Application	:	A.05-12-002
Exhibit Number	:	DRA-17
Commissioner	:	Bohn
Admin. Law Judges	:	Kenney, Econome
Witness	:	Cabrera

DIVISION OF RATEPAYER ADVOCATES
CALIFORNIA PUBLIC UTILITIES COMMISSION

Report on the Results of Operations Electric and Gas Distribution Electric Generation for Pacific Gas and Electric Company

General Rate Case

Test Year 2007

Rate Base

San Francisco, California
April 14, 2006

RATE BASE

I. INTRODUCTION

This Exhibit presents DRA's analysis and recommendations regarding PG&E's weighted average electric generation, electric distribution, and gas distribution rate base. PG&E's presentation of weighted average rate base is contained in Exhibit PG&E-2, Chapter 13 (Gas & Electric Distribution) and Exhibit PG&E-3, Chapter 11 (Electric Generation). Chapter 4 of Exhibit PG&E-3 (Nuclear Operations Costs) contains testimony related to Nuclear Fuel Inventory, a component of Electric Generation rate base. Several components of rate base are discussed in other Exhibits and are incorporated herein by reference. This Exhibit specifically addresses: (1) Working Cash; (2) Customer Advances; and (3) Fuel Inventory. Section II summarizes DRA's recommendations while Section III discusses DRA's analysis of PG&E's request and the basis for its recommended adjustments for Working Cash and Fuel Inventories.

II. SUMMARY OF RECOMMENDATIONS

The table at the end of this section summarizes the differences between DRA's and PG&E's estimates for the indicated components of rate base. The following are DRA's recommendations with respect to the indicated rate base components:

A. Specific to Electric Generation Only

1. The payment terms adopted pursuant to Commission Decision 05-09-003 approving PG&E's petition to modify D.01-03-067 should be used in computing the correct lead lag days to be applied to Purchased Power Expense in its Working Cash computation for Electric Generation. The effect of the change increases total weighted average lag days to 45.91, from 33.90 days, or an increase of 12.01 days. The overall rate base

change is a reduction of approximately $75 million based on the 2007 working cash calculation presented in PG&E's application.

2. The value of Nuclear Fuel Inventory should not be included in Electric Generation rate base. This results in a reduction to rate base of $221.9 million in 2007 and affects the Plant in Service component of rate base.
3. The value of Fossil Fuels should not be included in Electric Generation rate base. This results in a reduction to rate base of $831,000 in 2007 and affects the Working Capital component of rate base.

B. Applicable to Gas and Electric Distribution and Electric Generation

1. The Working Cash allowance for Franchise Requirements should not be based on the results of operations estimate of franchise expense which is based on a functional area basis. It should be computed on the basis of total franchise requirements based upon total revenues received by PG&E for functional and non-functional area plant.
2. The Working Cash Lead Lag component for Settlements and Claims should be increased to 38.08 lead lag days from 36.09 days, or an increase of 1.99 days. DRA recalculated the Third Party Claims component of Settlement and Claims from 4 days, as filed, to 15 days.
3. For it's next general rate case, PG&E should conduct a new study of paid invoices for purposes of estimating lag days for the Goods and Services Expense component of its Working Cash Lead Lag Study. The current estimate is based on a 1996 study.
4. The quarterly payment schedule adopted in its Pension Contribution proceeding (Application 05-12-021) settlement should be used in computing the correct lead lag days as applied to Pension Expense in its Working Cash computation.

5. PG&E's working cash estimate should include the lead lag days associated with bonus payments made under its Performance Incentive Plan. Currently, only the dollars paid are included in the payroll expense component of the lead lag summary. The effect is to increase the total weighted average lag days for Company Payroll Expense from 12.49 days to 22.11 days or an increase of 9.62 days. The overall rate base change is a reduction of approximately $7.296 million for electric generation, $7.371 million for gas distribution, and $12.932 million for electric distribution or a total reduction of $27.599 million based on the 2007 working cash calculations presented in PG&E's application.
6. DRA recommends that PG&E be directed to update its lead lag study to include a separate line for the Performance Incentive Plan payments and lag days in its next GRC.
7. The Working Cash Lead Lag component for FICA Tax Expense should be increased to 22.44 days from 12.83 days, or an increase of 9.61 days. This increase is based on the inclusion of the lead lag days for FICA tax expense associated with the Performance Incentive Plan payments.

Tables 17-1 to 17-3 compare DRA's recommended with PG&E's proposed estimates of weighted average rate base in 2007 for electric generation, electric distribution, and gas distribution, respectively:

Table 17-1
Weighted Average Rate Base Components for 2007
Electric Generation
(Thousands of Dollars)

Description	DRA Recommended	PG&E Proposed	Difference PG&E>DRA	Percentage PG&E>DRA
Plant in Service	$10,927,589	$11,187,601	$260,012	2.4%
Depreciation Reserve	$8,999,125	$8,991,584	-$7,541	0.0%
Working Capital	$86,742	$166,811	$80,069	92.3%
TRA86 Adjustments	$10,715	$10,715	$0	0.0%
Customer Advances	$0	$0	$0	0.0%
Deferred Taxes/ITC	$292,873	$294,088	$1,215	.4%
Rate Base	$1,733,049	$2,079,456	$346,407	20.0%

Table 17-2
Weighted Average Rate Base Components for 2007
Electric Distribution
(Thousands of Dollars)

Description	DRA Recommended	PG&E Proposed	Difference PG&E>DRA	Percentage PG&E>DRA
Plant in Service	$16,753,596	$16,823,438	$69,842	.4%
Depreciation Reserve	$7,177,097	$7,191,472	$14,375	.2%
Working Capital	$35,716	$76,568	$40,852	114.4%
TRA86 Adjustments	$290,969	$290,969	$0	0.0%
Customer Advances	$95,939	$95,939	$0	0.0%
Deferred Taxes/ITC	$1,355,422	$1,348,738	-$6,684	-.5%
Rate Base	$8,451,822	$8,554,825	$103,003	1.2%

Table 17-3
Weighted Average Rate Base Components for 2007
Gas Distribution
(Thousands of Dollars)

Description	DRA Recommended	PG&E Proposed	Difference PG&E>DRA	Percentage PG&E>DRA
Plant in Service	$6,027,976	$6,055,915	$27,939	.5%
Depreciation Reserve	$3,617,923	$3,613,613	-$4,310	-.1%
Working Capital	$37,475	$54,806	$17,331	46.3%
TRA86 Adjustments	$60,126	$60,126	$0	0.0%
Customer Advances	$29,485	$29,485	$0	0.0%
Deferred Taxes/ITC	$327,406	$327,810	$404	.2%
Rate Base	$2,150,763	$2,199,940	$49,177	2.3%

III. DISCUSSION

Rate base represents the net investment in utility plant, equipment and other property PG&E has constructed or purchased to provide electric and gas service to its customers. The adopted value of rate base[1] is used in the revenue requirement calculation to determine the rate of return on rate base adopted by the Commission. The four major components of rate base are Plant in Service, Depreciation Reserve, Working Capital and certain adjustments for Customer Advances, and Accumulated Deferred Taxes. Working Cash is a separate component of Working Capital as are Materials & Supplies and Fossil Fuels. Nuclear Fuel Inventory is a separate component of Plant in Service for Electric Generation rate base. Nuclear fuel as defined by PG&E, is comprised of In Core and Out of Core fuel. DRA examined the methodology used by PG&E to combine the various components of rate base to arrive at the forecasted weighted average 2007 rate base. PG&E first arrived at weighted average totals for each rate base component for 2007 then summed each individual component to arrive at the total weighted average rate base. Weighted averages for each component were computed by using a 13-month weighting using the December 2006 through December 2007 month-end balances in the weighting formula.[2] DRA used the same methodology.

DRA examined PG&E's testimony, supporting workpapers and responses to DRA data requests for all of the items discussed in this Exhibit.

A. Working Cash for Electric Generation, Gas & Electric Distribution Rate Base

The following discussion applies to the electric generation, gas distribution and electric distribution functional areas. Working cash consists of two overall parts: (1) operational cash requirements, and (2) working cash resulting from the lag in

[1] Rate base is traditionally valued at original cost and is the base for rate of return measurements. For purposes of setting rates, forecasted and adopted rate base is used in the general rate case which differs from recorded or original cost rate base.

[2] PG&E's response to Data Request ORA-066, Question 1.

collection of revenues over the payment of expenses. Working cash is a regulated utility concept, that is, working cash represents necessary investment in materials and supplies, and the cash required to meet current obligations and perform normal operations. DRA reviewed various components of PG&E's Working Cash forecast for 2007 such as the operational cash components of Other Receivables and the Accrued Vacation deduction. DRA reviewed whether Other Receivables were regular and recurring as well as studied the trend in their amounts as graphed in the workpapers. With the exception of Other Receivables, the other operational working cash components were relatively stable over the base years used to forecast the 2007 level. Other Receivables increased substantially in 2001 and 2002 due to non-recurring circumstances related to the energy crisis. However, the forecast excluded these spikes in their levels, and as a result, the forecast for working cash purposes reflects a normalized level. PG&E's methodology is reasonable, and DRA accepts the forecasted level of Other Receivables as requested. The Accrued Vacation component is calculated within the results of operations model by applying a predetermined vacation accrual factor to labor expense. DRA accepts PG&E's Accrued Vacation estimate methodology and concurs with its inclusion in operational cash requirements as a deduction.

DRA examined the computation of lead lag days for various expense items contained in the Development of Average Lag in Payment of Expenses (lead lag summary) for test year 2007, as well as the timeliness of the lead lag study on which lag days is based.[3] The following paragraphs discuss specific issues identified by DRA as a result of its review.

1. Franchise Requirements

PG&E calculates the franchise requirements of its working cash allowance by using the franchise expense generated by the results of operations model. PG&E

[3] The expense lags for the 2007 general rate case were generally determined in the first and second quarters of 2005 in order to meet the NOI filing schedule.

states that this approach is the appropriate method to use.[4] Specifically, the franchise fee expense amount shown in the development of average lag day summary is calculated by the model on a functional area basis. The model uses a franchise fee rate and the functional area revenues to calculate a forecasted franchise requirement expense.[5] What this means is that revenues associated with non functional areas are excluded from the calculation with the result of understating the amount of franchise requirements expense included in the summary of lag days. This has the mathematical effect of understating the average number of days lag in the payment of expenses to be subtracted from the average number of days lag in the collection of revenue thereby overstating the rate base impact. DRA recommends that the franchise fee expense be calculated based on total revenues, thereby increasing the average lag days in the lead lag summary. This will result in a more reasonable rate base impact associated with franchise fee expense. DRA's estimate of the franchise requirements of its working cash allowance is based on total projected revenues.

2. Settlements and Claims

DRA examined the calculation of the lead lag days for this component of the lead lag summary and observed that the Third Party Claims sub-component contained in the workpapers appeared low, calculated by PG&E to be only 4 days. DRA determined that PG&E calculated this 4 day lag as the average time to request a settlement payment, approve a settlement payment, generate a check, and deliver the check to the claimant via first class US mail. PG&E starts counting days, for purposes of calculating the lag, when the third party (claimant) requests a settlement check and not when the expense becomes an actual accrued liability based upon all the known facts and circumstances.

[4] PG&E's response to Data Request ORA-079, Question 8.

[5] PG&E's response to Data Request ORA-159, Question 10.

Third party claims arise out of claims by third parties against PG&E alleging personal injury, property damage, and economic loss as a result of PG&E's operations. According to PG&E, it considers a third party claim an accrued liability after it has conducted an investigation of the incident giving rise to the claim and after it determines that there is a greater than 80% probability that a claim could be successful.[6] DRA proposes to calculate the lag days for Third Party Claims starting when the claim becomes an actual expense or the date PG&E determines that there is a liability. Using the accrual date as the starting point, DRA estimated the lag days for Third Party Claims at 15 days.[7] This results in total weighted average lag days of 38.08 days for Settlements and Claims compared to 36.09 days calculated by PG&E. Using the date the payment becomes an actual liability to estimate lag days is more consistent with other expenses used to compute average lag days and results in a more realistic estimate of payment lag. Further, using the date that a claimant requests payment from PG&E requires an averaging of the lag days because claimants may or may not request payment and if requested, and will do so at varying times. The actual accrual date is more static and provides for more accurate information on which to estimate the actual lag days. Using the accrual day more directly ties the lag days with the expense or economic performance. From an accounting standpoint, the actual payment of the claim as a function of a claimant's request is a cash concept and distinct from the economic substance underlying the expense.

3. Goods and Services Expense Lag

DRA observed that the calculation of the days lag for this expense is based upon a 1996 study of 6,100 invoices.[8] For this GRC, DRA accepts PG&E's estimate of 40.31 lag days for this expense. However, DRA recommends that PG&E update

[6] PG&E's response to Data Request ORA-159, Question 8.
[7] PG&E's response to Data Request ORA-209, Question 5.
[8] Exhibit PG&E-2, Workpapers at page 12-114, Note 1.

its study in its next general rate case, to reflect more recent activity in its summary of lag days for Goods and Services.

4. Purchased Power Expense Lag

PG&E calculated a total weighted average lag of 33.90 days for Purchased Power Expense. Included in this total is a payment lag of 30 days for Qualifying Facilities (QF) contract payments based upon payment terms outlined in D.01-03-067 which generally had required PG&E to make advance payments for purchase power.[9] PG&E filed a Petition to Modify D.01-03-067 on December 15, 2004 and the Commission approved it with D.05-09-003, dated September 8, 2005. PG&E filed its GRC application on December 2, 2005 but did not include the revised weighted average lag days for Purchased Power Expense in its lead lag study for Working Cash.

The result of D.05-09-003 is to provide for QF power purchase payments in accordance with the standard terms of the contract. Payment lag days for QF payments increase from 30 days to 49 days, while total weighted average lag days for Purchased Power Expense increase from 33.90 days to 45.91 days. DRA recommends that 45.91 lead lag days be used to compute the working cash allowance for Purchased Power Expense. The impact to total electric generation rate base is a reduction of approximately $75 million in 2007 based on the working cash calculation presented in PG&E's application.[10] The decrease affects working cash for the EG-Purchased Power, and the EG-Hydro Facilities UCCs of Electric Generation rate base.

5. Pension Expense Lag

PG&E calculated its pension expense lead lag days based on an assumed quarterly payment schedule resulting in a lead lag of 60.75 days. DRA initially observed that this appeared too low knowing that a customer-funded contribution to

[9] Exhibit PG&E 2, Workpapers at page 12-78, Note 1.

[10] PG&E's response to Data Request ORA-236, Question 2b.

the pension trust fund has not occurred since 1992.[11] Therefore, there is no recent payment history on which to make a rational estimate of lag days. PG&E nevertheless estimated the lag days by assuming a quarterly payment schedule.

On December 20, 2005, PG&E filed Application No. 05-12-021 asking for a revenue increase in 2006 in order to make a contribution to PG&E's Retirement Plan trust, commonly referred to as a pension contribution. On March 8, 2006, PG&E and DRA (along with CCUE) reached a settlement agreement on that application and on the pension issue in this GRC. (See Exhibit DRA-10, Chapter 10-N, for more details about the pension issue). The settlement agreement provides that PG&E will make quarterly contributions to its pension fund for each of the years 2007, 2008 and 2009. PG&E will make the quarterly contributions during these years consistent with the quarterly payment schedule contained in its lead lag study filed in the GRC.[12] Therefore, DRA will not propose an adjustment to its lead lag days for pension expense as filed, and, instead, recommends that the quarterly payment schedule filed in its application be used for purposes of computing lag days consistent with the proposed settlement.

6. Performance Incentive Plan

PG&E's lead lag summary for Working Cash includes payroll expense. Included in the expense amount are payments made under its Performance Incentive Plan (PIP).[13] Under the PIP, payments are typically made once per year around the month of March in the following year. However, the corresponding average lag days associated with the PIP are not included in the lead lag summary resulting in only 12.49 average days for Payroll Expense. The 12.49 average day estimate is based on

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[11] PG&E's response to Data Request ORA-079, Question 7.

[12] The quarterly payment dates are April 15, July 15, October 15 and January 15 for each annual payment cycle.

[13] PG&E's response to Data Request ORA-209, Question 4b.

the regular monthly and biweekly schedule of paying wages. The lead lag days associated with payments made under the PIP are 255.50 days.[14]

There are two alternative methods to include the lead lag days associated with the PIP payments: (1) the PIP payments can be separated out from the payroll expense and a separate line created showing the dollars paid under PIP, with the related average lag days of 255.50; or (2) calculate a total weighted average lag days based on a combination of the regular Payroll Expense and the PIP payments. DRA will use the latter method in its results of operations to estimate a revised lead lag days for Payroll Expense. DRA recommends that PG&E be directed to update its lead lag study to include a separate line for the PIP payments and lag days in its next GRC. The result of including the PIP payment lag days in the Payroll Expense lag is to increase total weighted average lag days from 12.49 days to 22.11 days for the functional areas of electric generation, electric distribution, and gas distribution. The overall rate base change is a reduction of approximately $7.296 million for electric generation, $7.371 million for gas distribution, and $12.932 million for electric distribution or a total reduction of $27.599 million based on the 2007 working cash calculations presented in PG&E's application.

7. FICA Tax Expense Lag

PG&E calculates the lead lag days for Federal Insurance Contribution Act (FICA) taxes as the lag days for Payroll Expense before the float period, plus one additional day. This policy is consistent with Decision 95-12-055 in PG&E's 1996 GRC. The result is a lag day period of 12.83 days. Currently, the lead lag days for FICA tax expense associated with payments made under PG&E's PIP are not included in the total lead lag days for FICA taxes. However, payments made under PG&E's PIP are subject to FICA taxes.[15] The inclusion of bonus payments under the

[14] PG&E's response to Data Request ORA-232, Question 1b.

[15] PG&E's response to Data Request ORA-240, Question 7A.

PIP in the lead lag summary for payroll expense (discussed above) has a corresponding effect on the lead lag days for FICA tax payments because FICA taxes are included in the PIP payments.

The lead lag days for FICA tax expense should be increased to reflect the lead lag days of the FICA taxes associated with the PIP payments.[16] DRA recommends that the lead lag days for FICA tax expense be increased from 12.83 days to 22.44 days which is the recommended lead lags days for Payroll Expense (discussed above) of 22.11 days, less the float of .67 days plus one day. This calculation is consistent with how PG&E computed lead lag days for FICA tax expense and follows the procedure adopted in D.95-12-055 in PG&E's 1996 GRC.[17]

B. Gas and Electric Distribution

1. Customer Advances

Customer Advances, or advances made by customers requiring construction of facilities not already available, are normally refunded at some future date. PG&E forecasted the level of customer advances in 2007 to be an amount equal to the recorded end of the month December 2004 balance. This method was used because it was used and agreed to in the 2003 GRC and there is no expectation that there will be a substantial change in the level of customer advances over the next several years. DRA agrees with PG&E, observing that the December 2004 balance of customer advances was close to the weighted average balances over the years 2001 to 2005. DRA studied the monthly trend in the level of customer advances from 2004 to 2005 and did not observe any unusual or substantive changes. The difference between the forecasted 2007 level and recorded levels including the change in the level of customer advances from 2004 to 2007 are reasonable. DRA accepts PG&E's forecast as filed as it yields a reasonable result.

[16] PIP payments have approximately a 255 day lag period and are subject to FICA taxes just like regular payroll payments.

[17] Exhibit PG&E-2, workpapers, page 12-90.

C. Electric Generation

1. Nuclear and Fossil Fuel Inventory

PG&E includes all net nuclear fuel in the Plant in Service component of Electric Generation rate base.[18] That is, in this rate case, PG&E is including out-of-core and in-core nuclear fuel in Plant in Service (one rate base component). In the 2003 GRC, PG&E included nuclear fuel in three separate components of rate base: in-core nuclear fuel in Plant in Service and Depreciation Reserve, and out-of-core nuclear fuel in Working Capital. PG&E states that it included all net nuclear fuel in the Plant in Service component of Electric Generation rate base to be consistent with the treatment of plant assets that meet regulatory criteria as used and useful and having a service life greater than one year, and to be consistent with its presentation in the FERC Form 1, Comparative Balance Sheet section.[19]

The Diablo Canyon nuclear fuel inventory is included in rate base. The total weighted average value of the inventory is $200.3 million in 2006 and $221.9 million in 2007. Nuclear fuel consists of out-of-core and in-core inventories. The out-of-core inventory balance includes the weighted average cost of uranium in the process of conversion and enrichment, and fuel assembly fabrication. The in-core inventory balance includes the weighted average cost of fabricated fuel assemblies in the reactor core. The forecasted fuel inventory balances are based on projected purchases of uranium, conversion, enrichment and fabrication services as well as fuel usage.

PG&E also included the value of fossil fuel inventory in the rate base component of Working Capital. In 2006, the amount is $1.191 million and in 2007 it is $831,000.

DRA opposes the inclusion of Fuel Inventory in rate base given the historical treatment of these costs and the fact that rate base carries a higher carrying cost than

[18] PG&E's response to Data Request ORA-142, Question 6b.
[19] PG&E's response to Data Request ORA-066, Question 2.

the short term rates usually applied to fuel costs. Including PG&E's nuclear and fossil fuel inventories in rate base would cost ratepayers more in rates, with no corresponding benefit. In other words, ratepayers will bear the carrying costs for fuel inventory at the weighted cost of capital rather than the three-month commercial paper rate. PG&E's fuel inventory carrying costs should be recovered in its Energy Resource Recovery Account (ERRA) proceeding which is consistent with long-standing Commission policy.

The issue of including fuel costs in rate base has been considered and rejected by the Commission in a number of prior proceedings. It is relevant to understand the background regarding the Commission's treatment of fuel inventory carrying costs. Fuel inventories are evaluated annually in the ERRA proceedings. The cost of holding or storing fuel inventory is known as the carrying cost. Ratepayers do not have to pay for fuel until it is used to generate electricity. However, ratepayers pay for the cost of holding or storing fuel until it is consumed.

In D.85-12-107, the Commission first addressed the question of proper rate treatment of fuel inventory for Southern California Edison (SCE).

> Edison no longer shall be allowed to charge ratepayers the cost of carrying fuel oil in inventory at the authorized rate of return. There are several reasons for this. First, the authorized rate of return includes equity and long-term debt. The cost of using equity rather than debt is higher to the ratepayer because of the income tax that must be recovered with a return on equity. Second, the balancing account associated with the ECAC expense was not designed to reward the company with its rate of return on a non-rate base item but to shield the company from wide swings in fuel expenses. Finally, the low-risk nature of fuel oil inventories call for a different ratemaking approach (D.85-12-107, 20CPUCd 111,112, as modified in D. 86-05-095, slip op. at p.2)

The Commission concluded:

> Fuel oil inventory is low risk. Unlike rate base assets, fuel oil inventory is subject to balancing account treatment. In effect, Edison (SCE) has been guaranteed recovery of its rate of return on a low-risk asset. This result was never intended to occur through ECAC procedures. (Id, at p.3.)

In D.87-12-066, 26 CPUC2d 392, the Commission extended the above holding to SCE's coal and fuel inventories.

The Commission stated:

> Although Edison (SCE) points out that the operating and life cycle characteristics of nuclear fuel are not the same as coal, gas, and oil, we believe that this is not enough to warrant a different ratemaking treatment. In fact Edison (SCE) proposes to finance nuclear fuel with a combination of short-` and intermediate-term debt. While this might indicate that there is a need to factor in the cost of intermediate debt in deriving the carrying cost associated with nuclear fuel, it does not justify rate base treatment. (Id.)

The Commission further stated it preferred the use of short-term debt instruments to determine carrying charges on fuel. Because fuel "is a commodity that can be used as collateral for financing and is distinguishable from fixed plant and land…fuel should not be afforded rate base treatment, regardless of its characteristics." The Commission directed SCE to calculate carrying costs on its unspent nuclear fuel and coal reserves using the cost of short-term debt, and continue to include these costs in its former ECAC (now ERRA) balancing account. (Id.)

In D.88-09-031, 29 CPUC2d 314, 342, the Commission authorized SCE to finance nuclear fuel with a blend of short and intermediate-term debt. DRA argued that one short-term interest rate should be used to calculate the carrying costs of all fuel inventories, especially since, at that time; SCE was not actually financing its nuclear fuel with any intermediate-term debt.

The Commission agreed with DRA, stating, “[w]e see no difference in the financing of these fuels. SCE and other utilities can use a myriad of borrowing arrangements…including intermediate-term debt …to finance carrying costs.” (D.93-01-027, 47 CPUC2d at 694.). As noted earlier, the utility is free to finance these inventories however it pleases, but the Commission has decided to limit the ratepayer’s share in that expense in the short-term interest rate. (Id.)

In 1985, the Commission established the Energy Cost Adjustment Clause (ECAC now ERRA) mechanism to provide an industry-wide mechanism to provide public utilities with yearly recovery of fuel costs for electric operation. The Commission determined the most cost effective procedure to pay utilities for fuel costs was in annual ERRA proceedings. All California public utilities are currently subject to this fuel cost recovery mechanism.

DRA recommends that the Commission maintain the current fuel cost recovery mechanism, as articulated in D.96-01-011. In that decision, the Commission denied SCE’s previous proposal to split fuel costs into permanent and temporary portions and disagreed with the permanent inventory level concept, stating the increased risk was “insufficient to justify the change in financing” (Pg 226). On page 227, the Commission stated,

> We believe it more efficient to include determinations of the reasonableness of fuel inventory levels in the ECAC proceedings. That proceeding engages fuel experts who review the utility’s fuel purchasing policies as a whole taking out one piece of that puzzle.

The Commission has established precedents against including fuel inventories in rate base in general rate cases. One of the primary reasons is that the cost of using equity rather than debt is higher to the ratepayer because of the income tax that must be recovered with a return on equity. In short, nothing has changed since the Commission established that policy in 1985 and in intervening cases since that time.

Therefore, DRA recommends the Commission reject PG&E's inclusion of nuclear and fossil fuel inventories in rate base based on the Commission's past precedents against including fuel costs in GRC's, and the fact that nothing has changed to deviate from the current policy. The Commission has stated that fuel inventories do not pose a significant enough risk to justify earning a rate of return on fuel inventories when added to rate base.

Fuel inventory costs should be fully paid for by ratepayers within PG&E's current ERRA. Fuel inventories pose a low financial risk to the utility that does not justify earning a rate of return paid for at ratepayer expense with no ratepayer benefit. Therefore, it is to the advantage of ratepayers that nuclear fuel inventory be treated as fuel costs to be recovered in the ERRA.