illustrated in the attached Figures 1, 2, and 3.

1. The Existing Interconnection.

LLNL is currently connected to PG&E's Tesla Substation through a single circuit 115 kV transmission line and a single circuit 230 kV transmission line. The 230 kV transmission line serves only the pulsed power substation dedicated to a magnetic fusion experimental project. This line has a thermal rating of over 300 MVA, but the isolated pulsed power substation includes only 120 MVA of transmission capacity in two identical 60 MVA transformers. The phase angle configuration of the transformer primaries and the absence of other 230 kV facilities make the 230 kV line incompatible with the existing power distribution system at the LLNL site.

With the exception of the pulsed power substation, power service is provided by PG&E (including Western CVP power) for all of LLNL through

FIGURE 1

EXISTING LLNL TRANSMISSION FACILITIES

KEY: EXISTING _____

**NOTE: THIS DRAWING IS A REPRESENTATION FOR PUPOSES OF ILLUSTRATION.
IT IS NOT TO SCALE OR GEOGRAPHICALLY ACCURATE.**

the 115 kV transmission line. This 115 kV line was recently upgraded by PG&E to replace an old 115 kV line along a similar path which was limited to 56 MVA during the summer peak. At the time that this line was upgraded, a potential backup line to PG&E's Newark Substation, southwest of LLNL, with a summer rating of approximately 50 MVA, was taken out of service. The new 115 kV line to Tesla has a summer peak rating of approximately 159 MVA. The line was originally a tap off of the PG&E Tesla to Solado transmission line, but in December 1987 PG&E reconfigured its system so that the line is a radial transmission line from Tesla into LLNL. For most of the route from Tesla to LLNL, the 115 kV line is carried on the opposite side of the same transmission towers that carry the 230 kV pulse power substation line.

The existing PG&E transmission interconnections with LLNL do not involve any specific facilities payments by DOE. The transmission service remains in place on the basis of payment by DOE for retail capacity and energy purchased from PG&E and payment by Western for wheeling of Central Valley Project (CVP) CRDs to LLNL. PG&E may at any time replace or upgrade transmission or substation facilities, and attempt to obtain upfront contributions in aid of construction or long-term commitments to minimum power takes by LLNL.

2. PG&E Tesla Transmission Proposal.

PG&E's proposal really involves two primary components. First, the old 115 kV transmission line from the Tesla Substation, which was replaced as described above, would be renovated and upgraded. The improvements included replacement of some existing conductor and facilities, and a second 2/0 copper conductor would be strung on the other side of the wood poles supporting the existing 2/0 copper conductor. The new conductor would be operated in parallel with the old conductor to provide a second transmission line from Tesla to LLNL. Second, the connection of the current 115 kV transmission line and the renovated old 115 kV transmission line would be reconfigured at the Tesla Substation. Under this reconfiguration each line would be connected to a separate 115 kV bus at the Tesla Substation. Each 115 kV bus would be connected through a separate 230/115 kV transformer to the same 230 kV bus. The 230 kV bus can be sectionalized for maintenance or outages so that at least one of the 115 kV lines could continue to be energized. The two 115 kV lines would be operated in parallel into LLNL to provide "loop" service from the 230 kV bus. With this loop service transmission service would continue to be provided to LLNL even in the event of an outage on one or the other 115 kV lines.

In addition to these two principal components of the PG&E proposal, an upgrade of the old 115 kV transmission line from Newark to LLNL is also contemplated to provide 112 MVA of standby transfer capacity. This third transmission line would not be operated in parallel but would, with appropriate substation additions and modifications by LLNL, provide an emergency standby transmission line in the event of an

FIGURE 2

EXISTING AND PG&E PROPOSED LLNL TRANSMISSION FACILITIES

KEY: EXISTING _____
PROPOSED PG&E - - - - -

**NOTE: THIS DRAWING IS A REPRESENTATION FOR PUPOSES OF ILLUSTRATION.
IT IS NOT TO SCALE OR GEOGRAPHICALLY ACCURATE.**

outage of the Tesla 230 kV system or a double contingency outage of both of the Tesla to LLNL 115 kV transmission lines.

The PG&E proposal would not increase the power transfer rating over the existing 159 MVA line; although the proposal does state that 300 MVA of 230/115kV transformation capacity would be reserved. The PG&E proposal provides for a higher transfer capacity of 300 MVA subject to additional payments by DOE. This additional capacity exceeds any planned future requirements at LLNL.

The PG&E proposal requires payments by DOE of not more than \$737,000 per year for the life of the facilities (i.e., 50 years). To provide 300 MVA of transfer capability instead of the contemplated 159 MVA would involve annual payments of not more than \$1,350,000 per year. It should be noted that these not to exceed limits are conditioned upon a 50 year deal and LLNL continuing to buy comparable amounts of PG&E power. The necessary switching facilities will be constructed by LLNL to take proper advantage of the proposed PG&E loop service (or the Western service). Construction by PG&E of the other substation and distribution improvements contemplated in the Western project would involve additional upfront payments or increased annual payments over and above the ones already described. DOE ownership of these distribution facilities, if built by PG&E, is probably only possible with an even larger upfront payment by DOE.

3. Western Transmission Line to Tracy.

Current plans call for Western to construct a single circuit 230 kV transmission line from its Tracy Substation to LLNL. The 230 kV bus at Tracy is sectionalized so that the 230 kV transmission line can continue to be energized in the event of an outage of either of the 230 kV Western lines coming into the Tracy Substation. The Tracy Substation will be further reinforced upon construction of the California-Oregon Transmission Project, Third AC Intertie Upgrade, by a 500 kV AC transmission line coming into Tracy and one or more 500 kV AC ties to the Tesla Substation.

The proposed Tracy tie line will have a rating of 325 MVA, which exceeds any planned requirements at LLNL. The Western proposal involves a 230/115 kV transformer at the LLNL substation so that the existing 115 kV system supplied by PG&E would continue to be operational. The Western project also involves considerable additional substation and on-site distribution facilities (i.e., underground 13.8 kV distribution) at the LLNL site.

The proposed Western Tracy tieline would require payments of \$281,600 per year for the life of the project, and includes all facilities from Tracy to LLNL. The additional on-site distribution facilities would be included as part of the project at no additional cost to DOE/SAN.

FIGURE 3

EXISTING AND WESTERN PROPOSED LLNL TRANSMISSION FACILITIES

KEY: EXISTING
WESTERN PLANNED

NOTE: THIS DRAWING IS A REPRESENTATION FOR PUPOSES OF ILLUSTRATION. IT IS NOT TO SCALE OR GEOGRAPHICALLY ACCURATE.

Comparative Reliability

Reliability consists of both adequacy and security. All three of the alternatives described above provide sufficient adequacy of power supply resources and transmission transfer capacity, although the Western plan provides more transmission transfer capacity. Security has to do with the frequency, severity and duration of outages in the transmission and substation facilities. In order to properly consider the comparative security of the potential transmission interconnection, it is necessary to consider three regimes of reliability: instantaneous, short-term, and long-term. A transmission interconnection with instantaneous reliability would allow LLNL loads to continue to be served without interruption even if one of the transmission interconnections were momentarily or permanently interrupted. Instantaneous reliability requires more than one transmission feed, and requires instantaneous switching facilities either to transfer LLNL load from interrupted transmission to alternate transmission, or to remove any one of several simultaneously energized transmission connections upon an outage. Instantaneous reliability does not necessarily eliminate transients in voltage and current. To do so would require an Uninterrupted Power Supply system.

Short-term reliability would allow LLNL loads to continue to be served from an alternate or standby transmission connection in the event that the primary interconnection is interrupted for several minutes, hours, or even days, for maintenance or due to facilities failures. It is possible to have short-term reliability without instantaneous reliability. That is, the LLNL loads could be interrupted when the primary transmission feed is interrupted, but quickly reenergized through the alternate or standby feed. Any scheme having instantaneous reliability is likely to provide for short-term reliability.

Long-term reliability would involve the provision for LLNL loads to be served by an alternate transmission interconnection in the event that the primary transmission interconnection becomes nonviable. While long-term reliability may, in some cases, simply be an extension of short-term reliability, it also involves strategic factors. That is, a transmission connection may become nonviable for institutional or economic as opposed to technical reasons. Reliability would be obtained if LLNL has not only long-term technical reliability, but also viable options for the delivery of alternative power supply resources. It is possible to have long-term technical or strategic reliability without instantaneous reliability. Short-term reliability, as described above, does not necessarily result in long-term technical or strategic reliability. With these simplified concepts in mind, it is now possible to consider the relative reliability of the transmission interconnection options for LLNL enhanced electric service.

1. Existing Transmission.

The existing transmission interconnection, involving a single 115 kV transmission line from the Tesla substation, does not provide instantaneous, short-term, or long-term reliability. Any momentary or prolonged outage of the transmission interconnection will result in a corresponding outage of LLNL loads. Adequate reliability can only be achieved through the construction of new facilities.

2. PG&E Tesla Transmission Proposal.

The PG&E proposal provides for instantaneous, short-term, and long-term technical reliability, but not for long-term strategic reliability (i.e., does not provide for an alternate source of power that may be required in the future for institutional or economic reasons). A major outage of the Tesla 230 kV bus would be required for a momentary or short-term interruption of LLNL power service or a simultaneous outage of the energized two 115 kV lines would be required to interrupt LLNL loads. The PG&E proposal does not provide strategic reliability because it involves LLNL continuing to be served CVP, COTP or PG&E power only through PG&E transmission facilities.

3. Western Transmission Line to Tracy

The basic design of the Western Transmission Line to Tracy does not provide instantaneous reliability if Tracy and Tesla cannot be operated in loop configuration. It does, however, provide short-term reliability and long-term reliability, including strategic reliability; as long as the existing PG&E 115 kV line to Tesla remains in service. Furthermore, LLNL is planning to construct additional facilities, for automatic switching to serve LLNL loads with instantaneous reliability by utilizing the Tesla and Tracy transmission lines as a form of loop service. The Western proposal provides somewhat greater long-term reliability because it provides for service from two independent transmission sources.

4. Additional Aspects of Comparative Reliability.

It is also helpful to consider three portions of the transmission interconnection to better understand reliability: (1) supplier's substation, (2) the transmission line, and (3) the LLNL substation. The Tesla Substation is a major substation on the "backbone" transmission system of PG&E. It should have acceptable short-term and long-term (other than strategic) reliability. The instantaneous reliability will be dependent on the amount of switching and other disturbances at the 500 kV and 230 kV levels which may impact the sectionalized 230 kV bus supplying the two 115 kV transmission lines to

LLNL. While not currently as strongly interconnected with the "backbone" California transmission grid as Tesla, Western's Tracy Substation is a major substation which has not been subject to outage at the 230 kV level in more than a decade. Service to LLNL from the Tracy 230 kV bus should provide acceptable short-term and long-term reliability. Instantaneous reliability may be obtained when LLNL installs the planned substation switching facilities and if the Tracy tie line and the PG&E Tesla transmission line can be operated as loop service. In the future, as the COTP Third AC Intertie Upgrade is completed, the strength and reliability of the Western 230 kV bus at Tracy will be comparable to that of the PG&E 230 kV bus at Tesla. This is because Western will have 500 kV transmission directly into Tracy, and will have much stronger 500 and 230 kV ties to Tesla.

It is to be expected that the technical reliability of PG&E's 115 kV transmission line and Western's 230 kV transmission line would be comparable. They are of similar length and routed over similar terrain subject to identical weather conditions. It would not be likely that the Tracy tie line would experience outages any more often or for any longer duration than either of the PG&E Tesla transmission lines.

The reliability of the LLNL substation facilities will not be a direct function of whether the PG&E proposal or the Western plan is pursued. In fact, the overall instantaneous, short-term and long-term technical reliability will be the same for the Western plan as for the PG&E proposal so long as the existing 115 kV line remains in service. If LLNL is prepared to invest in the additional substation switching facilities necessary to take advantage of instantaneous reliability offered by the PG&E proposal, similar facilities could be constructed to result in equivalent instantaneous and short-term reliability for the Western plan utilizing the PG&E 115 kV transmission line with the new Western 230 kV line.

Other Critical Facilities and Operational Considerations

There are several other critical facilities and operational considerations that bear upon the comparison of the Western plan and the alternative PG&E proposal. The most important of these factors are discussed in this section.

1. Additional Facilities.

The PG&E proposal will involve additional facilities improvements for 300 MVA transfer capability instead of the base case 159 MVA. The

annual payments would then be \$1,350,000 instead of \$737,000.

The additional substation switching facilities needed to take advantage of instantaneous reliability are already planned for construction by LLNL. PG&E has not proposed any of the LLNL on-site distribution system improvements contained in the Western project plan. PG&E would construct and own these improvements for an upfront contribution in aid of construction or a continuing annual ownership charge equal to 20.76 percent of the capital cost. DOE could own the improvements for an upfront payment equal to 128 percent of the capital costs.

The Western project will involve additional facilities improvements only if instantaneous reliability is desired through automatic switching of the 230 kV and 115 kV lines. The cost of additional facilities would be no more than the range given above for the cost of automatic switching under the PG&E proposal. However, for both proposals, it is assumed that LLNL will install the required switching capability.

2. Instantaneous Reliability

While it is possible to talk about instantaneous reliability, any momentary interruption or other disturbance on any PG&E transmission lines into LLNL will cause some fluctuation in voltages and currents at LLNL. It may well be the case that, even though either proposal could result in instantaneous reliability, these voltage and current fluctuations and/or the electromagnetic transients would still cause outages of LLNL critical loads, most notably computer loads.

3. Loss Differentials and Transfer Capabilities.

The Western 230 kV transmission line will have 30 to 40 percent less transmission loss than will the PG&E transmission lines under the same power transfer circumstances. Furthermore, while the Western transmission plan only contemplates redundant transfer capacity up to the 159 MVA capacity of the existing PG&E Tesla line, nonetheless it does provide immediate capacity for load growth without DOE expending additional funds. The PG&E proposal will require additional investments or annual fees for load growth above 159 MVA.

4. PG&E Standby for the Tracy Tie Line.

Since the redundant capability of the Western proposal is dependent on the continued operation of PG&E's Tesla line, a critical issue in the comparison of the two proposals is whether and at what cost PG&E will provide emergency standby transmission service over its Tesla line.

PG&E's contractual and franchise obligations means PG&E must keep its Tesla line energized and that it must provide standby transmission for LLNL's Western preference power as long as LLNL continues to take supplemental power from PG&E under its retail tariff. Moreover, the provision of standby transmission for Western power will cost nothing, except the cost that is already incurred for actual transmission during those times when the Tracy tie line is down for purposes of maintenance or due to a forced outage.

At the time that the 230 kV Western line is completed, LLNL will still be purchasing retail power from PG&E as well as CVP preference power from Western. PG&E is under an obligation to provide service to LLNL under its retail tariff and to maintain adequate transmission capacity to do so. With the 115 kV transmission line rated at 159 MVA, it is not likely that PG&E will have inadequate capacity for some time. In addition to its retail service obligations, PG&E is also required to support and wheel CVP preference power under its Contract 2948A with Western, and it must utilize any available "excess" capacity to do so. Again, with 159 MVA of new 115kV capacity in place, PG&E is not likely to be able to refuse to provide the necessary standby service even if all power is ordinarily delivered to LLNL over the Western 230 kV line.

PG&E's obligations mean that PG&E must continue to wheel Western preference power under a standard, FERC-approved tariff when the Tracy tieline fails or is out of service for maintenance. There is little likelihood in our judgement that PG&E can evade this obligation just because the Western line is built, especially if PG&E continues to serve LLNL under its retail tariff. If and when PG&E retail service to LLNL is displaced, then it becomes reasonable to expect PG&E to be able to charge DOE for transmission standby service on a ratcheted or contract demand basis. However, we believe there will be a clear limit to the rate PG&E will be allowed to charge for its standby service under FERC regulated rates.

It is unlikely that FERC will allow PG&E to charge more for transmission standby than the \$1.433 per kW-month it currently charges Western for firm wheeling over the same facilities. That is, PG&E surely cannot charge more not to wheel than it now charges to wheel. Further, PG&E currently provides firm wheeling to NCPA cities under the NCPA integration agreement for \$1.134 per kW-month, or 30 cents less than the charge for actual wheeling of Western preference power, and we believe it is highly unlikely that the FERC would authorize a higher rate for similar service to LLNL. Finally, PG&E has provided a preliminary \$529,000 estimate of its annual standby costs, based on the carrying costs of the facilities that would be involved. That would translate into a charge of \$.73 per kW-month at a 60 mW LLNL load. These costs will become important only when DOE faces the decision whether to displace most or all of PG&E's retail sales to LLNL. For purposes of the comparative economic analysis to follow, we will use a cost of \$.90 per kW-month, which is approximately the midpoint in the range of \$.73 to \$1.13 per kW-month.

5. Load Segregation at LLNL.

It is possible, but not at all likely, that all Western power would be delivered over the new 230 kV line and all PG&E power would be delivered over the existing 115 kV line. This would require that the LLNL loads be split if in fact the two lines cannot be operated in parallel because of loop flow. However, even if the two lines cannot be operated in parallel, the segregation of loads and power flow mentioned above will not be necessary. All of LLNL's load could be supplied over the Western 230 kV line with the PG&E 115 kV line as "hot" standby (i.e., energized but not connected unless the Western line is out). This might be preferable to maximize the Western CRD energy under the "X over Y" billing algorithm as compared to segregating load.

In this regard, it is critical to note that PG&E's obligations under its retail service certificate in combination with Contract 2948A remain the same whether there is a single Western line, a single PG&E line, or both. Certainly the existence of both lines would allow a straightforward resolution.

Comparative Economics

In this section we evaluate and compare the potential savings to DOE/SAN and to the U.S. Government that are associated with the PG&E Tesla Transmission proposal and the Western Tracy Tie Line Project. These savings for each alternative will be examined under each of three LLNL supply scenarios for the time period of FY 1989 to FY 2001:

1. No change in the resource mix at LLNL;
2. Maximizing the savings from wheeling Western and COTP power to the DOE laboratories; and
3. Including 3rd-party resources to displace PG&E power.

The economic analysis shows that the potential savings associated with the Western proposal exceeds the savings that are likely to be associated with the PG&E proposal. The following is a summary of the results of the comparative savings analysis:

1988 Present Value of DOE/SAN Savings

	PG&E Proposal	Western Proposal
Scenario 1	-\$251,000	\$3,078,000
Scenario 2	\$8,516,000	\$9,951,000
Scenario 3	N/A	\$5,600,000

1. Key Assumptions.

We have undertaken the comparison by incorporating identical critical assumptions when estimating the potential savings for both options. These assumptions are as follows:

- o Time Period: The analysis is based on fiscal years, ending on September 30, from 1989 to 2001. All changes in resource availability and transmission options are assumed to occur at the beginning of a fiscal year for the sake of simplicity.
- o PG&E Facilities and Costs: The proposed PG&E facilities include modifications at the Tesla Substation and an existing 115 kV, 159 MVA line and operated in parallel with an upgraded 115 kv, 112 MVA line, which will provide loop service; at a total cost to DOE/SAN of \$654,000 per year.
- o Western Facilities and Costs: The Western project includes a new 230 kV, 300 MVA, line; a new substation at LLNL, on-site 13.8 kV distribution system; at a total cost to DOE/SAN of \$281,600 per year.
- o Western CRDs: All current Western CRDs (88 mW) remain in place through FY 1990. Effective October 1, 1990, DOE/SAN losses the Air Force allocation, and all withdrawable and diversity allocations are eliminated. Thus, the total DOE/SAN Western CRD falls to 48 mW on October 1, 1990.
- o COTP Operation: The COTP commences full operation on October 1, 1991. DOE/SAN will have access to 90 mW of Northwest power delivered at the meter. The cost of COTP power was not included in this analysis.
- o Load Forecasts: DOE laboratory loads are those forecast by the laboratories, which are currently in affect and appear in the November 1987 entries in the DOE/SAN Laboratory Monitoring Notebook. We have used LLNL's lower Scenario #1 forecasts. These forecasts are provided in Table 4.1.

- o Constant Prices: All rates, costs and savings estimates are developed in constant 1988 dollars. Savings streams are estimated from FY 1989 through FY 2001. Net savings streams are restated in 1988 present value terms based on an assumed 5 percent discount rate that is chosen to reflect the real cost of money to the U.S. Government, exclusive of inflation.
- o Wheeling Charges: PG&E's rate for wheeling Western is \$1.433 per kW-month, and its assumed rate for wheeling COTP power is \$2.09 per kW-month.
- o Western Losses: The reduction in losses from wheeling Western and COTP power over the Tracy tieline are estimated at 4.2 percent, and are valued at 32.58 mills per kWh (the current arrangement between PG&E and Western). These savings for the Western CRDs of 36,415 kW are incorporated into the annual carrying charge that is proposed by Western. These same savings were assumed for losses associated with the wheeling of COTP power.
- o Displaced PG&E Sales: It is assumed that power can be obtained from a 3rd party (non-COTP) for delivery to LLNL at a minimal savings of \$5 per MWh.
- o Standby Costs: It is assumed that emergency transmission standby service can be obtained from PG&E for \$0.90 per kW-month. It is assumed that no such standby charges will be required until COTP or 3rd-party power largely displaces PG&E retail sales to LLNL in their entirety.

2. Scenario 1: No Change in LLNL Resource Mix.

Under this scenario no change in LLNL's resource supply mix occurs. LLNL's Western CRD is held constant at the current level of 36,415 kW throughout the study period. This would require shifting firm CRD from Site 300 and/or SLAC after 1990. It is assumed that PG&E continues to provide the remainder of LLNL's load with supplemental service under its E-20 firm power rate schedule. Therefore, no standby charge will be involved, and PG&E would be required under Contract 2948A to wheel Western CRD to LLNL under emergency conditions at the \$1.433 per kW-month rate set by the FERC.

The results are presented in Table 1. The only savings that would result under either proposed arrangement would be the \$626,000 a year resulting from the elimination of the PG&E wheeling charge for LLNL's Western power. Under this "no-change" scenario, the PG&E savings are negative because the annual carrying charge would exceed the annual wheeling savings. The present value of the savings are -\$251,000 at the lower PG&E facilities charge of \$654,000, which excludes the cost of the Newark upgrade. The present value of savings under the Western arrangement is \$3,078,000.

TABLE 1

Comparison of Savings
PG&E and Western Transmission Proposals

Scenario 1: No Change in LLNL Resource Mix
(\$1,000s)

Net Savings

Fiscal Year (1)	Wheeling Savings (2)	PG&E Cost <u>a/</u> (3)	Western Option <u>b/</u> (4)
1989	\$626	(\$28)	\$344
1990	626	(28)	344
1991	626	(28)	344
1992	626	(28)	344
1993	626	(28)	344
1994	626	(28)	344
1995	626	(28)	344
1996	626	(28)	344
1997	626	(28)	344
1998	626	(28)	344
1999	626	(28)	344
2000	626	(28)	344
2001	<u>626</u>	<u>(28)</u>	<u>344</u>
TOTAL	\$8,138	(\$364)	\$4,472
1988 Present Value at 5% Discount		(\$251)	\$3,078

a/ Annual carrying charge of \$ 654,000.

b/ Annual carrying charge of \$ 282,000.

Thus, the Western proposal is superior in terms of the associated savings if LLNL were only to continue meeting its power supply requirements with the same mix of resources it currently uses.

3. Scenario 2: Maximizing Western and COTP Wheeling Savings.

Scenario 2 assumes that the COTP is in operation and that available resources to DOE/SAN will be allocated among the several labs so as to maximize the net savings associated with eliminating the costs of wheeling power to LLNL. For purposes of our analysis, we have assumed 90 mW of Northwest firm power be will available at the meters for the DOE laboratories. The 90 mW exceeds the forecast peak demand at LLNL for each year in our study. Since the assumed wheeling charge for COTP is \$2.09 per kW-month, or \$0.657 higher than the PG&E wheeling charge for Western power, the savings from the PG&E proposed arrangement will be highest if LLNL is served entirely with COTP power, beginning in 1992 when it planned to become available.

Prior to 1992, savings will be maximized under the PG&E proposal by shifting as much Western power as possible to LLNL. Since we have assumed the diversity and withdrawable CRDs will be available in 1989 and 1990, there are limits to the amount of Western power that can be moved to LLNL in those years, without losing CRDs. We are sure that the 3,000 kW at Site 300 could be moved to LLNL. However, since LLNL cannot use diversity power, and since none of the firm power at SLAC could be moved without violating the Diversity Agreement with Western, additional power could be shifted only if total Western CRDs were reduced during 1989 and 1990. In fact, our evaluation of the associated wheeling savings indicates that it would be advantageous to do so under PG&E's proposal, as long as DOE knew with certainty that the withdrawable and diversity power would be lost in 1991 in any event, and as long as PG&E's interruptible E-20 rate did not rise significantly compared to its firm E-20 rate. Thus, we assumed that under the PG&E proposal, the entire LLNL load will be met by Western power in 1989 and 1990. In 1991, the entire remaining long-term firm CRD of 47,800 kW will be placed at LLNL. Then, beginning with 1992, LLNL loads would be met entirely by COTP power and the remaining Western CRD would be placed at the other laboratories.

The estimated savings associated with the PG&E proposal under Scenario 2 are presented in Table 2. The 1988 present value of the associated savings stream is \$8.5 million at the lower PG&E facilities cost of \$654,000 a year.

The savings to DOE/SAN under Scenario 2 associated with the Western arrangement are presented in Table 3. For this scenario, it will be of benefit to DOE to avoid PG&E standby charges until the COTP comes on line. Therefore, we have assumed that 36.415 mW of Western CRD remains at LLNL in 1989, 1990 and 1991. Beginning in 1992, the entire LLNL load could be met with COTP power, and the remaining Western CRD would be placed at the other laboratories.

TABLE 2

Savings Under the PG&E Proposal

Scenario 2: Maximum Wheeling Savings
(\$1,000s)

Fiscal Year (1)	Western Wheeling <u>a/</u> (2)	COTP Wheeling (3)	Net Savings <u>b/</u> (4)
1989	\$1,049	\$ 0	\$395
1990	1.101	0	447
1991	822	0	168
1992	0	1,705	1,051
1993	0	1,731	1,077
1994	0	1,731	1,077
1995	0	1,781	1,127
1996	0	1,831	1,177
1997	0	1,906	1,252
1998	0	1,956	1,302
1999	0	1,981	1,327
2000	0	2,031	1,377
2001	<u>0</u>	<u>2,082</u>	<u>1,428</u>
TOTAL	\$2,972	\$18,735	\$13,205
1988 Present Value at 5% Discount			\$8,516

a/ Western CRD at LLNL is 61 mW in 1989, 64 mW in 1990, and 47.8 mW in 1991.

b/ Annual facilities charge is \$654,000.

TABLE 3

Savings Under the Western Proposal

Scenario 2: Maximum Wheeling Savings
(\$1,000s)

Fiscal Year (1)	Western Wheeling Savings (2)	COTP Wheeling Savings a/ (3)	Additional Reduced Losses b/ (4)	Standby Charges c/ (5)	Net Savings d/ (6)
1989	\$ 626	\$ 0	\$ 0	\$ 0	\$ 344
1990	626	0	0	0	344
1991	626	0	0	0	344
1992	0	1,705	570	734	1,259
1993	0	1,731	583	745	1,287
1994	0	1,731	585	745	1,289
1995	0	1,781	614	767	1,346
1996	0	1,831	638	788	1,399
1997	0	1,906	673	821	1,476
1998	0	1,956	698	842	1,530
1999	0	1,981	724	853	1,570
2000	0	2,031	748	875	1,622
2001	<u>0</u>	<u>2,082</u>	<u>775</u>	<u>896</u>	<u>1,679</u>
TOTAL	\$ 1,878	\$18,735	\$6,668	\$8,066	\$15,489

1988 Present Value at 5% Discount

\$ 9,951

a/ Full LLNL load met with COTP beginning 1992.

b/ (.955)(.042)(gWh at LLNL) (PG&E rolled-in rate). The rolled in PG&E rate used is \$55 per mWh. The value of reduced losses is lowered by \$326,000 each year, which is the loss reduction accounted for in the annual \$282,000 facilities charge.

c/ PG&E standby charge is \$.90 per kW-month.

d/ Includes annual facilities charge of \$282,000.

The savings shown in Table 3. assumes that the loss differential from wheeling COTP power over PG&E and Western lines is the same 4.2 percent that applies to the wheeling of Western power. We have no other basis for estimating this differential since PG&E was unable or unwilling to indicate even the conceptual method by which it would estimate losses.

If 4.2 percent fewer losses are experienced over the Tracy line as opposed to wheeling over PG&E lines, then there will be additional energy to be used elsewhere to displace PG&E energy. The amount of this energy is estimated as .042 times the COTP energy used at LLNL. This is reduced by 4.5 percent to reflect the losses that will be extracted when PG&E wheels this energy to a different lab.. The value of this energy is the cost of PG&E energy that is displaced, since DOE will have already paid for that power to be delivered to the Tracy substation. We have used \$55 per MWH, which is the average cost of PG&E energy in FY 1987 at all of the labs. This includes much less expensive interruptible power at LBL1 and SLAC, and so is a lower bound estimate of the 1988 price. For example, the average 1987 cost at LBL2 was \$68 per MWH. This same price has been used in all the outyears, which assumes there will be no change in the real PG&E price. When Diablo is placed in rate base, one can expect an increase from between 10 percent and 20 percent, which again would place the 1988 cost somewhere between \$60 and \$66 per MWH.

The 1988 present value of the resulting stream of net savings are estimated at \$9.9 million for Scenario 2. This exceeds by nearly \$1.4 million the present value of the savings associated with the PG&E proposal for Scenario 2.

4. Scenario 3: 3rd-Party Power Displacement of PG&E

Under Scenario 3 we entertain the possibility of importing non-COTP power from a 3rd-party such as the Department of Water Resources (DWR) or NCPA to displace PG&E retail sales at LLNL. This would leave the entire Western and COTP power allocations available to meet the requirements of the other labs. The annual peak demands and energy requirements for each laboratory are presented in Table 4.1 for each fiscal year 1989 through 2001. Table 4.2 shows the residual load that must be served by PG&E or a 3rd-party supplier after Western and COTP power is fully utilized. This residual load defines the maximum opportunity to displace PG&E retail sales.

Evaluation of DOE/SAN options under this scenario indicates that the largest savings can be realized by using the Tracy tie line to displace PG&E power, when the savings from such displacement amount to the assumed \$5 per MWh. We are firmly convinced that that figure is a conservatively low estimate of the potential savings that will be achievable, and so the resulting PG&E displacement savings estimates should be viewed as conservatively low. There is almost no likelihood that PG&E would permit the wheeling of 3rd-party power under its proposed arrangement, and so we need examine only the Scenario 3

savings associated with Western's proposal.

The savings estimates are presented in Table 4.3. For the first three years savings would again be limited to avoiding Western wheeling charges because it is unlikely that arrangement could be made for the delivery of 3rd-party resources before 1992. Beginning in 1992, COTP and 3rd-party sources are used to meet LLNL requirements. By 1995, with the growth of load at SLAC, there is sufficient combined residual load to allow the entire LLNL load to be met with 3rd-party power. The savings are based on a conservative \$5 per MWh of displaced PG&E power. In addition, PG&E standby costs of \$.90 per kW-month would begin in 1992 with the displacement of PG&E.

There would be no Western CRD at LLNL, and so the reduced losses from avoiding PG&E wheeling of Western power would not be realized. Since the \$326,000 annual savings was accounted for by reducing the annual Western facilities charge, it needs to be added back in to determine the net savings. This calculation, when discounted back to 1988, results in a net present value of savings of approximately \$5.6 million.

We noted above that this should be viewed as a conservatively low estimate of the potential savings to be associated with displacing PG&E retail sales. Moreover, the present value of the net savings to the Federal Government will increase by a much larger percentage than the increase in the savings per kWh. For example, if the savings is \$7.50 per MWh, the 1988 present value of the U.S. Government's savings will exceed \$8 million.

We should also note that these savings need not actually result from the displacement of PG&E retail service by a 3rd-Party supplier. Instead, PG&E could displace its own retail service by offering some kind of special bypass rate discount. This is allowed under PG&E's CPUC tariff, as long as the customer (and PG&E) can make a showing that PG&E will lose retail load in the absence of such a discount, and as long as the resulting rate is above PG&E's marginal cost of service. The spread between PG&E average embedded cost-based rate and its marginal costs will increase when any significant portion of the Diablo plant is included in rates. Thus, the magnitude of the potential discount will also increase. However, DOE will be unable to show that it has alternatives if it accepts the PG&E Tesla offer, because it will remain a captive retail customer of PG&E. The Tracy tie line will permit real negotiations with PG&E and likely acceptance by the CPUC of a discounted retail rate, because DOE will always have the option of using the Tracy line to displace PG&E sales with 3rd-Party power over and above its COTP and Western allocations.

TABLE 4.1

DOE/SAN Laboratory Load Forecasts

Peak Demand in Megawatts

	LBL1	LBL2	LLNL	Site 300	SLAC	Total
1989	17	12	61	4	63	157
1990	17	13	64	5	63	162
1991	10	14	67	5	77	173
1992	17	15	68	5	77	182
1993	18	16	69	5	77	185
1994	19	17	69	5	77	187
1995	20	18	71	5	132	246
1996	21	19	73	5	132	250
1997	22	19	76	5	132	254
1998	22	20	78	5	132	257
1999	22	20	79	5	132	258
2000	22	20	81	5	132	260
2001	22	20	83	5	132	262

Energy in Gigawatt-hours

	LBL1	LBL2	LLNL	Site 300	SLAC	Total
1989	52	50	362	16	335	815
1990	53	53	377	17	335	835
1991	45	55	396	17	370	883
1992	45	66	406	18	370	899
1993	50	70	412	18	370	920
1994	52	75	413	19	370	929
1995	54	77	426	19	636	1,212
1996	54	78	437	20	636	1,225
1997	55	79	453	20	636	1,243
1998	55	80	464	20	636	1,255
1999	55	80	476	20	636	1,267
2000	55	80	487	20	636	1,278
2001	55	80	499	20	636	1,290

TABLE 4.2
Combined DOE/SAN Loads
and Western/COTP Deliveries

Fiscal Year	Megawatts			Gigawatt-Hours		
	Western DOE Load	Plus COTP	Residual	Western DOE Load	Plus COTP	Residual
1989	157	88	69	815	540	275
1990	162	88	74	835	540	295
1991	173	48	125	883	294	589
1992	182	138	44	899	767	132
1993	185	138	47	920	767	153
1994	187	138	49	929	767	162
1995	246	138	108	1,212	767	445
1996	250	138	112	1,225	767	458
1997	254	138	116	1,243	767	476
1998	257	138	119	1,255	767	488
1999	258	138	120	1,267	767	500
2000	260	138	122	1,278	767	511
2001	262	138	124	1,290	767	523

TABLE 4.3

Savings Associated with Western Proposal

Scenario 3: Displaced PG&E Sales
(\$1,000s)

Fiscal Year	Western Wheeling	COTP Wheeling <u>a/</u>	Displaced PG&E Sales <u>b/</u>	Standby Costs <u>c/</u>	Net DOE/SAN Savings <u>d/</u>
1989	\$626	\$ 0	\$ 0	\$ 0	\$344
1990	626	0	0	0	344
1991	626	0	0	0	344
1992	0	1,154	660	734	472
1993	0	1,129	765	745	541
1994	0	1,104	810	745	561
1995	0	0	2,130	767	755
1996	0	0	2,185	788	789
1997	0	0	2,265	821	836
1998	0	0	2,320	842	870
1999	0	0	2,380	853	919
2000	0	0	2,435	875	952
2001	<u>0</u>	<u>0</u>	<u>2,495</u>	<u>896</u>	<u>991</u>
TOTAL	\$1,878	\$3,387	\$18,445	\$8,066	\$8,718

1988 Present Value at 5% discount

\$5,623

a/ COTP power at LLNL is 46 mW, 45 mW and 44 mW in 1992, 1993, and 1994, respectively.

b/ Savings of \$5 per MWh for displaced PG&E sales.

c/ Assumed cost of \$.90 kW-month.

d/ Includes \$292,000 annual Western facilities charge and \$326,000 for lost CVP loss savings.

Conclusions and Recommendations

As a result of our analyses, it is concluded that both proposals provide the necessary redundancy/reliability required by DOE. The Western proposal is superior in terms of economics. It should be noted that the no change in LLNL resource mix scenario involves very little risk; thus the savings estimated are likely to occur. The COTP wheeling savings scenario, on the other hand, involves a great deal of risk. Given the current situation, completion of the COTP is highly speculative; thus any savings related to the COTP must be examined carefully. Finally, the Western proposal is superior in terms of planning flexibility. With the uncertainty of the COTP, planning flexibility becomes very important. Therefore, it is recommended that the Western proposal be accepted.

**PHASE I OF A FURTHER EVALUATION OF THE
ECONOMIC BENEFITS ASSOCIATED WITH
THE PG&E TESLA TRANSMISSION PROPOSAL IN
COMPARISON TO THE WESTERN TRACY TIELINE PROJECT**

PREPARED FOR:

**THE UNITED STATES DEPARTMENT OF ENERGY
SAN FRANCISCO OPERATIONS OFFICE**

DECEMBER 6, 1988

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EXECUTIVE SUMMARY

1. Background. PG&E has proposed to provide special transmission service through upgraded, redundant transmission lines to LLNL to substitute for a transmission line being constructed by Western. After an extensive comparative evaluation, DOE concluded that the Western project was more desirable and that it should proceed. DOE reaffirmed this decision after a subsequent re-evaluation at PG&E's request. PG&E has requested a further reconsideration of its revised and augmented proposal, and DOE has agreed to such a reconsideration.

2. The Analytical Approach. The re-evaluation of the PG&E proposal is to take place in two phases. Phase 1 will compare the PG&E proposal with the cost of all of the transmission facilities to be constructed by Western, including those that are transmission/transformation betterments intended to be used to improve distribution system reliability at LLNL, but excluding the distribution system facilities. If there is reason for a Phase 2 analysis to proceed, Phase 2 would compare the costs and benefits of the entire Western project with PG&E's proposal. For Phase 2, PG&E's proposal would be amended to include the distribution system facilities and the related transmission/transformation betterments.

3. The Report. Exeter Associates, Inc. and C.H. Guernsey and Company have been asked by DOE/SAN to recalculate the net savings to DOE/SAN that would result from the Western project and the PG&E proposal, based on the detailed specification of a Phase 1 analytical method that has been agreed to by DOE/SAN and PG&E. This report provides the results of these recalculated savings estimates and a brief discussion of certain additional benefits associated with the Western project that are not included in the quantitative comparison.

4. The Results. When the comparisons are based upon the real economic costs to the Government of both alternatives, excluding the sunk costs of the Western project, the net savings from the Western project exceed the net

savings from the PG&E proposal under three of the four scenarios examined, including the most likely base case or "business as usual" scenario. Higher savings are associated with the PG&E proposal only under the least likely scenario, which depends upon completion of the COTP. The expected value of the discounted stream of net savings is highest for the Western project under all reasonable assumed relative values of the probabilities of occurrence of the four scenarios. The expected value is higher for the PG&E proposal only if it is assumed that the probability of completion of the COTP exceeds 85 percent.

5. Other Western Benefits. Several important economic and reliability benefits are also provided by the Western project that are not accounted for in the Phase 1 quantitative comparison, and which are not provided by the PG&E proposal. These include improved reliability for the on-site distribution system at LLNL, certainty of terms and conditions, power supply planning flexibility through access to the Western transmission system, and certain rights in the Western line that afford the possibility of collecting rent for unused portions of the line and buying into any future extensions or upgrades of the facilities for economic or reliability reasons.

6. Conclusion and Recommendation. Exeter and Guernsey conclude that the Phase 1 results, even absent consideration of the intangible benefits of the Western project, reconfirm the economic superiority of the Western project. Therefore, Exeter and Guernsey recommend that DOE proceed with completion of the Western project.

PHASE I OF A FURTHER EVALUATION OF THE
ECONOMIC BENEFITS ASSOCIATED WITH THE PG&E
TESLA TRANSMISSION PROPOSAL IN COMPARISON
TO THE WESTERN TRACY TIELINE PROJECT

I. INTRODUCTION AND BACKGROUND

The purpose of this report is to assess the comparative economic benefits to accrue to the U.S. Department of Energy, San Francisco Operations Office (DOE/SAN) from: (1) the Western Area Power Administration (Western) project under which it would construct a 325 MVA, 230 kV tieline from its Tracy substation to the Lawrence Livermore National Laboratory (LLNL); and (2) the proposal by the Pacific Gas and Electric Company (PG&E) to provide special transmission service through upgraded redundant 115 kV feeds from its Tesla and Newark substations to LLNL that would be rated at 159 MVA. These two alternatives were initially evaluated by Exeter Associates, Inc. and C.H. Guernsey & Company in April 1988, both in terms of reliability and economics.¹ Exeter and Guernsey concluded that the Western proposal was marginally superior with regard to reliability, and significantly better with regard to both economics and power supply flexibility. After due consideration, DOE determined that both alternatives provide the necessary redundancy/reliability required by DOE, but that the Western proposal is superior in terms of economics.

¹"A Comparison of the PG&E Tesla Transmission Proposal with the Western Tracy Tie Line Project," C.H. Guernsey and Company and Exeter Associates, Inc., April 4, 1988.

Based on that evaluation, it was decided by DOE to proceed with the Western project. PG&E asked for a reconsideration based on what it viewed as certain errors in the analysis. PG&E's request was granted. DOE/SAN's conclusion was reviewed and it was found to be correct. The confirmed decision to proceed with the Western project was reported to PG&E in a July 8, 1988 letter to Richard A. Clarke, Chairman of the Board and CEO, from Joseph F. Salgado, Acting Deputy Secretary and Undersecretary, U.S. Department of Energy. Based on this decision, Western began to construct the Tracy tieline.

PG&E again appealed for an opportunity to revise and augment its prior best proposal for a further reconsideration. The DOE/SAN Manager met with Gregory Rueger, PG&E Senior Vice President, on August 12, 1988. It was agreed at that meeting that DOE would take another look at the comparative economics of the two alternatives, and that led to several meetings between DOE/SAN and PG&E staffs to establish a framework for a further review of PG&E's proposal and to obtain from PG&E revisions to or further elaboration of its original proposal. This process culminated in a November 3, 1988 letter from Jerald S. Scheinberg, DOE/SAN Utilities Program Manager, to Kirk Patterson and Mark Smith of PG&E, which set forth the assumptions, the input values and the analytical method that were agreed upon by PG&E and DOE/SAN, and also set forth certain commitments and additional information that would be required from PG&E before the analysis could proceed. PG&E provided this information in letters to Jerald S. Scheinberg, dated November 4, 1988, November 14, 1988 and November 22, 1988.

Exeter and C.H. Guernsey were asked by DOE/SAN to reestimate the net savings to be realized from the Western project and the PG&E proposal according to the specific and detailed Phase 1 analytical method that was agreed to by DOE/SAN and PG&E. This methodology, as well as the specification of certain critical input values and other assumptions, are spelled out in an October 27, 1988 document, a copy of which is provided in Appendix A.² This report provides the results of the reestimated savings according to the terms and conditions specified in Appendix A.

²"Reevaluation of PG&E's Electric Service Enhancement Proposal for LLNL: Assumptions, Input Values and Analytical Method," October 27, 1988 (Revised). Exeter and C.H. Guernsey have used the analytical method as specified by DOE/SAN in order to follow the letter of the agreement regarding the reconsideration of PG&E's proposal. This does not mean that Exeter and C.H. Guernsey believe their initial analysis was in error, or that either firm necessarily agrees with the Phase 1 methodology.

II. CHANGES COMPARED TO THE APRIL 1988 ANALYSIS

There are a number of important changes in the Phase 1 reconsideration analysis as compared to the analysis that was conducted in April 1988. To assist the reader in understanding how the reconsideration differs from the April 1988 evaluation, we shall identify and briefly explain the most important of these changes.

A. New Reliability Considerations

It was originally agreed that this reconsideration would be limited to a further look at only the economics of the two alternatives, since DOE's original conclusion was that both proposals provided acceptable redundancy/reliability. This view changed as a result of the approximate three-hour outage that was experienced at LLNL on October 13, 1988. As a result of a lightning strike shortly after midnight, PG&E lost both of the 115 kV buses at the Tesla substation that would feed LLNL under PG&E's redundant feed proposal, as well as a number of other parts of its 115 kV system. Thus, the LLNL outage would have been experienced under the PG&E proposal. However, Western's Tracy substation and its 230 kV system in general were unaffected and so service would not have been interrupted at LLNL under the Western project. The lesson is that: (1) a feed directly from the more robust 230kV system is likely to be more reliable than one from the weaker 115kV system, and (2) multiple feeds from electrically "independent" substations will be more reliable than multiple feeds from the same substation. Thus, for the PG&E proposal to provide acceptable redundancy/reliability that is comparable

to that provided by the Western project, it was agreed that a third line from PG&E's Newark substation should be reincluded in the analysis. Such a line was originally included in PG&E's proposal, but it was not incorporated in the analysis because, among other things, it was not designed to carry the full required 159 MVA. PG&E's revised proposal will include the Newark line, upgraded to 159 MVA. The additional capital investment cost for the upgrade (over and above PG&E's original proposal, including Newark) has been estimated at \$30,000 by PG&E.³

B. PG&E Annual Facilities Charge

PG&E capital costs are increased to \$3,580,000 from \$3,150,000 to include the original \$400,000 cost of the line from the Newark substation, plus the cost of the upgrade to 159 MVA, assuming the capital investment cost of the upgrade will be held to \$30,000 per PG&E's commitment. PG&E also proposes to lower its ownership charge to 17.4 percent per year from 20.76 percent per year. Combined, these two changes result in an annual PG&E cost of \$622,920.

C. Western Annual Facilities Cost

A number of changes are incorporated in the Phase 1 analysis that change the cost to the taxpayer of the Western project as compared to the cost used in the April 1988 evaluation. One of the most important changes is the

³November 22 letter from Kirk Patterson to Jerald S. Scheinberg.

inclusion in the cost of the Western project of all of the transmission-level equipment, including the non-reimbursable costs of certain transformation/transmission betterments that will permit certain distribution system improvements. Adding this equipment at its full cost raises the Western investment cost to \$8,643,900 which, along with the revised O&M estimate of \$76,016, raises the annual facilities cost to \$924,477.

This estimate will overstate the actual costs that would be incurred by the U.S. taxpayer by a decision today to complete the Western project. Western proceeded with the project in an expeditious manner once the decision had been made to pursue the Western alternative and was confirmed in July 1988 at high levels in DOE. Equipment was ordered, rights of way were obtained, land was purchased and construction was initiated. As a result, any decision to reverse the original judgment to accept the Western alternative will result in costs that cannot be recovered. Since the comparative analysis is intended to reflect the true cost to the taxpayer, it is only relevant to account for recoverable costs already incurred and the balance of funds to be expended from now until completion of the Western project. Incurred costs that cannot be recovered (i.e., sunk costs) will not be saved for the taxpayer by acceptance of the PG&E proposal. Based on costs to completion, the Western capital investment cost falls to \$3,940,087, which results in an annual facilities cost of \$460,539. These lower costs are set forth in Appendix A and, as it is also stated in that appendix, the economic analysis to follow will be conducted by first including and then excluding the sunk costs of the Western project.

D. Reduced Losses

Losses that are associated with wheeling CVP or COTP power to LLNL will be assessed at the rate of 0.3 percent by Western. This will result in savings compared to the 4.5 percent currently charged by PG&E for wheeling CVP power under contract No. 2948A. Western will pass on to LLNL the value associated with the reduced losses. The estimated reduction in losses was placed at just over 10,000 mWh and Western valued that energy at 32.58 mills per kWh, for an annual total credit to LLNL of \$326,000. This was accounted for in the April analysis by reducing the annual payment to Western by the amount of the credit. No similar adjustment was made for the PG&E proposal since there was no basis upon which to conclude that PG&E would forgive Western's contractual loss obligation under contract 2948A or pass the savings on to LLNL.

PG&E has indicated in its revised proposal that it will only impose losses of 0.7 percent on LLNL for wheeling CVP power. Western will continue to charge standard rates for LLNL's use of CVP power, which is based on the 4.5 percent contractual loss rate. Thus, PG&E would charge Western with the 4.5 percent rate and will "credit [LLNL's] account with the equivalent of 3.8 percent". These kilowatt-hours would be valued at Western energy prices, which PG&E indicated would be around \$32 per megawatt hour.⁴ If we use the

⁴Letter to Jerry Scheinberg from Mark J. Smith, November 4, 1988. Mr. Smith actually indicated that the price would be \$32/Gigawatt-hour, but we are sure he meant \$32 per megawatt-hour.

same 32.58 mills that is used by Western, then we can account for the PG&E energy credit by reducing the annual PG&E charges by \$295,000.⁵

A similar approach must be used to handle the proposed reduced losses that PG&E now proposes to impose for wheeling COTP power. In the April report we estimated the net savings associated with Western's Tracy tieline that resulted from the delivery of 4.2 percent more energy at DOE meters as compared to the assumed PG&E loss factor of 4.5 percent. Based on PG&E's revised proposal, the difference is now 0.4 percent -- that is, the difference between the loss factors that would be applied by PG&E and Western. That energy, after accounting for the 4.5 percent losses that would be assessed by PG&E when wheeling this power to other labs, would be valued at the estimated melded cost per MWh of PG&E power of \$55 per MWh that was used in the April 1988 report. Thus, the net savings on loss differentials associated with wheeling COTP power over the Western Tracy line as compared to the PG&E proposal are calculated as:

$$(.955) (.004) (\text{COTP MWh at LLNL}) \times \$55.$$

E. Period of Analysis

The April 1988 evaluation covered the period from FY 1989 through FY 2001. The Phase 1 reconsideration covers the period from FY 1990 through FY 2001.

⁵36,415 kW X .746 X 8760 X .038 X \$.03258 = \$294,617.

III. THE REVISED NET SAVINGS CALCULATIONS

Net savings will accrue to the U.S. Government from acceptance of the Western project or the PG&E proposal. These savings can result from three possible sources: (1) avoidance of PG&E wheeling charges; (2) reduction in losses assessed by PG&E when wheeling CVP or COTP power; and (3) displacement of PG&E power with less expensive power made possible, only under the Western project by direct access to the Western transmission system. From these savings must be subtracted the annual capital and O&M costs for the transmission upgrade and any standby charges that are likely to be incurred as a result of selecting the Western project. As is specified in Appendix A, the resulting net savings are estimated under four scenarios:

- Scenario 1: No change in the resource mix and no COTP
- Scenario 2: Maximum wheeling savings with COTP available in 1992
- Scenario 3: 3rd-Party power displacement of PG&E with COTP available in 1992
- Scenario 4: 3rd-Party power displacement of PG&E and no COTP

The present values of the net savings are presented below in Table 1 for each alternative under each scenario. The net savings are shown for the Western project based both on the total Phase 1 cost of facilities, including sunk costs, as well as on the Phase 1 costs to completion for the project.

TABLE 1

Summary of the 1989 Present Value of
Savings to the Government Based on Phase 1 Analysis
(\$1,000)

	PG&E Proposal	Western Project	
		With Sunk Costs	Costs to Completion
Scenario 1	\$ 2,641	\$ 248	\$ 4,352
Scenario 2	10,119	4,918	9,022
Scenario 3	N/A	7,240	11,344
Scenario 4	N/A	6,782	10,866

The stream of savings under each scenario is presented in annual detail in Tables 2 through 6 that follow. The calculations under each scenario are discussed in some detail, and then we present our conclusions and recommendations based on the results of our analysis.

A. Scenario 1: No Change in the Resource Mix and No COTP

The year-by-year results of the analysis for Scenario 1 are presented in Table 2. This scenario is identical to the first scenario examined in the April 1988 report, and the analysis is the same with one major exception. A loss savings credit of \$295,000 a year now applies under the PG&E proposal, making that option much more attractive than was indicated in the April report. The present value of the stream of net savings over the 12-year study period is estimated at \$2.6 million under the PG&E proposal. The present value of the savings associated with the Western project, when compared to the

TABLE 2

Comparison of Savings
PG&E and Western Transmission Options
Based on Phase 1 Analysis

Scenario 1: No Change in LLNL Resource Mix
(\$1,000s)

Fiscal Year (1)	Wheeling Savings (2)	Net Savings with PG&E Proposal ^(a) (3)	Net Savings With Western Project	
			With Sunk Costs ^(b) (4)	Costs to Completion ^(c) (5)
1990	\$ 626	\$ 298	\$ 28	\$ 491
1991	626	298	28	491
1992	626	298	28	491
1993	626	298	28	491
1994	626	298	28	491
1995	626	298	28	491
1996	626	298	28	491
1997	626	298	28	491
1998	626	298	28	491
1999	626	298	28	491
2000	626	298	28	491
2001	<u>626</u>	<u>298</u>	<u>28</u>	<u>491</u>
TOTAL	\$7,512	\$3,576	\$336	\$5,892
1989 Present Value at 5% Discount				
		\$2,641	\$248	\$4,352

^(a)Includes annual facilities costs of \$623,000 and a loss savings credit of \$295,000.

^(b)Includes annual facilities costs of \$924,000 and a loss savings credit of \$326,000.

^(c)Includes annual facilities costs of \$461,000 and a loss savings credit of \$326,000.

April analysis, falls significantly, and particularly, when the sunk costs are included. This is a direct result of including certain facilities capital costs in the comparison, which raises the cost of the Western project as compared with the PG&E proposal. With a present value of the 12-year net savings of only \$248,000, the PG&E proposal would be accepted if the decision were to turn on this comparison. However, the present value of the net savings for the 12-year study period are nearly \$4.4 million under the Western project if the analysis is based only on the costs to completion. Since it is only the costs to completion that can be avoided if the PG&E proposal were accepted, this is the proper comparison to make.

Scenario 1 is the most likely scenario of the four examined because it is the "default" or "do nothing" scenario. It does not require completion of the COTP or the acquisition of third party power. It represents the base case and, as such, it should be given the greatest weight in DOE's consideration of the two transmission alternatives. This consideration is further elaborated in Section IV on the expected value of the savings to be realized from each alternative.

B. Scenario 2: Maximum Wheeling Savings with COTP Available in 1992

The annual net savings streams for the PG&E proposal and the Western project under Scenario 2 are presented in Tables 3 and 4, respectively. The analysis for PG&E is essentially the same as reported in April, except it begins in FY 1990 and it includes the loss savings credits on CVP power in

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TABLE 3

Savings Under the PG&E Proposal
Based on Phase 1 AnalysisScenario 2: Maximum Wheeling Savings
(\$1,000s)

Fiscal Year (1)	Wheeling Savings		Loss Savings (4)	Net Savings ^(a) (5)
	Western Power (2)	COTP Power (3)		
1990	\$1,101	0	\$ 448	\$ 926
1991	822	0	467	666
1992	0	1,705	0	1,082
1993	0	1,731	0	1,108
1994	0	1,731	0	1,108
1995	0	1,781	0	1,158
1996	0	1,831	0	1,208
1997	0	1,906	0	1,283
1998	0	1,956	0	1,333
1999	0	1,981	0	1,358
2000	0	2,031	0	1,408
2001	<u>0</u>	<u>2,082</u>	<u>0</u>	<u>1,459</u>
TOTAL	\$1,923	18,735	\$ 915	\$14,097
1989 Present Value at 5% Discount				\$10,119

^(a)Includes annual facilities costs of \$623,000.

TABLE 4

Savings Under the Western Project
Based on Phase 1 AnalysisScenario 2: Maximum Wheeling Savings
(\$1,000s)

Fiscal Year (1)	Wheeling Savings		Loss Savings (4)	Standby Charges ^(a) (5)	Net Savings	
	Western Power (2)	COTP Power (3)			With Sunk Costs ^(b) (6)	Costs to Completion ^(c) (7)
1990	\$ 626	\$ 0	\$ 326	\$ 0	\$ 28	\$ 491
1991	626	0	326	0	28	491
1992	0	1,705	85	330	536	999
1993	0	1,731	87	330	564	1,027
1994	0	1,731	87	330	564	1,027
1995	0	1,781	90	330	617	1,080
1996	0	1,831	92	330	669	1,132
1997	0	1,906	95	330	747	1,210
1998	0	1,956	97	330	799	1,262
1999	0	1,981	100	330	827	1,290
2000	0	2,031	102	330	879	1,342
2001	<u>0</u>	<u>2,082</u>	<u>105</u>	<u>330</u>	<u>933</u>	<u>1,396</u>
TOTAL	\$1,252	\$18,735	\$1,592	\$3,300	\$7,191	\$ 12,747
1989 Present Value at 5% Discount					\$4,918	\$ 9,022

^(a)\$.90 per kW-month times 30,585 kW x 12.^(b)Includes annual facilities costs of \$924,000.^(c)Includes annual facilities costs of \$461,000.

1990 and 1991. The present value of the 12-year stream of net savings under the scenario with the PG&E proposal is estimated at \$10.1 million.

The Scenario 2 analysis of the savings under the Western project is presented in Table 4. In addition to the fact that the annual facilities costs are now based on additional equipment, this analysis differs from that reported in April 1988 in two respects. First, now that PG&E has revised its proposal to charge only point-to-point losses of 0.7 percent, the loss savings from wheeling COTP power, compared to the PG&E proposal, have fallen significantly -- from \$6.6 million to \$940,000. Second, we have revised the estimate of probable PG&E standby charges that would have to be paid if LLNL were served entirely by COTP power. In the April 1988 report it was assumed that standby would have to be paid for all power delivered to LLNL. Upon further reflection, we believe there is no basis to pay for standby on power that was not previously supplied by PG&E. In fact, the most logical basis for a payment to PG&E to keep the Tesla line open is the annual cost of amortizing the salvage value of the equipment less the cost of removal, plus the appropriate annual O&M on the facilities, because those are the only costs that PG&E could avoid by taking the line out of service. Since we do not have those figures, we have used as a proxy the assumed \$.90 per kW-month standby charge for the power that would be purchased from PG&E prior to the shift to COTP power in 1992, or 30,585 kW. This reduces the sum of the 12-year standby charges to \$3.3 million from the \$8.0 million estimate used in the April 1988 report.

The resulting present value of the net 12-year savings stream, including the sunk costs, is estimated to be \$4.9 million. The proper calculation would account only for the costs to completion, and the present value of the 12-year net savings stream is estimated at \$9.0 million under that method.

C. Scenario 3: 3rd-Party Power Displacement of PG&E with COTP Available in 1992

Scenario 3 considers the possibility of obtaining power from another source, other than CVP power and COTP power, that would enable DOE/SAN to displace PG&E power purchases at a savings. The analysis proceeds essentially in the same manner as did the Scenario 3 analysis in the April 1988 report. Only the Western project is evaluated under this scenario because PG&E refuses to wheel other than CVP and COTP power over its line if its proposal is accepted. No PG&E displacement occurs in 1990 or 1991 on the assumption that an alternate supply could not be arranged until 1992. Beginning in 1992, the amount of displacement is set equal to the lesser of the residual combined demand of the three laboratories or the demand at LLNL. This results in a combination of COTP power and 3rd-party power being placed at LLNL during the years 1992 through 1994. Beginning in 1995, the entire LLNL load would be met with 3rd-party power. The assumed value of the associated displacement savings is \$5 per MWh, which is the same conservative assumption that was used in the April 1988 analysis.

The annual Scenario 3 net savings for the 12-year study period under the Western proposal are presented in Table 5. Several refinements and data

TABLE 5

Savings Under the Western Project
Based on Phase 1 Analysis

Scenario 3: Displaced PG&E Sales with COTP
(\$1,000s)

Fiscal Year (1)	Wheeling Savings ^(a) (2)	Loss Savings ^(b) (3)	Displaced PG&E Sales ^(c) (4)	Standby Charges ^(d) (5)	Net Savings	
					With Sunk Costs ^(e) (6)	Costs to Completion ^(f) (7)
1990	\$ 626	\$ 326	\$ 0	\$ 0	\$ 28	\$ 491
1991	626	326	0	0	28	491
1992	602	315	1,315	330	978	1,441
1993	552	289	1,405	330	992	1,455
1994	502	265	1,465	330	978	1,441
1995	0	0	2,130	330	876	1,339
1996	0	0	2,185	330	931	1,394
1997	0	0	2,265	330	1,011	1,474
1998	0	0	2,320	330	1,066	1,529
1999	0	0	2,380	330	1,126	1,589
2000	0	0	2,435	330	1,181	1,644
2001	<u>0</u>	<u>0</u>	<u>2,495</u>	<u>330</u>	<u>1,241</u>	<u>1,704</u>
TOTAL	\$2,908	\$1,521	\$20,395	\$3,300	\$10,436	\$15,992
1989 Present Value at 5% Discount					\$ 7,240	\$11,344

^(a)Wheeling savings on 24, 22 and 20 megawatts of COTP power in 1992, 1993 and 1994, respectively.

^(b)Loss savings on COTP power in 1992, 1993 and 1994 computed as (COTP mWh) x .955 x .042 x \$55, as was used in the April 1988 report.

^(c)Displaced PG&E sales determined by 3rd-party mW times LLNL load factor times 8,760 hours times \$5 for 1992, 1993 and 1994. Total LLNL energy used for 1995 through 2001.

^(d)Standby charge same as in Scenario 2.

^(e)Includes annual facilities costs of \$924,000.

^(f)Includes annual facilities costs of \$461,000.

changes have been made in calculating these net savings, as compared to the April 1988 report. First, the analysis excludes 1989 and the net savings are based on the higher Western capital costs as specified in Appendix A. Second, the COTP wheeling savings were somewhat overstated in the April 1988 report and this has been corrected in Table 5. Third, the PG&E displacement savings were understated in the April 1988 report for the years 1992, 1993 and 1994 when the displacement was defined by the residual load. The combined residual energy was used in the April report. What should be used is the combined residual demand (kW) at LLNL's annual load factor since the displacement will actually occur at LLNL. This adjustment is made in Table 5. Finally, the more realistic adjusted standby costs that were described in our discussion of Scenario 2 are incorporated in the Scenario 3 analysis.

Table 5 shows that the present value of the 12-year net savings associated with the Western project under this scenario is estimated at \$7.2 million if the Phase 1 capital costs, including sunk costs, are used in the calculations. Based on the more appropriate Phase 1 costs to completion, the present value of the 12-year savings stream is estimated at \$11.3 million. We continue to believe that this estimate of the potential savings is conservative, especially in view of PG&E's current and anticipated actions before the CPUC, which are likely to result in significant increases in PG&E retail rates. While these potential savings are significant, we note that this particular scenario, including the availability of the COTP, is not very likely to occur. Thus, we have developed an alternate PG&E displacement scenario that assumes the COTP will not be completed within the relevant time frame.

D. Scenario 4: 3rd-Party Power Displacement of PG&E Without COTP

Because completion of the COTP within the test period is very problematic, we have developed a separate set of PG&E displacement savings based on the assumption that the COTP will be unavailable. The results of this Scenario 4 are presented in Table 6. The calculations are identical to those in Scenario 3 except for the years 1992, 1993 and 1994. Since no COTP power would be available, the total displacement is equal to the total energy consumed by LLNL in those years. Further, there are no wheeling savings or loss savings on COTP power during that three-year period.

The present value of the 12-year savings stream associated with the Western project under this scenario is estimated at \$6.8 million based on Phase 1 costs including sunk costs, and \$10.9 million based on Phase 1 costs to completion. These savings are slightly less than the Scenario 3 savings estimates because of the loss of COTP wheeling and loss savings. They are still significant, however, and we believe they represent a conservative view of the long-term potential savings associated with the Western project.

TABLE 6

Savings Under the Western Project
Based on Phase 1 Analysis

Scenario 4: Displaced PG&E Sales Without COTP
(\$1,000s)

Fiscal Year (1)	Wheeling Savings (2) ^(a)	Loss Savings (3) ^(a)	Displaced PG&E Sales ^(b) (4)	Standby Charges ^(c) (5)	Net Savings	
					With Sunk Costs ^(d) (6)	Costs to Completion ^(d) (7)
1990	\$ 626	\$ 326	\$ 0	\$ 0	\$ 28	\$ 491
1991	626	326	0	0	28	491
1992	0	0	2,030	330	776	1,239
1993	0	0	2,060	330	806	1,269
1994	0	0	2,065	330	811	1,274
1995	0	0	2,130	330	876	1,339
1996	0	0	2,185	330	931	1,394
1997	0	0	2,265	330	1,011	1,474
1998	0	0	2,320	330	1,066	1,529
1999	0	0	2,380	330	1,126	1,589
2000	0	0	2,435	330	1,181	1,644
2001	<u>0</u>	<u>0</u>	<u>2,495</u>	<u>330</u>	<u>1,241</u>	<u>1,704</u>
TOTAL	\$1,252	\$ 652	\$22,365	\$ 3,300	\$9,881	\$15,437
1989 Present Value at 5% Discount					\$6,782	\$10,886

^(a)Wheeling and loss savings on CVP power are as calculated in Scenario 1.

^(b)At \$5 per mWh for all energy forecasted to be consumed at LLNL.

^(c)Same as in Scenarios 2 and 3.

^(d)Includes annual facilities costs of \$924,000.

^(e)Includes annual facilities costs of \$461,000.

IV. EXPECTED VALUE OF SAVINGS

Scenarios 1 through 4 have different probabilities of being realized and, since the Western project and the PG&E proposal will lead to different estimated net savings under each scenario, the expected value of each alternative can be evaluated by assigning probabilities to the likelihood that each scenario will occur. Assuming that these four scenarios exhaust the relevant possible outcomes, the sum of the probabilities of these four scenarios occurring will equal 100 percent, or certainty. Weighting the net savings for each alternative under each scenario by the probability of that scenario occurring, and summing the weighted savings across the four scenarios, yields the expected value of the discounted stream of net savings of each alternative.

The most likely outcome is in base case Scenario 1, which represents business as usual. This scenario requires no COTP and no PG&E power displacement. It is the "Do Nothing" Scenario. To reflect its more likely outcome, we start by assigning a probability of 40 percent to Scenario 1, and 20 percent each to the remaining scenarios. Under this set of probability weights, the expected value of the discounted stream of net savings from the Western project is estimated at \$7.988 million, or more than two-and-a-half times the \$3.080 million estimated expected value of the savings to be realized from the PG&E proposal.

This analysis can be carried further to permit an evaluation of the two alternatives under different assumptions regarding the relative likelihood of

the four scenarios occurring. Since the estimated discounted stream of net savings of the PG&E proposal are higher than the estimated savings from the Western project only under Scenario 2, the ranking of expected values for the two alternatives can only turn on changes in the assumed probability of Scenario 2 occurring. The sensitivity of the result to the probability assumed for Scenario 2 is demonstrated in Table 7. The expected values of the savings from the two alternatives are equal if the probability of Scenario 2 is 85.39 percent. At all probabilities below this, the Western project results in higher expected savings; at all higher probabilities for Scenario 2, the expected savings are higher for the PG&E proposal. We would note, however, that even at an assumed probability of 90 percent for completion of the COTP, the PG&E expected savings are only \$346,000, or 3.9 percent, higher than the expected value of the discounted savings stream associated with the Western proposal.

The highest probability that seems reasonable to attach to the completion of the COTP is 50 percent. If that probability is used to describe the likelihood of Scenario 2 occurring,⁶ then the expected value of the Western

⁶The potential savings associated with displacing PG&E power with completion of the COTP are higher than the savings under Scenario 2 with the PG&E proposal. Thus, if it were known with certainty that the COTP would be completed, it would be sensible for DOE to take steps to realize Scenario 3. Therefore, the probability of Scenario 2 occurring is actually much lower than the probability of the COTP being completed.

TABLE 7

Expected Value of the Stream
of Discounted Net Savings of the Western Project and the PG&E Proposal
Under Varying Probabilities of
Occurrence of Four Scenarios*
(\$1,000's)

<u>Probability of Scenario 2 Occurring</u> (%)	<u>Expected Value of Savings</u>	
	<u>Western Project</u>	<u>PG&E Proposal</u>
20.0%	\$7,988	\$3,080
40.0	8,246	4,840
50.0	8,376	5,720
60.0	8,505	6,599
80.0	8,763	8,359
85.4	8,833	8,834
90.0	8,893	9,239

*Values are calculated by evaluating the following equations at varying values of "b", the probability of Scenario 2:

$$\text{Western Savings} = 1-b (\$7,729) + b (\$9,022)$$

$$\text{PG\&E Savings} = 1-b (\$1,320) + b (\$10,119).$$

project exceeds the expected value of the savings from the PG&E proposal by \$2.656 million or 46 percent. In short, there is no basis for assigning a 90 percent probability to the realization of Scenario 2, and any reasonable value will lead to a higher expected value of the discounted stream of savings from the Western project.

V. OTHER WESTERN PROJECT BENEFITS

In addition to the quantifiable economic benefits that were identified and measured in Sections III and IV, there are a number of other important benefits associated with the Western project that have not been quantified and specifically accounted for in this analysis. Some of these benefits are primarily financial and others have to do with improved reliability of service.

A. Improved Reliability of the On-Site Distribution System

The Phase 1 comparative economic analysis conducted in this report is based on Western investment costs that include the construction of certain transformation/transmission betterments designed to facilitate the on-site distribution improvements that will make up the remainder of the total Western project. These costs will lead to significant improvements in the capability, flexibility and reliability of LLNL's distribution system that will not be provided by the PG&E proposal.

B. Certainty of Terms and Conditions

The Western project provides DOE/SAN with certainty of terms and conditions governing the cost and use of its project. There will be no certainty of terms and conditions regarding the PG&E proposal until there exists an executed contract that is approved by the regulatory authority with jurisdiction; or until PG&E management offers an ironclad written commitment

that it will honor specific terms and conditions notwithstanding regulatory disapproval.

C. Power Supply Planning Flexibility

The Western project provides LLNL (and, therefore, DOE/SAN) with access to any alternative power supplies that can successfully be delivered to the Tracy substation on behalf of DOE/SAN. This will provide important flexibility in planning for DOE/SAN power requirements in the long term and will permit possible major savings as a result of competitive procurement. This includes the possibility of purchasing PG&E power at lower rates as well as purchasing power produced by third-party suppliers. Since PG&E will not permit unfettered wheeling over its lines to LLNL, and since it has offered nothing comparable to the Western transmission access and planning benefits, these must be viewed as additional benefits only associated with the Western project.

D. DOE/SAN Rights in the Western Line

DOE/SAN will have rights under the Western project that will not be available under the PG&E proposal. This is primarily because Western is providing transmission facilities in which DOE would have specific rights, whereas PG&E is proposing to provide special transmission service. Specifically, under the Western project, DOE/SAN would have the potential to improve on the economics by collecting rent for unused portions of the line and by

buying into any future extensions or upgrades of the facilities for economic or reliability reasons.

VI. SUMMARY OF CONCLUSIONS AND RECOMMENDATION

The Phase 1 analysis that Exeter Associates, Inc. and C.H. Guernsey and Company have been instructed to conduct, and that is described in this report, has led to the following conclusions:

1. The proper basis for comparison of the Phase 1 net savings is to exclude the sunk costs of the Western project.
2. The estimated Phase 1 net savings are higher for the Western project under all but one of the four scenarios examined, including the most likely scenario.
3. Net savings under the PG&E proposal are higher only under the least likely scenario that requires completion of the COTP.
4. The expected value of the discounted stream of net savings is much higher under the Western project for all reasonable assumptions regarding the probabilities of occurrence of the four scenarios examined. The probability of completion of the COTP must exceed 85 percent in order for the expected value of the PG&E proposed project savings to exceed those of the Western project.
5. There are a number of important economic and reliability benefits associated with the Western project that are not specifically included in the Phase 1 analysis.

Recommendation: For all of the above reasons, Exeter Associates, Inc. and C.H. Guernsey and Company recommend that the Department of Energy proceed with the Western project.

APPENDIX A

REEVALUATION OF THE ELECTRIC SERVICE ENHANCEMENT FOR LLNL: ASSUMPTIONS, INPUT VALUES AND ANALYTICAL METHOD

Department of Energy

San Francisco Operations Office
1333 Broadway
Oakland, California 94612

November 3, 1988

Mr. Kirk Patterson
Mr. Mark J. Smith
Pacific Gas and Electric Company
123 - Mission Street
San Francisco, CA 94106

Gentlemen:

Please find enclosed a revised re-evaluation package that reflects the changes agreed upon at our meeting of October 27, 1988.

In summary, DOE is prepared to complete phase one of the analysis within three weeks after receiving the additional data PG&E agreed to submit. In substance, PG&E has agreed to submit information relating to:

- (1) valuation of the line loss factor and the methodology for providing SAN with the benefits of the reduction in line losses. Our previous correspondence was intended to request this information but apparently there was some mis-communication.
- (2) the costs associated with upgrading the Newark line to LLNL to 159 MVA, including manual switchover capability. PG&E agreed that the Newark line and the associated costs are being added as a result of a recent outage at LLNL. That outage demonstrated the need for PG&E to have independent sources of power to LLNL to be equivalent to the Western proposal.

Also, DOE agreed not to undertake phase two of the analysis until DOE's management has reviewed phase one and decided that phase two is necessary and appropriate.

Again, thank you for your cooperation. If there are any corrections or additions you wish to make to the re-evaluation package, please advise me of them as soon as possible.

Sincerely,

Original signed by
Jerald S. Scheinberg

Jerald S. Scheinberg
Utilities Program Manager
Engineering and Facilities
Management Division

Enclosure

REEVALUATION OF THE ELECTRIC SERVICE ENHANCEMENT FOR LLNL

Assumptions, Input Values and Analytical Method

October 27, 1988 (Revised)

This document sets forth the assumptions, certain input values and the analytical approach that will be used to evaluate the long-term economic value to the Government from the Western project and the PG&E proposal. The data and the assumptions are based on discussions between DOE and PG&E and memorialized in the letters of 9/22/88 and 10/12/88 from DOE (J. Scheinberg) to PG&E (Patterson). The first phase of the analysis will be based on the capital costs and associated O&M costs of all of the transmission-level facilities (all equipment above the 115/13.8 kV transformation) that Western would actually construct, which have been annualized for the purposes of comparison. This annual cost will be compared with the "not-to-exceed" amounts provided by PG&E in its proposal.

DOE agrees to complete the first phase of the analysis within 3 weeks of receipt of the data identified in Section A.3. of this document.

The second phase of the analysis is intended to evaluate the benefits of the entire Western project to the Government, including certain transmission/transformation betterments and the 13.8 kV distribution system that are part of the Western project. At that time the costs and benefits of this entire project will be examined by DOE.

The second phase of the analysis will not be undertaken until DOE's management has had the opportunity to review the first phase and decide if the second phase is necessary and appropriate.

I. PHASE ONE OF THE ANALYSIS

A. Assumptions and Certain Input Values

1. Common Assumptions

- (a) Review period will be FY 1990 through FY 2001.
- (b) CRD at LLNL will be the same as in the April 1988 report.
- (c) DOE/SAN loads will be the same as in the April 1988 report.
- (d) Discount rate = a real 5 percent rate.
- (e) PG&E wheeling charges:
 - o \$1.433/kW-month for Western
 - o \$2.09/kW-month for COTP
- (f) PG&E standby charge = \$.90/kW-month

2. Western

- (a) Total capital costs = \$4,878,000 Basic Transmission System
\$4,382,000 Plus Distribution Related Transmission
\$9,260,000 Total
(566,100) Tracy Banks credit
\$8,693,900 Net

Unrecoverable Capital Costs as of October 27, 1988 =
\$4,750,000

Capital Costs to complete as of October 27, 1988 =
\$3,940,087

- (b) Amortization period = 30 years
- (c) Cost of money = 9.12%
- (d) Annual O&M Costs = \$76,016
- (e) Point-to-point loss factor for Western and COTP power = 0.3%

- (f) Annual facilities costs to Government including O&M = \$924,477
- (g) Access by LLNL to Western, PG&E, COTP and any other resource that can be delivered to the Tracy substation for use by DOE/SAN
- (h) Savings by displacing PG&E power with sources other than COTP & CVP Power = \$5/mWh

3. PG&E

- (a) Annual facilities charge = \$548,000 (without the Newark line)

This annual facilities charge is assumed to be based upon PG&E's report of a CPUC- approved transmission cost of ownership rate of 17.4 percent per year for a period of 50 years.

- (b) Point-to-point loss factor for Western and COTP = 0.7%
- (c) PG&E will provide access only to PG&E, Western and COTP power, if available. PG&E will not provide unfettered wheeling rights.
- (d) The line to LLNL from the Newark substation will be included. This line is to be capable of carrying the full load of LLNL equal to that provided by the existing primary line (159 MVA) from the PG&E Tesla Substation to LLNL.

ACTION FOR PG&E

- (1) PG&E is to verify the annualized costs of the Newark line upgrade to 159 MVA line and these costs will be included in the revised Annual Facilities Charge.
- (2) PG&E is to state the Tracy-to-LLNL line loss value and to explain how that value is calculated. Further PG&E is to explain how the difference between the 0.7% loss factor and the 4.5 percent factor specified in Contract 2948A will be provided to DOE/SAN. If a discount off PG&E retail rates is envisioned as the mechanism by which to flow these benefits to DOE/SAN, PG&E is to state how the discount will be computed. Also, PG&E needs to explain how these savings will be passed on to DOE/SAN in the event that LLNL takes all service from Western and COTP sources.

B. Outline of Analytical Approach

1. The approach will be essentially the same as in the April 1988 report. The present value of net savings, in constant 1989 dollars, will be estimated over the period FY 1990 through FY 2001.
2. Losses will be treated as described in assumptions 2(e) and 3(b).
3. The comparison will be based on a PG&E annual facilities charge as contained in its submittal to DOE (Scheinberg) by PG&E (M.J. Smith) regardless of the future actions of any regulatory authority with jurisdiction. Added to this will be the costs of the Newark to LLNL line as discussed in A.3(d) above.
4. Four scenarios will be examined:
 - (a) no change in the resource mix, no COTP
 - (b) maximum wheeling savings with COTP available in 1992
 - (c) 3rd-party power displacement of PG&E power with COTP available in 1992
 - (d) 3rd-party power displacement of PG&E power, no COTP

These are essentially the same as the scenarios examined in the April 1988 report with one change. The additional fourth scenario will assume that the COTP will not be built within the relevant time period.
5. For each scenario, one version will treat the total capital costs and the other will treat only the costs remaining to complete the project as of October 27, 1988.

II. PHASE TWO OF THE ANALYSIS

A. Assumptions and Certain Input Values

1. Western

- (a) Total Capital costs = \$19,925,900 net

Detail: \$20,492,000 Total
 (566,100) Tracy Banks credit

\$19,925,900 Net

Unrecoverable Capital Costs as of October 27, 1988 =
\$5,373,813

Capital Costs to Complete as of October 27, 1988 =
\$14,552,087

(b) Annual O&M Costs = \$97,329

From Phase 1	\$76,016
115/13.8 kV trans-	
former	3,035
13.8 kV switchgear	<u>18,278</u>
Total	\$97,329

(c) All other inputs to the cost calculation are the same as in phase 1.

(d) Annual facilities costs, including O&M = \$2,041,950

B. Outline of Analytical Approach

1. The analysis for Western will be identical to the phase 1 analysis, except the annual capital and O&M costs will be higher to account for the costs of the distribution system.
2. The analysis for PG&E will depend on: (i) what PG&E proposes or (ii) in the absence of a specific proposal, a third party financed/leased project will be used as a substitute. The PG&E proposal needs to include:
 - (a) higher annual facilities charges to account for transmission/transformation betterments, the distribution upgrade, and all related O&M costs; and
 - (b) PG&E power displacement savings identical to those in the Western analysis if unfettered wheeling rights are provided; or some other method upon which to evaluate the potential planning benefits to be offered by PG&E.
3. As in phase 1, both total capital costs and remaining costs to complete will be treated in separate versions.

EXETER

Associates, Inc.

CONSULTING ECONOMISTS

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April 18, 1989

Thomas S. Catlin
Steven L. Estomin
Richard A. Galligan
Charles E. Johnson
Matthew I. Kahal
Marvin H. Kahn
Dale E. Swan

REF: 1607

Memorandum

To: Jerry Scheinberg
CC: Steve Collier
From: Dale Swan
Subject: Summary Paper on COTP Agency Agreement

Following is the summary paper on the background to and status of the COTP agency agreement with Western. If you require any changes, or if Steve Collier thinks adjustments are necessary, please give me a call.

A SUMMARY OF
DOE/SAN'S INVOLVEMENT IN AND USE OF
THE CALIFORNIA-OREGON TRANSMISSION PROJECT

APRIL 1989

BACKGROUND

Public Law 98-360, passed in the summer of 1984, directed the Secretary of Energy to facilitate the financing, planning and construction of a third 500 kV AC transmission line between the Pacific Northwest and California. The project has come to be known as the California-Oregon Transmission Project (COTP) and is also sometimes referred to as the 3rd AC Intertie. The COTP will run from the Malin substation in southern Oregon into and through California via Western's Redding and Tracy substations, with extension to Pacific Gas & Electric Company's (PG&E) Round Mountain substation in the north and its Tesla substation in central California. The transfer capability from the California-Oregon border to Tesla is estimated at 1600 mW, while the thermal rating of the line will be in excess of 2,500 mW. The actual transfer capability of the line will be limited by system stability and loop flow considerations.

DOE'S ENTITLEMENT

The Western Area Power Administration (Western) will receive 300 mW of the line's transfer capability from Redding to Tracy in replacement of

Western's existing double-circuit 230 kV AC line that will be upgraded as part of the COTP. In addition, Western is entitled to the first 300 mW of transfer capacity in the event that the line is rated above 1900 mW from Redding to Tracy. Further, and most important from the perspective of the Department of Energy, San Francisco Operations Office (DOE/SAN), the participants' Memorandum of Understanding (MOU) allocates a share of the project transfer capability to January 1, 2005, to DOE/SAN. Specifically, "Western for the DOE laboratories and federal wildlife refuges shall be entitled to 6.25 percent." At the 1600 mW rating, that will mean approximately 100 mW reserved for use by the laboratories under the supervision of DOE/SAN and the wildlife refuges in California. The loads of the wildlife refuges are small and geographically dispersed, which should result in the DOE/SAN laboratories obtaining most of the value of the 6.25 percent entitlement.

THE CURRENT STATUS OF THE PROJECT

The likelihood of completion of the project has varied considerably over the past three to four years. The major stumbling block has been approval by the California Public Utilities Commission (CPUC), which must approve of the participation of the California investor owned utilities (IOUs). The CPUC has rejected several filings of the IOUs as incomplete because wheeling south of the Tesla substation has not been adequately addressed. This problem seems now to be resolved and the CPUC expects to render its decision by the end of 1989. That decision remains in doubt, however, because the CPUC staff has voiced opposition to the project. However, in the event the IOUs are prevent-

ed from participating, the public participants are likely to proceed on their own.

Design work is ongoing and Western and the Transmission Agency of Norther California (TANC) are proceeding with the purchase of rights of way. BPA has been authorized to move forward with construction of the northern end of the line, and approvals have been obtained from Fish and Wildlife and the Department of Forestry. The negotiation of a number of critical contracts needs to be completed, including the Project Participation Agreement (PPA), several interconnection agreements, and the TANC and Western contracting agreements. The unofficial schedule of the project manager projects construction to begin in October 1989 and an in-service date of January 1992. Based on all the information we have gathered to this point, we place the probability of completion at better than 50 percent, but expect the earliest that the line could be energized is late 1992.

DOE/SAN OPPORTUNITIES AND OBLIGATIONS

Entitlement to significant transfer capability on the COTP provides DOE/SAN with the opportunity to take advantage of alternative power supply resources with guaranteed access to the transmission service necessary for delivery of these resources. There are three basic ways that DOE/SAN can use its entitlement to reduce the costs of its bulk power supply:

1. Direct utilization of the line by DOE/SAN and/or the laboratories;
2. Utilization of the entitlement through a utility agent; and

3. Lay-off the entitlement to another entity for appropriate compensation.

While some consideration has been given to direct utilization, this option is least attractive because it requires DOE/SAN to take on a number of normal utility functions, such as procuring and scheduling power and coordination services. Thus, the major efforts have been to negotiate a lay-off arrangement with PG&E and an agency agreement with Western. Under the lay-off arrangement, the DOE/SAN laboratories would have received a discount off PG&E retail rates in exchange for use by PG&E of the DOE/SAN entitlement. Under the agency arrangement, Western, or some other utility, would act as DOE/SAN's agent in contracting for resources and in arranging for the necessary transmission and coordination services.

The value of the entitlement to DOE/SAN will depend on the power cost savings that can be realized from displacing or threatening to displace current, traditional supplies. The labs are currently served with Western preference power (around 65 percent of requirements) and supplemental power from PG&E provided under a CPUC-regulated retail tariff (the remaining 35 percent of requirements). The average melded cost per kWh of PG&E power in FY 1988 at all of the labs combined was 49.92 mills. The melded cost of Western power was 33.45 mills, for a differential of 16.47 mills. That differential is expected to rise over the next several years. Thus, if Northwest power is brought in over the COTP it will first be used in place of PG&E power. It is doubtful that Northwest resources will even be cheap enough to displace

Western power, except over very short periods when very inexpensive "spill" energy may be available in limited quantities.

The value of DOE's COTP entitlement will therefore depend directly on the price and availability of Northwest power, PG&E and Western rates, the amount of DOE/SAN's Western allocation, and the growth of load at the laboratories. By making some simplifying assumptions, a very crude estimate of the range of potential annual savings can be developed. If the DOE/SAN laboratories receive no more Western power; if the COTP is not used in real-time dispatch mode; if the current long-term load forecasts of the labs are realized; and if Northwest power can be obtained at an 80 percent load factor and at a price 10 mills below the relevant PG&E rates; then the annual savings in 1998 would be approximately \$6.3 million. Operating in real-time, or purchasing Northwest power at a savings of 20 mills per kWh, would double the annual savings toward the end of the century. The forecasted growth of loads by 1998 could absorb all of the Northwest capacity made available over the COTP entitlement, leaving PG&E and Western contributing approximately the same to the labs noncoincident peaks. But PG&E would likely sell significantly less energy, and the amount of the labs' peak demands that it would meet is also likely to fall significantly if the labs utilize their Northwest supplies under conditions of real-time dispatch, which will probably be required. In short, the major value to the federal government of the 6.25 percent COTP entitlement will result from displacing PG&E power with less expensive Northwest power, both for the expected growth in load at the laboratories and for a portion of the loads currently met by PG&E. This was fully recognized by Congress when PL 98-360 was passed.

NEGOTIATION WITH PG&E FOR LAY-OFF

SAN's initial approach was to negotiate with PG&E to lay off it's entitlement for appropriate compensation. This was due, in large part, to the initial indication to DOE/SAN that it had only two options by which it could benefit from the entitlement -- utilize the transfer capability itself, or lay it off to PG&E for compensation. PG&E proposed to provide to the DOE/SAN laboratories a discount off the PG&E retail rates that they pay for PG&E supplemental service. The discount was to be based on the cost savings that DOE/SAN would realize were it to use its entitlement itself to acquire Northwest resources, plus a share of the cost savings that would be realized by PG&E from PG&E use of the DOE/SAN entitlement. While this approach was reasonable conceptually, DOE/SAN and PG&E were unable even to come close to an agreement on the quantification of the future savings that either PG&E would realize or that DOE would realize if it used the COTP entitlement itself.

Several negotiation sessions were held with PG&E between the fall of 1984 and the fall of 1985, with very limited progress achieved regarding a mutually acceptable method by which the discount would be calculated. Substantive discussions ceased at that point, when DOE/SAN was informed that it would not be possible to obtain the economic benefits of its entitlement by laying it off to another entity, such as PG&E, for just and adequate compensation.

NEGOTIATION OF AN AGENCY AGREEMENT

By December 1984, it became clear that DOE/SAN could also pursue negotiation of an arrangement with Western for use of DOE/SAN's entitlement. As we noted above, by the end of 1985, Western became the only avenue, other than direct utilization, by which DOE/SAN would be able to obtain the benefits of the COTP entitlement. Western proposed to act as DOE/SAN's agent in utilizing the entitlement. Specifically, Western proposed to take the lead in securing Northwest resources on behalf of DOE/SAN, in obtaining necessary transmission and coordination services, and in scheduling the laboratories resources in real-time mode. While Western would take the lead in these utility activities, DOE/SAN would not be able to simply be a normal, firm customer of Western for this part of its loads. Rather it would be required to take on a responsible role in the power supply planning activity, and the risks associated with long-term resource procurement would be carried by DOE/SAN.

Problems in the Western Negotiations

Despite a very optimistic beginning, negotiations stalled soon after, and by the spring of 1987 major concerns over the agency arrangement were registered by the DOE/SAN negotiating team. By this time the signals were very clear that DOE/SAN would not be able to negotiate a compensated lay off with PG&E, effectively making Western "the only game in town." Of particular concern to DOE/SAN was Western's insistence that the agency agreement between

Western and DOE/SAN would be subordinate to the PPA. Since Western, and not DOE/SAN, was the federal government's representative in negotiating the PPA, DOE/SAN was particularly concerned over how the value of DOE/SAN's entitlement would be protected in that process.

DOE/SAN's concerns were set forth in a detailed issue paper, "Summary Discussion of Issues Related to the Utilization of the Third AC Intertie", dated April 14, 1987. In particular, five critical issues were identified which required resolution by DOE in order to permit DOE/SAN to arrange for the most beneficial utilization of its COTP entitlement. These five issues were:

- Is Western to be allowed to make unilateral determinations regarding SAN's ability to utilize its entitlement?
- Is Western to be the sole representative for the 6.25 percent entitlement in the development of the PPA and other agreements, or is SAN to have a more direct role in these activities?
- Is Western to be the sole trustee of the 6.25 percent entitlement, with sole discretion regarding the division of the entitlement and lay-off of unused portions?
- Can SAN utilize its entitlements by laying off any or all of it for just and adequate compensation?

- Is Western prohibited from direct utilization of the 6.25 percent entitlement as a lay-off beneficiary?

Resolution of DOE/SAN's Concerns

Subsequent negotiations with Western have produced a COTP agency agreement that should permit DOE/SAN to make the most beneficial use of its entitlement, and the DOE/SAN negotiating team has recommended that DOE/SAN execute this agreement. Before outlining the major aspects of the agreement, we shall discuss specifically how each of the five issues set forth above have been resolved.

Western's Unilateral Determinations. Western argued that the entitlement is actually vested in Western "for the use of" DOE/SAN, according to the enabling legislation and the MOU. Thus, Western must represent the government's interests in negotiating the PPA and other critical COTP agreements. Western also argued that it would make negotiations very difficult if DOE/SAN were also to participate since there would no longer be a single voice reflecting the government's positions. Western's argument was not persuasive but, in any event, DOE/SAN was unable to provide the necessary personnel to participate in all of the required negotiation sessions.

Still, DOE/SAN was concerned that Western's agenda and interests are different than those of DOE/SAN, and so some mechanism was required to protect DOE/SAN's long-term interests. This was achieved by getting Western to agree to the following:

- Western would use its best efforts to include language in the PPA that recognizes DOE/SAN's priority rights to the 6.25 percent entitlement, and Western's obligation to protect and preserve those rights;
- A letter of understanding between Western and DOE/SAN was executed which expressed Western's commitment to take all steps necessary to preserve and protect DOE/SAN's priority rights;
- Western agreed to provide to DOE/SAN minutes of all PPA Committee meetings, to consult with DOE/SAN on all major proposed changes to the PPA that would effect the value of DOE/SAN's entitlement, and to consider all changes proposed by DOE/SAN; and
- These commitments are also included in the agency agreement between Western and DOE/SAN.

In and of themselves, these agreements and commitments do not protect DOE/SAN's long-term interest in the COTP. However, they can be used in any future attempt, if necessary, to appeal to the Secretary to require Western to follow a course of action that protects DOE/SAN's priority COTP rights, since there will be a clear trail indicating that Western committed itself to act in DOE/SAN's interests.

Entitlement Division and Lay-off Conditions. DOE/SAN had major concerns regarding Western's insistence that it retain sole discretion over the division of the 6.25 percent entitlement between DOE/SAN and the wildlife refuges, and over the conditions under which a layoff of the entitlement would occur and the terms of any such layoff. Western was unwilling to agree that these decisions be made by mutual agreement among the affected parties, and so compromise language was included in the agency agreement.

Language has been included in the agency agreement that provides identical territorial definitions of qualifying DOE laboratories and federal wildlife refuges. In addition, Section 22 of the agreement limits the initial share of the entitlement allocated to the refuges as equal to the ratio of their loads not currently served by Western to the sum of the DOE and wildlife refuge loads not served by Western. Finally, future changes in this division must be done with adequate notice and in consideration of long-term commitments for use of the COTP that parties will have made. These commitments cannot guarantee that a major shift of the entitlement away from DOE/SAN will never occur but, again, there is sufficient constraining language that can be referred to in any future appeal to the Secretary, should that become necessary.

There is sufficient language in the agency agreement, the letter of understanding and in the PPA to protect against arbitrary lay-off of DOE/SAN's entitlement when DOE/SAN could actually use it. Moreover, sufficient language also exists in these documents to largely guarantee that any laid-off capacity

is returned to DOE/SAN in the event it can again utilize the COTP transfer capacity after having laid it off. For example, Section 21.3 of the agency agreement prohibits Western from laying off any portion of DOE/SAN's entitlement for longer than one month without the prior written approval of DOE/SAN.

What the negotiating team was more concerned with is that, to the extent possible, DOE/SAN's financial obligations for the COTP capacity and the contracted resources corresponding to the COTP entitlement, be transferred to the lay-off beneficiary along with the resources and the entitlement. This language is now contained in Sections 21.2 and 21.3. Western is obligated to use its best efforts to obtain payment for the entitlement at least equal to the direct and administrative costs allocated to the unused portion of the entitlement that is laid off. Further, any resources that have been committed to on a long-term basis for import over the COTP must be laid off along with the entitlement, unless prior approval is obtained from DOE/SAN.

Lay-off for Compensation. The issue of whether DOE/SAN could lay off its entitlement to PG&E or any other entity for just and adequate compensation has never been formally resolved. Western has stated that its own counsel has determined that such a lay-off would not constitute appropriate "use" as envisioned in the legislation and so could not be accommodated. We have also received an informal indication that, if formally requested, HQ would likely concur with the conclusion of Western counsel. While we believe there is much support for the opposite conclusion, it does not appear beneficial at this point to force a formal ruling on this issue and run the risk of a negative ruling. Therefore, DOE/SAN should operate on the assumption that it may not

lay off the entitlement for compensation unless that alternative becomes especially attractive, in which instance a formal ruling can be pursued.

Western as a Lay-off Beneficiary. We are informed that Western's own counsel has determined that Western does not qualify as a federal agency that has prior rights to any of the 6.25 percent transfer capability over any other project participant. This is confirmed by Western's proposed language in the March 1, 1988 draft of the PPA. Section 17.2 of that draft states that, with regard to any capacity unused by DOE/SAN and the wildlife refuges:

Western shall make available that portion of the Western Entitlement first to other federal agencies (except Western)... and then if no Federal agency (except Western) is able to use that portion of the Western Entitlement, then to Western or another entity consistent with Section 74.

Section 74 of the PPA governs the conditions of a lay-off by any project participant. Essentially this section states that unused capacity must first be offered to other project participants at " a price no lower than the price floor established by Section 10.4 of the MOU." If no participant accepts the offer, the capacity may be laid off to any entity at any price. In short, Western is not precluded from using any laid-off portion of the 6.25 percent entitlement on the same terms and conditions as all other project participants.

A SUMMARY OF THE AGENCY AGREEMENT

On November 14, 1988, Dale Swan, Project Manager for Exeter Associates, recommended that DOE/SAN execute the October 18, 1988 draft of the agency agreement "with a couple of minor revisions, subject to the necessary DOE legal and contract staff reviews." Following is a summary of the major terms and conditions of that agreement.

1. The agreement confirms that DOE/SAN has priority rights to the 6.25 percent entitlement and that Western is obligated to project and preserve those rights.
2. The agreement establishes the basis for dividing the entitlement between DOE/SAN and the wildlife refuges.
3. It is an umbrella agreement under which Western will provide comprehensive power supply services to the DOE/SAN laboratories. This includes the provision of firm and non-firm power transmitted from the Northwest over the COTP entitlement, and it also provides a vehicle for the supply of power from other sources. It also contemplates the provision of coordination and scheduling services.
4. The agreement provides for the establishment of new points of physical interconnection and new points of delivery upon request by DOE/SAN.

5. The agreement provides for the ongoing responsibility of Western for power supply resource planning to meet the load requirements of the DOE/SAN laboratories, including the obligation to identify and acquire appropriate resources and coordination services. DOE/SAN will carry the risk of long-term resource commitments made by Western on behalf of and with the approval of DOE/SAN.

6. DOE/SAN will reimburse Western for the direct costs of resources, transmission delivery, and coordination services, as well as general and administrative overhead costs through rate schedules for firm and/or interruptible service.

7. The agreement provides for a mechanism by which the DOE/SAN laboratories can make certain payments directly to the power suppliers.

8. The agreement confirms that Western will be responsible for laying off any COTP capacity and/or associated power supply resources in the event they cannot be used by DOE/SAN. The agreement also places constraints on the manner in which Western can make such lay-offs, and specifies the basis upon which DOE/SAN will be compensated for such lay-offs.

9. DOE/SAN, at its sole discretion, can terminate the agency agreement upon 90 days notice if agreement cannot be reached with Western regarding either the initial or subsequent power supply arrangements and/or rates. This should provide DOE/SAN with a continuing opportunity to make the best use of

its entitlement through alternative arrangements, such as direct use or an agency agreement with another utility.

**PROPOSED STRATEGY TO MAINTAIN
PACIFIC GAS & ELECTRIC COMPANY SERVICE
TO THE LAWRENCE LIVERMORE NATIONAL LABORATORY
WITH THE COMPLETION OF THE TRACY TIE LINE**

**A REPORT PREPARED FOR
THE U.S. DEPARTMENT OF ENERGY
SAN FRANCISCO OPERATIONS OFFICE**

**UNDER CONTRACT NO.
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**PREPARED BY:
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PROPOSED STRATEGY TO MAINTAIN
PACIFIC GAS & ELECTRIC COMPANY SERVICE
TO THE LAWRENCE LIVERMORE NATIONAL LABORATORY
WITH THE COMPLETION OF THE TRACY TIE LINE

During the summer of 1988, Western Area Power Administration (Western) began efforts for the construction of an approximate 12-mile, 230 kV transmission line (the Tracy Tie Line) from Western's Tracy Substation to the U.S. Department of Energy's (DOE) Lawrence Livermore National Laboratory (LLNL) in Livermore, California. This line was planned to provide a redundant transmission feed to LLNL, thus improving the reliability of service, which is presently provided by 115 kV transmission facilities owned by the Pacific Gas & Electric Company (PG&E). LLNL receives power from both Western and PG&E, and the line is also intended to reduce DOE power costs, partly through the elimination of wheeling charges that must be paid to PG&E for wheeling Western power from the Tracy Substation to LLNL.

The purpose of this paper is to provide a baseline document for use in DOE's future dealings with PG&E regarding arrangements by which the Tracy Tie Line and the PG&E transmission path could operate together to provide the cost savings and the increased reliability for which the Government built the line. In Section I, we provide a more detailed discussion of the background of the present interaction with PG&E, including a detailed summary of PG&E's position regarding the Tracy Tie Line. In Section II are discussed a number of alternatives for interconnecting and operating the Tracy Tie Line with PG&E facilities. In Section III, we discuss in detail DOE's position with regard to the rights and obligations under contracts and franchises of PG&E, Western and DOE and under two different LLNL power supply scenarios. Finally, in Section IV, the preferred approach for dealing with PG&E is discussed in detail, and we consider the possible PG&E responses and what further actions will need to be taken in response by DOE.

I. BACKGROUND

A. DOE Objectives

The importance of the Tracy Tie Line and the different ways LLNL might operate that line can only be understood in the context of DOE's overall power supply objectives. Most simply put, DOE hopes to arrange for long-term electric power supplies that are adequate and economic for all three major laboratory facilities operating under the aegis of the DOE San Francisco Operations Office (DOE/SAN): Lawrence Berkeley Laboratory (LBL), Stanford Linear Accelerator Center (SLAC), and LLNL, including Site 300. By "adequate" is meant a power supply that meets all of DOE's reliability and security requirements, and arrangements which will permit significant growth in laboratory loads over the next 15 to 20 years. Because it is recognized that DOE requirements and institutional and market supply conditions can change dramatically over the planning period, DOE has established "flexibility" as another explicit power supply planning objective. That is, to take advantage of shorter-term changes in requirements and supply conditions, DOE shall attempt to develop and retain as many avenues as possible by which it can exercise supply options in the future.

A number of power supply planning activities are expected to be undertaken in pursuit of these objectives. The focus will always be on obtaining adequate power supplies at minimum costs for the three laboratories combined. To that end, serious consideration will be given to arrangements that permit service to the integrated loads of the three facilities, thereby gaining for DOE the benefits of the diversity in loads among the laboratories. As we noted above, DOE will pay special attention to increasing and maintaining access of the laboratories to alternative power supply sources. This flexibility will permit DOE to respond to changes in supply and demand conditions, and it will create the competitive conditions under which better rates, terms and conditions can be negotiated. These alternatives will be increased if DOE can obtain acceptable coordination services such as standby, wheeling and scheduling, because it will allow DOE to consider inexpensive non-firm power

to meet some or all of its requirements. Therefore, negotiating an acceptable coordination service arrangement is another activity that DOE is considering. Finally, DOE expects to maintain, with the support of Western, ongoing power supply planning and investigation activities to ensure that new advantageous supply alternatives are developed, and that the best available combination of existing alternatives is used to meet the power requirements of the laboratories.

1. The Tracy Tie Line and the California/Oregon Transmission Project

It is useful to emphasize at the outset that the Tracy Tie Line plays a critical role, and perhaps the most critical role, in DOE's attempt to realize its power supply planning objectives for the three California laboratories. Transmission is the key to gaining access to alternative power supply sources. At present, the laboratories are interconnected to the California transmission grid only through PG&E transmission lines. The Tracy Tie Line provides a direct connection to Western's bulk transmission system, and Western has indicated a willingness to provide other resources (other than PG&E and Western) to LLNL over this line. Thus, the Tracy Tie Line provides access to the competitive bulk power supply market. It is the first such access route for the DOE California laboratories, and the only one that will be available in the near future with a high degree of certainty.

Even if direct transmission access is not provided to the other laboratories, LLNL's Tracy Tie Line can be used to benefit all three labs. For example, less expensive Western power presently in use by LLNL might be shifted to SLAC or LBL once it becomes possible to provide other less expensive resources to LLNL over the Tracy Tie Line. In fact, access to northwest power supplies may become possible for all three laboratories if the California/Oregon Transmission Project (COTP) is completed. DOE will have a 6.25 percent entitlement in the transfer capability of the COTP, and PG&E will be obligated to wheel northwest power imported over the COTP from the Western system to the laboratories under reasonable terms and conditions, as long as PG&E remains a participant in the project. Completion of the Tracy Tie Line,

in conjunction with access by all the laboratories to the northwest bulk power market via the COTP, will provide important power supply planning opportunities that neither access route could provide by itself. With these "windows" to the market, the alternative arrangements by which DOE power supply requirements can be met will depend largely on DOE's commitment to the planning process, and by Western's willingness to provide the day-to-day power planning and operating assistance that the laboratories will require with more complicated supply arrangements.

B. History of the Tracy Tie Line Project

The effort to construct the Tracy Tie Line dates back to the early 1980s. By 1984 DOE was successful in obtaining Energy Research program support funds to permit Western to conduct a planning study for the 230 kV line, associated transformation and switching equipment and certain distribution facility improvements at LLNL. DOE was nearly successful in obtaining construction funds in the FY 1987 budget, but the item was finally excluded without prejudice. The effort was renewed to include the construction costs in the FY 1988 budget, and this time with some success. The project was included in the FY 1988 budget, but with the condition that PG&E was to be given the opportunity to submit a proposal to DOE that would provide greater benefits to the government than would the project proposed by Western.

PG&E made its proposal to DOE in November 1987, and the Secretary had the responsibility to decide which alternative would be in the best interests of LLNL and the other northern California laboratories. A comparative evaluation of the reliability and economics of the Western project and the PG&E proposal was conducted. A report on the analysis was submitted to DOE on April 4, 1988. Based on the findings of that report, a recommendation was made that the Western project be developed.

The Secretary accepted the recommendation, and Western was instructed to proceed with the project. PG&E objected to the comparative analysis and the

Secretary's decision to proceed with the Western project. PG&E asked for a reconsideration based on what it viewed as certain errors in the analysis. PG&E's request was granted. DOE's conclusion was reviewed and it was found to be correct. The confirmed decision to proceed with the Western project was reported to PG&E on July 8, 1988, and Western began to build the Tracy Tie Line.

PG&E again appealed for an opportunity to revise and augment its prior best proposal for further reconsideration. In August 1988, it was agreed that DOE would take another look at the comparative economics of the two alternatives. Several meetings were held with PG&E staff to establish a mutually acceptable framework for a further review of PG&E's proposal, and on November 3, 1988, the agreed-upon assumptions, input values and analytical method were set forth in a letter from DOE to PG&E. A second comparative evaluation was conducted based on the analytical terms agreed to by DOE and PG&E. The superiority of the Western project was reconfirmed, and Western was directed to continue with construction of the line. Thus, the focus of Tracy Tie Line activities shifted from getting authorization to construct the line, to negotiating necessary interconnection agreements with Western and PG&E for proper operation and maintenance of the new facilities.

C. Interconnection Negotiations with Western and PG&E

Construction of the Tracy Tie Line will result in LLNL having a direct feed to the transmission system of each of its current suppliers -- Western and PG&E. DOE believed that each utility had certain obligations to provide service to LLNL as long as DOE chooses not to change its current resource mix in any significant way. Most important, that would include continuing to take service from PG&E under retail rate schedule E-20T, as is currently the case. This rate has been approved by the California Public Utilities Commission (CPUC). Western and DOE agreed that DOE would take the initiative in working out acceptable arrangements with PG&E, under which PG&E's Tesla line would continue in operation so that the laboratory would obtain the reliability

benefits of redundant feeds from two separate substations. As a result, DOE initiated interconnect agreement negotiations with both Western and PG&E.

1. The Western Interconnect Agreement

Negotiation of the interconnect agreement between the DOE San Francisco Operations Office and Western began in earnest during the late summer of 1988. After numerous drafts, the intra-agency agreement was finally approved by both Western and DOE managements, and the agreement was executed on September 18, 1989. The agreement covers a number of important issues relating to the entire Western Tracy project, including:

- the division of responsibility for the design, construction and funding of the various transmission and distribution facilities;
- the division of rights and responsibilities regarding the ownership, operations, maintenance and replacement of the various transmission and distribution facilities;
- the capacity reservation to be furnished to DOE; and
- the charges to be imposed on DOE and the billing mechanism for collecting those charges.

The agreement identifies and allocates those Western costs that DOE must reimburse, or provides guidelines by which those charges will be determined in the future. The agreement also provides the mechanism by which LLNL can design and construct the distribution improvements with the Western funds appropriated for that purpose. Essentially, DOE will retain ownership of the distribution facilities and the 115 kV facilities located on LLNL property, and DOE will be responsible for the costs of operation, maintenance and replacement (OM&R) of these facilities. Western will own, operate, maintain and replace the 230 kV transmission line, the new Livermore substation, and the 115 kV and 13.8 kV facilities not on LLNL property. The OM&R for the 115 kV and 13.8 kV facilities in the new Livermore substation, and the other 13.8 kV facilities not on LLNL property, will be done at DOE's expense. In addition, DOE will be responsible for the reimbursement of certain capital costs of the project as set forth in one of the exhibits to the contract. That exhibit

also sets forth certain credits that DOE will receive from Western for use of the line to serve the Banks pumping station, and for the cost of losses that Western will avoid paying to PG&E as a result of delivering power directly to LLNL.

Of particular concern to DOE in negotiating the interconnect agreement with Western, was preserving its entitlement to the transfer capacity of the Tracy Tie Line and maintaining maximum flexibility for DOE to use the line. Both objectives were realized. The final version of the contract retains for DOE a reservation to the full rated 342 MW maximum capacity of the 230 kV facilities, and this reserved capacity can only be changed by mutual agreement of the parties.¹ The agreement reserves this capacity for DOE "to serve the loads of the LLNL System up to the maximum transmission capacity specified in Exhibit A." The agreement is silent regarding what power can be transferred over the facilities in order to service the LLNL loads, thereby preserving for DOE the right to import any resource over this path that DOE is able to have delivered at the Tracy substation.

The 230 kV transmission line has been completed, and the new Livermore substation is scheduled for completion in September 1990. The distribution system improvements were also initially scheduled to be activated during the fourth quarter of FY 1990. However, the delay in completing an interconnection agreement also delayed the availability of the earmarked Western funds, and that delay will probably cause completion of the distribution improvements to slip to somewhere around February to April of 1991. Without completion of the distribution improvements, LLNL will not be able to take power from the Tracy Tie Line until the 115 kV tie is completed between the new Livermore substation and the existing Building 424 substation. Initiation of that effort has been delayed by resolution of the question whether the tie should be underground or overhead. C.H. Guernsey has recently completed an independent estimate of the costs of the different technologies and this report hopefully will provide the fillip for a decision. LLNL staff believe that a

¹However, the 230 kV/115 kV transformer in the new Livermore substation currently has a lower rating.

September 1990 completion date might still be possible if the decision is made very soon, but that appears to be a very optimistic schedule. A report by C.H. Guernsey & Company estimates completion in January of 1991, and that appears a more realistic forecast.

The 115 kV tieline is the critical path portion of the project. Unless the completion of the tieline slips beyond the expected completion of the distribution upgrade, that will be the earliest date that DOE can represent to PG&E that LLNL will begin to take service over the Tracy Tie Line. Second, the overhead/underground decision will also have a bearing on how DOE and Western deal with PG&E, because the overhead route will require the purchase of certain existing PG&E facilities and the rebuilding of PG&E's delivery system to LLNL. While PG&E has appeared cooperative on this issue, that posture could change when PG&E recognizes that DOE will not accede to its demands regarding the operation of the Tracy Tie Line.

2. Interconnect Discussions with PG&E

DOE began serious discussions with PG&E regarding the operation of PG&E facilities with the completion of the Tracy Tie Line on June 28, 1989. DOE's initial posture was that it contemplates no immediate change in the purchased power mix at LLNL, but only a change in transmission arrangements. It was recognized that that situation could change over the next few years, and so DOE was guarded against entering into any agreement with PG&E that would eliminate or unduly constrain the future flexibility and bargaining leverage provided by the Tracy Tie Line. Thus, the issues DOE wanted resolved through discussions with PG&E were:

- How PG&E will continue to provide retail service to LLNL after the Tracy Tie Line is energized;
- The establishment of an additional delivery point at the Tracy substation;
- Arrangements for the preferred routing for the 115 kV tie between the new Livermore substation and Building 424; and

- Arrangements for the development of standard operating procedures for connection, protective relaying, automatic standby switching, and operation and maintenance of the Western and PG&E facilities.

PG&E added the following issues to the agenda, some of which indicated that PG&E intended to take a hard line position in negotiations:

- Timing and completion of the Western "direct service" facilities;
- Generation and transmission standby facilities and charges;
- Maintenance of an existing dedicated station breaker and/or 115 kV transmission line and resulting special facilities charges;
- Metering; and
- System reliability.

At the meeting of June 28, 1989, PG&E indicated its willingness to make the necessary modifications to on-site facilities to accommodate an overhead route for the 115 kV tie line between the new Livermore substation and Building 424. PG&E stated that the charge to DOE would be for the actual labor and materials involved in the rearrangement, and PG&E will provide DOE with a preliminary cost estimate as soon as DOE provides PG&E with a description of the proposed rearrangement.

Another issue that should be easy to resolve relates to the use of and payment for a dedicated breaker at Tesla. Apparently, PG&E, on its own initiative, switched the Tesla transmission line from a breaker shared with other loads to one dedicated to support the load at LLNL. PG&E will require the payment of a special facilities charge of \$130,000 a year if DOE wishes to be served with the dedicated breaker under any alternative that would require PG&E to keep the Tesla line in operation. At the June 28 meeting, PG&E indicated that it needed to use a portion of that breaker to serve an additional 30 miles of transmission into the San Joaquin Valley, and DOE would have to make this choice relatively soon. That position was altered in PG&E's follow-up letter of July 24, 1989, in which it indicated that temporary rearrangement

work already completed at Tesla will relieve the overload conditions through 1990. Thus, DOE will be able to decide on the dedicated breaker in the context of its broader decisions regarding what PG&E facilities will serve LLNL.

Following is a summary of PG&E's position on the remaining issues:

- (1) Upon completion of the Tracy Tie Line, PG&E will consider LLNL to be a "direct service" customer of Western. As such, PG&E views Western as having acquired the utility obligation to serve LLNL.
- (2) PG&E will only be obligated to provide supplemental service at the Tracy substation, and will have no obligation to provide supplemental service along any other path.
- (3) If LLNL wishes to receive standby service from PG&E when the Tracy Tie Line is out of service, then:
 - (a) LLNL will have to pay special facilities charges to keep a transmission line in service from Tesla to LLNL, and
 - (b) LLNL will have to pay for generation and system transmission standby under CPUC retail Schedule S.
- (4) PG&E will not deliver Western power to LLNL along any PG&E transmission path if the Tracy Tie Line is down, or even if the Tesla line were to operate in parallel with the Tracy Tie Line.
- (5) PG&E will require a new contract with DOE in order to establish a new point of delivery at the Tracy substation.
- (6) PG&E will consider serving a portion of the LLNL load over the Tesla line if the loads can be segregated between those served by Western and those served by PG&E. However, that would only be considered if LLNL can guarantee that none of the load served by Western would be switched to the Tesla line in the event the Tracy Tie Line is out of service.

PG&E justifies its position on the basis of its interpretation of Contract 2948A. Specifically, it claims that any Western preference customer that becomes directly connected to the Western system becomes a "direct service customer" of Western. As such, PG&E argues that Western takes over the utility obligation to provide service to such a customer, and PG&E retains only the obligation to support Western's service at the Tracy substation. PG&E seems to recognize that Contract 2948A does not establish a specific

category of "direct service customers," but seems to argue that is implied by the contract. In particular, PG&E believes that it has no obligation to provide transmission service for Western power or supplemental PG&E service to the customer's premises absent payment of wheeling and loss charges. PG&E also maintains that it has no retail franchise obligation to keep the Tesla line open to provide retail power to LLNL. It maintains that all of these matters will be subject to FERC and not CPUC jurisdiction, despite the fact that LLNL would be required to pay CPUC regulated rates for all PG&E service. Interestingly, PG&E denied that LLNL would become a wholesale customer of PG&E, though it also maintained that LLNL was not a PG&E retail customer.

PG&E's position seems to be driven primarily over its concern about setting a precedent for service to "direct service" customers of Western. At present, PG&E provides an alternate transmission path to the Sacramento Municipal Utility District (SMUD), which is one of four Western customers that have direct connections to the Western grid. PG&E proposes to alter its current arrangement with SMUD by requiring SMUD to pay significant charges for support services provided by PG&E. This proposed revision is expected to result in strongly contested litigation before the FERC. PG&E may be concerned that providing LLNL with an alternate transmission path for Western power or for PG&E supplemental power could be used to advantage by SMUD in the anticipated FERC case. The fact that all other "direct service" customers are utilities served under wholesale tariffs was held to be an unimportant distinction by PG&E.

PG&E apparently believes no harmful precedent will be set if it segregates LLNL loads into Western and PG&E retail portions, essentially making LLNL two customers; or if it imposes on DOE special facilities charges for the Tesla line and generation and system transmission standby charges, thereby committing to provide PG&E retail service in the event the Tracy Tie Line goes down. Certain proposals also may be affected by PG&E's interest in locking in some portion of LLNL's business over the next few years, though we believe this is of secondary importance to PG&E.

As a follow-up to the meeting, PG&E provided DOE with a written description of the various arrangements under which PG&E would be willing to meet the reliability and supplemental service requirements of LLNL. These alternatives were summarized by PG&E in matrix form, a copy of which is reproduced here as Table 1.1. This table proposes three different arrangements with PG&E. Under two of these arrangements, the Tesla line would be maintained and so DOE would have to decide whether it wants to pay an additional \$130,000 a year for a dedicated breaker at Tesla. This decision would probably have to have been made even if the Tracy Tie Line were not constructed, and so this issue can be ignored in examining the impacts on DOE from the three PG&E alternatives.

Under the first case, the Tesla line would be disconnected. PG&E would provide supplemental power at Tracy, and Western would deliver all of LLNL's requirements over the Tracy Tie Line. PG&E power would be metered at Tracy and PG&E billing would include the costs of losses between Tracy and LLNL. There would be no special facilities or standby charges. Most important, LLNL would again be served by one line from one substation. Reliability could be improved marginally by stringing another conductor on the Tracy Tie Line, the cost of which would be borne by DOE.

Under the second case, PG&E would keep the Tesla line in operation and provide LLNL with two points of delivery -- Tracy and LLNL. Further, PG&E would provide standby service to LLNL. Specifically, PG&E would provide E-20T power over its Tesla line in the event the Tracy Tie Line goes out of service. PG&E would not wheel Western power in that situation. For this service, DOE would have to pay \$140,000 a year as a special facilities charge for the Tesla line, and \$9,480 per megawatt-year for standby service under its current Schedule S. Based on LLNL's current CRD of 36,415 kW at the LLNL main meter, these charges would translate into an annual cost of \$485,214. Without accounting for the higher cost of replacing Western power with PG&E E-20T power during those few times when the Tracy Tie Line is actually of service, these PG&E charges will eliminate more than three-fourths of the \$626,000 annual savings realized by LLNL through avoidance of PG&E wheeling charges.

Table 1.1

PG&E Proposed Alternatives for Service to
Lawrence Livermore National Laboratory
After Completion of the Tracy Tie Line

Option	Description	Supplemental Sales		Metering	Standby		Special Facilities	
		PG&E Point of Delivery	Schedule	Location(s)	Sales Schedule	Charges (\$/mH/yr)*	Equipment Components	Charges (\$/year)
1	100% WAPA Direct service, no alternate PG&E feed; no standby generation for WAPA line maintenance or failure	Tracy	"E201"	at Tracy	N/A	N/A	N/A	\$ 0
2a	100% WAPA Direct service, alternate PG&E feed with SHARED breaker at Tesla Substation; standby generation for WAPA line maintenance or failure	Tracy	"E20T"	at Tracy and LLNL**	"S"	\$9,480	Tesla-LLNL #1 115kV line	\$140,000
2b	100% WAPA Direct service, alternate PG&E feed with DEDICATED breaker at Tesla Substation; standby generation for WAPA line maintenance or failure	Tracy	"E20T"	at Tracy and LLNL**	"S"	\$9,480	Tesla-LLNL #1 115 kV line Breaker	\$140,000 \$130,000
3a	Split WAPA Direct/PG&E service PG&E feed with SHARED breaker at Tesla Substation; standby generation for WAPA line maintenance or failure	LLNL 115 kV switchyard	"E201"	at LLNL	"S"	\$9,480	N/A	\$ 0
3b	Split WAPA Direct/PG&E service PG&E feed with DEDICATED breaker at Tesla Substation; standby generation for WAPA line maintenance or failure	LLNL 115 kV switchyard	"E20T"	at LLNL	"S"	\$9,480	Breaker	\$130,000

Notes:

* See Special Condition 3 regarding applicable reductions in standby charges.

**Metering totalized including losses between Tracy and LLNL.

Under the third case, LLNL would have to split its load between that served by Western and that served by PG&E. PG&E would deliver E-20T retail power only at LLNL. Essentially, LLNL would be divided into two customers: retail customer of PG&E served over the Tesla line. Under this split-load arrangement, PG&E would be willing to waive the special facilities charge for the Tesla line "strictly as an accommodation" to LLNL. However, PG&E would require some guarantee of revenues for that waiver, most likely through some form of facilities charge agreement. In addition, PG&E would be willing to provide standby E-20T service for the portion of the load that would be served by Western. That power would be delivered over the Tesla line at E-20T retail rates and the standby charges would be those under Schedule S, presently at \$9,480 per megawatt year.

This third alternative is undesirable from DOE's and LLNL's perspective, and will likely lead to the highest cost, despite the waiver of the \$140,000 annual facilities charge. A major disadvantage is the absence of a second delivery point at Tracy, which may mean that there is no contractual way by which the Tracy Tie Line can back up the load served by the Tesla line. The minimum revenue commitment is also objectionable, for it is likely to have the effect of locking DOE into PG&E service for a number of years, thereby eliminating the flexibility that remains one of DOE's goals. Splitting the loads will also lead to higher costs. The nomination of loads to be served by Western will have to sum to less than the Western CRD. Since "X-over-Y" billing would no longer apply, the Western CRD would be underutilized, unless another power source were delivered over the Tracy tieline under an "X-over-Y" billing arrangement. Further, LLNL would lose the benefit of some of the diversity among the various loads on the site. That is, LLNL would have to pay a PG&E and Western monthly demand charge based on two separate noncoincident maximum demands. All of these drawbacks are likely to lead to much higher power costs than under either of the other cases, and it would also place a part of LLNL's load squarely in PG&E's retail franchise.

II. PHYSICAL INTERCONNECTION AND OPERATING ALTERNATIVES

A complete view of the actions that might be taken in interconnecting and operating the Tracy Tie Line requires an understanding of the various options for the physical interconnection and operation of the project. This includes attention to: (1) interconnection and operation of the transmission lines from PG&E and Western to LLNL; and (2) the interconnection and operation, including metering, at LLNL. Several approaches are possible and a preferable option has been identified on the basis of economics and reliability in each area except the interconnection of the new Western 230 kV substation at LLNL to the existing LLNL 115 kV substation at Building 424. The most practical option in each area will depend, in part, on PG&E's final requirements for interconnection and operation. These will include any constraints caused by PG&E's ultimate requirements for standby and special facilities charges, which may have to be determined by the appropriate regulatory authority or court.

A. Interconnection and Operation of PG&E and Western Transmission to LLNL

LLNL currently receives transmission service solely from PG&E for delivery of both PG&E's retail supplemental power service and Western's CVP power. The transmission service is normally provided over a relatively new 115 kV transmission line from PG&E's Tesla substation. This service is provided through a single dedicated breaker from the 115 kV bus at the Tesla substation. The line is currently rated at 159 MVA. In the event of an outage of this line, standby service can be provided through another older 115 kV transmission line also originating in PG&E's Tesla Substation. For the most part, this possible standby transmission path is not utilized by PG&E for any other purpose.

LLNL has a 230 kV interconnection with PG&E for a special intermittent "pulse" load in the MFE facility. It is not currently possible for LLNL to receive either PG&E retail supplemental service or Western CVP project allo-

cations over this 230 kV path for two reasons. First, there is no connection from the MFE 230 kV facility to the rest of the LLNL site. Second, even if a connection existed, the pulsating nature of the load served by the 230 kV line would have an unacceptable impact on voltage regulation for LLNL's remaining load. The current transmission system arrangements for LLNL are summarized graphically in the sketch provided as Figure 2.1.

The new transmission line from Western's Tracy substation to LLNL will be a 230 kV transmission line, rated at 342 MW. The transmission line consists of a single circuit on one side of a series of transmission towers capable of supporting a second 230 kV circuit at some point in the future. The transmission line is a radial line from the Tracy substation to LLNL. Western is proceeding with installation of a 2-mile line between Tracy and the Banks Pumping Plant, utilizing the second circuit capability of the Tracy-LLNL line. The Tracy Tie Line and the new 230 kV substation at LLNL should be completed and ready for energization by August 1990. The configuration of the new Tracy Tie Line is summarized in the sketch provided as Figure 2.2.

There are four distinct options for the interconnection and operation of the Western and PG&E transmission lines into LLNL:

1. Parallel Interconnection and Operation. Both the PG&E Tesla and Western/Tracy transmission lines could be interconnected and operated in parallel. That is, both lines could be put in service at the same time, providing LLNL with simultaneous redundant service from two separate major substations in the northern California transmission grid. This approach is preferable for reliability, provided that LLNL, Western and PG&E make mutually acceptable arrangements for protective relaying and automatic load switching to permit the parallel operation. Western representatives indicated in a meeting on August 24, 1989 that preliminary power flow studies show that paralleling the Tracy and Tesla buses through the LLNL site should not cause unacceptable flows, since the LLNL parallel path will have a higher impedance than other paths already in existence between Tesla and Tracy.

FIGURE 2.1

FIGURE 2.2

PROPOSED
TRACY
TIE LINE

Approximate Sketch
Not to Scale

Bill
9/21/88

2. Simultaneous Service to Split Load. In the event that the Tracy and Tesla paths cannot be paralleled, then it is technically feasible to split the LLNL load into two separate loads. One load could be connected to Western and the other to PG&E. This is not a particularly attractive option for several reasons as discussed further below.

3. Tracy Service with Tesla Standby. In the event that true parallel interconnection and operation proves unworkable, because of system operation constraints or PG&E's refusal to allow parallel operation, then the next best option would be to have LLNL's regular transmission service provided over the Tracy Tie Line, with the Tesla transmission line as a standby path. In this instance, the Tesla transmission line could be a "hot standby" path (i.e. - energized, but switch open at LLNL) with automatic switching provided for instantaneous load transfer to the Tesla line in the event the Tracy line is interrupted. Alternatively, the Tesla line could be "hot standby" with remote control switching provided for the PG&E and/or Western dispatchers. This would not allow instantaneous transfer of load in the event of an interruption of Tracy Tie Line service. At the very least, the Tesla line could be "hot standby" with provisions for manual switching at the LLNL site by PG&E, Western and/or LLNL operating personnel.

4. Tesla Service with Tracy Standby. It is technically feasible for LLNL to continue to be served through the PG&E Tesla transmission path with the new Western Tracy Tie Line as a standby path. However, this is not a desirable option since it would eliminate the wheeling and loss savings, and it largely diminishes the power supply flexibility provided by the Tracy Tie Line.

In all of the options described above, the second PG&E transmission line to the Tesla substation will have to be eliminated. The existing LLNL 115 kV substation only has provision for receiving two outside transmission lines. Since the new Western 230 kV substation at LLNL will be connected to the existing LLNL 115 kV substation by a 115 kV transmission tie line, only one space remains for an additional transmission line into the substation.

Furthermore, in the event that the 115 kV tie line to the new Western substation is brought into the existing 115 kV substation by overhead line as further discussed below, physical modifications will be required to on-site PG&E facilities, allowing only one PG&E transmission line into the substation.

B. Interconnection and Operation at the LLNL Site

There are several important issues to be considered with regard to the interconnection and operation of the new Tracy Tie Line at the LLNL site. In fact, the most important item on the critical path to placing the Tracy Tie Line in service is related to on-site interconnection issues.

The new Western 230 kV substation next to the LLNL site, at which the new Tracy 230 kV transmission line terminates, will be interconnected with the LLNL site in two ways. First, there will be a 115 kV transmission tie line from the new substation to the existing LLNL 115 kV substation at Building 424. Second, there will be 13.8 kV distribution feeders from the new Western substation to the LLNL distribution system. One or both of these interconnections must be placed in service in order for the Tracy Tie Line to be placed in service and be used by LLNL.

The 13.8 kV interconnection from the new substation to the LLNL distribution system is part of a more comprehensive program of LLNL distribution system improvements which have been funded and are being constructed as a part of the Tracy Tie Line project. Transfer of funds from Western to DOE/SAN is necessary for LLNL to begin the required distribution system improvements. Such funding has only recently been transferred since the necessary intra-agency interconnection agreement was not executed until September 18, 1989.

The 115 kV tie line from the new Livermore 230 kV substation to the existing LLNL Building 424 115 kV substation has not yet been started, because an acceptable route has not yet been selected. LLNL and DOE/SAN are currently considering several possible routes including both overhead and underground routes. C.H. Guernsey & Company has developed independent cost

estimates and critical path time estimates for an overhead and underground construction approach. The underground approach will cost approximately 1.9 to 3.0 times as much as the overhead approach and may take approximately three weeks longer to complete. Both approaches will take at least 15 months to complete.

LLNL has judged the underground approach to be superior due to appearance, electromagnetic field effect, vulnerability/security and interference with already crowded facilities near the existing LLNL 115 kV substation. The overhead approach would require PG&E to make modifications to existing facilities at LLNL, and PG&E has indicated willingness to do so. There does not appear to be a substantial advantage to overhead or underground with regard to the contractual matters currently at issue with PG&E. The availability of funding for the more expensive underground option as part of the Tracy Tie Line project is uncertain.

One additional option that has been considered at the LLNL site is related to whether or not the load should be split. That is, it is possible to physically segregate the lab load so that a portion is served by the Tracy Tie Line and a portion is served by the existing PG&E Tesla Line without paralleling the Tracy and Tesla lines. This splitting of load is technically feasible, and could be accomplished with automatic sectionalizing so that load could be instantaneously switched in the event of an outage of either line. Alternatively, it would be possible to arrange remote control switches to allow load transfer by PG&E and/or Western dispatchers, or LLNL operations staff, after an outage on either line. It would also be possible to arrange for only manual switching of load after an outage of either line by PG&E, Western and/or LLNL operations personnel at the LLNL site.

Splitting the lab load may be desirable for either of two reasons. First, it might allow simultaneous redundant service from Western and PG&E even if operations constraints (e.g., parallel flow, stability, system protection concerns, etc.) preclude actual parallel operation. Second, splitting the lab load may overcome PG&E's insistence on payment of special

facilities charges for the existing Tesla transmission line once the Tracy Tie Line is placed in service.

However, splitting the lab load would result in several undesirable constraints. First, splitting load, even with automatic load sectionalizing, would reduce the operating advantage of simultaneous transmission service from Tracy and Tesla. It would not be true parallel service, and critical electronic loads would almost certainly be affected by the load sectionalizing in the event of outage of one or the other transmission line. Second, splitting the lab load would probably constrain the maximum utilization of Western CRD energy. PG&E supplemental power and Western CRD power would not automatically be "mixed" with after-the-fact "X-over-Y" billing. More load would have to be placed under PG&E rates than under the "X-over-Y" arrangement to ensure that the demand on the Tracy portion of the split load never exceeds the CRD. Furthermore, the natural diversity of demand of the total load would be reduced when the load is split into two separately metered delivery points where demand charges would be incurred on a non-coincident basis. Third, splitting the load would require continued vigilance and effort on the part of LLNL operations staff to monitor LLNL site loads and reallocate loads between the split systems. Finally, splitting the load would result in very little power supply flexibility for that portion of the load that actually becomes PG&E retail load. In a sense, the LLNL site would be segregated into two customers. One would be a Western direct service customer, and the other would be a PG&E retail customer. This would give PG&E considerable additional control over LLNL's future options for the portion of LLNL that has become a true retail customer of PG&E.

C. Scheduling and Metering

One final issue that will have to be addressed is how the scheduling of resources and associated metering will be handled. Of course, under the current circumstances (i.e., no change in resource mix and no displacement of PG&E supplemental service by other power supply resources), the metering can still be accomplished at LLNL in the same manner that it is done now. In the event that the LLNL load is split, there would be separate Western and PG&E metering at the new Western substation and at LLNL's existing 115 kV substation, respectively. In the event that the Tracy and Tesla transmission lines are actually operated in parallel, some sort of totalized metering scheme will be required for metering at the new Western 230 kV substation and the existing LLNL 115 kV substation at Building 424. The exact approach to the metering will depend, in part, on the contract and rate arrangements that are finally worked out with PG&E.

In the event that new power supply resources are delivered by Western over the Tracy Tie Line, thereby displacing PG&E or even Western CVP power, some sort of resource scheduling will have to be arranged. It would be technically feasible to utilize the same sort of after-the-fact accounting treatment for accumulated meter readings, but this might be unacceptable to PG&E. It would also likely limit the economic benefit of the alternative source. The most obvious alternative is real time scheduling, probably under the oversight of a Western system dispatcher. If the power supply alternative being delivered is some sort of fixed capacity resource, and if acceptable firming arrangements are made with PG&E and/or Western, it may be possible to use deterministic advance block scheduling rather than real time dispatch scheduling. However, it would be necessary to have some sort of inadvertent account to allow for mismatches in hour to hour loads and advanced schedule resources.

III. DOE'S POSITION

It is proposed that the Department of Energy take the position that PG&E does not have the right to disconnect the Tesla line, nor can it refuse to wheel Western power to LLNL over that line. DOE also believes that its obligations to pay PG&E special facilities charges for the Tesla line and generation and transmission standby charges will be restricted to certain supply scenarios. In fact, PG&E's and DOE's obligations must be determined in the context of the particular path by which DOE will meet the power supply requirements at LLNL and the other laboratories. Particularly critical in that regard is whether and the extent to which PG&E retail E-20T service at LLNL will be displaced by other resources.

A. Possible Supply Scenarios

There are a number of possible alternatives by which DOE will be able to meet laboratory loads, several of which could result in the displacement of PG&E sales to LLNL. These possible alternatives will increase in number in the long-term, though none of these alternatives is certain to materialize. Thus, the scenarios we identify should be viewed as possible solutions to DOE's future power requirements; and one of DOE's objectives is to retain sufficient flexibility to pursue these alternatives if and when they become possible.

1. Maintain Current Resource Mix

Completion of the Tracy Tie Line changes only transmission arrangements. LLNL could continue to meet its loads with essentially the same mix of Western preference power and PG&E E-20T power. Without shifts of Western allocations among the laboratories, LLNL is limited to 36,415 kW of Western power with retention of the Air Force CRD, and 25,711 kW after the Air Force reclaims its CRD. That means that load growth at LLNL would have to be met with additional PG&E power. In the near-term this is the scenario that is expected to be followed.

2. CRD Shifts Among the Laboratories

The sum of the peak loads at the three laboratories (including Site 300) is currently around 145 mW. The combined Western allocation to the laboratories is approximately 88 mW with the Air Force CRD, and 78 mW without it. Changes in load patterns or load levels at one or more of the labs could lead to shifts of the available Western power among the laboratories in order to minimize combined DOE power costs. Given the relatively high load factor at LLNL, such shifts would probably result in increasing the CRD at LLNL, although reductions or changes in programs could conceivably lead to shifts away from LLNL. Any resulting decrease in PG&E service to LLNL does not change PG&E's obligations to transmit Western power to LLNL under the terms of Contract 2948A, as long as those shifts meet the notice and minimum transfer requirements. Indeed, Site 300's total load is currently served entirely by Western power wheeled to the facility by PG&E.

3. COTP Power Displacement

The DOE laboratories and the Federal Wildlife Refuges in California were allocated, through Western, a 6.25 percent entitlement in the California-Oregon Transmission Project (COTP). The Memorandum of Understanding (MOU) among the participants, and the Secretary's Memorandum of Decision (MOD) regarding the rights and obligations of the parties affected by the COTP, contemplated the importation of less expensive northwest power by the laboratories. Moreover, these agreements call for PG&E to wheel northwest power brought in over the COTP to the laboratories at reasonable terms and conditions, as long as PG&E remains a participant in the project. Use by the laboratories of up to a delivered 90 mW of northwest power, along with the DOE Western allocation, is expected to largely displace PG&E power at all of the labs unless and until loads grow beyond these resources. Under this scenario, PG&E will remain obligated to wheel power to LLNL even though it would cease to sell any of its own power to LLNL. Under these circumstances, we believe PG&E would be violating the terms of its agreement to disconnect the Tesla

line, although PG&E will undoubtedly argue that it will require payment of a special facilities charge to keep the line open. PG&E will likely argue that it no longer has an obligation to maintain that line since the Tracy Tie Line provides a path for delivery of COTP northwest power to LLNL. In addition, DOE may wish to contract with PG&E to provide standby service for any non-firm northwest resources that Western may obtain for the DOE laboratories.

4. Displacement of PG&E with Other Resources

Completion of the Tracy Tie Line makes possible the purchase of resources other than COTP northwest power for use by LLNL. Any resource that can be delivered to Tracy could be made available to LLNL. This could be non-CVP power obtained by Western, or power delivered to the Western system by any other supplier, for example by DWR or NCPA. Displacement of PG&E sales by these other resources creates different obligations for DOE because PG&E has no current contractual obligation to transmit these resources. Thus, PG&E has a stronger argument for imposing special facilities charges on DOE to maintain the Tesla line in operation. It may also have a basis for charging for some kind of bulk transmission standby, and for generation standby should DOE desire to have PG&E firm any of these other sources of power.

B. The Premises Underlying DOE's Position

DOE's position regarding PG&E obligations after completion of the Tracy Tie Line, and the approaches that DOE can take with PG&E are based on a number of critical premises regarding contractual and franchise obligations of PG&E and Western and the reliability requirements of LLNL. It is useful to list these premises before discussing the rights and obligations of the parties under alternative supply scenarios, and DOE's alternative approaches to PG&E's proposals.

1. For reasons of national security, LLNL requires dual feeds from different substations, preferably operating in parallel.
2. Tesla and Tracy transmission are integrated system facilities, not special dedicated customer facilities. In its most recent rate

cases before the FERC and the CPUC, PG&E has treated the Tesla transformation and transmission facilities as system facilities for purposes of establishing rates.

3. PG&E has, and will retain after the completion of the Tracy Tie Line, a utility obligation to serve the LLNL supplemental (retail) load, as long as LLNL desires such service. This obligation is set forth in its CPUC franchise, in its power supply contract with LLNL, in the GSA Area-wide Contract, and in Contract 2948A with Western.
4. PG&E and Western have agreed to the provision of mutual system emergency standby under Contract 2948A.
5. Under the terms of Contract 2948A, PG&E must continue to wheel Western CVP power to Western preference customers, whenever needed, under current rates, unless directed otherwise by Western.
6. PG&E may be entitled to special facilities charges for the Tesla line only if and when LLNL retail load falls below some unspecified level. That determination would be made by the CPUC if it cannot be negotiated by DOE and PG&E.
7. All terms and charges for wheeling and standby of CVP service to Western preference customers are FERC-regulated matters between PG&E and Western.

C. Rights and Obligations Under Alternative Supply Scenarios

It was noted above that DOE has a number of ways by which it can meet the laboratories' power supply requirements at minimum cost. The rights and obligations of DOE, PG&E and Western will differ under these scenarios, especially to the extent that there results the possibility of replacing PG&E power through competitive procurement. The notion of competitive procurement should be used rather than PG&E displacement, because PG&E will always have the option of meeting the terms offered by other power suppliers. The decision whether to purchase power from PG&E or an alternate supplier will turn, in part, on the additional costs that DOE may have to bear as a result of PG&E losing LLNL as a customer for its E-20T retail service. To place in proper perspective the discussion in Section IV on DOE's alternative approaches to the problem, it will be useful to enumerate the obligations of PG&E, DOE and Western under these two power supply scenarios. The first is no change in the LLNL resource mix, and the second is a competitive procurement

process under which LLNL meets its requirements with power purchased from suppliers other than PG&E, because PG&E was unable or unwilling to meet the competition.

1. No Change in LLNL's Resource Mix

Under this scenario, PG&E retains its approximate share of the LLNL load. This is the supply scenario that is expected to be followed in the near-term.

(a) Under this arrangement, PG&E has the following obligations:

- To deliver supplemental power to LLNL under the prevailing E-20T rate;
- To maintain the Tesla path in order to provide LLNL with E-20T supplemental power; and
- To wheel CVP power to LLNL over the Tesla path when necessary at the charges set forth in PG&E's FERC wheeling tariff.

(b) DOE and LLNL have the following obligations under this "no change" supply scenario:

- To meet reasonable criteria for safety and system protection in interconnecting to Western and PG&E;
- To pay E-20T rates for supplemental service provided by PG&E, but to pay no special facilities charges or standby charges; and
- To pay for Western power at the current CVP rate and to reimburse Western for any wheeling and loss charges imposed on Western for wheeling CVP power when the Tracy Tie Line is out of service.

(c) Western's obligations can be summarized as follows:

- It must provide to LLNL Western CVP power and PG&E supplemental power delivered at Tracy;

- It must pay the prevailing monthly unratcheted wheeling charges and loss charges to PG&E when CVP power is wheeled to LLNL during those times when the Tracy Tie Line is out of service; but it has no obligation to pay special facilities charges standby charges to PG&E; and
- It must coordinate interconnection, protection and operation with PG&E.

2. Competitive Procurement Scenario

In the event that PG&E were to lose its sales to LLNL under a competitive procurement scenario because it is unable or unwilling to match the rates, terms and conditions offered by competing suppliers, then the obligations of the parties may change. We believe Western will retain the same obligations as under the scenario where there is no change in the LLNL supply mix. It will still be obligated to deliver Western and PG&E supplemental power to LLNL over the Tracy Tie Line and to pay PG&E for wheeling CVP power when and if the Tracy Tie Line goes out of service. Finally it will maintain the obligation to coordinate interconnection, protection and operation with PG&E.

PG&E's obligations become less well defined. It will retain the obligation to wheel CVP power to LLNL under Contract 2948A, but that obligation will apply only to the extent that PG&E has excess transmission capacity available. That capacity will exist as long as the Tesla line remains in operation. However, with no retail sales to LLNL, PG&E would have no obligation under its retail franchise to keep the line in operation. We are doubtful if there is any language in Contract 2948A that could be used to force PG&E to maintain the line. Thus, absent payment to PG&E to keep the line open, PG&E may no longer be obligated to provide transmission backup for the laboratory. Rather, it would be able to deliver its supplemental E-20T power at Tracy. This is essentially PG&E's Option 1 in Table 1.1.

DOE would retain the same obligations as under the "no change" scenario. It would have to meet reasonable criteria for safety, system protection,

operation and scheduling; and it would be obligated to pay E-20T rates for all supplemental service provided by PG&E, and Western's current charges for CVP power, plus the \$1.433 per kW-month for any CVP power that PG&E wheels to LLNL when the Tracy Tie Line is down.

In addition, DOE and LLNL may take on additional obligations under this supply scenario:

- DOE may have to pay reasonable facilities charges for Tesla or some other PG&E Transmission path to LLNL to provide backup to the Tracy Tie Line. The payment of these facilities charges should provide DOE with the right to use that path for CVP, PG&E, COTP and other resources.
- DOE will have to arrange for acceptable transmission standby as necessary for non-CVP and non-PG&E power. That is most likely to be with PG&E, but other possibilities may exist. It is expected that Western would play an important role in this exercise, operating as DOE's agent.
- DOE will have to arrange for generation standby, as necessary, for non-firm alternative power sources. Generation standby could be obtained from PG&E, Western or other suppliers. This activity would likely be undertaken by Western acting as DOE's agent.

IV. DOE'S RESPONSE TO PG&E

A. Alternative DOE Actions

There are several possible actions which DOE might take in response to PG&E's initial position on the interconnection and operation of the Tracy Tie Line. These include:

1. DOE could continue dialogue with PG&E while proceeding with the completion of the construction of the Tracy Tie Line and associated facilities;
2. DOE could undertake immediate complaint actions at the California Public Utility Commission and/or the Federal Energy Regulatory Commission;
3. DOE could undertake immediate pursuit of contract dispute litigation in the appropriate federal court; or
4. DOE could deliver a formal ultimatum to PG&E threatening regulatory or judicial action unless PG&E arranges to wheel supplemental power service to LLNL over Western's Tracy Tie Line for appropriate compensation.

A variation of the first alternative given above would be to attempt to negotiate an acceptable deal whereby DOE/SAN begins to pay for and reserve acceptably priced and adequately flexible standby arrangements for future power supply alternatives. This variation will be difficult to justify because it is likely that DOE/SAN would be making payments for standby and other coordinating services for some time before a power supply alternative would be implemented. Furthermore, it would be very difficult to negotiate the most appropriate contract terms and conditions and service rates for a prospective and, as of yet, unknown power supply alternative without possibly causing constraints that would restrict the pursuit of specific options which might be encountered in the future.

Since PG&E has taken no official action by way of notice of termination of service or demand for payment, it does not appear that DOE/SAN has sufficient justification for regulatory or judicial action, or even for a formal

ultimatum to PG&E. As a result, the preferred approach would appear to be the first one given above. That is, DOE/SAN would engage in further dialogue with PG&E, awaiting their specific action, while proceeding as expeditiously as possible with the completion of construction of the Tracy Tie Line and associated interconnection facilities. It may be possible for the Tracy Tie Line project to be completed and placed in service with appropriate coordination among LLNL, Western and PG&E before final resolution of the various contract and pricing issues.

There are no significant technical barriers that must be overcome in the event that the Tracy Tie Line is placed in service prior to the resolution of the PG&E contract issues. If, as Western suggests, paralleling Tesla and Tracy through LLNL poses no load flow problem, then the PG&E Tesla line could just continue to operate in parallel. In the unlikely event that loop flow or system stability difficulties result, one or both lines would trip temporarily, and only the Tracy Line would be returned to service. The existing LLNL metering, along with new Western metering at the new 230 kV substation could be utilized to calculate totalized usage for purposes of the "X-over-Y" billing.

Of course, Western would cooperate with PG&E operations representatives to coordinate the actual energization. In fact, Western would work with PG&E operations representatives ahead of time to coordinate the installation and adjustment of appropriate relaying and switching equipment as well as to develop acceptable procedures for operation and maintenance of the facilities. At worst, PG&E would simply remove the Tesla line from service when the Tracy line is energized. PG&E could not physically prevent the Tracy Tie Line from being energized, and there are no technical reasons otherwise why the Tracy Tie Line would fail to successfully serve LLNL.

B. Recommendation

The specific approach being recommended is as follows:

1. DOE will provide PG&E with a written response to Allen Schurr's July 24, 1989 letter to Jerry Scheinberg. This response would:
 - (a) State DOE/SAN's disagreement with both PG&E's proposed actions and their somewhat vague basis for such actions, noting Western's concurrence.
 - (b) Remind PG&E of its retail franchise obligation, as well as its voluntary commitment under contract 2948A, the power supply contract with LLNL, and the government services agreement with the GSA, to provide supplemental retail service to LLNL, and its attendant obligation to maintain the necessary facilities (i.e., the existing Tesla line).
 - (c) Explain that LLNL has no current obligation to pay special facilities charges or other standby charges given the mix of Western CVP power and PG&E supplemental service power being purchased, and that no such obligations would occur until such time as LLNL changes its purchased power mix, not just its transmission line arrangements.
 - (d) State that DOE does not intend to pay any bills submitted to LLNL by PG&E for special facilities charges or standby service charges under the current power supply resource circumstances.
 - (e) Warn PG&E that refusal to provide service through the Tesla transmission path, or disconnection or removal of the Tesla transmission facilities, will result in an immediate complaint to the California Public Utility Commission by DOE.
 - (f) Notify PG&E that Western will be contacting appropriate PG&E operations personnel to make mutually acceptable arrangements for the safe and reliable interconnection, system protection, and operation of the Tracy Tie Line, and indicate that LLNL operations personnel will be involved in such arrangements.
 - (g) Explain PG&E's obligations to wheel Western's CVP power over available PG&E facilities under the current prevailing rates, and remind PG&E that Western has not terminated its wheeling service to LLNL in conjunction with the completion of the Tracy Tie Line project.

2. DOE will take no further specific action other than proceeding with the Tracy Tie Line project until PG&E takes action(s) requiring LLNL or DOE response.
3. Western will contact PG&E to make arrangements for interconnection and operation, including system protection and switching, of the Tracy Tie Line.
4. The Tracy Tie Line project will be completed and energized in late 1990 or early 1991 with appropriate coordination by Western and LLNL with PG&E operations and dispatch personnel.

There are several actions that PG&E might take upon receipt of DOE's letter. These actions and the appropriate DOE responses are as follows:

1. If PG&E disconnects the Tesla transmission line, then DOE would:
 - (a) File a complaint at the California Public Utility Commission; or
 - (b) Litigate a contract dispute against PG&E in federal court.
2. If PG&E submits to LLNL or DOE a demand for payment for special facilities or standby charges, then DOE would:
 - (a) Notify PG&E of its refusal to pay and await subsequent PG&E action; or
 - (b) Notify PG&E of its refusal to pay and file a complaint in the appropriate forum. Demands for special facilities charges might be pursued at the CPUC, Federal court, or the Federal Energy Regulatory Commission. In the event of demand for special facilities charges or standby charges related to the delivery of Western CVP power, it will be necessary for Western to take part, if not take the lead, in such regulatory or other legal actions.
3. If PG&E refuses to wheel Western CRD power during Tracy Tie Line outage periods, and bills DOE for replacement power under PG&E retail rates and/or bills DOE for other PG&E standby charges, then DOE would:
 - (a) Notify PG&E of its refusal to pay and await further PG&E action; or

- (b) Notify PG&E of its refusal to pay, and immediately file appropriate regulatory or other legal actions in the appropriate forum with Western taking part, if not taking the lead.
- 4. If PG&E files new rates with the CPUC and/or the FERC for the Tracy Tie Line situation, then:
 - (a) DOE and Western would intervene and litigate fully; and/or
 - (b) DOE and Western would seek Federal court intervention.
- 5. Finally, if PG&E attempts to force the issue by exerting pressure on DOE management, then:
 - (a) It will be important that DOE/SAN and Western have already fully briefed their respective managements on the principal issues and options; and
 - (b) DOE/SAN and Western would continue to keep their respective managements within DOE apprised of their evaluations of continuing events.

**SUMMARY ANALYSIS OF THE DOE
INTERVENTION EFFORT IN THE
PACIFIC GAS AND ELECTRIC COMPANY CASES
RELATING TO THE TRACY TIE LINE
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION
DOCKET NO. ER91-499-000
AND THE
CALIFORNIA PUBLIC UTILITIES COMMISSION
DOCKET NO. 91-06-060**

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U.S. DEPARTMENT OF ENERGY
OFFICE OF ORGANIZATION, RESOURCES
AND FACILITIES MANAGEMENT
UNDER CONTRACT NO. DE-AC01-90-MA00256
TASK ASSIGNMENT NO. 19**

OCTOBER 1993

EXETER

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EXECUTIVE SUMMARY

1. In May of 1991, Western Area Power Administration (Western) completed a 12-mile 230 kV transmission line (the Tracy Tie Line) and a new substation to provide a redundant transmission feed to the Department of Energy (DOE) Lawrence Livermore National Laboratory (LLNL), which was served by a 115 kV line from Pacific Gas and Electric Company's (PG&E's) Tesla substation.
2. PG&E demanded that LLNL pay a special facilities charge for the Tesla line and take standby service under its retail Schedule S in order to keep its Tesla line in operation. Further, PG&E refused to wheel Western power to LLNL in the event of an outage on the Tracy Tie Line. PG&E threatened to remove the Tesla line if these conditions were not agreed to.
3. On June 21, 1991, PG&E filed a "Notice of Cancellation of Transmission Service to Lawrence Livermore Laboratory Pursuant to Contract No. 14-06-2000-2948A" (Docket No. ER91-499-000) with the Federal Energy Regulatory Commission (FERC). PG&E also filed an Advice Letter with the California Public Utilities Commission (CPUC) to impose standby and special facilities charges on LLNL (Docket No. 91-06-060).

4. Western and DOE filed protests and motions to intervene with the FERC. DOE also filed a complaint with the CPUC requesting a formal hearing on the issues raised by PG&E.
5. FERC issued an Order rejecting PG&E's notice on August 22, 1991. PG&E filed a "Request for Rehearing" and the FERC issued a tolling order. The CPUC granted DOE's request for a hearing and set up procedures for discovery, the filing of testimony and hearing dates. Both cases were stayed pending the outcome of settlement discussions that were initiated by PG&E.
6. Settlement discussions were held between September 18, 1991 and April 29, 1992, when a Settlement Agreement was filed with the FERC. The agreement was finally accepted by the FERC on October 13, 1992, after certain minor changes were made to meet concerns of the FERC Staff. As a result, DOE withdrew its Complaint before the CPUC.
7. Under the initial terms and conditions demanded by PG&E, DOE would have incurred an estimated \$1.2 million a year to keep the Tesla line operating as a redundant feed. Under the Settlement, the cost to DOE will fall to less than \$0.25 million.

8. DOE realized most of its initial objectives and gained some additional important benefits:

- PG&E committed to operate its system in parallel with the Western system at LLNL. This confers additional reliability benefits on LLNL.
- PG&E committed to negotiating in good faith the coordination agreements necessary for DOE to use its share of the California-Oregon Transmission Project (COTP). PG&E has honored this commitment.
- PG&E has agreed to wheel Western and other non-PG&E power to LLNL in the event of an outage on the Tracy Tie Line, for the payment of a transmission standby charge based on PG&E's area transmission costs.

9. The Settlement represents a major victory in DOE's efforts to obtain alternative power supplies to lower the electric service costs of the three Northern California laboratories.

I. INTRODUCTION AND BACKGROUND

In 1988, the Department of Energy San Francisco Operations Office (DOE/SF) selected Western Area Power Administration (Western) to construct a 12-mile, 230 kV transmission line from Western's Tracy Substation to Lawrence Livermore National Laboratory (LLNL), and to construct a new 230/115 kV substation (the Livermore Substation) adjacent to LLNL. The Western line (known as the Tracy Tie Line) and substation project was selected over an alternative proposed by Pacific Gas and Electric Company (PG&E) -- specifically, an additional 115 kV line from PG&E's Tesla Substation to the Building 424 substation located on LLNL property. Western began construction of the project in 1988, and the line was placed into operation in May 1991.

There were two basic purposes for construction of the Tracy Tie Line:

1. To improve reliability at LLNL by obtaining feeds from two separate and independent substations; and
2. To realize power cost savings by eliminating wheeling charges from Western, reducing loss adjustments, and by gaining a direct path to Western and any resources that Western is able and willing to provide to LLNL.

Realizing the reliability objective required the maintenance and the continued operation of PG&E's Tesla No. 1 line to LLNL. Negotiations with PG&E and Western, regarding the operation and interfacing of the Tracy and Tesla lines, began in June 1989. In developing the DOE/SF negotiating strategy, parallel service to LLNL appeared to be the natural

engineering solution and it would provide significant additional reliability benefits to LLNL. Consequently, parallel operation became an additional reliability objective.

PG&E took a hard-line position during initial discussions regarding operation of the Tracy Tie Line. PG&E required, among other things, payment of special facilities charges and standby charges, and it refused to wheel Western power to LLNL. On June 21, 1991, PG&E filed with the Federal Energy Regulatory Commission (FERC) a "Notice of Cancellation of Transmission Service to Lawrence Livermore Laboratory Pursuant to Contract No. 14-06-200-2948A" (Docket No. ER91-499-000). DOE intervened, and Western filed a motion for FERC to reject PG&E's filing. A number of other Western Central Valley Project customers also intervened.

FERC acted favorably on Western's motion. On August 22, 1991, the FERC found PG&E's argument for cancellation of LLNL's service to be without merit, and issued an "Order Rejecting Notice of Cancellation." On September 20, 1991, PG&E filed a "Request for Rehearing" of the FERC's August 22, 1991 Order, in response to which the Commission issued a tolling order on October 6, 1991.

DOE simultaneously pursued relief before the California Public Utilities Commission (CPUC). On June 28, 1991, DOE filed a Complaint with the CPUC, requesting that the CPUC enjoin PG&E from discontinuing service to LLNL, and to schedule a hearing to consider the issues. PG&E tried to preempt the Complaint by filing an Advice Letter with

the CPUC which would have imposed standby charges on LLNL. However, at DOE's motion, the CPUC consolidated these actions (Docket No. 91-06-060). Discovery was conducted and a prehearing conference took place on September 30, 1991, at which time procedural dates were established. On October 25, 1991, PG&E filed a "Motion for Summary Adjudication and to Limit Discovery and Admissibility of Evidence." The main purpose of this pleading was to keep the issue of parallel operation out of the proceeding. DOE responded to PG&E's motion on November 11, 1991.

PG&E began to negotiate in earnest in October of 1991, after it became clear that DOE and Western intended to follow the litigation option to the very end, and after the FERC rejected PG&E's Notice of Cancellation. Both the FERC and the CPUC proceedings were stayed to provide time to work out a settlement. A settlement agreement was reached and was filed with the FERC on April 29, 1992. After certain minor revisions, the settlement was accepted by the FERC on October 13, 1992. DOE then filed a letter with the CPUC Administrative Law Judge (ALJ) on October 23, 1992, indicating the settlement had been accepted by the FERC and requesting that the DOE Complaint be dismissed. A CPUC Order was issued on November 18, 1992 dismissing DOE's Complaint.

II. DOE'S PARTICIPATION

DOE played an active role in both the FERC and CPUC proceedings. Efforts were coordinated closely with Western, especially in the FERC proceeding where both Western and DOE intervened. Litigation strategy for both cases was developed jointly. Western and DOE also cooperated closely during settlement discussions with PG&E. Unified positions were established and presented to PG&E, and language was crafted jointly by Western and DOE representatives.

Exeter Associates, Inc. had been providing assistance to the Department of Energy San Francisco Operations Office (DOE/SF) on Tracy Tie Line and related power planning issues since 1984 under DOE/SF's own utility support services contract with Exeter. However, when it became clear that arranging for the operation of the Tracy Tie Line would require litigative efforts, Exeter was issued a Task Assignment (No. 19) by the DOE Headquarters Office of Organization, Resources and Facilities Management (DOE/HQ) under Contract No. DE-AC01-90MA00256, to provide expert financial, economic and engineering assistance in DOE's litigative and related efforts. Exeter worked closely with DOE/HQ and DOE/SF throughout the conduct of the proceedings and the settlement discussions.¹

¹The terms DOE/SF and DOE are used interchangeably throughout the remainder of this report for expository purposes. The reader should understand that this was a cooperative effort between Headquarters and the Operations Office.

DOE initiated the proceeding before the CPUC. It filed several pleadings and affidavits of several witnesses. DOE was prepared to file a direct case on policy, contracting, engineering, and ratemaking issues had a settlement not been reached. The outline of DOE's direct case had already been developed. Western took the lead in the FERC proceeding, but DOE played an active role throughout. At the time the proceeding was stayed to facilitate settlement discussions, it had not yet been decided what testimony DOE would submit to the FERC.

PG&E initially demanded the following conditions in order to keep the existing Tesla line in place:

- Payment of special facilities charges;
- Payment of Schedule S retail standby charges;
- Point of delivery only at Tracy Substation;
- Payment of 3.7 percent losses between Tracy and LLNL; and
- Payment for PG&E E-20 retail power if the Tracy Tie Line fails.

It is estimated that the annual cost of meeting these terms would have been approximately \$1.2 million. Moreover, PG&E refused to operate the two lines in parallel, thereby depriving LLNL of one of its reliability objectives.

As a result of the settlement, it is estimated that the annual cost of keeping the Tesla line in operation will be approximately \$218,000 prior to parallel operation, and \$237,000

after the parallel is complete. More specifically, the major features of the Settlement Agreement are as follows:

- PG&E and Western will provide parallel service to LLNL as soon as required system upgrades are completed;
- PG&E's Tesla No. 1 line will remain in hot standby until parallel operation begins;
- PG&E will wheel Western power to LLNL in the event of a Tracy Tie Line outage;
- There will be no line losses assessed after parallel operation; DOE will reimburse Western for PG&E energy losses on the Tracy Tie Line until parallel operation at a rate not to exceed one percent;
- DOE/SF will pay annually adjusted standby wheeling charges applied to the amount of non-PG&E power used by LLNL. The rate is set at an initial \$.70 per kW-month.
- There will be no facilities charges; and
- PG&E will meet with DOE/SF to negotiate in good faith for the provision of coordination services to support DOE/SF's use of its entitlement in the California-Oregon Transmission Project (COTP).

In the remainder of this report, we shall discuss in some detail the DOE/Western litigation and negotiation efforts. More specifically, we shall provide a detailed description of the events leading up to the FERC and CPUC cases, and the actions and issues in the FERC case, the CPUC case, and in the settlement discussions. In the remainder of this section we provide an overview assessment of DOE's combined efforts to reduce costs and increase reliability at LLNL through the effective use of the Tracy Tie Line.

DOE should view the Tracy Tie Line Settlement Agreement as one of the major victories in its utility intervention program. A direct connection to Western was a concept that PG&E fought, sometimes at the highest levels, for more than a decade. Completion of the line by Western was a first and critical step in establishing some power supply independence for the DOE/SF laboratories. But, if PG&E could successfully constrain the way in which the line could be used to serve the labs, the value of the line to DOE/SF would be greatly diminished. Further, and very important, PG&E was concerned that successful operation and use of the Tracy Tie Line by Western and DOE/SF would establish (from its perspective) adverse precedents on a number of issues.

For these reasons, PG&E's initial position was designed to deprive DOE/SF of the reliability benefits associated with redundant feeds; to limit the way in which DOE/SF could use the line to obtain non-PG&E power; and to make it costly to DOE/SF to use the line for any purpose. In fact, PG&E realized none of these objectives under the terms of the Settlement Agreement. Not only does LLNL gain the benefit of dual feeds from two separate, major regional substations, but the two lines will eventually be operated in parallel, providing further reliability benefits to LLNL. The payments to PG&E for losses and limited standby services are reduced to reasonable levels. Finally, the settlement requires PG&E to negotiate in good faith the arrangements necessary to permit DOE/SF to utilize its share of the federal entitlement in the California-Oregon Transmission Project (COTP). We cannot emphasize too strongly the importance of this condition. Since PG&E is no

longer a participant in the COTP, it is doubtful that any of the protections afforded federal facilities in the initial COTP agreements were enforceable.

The 3-party agreement among DOE/SF, Western and PG&E to implement these arrangements is nearly complete, and less expensive Northwest power to displace PG&E power is expected to begin to flow over the COTP to LLNL by the beginning of 1994. The savings to DOE/SF over the 5-year term of this agreement are estimated at between \$10 and \$20 million, depending on the level of laboratory loads.

III. EVENTS LEADING UP TO LITIGATION

DOE began serious discussions with PG&E regarding the operation of PG&E facilities on June 28, 1989. DOE's initial posture was that it contemplated no immediate change in the purchased power mix at LLNL, but only a change in transmission arrangements. It was recognized that the situation could change over the next few years, and so DOE was guarded against entering into any agreement with PG&E that would eliminate or unduly constrain the future flexibility and bargaining leverage provided by the Tracy Tie Line. Thus, the issues DOE wanted resolved through discussions with PG&E were:

- How PG&E would continue to provide retail service to LLNL after the Tracy Tie Line was energized;
- The establishment of an additional delivery point at the Tracy substation;
- Arrangement for the preferred routing for the 115 kV tie between the new Livermore substation and Building 424; and
- Arrangements for the development of standard operating procedures for connection, protective relaying, automatic standby switching, and operation and maintenance of the Western and PG&E facilities.

PG&E added the following issues to the agenda, some of which indicated that PG&E intended to take a hard line position in negotiations:

- Timing and completion of the Western "direct service" facilities;
- Generation and transmission standby facilities and charges;

- Maintenance of an existing dedicated station breaker and/or 115 kV transmission line and resulting special facilities charges;
- Metering; and
- System reliability.

At the meeting of June 28, 1989, PG&E indicated its willingness to make the necessary modifications to on-site facilities to accommodate an overhead route for the 115 kV tie line between the new Livermore substation and Building 424. PG&E stated that the charge to DOE would be for the actual labor and materials involved in the rearrangement, and PG&E would provide DOE with a preliminary cost estimate as soon as DOE provided PG&E with a description of the proposed rearrangement.

Another unexpected issue surfaced that related to the use of and payment for a dedicated breaker at Tesla. PG&E, on its own initiative, had switched the Tesla transmission line from a breaker shared with other loads to one dedicated to support the load at LLNL. PG&E required the payment of a special facilities charge of \$130,000 a year if DOE wished to be served with the dedicated breaker under any alternative that would require PG&E to keep the Tesla line in operation. At the June 28 meeting, PG&E indicated that it needed to use a portion of that breaker to serve an additional 30 miles of transmission into the San Joaquin Valley, and DOE would have to make the choice quickly. That position was altered in PG&E's follow-up letter of July 24, 1989, in which it indicated that temporary rearrangement work already completed at Tesla relieved the overload conditions through 1990. Thus, DOE was able to decide whether to use the dedicated

breaker in the context of its broader decisions regarding what PG&E facilities would serve LLNL.

Following is a summary of PG&E's positions on the remaining issues:

- (1) Upon completion of the Tracy Tie Line, PG&E would consider LLNL to be a "direct service" customer of Western. As such, PG&E viewed Western as having acquired the utility obligation to serve LLNL.
- (2) PG&E would only be obligated to provide supplemental service at the Tracy substation, and would have no obligation to provide supplemental service along any other path.
- (3) If LLNL wished to receive standby service from PG&E when the Tracy Tie Line is out of service, then:
 - (a) LLNL would have to pay special facilities charges to keep a transmission line in service from Tesla to LLNL, and
 - (b) LLNL would have to pay for generation and system transmission standby under CPUC retail Schedule S.
- (4) PG&E would not deliver Western power to LLNL along any PG&E transmission path if the Tracy Tie Line went down, or even if the Tesla line were to operate in parallel with the Tracy Tie Line.
- (5) PG&E would require a new contract with DOE in order to establish a new point of delivery at the Tracy substation.
- (6) PG&E would consider serving a portion of the LLNL load over the Tesla line if the loads could be segregated between those served by Western and those served by PG&E. However, that would only be considered if LLNL could guarantee that none of the load served by Western would be switched to the Tesla line in the event the Tracy Tie Line were out of service.

PG&E justified its position on the basis of its interpretation of Contract 2948A. Specifically, it claimed that any Western preference customer that becomes directly

connected to the Western system becomes a "direct service customer" of Western. As such, PG&E argued that Western takes over the utility obligation to provide service to such a customer, and PG&E retains only the obligation to support Western's service at the Tracy substation. PG&E seemed to recognize that Contract 2948A does not establish a specific category of "direct service customers," but argued that it is implied by the contract. In particular, PG&E believed that it had no obligation to provide transmission service for Western power or supplemental PG&E service to the customer's premises absent payment of wheeling and loss charges. PG&E also maintained that it had no retail franchise obligation to keep the Tesla line open to provide retail power to LLNL. It maintained that all of these matters would be subject to FERC and not CPUC jurisdiction, despite the fact that LLNL would be required to pay CPUC regulated rates for all PG&E service. Interestingly, PG&E denied that LLNL would become a wholesale customer of PG&E, though it also maintained that LLNL was not a PG&E retail customer.

PG&E's position seemed to be driven primarily by its concern about setting a precedent for service to "direct service" customers of Western. At the time, PG&E provided an alternate transmission path to the Sacramento Municipal Utility District (SMUD), which was one of four Western customers that had direct connections to the Western grid. PG&E was proposing to alter its arrangement with SMUD by requiring SMUD to pay significant charges for support services provided by PG&E, and this proposed revision was expected to result in strongly contested litigation before the FERC.

PG&E seemed to believe that no harmful precedent would be set if it segregated LLNL loads into Western and PG&E retail portions, essentially making LLNL two customers; or if it imposed on DOE special facilities charges for the Tesla line and generation and system transmission standby charges, thereby committing to provide PG&E retail service in the event the Tracy Tie Line goes down. Some of PG&E's proposals may have reflected some PG&E interest in locking in some portion of LLNL's business over the next few years, although the DOE negotiating team viewed this to be of secondary importance to PG&E.

As a follow-up to the meeting, PG&E provided DOE with a written description of three arrangements under which PG&E was willing to meet the reliability and supplemental service requirements of LLNL. Under the first case, the Tesla line would have been disconnected. PG&E would have provided supplemental power at Tracy, and Western would have delivered all of LLNL's requirements over the Tracy Tie Line. PG&E power would have been metered at Tracy and PG&E billing would have included the costs of losses between Tracy and LLNL. There would have been no special facilities or standby charges. Most important, LLNL would again have been served by one line from one substation. Reliability could have been improved marginally by stringing another conductor on the Tracy Tie Line, the cost of which would have been borne by DOE.

Under the second case, PG&E would have kept the Tesla line in operation and provided LLNL with two points of delivery -- Tracy and LLNL. Further, PG&E would have

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provided standby service to LLNL. Specifically, PG&E would have provided E-20T power over its Tesla line in the event the Tracy Tie Line went out of service. PG&E would not have wheeled Western power in that situation. For this service, DOE could have paid up to \$1.2 million a year, or nearly twice the \$626,000 annual savings to be realized by LLNL through avoidance of PG&E wheeling charges.

Under the third case, LLNL would have had to split its load between that served by Western and that served by PG&E. PG&E would have delivered E-20T retail power only at LLNL. Essentially, LLNL would have been divided into two customers. Under this split-load arrangement, PG&E would have been willing to waive the special facilities charge for the Tesla line "strictly as an accommodation" to LLNL. However, PG&E required some guarantee of revenues for that waiver, most likely through some form of facilities charge agreement. In addition, PG&E was willing to provide standby E-20T service for the portion of the load that would have been served by Western. That power would have been delivered over the Tesla line at E-20T retail rates and the standby charges would have been those under Schedule S, then estimated at \$9,480 per megawatt year.

DOE found none of these alternatives to be acceptable. The idea of splitting the load was rejected out of hand. The reliability benefits of two feeds would have been lost and it would have increased LLNL's power costs by losing diversity benefits and from under-utilizing Western power, because the "X-over-Y" billing algorithm would have no longer applied. Disconnection of the Tesla line was unacceptable for a number of reasons, but

mostly because it would have deprived LLNL of the benefits of a dual feed from separate substations. The payment of special facilities and standby charges was the best of the three options, but DOE believed PG&E did not have a strong basis upon which to impose in excess of a million dollars a year on LLNL.

DOE/SF faced a major problem in dealing with PG&E. It was becoming increasingly clear that the contractual issues would have to be adjudicated by the appropriate regulatory body, and it was tempting to initiate this process at once in order to speed up the resolution. However, there were a number of engineering issues that had to get resolved in order to reconfigure the facilities at LLNL to replace one of PG&E's feeds with the 115 kV feed from the new Livermore Substation. The least costly way to accomplish this required PG&E's cooperation. Also, the switchover to the Tracy Tie Line required cooperation from PG&E. DOE had managed to separate the engineering and contractual discussions. Two largely different PG&E groups were dealing with these two areas, and PG&E was largely cooperating on the engineering side. DOE remained concerned well into 1990 that it not disrupt the cooperative progress on the engineering side by initiating a proceeding before the CPUC or FERC on the contractual issues.

Exeter prepared a report for DOE/SF in November 1989 summarizing the issues and proposing a strategy for dealing with PG&E.² It was recommended that DOE "continue

² "Proposed Strategy to Maintain Pacific Gas and Electric Company Service to the Lawrence Livermore National Laboratory with the Completion of the Tracy Tie Line," November 1989, prepared by Exeter Associates and C.H. Guernsey & Co. under

dialogue with PG&E while proceeding with completion of the construction of the Tracy Tie Line and associated facilities." Following one of the specific recommendations of the report, DOE/SF sent a letter to PG&E on December 9, 1989, in which DOE's position in response to the July 24, 1989 letter from PG&E in which the three options were delineated.³ DOE stated that PG&E had a continuing obligation to provide service to LLNL under its existing contracts and its CPUC franchise. Specifically, DOE stated that PG&E had no right to remove the Tesla line, that DOE had no obligation to pay special facilities charges for the line or standby charges, and PG&E was obligated to wheel Western power to LLNL under Contract 2948A with Western. DOE stated its intention to resolve its differences with PG&E and pointed out that DOE would continue to work with PG&E and Western to facilitate the engineering changes required for the energization of the Tracy Tie Line.

This approach seemed to work. Negotiations on the contractual issues continued throughout 1990, although with little substantive progress. DOE/SF even offered to pay the annual \$270,000 facilities charges in return for PG&E's commitment to provide delivery points at both Tracy and LLNL, to operate in parallel through LLNL, and to wheel Western power to LLNL in the event of a Tracy Tie Line outage.⁴ At the same time engineering issues were getting resolved relating to the reconfiguration of facilities at LLNL and the switchover to and testing of the Tracy Tie Line. As part of the arrangements, PG&E agreed

Contract No. DE-AC03-86-SF16343.

³Letter to Allan Schurr from Jerald S. Scheinberg, December 8, 1989.

⁴Letter from Jerald S. Scheinberg to Daniel Wilcox, August 29, 1990.

to leave LLNL on the dedicated breaker and to accommodate "make-before-break" switching between the Tesla and Tracy lines for one month following energization of the Tracy Tie Line. Beyond this "burn-in" period, PG&E had also committed to proving backup at least one time even without the necessary contractual agreements in place.

The situation began to heat up in December 1990. On December 21, Robert J. Haywood, PG&E Vice President for Power Planning and Contracts, wrote a letter to the Area Manager for Western, threatening to disconnect the Tesla line with 24 hours notice after energization of the Tracy Tie Line if standby arrangements were not in place by then. In response, DOE and Western held a strategy meeting in Washington D.C., on January 30, 1991. As a result of that meeting, Western send a formal letter to Robert Haywood of Western requesting, under the terms of Contract 2948A, that the Tracy Tie Line be operated in parallel with PG&E. Further, Western legal counsel developed a comprehensive legal analysis of Western's options, with particular attention focused on actions before the FERC. A similar analysis was developed by DOE Office of General Counsel covering DOE's option, particularly before the CPUC. These analyses were provided during February of 1991.

A draft "Action Plan" was developed by Exeter and distributed to the DOE/Western team on March 25, 1991. This plan anticipated simultaneous filings before the FERC by Western and the CPUC by DOE/SF. Drafts of the documents to be filed were discussed at another DOE/Western strategy meeting in Washington, D.C. on April 25, 1991. By this

time Exeter had been issued a Task Assignment under the HQ contract, since it was clear that DOE would have to litigate the issues.

Things came to a head with the energization of the line on May 18, 1991. On June 12, Nancy Munro, LLNL's PG&E account representative, sent a letter and proposed contracts to DOE/SF. The contracts were for the provision of standby service and special facilities, consistent with PG&E's original position. Ms. Munro informed DOE/SF that, "Should you decide not to pursue one of the options set out above for tariffed service, PG&E will have no choice but to de-energize the Tesla-LLNL No. 1 tap line at Tesla." DOE/SF and Western both wrote letters to PG&E management objecting to PG&E's unwillingness to extend the period that Tesla would remain connected beyond the 30 days ending June 18, 1991. On June 21, PG&E sent essentially the same letter to Donald Pearman, DOE/SF Manager, and David Coleman, the Western Area Manager, informing them that PG&E would file a Notice of Cancellation with the FERC and an Advice Letter with the CPUC seeking a declaration "permitting PG&E to bill LLNL for the service it is receiving despite the refusal to sign contracts for this service." PG&E made its FERC filing on June 21, 1991, and sent its Advice Letter to the CPUC on July 10, 1991. The litigative battle was thus joined.

IV. THE FERC PROCEEDING

On June 21, 1991, PG&E filed with the FERC a "Notice of Cancellation of Transmission Service to Lawrence Livermore Laboratory Pursuant to Contract No. 14-06-200-2948A. The FERC accepted the filing and assigned Docket No. ER 91-499-000. PG&E requested a waiver of the usual notice provisions and requested that the cancellation of service be made effective June 18, 1991, the end of the 30-day "burn-in period" for the Tracy Tie Line. Its arguments were essentially those presented to DOE a year or so earlier. Specifically, PG&E argued that, when LLNL became a "direct service customer" of Western, PG&E retained no obligation to wheel power to LLNL under Contract 2948A. DOE/SF could have switched back to the Tesla line as its main feed on June 18, and used the Tracy Tie Line for standby. Under that arrangement PG&E would have retained its obligation to wheel to LLNL. Instead LLNL maintains its primary feed through the Tracy Tie Line and insists that PG&E maintain the Tesla line as backup without compensation. PG&E accused DOE/SF of trying to get all other PG&E ratepayers to subsidize LLNL standby service.

As a result of discussions at several meetings between DOE and Western, it was agreed that Western would take the lead for the government in this proceeding. On July 15, 1991, Western filed a "Protest and Motion to Reject Filing or, in the Alternative, Motion to Intervene and Request for Hearing." Also on July 15, 1991, DOE filed a "Motion to Intervene and a Request for Hearing." DOE's pleading emphasized that PG&E's threat to remove its transmission facilities would "degrade the electrical service reliability available to

LLNL and would seriously jeopardize LLNL's critical mission and programs." Eight other Western CVP customers intervened in the proceeding, including SMUD, Santa Clara, NCPA and TANC.

Western moved the Commission to reject PG&E's filing as deficient. The wheeling service in question is provided under Rate Schedule No. 79, Supplement No. 25, which was the result of a Rate Settlement Agreement between PG&E and Western. Western pointed out that Agreement does not permit PG&E to unilaterally terminate or cancel service to a given Western customer. Western also argued that PG&E relied on an improper FERC regulation (Section 35.15), because PG&E is not trying to terminate all or a portion of an existing rate schedule. Rather, PG&E is trying to unilaterally modify the rate schedule to deny service to just one customer -- LLNL. Western went on to add that, even if this were the right regulation, PG&E's filing would still be deficient because PG&E failed to include as part of its filing considerable information that is required under the regulation. As part of its pleading, Western also emphasized that PG&E was filing its notice as retaliation for Western building the line over PG&E's objections, and that LLNL, as a critical national defense installation, "requires a level of electric service reliability that only fully redundant feeds from different substations can provide."

On July 29, 1991, PG&E filed its "Opposition to the Western Area Power Administration's Protest and Motion to Reject Filing." It largely reiterated its initial arguments, but also argued that it was legally within its rights to cancel the service to LLNL

under Section 35.13 as the cancellation of part of a rate schedule on file with the Commission. The part being cancelled, argued PG&E, was the part relating to service to LLNL.

The FERC was unconvinced. On August 22, 1991, the Commission issued an Order rejecting PG&E's Notice of Cancellation as without merit. FERC identified two arguments being made by PG&E, and it rejected both. The first was the argument that PG&E need not provide transmission service to LLNL under 2948A because, after the energization of the Tracy Tie Line, the service was no longer necessary. The Commission concluded that, "There is no contract provision [in 2948A] which prohibits WAPA from serving its customers directly with transmission service," and "nothing in the contract...permits PG&E to cancel the contract provision relating to transmission service to a given WAPA customer."

The second rejected argument was that Contract 2948A does not provide for standby transmission service and so that must be provided under retail tariff. The operative language is that, "no matter what PG&E terms the transmission service (or lack thereof) ... this does not change PG&E's contractual obligation. FERC noted that the rate was to be applied to actual "energy flows to Livermore over PG&E's lines," and does not address the issue of payment when the service falls to zero. In conclusion, the Commission stated that, "by attempting to cancel the portion of the contract providing for transmission service to Livermore, PG&E is attempting to indirectly modify contract terms and rates -- something it may not do directly under the present contract."

This decision was a clear and important victory for DOE and Western. It prevented PG&E from disconnecting the Tesla line and meant that PG&E would be required to wheel Western to LLNL. Given that requirement under FERC regulation, DOE's case before the CPUC was greatly strengthened. PG&E filed a lengthy motion before FERC on September 20, 1991, requesting a rehearing of the Commission's Order. Its story was that it (PG&E) had failed to properly explain what it was attempting to do by cancelling service to LLNL. It emphasized it was not permanently extinguishing forever Western's rights to require transmission service to LLNL, and would honor a future request to return LLNL to wheeling service. Rather, it was the insistence on providing standby service to LLNL that prompted PG&E to take the action, since there is no provision for standby transmission service in Contract 2948A. On October 16, the Commission issued a tolling order, holding the process in abeyance.

It was at this time that PG&E made serious settlement overtures to DOE and Western. With the agreement of all the parties, PG&E sent a letter to the FERC on October 25, 1991, requesting the Commission to defer action on PG&E's motion for reconsideration to December 31, 1991, at which time the parties were to notify the Commission as to the status of the negotiations. On January 2, 1992, PG&E notified the Commission of a settlement in principle and the parties' hope that a detailed settlement could be filed by March 15, 1991. In fact the settlement was filed on April 29, 1992. Amended filings were made on June 9 and August 13, 1992 to respond to certain concerns of the Staff. A letter from Donald J. Gelinas, Director of the Division of Applications, was

sent on October 13, 1992, accepting the Settlement for filing and stating that this would be the final action by the FERC on this matter.

V. THE CPUC PROCEEDING

On June 28, 1991, DOE filed a Complaint with the CPUC (Docket No. 91-06-060). The Complaint explained PG&E's threat to terminate service at LLNL and asked the Commission to enjoin PG&E from any such act. DOE further requested the Commission to hold a hearing to permit the development of an adequate record upon which the Commission should base its decision. In support of its motion, DOE included the Affidavit of Jerald A. Scheinberg, DOE/SF Utilities Program Manager, and the Declaration of Dennis K. Fisher, Associate Director for Plant Operations for LLNL.

The DOE filing explained to the Commission the critical nature of the operations at LLNL, and that the Secretary of Energy had set forth a policy that National Defense facilities should have fully redundant transmission service from different substations for reliability reasons. It was to achieve this improvement in reliability that Congress authorized the construction of the Tracy Tie Line. DOE explained that no change in supply arrangements was occurring, except that LLNL's service reliability was being significantly enhanced by the government constructing the line. Most important, there would be no change in PG&E power sales to LLNL as a result of the line.

DOE's pleading clearly indicated how unreasonable were PG&E's demands. These included:

- \$270,000 a year for the line and the breaker;
- Its refusal to wheel Western power over the line;
- The requirement to pay standby charges even if DOE pays for the line; and
- PG&E's threat to disconnect the line if DOE/SF refuses to agree to these terms.

DOE made two legal arguments, both of which boiled down to PG&E's lack of authority to discontinue service to LLNL without the CPUC's permission. The first was that changing LLNL's point of delivery from Building 424 at LLNL to the Tracy Substation amounts to a change in the character and conditions of service, and cannot be done without CPUC approval. The second was that PG&E had allocated a portion of the Tesla No. 1 line to CPUC rate base, and so the line was devoted to public use. Therefore, PG&E could not discontinue the service without CPUC approval.

On July 10, PG&E filed Advice No. 1363-E with the Commission, requesting that it be allowed to bill LLNL for special facilities costs and standby costs under Rate Schedule S. PG&E argued that LLNL was trying to get something for nothing and that PG&E should be compensated for the provision of standby service. On July 30, 1991, DOE/SF filed a "Protest, Motion for Suspension of Advice Letter and Hearing and Motion for Consolidation," arguing that the action initiated by PG&E's Advice Letter provided no new information and should be consolidated with DOE's Complaint. The CPUC granted DOE's request for consolidation.

PG&E answered DOE's Complaint on August 1, 1991. It painted DOE/SF as the "heavy," noting that the move to "direct service" from Western makes it no longer possible for PG&E to provide the services desired by DOE/SF under PG&E's existing contracts. PG&E argued that it no longer had any legal obligation to maintain the line and related facilities in service. PG&E also argued that, despite DOE's claim, the line was not in public use because it was not being used to transmit any energy to LLNL. PG&E countered DOE's charge of changing the character of the service by refusing to deliver anywhere but the Tracy Substation, by arguing that it was not possible to deliver to Building 424 at LLNL because the line was physically disconnected.

A prehearing conference was held before the Administrative Law Judge (Honorable Janet Econome) on September 30, 1991. A procedural schedule was established, including a process for extending the schedule should any progress be made in settlement discussions. Interestingly, PG&E attempted to get the ALJ to exclude the issue of paralleling at the conference, but was unsuccessful. Discovery proceeded, with a scheduled deadline of December 16, 1991.

On October 25, 1991, PG&E filed for a "Summary Adjudication of Issues and Motion to Limit Discovery..." The purpose of this filing was to exclude the issue of parallel operation from the proceeding. PG&E was ardent in its case that the CPUC has no jurisdiction to order parallel operation, because the issue falls within the exclusive jurisdiction of the FERC.

DOE filed its response on November 11, 1991. In essence, DOE argued that parallel operation had to be discussed in the proceeding. That is because the interconnection of PG&E's Tesla No. 1 line with Western and LLNL is necessary in order for PG&E to provide service to LLNL in accordance with the CPUC's regulated tariffs and rules. DOE argued that interconnection and parallel operation of the Tesla No. 1 and Tracy Tie Line "is the only practicable means of operation and best meets the reliability needs of LLNL." This was supported by a Declaration filed by Steven E. Collier, a consulting engineer provided through the Exeter contract. Finally, DOE argued that, "such parallel operation in no way affects any wholesale transactions occurring between Western and PG&E, nor does it create any new wholesale obligations on PG&E." Thus, by addressing the issue of paralleling in this specific context, the CPUC would, in no way, be infringing on the wholesale jurisdiction of the FERC.

It is clear that PG&E was extremely anxious to avoid the CPUC's involvement in the paralleling question. This concern, along with the FERC's rejection of PG&E's Notice of Cancellation, no doubt fueled PG&E's interest in reaching a settlement. To accommodate the settlement effort, the CPUC schedule was postponed indefinitely. DOE requested that its Complaint be dismissed on October 23, 1992, after the Settlement was accepted by the FERC. The case was officially closed by the CPUC on November 18, 1992.

VI. THE SETTLEMENT

PG&E and Western met on September 18, 1991 to initiate settlement discussions on issues being litigated in both the FERC and the CPUC cases. As a result of those preliminary discussions, the parties, including DOE, met the following October 16, at which time PG&E submitted a formal proposal to resolve all the issues in both proceedings. PG&E's offer included a commitment for a new parallel connection between PG&E and Western at LLNL. However, the remainder of the proposal was so onerous that PG&E would have gained more, at the expense of DOE/SF, than it would have gained with complete success at both the FERC and the CPUC. The critical elements of the PG&E proposal are as follows:

- DOE/SF would be required to take standby service under PG&E's retail Schedule S;
- DOE/SF would be required to pay special facilities charges for the Tesla line and associated facilities;
- LBL would be required to use PG&E power;
- The Western allocations at SLAC, LLNL and Site 300 would have to be fixed on an annual basis;
- DOE/SF would have to pay 3.7 percent losses on PG&E power delivered over the Tracy Tie Line;
- DOE/SF would have to pay the cost of any upgrade of the Tesla line if PG&E needed the existing capacity for other purposes.

On October 29, 1991 DOE provided a point-by-point response to PG&E's October 16, 1991 proposal, and also provided a counter settlement offer. The counter offer was largely a reiteration of DOE's original position. DOE/SF agreed to pay for the Tesla line but required that it have unrestricted use of the full capacity of the line, including the right to transmit over that line any source of power DOE/SF shall have delivered at Tesla substation. DOE/SF agreed to the annual fixing of the combined Western CRD for all the labs, but reserved the right to allocate Western power among the labs on a monthly basis. A commitment by PG&E to negotiate necessary contracts for DOE's use of the COTP was also included in the DOE counter offer.

The parties met again on November 5, 1991. Western had developed its own counter offer, and DOE and Western agreed that the Western proposal would represent the positions of both parties. Much of the Western counter proposal was similar to that developed by DOE, but the Western proposal did include a few wrinkles:

- There will be no Schedule S charges for Western CVP power deliveries, but Western proposed that Schedule S be used to stand by all COTP imports. This would extend to LBL and SLAC;
- LLNL would pay for the Tesla No. 1 line, but would have priority wheeling rights to the line. PG&E could use any portion unused by LLNL;
- Western agrees to 1 percent losses on the Tracy Tie Line, instead of 3.7 percent;

PG&E was unwilling to commit to the Western-DOE proposal or to make a counter offer on the spot. It was agreed the parties would meet again, at which time PG&E would

offer a counter proposal. The PG&E representatives did, however, take the time to identify what they viewed as trouble spots. They indicated that PG&E's main concern is DOE's and Western's refusal to pay standby charges for CVP power. PG&E indicated there was room to find a compromise on the dollars, but PG&E required recognition of standby service. The loss factor issue turned out to be over how losses will be recognized between LLNL and Tracy in order to determine LLNL's contribution to the system simultaneous peak at Tracy. The issue really had more to do with keeping Western within the 1152 mW support level, and it seemed likely there was room for compromise on this question.

The last issue that PG&E seemed to view as a deal breaker was the elimination of LBL as a delivery point for Western CRD and restrictions on the use of the Western allocation among the labs. This was surprising since it was an issue never before mentioned by PG&E. PG&E counsel indicated it was additional compensation for PG&E's willingness to parallel because termination of the two cases was not enough.

The breakthrough came at the next meeting at Rancho Solano on November 13, 1991. PG&E submitted a counter offer that provided the basis for a settlement agreement in principle. Most of the onerous conditions were deleted, including the elimination of LBL as a point of delivery and limitation on DOE's use of its Western allocation. PG&E solved its need for standby recognition by eliminating the requirement that DOE/SF pay facilities charges, and instead proposed a standby transmission charge in place of the Schedule S tariff. PG&E proposed an initial rate of \$1.01/kW-month, but this was negotiated down to

\$.70, reflective of its cost of area transmission service. The critical parts of the agreement are as follows:

1. PG&E agreed to operate Tesla No. 1 in parallel with the Tracy Tie Line.
2. There would be no standby charge per se on Western CVP power.
3. There would be no facilities charges for the Tesla line or any associated facilities.
4. There would be no upgrade costs imposed on DOE/SF as a result of load growth on the Tesla No. 1 line. These costs would be rate based.
5. Losses on the Tracy Tie Line would be calculated at 1 percent until parallel operations. No losses would be assessed after the parallel is completed.
6. DOE/SF would be required to pay a standby transmission charge on all CVP and other non-PG&E power on a contract-demand basis. The rate would be based on PG&E area transmission cost and escalated by formula.
7. PG&E would negotiate in good faith other agreements necessary to permit DOE to utilize its share of the federal entitlement in the COTP.

PG&E took off the table its demand to eliminate LBL as a delivery point and its requirement to fix the CRDs at each of the labs on an annual basis. The parties agreed that these issues were more properly addressed in the Contract 2948A restructuring negotiations that were taking place at the time.⁵ The major concession made by DOE and Western was the payment of standby transmission charges. This is effectively a contract or ratcheted demand charge applied to all non-PG&E power, and it is an adjustment that PG&E could

⁵Those discussions have since been terminated for all intents and purposes.

have obtained from the FERC had it sought a modification of the 2948A wheeling rate (which includes a backbone transmission charge).

DOE/SF got nearly all that it had hoped to in litigation. It avoided paying facilities charges. It reduced the loss assessment down to 1 percent and to zero after parallel operation. It got PG&E to operate Tesla No. 1 as a rate-based facility with no upgrade obligations, and it got a commitment that PG&E would wheel non-PG&E power over that line. Most important, it got parallel operation out of the settlement, which was not even one of the original objectives. Finally, and very important, it won from PG&E a commitment to negotiate in good faith the coordination agreements necessary for DOE to utilize its share of the COTP. PG&E has followed through on that commitment, and the three party agreement governing DOE use of the COTP is nearly complete.

It took another 5½ months of negotiating and redrafting to arrive at a final agreement, but the settlement was finally filed with the FERC on April 29, 1992, and accepted by the FERC on October 13, 1992. The document provides the basis for DOE/SF to pursue alternate ways to lower its power supply costs over the next decade or so. The nearly completed 3-party agreement with PG&E and Western for coordination services to support DOE's use of the COTP is the first step in this long-term process.

Analysis of Proposed Settlement Among
PG&E, Western and DOE/SF
Regarding Electric Power Service to LLNL

March 11, 1992

BACKGROUND

In 1988, DOE/SF selected Western Area Power Administration (Western) to construct a 12-mile, 230 kV transmission line from Western's Tracy Substation to Lawrence Livermore National Laboratory (LLNL). The Western line (Tracy Tie Line) was selected over an alternative additional 115 kV line from Pacific Gas and Electric Company (PG&E). Western began construction in 1988 and the line was energized in May 1991.

There were two basic purposes for construction of the Tracy Tie Line:

1. To improve reliability at LLNL by obtaining feeds from two separate and independent substations; and
2. To realize power cost savings by eliminating wheeling charges from Western, reducing loss adjustments, and by gaining a direct path to Western and any resources that Western is able and willing to provide to LLNL.

Realizing the reliability objective requires the maintenance and the continued operation of PG&E's Tesla No. 1 line to LLNL. Negotiations with PG&E and Western, regarding the operation and interfacing of the Tracy and Tesla lines, began in June 1989. In developing the DOE/SF negotiating strategy, parallel service to LLNL appeared to be the natural engineering solution and it would provide significant additional reliability benefits to LLNL. Consequently, parallel operation became an additional reliability objective.

PG&E AND DOE/SF-WESTERN POSITIONS

DOE/SF and Western argued that the completion of the Tracy Tie Line did not alter any contractual or franchise obligations. Specifically DOE/SF and Western maintained that:

- PG&E is obligated to maintain the Tesla No. 1 line under its CPUC franchise, and the costs of these facilities are included in E-20 retail rates;
- PG&E is obligated to wheel Western power to LLNL under Contract 2948A at the FERC-approved rate;
- Parallel service is the logical and appropriate way to operate the two lines;
- LLNL has no obligation to pay standby charges or facilities charges as long as E-20 retail power is purchased in sufficient quantity.

PG&E took a hard-line position, arguing that it had no obligation to provide service to LLNL but only at the Western Tracy Substation once LLNL became a "direct service" customer of Western. Therefore, PG&E proposed to continue operation of the Tesla No. 1 line only if the Tracy Tie Line were operated as standby, or if LLNL segregated the PG&E and Western loads. If the Tracy Tie Line were to provide primary service to LLNL, PG&E took the following specific positions:

- PG&E would maintain the Tesla No. 1 line only if LLNL paid facilities charges of \$270,000 a year;
- PG&E would stand by if LLNL paid Schedule "S" standby charges on its non-PG&E power;
- PG&E would not wheel Western power to LLNL in the event of a Tracy Tie Line outage, but would provide only E-20 retail power;

- PG&E would deliver E-20 supplemental power only to Tracy Substation and would impose costs for line losses to LLNL, later specified at 3.7 percent; and
- PG&E would not provide parallel service.

The combined annual cost of meeting PG&E's initial demands would have amounted to approximately \$1.2 million in 1992, based on LLNL forecasted 1992 loads and its current Western CRD of 28,211 kW. These calculations are shown in Table 1.

PG&E filed a petition with the FERC to cancel wheeling service to LLNL under Contract 2948A with Western. Both Western and DOE/SF protested PG&E's action. In addition, DOE/SF filed a complaint with the CPUC to enjoin PG&E from disconnecting the Tesla No. 1 line, to require PG&E to deliver its E-20 power at LLNL, and to prevent the imposition of standby charges. Serious settlement discussions resumed in the fall of 1991 and a Settlement Agreement was reached and signed by attorneys for the parties on February 19, 1992.

The major features of the Settlement Agreement are:

- PG&E and Western will provide parallel service to LLNL as soon as required system upgrades are completed (expected by 1993);
- PG&E's Tesla No. 1 line will remain in hot standby until parallel operation begins;
- PG&E will wheel Western power to LLNL in the event of a Tracy Tie Line outage;
- There will be no line losses assessed after parallel operation; DOE will reimburse Western for PG&E energy losses on the Tracy Tie Line until parallel operation at a rate not to exceed one percent;

TABLE 1

PG&E - WESTERN - DOE/SF SETTLEMENT AGREEMENT
RELATING TO
TRANSMISSION SERVICE TO
LAWRENCE LIVERMORE NATIONAL LABORATORY

PG&E Demands

Facilities payments	\$ 270,000
Schedule S standby charge (.85 x \$.60 x 28,211 kW x 12)	172,651
Losses (3.7% of estimated PG&E 1992 bill -- \$11,840,627)	438,103
Outage cost (1 24-hour summer outage)	
• 28,211 kW x [(\$9.00 + \$.60) - (\$85 x \$.60)]	256,438
• 481 mwh x (\$54.40 - \$16.30)	<u>18,326</u>
TOTAL	\$1,155,518

Costs Under Settlement Agreement

Standby charge (28,211 kW x \$.70 x 12)	\$ 236,972
Losses (until parallel operation) 192,329 mwh x \$23 x .01	<u>44,236</u>
TOTAL	\$ 281,208

Net Annual Savings

• Prior to parallel operation	\$ 874,310
• After parallel operation	\$ 918,546

NOTES TO TABLE 1

1. Calculations are based on 1992 LLNL estimated bills and Western CRD:

Peak Demand	65,321 kW
Western CRD	28,211 kW
Summer monthly load factor	71%
Total energy	383,119 mWh
PG&E energy	192,329 mWh
Total Cost	\$17,807,720
PG&E E-20 Costs	\$11,840,627

2. Facilities payments are comprised of \$140,000 for the Tesla line and \$130,000 for a dedicated breaker.
3. 3.7 percent loss factor was PG&E's initial demand for additional power and energy to be delivered at Tracy for wheeling and metering at LLNL over the Tracy Tie Line.
4. The cost of a 12-hour summer outage is based on the terms of PG&E's Schedule S. \$54.40 per mWh is the weighted cost of E-20 energy, using LLNL period usage weights: peak - 20.6%; partial peak - 21.46%; and off-peak - 57.86%. \$16.30 is the Western energy rate.
5. The \$.70 standby charge under the agreement is prior to any escalation.
6. It is assumed that DOE can replace Western losses with non-firm purchases in the Northwest at a rate similar to \$23/mWh rate in the December 1, 1991 Western/Pacificorp 20-year purchase agreement.

- DOE/SF will pay annually adjusted standby wheeling charges applied to the amount of non-PG&E power used by LLNL. The rate is set at an initial \$.70 per kW-month;
- There will be no facilities charges; and
- PG&E will meet with DOE/SF to negotiate in good faith for the provision of coordination services to support DOE/SF's use of its entitlement in the California-Oregon Transmission Project (COTP).

The annual cost under the Settlement Agreement is estimated at approximately \$281,000 prior to parallel operation and \$237,000 after the parallel is complete. DOE/SF will also be required to pay for necessary system upgrades to permit the parallel interconnection. The savings in annual operating cost compared to the cost under PG&E's initial demands are estimated at approximately \$874,000 a year before the parallel and \$919,000 a year after the parallel. This assumes one 12-hour summertime Tracy Tie Line outage each year. In years when no Tracy Tie Line outage occurs, the savings are estimated at approximately \$600,000 a year before parallel operation, and \$644,000 a year after parallel operation. These calculations are also shown in Table 1.

It is unclear whether PG&E would have any obligation to agree to a parallel connection without this settlement agreement. This is an issue before the CPUC. Western would have to file a complaint at the FERC to raise the issue there. Also, PG&E has no contractual obligation to negotiate with Western or DOE regarding services for DOE's use of COTP capacity. Because PG&E is no longer a participant in the COTP, PG&E no longer has any obligation to wheel power from the COTP to federal agencies as provided in the MOU for the COTP. These are all unquantifiable benefits of the settlement.

ANALYSIS OF SELECTED ISSUES

The following is in response to specific questions raised by the Public Utilities Branch of the Office of Organization, Resources and Facilities Management.

QUESTION 1: Beginning at line 2 of Section 3.B., it is stated that, "Western and/or DOE/SF shall pay PG&E" for the costs of reinforcements necessary for parallel operation. Why is payment to be made by Western and/or DOE/SF?

ANSWER 1:

PG&E's agreement to operate in parallel is with Western, and it will presumably bill Western for these costs. The expectation is that DOE/SF will ultimately bear these costs, most likely through a surcharge added to LLNL's monthly bills from Western. However, the specific mechanism is uncertain. Rather than having the settlement get bogged down by trying to hammer out specific appropriate billing and reimbursement mechanisms between Western and DOE/SF, it is simply agreed that Western and/or DOE/SF will pay the bill once the amount is agreed upon.

QUESTION 2: The second paragraph in Section 3.B., p. 5, includes the phrase, "energized and capable of service to LLNL if required". How is this different than "hot standby"? Why is this language used?

ANSWER 2:

This language is used synonymously with "hot standby" at the insistence of DOE/SF and Western to avoid use of the term "standby". The term, "stand-

by", had emotive quality, especially in the early days of negotiation. DOE/SF argued that PG&E was not supplying standby, but simply meeting its obligations under its CPUC franchise and its obligations under Contract 2948A. This euphemism was first used in DOE/SF's filing with the CPUC to move the discussion away from the issues as PG&E chose to define them. The language carried over to the Settlement Agreement.

QUESTION 3: What is the economic or cost-of-service justification for the standby transmission service set forth in Sections 4 and 5?

ANSWER 3:

This is a negotiated element of the overall Settlement Agreement. DOE/SF argued that, under the present CPUC tariff, PG&E had no basis for requiring LLNL to take standby service as long as LLNL continued to purchase significant amounts of E-20 retail power from PG&E. PG&E is also obligated to maintain transmission facilities to LLNL under its retail franchise obligations. Further, Contract 2948A requires PG&E to wheel Western power as long as there is excess capacity available on the PG&E transmission system. However, standby service (and/or purchase of facilities) will become necessary if either: (1) LLNL stops taking a sufficient amount of E-20 retail power from PG&E; or (2) if Contract 2948A is terminated with no alternative accommodation for wheeling to Western retail customers. Either or both of these conditions may occur within the next two years.

The litigation and negotiating team believed it had a good case on the standby issue before the CPUC. However, it did depend on the CPUC understand-

ing the very complex interface between PG&E's FERC and CPUC obligations, and a favorable ruling was hardly guaranteed. Consequently, the prudent approach was to pay for the transmission standby service for an additional one or two years as part of the overall settlement, since that service will be justified when COTP power displaces PG&E service. This is especially true when one considers that the Tesla facilities will be made continuously available with no special facilities costs to LLNL, and considering the major additional benefit of parallel operation that was agreed to by PG&E.

QUESTION 4: What is the basis for the \$.70 per kW-month charge in section 6.B.? How does this compare to the rate Western pays for wheeling service?

ANSWER 4:

The conceptual basis for the initial value of \$.70 is the average embedded cost of PG&E's "Area Transmission Service". DOE/SF successfully argued that no part of PG&E's "Backbone Transmission" system should be included, even though certain parts of the backbone substation equipment are required to wheel Western power to LLNL. The "Area Transmission" rates for most FERC-approved contracts have been in the neighborhood of \$1.04 per kW month.

The current Western wheeling rate (combined backbone plus area) is \$1.09/kW-month. The \$.70 is much closer to the backbone component of Western's combined negotiated rate with PG&E, than any cost-based rate. It should be noted, however, that every attempt has been made to disassociate the Settlement Agreement from Contract 2948A, which may be terminated at any time.

Thus, the \$.70 is simply identified as a negotiated rate. PG&E also insisted on this, not wanting to set any cost-of-service precedent for transmission rates for other customers. It should also be noted that this \$.70 per kW-month is not really similar to the Schedule S standby rate. Schedule S also imposes very high additional costs every time there is actual provision of standby service to cover an outage. For example, Table 1 shows that one annual 12-hour summertime outage would cost approximately \$275,000, which is 60 percent higher than the Schedule S monthly standby charges for that year.

QUESTION 5: Will the formula rate adjustment referred to in Section 6.C. require an annual filing by PG&E with the FERC?

ANSWER 5:

No. Once the FERC accepts the formula rate, no annual filing is required. According to Western's General Counsel, the FERC staff could require the Annual Transmission Rate Adjustment Factor (ATRAF) to be filed with it annually for its review. However, there are so many formula rates now that the staff would be unable to review all the calculations. The burden will be upon Western and DOE/SF to ensure the ATRAF is calculated properly. If unresolved differences remain, Western and DOE/SF would have the right to file with the FERC for adjudication of the issue.

QUESTION 6: Please explain what is meant by the statement in Section 9 that cost of metering will be "paid for by Western and/or DOE/SF"?

ANSWER 6:

The language was included for the same reason it was used in Section 3.B. (See ANSWER 1.) The intent of the language is that PG&E will not bear

these costs. It is expected that Western will absorb these costs since its policy is to generally provide meters at points where it delivers Central Valley Project (CVP) power. The "and/or" language permitted the negotiations with PG&E to proceed by deferring determination of a payment mechanism to compensate Western, if necessary.

QUESTION 7: Please explain the intent of the phrase "negotiate in good faith" as it is used in Section 12.

ANSWER 7:

PG&E has been denied participation in the COTP by the CPUC, and PG&E has been extremely difficult to deal with in negotiating wheeling and coordination services for the public participants. This section of the Settlement Agreement requires that PG&E meet with DOE/SF to negotiate the provision of these services "in good faith". This gives DOE/SF a leg up because the "good faith" requirement is enforceable. The agreement will be filed with the FERC. If DOE/SF believes PG&E is not negotiating in good faith it can file a complaint with the FERC along with a proposed contract for these services. FERC could accept the proffered contract or some variation of it. This is essentially the same process that the Transmission Agency of Northern California (TANC) used in forcing commencement of service and a reduction in its PG&E wheeling rate under the "South of Tesla Agreement".

QUESTION 8: Is there a legitimate basis for DOE/SF to pay for the losses identified in Sections 13.C. and 13.D.?

ANSWER 8:

PG&E sales to LLNL will be metered at LLNL. PG&E must deliver more power at the Tracy Substation than is metered at LLNL to account for the line and transformation losses between Tracy and the LLNL meter. Western has agreed to incur these losses (i.e., not assess them to PG&E) until such time as DOE/SF can purchase energy in the Northwest (presumably at non-firm or even spill rates) to reimburse Western.

DOE/SF maintained that these losses should be borne by PG&E as part of the cost of providing retail E-20 service. While losses would have to be incurred on Western's Tracy Tie Line, losses would be avoided on the Tesla No. 1 line. PG&E maintained that losses resulting from wheeling by a third party are always paid for by the customer and are not included as part of system costs. The point had merit, and PG&E identified this issue as a "deal breaker."

Given that these losses only apply up until parallel operation begins, and given that Western offered a very inexpensive reimbursement solution, the negotiation team considered this a small concession to make to obtain the numerous other cost and reliability benefits from the settlement.

QUESTION 9: Please explain Section 14 relating to "Contract 2948A Accounting".

ANSWER 9:

Under Contract 2948A between Western and PG&E, Western may not market more than 1152 MW of CVP power, as measured at the Tracy Substation. Power

metered at LLNL must be adjusted back to the Tracy Substation for purposes of calculating the Maximum Simultaneous Demand under Contract 2948A. Section 14 accomplishes this.

QUESTION 10: Please explain the general nature of the ATRAF set forth in Exhibit B. Has the formula been tested or reviewed, and how will DOE be assured of its proper application?

ANSWER 10:

The ATRAF formula calculates the percentage change from year to year in the average embedded cost per kilowatt-hour of the transmission system. An annual transmission revenue requirement is calculated for each calendar year based on expense and rate base elements reported in the FERC Form 1 Annual Report. Allocation to the transmission function of common plant and general and administrative expenses is based on allocations approved by the FERC in a 1989 case, as adjusted to reflect changes in these overall cost components since 1989. The rate of return is based on the capital structure and the cost of equity and debt allowed by the CPUC each calendar year.

This formula is the same as the one contained in the NCPA interconnection agreement and has been approved by the FERC. We have reviewed the formula in detail and find it a reasonable basis upon which to adjust the standby transmission rate. Each year when PG&E calculates the adjustment factor, DOE/SF and Western will be provided with the calculations and the supporting workpapers. As stated in ANSWER 5, it will be the responsibility of DOE/SF to review the calculation for accuracy. DOE/SF retains the right to

file a complaint with the FERC if it believes the ATRAF is being calculated or applied improperly by PG&E.

EXETER

Associates, Inc.

CONSULTING ECONOMISTS

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July 2, 1993

Thomas S. Catlin
Steven L. Estomin
Richard A. Galligan
Charles E. Johnson
Matthew I. Kahal
Marvin H. Kahn
Dale E. Swan

REF: 5503

Memorandum

To: Jerry Scheinberg
cc: Dave Magaw

From: Dale Swan

Subject: Contract Approvals

Following is a draft memo requesting approval of the 3-party agreement and the exhibits to the Intra-agency Agreement. Dave should provide his comments directly to Jerry.

DRAFT LANGUAGE
FOR
APPROVAL OF COTP CONTRACTS

We hereby request approval of:

- (1) Contract No. 93-SAO-00018 among DOE/SF, Western Area Power Administration and Pacific Gas and Electric Company, covering the power scheduling, sale of power, and sale of services related to federal use of the California-Oregon Transmission Project (COTP) for the DOE laboratories; and
- (2) Exhibits A through F to the Intra-agency Agreement No. 90-SAO-00001 between DOE/SF and Western Area Power Administration, through which Western agreed to act as DOE/SF's agent in utilizing the DOE laboratories' entitlement in the COTP.

Three copies of each document are enclosed for your consideration.

The successful negotiation of these agreements represents the culmination of nearly a decade of effort to get access to less-expensive Pacific Northwest power for the DOE/SF labs in order to displace expensive PG&E power. These agreements provide the means. The 3-party agreement commits PG&E to, among other things, schedule and transmit such power to the labs, and to provide all the coordination services necessary to use Northwest power. The exhibits to the Intra-agency Agreement provide the terms and conditions under which Western will layoff to DOE SF a portion of its long-term power purchase from PacifiCorp and the necessary capacity in the COTP to transmit that resource to LLNL. These exhibits also cover the provision by Western of certain standby services.

Once the 3-party agreement is executed, PG&E will file the contract with the FERC, and Western and DOE would submit letters of concurrence. The contract would become effective as soon as FERC accepts the contract for filing. If we can expedite approval, that could be as early as September 1, 1993. The exhibits to the Intra-agency Agreement do not have to be filed with any regulatory authority. We estimate the first-year savings from the use of the COTP under these agreements at approximately \$4

million.¹ Total nominal savings over the course of the 5-year term of the 3-party agreement are expected to approximate \$24 million.

In general terms, we believe the terms and conditions contained in the 3-party agreement and in the exhibits to the Intra-agency agreement provide DOE/SF with what it requires to effectively utilize its COTP entitlement during a 5-year interim period, while we explore other arrangements by which we can serve the integrated loads of the labs with a mix of resources, including COTP power. That will require getting wheeling service from PG&E to the Lawrence Berkeley Laboratory (LBL) and Stanford Linear Accelerator Center (SLAC). We also believe the terms, conditions and rates for services in both of these agreements are fair to DOE/SF, and generally are based on existing tariffs or cost-of-service calculations.

Summary of the 3-Party Agreement

The major features of Contract No. 93-SAO-00018 among DOE/SF, Western and PG&E are as follows:

- Term
 - Five years, but any party can terminate with one year notice
 - Parties are obligated to negotiate a replacement agreement(s) if terminated.
- Scheduling/Metering
 - Western will schedule COTP power into PG&E's control area for LLNL.
 - The amount of COTP power is initially set at 46.2 MW at the LLNL meter. This can be revised once per calendar year with 3 months notice.
 - The order of dispatch will be COTP, Western, then PG&E supplemental.
 - Energy billing will be proportional (same as current X-over-Y).

¹The \$4 million first-year savings estimate is very firm because it is based on certain rates for all three suppliers -- PG&E, Western and PacifiCorp. Only lab usage variations will cause the estimated savings to vary.

- Variations in actual hourly load and schedule will be handled in a deviation account. Energy will be made up to PG&E in similar hours in same month or next month.

- Other Coordination Services

- DOE/SF can elect to take spinning reserves and/or standby services from either PG&E or Western, with 1-year advance notice.
- Spinning reserve requirements are 0 percent for in-area firm resources, 7 percent for out-of-area firm resources, and 100 percent for non-firm resources. DOE/SF will initially take spinning reserve service from PG&E because it is currently less expensive.
- Standby for COTP power is to be provided first by Western and then by PG&E under its retail Schedule S, in the event Western cannot meet LLNL's needs. The possible need of Schedule S service is limited to double and triple contingency outage situations where Western cannot supply as-available standby. The potential cost is high -- up to \$175,000 (including a 12-month ratchet penalty) for one 6-hour curtailment of the entire COTP resource during the summer peak period. In the alternative, LLNL can shed the appropriate amount of load (around 31 mW). This potential cost can also be mitigated by purchasing additional standby from other entities in those years when Western forecasts inadequate standby reserves.

Summary of the Intra-agency Exhibits

The major features of the several exhibits to the Intra-agency Agreement No. 90-SAO-00001 are as follows:

- Layoff of PacifiCorp Power

- Western will layoff up to 55 mW of its purchase of PacifiCorp power under its Contract No. 91-SAO-5005.
- The actual amount that DOE/SF can use in any one year is between 75% and 100% of the maximum amount. The 75 percent level also defines DOE/SF's take-or-pay liability. ✓
- The maximum can be reduced with 36 months advance notice.

- DOE will initially purchase 49 mW. It can vary the amount taken within the prescribed range once a calendar year with 100 days advance notice.
- The term of the contract is dependent on the term of the 3-party agreement or its successor, or the term of Western's agreement with PacifiCorp.
- Prices are flowed through to DOE/SF. They are based on the actual cost of a pool of four coal-fired generating plants
- Use of COTP Entitlement Capacity
 - DOE/SF will designate its required COTP capacity for 3 years, with 1-year written notice.
 - Western will standby for a curtailment of up to one-third of DOE/SF's COTP power at a charge equal to 50 percent of the O&M cost associated with the amount of additional COTP capacity DOE/SF would have to subscribe to to avoid a single contingency curtailment.
- Other Services
 - Western will provide as available emergency service for the remaining COTP power in the event of a 2-line or 3-line outage.
 - Western will provide certain scheduling services.
 - Western will probably be able to offer spinning reserve services within a year or so, at which time an additional exhibit will be included.

Evaluation of the Agreements

The overall set of terms and conditions in the agreements are very favorable to DOE. Where risks exist, they have been minimized and mitigating actions have been identified. Of most importance are the following points:

1. DOE SF will only pay for the portion of the COTP that it uses, but retains the right to grow into or out of its use of the transmission capacity.
2. DOE SF has the right to take some additional PacifiCorp power if loads grow. More important, the take-or-pay liability has been set so that it will

only come into play with over a 35 percent reduction in LLNL loads. Even in that event, the Western's layoff obligations make it unlikely that take-or-pay penalties will ever be paid.

3. There are several levels of backup provided for LLNL's use of the COTP power. The resource is a slice of the Pacificorp system and so is firm at the northern terminus of the COTP. Western has firmed the resource at LLNL under a single contingency (one-third) curtailment. Further, "as-available" standby is provided by Western, and PG&E also provides firm standby as a final recourse, but at a high penalty price. Given all of these arrangements, LLNL's service is no less reliable than under its current arrangement with PG&E.
4. The savings are substantial -- estimated at \$4 million during the first year, even with PG&E's recent rate discount to large customers. It is expected that actual savings can be increased after DOE/SF gains operating experience and adjustments can be made in the way the several resources are used.

In summary, it is strongly urged that these agreements be approved for execution.

/approval.com

MONITORING NOTEBOOK

For the Department of Energy

San Francisco Operations Office Laboratories

Prepared for the

U.S. Department of Energy
San Francisco Operations Office
Oakland, California

Under Contract
DE-AC03-92SF19198

February 1994

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LLNL - Meter YJN A1-00011-4

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S-1 LIST OF SOURCE DOCUMENTS

Source Documents for Notebook

Tariffs

- o Current PG&E tariffs.
- o Western's Schedule for Rates for Commercial Firm Power Service.

Contracts

- o DE-AC03-82SF11672: Contract with PG&E to provide interruptible service to LBL1.
- o 92-SAO-20059: Contract with Western to provide electric service to LBL1.
- o DE-AC03-82SF11671: Contract with PG&E to provide firm power to LBL2.
- o DE-AA03-84SF12187: Contract with PG&E to provide interruptible pulse power to LLNL.
- o DE-AD03-90SF18447: Contract with PG&E to provide firm power to LLNL.
- o 92-SAO-20050: Contract with Western to provide power to LLNL and Site 300.
- o 89-SAO-90001: Contract with Western for the Direct Interconnection of LLNL with the Tracy Substation
- o 90-SAO-00001: COTP Agency Agreement
- o 92-SAO-10113: PG&E - WAPA - DOE/OAK Settlement Agreement
- o DE-AC03-83SF11715: Contract with PG&E to provide firm power to Site 300.
- o DE-AA03-84SF11991: Contract with PG&E to provide interruptible power to SLAC.
- o 92-SAO-20051: Contract with Western to provide power to SLAC.

S-1 LIST OF SOURCE DOCUMENTS (Cont'd.)

- o 93-SAO-10155 Agreement between Western and Northern California Power Agency (NCPA) for the Protection of SLAC's Diversity CRD allocation.
- o 93-SAO-10154: Agreement between Western and SLAC modifying Memorandum of Agreement No. DE-MS65-83WP59047.
- o DE-AC03-90SF18443 Contract with PG&E to provide Natural Gas to LBL1 and LBL2.
- o DE-AC03-89SF18230 Contract with PG&E to provide Natural Gas to LBL4.
- o DE-AD03-89SF18226 Contract with PG&E to provide Natural Gas to LLNL.
- o DE-AD03-89SF18232 Contract with PG&E to provide Natural Gas to SLAC1.
- o DE-AD03-89SF18231 Contract with PG&E to provide Natural Gas to SLAC2.
- o 93-SAO-00018 3-Party COTP Agreement between DOE/OAK – PG&E – WAPA
- _____ Inter-Agency Agreement for Natural Gas Supply to the DOE/OAK Labs

Other

- o CVP Power Allocations.

S-2 LIST OF CONTACTS AT LABS

<u>Data</u>	<u>Contact</u>	<u>Phone</u>
<u>LBL</u>		
Electric and gas bills and forecasts	Toni Reaves	510-486-7228
<u>LLNL & Site 300</u>		
Electric and gas bills	Kathy Allen	510-423-4009
Electric forecasts	Kathy Allen	510-423-4009
Gas Forecasts	Rudy Parisotto	510-423-2092
<u>SLAC</u>		
Electric and gas bills	Lana Smith	415-926-2207
Electric forecasts	Greg Loew	415-926-2799
Gas Forecasts	Rick Challman	415-926-3004
<u>Western</u>		
Rates and CRDs	Guy Nelson	416-649-4435

E. SUMMARY OF ELECTRIC DEMAND, ENERGY AND COSTS AT THE DOE/OAK LABS

SUMMARY OF ELECTRIC DEMAND
AT THE DOE/OAK LABS*

FY 1992 - FY 1993
(kW)

	LBL.			LLNL			SLAC		
	LBL 1	LBL 2	TOTAL LBL	LLNL Main	MFTF/TMX	Site 300	TOTAL LLNL	TOTAL SLAC	TOTAL DOE/OAK
FY 1992									
OCTOBER	6,518	7,398	13,916	58,028	504	2,252	60,784	20,674	95,374
NOVEMBER	6,426	7,218	13,644	51,905	0	2,349	54,254	14,391	82,289
DECEMBER	7,160	6,696	13,856	48,665	0	2,565	51,230	26,271	91,357
JANUARY	6,353	6,642	12,995	48,956	0	2,700	51,656	43,854	108,505
FEBRUARY	7,399	7,074	14,473	50,641	252	2,506	53,399	53,358	121,230
MARCH	7,234	6,804	14,038	49,961	0	2,068	52,029	53,358	119,425
APRIL	7,032	6,984	14,016	57,154	0	1,960	59,114	53,989	127,119
MAY	7,234	7,020	14,254	57,348	504	2,025	59,877	54,291	128,422
JUNE	10,373	6,894	17,267	59,162	504	2,144	61,810	54,567	133,644
JULY	10,282	7,434	17,716	61,106	504	2,322	63,932	58,736	140,384
AUGUST	12,668	7,110	19,778	61,301	504	2,408	64,213	53,825	137,816
SEPTEMBER	13,293	7,110	20,403	59,227	504	2,284	62,015	54,430	136,848
ANNUAL	101,972	84,384	186,356	663,454	3,276	27,583	694,313	541,744	1,422,413
FY 1993									
OCTOBER	8,354	7,380	15,734	57,283	252	1,960	59,495	22,798	98,027
NOVEMBER	11,677	6,678	18,355	53,071	252	2,133	55,456	38,454	112,265
DECEMBER	11,585	6,426	18,011	47,822	0	2,317	50,139	43,430	111,580
JANUARY	10,373	6,804	17,177	47,822	0	2,830	50,652	54,230	122,059
FEBRUARY	10,796	6,768	17,564	45,878	0	2,349	48,227	53,617	119,408
MARCH	2,919	7,704	10,623	48,600	0	2,176	50,776	53,833	115,232
APRIL	3,084	7,452	10,536	49,831	0	2,014	51,845	54,654	117,035
MAY	2,809	6,642	9,451	51,386	0	2,516	53,902	53,393	116,746
JUNE	3,000	7,776	10,776	56,570	0	2,111	58,681	53,868	123,325
JULY	3,000	7,578	10,578	55,598	504	2,160	58,262	53,825	122,665
AUGUST	1,965	7,830	9,795	58,189	252	2,468	60,909	48,641	119,345
SEPTEMBER	2,093	8,082	10,175	56,570	504	2,187	59,261	16,534	85,970
YR TO DATE	71,655	87,120	158,775	628,620	1,764	27,221	657,605	547,277	1,363,657

* See Notes on Pages E-2.2

E SUMMARY OF ELECTRIC DEMAND, ENERGY AND COSTS AT THE DOE/OAK LABS

SUMMARY OF ELECTRIC USAGE
AT THE DOE/OAK LABS*

FY 1992 - FY 1993
(kWh)

	LBL			LLNL			SLAC		
	LBL 1	LBL 2	TOTAL LBL	LLNL Main	MFTF/TMX	Site 300	TOTAL LLNL	TOTAL SLAC	TOTAL DOE/OAK
FY 1992									
OCTOBER	3,295,418	3,582,000	6,877,418	31,888,800	168,757	1,263,600	33,321,157	13,189,500	53,388,075
NOVEMBER	3,031,695	3,726,000	6,757,695	28,756,800	126,757	1,221,000	30,104,557	7,852,800	44,715,052
DECEMBER	2,846,544	3,150,000	5,996,544	29,268,180	125,157	1,473,000	30,867,937	14,222,100	51,086,581
JANUARY	2,468,208	3,546,000	6,014,208	29,599,200	126,757	1,610,400	31,336,357	22,891,800	60,242,365
FEBRUARY	3,416,503	3,402,000	6,818,503	27,601,200	126,757	1,299,600	29,027,557	32,917,200	68,763,260
MARCH	3,669,273	3,420,000	7,089,273	29,790,000	126,757	1,251,600	31,168,357	37,285,200	75,542,830
APRIL	3,293,491	3,672,000	6,965,491	29,325,784	126,757	1,111,200	30,563,741	32,155,500	69,684,732
MAY	2,249,320	3,582,000	5,831,320	31,672,800	126,757	1,161,000	32,960,557	37,617,000	76,408,877
JUNE	2,604,834	3,420,000	6,024,834	30,470,400	168,757	1,118,400	31,757,557	36,707,700	74,490,091
JULY	4,428,056	3,798,000	8,226,056	33,294,046	126,757	1,216,200	34,637,003	38,475,300	81,338,359
AUGUST	5,395,352	3,474,000	8,869,352	33,127,200	126,757	1,250,400	34,504,357	36,735,300	80,109,009
SEPTEMBER	4,611,086	3,510,000	8,121,086	31,633,200	126,757	1,179,600	32,939,557	27,398,400	68,459,043
ANNUAL	41,309,780	42,282,000	83,591,780	366,427,610	1,605,084	15,156,000	383,188,694	337,447,800	804,228,274
FY 1993									
OCTOBER	4,043,450	3,636,000	7,679,450	31,708,800	126,757	1,153,800	32,989,357	5,998,419	46,667,226
NOVEMBER	4,319,144	3,528,000	7,847,144	28,504,800	126,757	1,203,600	29,835,157	21,359,856	59,042,157
DECEMBER	4,175,725	3,312,000	7,487,725	29,167,200	0	1,413,000	30,580,200	24,039,900	62,107,825
JANUARY	3,065,294	3,348,000	6,413,294	28,807,200	0	1,464,600	30,271,800	30,896,100	67,581,194
FEBRUARY	3,679,555	3,654,000	7,333,555	25,293,600	0	1,287,000	26,580,600	34,294,800	68,208,955
MARCH	1,426,049	3,690,000	5,116,049	28,396,800	0	1,209,600	29,606,400	37,743,900	72,466,349
APRIL	1,733,928	3,726,000	5,459,928	26,935,200	0	1,103,400	28,038,600	36,691,800	70,190,328
MAY	1,200,166	3,438,000	4,638,166	27,997,200	0	1,073,406	29,070,606	37,983,900	71,692,672
JUNE	1,052,268	3,655,628	4,707,896	28,629,872	0	1,081,800	29,711,672	35,595,561	70,015,129
JULY	1,045,978	3,528,000	4,573,978	30,470,400	126,757	1,185,000	31,782,157	37,919,700	74,275,835
AUGUST	1,112,818	3,744,000	4,856,818	31,125,600	126,757	1,172,400	32,424,757	33,203,400	70,484,975
SEPTEMBER	1,171,634	4,086,000	5,257,634	29,318,400	126,757	1,134,000	30,579,157	5,649,000	41,485,791
YR TO DATE	28,026,009	43,345,628	71,371,637	346,355,072	633,785	14,481,606	361,470,463	341,376,336	774,218,436

* See Notes on Pages E-2.2

E. SUMMARY OF ELECTRIC DEMAND, ENERGY AND COSTS AT THE DOE/OAK LABS

SUMMARY OF ELECTRIC POWER COSTS*
AT THE DOE/OAK LABS

FY 1992 - FY 1993

	LBL			LLNL			SLAC		
	<u>LBL 1</u>	<u>LBL 2</u>	<u>TOTAL LBL</u>	<u>LLNL Main</u>	<u>MITF/TMX</u>	<u>Site 300</u>	<u>TOTAL LLNL</u>	<u>TOTAL SLAC</u>	<u>TOTAL DOE/OAK</u>
<u>FY 1992</u>									
OCTOBER	\$158,275	\$342,490	\$500,765	\$1,630,096	\$10,512	\$89,686	\$1,730,294	\$387,529	\$2,618,587
NOVEMBER	122,584	222,665	345,250	1,101,232	6,470	56,183	1,163,885	267,021	1,776,156
DECEMBER	120,502	189,010	309,512	1,067,463	6,519	67,472	1,141,453	482,484	1,933,449
JANUARY	106,220	215,249	321,469	1,089,222	8,407	75,051	1,172,680	794,863	2,289,013
FEBRUARY	138,508	209,127	347,635	1,045,052	8,349	55,126	1,108,528	1,033,030	2,489,193
MARCH	145,874	209,649	355,523	1,111,294	7,515	53,442	1,172,251	1,143,599	2,671,374
APRIL	129,523	234,530	364,053	1,111,368	7,515	47,229	1,166,111	970,769	2,500,933
MAY	142,020	339,861	481,881	1,535,618	11,553	70,018	1,617,189	1,078,554	3,177,624
JUNE	157,869	330,206	488,075	1,571,863	15,008	70,857	1,657,728	1,065,355	3,211,158
JULY	242,132	360,522	602,654	1,718,478	11,385	78,337	1,808,201	1,135,227	3,546,082
AUGUST	296,814	335,953	632,767	1,698,808	11,153	80,506	1,790,466	1,109,363	3,532,596
SEPTEMBER	<u>263,037</u>	<u>336,332</u>	<u>599,369</u>	<u>1,607,645</u>	<u>11,538</u>	<u>75,490</u>	<u>1,694,673</u>	<u>836,055</u>	<u>3,130,097</u>
ANNUAL	\$2,023,357	\$3,325,596	\$5,348,953	\$16,288,140	\$115,923	\$819,397	\$17,223,460	\$10,303,849	\$32,876,262
<u>FY 1993</u>									
OCTOBER	\$180,804	\$348,857	\$529,661	\$1,565,805	\$10,985	\$69,099	\$1,645,890	\$204,267	\$2,379,818
NOVEMBER	186,207	214,354	400,561	1,064,241	8,396	51,024	1,123,661	651,826	2,176,048
DECEMBER	179,684	201,042	380,726	1,034,450	6,550	60,006	1,101,006	739,206	2,220,937
JANUARY	140,334	211,997	352,331	1,042,225	6,550	65,653	1,114,427	941,060	2,407,817
FEBRUARY	164,725	228,897	393,622	922,555	6,550	56,871	985,976	1,038,435	2,418,032
MARCH	46,942	235,557	282,499	1,044,363	6,550	53,084	1,103,997	1,108,079	2,494,575
APRIL	55,049	246,901	301,950	1,014,423	6,550	48,315	1,069,287	1,103,790	2,475,027
MAY	68,727	334,439	403,167	1,376,637	6,550	74,586	1,457,773	1,137,258	2,998,197
JUNE	62,531	368,058	430,589	1,534,099	6,550	71,326	1,611,975	1,089,547	3,132,110
JULY	50,391	322,782	373,173	1,422,146	9,718	67,802	1,499,666	1,101,156	2,973,995
AUGUST	47,321	327,964	375,285	1,420,887	9,643	67,146	1,497,677	909,606	2,782,568
SEPTEMBER	<u>49,772</u>	<u>348,034</u>	<u>397,806</u>	<u>1,335,531</u>	<u>10,970</u>	<u>62,333</u>	<u>1,408,834</u>	<u>203,621</u>	<u>2,010,261</u>
YR TO DATE	\$1,232,488	\$3,388,880	\$4,621,368	\$14,777,362	\$95,563	\$747,244	\$15,620,169	\$10,227,848	\$30,469,386

* See Notes on Pages E-2.2

G. SUMMARY OF GAS USAGE AND COSTS AT THE DOE/OAK LABS

SUMMARY OF NATURAL GAS USAGE
AT THE DOE/OAK LABS*

FY 1992 - FY 1993
(therms)

	LBL				LLNL	SLAC			
	<u>LBL 1</u>	<u>LBL 2</u>	<u>LBL 4</u>	<u>TOTAL LBL</u>	<u>TOTAL LLNL</u>	<u>SLAC 1</u>	<u>SLAC 2</u>	<u>TOTAL SLAC</u>	<u>TOTAL DOE/OAK</u>
<u>FY 1992</u>									
OCTOBER	625	7,031	84,918	92,574	302,176	2,263	48,833	51,096	445,846
NOVEMBER	1,067	11,816	121,040	133,923	459,505	4,441	55,777	60,218	653,646
DECEMBER	1,247	9,203	177,855	188,305	655,902	8,179	73,883	82,062	926,269
JANUARY	1,119	11,231	172,039	184,389	626,805	9,021	80,640	89,661	900,855
FEBRUARY	1,089	10,546	153,952	165,587	503,142	14,797	55,528	70,325	739,054
MARCH	994	8,907	133,219	143,120	449,361	11,068	50,529	61,597	654,078
APRIL	866	8,580	99,895	109,341	432,845	6,720	49,631	56,351	598,537
MAY	653	6,682	99,412	106,747	228,108	2,246	43,699	45,945	380,800
JUNE	812	7,211	95,299	103,322	344,085	994	40,388	41,382	488,789
JULY	683	6,509	82,133	89,325	312,666	893	36,612	37,505	439,496
AUGUST	618	6,005	70,339	76,962	297,531	904	27,979	28,883	403,376
SEPTEMBER	<u>713</u>	<u>6,310</u>	<u>71,233</u>	<u>78,256</u>	<u>345,363</u>	<u>1,079</u>	<u>35,488</u>	<u>36,567</u>	<u>460,186</u>
TOTAL	10,486	100,031	1,361,334	1,471,851	4,957,489	62,605	598,987	661,592	7,090,932
<u>FY 1993</u>									
OCTOBER	611	5,769	78,913	85,293	318,121	1,144	36,293	37,437	440,851
NOVEMBER	1,028	8,372	123,534	132,934	535,484	4,087	46,458	50,545	718,963
DECEMBER	1,701	8,479	167,209	177,389	585,552	8,531	74,315	82,846	845,787
JANUARY	1,386	16,454	215,509	233,349	595,874	12,480	67,221	79,701	908,924
FEBRUARY	1,484	11,546	161,000	174,030	746,877	16,049	59,709	75,758	996,665
MARCH	1,033	8,846	161,000	170,879	612,450	13,014	49,822	62,836	846,165
APRIL	1,091	10,332	140,024	151,447	473,564	9,160	53,851	63,011	688,022
MAY	982	7,579	119,075	127,636	412,202	6,208	35,197	41,405	581,243
JUNE	553	5,095	73,210	78,858	425,442	1,605	35,027	36,632	540,932
JULY	529	6,073	78,932	85,534	303,862	709	27,946	28,655	418,051
AUGUST	474	5,033	78,932	84,439	319,191	621	29,537	30,158	433,788
SEPTEMBER	<u>553</u>	<u>4,905</u>	<u>70,922</u>	<u>76,416</u>	<u>320,334</u>	<u>709</u>	<u>32,537</u>	<u>33,246</u>	<u>429,996</u>
TOTAL	11,451	98,483	1,468,260	1,578,204	5,648,953	74,317	547,913	622,230	7,849,387

* See Notes on Pages G-2 2.

G. SUMMARY OF GAS USAGE AND COSTS AT THE DOE/OAK LABS

SUMMARY OF NATURAL GAS COSTS
AT THE DOE/OAK LABS*

FY 1992 - FY 1993

	LBL				LLNL	SLAC			
	LBL 1	LBL 2	LBL 4	TOTAL LBL	TOTAL LLNL	SLAC 1	SLAC 2	TOTAL SLAC	TOTAL DOE/OAK
<u>FY 1992</u>									
OCTOBER	\$311	\$3,420	\$26,067	\$29,799	\$91,601	\$1,096	\$14,902	\$15,998	\$137,398
NOVEMBER	702	7,654	39,353	47,709	146,711	2,807	17,971	20,778	215,198
DECEMBER	821	5,991	62,478	69,290	226,572	5,302	25,561	30,863	326,725
JANUARY	770	7,605	62,622	70,997	226,742	6,077	29,179	35,256	332,995
FEBRUARY	749	7,142	54,105	61,996	177,701	10,015	19,760	29,775	269,472
MARCH	679	5,980	42,636	49,295	143,857	7,495	16,384	23,878	217,030
APRIL	448	4,309	30,227	34,984	130,418	3,562	15,501	19,063	184,465
MAY	339	3,359	29,180	32,877	66,584	1,138	13,212	14,350	113,812
JUNE	420	3,624	28,273	32,316	100,633	511	12,331	12,842	145,792
JULY	355	3,272	24,444	28,071	91,741	460	11,265	11,726	131,538
AUGUST	323	3,020	20,778	24,121	85,971	466	8,633	9,099	119,191
SEPTEMBER	<u>370</u>	<u>3,173</u>	<u>21,923</u>	<u>25,466</u>	<u>103,616</u>	<u>553</u>	<u>10,777</u>	<u>11,330</u>	<u>140,412</u>
TOTAL	\$6,287	\$58,548	\$442,086	\$506,922	\$1,592,149	\$39,482	\$195,475	\$234,957	\$2,334,028
<u>FY 1993</u>									
OCTOBER	\$324	\$2,949	\$24,736	\$28,010	\$98,018	\$586	\$11,294	\$11,880	\$137,908
NOVEMBER	611	4,870	41,232	46,713	175,262	2,340	15,346	17,686	239,661
DECEMBER	1,011	4,932	58,356	64,299	202,661	4,962	25,687	30,650	297,610
JANUARY	848	9,955	75,261	86,064	207,097	7,531	23,524	31,056	324,216
FEBRUARY	911	6,998	56,028	63,937	257,698	9,722	20,810	30,533	352,167
MARCH	627	5,266	56,028	61,920	199,307	7,886	16,418	24,305	285,532
APRIL	502	4,643	44,299	49,445	148,436	4,298	17,099	21,397	219,278
MAY	471	3,444	38,229	42,144	129,773	2,795	11,273	14,068	185,986
JUNE	281	2,475	25,020	27,776	119,742	782	10,213	10,995	158,513
JULY	269	2,949	26,444	29,663	84,346	356	7,955	8,311	122,320
AUGUST	243	2,456	26,526	29,225	89,106	315	8,438	8,753	127,084
SEPTEMBER	<u>299</u>	<u>2,394</u>	<u>23,685</u>	<u>26,378</u>	<u>87,882</u>	<u>357</u>	<u>9,127</u>	<u>9,484</u>	<u>123,743</u>
YR TO DATE	\$6,398	\$53,332	\$495,843	\$555,573	\$1,799,328	\$41,932	\$177,185	\$219,117	\$2,574,018

* See Notes on Pages G-2.2.

LBL Bank 1*

E-1 ELECTRIC SERVICE CHARACTERISTICS

E-1.1 Current Suppliers and Rate Schedules

- PG&E:

Rate Schedule (prior to February 1, 1994) - E-20T Interruptible Service
Provides time metered interruptible service at transmission voltage level.

Rate Schedule (after February 1, 1994) - E-20T Firm Service.
Bank 1 and Bank 2 are metered conjunctively.

- Western:

CRDs - (kW)

<u>Effective</u>	<u>Long-Term</u>	<u>Withdrawable</u>	<u>Diversity</u>	<u>Total</u>
11/86	---	---	3,000	3,000
10/92	---	---	3,000	3,000
2/94	11,500	---	---	11,500

Rate Schedule - CV-F7 and CV-TPT3

Billing Method - X/Y Formula

Notes: LBL1 did not use its 3 mW CRD during the months of May through October of 1987 and 1988.

LBL1 did not use its 3 mW CRD during the months of May through September of 1989, 1990, 1991 and 1992.

Western passes the PG&E transmission cost directly to its customers under Western Rate Schedule CV-TPT3.

Effective February 1, 1994: Bank 1's Western 3,000 kW diversity CRD was placed at SLAC; LBL's Western allocation serves both Bank 1 and Bank 2.

* Bank 1 serves all accelerators except the 1 84-inch cyclotron.

E-1.2 Physical Characteristics of Service

- Delivery Point - LBL Grizzly Substation

Revised Exhibit C of Intra-Agency Agreement No. 92-SAO-20059 changes the point of delivery from only Bank 1 to the entire Grizzly Substation. This permits the delivery of Western power to both Bank 1 and Bank 2.

- Voltage Level - 115 kV
- Metering (prior to February 1, 1994) - PG&E metering set @ 12.5 kV (for billing @ 115 kV)
- Metering (after February 1, 1994) - Power metered conjunctively (LBL1 and LBL2) at 12.5 kV and adjusted upward for losses of 2 percent to 115 kV for billing purposes.
- Transformer Lease - \$5,657 per month

Notes: Originally leased transformer to qualify for PG&E's A-18 interruptible rate schedule. Metered demand and energy is increased by 2 percent to account for transformer losses. Lease qualifies Bank 1 for larger voltage discount from PG&E. Without lease, voltage level would be 12 kV.

E-1.3 Contract Summary

DE-AC03-82SF11672: Pacific Gas and Electric Company
Contract for Interruptible Service
Time Metered

Governs the delivery of power from PG&E to LBL Bank 1. Initial contract term was for three years with subsequent terms of one year. Either party can cancel at the end of a term with one year's written notice. Interruptions can occur automatically due to reductions of frequency or voltage, or upon PG&E's request. Notified interruptions will not exceed the maximum annual duration specified in the tariff.

Contract has been modified to facilitate delivery of Western power at both transformer banks at LBL. As of February 1, 1994, PG&E delivers supplemental firm power under Schedule E-20T to both transformer banks on an X-over-Y billing arrangement. The current transformer lease agreement, dated June 11, 1982, has been extended and will be coterminous with the modified supplemental power agreement.

92-SAO-20059: Intra-agency Agreement for Electric Service to Lawrence Berkeley Laboratory, Berkeley, California

Contract effective from October 29, 1992 until midnight December 31, 2004. Replaces Memorandum of Agreement No. DE-MS65-83WP59050 and Intra-agency Agreement No. 88-SAO-14002. The diversity allocation may be terminated or withdrawn depending on certain conditions on the Western system. As long as LBL receives a diversity allocation, it is required to reduce its demand at the request of Western. As of February 1, 1994, all DOE/OAK diversity power has been placed at SLAC. It is possible to shift CRDs, in whole or in part, to other Department of Energy labs. The PG&E/Western contract 2948A overrides this contract.

E-2.1 HISTORICAL USAGE AND COSTS

LBL-1
HISTORICAL USAGE AND COSTS

FY 1992	PG&E				WESTERN				TOTAL				
	DEMAND (kW)	ENERGY (kWh)	TOTAL BILL (\$)	AVERAGE BILL (\$/mWh)	DEMAND (kW)	ENERGY (kWh)	TOTAL BILL (\$)	AVERAGE BILL (\$/mWh)	DEMAND (kW)	ENERGY (kWh)	TOTAL BILL (\$)	AVERAGE BILL (\$/mWh)	LOAD FACTOR (%)
Oct	3,518	1,778,656	\$107,413	\$60	3,000	1,516,762	\$50,862	\$34	6,518	3,295,418	\$158,275	\$48	67.96%
Nov	3,426	1,616,338	\$70,342	\$44	3,000	1,415,357	\$52,242	\$37	6,426	3,031,695	\$122,584	\$40	65.53%
Dec	4,160	1,653,858	\$72,311	\$44	3,000	1,192,686	\$48,190	\$40	7,160	2,846,544	\$120,502	\$42	53.44%
Jan	3,353	1,302,676	\$58,179	\$45	3,000	1,165,532	\$48,041	\$41	6,353	2,468,208	\$106,220	\$43	52.22%
Feb	4,399	2,031,247	\$88,731	\$44	3,000	1,385,256	\$49,777	\$36	7,399	3,416,503	\$138,508	\$41	66.34%
Mar	4,234	2,147,595	\$93,961	\$44	3,000	1,521,678	\$51,914	\$34	7,234	3,669,273	\$145,874	\$40	68.18%
Apr	4,032	1,888,418	\$83,149	\$44	3,000	1,405,073	\$46,374	\$33	7,032	3,293,491	\$129,523	\$39	65.05%
May	7,234	2,249,320	\$142,020	\$63	0	0	\$0	\$0	7,234	2,249,320	\$142,020	\$63	41.79%
Jun	10,373	2,604,834	\$157,869	\$61	0	0	\$0	\$0	10,373	2,604,834	\$157,869	\$61	34.88%
Jul	10,282	4,428,056	\$242,132	\$55	0	0	\$0	\$0	10,282	4,428,056	\$242,132	\$55	57.88%
Aug	12,668	5,395,352	\$296,814	\$55	0	0	\$0	\$0	12,668	5,395,352	\$296,814	\$55	57.25%
Sep	13,293	4,611,086	\$263,037	\$57	0	0	\$0	\$0	13,293	4,611,086	\$263,037	\$57	48.18%
ANNUAL	13,293	31,707,436	\$1,675,957	\$53	3,000	9,602,344	\$347,400	\$36	13,293	41,309,780	\$2,023,357	\$49	56.56%
FY 1993													
Oct	5,354	2,591,409	\$139,087	\$54	3,000	1,452,041	\$41,717	\$29	8,354	4,043,450	\$180,804	\$45	65.06%
Nov	8,677	3,209,490	\$144,713	\$45	3,000	1,109,654	\$41,494	\$37	11,677	4,319,144	\$186,207	\$43	51.37%
Dec	8,585	3,094,398	\$138,753	\$45	3,000	1,081,327	\$40,931	\$38	11,585	4,175,725	\$179,684	\$43	48.45%
Jan	7,373	2,178,773	\$102,719	\$47	3,000	886,521	\$37,615	\$42	10,373	3,065,294	\$140,334	\$46	39.72%
Feb	7,796	2,657,078	\$124,680	\$47	3,000	1,022,477	\$40,045	\$39	10,796	3,679,555	\$164,725	\$45	50.72%
Mar	0	0	\$704	\$0	2,919	1,426,049	\$46,238	\$32	2,919	1,426,049	\$46,942	\$33	65.66%
Apr	84	80,468	\$4,400	\$55	3,000	1,653,460	\$50,649	\$31	3,084	1,733,928	\$55,049	\$32	78.09%
May	2,809	1,200,166	\$68,727	\$57	0	0	\$0	\$0	2,809	1,200,166	\$68,727	\$57	57.43%
Jun	3,000	1,052,268	\$62,531	\$59	0	0	\$0	\$0	3,000	1,052,268	\$62,531	\$59	48.72%
Jul	3,000	1,045,978	\$50,391	\$48	0	0	\$0	\$0	3,000	1,045,978	\$50,391	\$48	46.86%
Aug	1,965	1,112,818	\$47,321	\$43	0	0	\$0	\$0	1,965	1,112,818	\$47,321	\$43	76.12%
Sep	2,093	1,171,634	\$49,772	\$42	0	0	\$0	\$0	2,093	1,171,634	\$49,772	\$42	77.75%
YR TO DATE	8,677	19,394,480	\$933,799	\$48	3,000	8,631,529	\$298,689	\$35	11,677	28,026,009	\$1,232,488	\$44	58.83%

E-2.2 NOTES TO HISTORICAL USAGE AND COSTS

FY 1992

October 1991 - Western

- Total Bill excludes \$15,545 Revenue Adjustment Credit carried over from previous month.

January 1992 - Western

- Total bill excludes late payment charge.

April 1992 - Western

- Total bill does not include \$8,721 FERC-mandated PG&E refund of pass-through wheeling cost 5/88-3/91.

FY 1993

October 1992 - Western

- Total bill excludes \$1,912.22 FERC-mandated PG&E interest refund of pass-through wheeling cost 5/88 - 3/91.
- Total bill excludes \$25,540 Revenue Adjustment Credit carried over from the previous month.

March 1993 - PG&E

- Lower PG&E usage reflects shut down of the Bevetron.

March 1993 - Western

- Total bill excludes \$820.91 late payment charge.

April 1993 - PG&E

- Lower PG&E usage reflects shut down of the Bevetron.
- Total bill was estimated based on a 10/19/93 telephone conversation with Steve Kromer.

E-2.2 NOTES TO HISTORICAL USAGE AND COSTS

May 1993 - Western

- Zero Western usage. Revenue adjustment credit carry-over \$1,195.

June 1993 - PG&E

- Usage and total bill are estimates based on a 10/19/93 telephone conversation with Steve Kromer. All PG&E power to LBL (Bank 1 and Bank 2) was received through Bank 1 for approximately 62 hours during the off-peak June billing period. Consequently, the demand and energy that would have occurred on Bank 2 were captured on the Bank 1 meter. PG&E has billed LBL1 for approximately 6.5 mW and 290 mWh that should have been properly reflected on LBL2's bill.

July 1993 - PG&E

- Demand and total bill are estimates based on a 10/19/93 telephone conversation with Steve Kromer. All PG&E power to LBL (Bank 1 and Bank 2) was received through Bank 1 for several hours during the off-peak July billing period. Consequently, the demand and energy that would have occurred on Bank 2 were captured on the Bank 1 meter. PG&E has billed LBL1 for approximately 5.4 mW that should have been properly reflected on LBL2's bill.

E-3.1 NEAR TERM PROJECTED USAGE

LBL1 PROJECTED USAGE

Month	FY 1993		FY 1994*		FY 1995*	
	DEMAND (kW)	ENERGY (kWh)	DEMAND (kW)	ENERGY (kWh)	DEMAND (kW)	ENERGY (kWh)
Oct	8,354	4,043,450	3,000	935,000	0	0
Nov	11,677	4,319,144	3,000	990,000	0	0
Dec	11,585	4,175,725	3,000	900,000	0	0
Jan	10,373	3,065,294	3,000	990,000	0	0
Feb	10,796	3,679,555	0	0	0	0
Mar	2,919	1,426,049	0	0	0	0
Apr	3,084	1,733,928	0	0	0	0
May	2,809	1,200,166	0	0	0	0
Jun	3,000	1,052,268	0	0	0	0
Jul	3,000	1,045,978	0	0	0	0
Aug	1,965	1,112,818	0	0	0	0
Sep	2,093	1,171,634	0	0	0	0
ANNUAL	11,677	28,026,009	3,000	3,815,000	0	0

* Beginning February 1, 1994, Bank 1 and Bank 2 Are Conjunctively Metered. LBL's Entire Load As of This Date Is Reflected on Page LBL2:E-3.1.

Source: FY 1993 - Data Represent Actual Usage. FY 1994 - Per an R. Gleason Table Dated April 30, 1993.

E-3.2 LONG-TERM LOAD FORECASTS

LBL1 LONG-TERM LOAD FORECASTS

<u>FISCAL YEAR</u>	<u>DEMAND (kW)</u>	<u>ENERGY (mWh)</u>
1986 Act.	16,781	44,850
1987 Act.	15,918	52,411
1988 Act.	15,110	51,550
1989 Act.	15,331	52,441
1990 Act.	14,890	47,791
1991 Act.	12,393	34,743
1992 Act.	13,293	41,310
1993 Act.	11,677	28,026
1994 Est.	3,000	3,815

Source: FY 1994 - October 1993 - January 1994 Data Per an R. Gleason Table Dated April 30, 1993. Beginning February 1, 1994, Bank 1 and Bank 2 Are Conjunctively Metered. LBL's Entire Load as of This Date is Reflected on Page LBL2:E-3.2. Decline in Demand from FY 1993-1994 is Due to the Shutdown of the Bevetron.

E-4.1 CURRENT TARIFFS

Beginning February 1, 1994, the DOE/OAK labs began to pool their electricity resources to their mutual benefit. Specifically, the commencement of PacifiCorp power delivery to LLNL over the California-Oregon Transmission Project (COTP) and the reassignment of Western power among the labs will result in savings that will be shared by each lab. Low-cost PacifiCorp power is used to displace higher-cost PG&E power, and Western power was reallocated among the labs in order to lower overall cost. Under this new arrangement, LLNL receives PacifiCorp power over the COTP and Western's Tracy tie-line. LLNL's previous long-term Western allocation has been split between LLNL and LBL, and LBL's previous 3 mW diversity allotment has been transferred to SLAC. Savings for calendar 1994 are estimated to be about \$2 million, and savings from February - April 1994 will be about \$30,000.

An interlab rebilling mechanism, operated by LLNL Accounting, has been established in order to distribute the savings to the labs. Uniform electricity rebilling charges, based on marginal costs, have been implemented to achieve this aim. The rebilling charges are similar to PG&E rates: summer and winter differential, three summer energy periods, two winter energy periods, different customer charges for each laboratory, and an interruptible demand credit. The power year is set from May 1 through April 30 at which time a true-up will occur.

While the rebilling mechanism is conducted through LLNL Accounting, each lab has specific responsibilities: reviewing and verifying the usage on the rebilling memos and supplier bills; authorizing transfer of rebilling memo funds; preparing usage projections; and addressing supplier billing errors with suppliers. All supplier bills (PG&E, WAPA, NCPA & COTP) are sent to LLNL Accounting and to the appropriate laboratory utility offices. Usage data for all labs are also sent to LLNL (initially through Exeter, later by WAPA). Rebilling memos are prepared for LBL, LLNL, Site 300, and SLAC and are issued by the 15th of each month. Each lab utility office is responsible for reviewing supplier bills and usage on the rebilling memos and reporting any discrepancies to LLNL Accounting and to the appropriate supplier. (LLNL may reissue rebilling memos in the following month to correct any usage or billing discrepancies.) Having reviewed the rebilling memos, the lab utility offices authorize the transfer of funds to LLNL Accounting who then pays all supplier bills. Finally, monthly reports showing cost data, usage data and variations from projections are prepared and sent to DOE/OAK.

E-4.1 CURRENT TARIFFS

LBL CURRENT REBILLING CHARGES*

CUSTOMER CHARGE	\$84,000.00 per month
DEMAND CHARGE (\$/kW)	\$8.00 per month
ENERGY CHARGES (\$/kWh)	
On-Peak	\$0.000 per month
Partial Peak	\$0.034 per month
Off Peak	\$0.024 per month

EFFECTIVE

February - April 1994

- * The Rebilling Charges Reflect the Pooling of Electricity Resources and the Redistribution of Costs Among the DOE/OAK Labs.

Billing For LBL Will Reflect the Conjunctive Metering of Bank 1 and Bank 2.

E-4.1 CURRENT TARIFFS

LBL 1 CURRENT TARIFFS**

PG&E E-20T FIRM		WESTERN CV-F7	
CUSTOMER CHARGE	\$715.00 per month	DEMAND	\$6.22 per kW
DEMAND CHARGES		ENERGY	
Max. Demand	\$0.35 per kW	Base*	\$0.01797 per kWh
		Tier*	NONE per kWh
Summer:		PG&E Wheeling	\$1.09 per kW
On-Peak	\$7.50 per kW		
Part-Peak	\$0.60 per kW		
Off-Peak	\$0.00 per kW		
Winter:			
On-Peak	\$0.00 per kW		
Part-Peak	\$0.75 per kW		
Off-Peak	\$0.00 per kW		
ENERGY CHARGES			
Economic Stimulus Rate Credit*	\$0.00400 per kWh		
Summer:			
On-Peak	\$0.06370 per kWh		
Part-Peak	\$0.04831 per kWh		
Off-Peak	\$0.04538 per kWh		
Rate Limiters:			
Average	\$0.00000 per kWh		
On-Peak	\$0.56370 per kWh		
Winter:			
On-Peak	\$0.00000 per kWh		
Part-Peak	\$0.05948 per kWh		
Off-Peak	\$0.04896 per kWh		

Effective October 1, 1993

* Applicable 5/1/94
Base = up to 70% Load Factor
Tier = above 70% Load Factor

Effective July 15, 1993

* The Economic Stimulus Rate Credit Shall
Terminate 12/31/94.

** As of February 1, 1994, Both Bank 1 and Bank 2 Will Share the LBL Western Allocation.
Metering Will Occur Conjunctively.

E-4.2 PROPOSED TARIFF CHANGES

LBL1 PROPOSED TARIFFS

INTERLAB REBILLING RATES --

Rebilling rates effective May 1, 1994 are not available.

PG&E --

There are no proposed rates. A rate freeze of the July 15, 1993 rates is currently in effect through December 31, 1994.

WESTERN --

WESTERN CV-F7		
DEMAND	\$6.22	per kW
ENERGY		
Base*	\$0.01699	per kWh
Tier*	\$0.03087	per kWh
PG&E Wheeling	\$1.09	per kW

Effective May 1, 1994

* Energy Charges

Base = up to 70% Load Factor

Tier = above 70% Load Factor

E-5.1 NEAR-TERM ESTIMATED BILLS AT CURRENT RATES

LBL ESTIMATED BILLS AT CURRENT RATES PROJECTED LOADS

Bill estimates under the new interlab rebilling mechanism are not available, as rebilling rates effective May 1, 1994, are currently being determined. Estimates will be provided as soon as new rebilling rates become available.

E-5.2 NEAR-TERM ESTIMATED BILLS AT PROPOSED RATES

LBL ESTIMATED BILLS AT PROJECTED RATES PROJECTED LOADS

Bill estimates under the new interlab rebilling mechanism are not available, as rebilling rates effective May 1, 1994, are currently being determined. Estimates will be provided as soon as new rebilling rates become available.

LBL Bank 2*

E-1 ELECTRIC SERVICE CHARACTERISTICS

E-1.1 Current Suppliers and Rate Schedules

- PG&E:

Rate Schedule (prior to February 1, 1994) - E-20P Firm Service

Provides all power to Bank 2 as time metered general service at primary voltage level.

Rate Schedule (after February 1, 1994) - E-20T Firm Service.

Bank 1 and Bank 2 are metered conjunctively.

Note: As of February 1, 1994, LBL's Western 15.5 mW allocation serves both Bank 1 and Bank 2.

* Bank 2 serves the computer, shop, research and support facilities and the 184-inch cyclotron.

E-1.2 Physical Characteristics of Service

- Delivery Point - LBL Grizzly Substation

Revised Exhibit C of Intra-Agency Agreement No. 92-SAO-20059 changes the point of delivery from only Bank 1 to the entire Grizzly Substation. This permits the delivery of Western power to both Bank 1 and Bank 2.

- Voltage Level - 12.5 kV
- Metering (prior to February 1, 1994) - PG&E metering set @ 12.5 kV
- Metering (after February 1, 1994) - Power metered conjunctively (LBL1 and LBL2) at 12.5 kV and adjusted upward for losses of 2 percent to 115 kV for billing purposes.

E-1.3 Contract Summary

DE-AC03-82SF11671: Pacific Gas and Electric Company
Contract for Electric Service
General Service - Time Metered

Governs electric service of PG&E to LBL Bank 2. Initial contract term was for three years with subsequent terms of one year. Either party can cancel at the end of a term with one year's written notice.

Contract has been modified to facilitate delivery of Western power at both LBL transformer banks. As of February 1, 1994, PG&E delivers supplemental firm power under Schedule E-20T to both transformer banks on an X-over-Y billing arrangement.

E-2.1 HISTORICAL USAGE AND COSTS

LBL2
HISTORICAL USAGE AND COSTS

	PG&E				WESTERN				TOTAL				
	DEMAND	ENERGY	TOTAL	AVERAGE	DEMAND	ENERGY	TOTAL	AVERAGE	DEMAND	ENERGY	TOTAL	AVERAGE	LOAD
FY 1992	(kW)	(kWh)	BILL (\$)	BILL (\$/mWh)	(kW)	(kWh)	BILL (\$)	BILL (\$/mWh)	(kW)	(kWh)	BILL (\$)	BILL (\$/mWh)	FACTOR (%)
Oct	7,398	3,582,000	\$342,490	\$96	0	0	\$0	\$0	7,398	3,582,000	\$342,490	\$96	65.08%
Nov	7,218	3,726,000	\$222,665	\$60	0	0	\$0	\$0	7,218	3,726,000	\$222,665	\$60	71.70%
Dec	6,696	3,150,000	\$189,010	\$60	0	0	\$0	\$0	6,696	3,150,000	\$189,010	\$60	63.23%
Jan	6,642	3,546,000	\$215,249	\$61	0	0	\$0	\$0	6,642	3,546,000	\$215,249	\$61	71.76%
Feb	7,074	3,402,000	\$209,127	\$61	0	0	\$0	\$0	7,074	3,402,000	\$209,127	\$61	69.10%
Mar	6,804	3,420,000	\$209,649	\$61	0	0	\$0	\$0	6,804	3,420,000	\$209,649	\$61	67.56%
Apr	6,984	3,672,000	\$234,530	\$64	0	0	\$0	\$0	6,984	3,672,000	\$234,530	\$64	73.02%
May	7,020	3,582,000	\$339,861	\$95	0	0	\$0	\$0	7,020	3,582,000	\$339,861	\$95	68.58%
Jun	6,894	3,420,000	\$330,206	\$97	0	0	\$0	\$0	6,894	3,420,000	\$330,206	\$97	68.90%
Jul	7,434	3,798,000	\$360,522	\$95	0	0	\$0	\$0	7,434	3,798,000	\$360,522	\$95	68.67%
Aug	7,110	3,474,000	\$335,953	\$97	0	0	\$0	\$0	7,110	3,474,000	\$335,953	\$97	65.67%
Sep	7,110	3,510,000	\$336,332	\$96	0	0	\$0	\$0	7,110	3,510,000	\$336,332	\$96	68.57%
ANNUAL	7,434	42,282,000	\$3,325,596	\$79	0	0	\$0	\$0	7,434	42,282,000	\$3,325,596	\$79	68.49%
FY 1993													
Oct	7,380	3,636,000	\$348,857	\$96	0	0	\$0	\$0	7,380	3,636,000	\$348,857	\$96	66.22%
Nov	6,678	3,528,000	\$214,354	\$61	0	0	\$0	\$0	6,678	3,528,000	\$214,354	\$61	71.01%
Dec	6,426	3,312,000	\$201,042	\$61	0	0	\$0	\$0	6,426	3,312,000	\$201,042	\$61	67.11%
Jan	6,804	3,348,000	\$211,997	\$63	0	0	\$0	\$0	6,804	3,348,000	\$211,997	\$63	73.22%
Feb	6,768	3,654,000	\$228,897	\$63	0	0	\$0	\$0	6,768	3,654,000	\$228,897	\$63	74.99%
Mar	7,704	3,690,000	\$235,557	\$64	0	0	\$0	\$0	7,704	3,690,000	\$235,557	\$64	66.52%
Apr	7,452	3,726,000	\$246,901	\$66	0	0	\$0	\$0	7,452	3,726,000	\$246,901	\$66	65.10%
May	6,642	3,438,000	\$334,439	\$97	0	0	\$0	\$0	6,642	3,438,000	\$334,439	\$97	71.89%
Jun	7,776	3,655,628	\$368,058	\$101	0	0	\$0	\$0	7,776	3,655,628	\$368,058	\$101	67.55%
Jul	7,578	3,528,000	\$322,782	\$91	0	0	\$0	\$0	7,578	3,528,000	\$322,782	\$91	60.62%
Aug	7,830	3,744,000	\$327,964	\$88	0	0	\$0	\$0	7,830	3,744,000	\$327,964	\$88	66.41%
Sep	8,082	4,086,000	\$348,034	\$85	0	0	\$0	\$0	8,082	4,086,000	\$348,034	\$85	65.83%
YR TO DATE	8,082	43,345,628	\$3,388,880	\$78	0	0	\$0	\$0	8,082	43,345,628	\$3,388,880	\$78	68.04%

E-2.2 NOTES TO HISTORICAL USAGE AND COSTS

FY 1993

November 1992 - PG&E

- Total bill excludes \$6,456.96 PG&E refund. This refund is the result of a CPUC decision ordering PG&E to distribute refunds that it received from gas suppliers.

June 1993 - PG&E

- Energy usage and total cost are estimated based on a 10/19/93 telephone conversation with Steve Kromer. All PG&E power to LBL (Bank 1 and Bank 2) was received through Bank 1 for approximately 62 hours during the off-peak June billing period. Consequently, the demand and energy that would have occurred on Bank 2 were captured on the Bank 1 meter. PG&E has underbilled LBL2 by approximately 290 mWh.
- Total bill includes \$1,008 economic stimulus credit associated with the two days of July included in the June billing period.

July 1993 - PG&E

- According to a 10/19/93 telephone conversation with Steve Kromer, all PG&E power to LBL (Bank 1 and Bank 2) was received through Bank 1 for several hours during the off-peak July billing period. Consequently, the demand and energy that would have occurred on Bank 2 were captured on the Bank 1 meter. The number of hours during which this occurred is not known. LBL2's July bill has not been corrected.

E-3.1 NEAR TERM PROJECTED USAGE

LBL2 PROJECTED USAGE

Month	FY 1993		FY 1994*		FY 1995*	
	DEMAND (kW)	ENERGY (kWh)	DEMAND (kW)	ENERGY (kWh)	DEMAND (kW)	ENERGY (kWh)
Oct	7,380	3,636,000	9,000	4,600,000	11,000	5,741,600
Nov	6,678	3,528,000	8,000	4,600,000	11,000	5,708,000
Dec	6,426	3,312,000	7,500	4,000,000	11,000	5,141,600
Jan	6,804	3,348,000	7,700	3,900,000	11,000	5,041,600
Feb	6,768	3,654,000	9,800	5,640,800	11,000	5,740,800
Mar	7,704	3,690,000	10,100	5,341,600	11,000	5,441,600
Apr	7,452	3,726,000	10,000	5,508,000	11,000	5,608,000
May	6,642	3,438,000	10,100	5,641,600	11,000	5,741,600
Jun	7,776	3,655,628	9,800	4,808,000	11,000	4,908,000
Jul	7,578	3,528,000	10,700	5,541,600	11,000	5,641,600
Aug	7,830	3,744,000	10,700	6,041,600	11,000	6,141,600
Sep	8,082	4,086,000	10,400	5,208,000	11,000	5,408,000
ANNUAL	8,082	43,345,628	10,700	60,831,200	11,000	66,264,000

* Beginning February 1, 1994, Bank 1 and Bank 2 Are Conjunctively Metered. LBL's Entire Load As of This Date Is Reflected in These Projections.

Source: FY 1993 - Data Represent Actual Usage. FY 1994 - Per R. Gleason Table Dated April 30, 1993.

E-3.2 LONG-TERM LOAD FORECASTS

LBL2 LONG-TERM LOAD FORECASTS

<u>FISCAL YEAR</u>	<u>DEMAND (kW)</u>	<u>ENERGY (mWh)</u>
1986 Act.	11,898	49,050
1987 Act.	10,368	47,142
1988 Act.	10,602	45,234
1989 Act.	9,720	45,342
1990 Act.	11,178	43,524
1991 Act.	7,758	42,570
1992 Act.	7,434	42,282
1993 Act.	8,082	43,346
1994 Est.	10,700	60,831
1995	11,000	66,264

Source: FY 1994 - October 1993 - January 1994 Data Per an R. Gleason
Table Dated April 30, 1993. Beginning February 1, 1994,
Bank 1 and Bank 2 Are Conjunctively Metered. LBL's Entire
Load as of This Date is Reflected in These Projections.

E-4.1 CURRENT TARIFFS

Beginning February 1, 1994, the DOE/OAK labs began to pool their electricity resources to their mutual benefit. Specifically, the commencement of PacifiCorp power delivery to LLNL over the California-Oregon Transmission Project (COTP) and the reassignment of Western power among the labs will result in savings that will be shared by each lab. Low-cost PacifiCorp power is used to displace higher-cost PG&E power, and Western power was reallocated among the labs in order to lower overall cost. Under this new arrangement, LLNL receives PacifiCorp power over the COTP and Western's Tracy tie-line. LLNL's previous long-term Western allocation has been split between LLNL and LBL, and LBL's previous 3 mW diversity allotment has been transferred to SLAC. Savings for calendar 1994 are estimated to be about \$2 million, and savings from February - April 1994 will be about \$30,000.

An interlab rebilling mechanism, operated by LLNL Accounting, has been established in order to distribute the savings to the labs. Uniform electricity rebilling charges, based on marginal costs, have been implemented to achieve this aim. The rebilling charges are similar to PG&E rates: summer and winter differential, three summer energy periods, two winter energy periods, different customer charges for each laboratory, and an interruptible demand credit. The power year is set from May 1 through April 30 at which time a true-up will occur.

While the rebilling mechanism is conducted through LLNL Accounting, each lab has specific responsibilities: reviewing and verifying the usage on the rebilling memos and supplier bills; authorizing transfer of rebilling memo funds; preparing usage projections; and addressing supplier billing errors with suppliers. All supplier bills (PG&E, WAPA, NCPA & COTP) are sent to LLNL Accounting and to the appropriate laboratory utility offices. Usage data for all labs are also sent to LLNL (initially through Exeter, later by WAPA). Rebilling memos are prepared for LBL, LLNL, Site 300, and SLAC and are issued by the 15th of each month. Each lab utility office is responsible for reviewing supplier bills and usage on the rebilling memos and reporting any discrepancies to LLNL Accounting and to the appropriate supplier. (LLNL may reissue rebilling memos in the following month to correct any usage or billing discrepancies.) Having reviewed the rebilling memos, the lab utility offices authorize the transfer of funds to LLNL Accounting who then pays all supplier bills. Finally, monthly reports showing cost data, usage data and variations from projections are prepared and sent to DOE/OAK.

E-4.1 CURRENT TARIFFS

LBL CURRENT REBILLING CHARGES*

CUSTOMER CHARGE	\$84,000.00 per month
DEMAND CHARGE (\$/kW)	\$8.00 per month
ENERGY CHARGES (\$/kWh)	
On-Peak	\$0.000 per month
Partial Peak	\$0.034 per month
Off Peak	\$0.024 per month

EFFECTIVE
February - April 1994

* The Rebilling Charges Reflect the Pooling of Electricity Resources and the Redistribution of Costs Among the DOE/OAK Labs.

Billing For LBL Will Reflect the Conjunctive Metering of Bank 1 and Bank 2.

E-4.1 CURRENT TARIFFS

LBL 2 CURRENT TARIFFS**

PG&E E-20T FIRM		WESTERN CV-F7	
CUSTOMER CHARGE	\$715.00 per month	DEMAND	\$6.22 per kW
DEMAND CHARGES		ENERGY	
Max. Demand	\$0.35 per kW	Base*	\$0.01797 per kWh
		Tier*	NONE per kWh
Summer:		PG&E Wheeling	\$1.09 per kW
On-Peak	\$7.50 per kW		
Part-Peak	\$0.60 per kW		
Off-Peak	\$0.00 per kW		
Winter:			
On-Peak	\$0.00 per kW		
Part-Peak	\$0.75 per kW		
Off-Peak	\$0.00 per kW		
ENERGY CHARGES			
Economic Stimulus Rate Credit*	\$0.00400 per kWh		
Summer:			
On-Peak	\$0.06370 per kWh		
Part-Peak	\$0.04831 per kWh		
Off-Peak	\$0.04538 per kWh		
Rate Limiters:			
Average	\$0.00000 per kWh		
On-Peak	\$0.56370 per kWh		
Winter:			
On-Peak	\$0.00000 per kWh		
Part-Peak	\$0.05948 per kWh		
Off-Peak	\$0.04896 per kWh		

Effective October 1, 1993

* Applicable 5/1/94
Base = up to 70% Load Factor
Tier = above 70% Load Factor

Effective July 15, 1993

* The Economic Stimulus Rate Credit Shall
Terminate 12/31/94.

** As of February 1, 1994, Both Bank 1 and Bank 2 Will Share the LBL Western Allocation.
Metering Will Occur Conjunctively.

E-4.2 PROPOSED TARIFF CHANGES

LBL2 PROPOSED TARIFFS

INTERLAB REBILLING RATES --

Rebilling rates effective May 1, 1994 are not available.

PG&E --

There are no proposed rates. A rate freeze of the July 15, 1993 rates is currently in effect through December 31, 1994.

WESTERN --

WESTERN CV-F7		
DEMAND	\$6.22	per kW
ENERGY		
Base*	\$0.01699	per kWh
Tier*	\$0.03087	per kWh
PG&E Wheeling	\$1.09	per kW

Effective May 1, 1994

* Energy Charges

Base = up to 70% Load Factor

Tier = above 70% Load Factor

E-5.1 NEAR-TERM ESTIMATED BILLS AT CURRENT RATES

LBL ESTIMATED BILLS AT CURRENT RATES PROJECTED LOADS

Bill estimates under the new interlab rebilling mechanism are not available, as rebilling rates effective May 1, 1994, are currently being determined. Estimates will be provided as soon as new rebilling rates become available.

E-5.2 NEAR-TERM ESTIMATED BILLS AT PROPOSED RATES

LBL ESTIMATED BILLS AT PROJECTED RATES PROJECTED LOADS

Bill estimates under the new interlab rebilling mechanism are not available, as rebilling rates effective May 1, 1994, are currently being determined. Estimates will be provided as soon as new rebilling rates become available.

LLNL Main Meter

E-1 ELECTRIC SERVICE CHARACTERISTICS

E-1.1 Current Suppliers and Rate Schedules

- PG&E:

Rate Schedule - E-20T Firm Service

Provides time metered general service at transmission voltage level.

Transmission Standby service under the 3-Party Settlement Agreement

- Western:

CRDs - (kW)

<u>Effective</u>	<u>Long-Term</u>	<u>Withdrawable</u>	<u>Diversity</u>	<u>Total</u>
11/86	29,300 ¹	7,606 ¹	---	36,906
8/87	29,300 ²	7,115 ²	---	36,415
5/90	26,300 ³	7,115	---	33,415
6/90	26,523 ³	7,115	---	33,638
10/90	43,203 ⁴	5,411 ⁴	---	48,614
1/91	20,300 ⁵	5,411	---	25,711
10/91	22,800 ⁶	5,911 ⁶	---	28,711
2/92	22,300 ⁷	5,911 ⁷	---	28,211
10/92	22,300	5,911	---	28,211
2/94	16,211	---	---	16,211

¹ Includes 9,000 kW Long-Term and 1,822 kW Withdrawable transferred from Mather AFB.

² Includes 9,000 kW Long-Term and 1,704 kW Withdrawable transferred from Mather AFB.

³ 2,777 kW Long-Term returned to Air Force. Long-Term CRDs inadvertently set at 26,300 kW for May; effective June error was corrected.

⁴ Remaining Air Force CRD returned to Mather AFB and 22,903 kW Long-Term transferred from SLAC to LLNL.

⁵ 22,903 kW Long-Term returned to SLAC.

⁶ CRD from Site 300 transferred to the Main Meter.

⁷ 500 kW Long-Term Power transferred to Site 300.

Rate Schedule - CV-F7

E-1.1 Current Suppliers and Rate Schedules (Cont'd.)

Billing Method (prior to February 1, 1994) - X/Y Formula

Billing Method (after February 1, 1994) - X/Y/Z Formula

- PacifiCorp: (beginning February 1, 1994)

Provides firm power over the California-Oregon Transmission Project.

CRDs (kW)

<u>Effective</u>	<u>Total</u>
1/94	39,600
1/95	36,800

Billing Method - X/Y/Z Formula

E-1.3 Contract Summary

DE-AD03-90SF18447: PG&E - DOE/OAK Supplemental Power Agreement

Provides for the sale of PG&E retail power to meet the supplemental requirements of LLNL. Contract effective November 1, 1989, through December 18, 1995. Contract has been modified to facilitate the delivery of COTP power to LLNL (beginning February 1, 1994).

92-SAO-20050: Intra-agency Agreement Between Western Area Power Administration and the U.S. Department of Energy for the Benefit of LLNL and Site 300

Contract effective October 29, 1992 until midnight December 31, 2004. Replaces Memorandum of Agreement No. DE-MS65-83WP59060 and Intra-agency Agreement No. 88-SAO-14003. Governs the delivery of Western power to both LLNL and Site 300. CRDs can be reduced or eliminated with various notification periods depending upon conditions on Western's system. Lab can request transfer, in whole or in part, of Long-Term Firm and Type III Withdrawable power to other Department of Energy labs. Lab must conduct an on-going energy management program. The PG&E/Western Contract No. 2948A overrides this contract.

89-SAO-90001: Intra-Agency Agreement between Western Area Power Administration and the U.S. Department of Energy for the Direct Interconnection of the Lawrence Livermore National Laboratory

Specific responsibilities of Western and DOE/OAK for the funding, construction and O&M of the 230 kV line (Tracy Tie Line) between Western's Tracy Substation and the Livermore Substation, of the 115 kV line between the Livermore Substation and U424 Substation and of the distribution system at LLNL. Establishes Western ownership of property and facilities (except those on LLNL property) and rights-of-way (procured for the construction of the Tracy Tie Line). DOE is responsible for maintaining a power factor of at least 95 percent leading or lagging. Contract effective September 18, 1984 - September 18, 2019, unless terminated earlier.

E-1.3 Contract Summary (Cont'd.)

90-SAO-00001: Intra-Agency Agreement Between Western Area Power Administration and the U.S. Department of Energy Regarding the California-Oregon Transmission Project

Obligates Western to act as DOE/OAK's agent to provide for acquisition of resources, arrangement of transmission service, and/or construction of transmission, and other coordination services. These actions (with DOE/OAK's approval) provide for the use of the DOE laboratories' 6.25 percent COTP entitlement. The DOE labs and the Federal Wildlife Refuges have equal priority rights to the entitlement. DOE shall pay Western for the services provided either through standard billing and payment or through reimbursement. Unused portions of the COTP entitlement may be laid off to other Federal entities. Contract effective March 19, 1990, with various termination options.

92-SAO-10113 PG&E - WAPA - DOE/OAK Settlement Agreement

Contract effective from June 18, 1991 through December 31, 2004. Resolves disputes between PG&E, DOE/OAK and Western concerning transmission service for LLNL. PG&E and Western agree to operate in parallel at LLNL without establishing a new point of interconnection (within the specifications of Contract No. 2948A). LLNL will pay a PG&E Standby Transmission Rate of \$0.701. This is applicable to providing an alternate transmission path for delivery between Western's Tracy Substation and the U424 Substation in the event of an outage on the Tracy Tie Line.

93-SAO-00018 DOE/OAK - PG&E - WAPA COTP Agreement

Contract provides details of COTP power operations and of the rights and responsibilities of each party. LLNL's load will be met first with COTP power followed by that of Western and PG&E, respectively. Western is required, initially, to provide Spinning Reserve for LLNL. Additionally, Western must use its best effort to provide Standby, Emergency Power and Replacement power in the event of a curtailment of COTP power. If sufficient standby emergency and replacement power are not available, PG&E shall provide standby service under Rate Schedule S. Contract establishes point of delivery, criteria for scheduling and deviation of COTP power, X/Y/Z energy calculation, and billing and payment. Contract is effective for five years beginning on February 1, 1994, and can be terminated with 12-month advance written notice to each of the other parties.

E-2.1 HISTORICAL USAGE AND COSTS

LLNL
HISTORICAL USAGE AND COSTS

FY 1992	PG&E				WESTERN				TOTAL				
	DEMAND	ENERGY	TOTAL	AVERAGE	DEMAND	ENERGY	TOTAL	AVERAGE	DEMAND	ENERGY	TOTAL	AVERAGE	LOAD
	(kW)	(kWh)	BILL	BILL	(kW)	(kWh)	BILL	BILL	(kW)	(kWh)	BILL	BILL	FACTOR
			(\$)	(\$/mWh)			(\$)	(\$/mWh)			(\$)	(\$/mWh)	(%)
Oct	29,317	16,110,911	\$1,162,230	\$72	28,711	15,777,889	\$467,867	\$30	58,028	31,888,800	\$1,630,096	\$51	73.86%
Nov	23,194	12,850,115	\$583,945	\$45	28,711	15,906,685	\$517,287	\$33	51,905	28,756,800	\$1,101,232	\$38	76.95%
Dec	19,954	12,005,120	\$542,512	\$45	28,711	17,263,060	\$524,951	\$30	48,665	29,268,180	\$1,067,463	\$36	80.84%
Jan	20,245	12,245,841	\$562,800	\$46	28,711	17,353,359	\$526,423	\$30	48,956	29,599,200	\$1,089,222	\$37	81.26%
Feb	22,430	12,225,172	\$555,080	\$45	28,211	15,376,028	\$489,972	\$32	50,641	27,601,200	\$1,045,052	\$38	78.31%
Mar	21,750	12,968,766	\$597,765	\$46	28,211	16,821,234	\$513,529	\$31	49,961	29,790,000	\$1,111,294	\$37	80.14%
Apr	28,943	14,857,886	\$689,518	\$46	28,211	14,467,898	\$421,850	\$29	57,154	29,325,784	\$1,111,368	\$38	71.26%
May	29,137	16,092,111	\$1,151,733	\$72	28,211	15,580,689	\$383,885	\$25	57,348	31,672,800	\$1,535,618	\$48	74.23%
Jun	30,951	15,940,796	\$1,185,363	\$74	28,211	14,529,604	\$386,500	\$27	59,162	30,470,400	\$1,571,863	\$52	71.53%
Jul	32,895	17,923,079	\$1,318,264	\$74	28,211	15,370,967	\$400,215	\$26	61,106	33,294,046	\$1,718,478	\$52	73.23%
Aug	33,090	17,881,911	\$1,300,642	\$73	28,211	15,245,289	\$398,166	\$26	61,301	33,127,200	\$1,698,808	\$51	72.63%
Sep	31,016	16,565,677	\$1,212,376	\$73	28,211	15,067,523	\$395,268	\$26	59,227	31,633,200	\$1,607,645	\$51	74.18%
ANNUAL	33,090	177,667,385	\$10,862,228	\$61	28,711	188,760,225	\$5,425,912	\$29	61,301	366,427,610	\$16,288,140	\$44	75.70%
FY 1993													
Oct	29,072	16,092,702	\$1,164,416	\$72	28,211	15,616,098	\$401,389	\$26	57,283	31,708,800	\$1,565,805	\$49	74.40%
Nov	24,860	13,352,477	\$613,261	\$46	28,211	15,152,323	\$450,980	\$30	53,071	28,504,800	\$1,064,241	\$37	74.60%
Dec	19,611	11,960,979	\$549,992	\$46	28,211	17,206,221	\$484,458	\$28	47,822	29,167,200	\$1,034,450	\$35	81.98%
Jan	19,611	11,813,349	\$561,228	\$48	28,211	16,993,851	\$480,996	\$28	47,822	28,807,200	\$1,042,225	\$36	80.97%
Feb	17,667	9,740,225	\$465,039	\$48	28,211	15,553,375	\$457,517	\$29	45,878	25,293,600	\$922,555	\$36	82.04%
Mar	20,389	11,913,217	\$571,684	\$48	28,211	16,483,583	\$472,679	\$29	48,600	28,396,800	\$1,044,363	\$37	78.53%
Apr	21,620	11,686,280	\$561,870	\$48	28,211	15,248,920	\$452,553	\$30	49,831	26,935,200	\$1,014,423	\$38	75.07%
May	23,175	12,626,690	\$938,317	\$74	28,211	15,370,510	\$438,320	\$29	51,386	27,997,200	\$1,376,637	\$49	73.23%
Jun	28,359	14,352,387	\$1,113,595	\$78	28,211	14,277,485	\$420,504	\$29	56,570	28,629,872	\$1,534,099	\$54	70.29%
Jul	27,387	15,009,404	\$982,323	\$65	28,211	15,460,996	\$439,823	\$28	55,598	30,470,400	\$1,422,146	\$47	73.66%
Aug	29,078	16,035,648	\$984,573	\$61	28,211	15,089,952	\$436,314	\$29	58,189	31,125,600	\$1,420,887	\$46	71.90%
Sep	28,359	14,697,552	\$909,404	\$62	28,211	14,620,848	\$426,127	\$29	56,570	29,318,400	\$1,335,531	\$46	71.98%
YR TO DATE	29,978	159,280,910	\$9,415,702	\$59	28,211	187,074,162	\$5,361,659	\$29	58,189	346,355,072	\$14,777,362	\$43	75.72%

E-2.2 NOTES TO HISTORICAL USAGE AND COSTS

FY 1992

January 1992 - PG&E

- Total bill is estimated based on revised Western usage.

March 1992 - Western

- Total bill excludes \$10,754 late payment charge.

April 1992 - PG&E

- Retroactive adjustments were made to billings in July, August and September 1991.

April 1992 - Western

- Total April bill excludes \$283,954 credit for misbilling of pass-through wheeling charges 6/91 - 9/91 and 10/91 - 3/92. Credits are given in the proper months.
- Total bill excludes \$137,630 FERC-mandated PG&E partial refund of pass-through wheeling cost 5/88 - 3/91; \$55,674.45 credit carried forward.
- Total bill does not account for adjustments to previous billings for power factor surcharge and energy charge.

May 1992 - Western

- Total bill excludes \$55,674.45 PG&E refund of pass-through wheeling cost 5/88 - 3/91 carry-over
- Total bill excludes \$43,721 refund of interest on pass-through wheeling cost 5/88 - 3/91.

June 1992 - Western

- Total bill excludes 10/91 - 5/92 pass through of PG&E standby charges \$159,382. Instead the standby charges were applied to the proper months.
- Total bill excludes 6/91 - 9/91 pass-through of PG&E standby charges \$61,792. Instead the standby charges were applied to the proper months.

E-2.2 NOTES TO HISTORICAL USAGE AND COSTS

FY 1993

October 1992 - Western

- Total bill excludes 8/92-9/92 pass-through of PG&E standby charges \$39,495. Instead, the standby charges are reflected in the proper months.

November 1992 - Western

- Total bill excludes late payment charge.

December 1992 - Western

- Total bill excludes \$8,672.32 late payment charge.

January 1993 - Western

- Total bill excludes late payment charge.

April 1993 - PG&E

- Total bill excludes \$7,584.54 rebate adjustment.

May 1993 - Western

- Total bill excludes 4/93 pass-through of PG&E standby charges \$19,747.70. The standby charge is reflected in the appropriate month.

July 1993 - Western

- Total bill adjusted to recognize 1 mill increase in pass through of PG&E standby charges from \$0.70 to \$0.701.

E-3.1 NEAR TERM PROJECTED USAGE

LLNL PROJECTED USAGE

Month	FY 1993		FY 1994		FY 1995	
	DEMAND (kW)	ENERGY (kWh)	DEMAND (kW)	ENERGY (kWh)	DEMAND (kW)	ENERGY (kWh)
Oct	57,283	31,708,800	53,654	28,879,200	53,654	28,879,200
Nov	53,071	28,504,800	48,146	25,790,400	48,146	25,790,400
Dec	47,822	29,167,200	43,546	25,668,000	43,546	25,668,000
Jan	47,822	28,807,200	43,344	26,163,216	43,344	26,163,216
Feb	45,878	25,293,600	41,551	22,371,804	41,551	22,371,804
Mar	48,600	28,396,800	44,273	25,475,004	44,273	25,475,004
Apr	49,831	26,935,200	45,504	24,013,404	45,504	24,013,404
May	51,386	27,997,200	47,059	25,055,404	47,059	25,055,404
Jun	56,570	28,629,872	52,243	25,708,076	52,243	25,708,076
Jul	55,598	30,470,400	51,271	27,548,604	51,271	27,548,604
Aug	58,189	31,125,600	53,863	28,203,804	53,863	28,203,804
Sep	56,570	29,318,400	52,243	26,396,604	52,243	26,396,604
ANNUAL	58,189	346,355,072	53,863	311,273,520	53,863	311,273,520

Source: FY 1993 and October 1993 Through January 1994 Data Represent Actual Usage. February 1994 Through September 1995 - Per Steve Imgarten. The Estimates are Based on Actual FY 1993 Demand and Energy. Adjusted by the 4-Month Average of the Difference Between the First Four Months of FY 1993 and FY 1994.

E-3.2 LONG-TERM LOAD FORECASTS

LLNL LONG-TERM LOAD FORECASTS

<u>FISCAL YEAR</u>	<u>DEMAND (kW)</u>	<u>ENERGY (mWh)</u>
1987 Act.	52,416	323,393
1987 Act.	56,798	329,086
1988 Act.	59,260	344,940
1989 Act.	61,657	360,273
1990 Act.	62,824	359,903
1991 Act.	61,463	356,275
1992 Act.	61,301	366,428
1993 Est.	58,189	346,355
1994	53,863	311,274
1995	53,863	311,274

Source: FY 1993 and October 1993 Through January 1994 Data Represent Actual Usage. February 1994 Through September 1995 - Per Steve Imgarten. The Estimates are Based on Actual FY 1993 Demand and Energy, Adjusted by the 4-Month Average of the Difference Between the First Four Months of FY 1993 and FY 1994.

E-4.1 CURRENT TARIFFS

Beginning February 1, 1994, the DOE/OAK labs began to pool their electricity resources to their mutual benefit. Specifically, the commencement of PacifiCorp power delivery to LLNL over the California-Oregon Transmission Project (COTP) and the reassignment of Western power among the labs will result in savings that will be shared by each lab. Low-cost PacifiCorp power is used to displace higher-cost PG&E power, and Western power was reallocated among the labs in order to lower overall cost. Under this new arrangement, LLNL receives PacifiCorp power over the COTP and Western's Tracy tie-line. LLNL's previous long-term Western allocation has been split between LLNL and LBL, and LBL's previous 3 mW diversity allotment has been transferred to SLAC. Savings for calendar 1994 are estimated to be about \$2 million, and savings from February - April 1994 will be about \$30,000.

An interlab rebilling mechanism, operated by LLNL Accounting, has been established in order to distribute the savings to the labs. Uniform electricity rebilling charges, based on marginal costs, have been implemented to achieve this aim. The rebilling charges are similar to PG&E rates: summer and winter differential, three summer energy periods, two winter energy periods, different customer charges for each laboratory, and an interruptible demand credit. The power year is set from May 1 through April 30 at which time a true-up will occur.

While the rebilling mechanism is conducted through LLNL Accounting, each lab has specific responsibilities: reviewing and verifying the usage on the rebilling memos and supplier bills; authorizing transfer of rebilling memo funds; preparing usage projections; and addressing supplier billing errors with suppliers. All supplier bills (PG&E, WAPA, NCPA & COTP) are sent to LLNL Accounting and to the appropriate laboratory utility offices. Usage data for all labs are also sent to LLNL (initially through Exeter, later by WAPA). Rebilling memos are prepared for LBL, LLNL, Site 300, and SLAC and are issued by the 15th of each month. Each lab utility office is responsible for reviewing supplier bills and usage on the rebilling memos and reporting any discrepancies to LLNL Accounting and to the appropriate supplier. (LLNL may reissue rebilling memos in the following month to correct any usage or billing discrepancies.) Having reviewed the rebilling memos, the lab utility offices authorize the transfer of funds to LLNL Accounting who then pays all supplier bills. Finally, monthly reports showing cost data, usage data and variations from projections are prepared and sent to DOE/OAK.

E-4.1 CURRENT TARIFFS

LLNL CURRENT REBILLING CHARGES*

CUSTOMER CHARGE (\$60,000.00) per month

DEMAND CHARGE (\$/kW) \$8.00 per month

ENERGY CHARGES (\$/kWh)

On-Peak \$0.000 per month

Partial Peak \$0.034 per month

Off Peak \$0.024 per month

EFFECTIVE

February - April 1994

- * The Rebilling Charges Reflect the Pooling of Electricity Resources and the Redistribution of Costs Among the DOE/OAK Labs.

E-4.1 CURRENT TARIFFS

LLNL CURRENT TARIFFS

PG&E E-20T FIRM		WESTERN CV-F7	
CUSTOMER CHARGE	\$715.00 per month	DEMAND	\$6.22 per kW
DEMAND CHARGES		ENERGY	
Max. Demand	\$0.35 per kW	Base*	\$0.01797 per kWh
Summer:		Tier*	NONE per kWh
On-Peak	\$7.50 per kW	PG&E Standby	\$0.701 per kW
Part-Peak	\$0.60 per kW		
Off-Peak	\$0.00 per kW		
Winter:			
On-Peak	\$0.00 per kW		
Part-Peak	\$0.75 per kW		
Off-Peak	\$0.00 per kW		
ENERGY CHARGES			
Economic Stimulus Rate Credit*	\$0.00400 per kWh		
Summer:			
On-Peak	\$0.06370 per kWh		
Part-Peak	\$0.04831 per kWh		
Off-Peak	\$0.04538 per kWh		
Rate Limiters:			
Average	\$0.00000 per kWh		
On-Peak	\$0.56370 per kWh		
Winter:			
On-Peak	\$0.00000 per kWh		
Part-Peak	\$0.05948 per kWh		
Off-Peak	\$0.04896 per kWh		

Effective October 1, 1993

* Applicable 5/1/94
Base = up to 70% Load Factor
Tier = above 70% Load Factor

Effective July 15, 1993

* The Economic Stimulus Rate Credit Shall
Terminate 12/31/94.

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E-4.1 CURRENT TARIFFS

LLNL CURRENT TARIFFS

PACIFICORP --

Demand (\$/kW)	\$12.89 per month
Energy (\$/kWh)	
< or = 70% LF	\$0.01578 per month
> 70% LF (1)	\$0.04100 per month

Effective January 1, 1994

OTHER COTP-RELATED CHARGES --

WAPA O&M (\$/kW)	\$0.3540 per month
WAPA Scheduling	\$4,689.00 per month
WAPA Standby	\$3,717.00 per month
LLNL Overhead	\$3,500.00 per month
	+ \$3,944.44 per month (2)
SLAC/NCPA Load Shed (3)	Varies
Tracy Facilities	\$25,402.00 per month
PG&E Spinning Reserve	\$73.35 per month

Effective February 1, 1994

NOTES:

- (1) Energy Price is a Pass-through of the Composite (Firm Capacity and Firm Energy) Costs Incurred by Western from PacifiCorp.
- (2) Charge is Applicable for 18 Months Effective February 1, 1994.
- (3) A Charge is Applicable When NCPA Curtails its Load on SLAC's Behalf.

E-4.2 PROPOSED TARIFF CHANGES

LLNL PROPOSED TARIFFS

INTERLAB REBILLING RATES --

Rebilling rates effective May 1, 1994 are not available.

PG&E --

There are no proposed rates. A rate freeze of the July 15, 1993 rates is currently in effect through December 31, 1994.

WESTERN --

WESTERN CV-F7

DEMAND	\$6.22 per kW
ENERGY	
Base*	\$0.01699 per kWh
Tier*	\$0.03087 per kWh
PG&E Standby	\$0.701 per kW

Effective May 1, 1994

* Energy Charges

Base = up to 70% Load Factor

Tier = above 70% Load Factor

E-5.1 NEAR-TERM ESTIMATED BILLS AT CURRENT RATES

LLNL ESTIMATED BILLS AT CURRENT RATES PROJECTED LOADS

Bill estimates under the new interlab rebilling mechanism are not available, as rebilling rates effective May 1, 1994, are currently being determined. Estimates will be provided as soon as new rebilling rates become available.

E-5.2 NEAR-TERM ESTIMATED BILLS AT PROPOSED RATES

LLNL ESTIMATED BILLS AT PROJECTED RATES PROJECTED LOADS

Bill estimates under the new interlab rebilling mechanism are not available, as rebilling rates effective May 1, 1994, are currently being determined. Estimates will be provided as soon as new rebilling rates become available.

MFTF/TMX Project

E-1 ELECTRIC SERVICE CHARACTERISTICS

E-1.1 Current Suppliers and Rate Schedules

- PG&E:

Rate Schedule - E-19T Interruptible Service

Provides time metered interruptible service at transmission voltage level.

E-1.2 Physical Characteristics of Service

- Delivery Point - Substation dead-end structure in the MFTF Project Area
- Voltage Level - 230 kV
- Metering - PG&E metering equipment @ 13.8 kV

E-1.3 Contract Summary

DE-AA03-84SF12187: Authorization for Utility Service or Change in Utility Service - MFTF/TMX Service Agreement

Governs the delivery of power over the 230 kV pulse line to the MFTF-B/TMX-U projects. Provides operating characteristics for "normal project," "conditioning mode" and "test" power requirements including mVA, duration, frequency, power factor and length of experiments. Interruptions or curtailments may occur if pulse service impairs services provided by PG&E or if power needed to meet requirements of firm customers. Contract effective from December 19, 1984.

E-2.1 HISTORICAL USAGE AND COSTS

MFTF/TMX
HISTORICAL USAGE AND COSTS

	PG&E				WESTERN				TOTAL				
	DEMAND	ENERGY	TOTAL	AVERAGE	DEMAND	ENERGY	TOTAL	AVERAGE	DEMAND	ENERGY	TOTAL	AVERAGE	LOAD
FY 1992	(kW)	(kWh)	BILL	BILL	(kW)	(kWh)	BILL	BILL	(kW)	(kWh)	BILL	BILL	FACTOR
			(\$)	(\$/mWh)			(\$)	(\$/mWh)			(\$)	(\$/mWh)	(%)
Oct	504	168,757	\$10,512	\$62	0	0	\$0	\$0	504	168,757	\$10,512	\$62	N/A
Nov	0	126,757	\$6,470	\$51	0	0	\$0	\$0	0	126,757	\$6,470	\$51	N/A
Dec	0	126,757	\$6,519	\$51	0	0	\$0	\$0	0	126,757	\$6,519	\$51	N/A
Jan	0	126,757	\$8,407	\$66	0	0	\$0	\$0	0	126,757	\$8,407	\$66	N/A
Feb	252	126,757	\$8,349	\$66	0	0	\$0	\$0	252	126,757	\$8,349	\$66	N/A
Mar	0	126,757	\$7,515	\$59	0	0	\$0	\$0	0	126,757	\$7,515	\$59	N/A
Apr	0	126,757	\$7,515	\$59	0	0	\$0	\$0	0	126,757	\$7,515	\$59	N/A
May	504	126,757	\$11,553	\$91	0	0	\$0	\$0	504	126,757	\$11,553	\$91	N/A
Jun	504	168,757	\$15,008	\$89	0	0	\$0	\$0	504	168,757	\$15,008	\$89	N/A
Jul	504	126,757	\$11,385	\$90	0	0	\$0	\$0	504	126,757	\$11,385	\$90	N/A
Aug	504	126,757	\$11,153	\$88	0	0	\$0	\$0	504	126,757	\$11,153	\$88	N/A
Sep	504	126,757	\$11,538	\$91	0	0	\$0	\$0	504	126,757	\$11,538	\$91	N/A
ANNUAL	504	1,605,084	\$115,923	\$72	0	0	\$0	\$0	504	1,605,084	\$115,923	\$72	N/A
FY 1993													
Oct	252	126,757	\$10,985	\$87	0	0	\$0	\$0	252	126,757	\$10,985	\$87	N/A
Nov	252	126,757	\$8,396	\$66	0	0	\$0	\$0	252	126,757	\$8,396	\$66	N/A
Dec	0	0	\$6,550	\$0	0	0	\$0	\$0	0	0	\$6,550	\$0	N/A
Jan	0	0	\$6,550	\$0	0	0	\$0	\$0	0	0	\$6,550	\$0	N/A
Feb	0	0	\$6,550	\$0	0	0	\$0	\$0	0	0	\$6,550	\$0	N/A
Mar	0	0	\$6,550	\$0	0	0	\$0	\$0	0	0	\$6,550	\$0	N/A
Apr	0	0	\$6,550	\$0	0	0	\$0	\$0	0	0	\$6,550	\$0	N/A
May	0	0	\$6,550	\$0	0	0	\$0	\$0	0	0	\$6,550	\$0	N/A
Jun	0	0	\$6,550	\$0	0	0	\$0	\$0	0	0	\$6,550	\$0	N/A
Jul	504	126,757	\$9,718	\$77	0	0	\$0	\$0	504	126,757	\$9,718	\$77	N/A
Aug	252	126,757	\$9,643	\$76	0	0	\$0	\$0	252	126,757	\$9,643	\$76	N/A
Sep	504	126,757	\$10,970	\$87	0	0	\$0	\$0	504	126,757	\$10,970	\$87	N/A
YR TO DATE	504	633,785	\$95,563	\$151	0	0	\$0	\$0	504	633,785	\$95,563	\$151	N/A

E-2.2 NOTES TO HISTORICAL USAGE AND COSTS

FY 1993

November 1992 - PG&E

- Total bill was rebilled to remove the demand charges per Jill Faubion's March memo dated 6/22/93.

December 1992 - May 1993 - PG&E

- Total bill was rebilled to the minimum charge per Jill Faubion's March memo dated 6/22/93.
- The 230 kV line was not in use during this time period. Consequently, zero usage or demand was recorded according to Kathy Allen (telephone conversation 10/26/93).

E-4.1 CURRENT TARIFFS

MFTF/TMX
CURRENT TARIFFSPG&E E-19T
NON-FIRM

MONTHLY CHARGES

Customer	\$810.00	per month
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DEMAND CHARGES

Max. Demand	\$0.35	per kW
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Summer:

On-Peak	\$0.00	per kW
Part-Peak	\$0.10	per kW
Off-Peak	\$0.00	per kW

Winter:

On-Peak	\$0.00	per kW
Part-Peak	\$0.25	per kW
Off-Peak	\$0.00	per kW

ENERGY CHARGES

Summer:

On-Peak	\$0.08313	per kWh
Part-Peak	\$0.07164	per kWh
Off-Peak	\$0.06721	per kWh

Winter:

On-Peak	\$0.00000	per kWh
Part-Peak	\$0.08865	per kWh
Off-Peak	\$0.07274	per kWh

UFR Credit:	\$0.00091	per kWh
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Noncompliance Penalty:*	\$8.40	per kWh/Event
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Effective July 15, 1993

* Noncompliance penalty for customers who fully complied with the previous year's operations is \$4.20 per kWh per Event

E-4.2 PROPOSED TARIFF CHANGES

MFTF/TMX PROPOSED TARIFFS

PG&E --

There are no proposed rates. A rate freeze of the July 15, 1993 rates is currently in effect through December 31, 1994.

Site 300

E-1 ELECTRIC SERVICE CHARACTERISTICS

E-1.1 Current Suppliers and Rate Schedules

- PG&E:

Rate Schedule - E-20T Firm Service

Provides time metered general service at transmission voltage level.

- Western:

CRDs - (kW)

<u>Effective</u>	<u>Long-Term</u>	<u>Withdrawable</u>	<u>Diversity</u>	<u>Total</u>
11/86	2,500	500	---	3,000
10/91	--- ¹	--- ¹	---	---
2/92	500 ²	---	---	500
10/92	500	---	---	500
2/94	2,500	---	---	2,500

¹ CRD transferred from Site 300 to the LLNL Main Meter.

² Includes 500 kW transferred from LLNL Main Meter.

Rate Schedule - CV-F7 and CV-TPT3

Billing Method - X/Y Formula

E-1.3 Contract Summary

DE-AC03-83SF11715: Pacific Gas and Electric Company Contract for Electric Service General Service - Time Metered

Governs delivery of PG&E power to Site 300. Initial contract term was for three years with subsequent one-year terms. Contract can be terminated at end of a term with 30 days written notice.

92-SAO-20050: Intra-agency Agreement Between Western Area Power Administration and the U.S. Department of Energy for the Benefit of LLNL and Site 300

Contract effective October 29, 1992 until midnight December 31, 2004. Replaces Memorandum of Agreement No. DE-MS65-83WP59060 and Intra-agency Agreement No. 88-SAO-14003. Governs the delivery of Western power to both LLNL and Site 300. CRDs can be reduced or eliminated with various notification periods depending upon conditions on Western's system. Lab can request transfer, in whole or in part, of Long-Term Firm and Type III Withdrawable power to other Department of Energy labs. Lab must conduct an on-going energy management program. The PG&E/Western Contract No. 2948A overrides this contract.

E-2.1 HISTORICAL USAGE AND COSTS

SITE 300
HISTORICAL USAGE AND COSTS

	PG&E				WESTERN				TOTAL				
	DEMAND	ENERGY	TOTAL	AVERAGE	DEMAND	ENERGY	TOTAL	AVERAGE	DEMAND	ENERGY	TOTAL	AVERAGE	LOAD
	(kW)	(kWh)	BILL	BILL	(kW)	(kWh)	BILL	BILL	(kW)	(kWh)	BILL	BILL	FACTOR
			(\$)	(\$/mWh)			(\$)	(\$/mWh)			(\$)	(\$/mWh)	(%)
FY 1992													
Oct	2,252	1,263,600	\$89,686	\$71	0	0	\$0	\$0	2,252	1,263,600	\$89,686	\$71	75.42%
Nov	2,349	1,221,000	\$56,183	\$46	0	0	\$0	\$0	2,349	1,221,000	\$56,183	\$46	72.19%
Dec	2,565	1,473,000	\$67,472	\$46	0	0	\$0	\$0	2,565	1,473,000	\$67,472	\$46	77.19%
Jan	2,700	1,610,400	\$75,051	\$47	0	0	\$0	\$0	2,700	1,610,400	\$75,051	\$47	80.17%
Feb	2,006	1,040,302	\$48,710	\$47	500	259,298	\$6,416	\$25	2,506	1,299,600	\$55,126	\$42	74.51%
Mar	1,568	948,989	\$43,989	\$46	500	302,611	\$9,454	\$31	2,068	1,251,600	\$53,442	\$43	81.35%
Apr	1,460	827,731	\$38,603	\$47	500	283,469	\$8,626	\$30	1,960	1,111,200	\$47,229	\$43	78.74%
May	1,525	874,333	\$61,802	\$71	500	286,667	\$8,216	\$29	2,025	1,161,000	\$70,018	\$60	77.06%
Jun	1,644	857,579	\$63,008	\$73	500	260,821	\$7,849	\$30	2,144	1,118,400	\$70,857	\$63	72.45%
Jul	1,822	954,314	\$70,470	\$74	500	261,886	\$7,867	\$30	2,322	1,216,200	\$78,337	\$64	70.49%
Aug	1,908	990,765	\$72,657	\$73	500	259,635	\$7,849	\$30	2,408	1,250,400	\$80,506	\$64	69.79%
Sep	1,784	921,369	\$67,702	\$73	500	258,231	\$7,788	\$30	2,284	1,179,600	\$75,490	\$64	71.73%
ANNUAL	2,700	12,983,382	\$755,332	\$58	500	2,172,618	\$64,065	\$29	2,700	15,156,000	\$819,397	\$54	75.08%
FY 1993													
Oct	1,460	859,463	\$60,789	\$71	500	294,337	\$8,310	\$28	1,960	1,153,800	\$69,099	\$60	79.12%
Nov	1,633	921,462	\$42,614	\$46	500	282,138	\$8,410	\$30	2,133	1,203,600	\$51,024	\$42	78.37%
Dec	1,817	1,108,080	\$51,225	\$46	500	304,920	\$8,781	\$29	2,317	1,413,000	\$60,006	\$42	81.97%
Jan	2,330	1,205,837	\$57,675	\$48	500	258,763	\$7,977	\$31	2,830	1,464,600	\$65,653	\$45	69.56%
Feb	1,849	1,013,054	\$48,594	\$48	500	273,946	\$8,276	\$30	2,349	1,287,000	\$56,871	\$44	81.53%
Mar	1,676	931,659	\$44,743	\$48	500	277,941	\$8,341	\$30	2,176	1,209,600	\$53,084	\$44	74.72%
Apr	1,514	829,468	\$40,041	\$48	500	273,932	\$8,274	\$30	2,014	1,103,400	\$48,315	\$44	76.09%
May	2,016	860,090	\$67,583	\$79	500	213,316	\$7,003	\$33	2,516	1,073,406	\$74,586	\$69	57.34%
Jun	1,611	825,571	\$63,393	\$77	500	256,229	\$7,933	\$31	2,111	1,081,800	\$71,326	\$66	71.17%
Jul	1,660	910,694	\$59,685	\$66	500	274,306	\$8,117	\$30	2,160	1,185,000	\$67,802	\$57	73.74%
Aug	1,968	934,880	\$59,629	\$64	500	237,520	\$7,518	\$32	2,468	1,172,400	\$67,146	\$57	63.85%
Sep	1,687	874,741	\$54,497	\$62	500	259,259	\$7,836	\$30	2,187	1,134,000	\$62,333	\$55	72.02%
YR TO DATE	2,330	11,274,999	\$650,468	\$58	500	3,206,607	\$96,776	\$30	2,830	14,481,606	\$747,244	\$52	73.29%

E-3.1 NEAR TERM PROJECTED USAGE

SITE 300 PROJECTED USAGE

Month	FY 1993		FY 1994		FY 1995	
	DEMAND (kW)	ENERGY (kWh)	DEMAND (kW)	ENERGY (kWh)	DEMAND (kW)	ENERGY (kWh)
Oct	1,960	1,153,800	2,282	1,299,479	2,297	1,315,533
Nov	2,133	1,203,600	2,380	1,255,669	2,396	1,271,182
Dec	2,317	1,413,000	2,599	1,514,824	2,616	1,533,539
Jan	2,830	1,464,600	2,736	1,656,126	2,754	1,676,586
Feb	2,349	1,287,000	2,539	1,336,501	2,556	1,353,012
Mar	2,176	1,209,600	2,096	1,287,138	2,109	1,303,040
Apr	2,014	1,103,400	1,986	1,142,751	1,999	1,156,869
May	2,516	1,073,406	2,052	1,193,965	2,066	1,208,716
Jun	2,111	1,081,800	2,173	1,150,156	2,187	1,164,365
Jul	2,160	1,185,000	2,353	1,250,733	2,368	1,266,185
Aug	2,468	1,172,400	2,440	1,285,904	2,456	1,301,790
Sep	2,187	1,134,000	2,255	1,167,755	2,269	1,182,182
ANNUAL	2,830	14,481,606	2,736	15,541,000	2,754	15,733,000

Source: FY 1993 - October 1992 Through June 1993 Data Represent Actual Usage.

July 1993 - FY 1995 Estimates Based on Kathy Allen Table Dated 10-JAN-93.

E-3.2 LONG-TERM LOAD FORECASTS

SITE 300 LONG-TERM LOAD FORECASTS

<u>FISCAL YEAR</u>	<u>DEMAND (kW)</u>	<u>ENERGY (mWh)</u>
1986 Act.	2,508	13,194
1987 Act.	2,716	14,194
1988 Act.	2,760	14,703
1989 Act.	2,705	15,173
1990 Act.	2,711	14,682
1991 Act.	2,527	14,689
1992 Act.	2,700	15,156
1993 Est.	2,830	14,482
1994	2,736	15,541
1995	2,754	15,733
1996	2,772	15,926
1997	2,790	16,118
1998	2,808	16,310
1999	2,826	16,503
2000	2,844	16,695
2001	2,862	16,887

Source: Kathy Allen Table Dated 10-JAN-93. October 1992 -
June 1993 Data Represent Actual Usage.

E-4.1 CURRENT TARIFFS

Beginning February 1, 1994, the DOE/OAK labs began to pool their electricity resources to their mutual benefit. Specifically, the commencement of PacifiCorp power delivery to LLNL over the California-Oregon Transmission Project (COTP) and the reassignment of Western power among the labs will result in savings that will be shared by each lab. Low-cost PacifiCorp power is used to displace higher-cost PG&E power, and Western power was reallocated among the labs in order to lower overall cost. Under this new arrangement, LLNL receives PacifiCorp power over the COTP and Western's Tracy tie-line. LLNL's previous long-term Western allocation has been split between LLNL and LBL, and LBL's previous 3 mW diversity allotment has been transferred to SLAC. Savings for calendar 1994 are estimated to be about \$2 million, and savings from February - April 1994 will be about \$30,000.

An interlab rebilling mechanism, operated by LLNL Accounting, has been established in order to distribute the savings to the labs. Uniform electricity rebilling charges, based on marginal costs, have been implemented to achieve this aim. The rebilling charges are similar to PG&E rates: summer and winter differential, three summer energy periods, two winter energy periods, different customer charges for each laboratory, and an interruptible demand credit. The power year is set from May 1 through April 30 at which time a true-up will occur.

While the rebilling mechanism is conducted through LLNL Accounting, each lab has specific responsibilities: reviewing and verifying the usage on the rebilling memos and supplier bills; authorizing transfer of rebilling memo funds; preparing usage projections; and addressing supplier billing errors with suppliers. All supplier bills (PG&E, WAPA, NCPA & COTP) are sent to LLNL Accounting and to the appropriate laboratory utility offices. Usage data for all labs are also sent to LLNL (initially through Exeter, later by WAPA). Rebilling memos are prepared for LBL, LLNL, Site 300, and SLAC and are issued by the 15th of each month. Each lab utility office is responsible for reviewing supplier bills and usage on the rebilling memos and reporting any discrepancies to LLNL Accounting and to the appropriate supplier. (LLNL may reissue rebilling memos in the following month to correct any usage or billing discrepancies.) Having reviewed the rebilling memos, the lab utility offices authorize the transfer of funds to LLNL Accounting who then pays all supplier bills. Finally, monthly reports showing cost data, usage data and variations from projections are prepared and sent to DOE/OAK.

E-4.1 CURRENT TARIFFS

SITE 300 CURRENT REBILLING CHARGES*

CUSTOMER CHARGE	\$6,000.00 per month
DEMAND CHARGE (\$/kW)	\$8.00 per month
ENERGY CHARGES (\$/kWh)	
On-Peak	\$0.000 per month
Partial Peak	\$0.034 per month
Off Peak	\$0.024 per month

EFFECTIVE

February - April 1994

* The Rebiling Charges Reflect the Pooling of Electricity Resources and the Redistribution of Costs Among the DOE/OAK Labs.

E-4.1 CURRENT TARIFFS

SITE 300
CURRENT TARIFFS

PG&E E-20T FIRM		WESTERN CV-F7	
CUSTOMER CHARGE	\$715.00 per month	DEMAND	\$6.22 per kW
DEMAND CHARGES		ENERGY	
Max. Demand	\$0.35 per kW	Base*	\$0.01797 per kWh
		Tier*	NONE per kWh
Summer:		PG&E Wheeling	\$1.09 per kW
On-Peak	\$7.50 per kW		
Part-Peak	\$0.60 per kW		
Off-Peak	\$0.00 per kW		
Winter:			
On-Peak	\$0.00 per kW		
Part-Peak	\$0.75 per kW		
Off-Peak	\$0.00 per kW		
ENERGY CHARGES			
Economic Stimulus Rate Credit*	\$0.00400 per kWh		
Summer:			
On-Peak	\$0.06370 per kWh		
Part-Peak	\$0.04831 per kWh		
Off-Peak	\$0.04538 per kWh		
Rate Limiters:			
Average	\$0.00000 per kWh		
Cn-Peak	\$0.56370 per kWh		
Winter:			
On-Peak	\$0.00000 per kWh		
Part-Peak	\$0.05948 per kWh		
Off-Peak	\$0.04896 per kWh		

Effective October 1, 1993

* Applicable 5/1/94
 Base = up to 70% Load Factor
 Tier = above 70% Load Factor

Effective July 15, 1993

* The Economic Stimulus Rate Credit Shall
 Terminate 12/31/94.

E-4.2 PROPOSED TARIFF CHANGES

SITE 300 PROPOSED TARIFFS

INTERLAB REBILLING RATES --

Rebilling rates effective May 1, 1994 are not available.

PG&E --

There are no proposed rates. A rate freeze of the July 15, 1993 rates is currently in effect through December 31, 1994.

WESTERN --

WESTERN CV-F7

DEMAND	\$6.22 per kW
ENERGY	
Base*	\$0.01699 per kWh
Tier*	\$0.03087 per kWh
PG&E Wheeling	\$1.09 per kW

Effective May 1, 1994

* Energy Charges

Base = up to 70% Load Factor

Tier = above 70% Load Factor

E-5.1 NEAR-TERM ESTIMATED BILLS AT CURRENT RATES

SITE 300
ESTIMATED BILLS AT CURRENT RATES
PROJECTED LOADS

Bill estimates under the new interlab rebilling mechanism are not available, as rebilling rates effective May 1, 1994, are currently being determined. Estimates will be provided as soon as new rebilling rates become available.

E-5.2 NEAR-TERM ESTIMATED BILLS AT PROPOSED RATES

SITE 300 ESTIMATED BILLS AT PROJECTED RATES PROJECTED LOADS

Bill estimates under the new interlab rebilling mechanism are not available, as rebilling rates effective May 1, 1994, are currently being determined. Estimates will be provided as soon as new rebilling rates become available.

SLAC

E-1 ELECTRIC SERVICE CHARACTERISTICS

E-1.1 Current Suppliers and Rate Schedules

- PG&E:

Rate Schedule - E-20T Interruptible Service

Provides time metered interruptible service at transmission voltage level.

- Western:

CRDs - (kW)

<u>Effective</u>	<u>Long-Term</u>	<u>Withdrawable</u>	<u>Diversity</u>	<u>Total</u>
11/86	25,000	14,903	6,000	45,903
6/90	25,000	5,000 ¹	--- ¹	30,000
10/90	2,097 ²	14,903	6,000	23,000
1/91	5,000	14,903	6,000	45,903
10/92	25,000	14,903	6,000	45,903
2/94	17,589	20,814	9,000	47,403

¹Withdrawable and diversity CRDs idled.

²22,903 kW temporarily shifted to LLNL.

Rate Schedule - CV-F7 and CV-TPT3

Billing Method - Western power is base loaded.

Notes: SLAC is required to reduce load to 17 mW upon Western's request.
Type I withdrawable can be reduced or eliminated if PG&E support levels are exceeded.

During the months of May through September of 1987, 1988 and 1989 SLAC's CRD was reduced to 17 mW. All power above 17 mW was supplied by PG&E. Therefore, SLAC was not subject to interruptions by Western but was subject to PG&E's interruptions.

E-1.1 Current Suppliers and Rate Schedules (Cont'd.)

During the months of June through September 1992 and of January 1993, the Northern California Power Agency reduced its demand on Western in lieu of SLAC shedding load during peak load conditions pursuant to SLAC's Diversity Contract with Western.

E-1.2 Physical Characteristics of Service

- Delivery Point - SLAC master substation
- Voltage Level - 230 kV and 60 kV
- Metering - @ 230 kV, 3 metering sets with one measuring PG&E power

E-1.3 Contract Summary

DE-AA03-84SF11991: Service Agreement Between Pacific Gas and Electric and the Department of Energy for Service to the SLAC

Governs the delivery of PG&E power to SLAC. Contract may be terminated by either party with 30 days written notice. Increase in power use shall not be greater than 12 mW per minute and the decrease in power use shall not be in excess of 18 mW per minute except for interruptions. Power is subject to both automatic and notified interruptions.

92-SAO-20051: Intra-agency Agreement for Electric Service to the Stanford Linear Accelerator Center

Contract effective from October 29, 1992, until midnight, December 31, 2004. Replaces Memorandum of Agreement No. DE-MS65-83WP59047, Memorandum of Agreement No. DE-MS65-83WP59061 and Intra-agency Agreement No. 88-SAO-14004. Provides Long-Term Firm, Type III Withdrawable and Diversity Power. Reductions of CRDs and/or termination of diversity CRDs can occur with varying notification periods depending upon conditions on Western's system. As long as SLAC receives diversity power, it is required to reduce load upon Western's request. SLAC may request transfers of CRDs, in whole or in part, to other Department of Energy labs. The PG&E/Western Contract No. 2948A overrides this contract.

93-SAO-10155: Letter Agreement Between Western Area Power Administration and Northern California Power Agency.

Contract effective January 1, 1994, through December 31, 1994. Northern California Power Agency (NCPA) has agreed to reduce its demand on Western in lieu of SLAC shedding load during peak load conditions. NCPA is not obligated to reduce its Western load and curtails deliveries of Western power at its sole discretion, on a case-by-case basis. This agreement in no way impacts other agreements currently in effect between Western and NCPA.

93-SAO-10154: Letter Agreement Between Western Area Power Administration and DOE/OAK for the Benefit of SLAC

Contract effective January 1, 1994, to midnight, December 31, 1994. Modifies Intra-Agency Agreement No. 92-SAO-20051 to comport with objectives of Letter Agreement No. 93-SAO-10155(IA) (NCPA/Western Agreement). SLAC has the discretion to reduce its demand to the level requested by Western (but not below

E-1.3 Contract Summary (Cont'd.)

17 mW) or to request a curtailment by Northern California Power Agency pursuant to the NCPA/Western Agreement. If curtailment is acceptable to NCPA, SLAC would have the discretion to curtail its load or to request that NCPA reduce demand. When NCPA curtails load on SLAC's behalf, SLAC will be allowed to continue to operate without curtailment during the curtailment period. To the extent that NCPA is unwilling or unable to reduce demand, SLAC is obligated to curtail load pursuant to the IA. SLAC will reimburse Western, on an unconditional basis, the transaction costs for each curtailment of Western power made by NCPA.

E-2.1 HISTORICAL USAGE AND COSTS

SLAC
HISTORICAL USAGE AND COSTS

FY 1992	PG&E				WESTERN				TOTAL				
	DEMAND	ENERGY	TOTAL BILL	AVERAGE BILL	DEMAND	ENERGY	TOTAL BILL	AVERAGE BILL	DEMAND	ENERGY	TOTAL BILL	AVERAGE BILL	LOAD FACTOR
	(kW)	(kWh)	(\$)	(\$/mWh)	(kW)	(kWh)	(\$)	(\$/mWh)	(kW)	(kWh)	(\$)	(\$/mWh)	(%)
Oct	0	0	\$381	\$0	20,674	13,189,500	\$387,147	\$29	20,674	13,189,500	\$387,529	\$29	85.75%
Nov	0	0	\$381	\$0	14,391	7,852,800	\$266,640	\$34	14,391	7,852,800	\$267,021	\$34	75.79%
Dec	0	0	\$381	\$0	26,271	14,222,100	\$482,103	\$34	26,271	14,222,100	\$482,484	\$34	72.76%
Jan	0	0	\$440	\$0	43,854	22,891,800	\$794,424	\$35	43,854	22,891,800	\$794,863	\$35	70.16%
Feb	7,455	2,347,662	\$103,959	\$44	45,903	30,569,538	\$929,071	\$30	53,358	32,917,200	\$1,033,030	\$31	88.64%
Mar	7,455	3,709,341	\$161,921	\$44	45,903	33,575,859	\$981,678	\$29	53,358	37,285,200	\$1,143,599	\$31	93.92%
Apr	8,086	2,487,230	\$110,960	\$45	45,903	29,668,270	\$859,809	\$29	53,989	32,155,500	\$970,769	\$30	82.72%
May	8,388	3,668,414	\$214,718	\$59	45,903	33,948,586	\$863,836	\$25	54,291	37,617,000	\$1,078,554	\$29	93.13%
Jun	8,664	4,132,184	\$219,086	\$53	45,903	32,575,516	\$846,269	\$26	54,567	36,707,700	\$1,065,355	\$29	93.43%
Jul	12,833	4,376,201	\$234,639	\$54	45,903	34,099,099	\$900,587	\$26	58,736	38,475,300	\$1,135,227	\$30	88.05%
Aug	7,922	3,643,359	\$192,904	\$53	45,903	33,091,941	\$916,458	\$28	53,825	36,735,300	\$1,109,363	\$30	91.73%
Sep	8,527	1,653,392	\$102,662	\$62	45,903	25,745,008	\$733,393	\$28	54,430	27,398,400	\$836,055	\$31	69.91%
ANNUAL	12,833	26,017,783	\$1,342,433	\$52	45,903	311,430,017	\$8,961,416	\$29	58,736	337,447,800	\$10,303,849	\$31	83.83%
FY 1993													
Oct	0	0	\$440	\$0	22,798	5,998,419	\$203,827	\$34	22,798	5,998,419	\$204,267	\$34	35.36%
Nov	0	0	\$440	\$0	38,454	21,359,856	\$651,386	\$30	38,454	21,359,856	\$651,826	\$31	77.15%
Dec	0	0	\$440	\$0	43,430	24,039,900	\$738,766	\$31	43,430	24,039,900	\$739,206	\$31	74.40%
Jan	8,327	1,782,156	\$84,679	\$48	45,903	29,113,944	\$856,381	\$29	54,230	30,896,100	\$941,060	\$30	76.58%
Feb	7,714	3,530,691	\$162,611	\$46	45,903	30,764,109	\$875,823	\$28	53,617	34,294,800	\$1,038,435	\$30	95.18%
Mar	7,930	3,819,728	\$177,078	\$46	45,903	33,924,172	\$931,000	\$27	53,833	37,743,900	\$1,108,079	\$29	94.24%
Apr	8,751	4,231,030	\$195,356	\$46	45,903	32,460,770	\$908,434	\$28	54,654	36,691,800	\$1,103,790	\$30	93.24%
May	7,490	3,990,273	\$218,057	\$55	45,903	33,993,627	\$919,201	\$27	53,393	37,983,900	\$1,137,258	\$30	95.62%
Jun	7,965	3,595,553	\$202,841	\$56	45,903	32,000,008	\$886,705	\$28	53,868	35,595,561	\$1,089,547	\$31	91.78%
Jul	7,922	3,792,066	\$177,016	\$47	45,903	34,127,634	\$924,140	\$27	53,825	37,919,700	\$1,101,156	\$29	94.69%
Aug	2,738	273,251	\$13,706	\$50	45,903	32,930,149	\$895,899	\$27	48,641	33,203,400	\$909,606	\$27	91.75%
Sep	0	0	\$907	\$0	16,534	5,649,000	\$202,714	\$36	16,534	5,649,000	\$203,621	\$36	47.45%
YR TO DATE	8,751	25,014,748	\$1,233,571	\$49	45,903	316,361,588	\$8,994,277	\$28	54,654	341,376,336	\$10,227,848	\$30	80.62%

E-3.1 NEAR TERM PROJECTED USAGE

SLAC PROJECTED USAGE

Month	FY 1993		FY 1994		FY 1995	
	DEMAND (kW)	ENERGY (kWh)	DEMAND (kW)	ENERGY (kWh)	DEMAND (kW)	ENERGY (kWh)
Oct	22,798	5,998,419	16,700	7,000,000	52,900	35,500,000
Nov	38,454	21,359,856	40,000	25,600,000	55,500	34,900,000
Dec	43,430	24,039,900	40,000	25,000,000	56,700	33,700,000
Jan	54,230	30,896,100	42,800	30,000,000	56,700	38,400,000
Feb	53,617	34,294,800	30,500	16,000,000	56,700	34,400,000
Mar	53,833	37,743,900	27,100	18,500,000	56,700	38,100,000
Apr	54,654	36,691,800	32,900	21,500,000	20,200	11,800,000
May	53,393	37,983,900	37,700	23,200,000	20,200	13,300,000
Jun	53,868	35,595,561	54,700	36,500,000	20,200	12,900,000
Jul	53,825	37,919,700	54,700	37,800,000	20,200	12,100,000
Aug	48,641	33,203,400	52,900	35,500,000	16,400	10,700,000
Sep	16,534	5,649,000	52,900	34,400,000	16,400	10,400,000
ANNUAL	<u>54,654</u>	<u>341,376,336</u>	<u>54,700</u>	<u>311,000,000</u>	<u>56,700</u>	<u>286,200,000</u>

Source: FY 1993 Data Represent Actual Usage. FY 1994 - 1995 Data Per a G. Loew Table
Dated February 25, 1994.

E-3.2 LONG-TERM LOAD FORECASTS

SLAC LONG-TERM LOAD FORECASTS

<u>FISCAL YEAR</u>	<u>DEMAND (kW)</u>	<u>ENERGY (mWh)</u>
1986 Act.	49,152	222,300
1987 Act.	32,786	192,568
1988 Act.	47,870	233,858
1989 Act.	51,408	318,190
1990 Act.	64,789	294,361
1991 Act.	50,187	235,368
1992 Act.	58,736	337,448
1993 Act.	54,654	341,376
1994 Est.	54,700	311,000
1995	56,700	286,200
1996	57,000	330,000
1997	58,000	340,000
1998	62,000	360,000
1999	68,000	380,000

Source: FY 1994 - FY 1997 Per G.A. Loew Table Dated February 25, 1994.
FY 1998 - FY 1999 Per December 17, 1993 Conversation with
G.A. Loew. Assumes B-Factory in Operation in 1998 or 1999.

E-4.1 CURRENT TARIFFS

Beginning February 1, 1994, the DOE/OAK labs began to pool their electricity resources to their mutual benefit. Specifically, the commencement of PacifiCorp power delivery to LLNL over the California-Oregon Transmission Project (COTP) and the reassignment of Western power among the labs will result in savings that will be shared by each lab. Low-cost PacifiCorp power is used to displace higher-cost PG&E power, and Western power was reallocated among the labs in order to lower overall cost. Under this new arrangement, LLNL receives PacifiCorp power over the COTP and Western's Tracy tie-line. LLNL's previous long-term Western allocation has been split between LLNL and LBL, and LBL's previous 3 mW diversity allotment has been transferred to SLAC. Savings for calendar 1994 are estimated to be about \$2 million, and savings from February - April 1994 will be about \$30,000.

An interlab rebilling mechanism, operated by LLNL Accounting, has been established in order to distribute the savings to the labs. Uniform electricity rebilling charges, based on marginal costs, have been implemented to achieve this aim. The rebilling charges are similar to PG&E rates: summer and winter differential, three summer energy periods, two winter energy periods, different customer charges for each laboratory, and an interruptible demand credit. The power year is set from May 1 through April 30 at which time a true-up will occur.

While the rebilling mechanism is conducted through LLNL Accounting, each lab has specific responsibilities: reviewing and verifying the usage on the rebilling memos and supplier bills; authorizing transfer of rebilling memo funds; preparing usage projections; and addressing supplier billing errors with suppliers. All supplier bills (PG&E, WAPA, NCPA & COTP) are sent to LLNL Accounting and to the appropriate laboratory utility offices. Usage data for all labs are also sent to LLNL (initially through Exeter, later by WAPA). Rebilling memos are prepared for LBL, LLNL, Site 300, and SLAC and are issued by the 15th of each month. Each lab utility office is responsible for reviewing supplier bills and usage on the rebilling memos and reporting any discrepancies to LLNL Accounting and to the appropriate supplier. (LLNL may reissue rebilling memos in the following month to correct any usage or billing discrepancies.) Having reviewed the rebilling memos, the lab utility offices authorize the transfer of funds to LLNL Accounting who then pays all supplier bills. Finally, monthly reports showing cost data, usage data and variations from projections are prepared and sent to DOE/OAK.

E-4.1 CURRENT TARIFFS

SLAC CURRENT REBILLING CHARGES*

CUSTOMER CHARGE	(\$88,000.00) per month
DEMAND CHARGE (\$/kW)	\$8.00 per month
INTERRUPTIBLE CREDIT (\$/kW)	\$3.00 per month
ENERGY CHARGES (\$/kWh)	
On-Peak	\$0.000 per month
Partial Peak	\$0.034 per month
Off Peak	\$0.024 per month

EFFECTIVE

February - April 1994

- * The Rebilling Charges Reflect the Pooling of Electricity Resources and the Redistribution of Costs Among the DOE/OAK Labs.

E-4.1 CURRENT TARIFFS

SLAC CURRENT TARIFFS

PG&E E-20T NON-FIRM		WESTERN CV-F7	
MONTHLY CHARGES			
Customer	\$915.00 per month	DEMAND	\$6.22 per kW
DEMAND CHARGES		ENERGY	
Max. Demand	\$0.35 per kW	Base*	\$0.01797 per kWh
		Tier*	NONE per kWh
Summer:			
On-Peak	\$0.00 per kW		
Part-Peak	\$0.10 per kW		
Off-Peak	\$0.00 per kW		
Winter:			
On-Peak	\$0.00 per kW		
Part-Peak	\$0.25 per kW		
Off-Peak	\$0.00 per kW		
		Effective October 1, 1993	
		* Applicable 5/1/94	
		Base = up to 70% Load Factor	
		Tier = above 70% Load Factor	
ENERGY CHARGES			
Summer:			
On-Peak	\$0.05123 per kWh		
Part-Peak	\$0.04699 per kWh		
Off-Peak	\$0.04406 per kWh		
Winter:			
On-Peak	\$0.00000 per kWh		
Part-Peak	\$0.05816 per kWh		
Off-Peak	\$0.04764 per kWh		
Economic Stimulus			
Rate Credit:*	\$0.00400 per kWh		
UFR Credit:	\$0.00091 per kWh		
Noncompliance Penalty:**	\$8.40 per kWh/Event		

Effective July 15, 1993

* The Economic Stimulus Rate Credit Shall
Terminate 12/31/94.

** Noncompliance penalty for customers who fully complied with the previous
year's operations is \$4.20 per kWh per Event

E-4.2 PROPOSED TARIFF CHANGES

SLAC PROPOSED TARIFFS

INTERLAB REBILLING RATES --

Rebilling rates effective May 1, 1994 are not available.

PG&E --

There are no proposed rates. A rate freeze of the July 15, 1993 rates is currently in effect through December 31, 1994.

WESTERN --

WESTERN CV-F7

DEMAND \$6.22 per kW

ENERGY

Base* \$0.01699 per kWh

Tier* \$0.03087 per kWh

PG&E Wheeling \$1.09 per kW

Effective May 1, 1994

* Energy Charges

Base = up to 70% Load Factor

Tier = above 70% Load Factor

E-5.1 NEAR-TERM ESTIMATED BILLS AT CURRENT RATES

SLAC ESTIMATED BILLS AT CURRENT RATES PROJECTED LOADS

Bill estimates under the new interlab rebilling mechanism are not available, as rebilling rates effective May 1, 1994, are currently being determined. Estimates will be provided as soon as new rebilling rates become available.

E-5.2 NEAR-TERM ESTIMATED BILLS AT PROPOSED RATES

SLAC ESTIMATED BILLS AT PROJECTED RATES PROJECTED LOADS

Bill estimates under the new interlab rebilling mechanism are not available, as rebilling rates effective May 1, 1994, are currently being determined. Estimates will be provided as soon as new rebilling rates become available.

LBL 1 - ACCOUNT NO. HJR 10 34501
(Former Account No. BJR 64-74001-2)

G-1 NATURAL GAS SERVICE CHARACTERISTICS

G-1.1 Current Supplier and Rate Schedule

-- PG&E:

Rate Schedule G-NR1 - Gas Sales to Small Non-Residential Core Customers.

- Applies only to core customers with gas usage which qualifies as priority levels P1 or P2A.
- Average monthly usage per meter must be less than 20,800 therms in those months during the last twelve months in which more than 200 therms were used. Service is reviewed every March to determine continued applicability.
- Provides bundled natural gas sales and delivery service.

G-1.2 Physical Characteristics of Service

- Load serves Buildings 73 and 73A only.
- Delivery point can be identified near LBL interface point G-3, Valve 13BG.
- The delivery line between valve 13BG and the metering point is owned by PG&E. All other distribution lines are owned by the U.S. Government. Part of the metering equipment is owned by PG&E.

G-2.1 HISTORICAL USAGE AND COSTS

LBL1 - ACCOUNT NO. HJR 10 34501
HISTORICAL USAGE AND COSTS

		<u>USAGE (THERMS)</u>	<u>TOTAL BILL (\$)</u>	<u>AVERAGE BILL (\$/THERM)</u>
OCTOBER	1991	625	\$311.49	\$0.4984
NOVEMBER	1991	1,067	702.16	0.6581
DECEMBER	1991	1,247	821.00	0.6584
JANUARY	1992	1,119	770.00	0.6881
FEBRUARY	1992	1,089	749.00	0.6878
MARCH	1992	994	679.04	0.6831
APRIL	1992	866	448.30	0.5177
MAY	1992	653	338.55	0.5185
JUNE	1992	812	419.71	0.5169
JULY	1992	683	355.12	0.5199
AUGUST	1992	618	322.57	0.5220
SEPTEMBER	1992	<u>713</u>	<u>370.14</u>	<u>0.5191</u>
TOTAL FY	1992	<u>10,486</u>	<u>\$6,287.08</u>	<u>\$0.5996</u>
OCTOBER	1992	611	\$324.23	\$0.5307
NOVEMBER	1992	1,028	610.83	0.5942
DECEMBER	1992	1,701	1,011.00	0.5944
JANUARY	1993	1,386	847.90	0.6118
FEBRUARY	1993	1,484	911.11	0.6140
MARCH	1993	1,033	626.77	0.6067
APRIL	1993	1,091	502.32	0.4604
MAY	1993	982	471.36	0.4800
JUNE	1993	553	280.64	0.5075
JULY	1993	529	269.04	0.5086
AUGUST	1993	474	243.43	0.5136
SEPTEMBER	1993	<u>589</u>	<u>299.24</u>	<u>0.5080</u>
TO DATE FY	1993	<u>11,461</u>	<u>\$6,397.87</u>	<u>\$0.5582</u>

G-3.1 NEAR TERM PROJECTED USAGE

LBL1 - ACCOUNT NO. HJR 10 34501
NEAR TERM PROJECTED USAGE

	FY 1993 <u>(THERMS)</u>	FY 1994 <u>(THERMS)*</u>
OCTOBER	611	611
NOVEMBER	1,028	1,028
DECEMBER	1,701	1,701
JANUARY	1,386	1,386
FEBRUARY	1,484	1,484
MARCH	1,033	1,033
APRIL	1,091	1,091
MAY	982	982
JUNE	553	553
JULY	529	529
AUGUST	474	474
SEPTEMBER	<u>589</u>	<u>589</u>
TOTALS	<u>11,461</u>	<u>11,461</u>

* FY 1994 Near-Term Forecasts Are Not Available.
FY 1993 Usage Assumed As Forecasted Usage.

G-3.2 LONG TERM PROJECTED USAGE

LBL1 - ACCOUNT NO. HJR 10 34501
LONG TERM PROJECTED USAGE

<u>FISCAL YEAR</u>	<u>TOTAL USAGE*</u> (THERMS)
1987	9,659
1988	7,329
1989	11,589
1990	12,496
1991	13,850
1992	10,486
1993	11,461
1994	11,461
1995	11,461
1996	11,461
1997	11,461

* Long-Term Forecasts Are Not Available.
FY 1993 Usage Assumed As Forecasted Usage.

G-4.1 CURRENT TARIFF

LBL1 - ACCOUNT NO. HJR 10 34501
CURRENT RATES

SCHEDULE G-NR1 -- GAS SALES TO SMALL NONRESIDENTIAL CORE CUSTOMERS

RATES:

CUSTOMER CHARGE	\$13.42 per month
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DELIVERED COMMODITY/TRANSPORTATION CHARGE:

WINTER SERVICE	\$0.63784 per therm
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SUMMER SERVICE	\$0.47247 per therm
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SEASONS:

WINTER SEASON BEGINS NOVEMBER 1 AND ENDS MARCH 31

SUMMER SEASON BEGINS APRIL 1 AND ENDS OCTOBER 31

EFFECTIVE DATE:

January 1, 1994

G-4.1 CURRENT TARIFF

PG&E's capacity brokering program requires PG&E to "unbundle" its interstate demand charges from its intrastate transportation rates. Implementation of this program was slated to occur in two phases. The first phase, partial capacity brokering on the El Paso and Transwestern pipeline systems, commenced August 1, 1993. The DOE/OAK labs elected to remain customers of PG&E, receiving gas under the rates for core (Rate G-NR1) and noncore (Rate G-CS) customers.

The partial capacity brokering plan was expected to continue until the commencement of full capacity brokering around August 1, 1994. However, during September 1993, the Federal Energy Regulatory Commission (FERC) granted the Pacific Gas Transmission Co. (PGT) approval to move forward with its capacity release program. As a result of the FERC's earlier-than-expected approval of capacity release on the PGT pipeline system, PG&E moved the date of full capacity brokering implementation to November 1, 1993.

Several options are available to the DOE/OAK labs under full capacity brokering. Core subscription customers (LBL4, LLNL and SLAC2) have the option to continue receiving gas from PG&E or to receive gas from a third party.

LBL1 is currently a core customer of PG&E. Since its gas requirements are relatively small, LBL1 will continue to receive gas service from PG&E under rate G-NR1.

G-5.1 NEAR TERM ESTIMATED BILLS AT CURRENT RATES

LBL1 - ACCOUNT NO. HJR 10 34501

PROJECTED USAGE PRICED

AT CURRENT RATES

		USAGE	TOTAL	AVERAGE
		(THERMS)	BILL	BILL
			(\$)	(\$/THERM)
OCTOBER	1992	611	\$302.10	\$0.4944
NOVEMBER	1992	1,028	669.12	0.6509
DECEMBER	1992	1,701	1,098.39	0.6457
JANUARY	1993	1,386	897.47	0.6475
FEBRUARY	1993	1,484	959.97	0.6469
MARCH	1993	1,033	672.31	0.6508
APRIL	1993	1,091	528.88	0.4848
MAY	1993	982	477.39	0.4861
JUNE	1993	553	274.70	0.4967
JULY	1993	529	263.36	0.4978
AUGUST	1993	474	237.37	0.5008
SEPTEMBER	1993	589	291.70	0.4953
TOTAL FY	1993	11,461	\$6,672.75	\$0.5822
OCTOBER	1993	611	\$302.10	\$0.4944
NOVEMBER	1993	1,028	669.12	0.6509
DECEMBER	1993	1,701	1,098.39	0.6457
JANUARY	1994	1,386	897.47	0.6475
FEBRUARY	1994	1,484	959.97	0.6469
MARCH	1994	1,033	672.31	0.6508
APRIL	1994	1,091	528.88	0.4843
MAY	1994	982	477.39	0.4861
JUNE	1994	553	274.70	0.4967
JULY	1994	529	263.36	0.4978
AUGUST	1994	474	237.37	0.5008
SEPTEMBER	1994	589	291.70	0.4953
TOTAL FY	1994	11,461	\$6,672.75	\$0.5822

LBL 2 - ACCOUNT NO. CJR A1-00141-2
(Former Account No. CJR SB-92121)

G-1 NATURAL GAS SERVICE CHARACTERISTICS

G-1.1 Suppliers and Rate Schedules

-- PG&E (prior to 11/1/93)

Rate Schedule G-NR1 - Gas Sales to Small Non-Residential Core Customers.

- Applies only to core customers with gas usage which qualifies as priority levels P1 or P2A.
- Average monthly usage per meter must be less than 20,800 therms in those months during the last twelve months in which more than 200 therms were used. Service is reviewed every March to determine continued applicability.
- Provides bundled natural gas sales and delivery service.

-- PG&E (from 11/1/93)

Rate Schedule FTS - Firm Intrastate Transportation Service to Noncore Commercial/Industrial Customers.

- Provides for firm intrastate gas transportation to the lab.

-- Defense Fuel Supply Center (from 11/1/93)

DFSC, acting as a third-party gas supplier for the lab, purchases gas on the spot gas market. All commodity and interstate transportation charges incurred on the lab's behalf are passed through to the lab.

As of November 1, 1993, the LBL2 load was combined with the main load (LBL4). The meter reading for the combined LBL2 and LBL4 loads is performed at the main (LBL4) meter.

G-1.2 Physical Characteristics of Service

- Load serves Buildings 74 and 74A only.
- Delivery point can be identified near LBL interface point G-4, Valve 496.
- The delivery line between valve 70G and valve 129 near the metering point is owned by PG&E. All other distribution lines are owned by the U.S. Government.
- The PG&E-owned metering equipment was removed as of November 1, 1993.

G-1.3 Contract Summary

GS-OOP-86-BS-D-0002 U.S. General Services Administration
Areawide Public Utilities Contract
Pacific Gas and Electric Company

Natural gas service is provided pursuant to the GSA Areawide Contract between the U.S. General Services Administration and PG&E. This contract is effective for a 10-year period beginning December 19, 1985 unless canceled by either party with 60 days' written notice.

DE-AC03-90SF18443 Pacific Gas and Electric Company
Natural Gas Supply Agreement

This contract provides for the supply of natural gas to LBL2. Contract was effective from August 1, 1991 until October 31, 1993.

_____ Inter-agency Agreement for Natural Gas Supply
Service at Lawrence Berkeley Laboratory

An inter-agency agreement between DOE and the Defense Fuel Supply Center (DFSC) should be in place within the next six months.

G-2.1 HISTORICAL USAGE AND COSTS

LBL2 - ACCOUNT NO. CJRA1 00141-2
HISTORICAL USAGE AND COSTS

		USAGE (THERMS)	TOTAL BILL (\$)	AVERAGE BILL (\$/THERM)
OCTOBER	1991	7,031	\$3,419.78	\$0.4864
NOVEMBER	1991	11,816	7,654.30	0.6478
DECEMBER	1991	9,203	5,991.23	0.6510
JANUARY	1992	11,231	7,604.85	0.6771
FEBRUARY	1992	10,546	7,141.81	0.6772
MARCH	1992	8,907	5,980.11	0.6714
APRIL	1992	8,580	4,309.15	0.5022
MAY	1992	6,682	3,358.82	0.5027
JUNE	1992	7,211	3,623.69	0.5025
JULY	1992	6,509	3,272.20	0.5027
AUGUST	1992	6,005	3,019.84	0.5029
SEPTEMBER	1992	6,310	3,172.55	0.5028
TOTAL FY 1992		100,031	\$58,548.33	\$0.5853
OCTOBER	1992	5,769	\$2,949.18	\$0.5112
NOVEMBER	1992	8,372	4,870.27	0.5817
DECEMBER	1992	8,479	4,932.34	0.5817
JANUARY	1993	16,454	9,955.01	0.6050
FEBRUARY	1993	11,546	6,998.29	0.6061
MARCH	1993	8,846	5,265.77	0.5953
APRIL	1993	10,332	4,643.40	0.4494
MAY	1993	7,579	3,444.03	0.4544
JUNE	1993	5,095	2,475.37	0.4858
JULY	1993	6,073	2,949.46	0.4857
AUGUST	1993	5,033	2,455.74	0.4879
SEPTEMBER	1993	4,905	2,393.62	0.4880
TO DATE FY 1993		98,483	\$53,332.48	\$0.5415

G-3.1 NEAR TERM PROJECTED USAGE

LBL2 - ACCOUNT NO. CJRA1 00141-2
NEAR TERM PROJECTED USAGE

	FY 1993 (THERMS)	FY 1994 (THERMS)*
OCTOBER	5,769	5,769
NOVEMBER	8,372	8,372
DECEMBER	8,479	8,479
JANUARY	16,454	16,454
FEBRUARY	11,546	11,546
MARCH	8,846	8,846
APRIL	10,332	10,332
MAY	7,579	7,579
JUNE	5,095	5,095
JULY	6,073	6,073
AUGUST	5,033	5,033
SEPTEMBER	<u>4,905</u>	<u>4,905</u>
TOTALS	<u>98,483</u>	<u>98,483</u>

* FY 1994 Near-Term Forecasts Are Not Available.
FY 1993 Usage Assumed As Forecasted Usage.

G-3.2 LONG TERM PROJECTED USAGE

LBL2 - ACCOUNT NO. CJRA1 00141-2 LONG TERM PROJECTED USAGE

<u>FISCAL YEAR</u>	<u>TOTAL USAGE (1) (THERMS)</u>
1987	113,258
1988	106,200
1989	117,300
1990	108,912
1991	108,819
1992	100,031
1993	98,483
1994 (2)	98,483
1995	98,483
1996	98,483
1997	98,483

NOTES:

- (1) Long-Term Forecasts Are Not Available - FY 1993 Usage Assumed As Forecasted Usage.
- (2) DFSC Began to Serve the Load Requirements of LBL2 and LBL4 on November 1, 1993. All LBL2 Load Has Subsequently Been Combined with That of LBL4.

G-4.1 CURRENT TARIFF

PG&E's capacity brokering program requires PG&E to "unbundle" its interstate demand charges from its intrastate transportation rates. Implementation of this program was slated to occur in two phases. The first phase, partial capacity brokering on the El Paso and Transwestern pipeline systems, commenced August 1, 1993. The DOE/OAK labs elected to remain customers of PG&E, receiving gas under the rates for core (Rate G-NR1) and noncore (Rate G-CS) customers.

The partial capacity brokering plan was expected to continue until the commencement of full capacity brokering around August 1, 1994. However, during September 1993, the Federal Energy Regulatory Commission (FERC) granted the Pacific Gas Transmission Co. (PGT) approval to move forward with its capacity release program. As a result of the FERC's earlier-than-expected approval of capacity release on the PGT pipeline system, PG&E moved the date of full capacity brokering implementation to November 1, 1993.

Several options are available to the DOE/OAK labs under full capacity brokering. Core subscription customers (LBL4, LLNL and SLAC2) have the option to continue receiving gas from PG&E or to receive gas from a third party. The DOE/OAK labs classified as core subscription customers have elected to purchase gas through the Defense Fuel Supply Center (DFSC) as of November 1, 1993. Under this "third party" arrangement, the DFSC will purchase gas for its customers on the spot gas market. The DFSC will charge each lab for the commodity and interstate transportation charges incurred, and PG&E will charge each lab for intrastate transportation under PG&E Rate Schedule FTS.

LBL2 has been a core customer of PG&E, receiving its gas requirements under PG&E rate G-NR1. However, as of November 1, 1993, LBL2 began to receive its gas requirements from DFSC. (The LBL2 and LBL4 loads have been consolidated and are being provided by DFSC.) In order for this transition to occur, LBL has removed the PG&E gas meter for LBL2 account number CJR SB-92121. Metering for this combined load occurs at the LBL4 (main) meter.

G-4.1 CURRENT TARIFF - PG&E TRANSPORTATION

LBL2 - ACCOUNT NO. CJRA1 00141-2
CURRENT RATES

SCHEDULE G-FTS -- FIRM INTRASTATE GAS TRANSPORTATION SERVICE
NONCORE COMMERCIAL/INDUSTRIAL CUSTOMERS

RATES:

CUSTOMER CHARGE:

(based on avg. monthly usage for the most recent 12-month period)

0 TO 5,000 THERMS	\$10.11	per month
5,001 TO 10,000 THERMS	\$79.62	per month
10,001 TO 50,000 THERMS	\$302.05	per month
50,001 TO 200,000 THERMS	\$796.23	per month
200,001 TO 1,000,000 THERMS	\$1,140.01	per month
1,000,001 THERMS AND ABOVE	\$3,313.86	per month

TRANSPORTATION CHARGES:

WINTER VOLUMETRIC:

Transmission	\$0.05469	per therm
Distribution	\$0.10709	per therm

SUMMER VOLUMETRIC:

Transmission	\$0.04038	per therm
Distribution	\$0.09288	per therm

SEASONS:

WINTER SEASON BEGINS NOVEMBER 1 AND ENDS MARCH 31

SUMMER SEASON BEGINS APRIL 1 AND ENDS OCTOBER 31

EFFECTIVE DATE:

January 1, 1994

G-4.1 CURRENT CHARGES - DFSC

LBL2 - ACCOUNT NO. CJRA1 00141-2
NATURAL GAS SPOT MARKET AND
FUTURES PRICES

		RANGE OF CITY GATE PRICES TO THE CALIFORNIA BORDER (1)		AVERAGE PRICE	DFSC CHARGE TO LAB (2)
		LOW (\$/THERM)	HIGH (\$/THERM)	(\$/THERM)	(\$/THERM)
FY 1993					
OCTOBER	1992	\$0.2600	\$0.2870	\$0.2735	\$0.2753
NOVEMBER	1992	0.2290	0.2480	0.2385	0.2403
DECEMBER	1992	0.2250	0.2470	0.2360	0.2378
JANUARY	1993	0.2250	0.2640	0.2445	0.2463
FEBRUARY	1993	0.1800	0.1910	0.1855	0.1873
MARCH	1993	0.1870	0.2150	0.2010	0.2028
APRIL	1993	0.2140	0.2220	0.2180	0.2198
MAY	1993	0.2350	0.2730	0.2540	0.2558
JUNE	1993	0.1800	0.1940	0.1870	0.1888
JULY (3)	1993	N/A	N/A	0.2250	0.2268
AUGUST (3)	1993	N/A	N/A	0.2360	0.2378
SEPTEMBER	1993	0.2380	0.2470	0.2425	0.2443
12-MONTH AVERAGE					<u>\$0.2303</u>
FY 1994					
OCTOBER	1993	\$0.2100	\$0.2260	\$0.2180	\$0.2198
NOVEMBER	1993	0.2030	0.2160	0.2095	0.2113
DECEMBER	1993	0.2480	0.2660	0.2570	0.2588
JANUARY (3)	1994	N/A	N/A	0.2045	0.2063
FEBRUARY (4)	1994	N/A	N/A	0.2305	0.2323
MARCH (5)	1994	N/A	N/A	0.2356	0.2374
APRIL (5)	1994	N/A	N/A	0.2236	0.2254
MAY (5)	1994	N/A	N/A	0.2165	0.2183
JUNE (5)	1994	N/A	N/A	0.2140	0.2158
JULY (5)	1994	N/A	N/A	0.2135	0.2153
AUGUST (5)	1994	N/A	N/A	0.2145	0.2163
SEPTEMBER (5)	1994	N/A	N/A	0.2175	0.2193
12-MONTH AVERAGE					<u>\$0.2230</u>

NOTES:

- (1) October 1992-June 1993 and September-December 1993 Represent the Range of City Gate Prices to the California Border as Reported by Inside FERC Gas Market Report.
- (2) Average Price is Increased to Include a Supply Adjustment Factor of \$0.0018/Therm Per DFSC Contract #DLA600-94-D-7502 With Mock Resources, Inc.
- (3) Prices are the Average of El Paso and Transwestern Pipeline City Gate Prices as Reported in Natural Gas Week (1/24/94).
- (4) Average Price Represents the Natural Gas Futures Price on January 21, 1994.
- (5) Average Prices Represent the Natural Gas Futures Prices on February 11, 1994, as Reported in Natural Gas Week (2/14/94)

G-5.1 NEAR TERM ESTIMATED BILLS AT CURRENT RATES

LBL2 - ACCOUNT NO. CJRA1 00141-2
PROJECTED USAGE PRICED
AT SPOT AND FUTURES MARKET PRICES*

		USAGE (THERMS)	INTRASTATE BILL (\$)	GAS SUPPLY COST (\$)	TOTAL BILL (\$)	AVERAGE BILL (\$/THERM)
OCTOBER	1992	5,769	\$615.44	\$1,588.21	\$2,203.65	\$0.3820
NOVEMBER	1992	8,372	976.18	2,011.79	2,987.97	0.3569
DECEMBER	1992	8,479	987.64	2,016.31	3,003.94	0.3543
JANUARY	1993	16,454	2,064.11	4,052.62	6,116.73	0.3717
FEBRUARY	1993	11,546	1,538.51	2,162.57	3,701.08	0.3206
MARCH	1993	8,846	1,026.94	1,793.97	2,820.91	0.3189
APRIL	1993	10,332	1,261.69	2,270.97	3,532.66	0.3419
MAY	1993	7,579	783.56	1,938.71	2,722.27	0.3592
JUNE	1993	5,095	552.84	961.94	1,514.78	0.2973
JULY	1993	6,073	643.68	1,377.36	2,021.04	0.3328
AUGUST	1993	5,033	547.09	1,196.85	1,743.93	0.3465
SEPTEMBER	1993	4,905	465.69	1,198.29	1,663.98	0.3392
TOTAL FY	1993	98,483	\$11,463.36	\$22,569.57	\$34,032.93	\$0.3456
OCTOBER	1993	5,769	\$615.44	\$1,268.03	\$1,883.47	\$0.3265
NOVEMBER	1993	8,372	976.18	1,769.00	2,745.18	0.3279
DECEMBER	1993	8,479	987.64	2,194.37	3,182.00	0.3753
JANUARY	1994	16,454	2,064.11	3,394.46	5,458.57	0.3317
FEBRUARY	1994	11,546	1,538.51	2,682.14	4,220.65	0.3656
MARCH	1994	8,846	1,026.94	2,100.04	3,126.98	0.3535
APRIL	1994	10,332	1,261.69	2,328.83	3,590.52	0.3475
MAY	1994	7,579	783.56	1,654.50	2,438.05	0.3217
JUNE	1994	5,095	552.84	1,099.50	1,652.34	0.3243
JULY	1994	6,073	643.68	1,307.52	1,951.20	0.3213
AUGUST	1994	5,033	547.09	1,088.64	1,635.72	0.3250
SEPTEMBER	1994	4,905	465.69	1,075.67	1,541.35	0.3142
TOTAL FY	1994	98,483	\$11,463.36	\$21,962.68	\$33,426.04	\$0.3394

* Total Bills are Calculated as if the Lab had been Receiving Third Party (DFSC) Gas Since October 1992
Actual Spot Market Gas Prices are Used for October 1992-January 1993 Calculations, and Futures Prices
are Used for the February - September 1994 Calculations.

LBL 4 - ACCOUNT NO. BJR A1-00051-2
(Former Account No. BJR SB-92221)

G-1 NATURAL GAS SERVICE CHARACTERISTICS

G-1.1 Suppliers and Rate Schedules

-- PG&E (prior to 11/1/93)

Rate Schedule G-CS - Core Subscription Service to Noncore Commercial/Industrial Customers.

- Provides combined natural gas procurement and transportation service to noncore customers who select this option.
- The commodity charge component of the procurement charge changes monthly based on the average cost of gas in PG&E's core supply portfolio, lagged 30 days.
- The full-requirements option, which prohibits the customer from using alternative fuels except when curtailed, for testing of alternative fuel systems or if given prior permission by PG&E, eliminates the applicability of use-or-pay and take-or-pay charges.
- Requires a service agreement with a minimum term of two years.
- The current Schedule G-CS procurement charge may be obtained by calling PG&E's Gas Rate Hotline at (415) 973-0461.

-- PG&E (from 11/1/93)

Rate Schedule FTS - Firm Intrastate Transportation Service to Noncore Commercial/Industrial Customers

- Provides for firm intrastate gas transportation to the lab.

-- Defense Fuel Supply Center (from 11/1/93)

DFSC, acting as a third-party gas supplier for the lab, purchases gas on the spot gas market. All commodity and interstate transportation charges incurred on the lab's behalf are passed through to the lab.

G-1.1 Suppliers and Rate Schedules (continued)

As of November 1, 1993, the LBL2 and LBL4 loads were consolidated. The meter reading for the combined LBL2 and LBL4 loads is performed at the main (LBL4) meter.

G-1.2 Physical Characteristics of Service

- Load serves all facilities at LBL not served by accounts BJR 64-74001 (LBL1) or CJR A100141-2 (LBL2).
- Gas is received at PG&E vault identified as LBL interface point G-2.
- Gas is received at 50 psi and redistributed at 13 psi.
- The on-site distribution system is owned by the U.S. Government.
- Equipment at PG&E vault is owned by PG&E.
- Gas is supplied by the Defense Fuel Supply Center (DFSC) through contract number DLA 600-94-7502.

G-1.3 Contract Summary

GS-OOP-86-BS-D-0002 U.S. General Services Administration
Areawide Public Utilities Contract
Pacific Gas and Electric Company

Natural gas service is provided pursuant to the GSA Areawide Contract between the U.S. General Services Administration and PG&E. This contract is effective for a 10-year period beginning December 19, 1985 unless canceled by either party with 60 days' written notice.

DE-AC03-89SF18230 Pacific Gas and Electric Company
Natural Gas Supply Agreement

This Natural Gas Supply Agreement between PG&E and DOE/OAK was modified effective November 1, 1993, to include only intrastate transportation service. Contract expires December 18, 1995.

_____ Inter-agency Agreement for Natural Gas Supply
Service at Lawrence Berkeley Laboratory

An inter-agency agreement between DOE and the Defense Fuel Supply Center (DFSC) should be in place within the next six months.

G-2.1 HISTORICAL USAGE AND COSTS

LBL4 - ACCOUNT NO. BJR A1 00051-2
HISTORICAL USAGE AND COSTS

	USAGE (THERMS)	INTRASTATE BILL (\$)	GAS SUPPLY COST (\$)	TOTAL COST (\$)	AVE. COST (\$/THERM)
<u>FY 1992</u>					
OCTOBER	84,918	\$10,353.21	\$15,714.08	\$26,067.29	\$0.3070
NOVEMBER	121,040	16,524.60	22,828.15	39,352.75	0.3251
DECEMBER	177,855	24,168.78	38,309.44	62,478.22	0.3513
JANUARY	172,039	24,166.29	38,455.88	62,622.17	0.3640
FEBRUARY	153,952	21,758.37	32,346.51	54,104.88	0.3514
MARCH	133,219	18,834.52	23,800.99	42,635.51	0.3200
APRIL	99,895	12,633.38	17,593.51	30,226.89	0.3026
MAY	99,412	12,575.35	16,604.72	29,180.07	0.2935
JUNE	95,299	12,081.13	16,191.74	28,272.87	0.2967
JULY	82,133	10,499.10	13,944.76	24,443.86	0.2976
AUGUST	70,339	9,081.93	11,696.46	20,778.39	0.2954
SEPTEMBER	71,233	9,189.36	12,733.90	21,923.26	0.3078
TOTAL	<u>1,361,334</u>	<u>\$181,866.02</u>	<u>\$260,220.14</u>	<u>\$442,086.16</u>	<u>\$0.3247</u>
<u>FY 1993</u>					
OCTOBER	78,913	\$10,112.19	\$14,624.16	\$24,736.35	\$0.3135
NOVEMBER	123,534	16,700.72	24,531.16	41,231.88	0.3338
DECEMBER	167,209	22,367.38	35,988.40	58,355.78	0.3490
JANUARY	215,509	29,447.11	45,813.67	75,260.78	0.3492
FEBRUARY	161,000	22,209.45	33,818.05	56,027.50	0.3480
MARCH	161,000	22,209.45	33,818.05	56,027.50	0.3480
APRIL	140,024	17,107.78	27,191.61	44,299.39	0.3164
MAY	119,075	14,946.19	23,282.34	38,228.53	0.3210
JUNE	73,210	10,677.70	14,342.57	25,020.27	0.3418
JULY	78,932	11,480.99	14,963.35	26,444.34	0.3350
AUGUST	78,932	11,480.99	15,044.69	26,525.68	0.3361
SEPTEMBER	70,922	10,568.02	13,117.03	23,685.05	0.3340
TOTAL	<u>1,468,260</u>	<u>\$199,307.97</u>	<u>\$296,535.08</u>	<u>\$495,843.05</u>	<u>\$0.3377</u>

* The Intrastate Bill Reflects the Customer Charge and Intrastate Transportation Charge.

The Gas Supply Cost Reflects the Commodity Charge, Brokerage Fee and Core Subscription Shrinkage Fee.

G-2.2 NOTES TO HISTORICAL USAGE & COSTS

FY 1993

February 1993

- Usage and cost estimates are based on a letter from Steve Kromer dated 10/12/93.

March 1993

- Usage and cost estimates are based on a letter from Steve Kromer dated 10/12/93.

June 1993

- Usage and cost estimates are based on a letter from Steve Kromer dated 10/7/93.

August 1993

- Total bill excludes \$426 refund credit.

G-3.1 NEAR TERM PROJECTED USAGE

LBL4 - ACCOUNT NO. BJR A1 00051-2
NEAR TERM PROJECTED USAGE

	FY 1993 <u>(THERMS)</u>	FY 1994 <u>(THERMS) *</u>
OCTOBER	78,913	78,913
NOVEMBER	123,534	123,534
DECEMBER	167,209	167,209
JANUARY	215,509	215,509
FEBRUARY	161,000	161,000
MARCH	161,000	161,000
APRIL	140,024	140,024
MAY	119,075	119,075
JUNE	73,210	73,210
JULY	78,932	78,932
AUGUST	78,932	78,932
SEPTEMBER	<u>70,922</u>	<u>70,922</u>
TOTALS	<u>1,468,260</u>	<u>1,468,260</u>

* FY 1994 Near-Term Forecasts Are Not Available.
FY 1993 Usage Assumed As Forecasted Usage.

G-3.2 LONG TERM PROJECTED USAGE

LBL4 - ACCOUNT NO. BJR A1 00051-2 LONG TERM PROJECTED USAGE

<u>FISCAL YEAR</u>	<u>TOTAL USAGE (1) (THERMS)</u>
1987	1,209,546
1988	1,237,273
1989	1,454,635
1990 (2)	1,354,815
1991	1,558,261
1992	1,361,334
1993	1,468,260
1994 (3)	1,468,260
1995	1,468,260
1996	1,468,260
1997	1,468,260

NOTES:

- (1) Long-Term Forecasts Are Not Available - FY 1993 Usage Assumed As Forecasted Usage.
- (2) Prior to January 15, 1990, LBL3 Was Separately Metered under the G-NR1 Tariff. Subsequently, All LBL3 Usage Was Combined with That of LBL4.
- (3) DFSC Began to Serve the Load Requirements of LBL2 and LBL4 on November 1, 1993. All LBL2 Load Has Subsequently Been Combined with That of LBL4.

G-4.1 CURRENT TARIFF

PG&E's capacity brokering program requires PG&E to "unbundle" its interstate demand charges from its intrastate transportation rates. Implementation of this program was slated to occur in two phases. The first phase, partial capacity brokering on the El Paso and Transwestern pipeline systems, commenced August 1, 1993. The DOE/OAK labs elected to remain customers of PG&E, receiving gas under the rates for core (Rate G-NR1) and noncore (Rate G-CS) customers.

The partial capacity brokering plan was expected to continue until the commencement of full capacity brokering around August 1, 1994. However, during September 1993, the Federal Energy Regulatory Commission (FERC) granted the Pacific Gas Transmission Co. (PGT) approval to move forward with its capacity release program. As a result of the FERC's earlier-than-expected approval of capacity release on the PGT pipeline system, PG&E moved the date of full capacity brokering implementation to November 1, 1993.

Several options are available to the DOE/OAK labs under full capacity brokering. Core subscription customers (LBL4, LLNL and SLAC2) have the option to continue receiving gas from PG&E or to receive gas from a third party. LBL4 has elected to purchase gas through the Defense Fuel Supply Center (DFSC) as of November 1, 1993. Under this "third party" arrangement, the DFSC will purchase gas for its customers on the spot gas market. The DFSC bill to the lab will reflect the consolidation of the LBL2 and LBL4 loads. The DFSC will charge each lab for the commodity and interstate transportation charges incurred, and PG&E will charge each lab for intrastate transportation under PG&E Rate Schedule FTS.

G-4.1 CURRENT TARIFF - PG&E TRANSPORTATION

LBL4 - ACCOUNT NO. BJR A1 00051-2
CURRENT RATES

SCHEDULE G-FTS -- FIRM INTRASTATE GAS TRANSPORTATION SERVICE
NONCORE COMMERCIAL/INDUSTRIAL CUSTOMERS

RATES:

CUSTOMER CHARGE:

(based on avg. monthly usage for the most recent 12-month period)

0 TO 5,000 THERMS	\$10.11 per month
5,001 TO 10,000 THERMS	\$79.62 per month
10,001 TO 50,000 THERMS	\$302.05 per month
50,001 TO 200,000 THERMS	\$796.23 per month
200,001 TO 1,000,000 THERMS	\$1,140.01 per month
1,000,001 THERMS AND ABOVE	\$3,313.86 per month

TRANSPORTATION CHARGES:*

WINTER VOLUMETRIC:

Transmission	\$0.05469 per therm
Distribution	\$0.10709 per therm

SUMMER VOLUMETRIC:

Transmission	\$0.04038 per therm
Distribution	\$0.09288 per therm

SEASONS:

WINTER SEASON BEGINS NOVEMBER 1 AND ENDS MARCH 31

SUMMER SEASON BEGINS APRIL 1 AND ENDS OCTOBER 31

EFFECTIVE DATE:

January 1, 1994

* LBL4 Receives Gas at Distribution Service Level.

G-4.1 CURRENT CHARGES - DFSC

LBL4 - ACCOUNT NO. BJR A1 00051-2
 NATURAL GAS SPOT MARKET AND
 FUTURES PRICES

		RANGE OF CITY GATE PRICES TO THE CALIFORNIA BORDER (1)		AVERAGE PRICE	DFSC CHARGE TO LAB (2)
		LOW	HIGH	PRICE	
		(\$/THERM)	(\$/THERM)	(\$/THERM)	(\$/THERM)
FY 1993					
OCTOBER	1992	\$0.2600	\$0.2870	\$0.2735	\$0.2753
NOVEMBER	1992	0.2290	0.2480	0.2385	0.2403
DECEMBER	1992	0.2250	0.2470	0.2360	0.2378
JANUARY	1993	0.2250	0.2640	0.2445	0.2463
FEBRUARY	1993	0.1800	0.1910	0.1855	0.1873
MARCH	1993	0.1870	0.2150	0.2010	0.2028
APRIL	1993	0.2140	0.2220	0.2180	0.2198
MAY	1993	0.2350	0.2730	0.2540	0.2558
JUNE	1993	0.1800	0.1940	0.1870	0.1888
JULY (3)	1993	N/A	N/A	0.2250	0.2268
AUGUST (3)	1993	N/A	N/A	0.2360	0.2378
SEPTEMBER	1993	0.2380	0.2470	0.2425	0.2443
12-MONTH AVERAGE					<u>\$0.2303</u>
FY 1994					
OCTOBER	1993	\$0.2100	\$0.2260	\$0.2180	\$0.2198
NOVEMBER	1993	0.2030	0.2160	0.2095	0.2113
DECEMBER	1993	0.2480	0.2660	0.2570	0.2588
JANUARY (3)	1994	N/A	N/A	0.2045	0.2063
FEBRUARY (4)	1994	N/A	N/A	0.2305	0.2323
MARCH (5)	1994	N/A	N/A	0.2356	0.2374
APRIL (5)	1994	N/A	N/A	0.2236	0.2254
MAY (5)	1994	N/A	N/A	0.2165	0.2183
JUNE (5)	1994	N/A	N/A	0.2140	0.2158
JULY (5)	1994	N/A	N/A	0.2135	0.2153
AUGUST (5)	1994	N/A	N/A	0.2145	0.2163
SEPTEMBER (5)	1994	N/A	N/A	0.2175	0.2193
12-MONTH AVERAGE					<u>\$0.2230</u>

NOTES:

- (1) October 1992-June 1993 and September-December 1993 Represent the Range of City Gate Prices to the California Border as Reported by Inside FERC Gas Market Report.
- (2) Average Price is Increased to Include a Supply Adjustment Factor of \$0.0018/Therm Per DFSC Contract #DLA600-94-D-7502 With Mock Resources, Inc.
- (3) Prices are the Average of El Paso and Transwestern Pipeline City Gate Prices as Reported in Natural Gas Week (1/24/94).
- (4) Average Price Represents the Natural Gas Futures Price on January 21, 1994.
- (5) Average Prices Represent the Natural Gas Futures Prices on February 11, 1994, as Reported in Natural Gas Week (2/14/94).

G-5.1 NEAR TERM ESTIMATED BILLS AT CURRENT RATES

LBL4 - ACCOUNT NO. BJR A1 00051-2
PROJECTED USAGE PRICED
AT SPOT AND FUTURES MARKET PRICES*

		USAGE (THERMS)	INTRASTATE BILL (\$)	GAS SUPPLY COST (\$)	TOTAL BILL (\$)	AVERAGE BILL (\$/THERM)
OCTOBER	1992	78,913	\$8,125.67	\$21,724.75	\$29,850.42	\$0.3783
NOVEMBER	1992	123,534	14,025.49	29,685.22	43,710.71	0.3538
DECEMBER	1992	167,209	18,702.64	39,762.30	58,464.94	0.3497
JANUARY	1993	215,509	24,218.87	53,079.87	77,298.74	0.3587
FEBRUARY	1993	161,000	18,037.72	30,155.30	48,193.02	0.2993
MARCH	1993	161,000	18,037.72	32,650.80	50,688.52	0.3148
APRIL	1993	140,024	13,801.66	30,777.28	44,578.93	0.3184
MAY	1993	119,075	11,855.92	30,459.39	42,315.30	0.3554
JUNE	1993	73,210	7,595.97	13,822.05	21,418.02	0.2926
JULY	1993	78,932	8,127.43	17,901.78	26,029.21	0.3298
AUGUST	1993	78,932	8,127.43	18,770.03	26,897.46	0.3408
SEPTEMBER	1993	70,922	7,383.47	17,326.24	24,709.71	0.3484
TOTAL FY	1993	1,468,260	\$158,039.99	\$336,115.00	\$494,154.99	\$0.3366
OCTOBER	1993	78,913	\$8,125.67	\$17,345.08	\$25,470.75	\$0.3228
NOVEMBER	1993	123,534	14,025.49	26,102.73	40,128.22	0.3248
DECEMBER	1993	167,209	18,702.64	43,273.69	61,976.33	0.3707
JANUARY	1994	215,509	24,218.87	44,459.51	68,678.38	0.3187
FEBRUARY	1994	161,000	18,037.72	37,400.30	55,438.02	0.3443
MARCH	1994	161,000	18,037.72	38,221.40	56,259.12	0.3494
APRIL	1994	140,024	13,801.66	31,561.41	45,363.07	0.3240
MAY	1994	119,075	11,855.92	25,994.07	37,849.99	0.3179
JUNE	1994	73,210	7,595.97	15,798.72	23,394.69	0.3196
JULY	1994	78,932	8,127.43	16,994.06	25,121.49	0.3183
AUGUST	1994	78,932	8,127.43	17,072.99	25,200.43	0.3193
SEPTEMBER	1994	70,922	7,383.47	15,553.19	22,936.66	0.3234
TOTAL FY	1994	1,468,260	\$158,039.99	\$329,777.15	\$487,817.14	\$0.3322

* Total Bills are Calculated as if the Lab had been Receiving Third Party (DFSC) Gas Since October 1992. Actual Spot Market Gas Prices are Used for October 1992-January 1993 Calculations, and Futures Prices are Used for the February - September 1994 Calculations.

LLNL - ACCOUNT NO. YJN A1 00011-4
(Former Account No. YJN SB-91041)

G-1 NATURAL GAS SERVICE CHARACTERISTICS

G-1.1 Suppliers and Rate Schedules

-- PG&E (prior to 11/1/93)

Rate Schedule G-CS - Core Subscription Service to Noncore Commercial/Industrial Customers.

- Provides combined natural gas procurement and transportation service to noncore customers who select this option.
- The commodity charge component of the procurement charge changes monthly based on the average cost of gas in PG&E's core supply portfolio, lagged 30 days.
- The full-requirements option, which prohibits the customer from using alternative fuels except when curtailed, for testing of alternative fuel systems or if given prior permission by PG&E, eliminates the applicability of use-or-pay and take-or-pay charges.
- Requires a service agreement with a minimum term of two years.
- The current Schedule G-CS procurement charge may be obtained by calling PG&E's Gas Rate Hotline at (415) 973-0461.

-- PG&E (from 11/1/93)

Rate Schedule FTS - Firm Intrastate Transportation Service to Noncore Commercial/Industrial Customers.

- Provides for firm intrastate gas transportation to the lab.

-- Defense Fuel Supply Center (from 11/1/93)

DFSC, acting as a third-party gas supplier for the lab, purchases gas on the spot gas market. All commodity and interstate transportation charges incurred on the lab's behalf are passed through to the lab.

G-1.2 Physical Characteristics of Service

- Load serves boilers, space and water heaters, and laboratory equipment located within the Livermore complex.
- Gas is delivered at 60 psi through a PG&E six-inch line and enters a metering station located off East Avenue.
- Metering equipment at the main metering station is owned by PG&E.
- Gas is delivered to on-site facilities through a government-owned distribution system.
- A liquid propane air system is available to meet gas requirements if gas deliveries from PG&E are curtailed.

Note: A portion of the total gas metered is allocated to Sandia Laboratory.

G-1.3 Contract Summary

GS-OOP-86-BS-D-0002 U.S. General Services Administration
Areawide Public Utilities Contract
Pacific Gas and Electric Company

Natural gas service is provided pursuant to the GSA Areawide Contract between the U.S. General Services Administration and PG&E. This contract is effective for a 10-year period beginning December 19, 1985 unless canceled by either party with 60 days' written notice.

DE-AD03-89SF18226 Pacific Gas and Electric Company
Natural Gas Supply Agreement

This Natural Gas Supply Agreement between PG&E and DOE was modified effective November 1, 1993 to include only intrastate transportation service. Contract expires December 18, 1995.

_____ Inter-agency Agreement for Natural Gas Supply
Service at Lawrence Livermore National Laboratory

An inter-agency agreement between DOE and the Defense Fuel Supply Center (DFSC) should be in place within the next six months.

G-2.1 HISTORICAL USAGE AND COSTS

LLNL - ACCOUNT NO. YJN A1 00011-4
HISTORICAL USAGE AND COSTS

	USAGE (THERMS)	INTRASTATE BILL (\$)	GAS SUPPLY COST (\$)	TOTAL COST (\$)	AVE. COST (\$/THERM)
<u>FY 1992</u>					
OCTOBER	302,176	\$35,607.44	\$55,993.92	\$91,601.36	\$0.3031
NOVEMBER	459,505	60,279.01	86,431.90	146,710.91	0.3193
DECEMBER	655,902	87,231.97	139,340.25	226,572.22	0.3454
JANUARY	626,805	86,811.89	139,930.56	226,742.45	0.3617
FEBRUARY	503,142	69,953.21	107,748.23	177,701.44	0.3532
MARCH	449,361	62,572.30	81,284.75	143,857.05	0.3201
APRIL	432,845	53,913.40	76,504.72	130,418.12	0.3013
MAY	228,108	28,311.46	38,272.81	66,584.27	0.2919
JUNE	344,085	42,247.25	58,386.09	100,633.34	0.2925
JULY	312,666	38,471.95	53,269.27	91,741.22	0.2934
AUGUST	297,531	36,653.32	49,317.79	85,971.11	0.2889
SEPTEMBER	345,363	42,400.82	61,214.97	103,615.79	0.3000
TOTAL	<u>4,957,489</u>	<u>\$644,454.02</u>	<u>\$947,695.26</u>	<u>\$1,592,149.28</u>	<u>\$0.3212</u>
<u>FY 1993</u>					
OCTOBER	318,121	\$39,127.42	\$58,890.43	\$98,017.85	\$0.3081
NOVEMBER	535,484	69,799.70	105,462.20	175,261.90	0.3273
DECEMBER	585,552	76,632.92	126,028.36	202,661.28	0.3461
JANUARY	595,874	80,319.01	126,778.00	207,097.01	0.3476
FEBRUARY	746,877	100,614.38	157,083.47	257,697.85	0.3450
MARCH	612,450	82,699.29	116,607.56	199,306.85	0.3254
APRIL	473,564	56,648.55	91,787.74	148,436.29	0.3134
MAY	412,202	49,223.27	80,550.17	129,773.44	0.3148
JUNE	425,442	36,393.75	83,348.35	119,742.10	0.2815
JULY	303,862	26,317.20	58,028.40	84,345.60	0.2776
AUGUST	319,191	28,429.31	60,677.16	89,106.47	0.2792
SEPTEMBER	320,334	28,579.34	59,302.23	87,881.57	0.2743
TOTAL	<u>5,648,953</u>	<u>\$674,784.14</u>	<u>\$1,124,544.07</u>	<u>\$1,799,328.21</u>	<u>\$0.3185</u>

* The Intrastate Bill Reflects the Customer Charge and Intrastate Transportation Charge.

The Gas Supply Cost Reflects the Commodity Charge, Brokerage Fee and Core Subscription Shrinkage Fee.

G-2.2 NOTES TO HISTORICAL USAGE & COSTS

FY 1993

July 1993

- Total bill excludes \$3,187 PG&E refund.

G-3.1 NEAR TERM PROJECTED USAGE

LLNL - ACCOUNT NO. YJN A1 00011-4
NEAR TERM PROJECTED USAGE

	FY 1993 (THERMS)	FY 1994 (THERMS)*
OCTOBER	318,121	318,121
NOVEMBER	535,484	535,484
DECEMBER	585,552	585,552
JANUARY	595,874	595,874
FEBRUARY	746,877	746,877
MARCH	612,450	612,450
APRIL	473,564	473,564
MAY	412,202	412,202
JUNE	425,442	425,442
JULY	303,862	303,862
AUGUST	319,191	319,191
SEPTEMBER	<u>320,334</u>	<u>320,334</u>
TOTALS	<u>5,648,953</u>	<u>5,648,953</u>

* FY 1994 Near-Term Forecasts Are Not Available.
FY 1993 Usage Assumed As Forecasted Usage.

G-3.2 LONG TERM PROJECTED USAGE

LLNL - ACCOUNT NO. YJN A1 00011-4
LONG TERM PROJECTED USAGE

<u>FISCAL YEAR</u>	<u>TOTAL USAGE*</u> (THERMS)
1987	4,136,562
1988	4,246,415
1989	5,127,929
1990	4,955,562
1991	5,211,461
1992	4,957,489
1993	5,648,953
1994	5,648,953
1995	5,648,953
1996	5,648,953
1997	5,648,953

* Long-Term Forecasts Are Not Available -
FY 1993 Usage Assumed As Forecasted Usage.

G-4.1 CURRENT TARIFF

PG&E's capacity brokering program requires PG&E to "unbundle" its interstate demand charges from its intrastate transportation rates. Implementation of this program was slated to occur in two phases. The first phase, partial capacity brokering on the El Paso and Transwestern pipeline systems, commenced August 1, 1993. The DOE/OAK labs elected to remain customers of PG&E, receiving gas under the rates for core (Rate G-NR1) and noncore (Rate G-CS) customers.

The partial capacity brokering plan was expected to continue until the commencement of full capacity brokering around August 1, 1994. However, during September 1993, the Federal Energy Regulatory Commission (FERC) granted the Pacific Gas Transmission Co. (PGT) approval to move forward with its capacity release program. As a result of the FERC's earlier-than-expected approval of capacity release on the PGT pipeline system, PG&E moved the date of full capacity brokering implementation to November 1, 1993.

Several options are available to the DOE/OAK labs under full capacity brokering. Core subscription customers (LBL4, LLNL and SLAC2) have the option to continue receiving gas from PG&E or to receive gas from a third party. LLNL has elected to purchase gas through the Defense Fuel Supply Center (DFSC) as of November 1, 1993. Under this "third party" arrangement, the DFSC will purchase gas for its customers on the spot gas market. The DFSC will charge each lab for the commodity and interstate transportation charges incurred, and PG&E will charge each lab for intrastate transportation under PG&E Rate Schedule FTS.

G-4.1 CURRENT TARIFF - PG&E TRANSPORTATION

LLNL - ACCOUNT NO. YJN A1 00011-4
CURRENT RATES

SCHEDULE G-FTS -- FIRM INTRASTATE GAS TRANSPORTATION SERVICE
NONCORE COMMERCIAL/INDUSTRIAL CUSTOMERS

RATES:

CUSTOMER CHARGE:

(based on avg. monthly usage for the most recent 12-month period)

0 TO 5,000 THERMS	\$10.11	per month
5,001 TO 10,000 THERMS	\$79.62	per month
10,001 TO 50,000 THERMS	\$302.05	per month
50,001 TO 200,000 THERMS	\$796.23	per month
200,001 TO 1,000,000 THERMS	\$1,140.01	per month
1,000,001 THERMS AND ABOVE	\$3,313.86	per month

TRANSPORTATION CHARGES:*

WINTER VOLUMETRIC:

Transmission	\$0.05469	per therm
Distribution	\$0.10709	per therm

SUMMER VOLUMETRIC:

Transmission	\$0.04038	per therm
Distribution	\$0.09288	per therm

SEASONS:

WINTER SEASON BEGINS NOVEMBER 1 AND ENDS MARCH 31

SUMMER SEASON BEGINS APRIL 1 AND ENDS OCTOBER 31

EFFECTIVE DATE:

January 1, 1994

* LLNL Receives Gas at Transmission Service Level.

G-4.1 CURRENT CHARGES - DFSC

LLNL - ACCOUNT NO. YJN A1 00011-4
NATURAL GAS SPOT MARKET AND
FUTURES PRICES

		RANGE OF CITY GATE PRICES TO THE CALIFORNIA BORDER (1)		AVERAGE PRICE	DFSC CHARGE TO LAB (2)
		LOW	HIGH		
		(\$/THERM)	(\$/THERM)	(\$/THERM)	(\$/THERM)
FY 1993					
OCTOBER	1992	\$0.2600	\$0.2870	\$0.2735	\$0.2753
NOVEMBER	1992	0.2290	0.2480	0.2385	0.2403
DECEMBER	1992	0.2250	0.2470	0.2360	0.2378
JANUARY	1993	0.2250	0.2640	0.2445	0.2463
FEBRUARY	1993	0.1800	0.1910	0.1855	0.1873
MARCH	1993	0.1870	0.2150	0.2010	0.2028
APRIL	1993	0.2140	0.2220	0.2180	0.2198
MAY	1993	0.2350	0.2730	0.2540	0.2558
JUNE	1993	0.1800	0.1940	0.1870	0.1888
JULY (3)	1993	N/A	N/A	0.2250	0.2268
AUGUST (3)	1993	N/A	N/A	0.2360	0.2378
SEPTEMBER	1993	0.2380	0.2470	0.2425	0.2443
12-MONTH AVERAGE					<u>\$0.2303</u>
FY 1994					
OCTOBER	1993	\$0.2100	\$0.2260	\$0.2180	\$0.2198
NOVEMBER	1993	0.2030	0.2160	0.2095	0.2113
DECEMBER	1993	0.2480	0.2660	0.2570	0.2588
JANUARY (3)	1994	N/A	N/A	0.2045	0.2063
FEBRUARY (4)	1994	N/A	N/A	0.2305	0.2323
MARCH (5)	1994	N/A	N/A	0.2356	0.2374
APRIL (5)	1994	N/A	N/A	0.2236	0.2254
MAY (5)	1994	N/A	N/A	0.2165	0.2183
JUNE (5)	1994	N/A	N/A	0.2140	0.2158
JULY (5)	1994	N/A	N/A	0.2135	0.2153
AUGUST (5)	1994	N/A	N/A	0.2145	0.2163
SEPTEMBER (5)	1994	N/A	N/A	0.2175	0.2193
12-MONTH AVERAGE					<u>\$0.2230</u>

NOTES:

- (1) October 1992-June 1993 and September-December 1993 Represent the Range of City Gate Prices to the California Border as Reported by Inside FERC Gas Market Report.
- (2) Average Price is Increased to Include a Supply Adjustment Factor of \$0.0018/Therm Per DFSC Contract #DLA600-94-D-7502 With Mock Resources, Inc.
- (3) Prices are the Average of El Paso and Transwestern Pipeline City Gate Prices as Reported in Natural Gas Week (1/24/94).
- (4) Average Price Represents the Natural Gas Futures Price on January 21, 1994.
- (5) Average Prices Represent the Natural Gas Futures Prices on February 11, 1994, as Reported in Natural Gas Week (2/14/94).

G-5.1 NEAR TERM ESTIMATED BILLS AT CURRENT RATES

LLNL - ACCOUNT NO. YJNA1 00011-4
PROJECTED USAGE PRICED
AT SPOT AND FUTURES MARKET PRICES*

		USAGE	INTRASTATE	GAS SUPPLY	TOTAL	AVERAGE
		(THERMS)	BILL	COST	BILL	BILL
			(\$)	(\$)	(\$)	(\$/THERM)
OCTOBER	1992	318,121	\$13,985.74	\$87,578.71	\$101,564.45	\$0.3193
NOVEMBER	1992	535,484	30,425.63	128,676.81	159,102.44	0.2971
DECEMBER	1992	585,552	33,163.85	139,244.27	172,408.11	0.2944
JANUARY	1993	595,874	33,728.36	146,763.77	180,492.13	0.3029
FEBRUARY	1993	746,877	41,986.71	139,890.06	181,876.78	0.2435
MARCH	1993	612,450	34,634.90	124,204.86	158,839.76	0.2594
APRIL	1993	473,564	20,262.52	104,089.37	124,351.89	0.2626
MAY	1993	412,202	17,784.73	105,441.27	123,226.00	0.2989
JUNE	1993	425,442	18,319.36	80,323.45	98,642.81	0.2319
JULY	1993	303,862	13,409.96	68,915.90	82,325.86	0.2709
AUGUST	1993	319,191	14,028.94	75,903.62	89,932.56	0.2818
SEPTEMBER	1993	320,334	14,075.10	78,257.60	92,332.69	0.2882
TOTAL FY	1993	<u>5,648,953</u>	<u>\$285,805.79</u>	<u>\$1,279,289.68</u>	<u>\$1,565,095.47</u>	<u>\$0.2771</u>
OCTOBER	1993	318,121	\$13,985.74	\$69,923.00	\$83,908.73	\$0.2638
NOVEMBER	1993	535,484	30,425.63	113,147.77	143,573.40	0.2681
DECEMBER	1993	585,552	33,163.85	151,540.86	184,704.71	0.3154
JANUARY	1994	595,874	33,728.36	122,928.81	156,657.17	0.2629
FEBRUARY	1994	746,877	41,986.71	173,499.53	215,486.24	0.2885
MARCH	1994	612,450	34,634.90	145,395.63	180,030.53	0.2940
APRIL	1994	473,564	20,262.52	106,741.33	127,003.85	0.2682
MAY	1994	412,202	17,784.73	89,983.70	107,768.42	0.2614
JUNE	1994	425,442	18,319.36	91,810.38	110,129.74	0.2589
JULY	1994	303,862	13,409.96	65,421.49	78,831.45	0.2594
AUGUST	1994	319,191	14,028.94	69,041.01	83,069.96	0.2603
SEPTEMBER	1994	<u>320,334</u>	<u>14,075.10</u>	<u>70,249.25</u>	<u>84,324.34</u>	<u>0.2632</u>
TOTAL FY	1994	<u>5,648,953</u>	<u>\$285,805.79</u>	<u>\$1,269,682.74</u>	<u>\$1,555,488.53</u>	<u>\$0.2754</u>

* Total Bills are Calculated as if the Lab had been Receiving Third Party (DFSC) Gas Since October 1992. Actual Spot Market Gas Prices are Used for October 1992-January 1993 Calculations, and Futures Prices are Used for the February - September 1994 Calculations.

G-1 NATURAL GAS SERVICE CHARACTERISTICS

G-1.1 Current Supplier and Rate Schedule

-- PG&E

Rate Schedule G-NR1 - Gas Sales to Small Non-Residential Core Customers.

- Applies only to core customers with gas usage which qualifies as priority levels P1 or P2A.
- Average monthly usage per meter must be less than 20,800 therms in those months during the last twelve months in which more than 200 therms were used. Service is reviewed every March to determine continued applicability.
- Provides bundled natural gas sales and delivery service.

G-1.2 Physical Characteristics of Service

- Delivery points - Central meter pad and then on-site distribution system.
- Load primarily used for space heating of SLAC buildings, insignificant amount for miscellaneous uses.
- SLAC distribution system is owned by U.S. Government.
- Metering equipment is owned by PG&E.

G-2.1 HISTORICAL USAGE AND COSTS

SLAC1 - ACCOUNT NO. XRN 09 19201-5
HISTORICAL USAGE AND COSTS

		<u>USAGE</u> <u>(THERMS)</u>	<u>TOTAL</u> <u>BILL</u> <u>(\$)</u>	<u>AVERAGE</u> <u>BILL</u> <u>(\$/THERM)</u>
OCTOBER	1991	2,263	\$1,096.24	\$0.4844
NOVEMBER	1991	4,441	2,807.33	0.6321
DECEMBER	1991	8,179	5,301.99	0.6482
JANUARY	1992	9,021	6,076.86	0.6736
FEBRUARY	1992	14,797	10,015.32	0.6768
MARCH	1992	11,068	7,494.67	0.6771
APRIL	1992	6,720	3,561.87	0.5300
MAY	1992	2,246	1,137.71	0.5065
JUNE	1992	994	510.84	0.5139
JULY	1992	893	460.27	0.5154
AUGUST	1992	904	465.77	0.5152
SEPTEMBER	1992	<u>1,079</u>	<u>553.40</u>	<u>0.5129</u>
TOTAL FY	1992	<u>62,605</u>	<u>\$39,482.27</u>	<u>\$0.6307</u>
OCTOBER	1992	1,144	\$585.94	\$0.5122
NOVEMBER	1992	4,087	2,340.12	0.5726
DECEMBER	1992	8,531	4,962.49	0.5817
JANUARY	1993	12,480	7,531.21	0.6035
FEBRUARY	1993	16,049	9,722.42	0.6058
MARCH	1993	13,014	7,886.37	0.6060
APRIL	1993	9,160	4,297.78	0.4692
MAY	1993	6,208	2,795.35	0.4503
JUNE	1993	1,605	781.93	0.4872
JULY	1993	709	356.02	0.5021
AUGUST	1993	621	314.64	0.5067
SEPTEMBER	1993	<u>709</u>	<u>357.47</u>	<u>0.5042</u>
TO DATE FY	1993	<u>74,317</u>	<u>\$41,931.74</u>	<u>\$0.5642</u>

G-3.1 NEAR TERM PROJECTED USAGE

SLAC1 - ACCOUNT NO. XRN 09 19201-5
NEAR TERM PROJECTED USAGE

	FY 1993 <u>(THERMS)</u>	FY 1994 <u>(THERMS)*</u>
OCTOBER	1,144	1,144
NOVEMBER	4,087	4,087
DECEMBER	8,531	8,531
JANUARY	12,480	12,480
FEBRUARY	16,049	16,049
MARCH	13,014	13,014
APRIL	9,160	9,160
MAY	6,208	6,208
JUNE	1,605	1,605
JULY	709	709
AUGUST	621	621
SEPTEMBER	<u>709</u>	<u>709</u>
TOTALS	<u>74,317</u>	<u>74,317</u>

* FY 1994 Near-Term Forecasts Are Not Available.
FY 1993 Usage Assumed As Forecasted Usage.

G-3.2 LONG TERM PROJECTED USAGE

SLAC1 - ACCOUNT NO. XRN 09 19201-5 LONG TERM PROJECTED USAGE

<u>FISCAL YEAR</u>	<u>TOTAL USAGE (1) (THERMS)</u>
1987	64,094
1988	76,700
1989 (2)	140,422
1990 (2)	208,949
1991 (2)	188,807
1992	62,605
1993	74,317
1994	74,317
1995	74,317
1996	74,317
1997	74,317

NOTES:

- (1) Long-Term Forecasts Are Not Available.
FY 1993 Usage Assumed As Forecasted Usage.
- (2) Per 1/15/93 Telephone Conversation with Kingston Chan, Increased Usage from FY 1989 - FY 1991 May Have Resulted from a Combination of Colder Than Normal Weather (FY 90), a Significant Gas Leak (Repaired April 1992) and a Shifting of Load Responsibility to SLAC2 (80,000 Therms Annually in March 1992)

G-4.1 CURRENT TARIFF

SLAC1 - ACCOUNT NO. XRN 09 19201-5
CURRENT RATES

SCHEDULE G-NR1 -- GAS SALES TO SMALL NONRESIDENTIAL CORE CUSTOMERS

RATES:

CUSTOMER CHARGE \$13.42 per month

DELIVERED COMMODITY/TRANSPORTATION CHARGE:

WINTER SERVICE \$0.63784 per therm

SUMMER SERVICE \$0.47247 per therm

SEASONS:

WINTER SEASON BEGINS NOVEMBER 1 AND ENDS MARCH 31

SUMMER SEASON BEGINS APRIL 1 AND ENDS OCTOBER 31

EFFECTIVE DATE:

January 1, 1994

G-4.1 CURRENT TARIFF

PG&E's capacity brokering program requires PG&E to "unbundle" its interstate demand charges from its intrastate transportation rates. Implementation of this program was slated to occur in two phases. The first phase, partial capacity brokering on the El Paso and Transwestern pipeline systems, commenced August 1, 1993. The DOE/OAK labs elected to remain customers of PG&E, receiving gas under the rates for core (Rate G-NR1) and noncore (Rate G-CS) customers.

The partial capacity brokering plan was expected to continue until the commencement of full capacity brokering around August 1, 1994. However, during September 1993, the Federal Energy Regulatory Commission (FERC) granted the Pacific Gas Transmission Co. (PGT) approval to move forward with its capacity release program. As a result of the FERC's earlier-than-expected approval of capacity release on the PGT pipeline system, PG&E moved the date of full capacity brokering implementation to November 1, 1993.

Several options are available to the DOE/OAK labs under full capacity brokering. Core subscription customers (LBL4, LLNL and SLAC2) have the option to continue receiving gas from PG&E or to receive gas from a third party. The DOE/OAK labs classified as core subscription customers have elected to purchase gas through the Defense Fuel Supply Center (DFSC) as of November 1, 1993. Under this "third party" arrangement, the DFSC will purchase gas for its customers on the spot gas market. The DFSC will charge each lab for the commodity and interstate transportation charges incurred, and PG&E will charge each lab for intrastate transportation under PG&E Rate Schedule FTS.

SLAC1 has been a core customer of PG&E and will continue to receive its gas requirements from PG&E. However, SLAC1 may choose the DFSC option in the future.

G-5.1 NEAR TERM ESTIMATED BILLS AT CURRENT RATES

SLAC1 - ACCOUNT NO. XRN 09 19201-5
PROJECTED USAGE PRICED
AT CURRENT RATES

		<u>USAGE</u>	<u>TOTAL</u>	<u>AVERAGE</u>
		<u>(THERMS)</u>	<u>BILL</u>	<u>BILL</u>
			<u>(\$)</u>	<u>(\$/THERM)</u>
OCTOBER	1992	1,144	\$553.93	\$0.4842
NOVEMBER	1992	4,087	2,620.27	0.6411
DECEMBER	1992	8,531	5,454.83	0.6394
JANUARY	1993	12,480	7,973.66	0.6389
FEBRUARY	1993	16,049	10,250.11	0.6387
MARCH	1993	13,014	8,314.27	0.6389
APRIL	1993	9,160	4,341.25	0.4739
MAY	1993	6,208	2,946.51	0.4746
JUNE	1993	1,605	771.73	0.4808
JULY	1993	709	348.40	0.4914
AUGUST	1993	621	306.82	0.4941
SEPTEMBER	1993	709	348.40	0.4914
TOTAL FY	1993	<u>74,317</u>	<u>\$44,230.20</u>	<u>\$0.5952</u>
OCTOBER	1993	1,144	\$553.93	\$0.4842
NOVEMBER	1993	4,087	2,620.27	0.6411
DECEMBER	1993	8,531	5,454.83	0.6394
JANUARY	1994	12,480	7,973.66	0.6389
FEBRUARY	1994	16,049	10,250.11	0.6387
MARCH	1994	13,014	8,314.27	0.6389
APRIL	1994	9,160	4,341.25	0.4739
MAY	1994	6,208	2,946.51	0.4746
JUNE	1994	1,605	771.73	0.4808
JULY	1994	709	348.40	0.4914
AUGUST	1994	621	306.82	0.4941
SEPTEMBER	1994	709	348.40	0.4914
TOTAL FY	1994	<u>74,317</u>	<u>\$44,230.20</u>	<u>\$0.5952</u>

SLAC 2 - ACCOUNT NO. XRN A1 00061-8
(Former Account No. XRN SB-91081)

G-1 NATURAL GAS SERVICE CHARACTERISTICS

G-1.1 Suppliers and Rate Schedules

-- PG&E (prior to 11/1/93)

Rate Schedule G-CS - Core Subscription Service to Noncore Commercial/Industrial Customers.

- Provides combined natural gas procurement and transportation service to noncore customers who select this option.
- The commodity charge component of the procurement charge changes monthly based on the average cost of gas in PG&E's core supply portfolio, lagged 30 days.
- The full-requirements option, which prohibits the customer from using alternative fuels except when curtailed, for testing of alternative fuel systems or if given prior permission by PG&E, eliminates the applicability of use-or-pay and take-or-pay charges.
- Requires a service agreement with a minimum term of two years.
- The current Schedule G-CS procurement charge may be obtained by calling PG&E's Gas Rate Hotline at (415) 973-0461.

-- PG&E (from 11/1/93)

Rate Schedule FTS - Firm Intrastate Transportation Service to Noncore Commercial/Industrial Customers

- Provides for firm intrastate gas transportation to the lab.

-- Defense Fuel Supply Center (from 11/1/93)

DFSC, acting as a third-party gas supplier for the lab, purchases gas on the spot gas market. All commodity and interstate transportation charges incurred on the lab's behalf are passed through to the lab.

G-1.2 Physical Characteristics of Service

- Delivery points - Central meter pad and then delivery to boilers.
- Load used for heating hot water boilers.
- SLAC distribution system is owned by U.S. Government.
- System by contract is capable of delivering 31,000 cf per hour:
- Metering equipment is owned by PG&E.

G-1.3 Contract Summary

GS-OOP-86-BS-D-002 U.S. General Services Administration
Areawide Public Utilities Contract
Pacific Gas and Electric Company

Natural gas service is provided pursuant to the GSA Areawide Contract between the U.S. General Services Administration and PG&E. This contract is effective for a 10-year period beginning December 19, 1985 unless canceled by either party with 60 days' written notice.

DE-AD03-89SF18231 Pacific Gas and Electric Company
Natural Gas Supply Agreement

This Natural Gas Supply Agreement between PG&E and DOE was modified effective November 1, 1993, to include only intrastate transportation. Contract effective from August 10, 1991, through December 18, 1995.

_____ Inter-agency Agreement for Natural Gas Supply
Service at SLAC

An inter-agency agreement between DOE and the Defense Fuel Supply Center (DFSC) should be in place within the next six months.

G-2.1 HISTORICAL USAGE AND COSTS

SLAC2 - ACCOUNT NO. XRNA1 00061-8
HISTORICAL USAGE AND COSTS

	USAGE (THERMS)	INTRASTATE BILL (\$)	GAS SUPPLY COST (\$)	TOTAL COST (\$)	AVE. COST (\$/THERM)
<u>FY 1992</u>					
OCTOBER	48,833	\$5,840.19	\$9,061.76	\$14,901.95	\$0.3052
NOVEMBER	55,777	7,471.49	10,499.05	17,970.54	0.3222
DECEMBER	73,883	9,952.61	15,608.09	25,560.70	0.3460
JANUARY	80,640	11,246.23	17,932.65	29,178.88	0.3618
FEBRUARY	55,528	7,859.66	11,900.13	19,759.79	0.3559
MARCH	50,529	7,173.60	9,210.07	16,383.67	0.3242
APRIL	49,631	6,726.12	8,774.72	15,500.84	0.3123
MAY	43,699	5,880.87	7,331.33	13,212.20	0.3023
JUNE	40,388	5,483.02	6,848.05	12,331.07	0.3053
JULY	36,612	5,029.30	6,235.95	11,265.25	0.3077
AUGUST	27,979	3,991.96	4,641.18	8,633.14	0.3086
SEPTEMBER	35,488	4,503.24	6,273.45	10,776.69	0.3037
TOTAL	<u>598,987</u>	<u>\$81,158.29</u>	<u>\$114,316.43</u>	<u>\$195,474.72</u>	<u>\$0.3263</u>
<u>FY 1993</u>					
OCTOBER	36,293	\$4,599.97	\$6,694.02	\$11,293.99	\$0.3112
NOVEMBER	46,458	6,231.94	9,113.83	15,345.77	0.3303
DECEMBER	74,315	9,887.73	15,799.67	25,687.40	0.3457
JANUARY	67,221	9,216.11	14,308.27	23,524.38	0.3500
FEBRUARY	59,709	8,243.07	12,567.05	20,810.12	0.3485
MARCH	49,822	6,925.43	9,492.97	16,418.40	0.3295
APRIL	53,851	6,689.16	10,409.68	17,098.84	0.3175
MAY	35,197	4,396.66	6,876.42	11,273.08	0.3203
JUNE	35,027	3,352.87	6,860.21	10,213.08	0.2916
JULY	27,946	2,616.39	5,338.75	7,955.14	0.2847
AUGUST	29,537	2,822.69	5,615.66	8,438.35	0.2857
SEPTEMBER	32,537	3,088.00	6,038.51	9,126.51	0.2805
TOTAL	<u>547,913</u>	<u>\$68,070.02</u>	<u>\$109,115.04</u>	<u>\$177,185.06</u>	<u>\$0.3234</u>

* The Intrastate Bill Reflects the Customer Charge and Intrastate Transportation Charge.

The Gas Supply Cost Reflects the Commodity Charge, Brokerage Fee and Core Subscription Shrinkage Fee.

G-2.2 NOTES TO HISTORICAL USAGE & COSTS

FY 1993

November 1992

- Total bill excludes \$2,119.91 PG&E refund. This refund is the result of a CPUC decision ordering PG&E to distribute the refunds that it received from gas suppliers.

March 1993

- Total bill excludes \$1,111.72 PG&E refund. This refund is the result of a CPUC decision ordering PG&E to distribute the refunds that it received from gas suppliers.

August 1993

- Total bill excludes \$518 PG&E refund.

G-3.1 NEAR TERM PROJECTED USAGE

SLAC2 - ACCOUNT NO. XRNA1 00061-8
NEAR TERM PROJECTED USAGE

	FY 1993 <u>(THERMS)</u>	FY 1994 <u>(THERMS)*</u>
OCTOBER	36,293	36,293
NOVEMBER	46,458	46,458
DECEMBER	74,315	74,315
JANUARY	67,221	67,221
FEBRUARY	59,709	59,709
MARCH	49,822	49,822
APRIL	53,851	53,851
MAY	35,197	35,197
JUNE	35,027	35,027
JULY	27,946	27,946
AUGUST	29,537	29,537
SEPTEMBER	<u>32,537</u>	<u>32,537</u>
TOTALS	<u>547,913</u>	<u>547,913</u>

* FY 1994 Near-Term Forecasts Are Not Available.
FY 1993 Usage Assumed As Forecasted Usage.

G-3.2 LONG TERM PROJECTED USAGE

SLAC2 - ACCOUNT NO. XRNA1 00061-8 LONG TERM PROJECTED USAGE

<u>FISCAL YEAR</u>	<u>TOTAL USAGE (1) (THERMS)</u>
1987	602,692
1988	569,662
1989	653,469
1990	499,647
1991	513,378
1992 (2)	598,987
1993	547,913
1994	547,913
1995	547,913
1996	547,913
1997	547,913

NOTES:

- (1) No Long-Term Forecasts Are Available - FY 1993 Usage Assumed As Forecasted Usage.
- (2) Load Responsibility Shifted from SLAC1 in March 1992 (80,000 Therms Annually)

G-4.1 CURRENT TARIFF

PG&E's capacity brokering program requires PG&E to "unbundle" its interstate demand charges from its intrastate transportation rates. Implementation of this program was slated to occur in two phases. The first phase, partial capacity brokering on the El Paso and Transwestern pipeline systems, commenced August 1, 1993. The DOE/OAK labs elected to remain customers of PG&E, receiving gas under the rates for core (Rate G-NR1) and noncore (Rate G-CS) customers.

The partial capacity brokering plan was expected to continue until the commencement of full capacity brokering around August 1, 1994. However, during September 1993, the Federal Energy Regulatory Commission (FERC) granted the Pacific Gas Transmission Co. (PGT) approval to move forward with its capacity release program. As a result of the FERC's earlier-than-expected approval of capacity release on the PGT pipeline system, PG&E moved the date of full capacity brokering implementation to November 1, 1993.

Several options are available to the DOE/OAK labs under full capacity brokering. Core subscription customers (LBL4, LLNL and SLAC2) have the option to continue receiving gas from PG&E or to receive gas from a third party. SLAC2 has elected to purchase gas through the Defense Fuel Supply Center (DFSC) as of November 1, 1993. Under this "third party" arrangement, the DFSC will purchase gas for its customers on the spot gas market. The DFSC will charge each lab for the commodity and interstate transportation charges incurred, and PG&E will charge each lab for intrastate transportation under PG&E Rate Schedule FTS.

G-4.1 CURRENT TARIFF - PG&E TRANSPORTATION

SLAC2 - ACCOUNT NO. XRNA1 00061-8

CURRENT RATES

SCHEDULE G-FTS -- FIRM INTRASTATE GAS TRANSPORTATION SERVICE
NONCORE COMMERCIAL/INDUSTRIAL CUSTOMERS

RATES:

CUSTOMER CHARGE:

(based on avg. monthly usage for the most recent 12-month period)

0 TO 5,000 THERMS	\$10.11	per month
5,001 TO 10,000 THERMS	\$79.62	per month
10,001 TO 50,000 THERMS	\$302.05	per month
50,001 TO 200,000 THERMS	\$796.23	per month
200,001 TO 1,000,000 THERMS	\$1,140.01	per month
1,000,001 THERMS AND ABOVE	\$3,313.86	per month

TRANSPORTATION CHARGES:*

WINTER VOLUMETRIC:

Transmission	\$0.05469	per therm
Distribution	\$0.10709	per therm

SUMMER VOLUMETRIC:

Transmission	\$0.04038	per therm
Distribution	\$0.09288	per therm

SEASONS:

WINTER SEASON BEGINS NOVEMBER 1 AND ENDS MARCH 31

SUMMER SEASON BEGINS APRIL 1 AND ENDS OCTOBER 31

EFFECTIVE DATE:

January 1, 1994

* SLAC2 Receives Gas at Transmission Service Level.

G-4.1 CURRENT CHARGES - DFSC

SLAC2 - ACCOUNT NO. XRNA1 00061-8
NATURAL GAS SPOT MARKET AND
FUTURES PRICES

		RANGE OF CITY GATE PRICES TO THE CALIFORNIA BORDER (1)		AVERAGE PRICE	DFSC CHARGE TO LAB (2)
		LOW (\$/THERM)	HIGH (\$/THERM)	(\$/THERM)	(\$/THERM)
FY 1993					
OCTOBER	1992	\$0.2600	\$0.2870	\$0.2735	\$0.2753
NOVEMBER	1992	0.2290	0.2480	0.2385	0.2403
DECEMBER	1992	0.2250	0.2470	0.2360	0.2378
JANUARY	1993	0.2250	0.2640	0.2445	0.2463
FEBRUARY	1993	0.1800	0.1910	0.1855	0.1873
MARCH	1993	0.1870	0.2150	0.2010	0.2028
APRIL	1993	0.2140	0.2220	0.2180	0.2198
MAY	1993	0.2350	0.2730	0.2540	0.2558
JUNE	1993	0.1800	0.1940	0.1870	0.1888
JULY (3)	1993	N/A	N/A	0.2250	0.2268
AUGUST (3)	1993	N/A	N/A	0.2360	0.2378
SEPTEMBER	1993	0.2380	0.2470	0.2425	0.2443
12-MONTH AVERAGE					<u>\$0.2303</u>
FY 1994					
OCTOBER	1993	\$0.2100	\$0.2260	\$0.2180	\$0.2198
NOVEMBER	1993	0.2030	0.2160	0.2095	0.2113
DECEMBER	1993	0.2480	0.2660	0.2570	0.2588
JANUARY (3)	1994	N/A	N/A	0.2045	0.2063
FEBRUARY (4)	1994	N/A	N/A	0.2305	0.2323
MARCH (5)	1994	N/A	N/A	0.2356	0.2374
APRIL (5)	1994	N/A	N/A	0.2236	0.2254
MAY (5)	1994	N/A	N/A	0.2165	0.2183
JUNE (5)	1994	N/A	N/A	0.2140	0.2158
JULY (5)	1994	N/A	N/A	0.2135	0.2153
AUGUST (5)	1994	N/A	N/A	0.2145	0.2163
SEPTEMBER (5)	1994	N/A	N/A	0.2175	0.2193
12-MONTH AVERAGE					<u>\$0.2230</u>

NOTES:

- (1) October 1992-June 1993 and September-December 1993 Represent the Range of City Gate Prices to the California Border as Reported by Inside FERC Gas Market Report.
- (2) Average Price is Increased to Include a Supply Adjustment Factor of \$0.0018/Therm Per DFSC Contract #DLA600-94-D-7502 With Mock Resources, Inc.
- (3) Prices are the Average of El Paso and Transwestern Pipeline City Gate Prices as Reported in Natural Gas Week (1/24/94).
- (4) Average Price Represents the Natural Gas Futures Price on January 21, 1994.
- (5) Average Prices Represent the Natural Gas Futures Prices on February 11, 1994, as Reported in Natural Gas Week (2/14/94).

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G-5.1 NEAR TERM ESTIMATED BILLS AT CURRENT RATES

SLAC2 - ACCOUNT NO. XRNA1 00061-8
 PROJECTED USAGE PRICED
 AT SPOT AND FUTURES MARKET PRICES*

		USAGE	INTRASTATE	GAS SUPPLY	TOTAL	AVERAGE
		(THERMS)	BILL	COST	BILL	BILL
			(\$)	(\$)	(\$)	(\$/THERM)
OCTOBER	1992	36,293	\$1,767.56	\$9,991.46	\$11,759.02	\$0.3240
NOVEMBER	1992	46,458	2,842.84	11,163.86	14,006.70	0.3015
DECEMBER	1992	74,315	4,860.52	17,671.11	22,532.62	0.3032
JANUARY	1993	67,221	4,472.55	15,516.53	21,029.08	0.3128
FEBRUARY	1993	59,709	4,061.72	11,183.50	15,245.21	0.2553
MARCH	1993	49,822	3,026.82	10,103.90	13,130.72	0.2636
APRIL	1993	53,851	2,970.73	11,836.45	14,807.18	0.2750
MAY	1993	35,197	1,723.30	9,003.39	10,726.70	0.3048
JUNE	1993	35,027	1,716.44	6,613.10	8,329.54	0.2378
JULY	1993	27,946	1,430.51	6,338.15	7,768.66	0.2780
AUGUST	1993	29,537	1,494.75	7,023.90	8,518.65	0.2884
SEPTEMBER	1993	32,537	1,615.89	7,918.79	9,564.68	0.2940
TOTAL FY	1993	<u>547,913</u>	<u>\$31,983.63</u>	<u>\$125,435.14</u>	<u>\$157,418.77</u>	<u>\$0.2873</u>
OCTOBER	1993	36,293	\$1,767.56	\$7,977.20	\$9,744.76	\$0.2685
NOVEMBER	1993	46,458	2,842.84	9,816.58	12,659.41	0.2725
DECEMBER	1993	74,315	4,860.52	19,232.72	24,093.24	0.3242
JANUARY	1994	67,221	4,472.55	13,867.69	18,340.24	0.2728
FEBRUARY	1994	59,709	4,061.72	13,870.40	17,932.12	0.3003
MARCH	1994	49,822	3,026.82	11,827.74	14,854.56	0.2982
APRIL	1994	53,851	2,970.73	12,138.02	15,108.75	0.2806
MAY	1994	35,197	1,723.30	7,683.51	9,406.81	0.2673
JUNE	1994	35,027	1,716.44	7,558.83	9,275.27	0.2648
JULY	1994	27,946	1,430.51	6,016.77	7,447.28	0.2665
AUGUST	1994	29,537	1,494.75	6,388.85	7,883.61	0.2669
SEPTEMBER	1994	<u>32,537</u>	<u>1,615.89</u>	<u>7,135.36</u>	<u>8,751.26</u>	<u>0.2690</u>
TOTAL FY	1994	<u>547,913</u>	<u>\$31,983.63</u>	<u>\$123,513.67</u>	<u>\$155,497.30</u>	<u>\$0.2838</u>

* Total Bills are Calculated as if the Lab had been Receiving Third Party (DFSC) Gas Since October 1992.
 Actual Spot Market Gas Prices are Used for October 1992-January 1993 Calculations, and Futures Prices
 are Used for the February - September 1994 Calculations.

A REVIEW OF THE DRAFT
REQUEST FOR PROPOSALS
BY SAN DIEGO GAS & ELECTRIC COMPANY
FOR PURCHASE OF THE
HEBER BINARY GEOTHERMAL POWER PLANT

A Report

Prepared for

U.S. Department of Energy
San Francisco Operations Office
FGS Division

Under Contract No. DE-AC03-86SF16343

November 1987

Prepared by:

EXETER ASSOCIATES, INC.

CONSULTING ECONOMISTS

4550 MONTGOMERY AVENUE
BETHESDA, MARYLAND 20814

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BY SAN DIEGO GAS & ELECTRIC COMPANY
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HEBER BINARY GEOTHERMAL POWER PLANT

I. INTRODUCTION AND BACKGROUND

The U.S. Department of Energy (DOE) entered into a cooperative agreement with San Diego Gas & Electric Company (SDG&E) to demonstrate the commercial feasibility of a 45 mW (net) binary geothermal power plant using reservoirs in the low to moderate temperature range. DOE has contributed \$61 million toward the design, construction and demonstration of the plant located at Heber, California. Under the cooperative agreement, DOE is to acquire two years of detailed technical data on the operation of the plant and has the right to recover its \$61 million investment through a revenue-sharing arrangement with SDG&E. As of this date (October 1987), total project costs are \$147.4 million, and DOE has contributed \$61 million or 41.38 percent of those costs.

Heat for the plant comes from hot geothermal fluids (brines), which are to be delivered by Chevron Geothermal and Unocal Corp. under a heat sales agreement with SDG&E. Full brine flow of 7.5 million pounds per hour (MLB/hr) was to be achieved by May 1987. However, the supply is currently at around 50 to 60 percent of full brine flow. Chevron estimates

full flow cannot be achieved before June 1989, and Chevron cannot guarantee that full flow will be achieved even at that point.

If the project continues at less than 100 percent brine flow until mid-1989 and then enters the demonstration period, SDG&E has estimated it will exceed the \$94 million project budget the California Public Utilities Commission (CPUC) approved for research and development purposes through the demonstration period.

SDG&E has terminated the heat supply contract on the grounds of non-performance, and SDG&E unsuccessfully attempted to renegotiate the terms of the contract. SDG&E has ceased operation of the plant and is preparing to place it in long-term storage condition by November 1, 1987. Further, SDG&E has proposed to sell the plant through a competitive bidding process.

SDG&E has proposed an extremely rapid schedule for the sale. The original target dates set by SDG&E are:

October 2	- assemble RFP
October 8	- review and approve RFP
October 8 (approximate)	- release of RFP
November 6 (Revised to 11/30)	- receive proposals
December 11	- negotiate plant sale
December 16	- approve sale

DOE INTERESTS

DOE has requested of SDG&E the right to protect its interests in the sale process through review and approval of the RFP, the selection of a buyer and the terms of the final negotiated sale agreement. Exeter Associates, Inc. has been tasked to review the SDG&E proposed RFP with regard to a number of utility regulatory issues in order to identify any areas of the RFP which are deficient in protecting DOE's interests. That is the purpose of this report. For our purposes, DOE's interests are defined as the recovery of its \$61 million investment and the accumulation of the outstanding demonstration data. It is our understanding that DOE places priority on the recovery of its financial investment.

The comments that follow are based on a review of selected background information on the project that was supplied by DOE on September 29 and October 1, 1987, and on a 2-day review of the draft RFP that was received on October 5. The extremely limited amount of time available in which to develop an understanding of the issues and to review the proposed RFP requires that we characterize our findings as "concerns" and "tentative evaluations." We may have incorrect understandings of and/or incomplete information regarding certain critical issues, and DOE should keep these qualifications in mind when utilizing the results of our analysis.

II. AN OVERVIEW OF THE PROPOSED SALE

There seem to be three critical factors affecting the viability of the project and therefore the likelihood of a satisfactory sale:

1. The heat delivery rate;
2. Electric power sales at an acceptably high price;
and
3. A transmission path from plant to market at reasonable cost.

HEAT DELIVERY RATE

The background information we have reviewed suggests that the failure to meet the planned heat delivery rate is due directly to Chevron's inability to successfully develop the field. If that is true, and if Chevron could be replaced or its errors corrected, then it may be that heat delivery will not be the binding constraint on the viability of the project. However, the investment in the field development and the operating cost of producing the brine will have a lasting effect on the division of electric power sales revenues and the potential profitability of the plant, other things constant.

POWER SALES CONTRACT

The most critical factor affecting the sale of the plant is arranging for the sale of the plant output at a sufficiently high price. At the very least, that price must cover

the operating costs of the plant, and the price should be high enough to cover the heat suppliers' operating costs, unless either the heat suppliers or the new plant owner were willing to incur out-of-pocket losses in the near term in the expectation of realizing an acceptable profit in the future. A DOE August 27, 1987 memo reported that SDG&E determined that its operating costs would exceed its avoided cost of energy at an 80 percent brine flow rate. That is consistent with other anecdotal information we have been able to glean from the documents made available to us. Further, even at a full brine flow rate, it is unlikely that SDG&E's avoided cost will exceed the total variable cost, including heat supply costs, for the next three or four years, and significant increases in SDG&E avoided cost would have to occur before any significant return to capital could be realized.

In short, we see little prospect of the project participants recovering a very large portion of their investment in the plant if sales to SDG&E at its avoided costs must be relied on. Moreover, it is likely that any significant recovery of participants' investments, if provided for, would be deferred for several years until the point when the plant is yielding a return on investment. In short, if project sales based on avoided costs must be relied upon, DOE may have the choice of receiving up front a small percentage of its \$61 million investment, or the opportunity of recovering a larger portion of its investment through deferred revenue-sharing arrangements.

A number of the documents we have reviewed indicate that SDG&E, DOE and other participants are relying heavily on the prospect of finding a buyer that can assign an existing "Standard Offer No. 4" (SO-4) contract commitment to the Heber Binary project. In particular, certain potential bidders may have an interest in SO-4 contracts with Southern California Edison Company (SCE) for other Heber projects. The SCE SO-4 price probably exceeds its current avoided cost, as well as SDG&E's, by more than 50 mills per kWh. If such a contract could be assigned to the project, it would make the project and the proposed sale viable on an economic basis by forcing SCE to subsidize the plant in the form of payments for power above the market value.

We would emphasize, however, that our review of recent CPUC cases and our discussions with a number of individuals, including Mr. Julian Ajello of the CPUC staff, lead us to conclude that the likelihood of gaining approval from the CPUC for an SO-4 contract assignment is very low. Mr. Ajello adamantly informed us that Staff has resisted every recent attempt to assign SO-4 contracts to new projects, new project owners/operators and new technologies. Staff's position is that such transfers violate the CPUC's decision in April 1985 that SO-4 contracts shall not be offered to new projects. Mr. Ajello spoke specifically to the SDG&E Heber Binary project. He noted that it has never had an SO-4 contract and so Staff would argue that any attempt to assign an existing SO-4 contract to the project would amount to providing a new

project with an SO-4, in violation of the CPUC's April 1985 decision. Mr. Ajello stated that there might be available some Heber-related contract with terms so general that it might be assignable, but suggested that Staff would likely oppose the assignment even in that circumstance. Further, Mr. Ajello stated that there are no special circumstances surrounding the Heber Binary project that would change Staff's position, including the fact that the plant is virtually completed and that a major purpose of the project is to demonstrate a new geothermal technology.

According to Mr. Ajello, Staff has formally opposed a number of recent attempts to transfer or otherwise assign SO-4 contracts. None of these contested assignments has yet been decided by the CPUC. Nor is that likely to occur in the near future. The earliest indication of the Commission's position will probably be a required report to the legislature on this and related issues, that will not be issued until the end of the year. Our own assessment is that the Commission is likely to side with Staff in its attempt to minimize a problem for which the CPUC and its staff are largely responsible -- the requirement that its jurisdictional utilities continue to purchase power from cogenerators and small power producers at prices well above their avoided costs, the burden of which ultimately falls on CPUC jurisdictional ratepayers.

Without access to an SO-4 contract, prospective bidders will be forced to market power from the project at market prices, which are likely to be defined by the avoided costs of SDG&E, SCE or PG&E. The size of the relevant market will be determined by the availability of adequate transmission capacity and access to that capacity at reasonable rates.

TRANSMISSION REQUIREMENTS

There appear to be significant obstacles to buyer transmission of the Heber project power to alternate markets. There is a current agreement between SDG&E and Imperial Irrigation District (IID) to use IID's lines for transmission to the SDG&E grid. But that agreement would not be assignable to the buyer, who would be required to negotiate its own transmission contract with IID.

Getting project power to SCE, if such a sale could be made, appears much more formidable. SDG&E and IID have indicated that they are willing to sign agreements with a buyer for transmission to the SCE system through 1991. After that, the buyer would probably have to buy into the new 230 kV Imperial Valley geothermal developer transmission line. Certain documents we have reviewed suggest that this line is already over-subscribed, which may require further delay in the project in addition to a significant up-front investment by the buyer. Finally, the documents reviewed indicate that SCE has no unused transfer capability north from San Onofre, the proposed point of delivery of Heber plant power. Thus,

SCE might attempt to impose transmission upgrade costs on the buyer if the buyer is successful in obtaining an SCE S0-4 contract. The availability and cost of transmission beyond these markets has not been explored, but the obstacles are likely to increase as the ultimate market moves further from the Heber plant.

III. REVIEW OF SDG&E'S DRAFT RFP

In general terms, we find the draft RFP woefully deficient in terms of protecting DOE's interests. Further, we believe that the terms set forth in the document will not permit a truly competitive bidding process, and may result in no legitimate offers, other than possibly an offer from Chevron/Unocal or another party already intimately involved in the process. Our view is based on three fundamental deficiencies in the RFP:

1. The entire risk associated with the sale would be imposed on the buyer. If SDG&E is legitimately seeking to sell the plant it should offer to provide some protection for the buyer.
2. No demonstration is required of the buyer that his proposed purchase is legitimate. While a sale under such conditions may serve SDG&E's interests, we do not believe it would serve the interests of DOE and the other sponsors.
3. The bid process itself, including the proposed timing, the absence of any warranties by SDG&E and the timing and availability of critical data, will discourage legitimate bids from prospective buyers, other than those with current access to confidential and critical information.

THE DIVISION OF RISKS

The proposed terms of sale strike us as most unusual in that SDG&E emphasizes that it make no warranties with regard to the accuracy of any of the information provided in the RFP. Further, and most important, the buyer is held responsible

for nearly all critical determinations and for securing all support contracts and services, including:

- heat supply arrangements;
- power sales contracts;
- transmission arrangements;
- water supply;
- operating service agreements;
- determination of validity and transferability of equipment warranties;
- determination of transferability of or the securing of necessary permits;
- determination of the risk associated with the pending Chevron/Unocal litigation.

Ordinarily, a seller that is legitimately interested in selling a project will sweeten the deal by taking on some of the risks associated with the sale. SDG&E proposes to do just the opposite. The degree of risk that would be imposed on the prospective buyer will discourage many offers, and it will likely ensure that any offers that are made will be low and likely will be contingent on the successful negotiation by the buyer of all the required subsidiary agreements. Further, it is likely that the division of risk contemplated in the RFP will result in offers that tie the purchase price to some share of net revenue over a fairly lengthy portion of the life of the project. If SDG&E is already authorized to recover its costs through rates, as we believe it is, it may be indifferent as to the method of recovery of its investment. That is likely not in the interests of DOE or the other participants.

If SDG&E is really committed to making a sale to a viable project operation, we believe that SDG&E should be willing to commit to the following:

- o To deliver the power over its system, utilizing all of its interconnect agreements, as far as possible and to the extent practicable;
- o To purchase the plant's output at its own avoided cost, which is probably consistent with CPUC policy; and
- o To enter into good faith negotiations on a long-term contract for purchase of the plant's output.

BIDDER REQUIREMENTS

The draft RFP requires little if any showing by the bidder that the bid is legitimate and that there is a reasonable prospect that the project will be financially viable. The absence of such a showing would be acceptable if proposals take the form of up-front payments in total with a third-party financial organization bearing the risk of successful operation. But SDG&E is not selling a house. We anticipate that most bids will take the form of payments tied to the operation of the plant and, most likely, a share of net revenues realized from sale of the output. In that event, DOE and the other sponsors stand to recover data and a portion of their investments only if the plant operates and is a financial success.

Therefore, to protect DOE's interests, we believe that certain requirements should be imposed on the bidders. These requirements would include:

- o A bond or surety from the winner that would essentially amount to earnest money;
- o The demonstration of an acceptable heat-supply agreement;
- o The demonstration of an acceptable power purchase agreement;
- o The demonstration of required transmission services from the plant to the market; and
- o The demonstration of a detailed financial plan, which would show DOE how the potential buyer plans to make the project work.

The importance of this type of requirement of the bidder needs to be qualified. It is possible that one of the current participants in the project, and most likely Chevron/Unocal, has had private discussions with SDG&E and is expecting to purchase the plant. Placing these requirements on prospective bidders is likely to result in fewer bids. Realizing that, the "insider" may make a less attractive offer than it would otherwise make if such requirements were not imposed on the bidders. That may not lead to DOE maximizing the recovery of its investment, which we understand to be DOE's primary objective.

ALTERATIONS IN THE BID PROCESS

The bid process itself is likely to discourage potential legitimate buyers because SDG&E proposes to warrant none of

the information in the bid package, and would require bids without adequate time to analyze critical information relating to the operation of the plant, and prior to access to critical information on the reliability of the heat resource. Detailed information on plant performance will not be available until the bidders conference on October 28, and information regarding the heat supply will only be made available to those bidders on the short-list.

Further, the heat supply agreement, a power sales contract, and required transmission agreements are so critical to the successful operation of the plant, that bidders without inside information are only likely to make offers contingent on the successful negotiation of these agreements. Again, the possible exception is Chevron/Unocal or another current participant that has knowledge of the heat supply, an SO-4 contract commitment from SCE that it believes can be assigned to the project, and commitments regarding the necessary transmission arrangements.

In our view, there are two approaches that could be taken to restructure the bid. The first is to strengthen the draft RFP. That would require that SDG&E take on certain risks and responsibilities as noted above, particularly providing warranties regarding certain information and committing to buy the plant's output and to wheel over its system. Further, the buyer would be required to make the kinds of commitments identified above to demonstrate that the project

is viable. That would require that the date for proposals be extended for a significant period -- probably several months -- to permit each legitimate potential bidder to hold negotiations with third parties regarding the heat supply, the sale of the power and transmission requirements.

The second and preferred alternative would be a 2-stage process. First, prospective buyers would be required to provide SDG&E with a letter of intent demonstrating how the bidder would buy the plant. At this stage the prospective bidder would be required to present a strategy for securing all the necessary subsidiary agreements, permits and data required for an evaluation of the project. Further the bidder would be required to provide the outline of a financial plan demonstrating how it would pay for the plant, and a conceptual price or value would be presented.

These initial submissions would then be used to develop a short list of legitimate bidders. Then, the short-list bidders would be provided with sufficient time to develop final bids, with all of the requirements that were specified earlier. Sufficient time (at least several months) would have to be provided to permit negotiation of the three critical subsidiary agreements: (1) heat supply, (2) power sales, and (3) transmission.

CONCLUSION

Our review of the SDG&E draft RFP leads us to conclude that DOE's interests are unlikely to be served by a sale that results from this bid process, as represented in the draft RFP.

- o We are not convinced the sale is legitimate.
- o SDG&E should be willing to carry some of the risk if it is anxious to make a sale that maximizes the owners' and sponsors' revenue recovery.
- o Prospective buyers must be required to make a showing that their offers are legitimate and that the project will be viable after the sale.
- o The bid process must be altered to allow sufficient time and to provide information necessary for prospective bidders to evaluate the project's potential and to negotiate critical subsidiary agreements.

115 KV TIE-LINE COST ESTIMATES
LAWRENCE LIVERMORE NATIONAL LABORATORY

Prepared for:

U.S. Department of Energy
San Francisco Operations Office
Contract No. DE-AC0386SF16343,
Task Order No. 3

September 1989

Prepared by:

Exeter Associates, Inc.
Silver Spring, Maryland

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Oklahoma City, Oklahoma

I. INTRODUCTION

A. PURPOSE

The purpose of this report is to document the results of an analysis to develop engineering cost estimates of the proposed 115 kV tie-line between the new Western Area Power Administration (Western) Lawrence Livermore substation and the existing Lawrence Livermore National Laboratory (LLNL) substation at building 424. Western is in the process of constructing a 230 kV line feeding the Lawrence Livermore Substation from the Western-owned Tracy Substation. Provision of power from the new substation to LLNL will be via the 115 kV tie-line to the existing LLNL Building 424 substation. Energization of the new LLNL substation is scheduled for August 1990.

A decision has yet to be made as to whether the 115 kV tie line will utilize overhead or underground construction. Preliminary cost estimates have been prepared for typical overhead and underground routings and technologies; however, these estimates have been put forth as being purely budgetary and lack sufficient engineering documentation to support the decision making process.

While there are many factors which will ultimately enter into the resolution of this issue, the sole purpose of this report is to examine the costs associated with a typical overhead routing and compare that with the costs associated with a typical underground routing. A comparative discussion of the various available underground technologies can be found in "Evaluation of Alternative Undergrounding Technologies" prepared by Power Engineers Incorporated (PEI) for the Western Area Power Administration.

This work was performed for the US DOE San Francisco Operations Office under Contract No. DE-AC03-86SF16343, Task Order No. 3.

B. SUMMARY

The engineering cost estimates presented herein indicate a clear economic advantage of the overhead construction as compared to underground construction. As shown in Table I.1, the least expensive underground option analyzed in this report is approximately 90% more expensive than the overhead option.

Table I.1
Comparison of Cost Estimates

<u>Option</u>	<u>Construction Cost</u>	<u>O&M Cost</u>	<u>Total Cost</u>	<u>Ratio</u>
Overhead	\$ 752,987*	\$262,000	\$1,014,987	1.00
Underground XLPE	1,564,200	341,500	1,905,700	1.88
Underground LPOF	2,742,828	248,100	2,990,928	2.95

* Includes four miles of PGandE rebuild

The second underground technology analyzed was approximately three times more expensive than the overhead option. While the economic advantage clearly rests with the overhead option, the underground options present advantages in areas which are much more difficult to quantify on an economic basis. For example, there is no question that the underground option would have less impact on the aesthetics of the site and would remove less land from future potential use for Laboratory development.

The project completion dates for both the overhead and underground options are comparable, differing by less than 30 days. This is due to the long lead times associated with the steel poles (overhead option) and the XLPE cable (underground option). However, neither option is projected to be completed by the scheduled completion date of the new substation. No consideration was given in this analysis to the loss of potential power cost savings during the time that the new substation is energized but the tie-line is under construction and therefore unavailable.

C. ORGANIZATION

This report is organized into four additional sections. Section II, "Review of Proposed Routes", briefly discusses those overhead and underground routes under consideration by LLNL and DOE/SAN staff. The specific routes for which cost estimates are prepared are identified. Section III, "Cost Estimate", presents the key assumptions and develops the detailed engineering cost estimates for the selected, typical tie line routes. Section IV, "Other Issues", recognizes those issues other than costs which enter into the selection of the final tie-line configuration. Finally, Section V, "Results", summarizes the results of the cost estimate calculations.

II. REVIEW OF PROPOSED ROUTES

A. OVERHEAD ROUTES

LLNL staff have identified four potential overhead routes, as shown on Figure II.1. All overhead options would require rerouting and rebuilding of the existing PGandE 115 kV transmission line to allow space for the new tie-line on existing PGandE poles. Access to the Building 424 substation is along the existing PGandE easement for all overhead options.

1. Option 1 - New Pole Line, East side of Greenville Road: Option 1 would place a new pole line south from the new Western Lawrence Livermore substation on the east side of Greenville Road. The new line would cross Greenville and enter the Building 424 substation along the existing PGandE easement. This option would minimize the possibility of interference with future on-site Lab development. However, this option could require the preparation of a new environmental assessment (EA) as it was not addressed in the existing, approved EA. An update to the EA could require new public hearings which could result in delays to the project. Additionally, the potential for the future widening of Greenville Road could either force pole line relocation at a future date or the acquisition of a wide utility easement at this point in time.
2. Option 2 - Shared Easement with PGandE: Option 2 embodies two separate configurations, both of which involve sharing the existing PGandE right-of-way along Greenville Road. As with Option 1, this option would also minimize the possibility of future conflicts with Lab development. The first configuration under this option is to over-build the existing PGandE 12 kV distribution line. This would require a larger county franchise agreement in order to expand the utility easement. However, maintenance on either the 115 kV or the 12 kV circuit would require an outage of the other circuit. Additionally, traffic on Greenville Road would be impacted during maintenance. It is reported that this configuration is unacceptable to Western due to reasons of maintenance safety and reliability. It has also been speculated that this configuration will likely be unacceptable to PGandE for the same reasons.

The second configuration of Option 2 is to bury the existing PGandE 12 kV distribution line, thus allowing Western less restricted use of the PGandE easement. As with the first configuration, the easement width would need to be expanded and Greenville Road traffic would be impacted during maintenance. It is reported that this option is unacceptable to Western due to reasons of maintenance safety and is possibly unacceptable to PGandE for the same reason.

3. Option 3 - New Pole Line Inside LLNL East Fence Line: Option 3 involves the construction of a new pole line inside the LLNL east fence line. This route would have minimal chance of conflicting with known LLNL and

III. COST ESTIMATES

A. GENERAL

This section will present detailed engineering cost estimates for three of the routing and technology options discussed in Section II above. Overhead Option 3 (new pole line inside east LLNL fence line) was chosen for cost evaluation as it has the lesser visual impact of any of the other overhead options. Additionally this routing has the longest straight line segments and thus requires fewer poles. For this reason it is considered to be the least expensive of the overhead options. The cost differential between Option 3 and the most expensive overhead option (probably Option 4) is estimated to be on the order of 10%.

Underground Option 2 (underground line outside of LLNL site fence connecting with Outer Loop Road just north of the UC Davis leasehold) was chosen as the underground route to be evaluated. The first technology examined was direct buried cross-linked polyethylene (XLPE), solid dielectric cable. This is considered to be the least expensive underground option. A second underground technology, low pressure oil filled (LPOF) cable, was also examined. The LPOF is considered to be one of the more expensive underground options under consideration for this project. These two results are thought to bracket the costs of the underground option being considered. The consideration of these technologies in this analysis in no way implies an endorsement or recommendation of either technology for the tie-line project.

Extensive telephone conversations were held with members of the Sacramento Municipal Utility District (SMUD) staff with regard to their recent experience with underground transmission line construction. While some useful data was obtained, caution was expressed concerning the inapplicability of the SMUD construction cost data to the LLNL tie-line due to the construction constraints imposed as a result of the urban location.

All cost estimates presented in this section are based on preliminary descriptions and sketches of the proposed routes and desired and required facilities. Since engineering design has not been initiated for the tie-line, detailed design drawings are not available for drawing take-off cost estimating. Therefore, these cost estimates rely heavily on engineering experience, vendor experience and data, and published sources. Table III.1 lists those data sources utilized in this analysis.

The estimates are developed strictly from a contractor's standpoint and do not include any costs that may be associated with project management, bid document preparation, construction supervision or other general or administrative activities that may be undertaken by LLNL or DOE staff.

All cost estimates are expressed in 1989 dollars assuming a lump-sum expenditure. No consideration is given to interest, carrying charges or other

possible expenses related to the time value of money. The operations and maintenance costs are estimated as a lump-sum expenditure in 1989 dollars over the life of the project, assumed to be 20 years. All labor rates obtained from the various construction companies contacted are "fully loaded" in that they include all payroll overhead, general and administrative, and profit multipliers.

In the following cost estimates, conductors were conservatively selected to provide a peak capacity of approximately 200 MVA. All designs are based on National Electric Safety Code requirements and industry-accepted standards of good engineering and construction practices.

B. OVERHEAD LINE

The overhead line route option chosen for evaluation is Option 3, the new line along the east fence of the LLNL site. This route has less visual impact than the other overhead options and affords a line route with fewer angles.

1. Description of the Line: The overhead line is as assumed to consist of painted steel, unguyed poles set on cast-in-place, reinforced concrete bases. The line will be single-circuit, using 1272 kcmil, non-specular ACSR conductor, and is estimated to be 5300 ft. in length. The line will utilize horizontal post insulators with an overhead static wire for lightning protection. A typical tangent structure is shown in Figure III.1.

2. Assumptions:

- a. Foundations: Foundations for steel poles will be augered piers with steel reinforcing bar cages and anchor bolts. Where soil boring tests indicate, foundations adjacent to the LLNL storm drainage ditch can be oversized to attain the necessary stability or steel piles driven to bedrock with welded top plates could be used. These conditions are conservatively assumed in the estimate. Cost data were taken from 1989 Means Construction Cost Data and adjusted for Sacramento area labor and material costs (Means City Cost Indexes, p.340).
- b. Steel Poles: Poles are tapered, 12-sided polygons using 0.25" steel plate. Self-supporting 90 degree angle poles and deadend poles are 0.50" steel plate. Poles are assumed to be painted. Pole prices were obtained from Valmount Industries of Valley, Nebraska. A unit price of \$1.40 per pound was used. Weights were calculated based on preliminary design criteria given to Valley. Delivery time on poles is 28 weeks. Design is based on 1272 kcmil ACSR conductor, 300-350 ft. spans and NESC light loading conditions.

TYPICAL STEEL POLE, UNGUYED STRUCTURE

Figure III. I

Table III.1
COST DATA RESOURCES

<u>Source</u>	<u>Item(s) Quoted</u>	<u>Quoted Price(s)</u>
Ray Saccany U.S. Silec Rep. 216-835-4111	Cable, Solid Dielectric, Cu	\$30.00/cable ft.
Brugg Cable Prod., Inc. 2929 Briar Pk., Ste 540 Houston, TX 77042 Bill Mathis 713-974-3035	Cable, Solid Dielectric, Cu Cable, Oil Filled Splices Terminations	\$27.00/cable ft. \$22.00/cable ft. \$3000.00 ea. \$6000.00 ea.
Nokia Cables 125 Wolf Road, Ste 13 Albany, NY 12205 James Moran 518-458-9011	Cable, Solid Dielectric, Al	\$23.00/cable ft.
Pirelli Cable Corp. 5801 E. 41st St. Ste 507 Tulsa, OK 74135 Don Davis 800-331-9089	Cable, Solid Dielectric, Cu Splices Terminations	\$20.00/cable ft. \$2000.00 ea. \$5000.00 ea.
Cablec Utility Cable Co. 17 Squadron Blvd. New York, NY 10956 John Russo 914-634-0106	Cable, Oil Filled, Cu Cable, Oil Filled, Al	\$31.00/cable ft. \$24.00/cable ft.
Okonite Co. 11500 Stemmons Freeway Dallas, TX 75229 Leo Wolf 214-243-3318	Cable, Oil Filled, Cu	\$26.00/cable ft.
Southwire Co. P.O. Box 1000 Carrolton, GA 30119 Steve Mckuen 404-832-5022	Overhead Conductor	\$2.23/cable ft.

Table III.1
COST DATA RESOURCES
(continued)

<u>Source</u>	<u>Item(s) Quoted</u>	<u>Quoted Price(s)</u>
Valmont Industries P.O. Box 2620 Tulsa, OK 74101 Jim Roby 918-583-5881	Steel Poles	\$ 1.40/pound
Lapp Insulator Co. Gilbert Street LeRoy, NY 14482 716-768-6221	Insulators	\$450.00 ea.
Koppers Co. 915 Koppers Bldg. Pittsburg, PA 15219 Tom Story 412-227-2421	Wood Poles	\$655.00 ea.
Wycoff Co. 520 Pike Street Towers Seattle, WA 98101 Bruce Lines 206-624-3535	Wood Poles	\$758.00 ea.
W. A. Chester Co. Mr. Barton 516-842-5700	Direct Buried Cable Instal. Cable in Conduit Instal. Splice Installation Termination Installation	\$10.75/cable ft. \$8.50/cable ft. \$11,400 ea. \$6,900 ea.
Interstate Construction Jake Leineke 916-351-0622	Direct Buried Cable Instal. Cable in Conduit Instal. Splice Installation Termination Installation	\$4.50/ckt. ft. \$4.50/ckt. ft. \$3,500 ea. \$2,500 ea.
J. B. Construction, Inc. Linton, ND 58552 Robert Jahner 701-254-4533	Overhead Line Installation	\$2.95/ cable ft.

- c. Conductor: Assuming a maximum load of 200 MVA, a 1272 kcmil, 54/19 (Pheasant) aluminum cable, steel reinforced (ACSR) was selected to allow for higher ambient temperatures. It is assumed that non-specular conductor would be used to minimize the visual impact to the site. Prices and delivery times were obtained from the Southwire Company of Carrollton, Georgia. Conductor prices of \$2.23 per foot were used with a lead time of 12-14 weeks.
- d. PGandE Rebuild: It was assumed that 4.0 miles of existing PGandE line would need to be upgraded to 159 MVA capacity, and that this would require building a new line. It was further assumed that the new line would be a single-pole line using direct-embedded wood poles with horizontal post insulators. Both of these assumption are conservative in that the amount of line that will need to be upgraded is likely to be less than four miles, thus reducing the cost. Additionally, it may be possible to utilize some of the existing towers, thus further reducing the cost. As the cost of the rebuild may become a critical negotiating point, further investigation may be justified to more closely define the associated costs. A 954 kcmil, 54/7 (rail) ACSR conductor would be used and the line would have an overhead static wire for lightning protection. Unit costs shown on the cost estimate detail were supplied by Koppers for wood poles and Southwire for the conductor.
- e. Labor Costs for Overhead Construction: Costs were obtained from J. B. Construction, Inc., Linton, North Dakota and from Means 1989 Electrical Cost Data. The Means data were adjusted in accordance with the City Cost Indexes for Sacramento (p.341). The J. B. Construction, Inc. costs for labor were adjusted by a factor of 1.65 to reflect Sacramento area wages.

The cost estimate for the overhead tie-line option is \$1,014,987 as shown in Table III.2. This estimate includes engineering fees of 12%, and a contingency of 20%. Continuing costs are estimated at \$262,000 over the 20 year life of the project.

The assumed four miles of PGandE rebuild accounts for \$453,578 of the total. While this cost is not strictly linear with distance due to such items as engineering, contingency, contractor mobilization and others, a first order approximation of a per mile cost can be obtained by dividing the above number by four. The result is \$113,395.

C. DIRECT-BURIED UNDERGROUND LINE

- 1. Description of the Line: The line is assumed to consist of three cross-linked polyethylene (XLPE), solid dielectric, 138 kV cables. The cables will be 1578 kcmil, copper conductor with 606 mils of XLPE insulation and a corrugated copper or lead sheath with a polyethylene

FILENAME: LLNL.WKS

DATE: 08/27/89
LOCATION: LAWRENCE LIVERMORE NATIONAL LABORATORY
ESTIMATOR:
CHECKED BY:

ITEM DESCRIPTION	QTY	NUMBER OF UNITS	LABOR RT PER UNIT	MAT & EQPT UNIT COST	TOTAL LABOR	TOTAL MAT & EQPT COST	LINE TOTAL
CONSTRUCTION COST							
Steel Poles	LB	223,700	\$.38	\$1.40	\$85,200.00	\$313,200.00	\$398,400.00
Foundations	EA	25	\$24.00	\$491.20	\$5,600.00	\$12,200.00	\$17,800.00
Insulators	EA	69	\$25.00	\$252.17	\$1,725.00	\$17,400.00	\$19,125.00
Cable, 1272 kcmil, ACSR	LF	15,000	\$2.95	\$3.84	\$47,200.00	\$61,440.00	\$108,640.00
Overhead Ground Wire	LF	5,333	\$1.01	\$.19	\$5,400.00	\$1,000.00	\$6,400.00
Tree Clearing and Trimming	LST	1	\$20,000.00	\$.00	\$20,000.00	\$.00	\$20,000.00
PG&E REBUILD							
Wood Poles	EA	52	\$991.15	\$678.85	\$51,540.00	\$35,300.00	\$86,840.00
Insulators	EA	156	\$25.00	\$251.92	\$3,900.00	\$39,300.00	\$43,200.00
Cable, 1272 kcmil, ACSR	LF	52,000	\$1.68	\$2.17	\$87,600.00	\$112,960.00	\$200,560.00
Overhead Ground Wire	LF	17,333	\$.58	\$.17	\$10,020.00	\$3,000.00	\$13,020.00
SUBTOTAL CONSTRUCTION					\$165,125.00	\$405,320.00	\$570,445.00
Engineering @12.0%							\$68,453.40
Contingency @20.0%							\$114,989.00
10 YEAR OVER 20 YEAR LIFE(Excluding PG&E Line)							
Tree Trimming							\$100,000.00
Pole Painting							\$12,000.00
Pole/Conductor Replacement							\$150,000.00
SUBTOTAL 1&M							\$262,000.00
GRAND TOTAL							\$1,014,987.40

jacket. The cable installation is illustrated in Figure III.2. As shown, the line will be buried in a 4.0 ft. wide, 6.0 ft. deep trench with a low-resistivity bed and backfill. Concrete slabs are to be installed approximately 2.0 ft. below grade to provide mechanical protection from dig-ins. The length of the line is assumed to be 7700 ft. Because the buried feeders represent minimal loss of LLNL building space, it is assumed that they will be buried adjacent to the Outer Loop Road. This route will include approximately 12 road crossings, including the one across Greenville Road. The cables are to be in conduit at these crossings with one spare conduit provided to facilitate replacement of a failed cable.

2. Assumptions:

- a. Cable: The cable is assumed to be XLPE, 660 mil insulation, 1578 kcmil, copper, metal sheath with polyethylene jacket, three conductors per circuit. Prices obtained from cable manufacturers ranged from \$26/ft. to \$35/ft. with lead times of 10-28 weeks. Most of the prices were in the \$30/ft. range and this was used as an average. Most lead times were at the high end; therefore, it was assumed that 28 weeks would be required for delivery.
- b. Splices and Terminations: The solid dielectric technology allows for the use of pre-assembled terminators and splices using slip-on splice bodies. The costs of these also varied, with the most recent cost data provided by Jake Leineke of Interstate Construction. These are the costs used in the detailed cost estimate. Labor prices also came from Interstate.
- c. Splicing Vaults: The cable length of 3,000 ft. per reel makes it necessary to install two splices per cable in the approximately 7,700 ft. circuit. Because splices are one of the most vulnerable points in the circuit, a pre-cast splice box will be required at each splice point. Prices were obtained by adjusting Means Building Construction Cost Data 1989 material and labor costs for the Sacramento area.
- d. Roadway Crossings: To minimize risk to the cables at road crossings, 6" conduits are installed, one per cable with one spare. Material and labor cost data used are from adjusted Means data.
- e. Overhead and Profit: Overhead and profit were calculated using the formulas in the Means Electrical Cost Data 1989. Overhead and profit used in these estimates is 51.0%, based on predominantly skilled workers being used. Foremen and common laborers do not seriously affect the aggregate result. The same overhead and profit percentage was used for overhead line construction where applicable.

TYPICAL INSTALLATION, SOLID-DIELECTRIC,
DIRECT BURIED CABLE
Figure III.2

The cost estimate for the direct buried underground option is \$1,905,700 as shown in Table III.3. As with the overhead cost estimate, this includes an engineering design fee of 12% and a contingency of 20%. Continuing costs over the 20 year life of the installation total \$341,500 in 1989 dollars. Disregarding the contingency and O&M costs, the total is \$1,327,200 or \$172.36 per foot. This compares favorably to the result presented in Table X-5 of the PEI report referenced in Section I. Disregarding the costs associated with the 230 kV installation, the unit costs presented are \$177.21 per foot. Of course, this simple comparison ignores any cost differential that may arise as a result of differences in the terrain or other differences between the LLNL project and the one analyzed in the PEI report.

D. LOW PRESSURE, OIL-FILLED UNDERGROUND LINE

1. Description of the Line: The line is assumed to follow the same route as the solid-dielectric cable. The line will consist of three paper-insulated, lead-sheathed (PILC) oil-filled cables. The cables will be installed in conduit within a cast-in-place, reinforced concrete duct bank. Total length of the route is 7,700 ft. The paper-insulated, oil-filled cable technology is a time-tested technology and much less expensive than high-pressure oil or gas installations.

2. Assumptions:

- a. Cable: The cable is assumed to be oil-filled, paper-insulated, 1000 kcmil copper conductor. Insulation is to be 386 mils with 0.7 inch diameter oil flow path in center of conductor. The lead sheath is assumed to be 110 mil polyethylene outer jacket. Pricing information from manufacturers varied from \$21/ft. to \$22/ft. The Brugg Cable Co. estimate of \$22/ft. was used. Lead time for delivery is 26-40 weeks.
- b. Conduit & Duct Bank: One cable is assumed to be installed in each of three 6" diam. fiber ducts, with three spare ducts. Ducts are arranged in a 3 x 2 configuration with PVC spacers. The ducts are assumed to be cast-in-place, reinforced concrete bank, 2.0 ft. high by 3.0 ft. wide, placed in a 6.0 ft. x 6.0 ft. trench with a 1.0 ft. sand bed. The trench is to be backfilled with excavated material, tamped in 6" lifts. Labor and material prices for duct, concrete work and trenching were obtained from Means Building Construction Cost Data 1989, adjusted for the Sacramento area.
- c. Splicing Vaults: Because of limitations on cable reel lengths, two splices per cable will be required. The splices are to be made in precast concrete vaults, 8.0 ft. x 14.0 ft. x 7.0 ft. high. The price of the vaults was taken from Means Electrical Cost Data 1989 and adjusted for the Sacramento area in accordance with the Means

TABLE III.3
ENGINEERING COST ESTIMATE
DIRECT BURIED XLPE

FILENAME: LLNL.MMS

CONSTRUCTION COST ESTIMATE
PROJECT: 115KV TRANSMISSION LINE
BY: C. H. GUERNSEY AND COMPANY

DATE: 09/22/89
LOCATION: LAWRENCE LIVERMORE NATIONAL LABORATORY
ESTIMATOR:
CHECKED BY:

DIRECT BUFILED XLFE

ITEM DESCRIPTION	QTY	NUMBER OF UNITS	LABOR RT PER UNIT	MAT & EQPT UNIT COST	TOTAL LABOR	TOTAL MAT & EQPT COST	LINE TOTAL
CONSTRUCTION COST							
Excavation 4ft x 4ft	EY	6,980	\$3.49	\$2.76	\$24,000.00	\$19,000.00	\$43,000.00
Backfill & Compaction	EY	4,000	\$3.10	\$18.05	\$12,400.00	\$72,200.00	\$84,600.00
Roadway Crossings	EA	12	\$450.00	\$2,116.67	\$5,400.00	\$25,400.00	\$30,800.00
Concrete Protectors	EA	750	\$21.60	\$139.20	\$23,700.00	\$104,400.00	\$128,100.00
Splice Boxes	EA	2	\$950.00	\$2,900.00	\$1,900.00	\$5,900.00	\$7,800.00
Splices	EA	5	\$7,500.00	\$3,000.00	\$21,000.00	\$18,000.00	\$39,000.00
Cable, 1578 kcmil, Cu. XLPE	LF	23,000	\$4.50	\$30.00	\$103,500.00	\$690,000.00	\$793,500.00
Terminations	EA	6	\$3,000.00	\$6,000.00	\$18,000.00	\$36,000.00	\$54,000.00
Seed	LBT	1	\$1,300.00	\$3,000.00	\$1,300.00	\$3,000.00	\$4,300.00
SUBTOTAL CONSTRUCTION					\$211,200.00	\$972,600.00	\$1,185,000.00
Engineering @12.0%							\$142,200.00
Contingency @20.0%							\$237,000.00
O&M OVER 20-YEAR LIFE							
Cable Replacement							\$304,000.00
Splices							\$19,500.00
Terminators							\$19,500.00
SUBTOTAL O&M							\$341,500.00
GRAND TOTAL							\$1,905,700.00

City Cost Indexes.

- d. Splices and Terminals: Splices for oil-filled, paper-insulated cables are made by hand and are labor intensive. A total cost of \$11,700 per splice (labor and materials) was furnished by the W. A. Chester Company, electrical contractor. Termination of PILC cables is done in a compound-filled pot head. Material and labor prices of \$6,900 per termination were also provided by the W. A. Chester Company.

The cost estimate for the low pressure, oil-filled underground option is \$2,990,928 as shown in Table III.4. As with the previous estimates, this includes an engineering design fee of 12% and a contingency of 20%. Continuing costs over the 20 year life of the installation total \$248,000 in 1989 dollars. Disregarding the contingency and O&M costs, the total is \$2,327,248 or \$302.24/ft. Comparison with Table X-9 in the Power Engineers report referenced earlier is complicated by the fact that the PEI report did not assume a concrete duct bank. Disregarding the 230 kV expenses in the PEI report, the unit cost is \$256.99 per foot. Disregarding the concrete duct bank expenses in Table III.4, the unit cost is \$235.86 per foot. As before, this simple comparison ignores any cost differential that may arise as a result of differences in the terrain or other differences between the LLNL project and the one analyzed in the PEI report.

TABLE III.4
ENGINEERING COST ESTIMATE
LOW PRESSURE OIL FILLED CABLE

FILENAME: LUNL.MVS

CONSTRUCTION COST ESTIMATE
PROJECT: 115KV TRANSMISSION LINE
AE: C. H. GUERNSEY AND COMPANY

DATE: 08/22/89
LOCATION: LAWRENCE LIVERMORE NATIONAL LABORATORY
ESTIMATOR:
CHECKED BY:

LOW PRESSURE OIL FILLED CABLE

ITEM DESCRIPTION	UOM	NUMBER OF UNITS	LABOR RT PER UNIT	MAT & EQPT UNIT COST	TOTAL LABOR	TOTAL MAT & EQPT COST	LINE TOTAL
<hr/>							
CONSTRUCTION COST							
Excavation 6ft x 6ft	CY	13,700	\$3.49	\$2.76	\$47,500.00	\$37,800.00	\$85,300.00
Backfill & Compaction	CY	10,600	\$3.10	\$7.10	\$33,500.00	\$76,700.00	\$110,200.00
Roadway Crossings	EA	12	\$466.67	\$2,500.00	\$5,600.00	\$30,600.00	\$36,200.00
Vaults	EA	2	\$1,900.00	\$4,400.00	\$3,800.00	\$8,800.00	\$12,600.00
Concrete Duct Bank	LF	7,700	\$23.99	\$32.39	\$261,700.00	\$249,400.00	\$511,100.00
Conduit	LF	23,000	\$11.86	\$14.10	\$272,800.00	\$324,400.00	\$597,200.00
Splices	EA	6	\$5,833.33	\$5,866.67	\$35,000.00	\$35,200.00	\$70,200.00
Cable, 1578 Kcmil, Cu, LPOF, PILE	LF	23,000	\$4.50	\$22.00	\$103,500.00	\$506,000.00	\$609,500.00
Terminations	EA	6	\$2,333.33	\$4,566.67	\$14,000.00	\$27,400.00	\$41,400.00
Seed	LOT	1	\$1,500.00	\$3,000.00	\$1,500.00	\$3,000.00	\$4,500.00
SUBTOTAL CONSTRUCTION					\$779,200.00	\$1,298,700.00	\$2,077,900.00
Engineering @12.0%							\$249,743.00
Contingency @20.0%							\$415,580.00
O&M OVER 20 YEAR LIFE							
Cable Replacement							\$204,000.00
Splices							\$23,400.00
Terminations							\$20,700.00
SUBTOTAL O&M							\$248,100.00
GRAND TOTAL							\$2,990,928.00

IV. OTHER ISSUES

A. GENERAL

There are a number of issues besides cost which may affect the ultimate selection of the 115 kV tie-line route and technology. While it is not the intent of this report to attempt to resolve any of these issues, they will be briefly discussed here in order to possibly more clearly state and define the areas of concern.

B. ELECTROMAGNETIC FIELDS

The issue of the potential health effects from electric and magnetic fields arising from power facilities is one which has been raised in connection with the tie-line routing. This topic is one which has received greatly increased exposure in recent months due to the conclusion of a number of studies funded by the Electric Power Research Institute (EPRI), the utilities in the state of California, and the utilities in the state of New York, which just names a few. The concern over the presence of electromagnetic fields is essentially two-fold. Electric and magnetic fields are produced by the voltage and associated with a transmission line. While biological effects have been reported in laboratory tests of mammalian specimens under the influence of electric and magnetic fields, the clear linkage between the biological effect and adverse health effects has not been conclusively identified.

The California Public Utilities Commission, in conjunction with the California State Department of Health Services, in response to Senate Bill 2519 (SB 2519) has embarked on an ambitious three year project to study key issues associated with extremely low frequency (ELF) electromagnetic fields. As a response to one of the requirements of SB 2519, a report was recently issued by the CPUC and is currently the focus of public comment. A final revised version of the report is scheduled for submission to the California Legislature in September of 1989. In summary, one of the conclusions of the CPUC report is:

"Existing research data are not sufficient for adequate accurate risk assessment. We do not know which components, if any, of electric power utility operations pose significant health hazards. Although biological effects are clearly established, the relationship of the effects to possible public health risks is not yet established."

With regard to the specific question of the 115 kV tie-line routing, there may be a difference in the strength of the electromagnetic fields between the overhead and underground options. Two variables are present in the routing consideration, that of distance and shielding. The overhead lines

would be on the order of 65 to 80 feet above grade, thus providing a relatively large separation between the source of the fields (i.e., the conductors) and the lab personnel at grade. With the underground option the configuration of the cable, the earth overburden, and the concrete protective sill will also provide some shielding and therefore attenuation to the electric fields. However, it should be pointed out that the magnetic fields generated by the current-carrying conductors are not significantly decreased in intensity by the three to four feet of overburden envisioned for the underground option.

C. LAND USE

Land use is an issue that has been raised by LLNL staff in regard to the selection of the tie-line technology. Table IV.1 presents some preliminary calculations performed by LLNL staff in an effort to arrive at an average value of the laboratory site surface area. The results of these calculations indicate an average land value of \$18.42/sq. ft. Assuming an overhead line length of approximately 4,000', and further assuming 50' and 24' easements for the overhead option, the value of the land displaced by the utility easements assuming the \$18.42 value is \$3.684M and \$1.768M respectively. For comparison purposes, assuming a 4' easement for the underground option with a length of 7,000' results in a displaced land value of \$0.516M. However, the \$18.42 value does not recognize the fact that the routings considered for the various tie-line options are those areas of very low land value. Specifically, the area between the two LLNL site security fences is of very low value with regard to future development. Similarly, the land immediately adjacent to the Outer Link Road, while of higher value than the intra-fence land, is also of relatively low value.

D. AESTHETICS

Considerable discussion and effort has been expended on the topic of aesthetics. LLNL staff have prepared overlay photographs showing the visual impact of the various overhead tie-line routes. The visual impact was shown to be minimal for Option 3, with slightly more impact exhibited with overhead Option 4. Obviously, this concern can be minimized by utilizing Option 3, which places the overhead line at the maximum distance from the Laboratory population. Additionally, utilizing the existing PGandE utility easement into building 424 does not add additional visual burden to the Laboratory landscape.

Table IV.1
Average Value of LLNL Property

Land	\$86.2M
including Landscaping	
Roads	
Parking	
Paths	
Site Grading & Prep	
Utilities	\$555.7M
including Electrical	
Communications	
Fire Alarm	
Gas	
Sewage	
Storm	
Water	
Total	\$641.9M

LLNL Area 800 acres including newly acquired lands

\$641.9M / 800 acres / 43,560 sq. ft. per acre = \$18.42 per sq. ft.

\$ 18.42 sq. ft. does not include any buildings

Overhead Option 4,000 ft. line on LLNL
 50 ft. easement (4,000)(50)(18.42) = \$3,684K
 24 ft. easement (4,000)(24)(18.42) = \$1,768K

Underground Option 7,000 ft. line on LLNL
 4 ft. easement (7,000)(4)(18.42) = \$516K

E. VULNERABILITY

The issue of sabotage/vulnerability has been raised by LLNL staff with regard to the selection of the tie-line configuration. The argument put forth is that an overhead tie-line configuration would be more susceptible to sabotage by the various anti-nuclear protest groups which occasionally target the Lab. While the susceptibility of overhead transmission lines to malevolent activities is evident due to the periodic occurrence of such events, utilization of an underground tie-line would not eliminate the possibility of malevolent activities directed at the power supply facilities. The new Lawrence Livermore substation should also be recognized as a more

critical sabotage target due to the potential for long-term outages resulting from sabotage induced damage to critical substation components. It is readily recognized that the substation components are at least as susceptible to sabotage as overhead transmission lines.

F. Maintainability/Reliability

Outages to overhead lines generally are the result of conductor breakage due to wind loading or burndown resulting from lightning strikes. The risk from lightning in the California area is very low, so it can be assumed that conductor damage will most likely be from wind loading, resulting in either conductor failure or insulator failure. With a minimum separation of 5.0 ft. between bare conductors and the steel poles, and a separation of 12.0 ft. between conductors, the likelihood of outages due to birds is also extremely low. In addition, annual maintenance of the right-of-way (tree trimming) will be required, as will painting the steel poles and washing the insulators. The most likely outages are:

<u>Event</u>	<u>Outage Time</u>	<u>Repair Cost</u>
Conductor failure	18-20 hours	\$ 9,000
Insulator failure	20-24 hours	10,000
Lightning strike	8-10 hours	6,000
Wood Pole failure	16-20 hours	11,000
Seismic event	10-12 days	84,000
Regular maintenance	8-10 hours	6,000

Table IX-2 of the PEI report presents an average outage time of 15.5 hours for 230 kV overhead lines; no data was given for 115kV lines.

The history of the new XLPE-insulated high-voltage cables is too brief to allow for any confident estimates of failure rates. It can be assumed that over a 20-year life, at least one section of cable will fail. The terminations are vulnerable to overvoltage stresses, contamination, and sabotage. At least two termination failures can be expected in 20-years. Splices are generally not as prone to failure, since they will be located in a splice box

Low-pressure, or self-contained, oil-filled, paper-insulated cables have a long history of relatively trouble-free service, provided that care is taken in the installation and splicing and terminating the cables. Splices and terminations are critical, labor-intensive procedures and are usually the point of failure for this type of cable. It is expected that at least two splices and three pot heads will fail over a 20-year period.

<u>Event</u>	<u>Outage Time</u>	<u>Repair Cost</u>
*Cable failure		
XLPE	14-16 days	\$347,000
Oil-filled	10-14 days	274,000
Termination failure		
XLPE	10-16 hours	13,500
Oil-filled	18-20 hours	12,000
Splice failure		
XLPE	16-20 hours	10,000
Oil-filled	24-36 hours	18,000

* Assume one section between splices to be repaired (3 cables)

Table IX-1 of the PEI report presents average outage times of 1 week and 2 weeks, for XLPE and LPOF (SCOF) underground cables, respectively.

G. CONSTRUCTION SCHEDULE

The issue of construction schedule and timing has also been a topic of discussion. The new Western substation is scheduled for completion in August 1990; any delays in the completion of the tie-line beyond that date will dilute the potential power cost savings expected by the avoidance of PGandE wheeling charges, and by the possible displacement of PGandE purchases with Western purchases.

Table IV.2 contains the data utilized in analyzing the construction schedules of both the overhead and underground options. Appendix A contains the CPM (arrow-on-activity) diagram for the overhead and underground options. As shown, neither the overhead nor the underground options can be completed in time to meet the August 1990 completion date of the new substation.

Table IV.2
CONSTRUCTION SCHEDULE DATA

<u>General Items</u>	<u>Duration</u>
Engineering Design	90 - 120 days
RFP Presentation	60 days
Bid Response (includes 30 day advertisement period)	60 days
DOE Approval	30 days
Notice to Proceed	30 days
Contractor Mobilization	10 days
 <u>Overhead Route</u>	
Steel Poles	27 weeks ARO *
Overhead Wire	12-14 weeks ARO
Insulators	16-20 weeks ARO
Construction Time	30 days
PGandE Rebuild Construction Time	60 days
 <u>Underground Route</u>	
Underground Cable	28-32 weeks ARO
Concrete Cure	5 days
Construction Time	30 days

Notes: * ARO - After Receipt of Order, time required for delivery of material on-site after placement of order.

V. RESULTS

A. COST CONSIDERATIONS

The primary purpose of this document is to develop engineering cost estimates which might be used in the decision making process to decide on the technology to be utilized in the new 115 kV tie-line. As shown in table V.1, the cost estimates exhibit the expected relationship to one another in that the overhead line option is approximately 50% as large as the least expensive underground tie-line option. The differential between the overhead and underground options is even larger when it is realized that approximately four miles of PGandE rebuild is included in the overhead option cost estimate. The low pressure oil filled underground option is approximately a factor of three more expensive than the overhead option. The ratio of the underground LPOF option compared to the underground XLPE option is 1.57, which is nearly identical to the 1.58 ratio presented in Table XII.1 in the PEI report.

B. OTHER CONSIDERATIONS

It has also been discussed that, while the overhead option offers a clear economic advantage, there are other issues which may tend to favor the underground option. With regard to construction scheduling, neither option presents a clear advantage, as the lead time on the steel poles necessary for the overhead option is essentially identical to the lead time on the underground cable. While each of these intangible items must be considered in the final decision, a discussion of the weight of these issues in the decision making process is beyond the scope of this report.

Table V.1
Comparison of Cost Estimates

<u>Option</u>	<u>Construction Cost</u>	<u>O&M Cost</u>	<u>Total Cost</u>	<u>Ratio</u>
Overhead	\$ 752,987*	\$262,000	\$1,014,987	1.00
Underground XLPE	1,564,200	341,500	1,905,700	1.88
Underground LPOF	2,742,828	248,100	2,990,928	2.95

* Includes four miles of PGandE rebuild

115 KV TIE-LINE COST ESTIMATES
LAWRENCE LIVERMORE NATIONAL LABORATORY

Appendix A
Project Construction CPM Chart

September 1989

Prepared by:

Exeter Associates, Inc.
Silver Spring, Maryland

C. H. Guernsey & Company
Oklahoma City, Oklahoma

CRITICAL PATH NETWORK REPORT

The following introduction provides a brief description of the attached Critical Path Method (CPM) diagrams of the projected schedules for both the overhead and underground 115kV tie-line options. This introduction may prove useful to those who are unfamiliar with the technique.

A. NETWORK ANALYSIS

Network or CPM analysis is both a planning and scheduling process. Planning consists of subdividing the objective into a number of individual activities and the defining their logical relationships to one another. Scheduling is the process of imposing estimates of time and resources on each activity within the plan. Once this is completed, the necessary dates can be calculated to complete the scheduling process, resulting in a network analysis.

The network analysis was performed by using a computer program called PMS II, which was developed by North America MICA, Inc., San Diego, California.

B. INPUT ASSUMPTIONS

Several assumptions were made in the development of the network analysis, of which one is the work week. For all activities except procurement, the work week was assumed to be 8 hour days, six days a week. For procurement and related work, the work week was assumed to be 7 days. For construction activities, the project duration was estimated in actual work days; however, for procurement and other administrative functions, the normal convention of calendar days was used, which necessitated defining the work week for those activities as seven days in length.

Holidays are taken into consideration as non-work days. The holidays observed are:

- Washington's Birthday
- Memorial Day
- Independence Day
- Labor Day
- Columbus Day
- Thanksgiving Day
- Christmas
- New Years Day

C. PROGRAM OUTPUT

The basic information developed within the program is scheduled dates and days. These are:

1. Early Start is the earliest possible date for starting an activity.
2. Early Finish is the earliest possible date for finishing an activity with existing durations.
3. Late Start is the latest date that this activity can start without delaying the start of any activity that is dependent on this activity.
4. Late Finish is the latest date that this activity can finish without delaying the start of an activity that is dependent on this activity.
5. Duration is the number of work days it will take to complete the activity.
6. Float is the number of working days between an activity's early finish date and its late finish date. This the most important item of information in the system for determining where attention should be focused to get the project completed on schedule.

These 6 items can be stated another way.

1. Early Start -- What is the earliest the activity can start?
2. Early Finish -- How soon can the activity be completed?
3. Late Start -- How long can the activity be delayed without affecting completion of the project?
4. Late Finish -- What is the latest the activity can be completed without delaying completion of the project?
5. Duration -- How long will it take to complete the activity?
6. Float -- How far is the activity ahead of schedule, on schedule, or behind schedule? (Plus days are activities ahead of schedule, minus days are activities behind schedule, and zero days are activities on schedule.)

This information is presented on the attached CPM, Activity-on-Arrow diagram.

Also attached is the Schedule Report. This report provides the start and end notes; description of the activity; the start, finish, early start, early finish, late start, and late start dates; and the status of the

activity. A quick glance at the "status" and the float columns of even long network reports provides a rapid update of the activities. The information found in the status column may include:

1. MIGHT STRT STATUS -- The report date is on or between the early start date and late start date.
2. MUST STRT STATUS -- The report date is between the late start and the late finish date.
3. PAST DUE STATUS -- The report date is after the late finish date or the activity has negative float.
4. DATE CTRL STATUS -- One of the "date control" selections has been made for this activity. The selection and the controlling date are displayed on the left half of the report. This message will be overridden by a more serious error, such as not meeting the selected date.
5. STRT ERROR STATUS -- The Date Control date and condition are different than the calculated Early Start date of the activity.
6. ACTIVE STATUS -- The report date is after the actual start date.
7. CRITICAL STATUS -- the activity has zero days of total float. This status may appear on the same line as another message. For example, the activity could be in a "Must Strt" status as well as "Critical."
8. HyperC STATUS -- The activity has a total float value of less than zero. This status may appear on the same line as another message. For example, the activity could be in a "Might Strt" status as well as "Hypercritical."
9. COMPLETE STATUS -- The activity has an actual finish date.

Sep89

SCHEDULE REPORT - DOE LLNL OVERHEAD
 SCHEDULING REPORT
 CONSTRUCTION SCHEDULING REPORT

Snode Jobcd	Enode Aux-2	Description 1 Description 2	Dur	Erly Strt	Erly Fnsh	Float	Status
1	20	ENGINEERING DESIGN	90	05Sep89	03Dec89	-161	Past Due Hyper
20	30	REQUEST FOR PROPOSAL PREP	60	04Dec89	01Feb90	-161	Past Due Hyper
30	40	BID RESPONSE	60	02Feb90	02Apr90	-161	Past Due Hyper
40	50	DOE APPROVAL	30	03Apr90	02May90	-161	HyperC
50	60	NOTICE TO PROCEED	10	03May90	12May90	-161	HyperC
60	90	SUBMITTAL OF LLNL OH	3	13May90	15May90	-161	HyperC
60	100	SUBMITTAL OF PG&E REBUILD	3	13May90	15May90	-133	HyperC
60	70	CONTRACTOR MOBILIZATION	10	13May90	22May90	5	
90	110	DOE APPROVAL OF LLNL	15	16May90	30May90	-161	HyperC
100	120	DOE APPROVAL OF PG&E REBUILD	15	16May90	30May90	-133	HyperC
70	80	SITE WORK	20	23May90	14Jun90	4	
120	130	ORDER AND DELIVERY OF OVERHEAD WIRE	91	31May90	29Aug90	-98	HyperC
120	160	ORDER AND DELIVERY OF WOOD POLES	98	31May90	05Sep90	-105	HyperC
120	140	ORDER AND DELIVERY OF INSULATORS	126	31May90	03Oct90	-133	HyperC
110	150	ORDER AND DELIVERY OF STEEL POLES	189	31May90	05Dec90	-161	HyperC
80	150	CONCRETE PLACEMENT AND CURE	7	15Jun90	22Jun90	4	
130	150	LINKAGE Only	0	29Aug90	29Aug90	-61	HyperC
130	160	LINKAGE Only	0	29Aug90	29Aug90	-98	HyperC
140	150	LINKAGE Only	0	03Oct90	03Oct90	-98	HyperC
140	160	LINKAGE Only	0	03Oct90	03Oct90	-133	HyperC
160	170	CONSTRUCT PG&E REBUILD	60	04Oct90	12Dec90	-114	HyperC
150	170	CONSTRUCT OVERHEAD LLNL	30	06Dec90	09Jan91	-138	HyperC
170	180	PROJECT COMPLETE	0	09Jan91	09Jan91	-161	HyperC

DOE
Early Start/Finish Display

Zone 2

Zone 3

Zone 4

==== Critical
===== In Process
===== Completed
===== Non-Critical

05Sep89 Activity-On-Arrow Diagram
C. H. Guernsey & Company
RANDY NASON

GPS-1: (A) N.A.MICA

Zone 8

Zone 9

Zone 10

98 -185 @ 31May 85Sep98
to 150 - Zone 10
ORDER AND DELIVERY OF WOOD
POLES

126 -133 @ 31May 83Oct98
to 150 - Zone 9
ORDER AND DELIVERY OF
INSULATORS

91 -98 @ 31May 29Aug98
to 150 - Zone 9
ORDER AND DELIVERY OF OVERHEAD
WIRE

7 4 4 15Jun 22Jun98
to 150 - Zone 10
CONCRETE PLACEMENT AND CURE

189 -161 @ 31May 85Dec98
to 150 - Zone 10
ORDER AND DELIVERY OF STEEL
POLES

0 -133 @ 83Oct 83Oct98
to 150 - Zone 10
LINKAGE ONLY

0 -98 @ 83Oct 83Oct98
to 150 - Zone 10
LINKAGE ONLY

0 -63 @ 29Aug 29Aug98
to 150 - Zone 10
LINKAGE ONLY

0 -99 @ 29Aug 29Aug98
to 150 - Zone 10
LINKAGE ONLY

52 -11- @ 84Oct 12Dec98
to 170 - Zone 11
CONSTRUCT POLE REBUILD

38 -132 @ 86Dec 89Jan91
to 170 - Zone 11
CONSTRUCT OVERHEAD LINES

Zone 11

Zone 12

0 -161 @ 89Jan 89Jan91
to 190 - Zone 12
PROJECT COMPLETE

05Sep89

SCHEDULE REPORT - DOE LLNL UNDERGROUND
DOE SCHEDULING REPORT
CONSTRUCTION SCHEDULING REPORT

Snode Jobcd	Enode Aux-2	Description 1 Description 2	Dur	Erly Strt	Erly Fnsh	Float	Status
1	20	ENGINEERING DESIGN	90	05Sep89	03Dec89	-182	Past Due HyperC
20	30	REQUEST FOR PROPOSAL PREP	60	04Dec89	01Feb90	-182	Past Due HyperC
30	40	BID RESPONSE	60	02Feb90	02Apr90	-182	Past Due HyperC
40	50	DOE APPROVAL	30	03Apr90	02May90	-182	HyperC
50	60	NOTICE TO PROCEED	10	03May90	12May90	-182	HyperC
60	80	SUBMITTAL OF DIRECT BURIAL CABLE	3	13May90	15May90	-182	HyperC
60	70	CONTRACTOR MOBILIZATION	10	13May90	22May90	13	
80	90	DOE APPROVAL OF UNDERGROUND CABLE	15	16May90	30May90	-182	HyperC
70	100	SITE WORK	20	23May90	14Jun90	11	
90	100	ORDER AND DELIVERY OF DIRECT BURIAL CABLE	210	31May90	26Dec90	-182	HyperC
100	110	CONSTRUCT LLNL UNDERGROUND LINE	30	27Dec90	30Jan91	-156	HyperC
110	120	PROJECT COMPLETE	0	30Jan91	30Jan91	-182	HyperC

DOE
Early Start/Finish Display

Zone 2

Zone 3

Zone 4

1 90 -182 0 05Sep 03Dec89
ENGINEERING DESIGN to 20 - Zone 2

20 60 -182 0 04Dec 01Feb90
REQUEST FOR PROPOSAL PREP to 30 - Zone 3

30 60 -182 0 02Feb 27Dec89
BID RESPONSE to 40 - Zone 4

40 30 -182 0 03Dec 07May90
DOE APPROVAL to 50 - Zone 5

05Sep89 Activity-On-Arrow Diagram
C. H. GUERNSEY & COMPANY
RANDY NASON

SPS-11 (A) N.A. MICA
Critical
In Process
Completed
Non-Critical

Zone 5

Zone 6

Zone 7

50 10 -182 0 03May 12May90
NOTICE TO PROCEED to 60 - Zone 6

60 3 -182 0 13May 15May90
SUBMITTAL OF DIRECT BURIAL CABLE to 80 - Zone 8

80 15 -182 0 15May 30May90
DOE APPROVAL OF UNDERGROUND CABLE to 90 - Zone 9

10 13 0 13May 20May90
CONTRACTOR MOBILIZATION to 20 - Zone 7

20 11 1 23May 1-Jun90
SITE WORK to 30 - Zone 7

Zone 8

Zone 9

Zone 10

Zone 11

90 210 -182 0 31May 25Dec90
ORDER AND DELIVERY OF DIRECT BURIAL CABLE to 100 - Zone 9

100 30 -155 0 27Dec 30Jan91
CONTRACTOR LAY UNDERGROUND LINE to 110 - Zone 10

110 0 -182 0 30Jan 30Jan91
PROJECT COMPLETE to 120 - Zone 11

DATE

FILMED

6/23/94

END