Appendix J

SMUD Annexation Feasibility Study, Final Report, R.W. Beck, 2005

(Provided on CD Only)

Final Report

SMUD Annexation Feasibility Study

January 2005

R·W·BECK

LUCY & COMPANY

Shaw® Stone & Webster Management Consultants, Inc.

SACRAMENTO MUNICIPAL UTILITY DISTRICT
ANNEXATION FEASIBILITY STUDY

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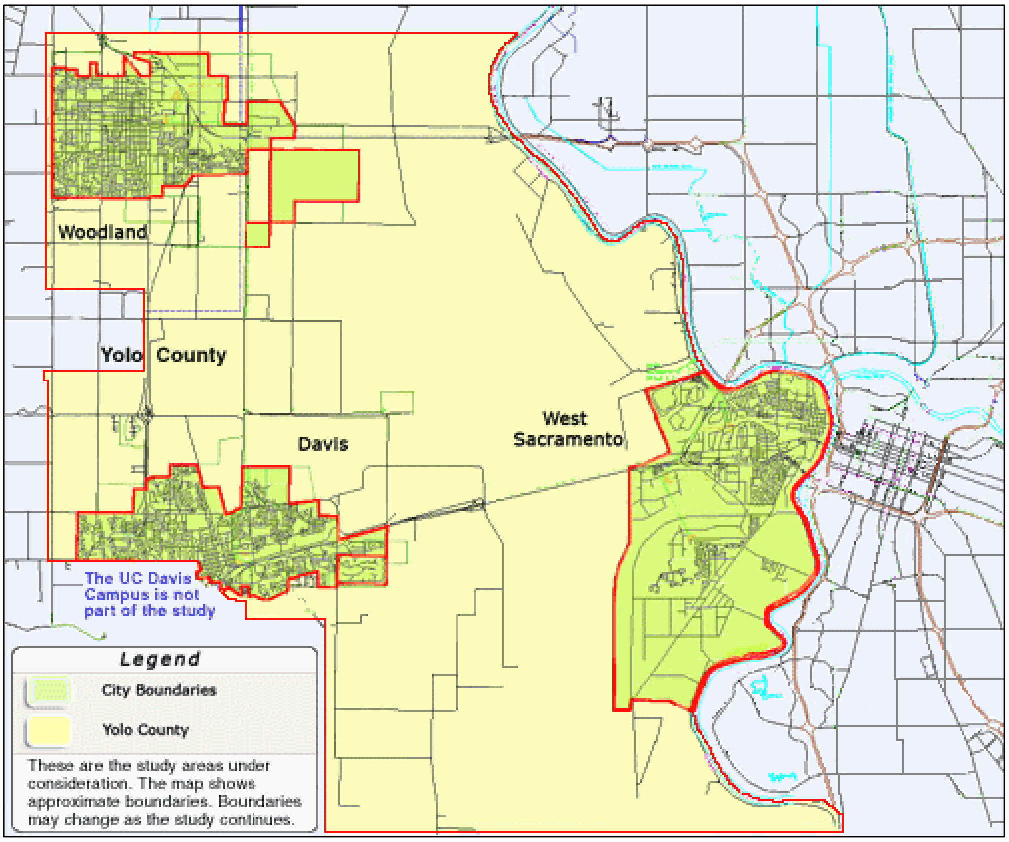
Introduction

In March 2004, the team of R. W. Beck, Inc. (R. W. Beck), Stone & Webster Management Consultants, Inc. (Stone & Webster), and Lucy & Company (Lucy & Co.) (the Study Team) was engaged by the Sacramento Municipal Utility District (SMUD); the Cities of West Sacramento, Davis and Woodland; and the County of Yolo (the Yolo Jurisdictions) to provide an independent analysis of the feasibility of SMUD providing electric service to the Yolo Jurisdictions. The Study Area includes the entire Cities of West Sacramento and Woodland; the City of Davis, with the exception of the University of California – Davis (UC Davis), and certain parts of unincorporated Yolo County. Figure ES-1 provides a map of the Study Area. Electric service in the Study Area is presently provided by the Pacific Gas and Electric Company (PG&E). R. W. Beck was the Project Manager and lead consultant for the Study, and was responsible for the economic analysis, conclusions, and the final report. Stone & Webster was responsible for the transmission and distribution system inventory. R. W. Beck and Stone & Webster collaborated on the valuation of the PG&E system, and Lucy & Co. provided the communication plan for the Study.

Figure ES-0-1
Map of Study Area



Purpose of Study

The purpose of the Annexation Feasibility Study is to evaluate the technical feasibility of annexing all or a portion of the Study Area into SMUD's system, the cost/benefit to existing PG&E ratepayers in the Study Area if annexation were to occur, and the impact on existing SMUD ratepayers.

Technical Assessment

Transmission

SMUD transmission service to the Study Area was evaluated in four different scenarios. The transmission scenarios are based on existing facilities, so they do not exactly correspond to Yolo Jurisdictions boundaries. They do serve load in each of the identified cities and Yolo County, as identified in the Study. These four scenarios are:

1. Scenario 1: Acquisition of the areas served by the West Sacramento and Deepwater Substations, as well as the U.S. Postal Service load (Post Substation).
2. Scenario 2: Scenario 1 plus the addition of areas served by the Davis and Hunt Substations.
3. Scenario 3: Scenario 2 plus the addition of areas served by the Woodland and Woodland Poly (Mobilche) and Woodland Bio Mass Substations.
4. Scenario 4: Scenario 3 plus the addition of the area served by the Plainfield Substation (presently served at 60 kV) annexed to the proposed 115-kV SMUD system.

In summary, the PG&E transmission system in the Study Area has many undersized facilities for the amount of load served. Significant investments are needed to more reliably serve existing load and meet projected load growth. The costs of such investments, up to $27 million, are included in this Study.

The transmission analysis concludes that if (a) SMUD can secure the necessary rights-of-way and permits for new lines and (b) there is the required space for expansion at the Elverta and Hurley Substations, then it would be feasible for SMUD to provide electric service to the Cities under any of the scenarios evaluated. However, the results show that transmission Scenarios 3 and 4 identified in Section 1 are less stringent in terms of the requirements for new rights-of-way and, in general, less costly in proportion to the size of the annexed market.

Distribution

Table ES-1 shows the consolidated results of the Distribution Network Assets according to the inventory carried out for the distribution networks associated with each substation located in Davis, Woodland, Plainfield, and West Sacramento.

Table ES-1 also shows from a high-level perspective that the city of Davis (Davis Substation) has the largest distribution system followed by the city of Woodland (Woodland Substation). When considered in aggregate, the city of West Sacramento (West Sacramento and Deepwater Substations) are very close to Woodland, however, individually the system associated with West Sacramento is the third largest, Deepwater the forth, and Plainfield the fifth. Customers in unincorporated Yolo County are served in each instance; however, the largest number of unincorporated customers are served from the Plainfield Substation.

Table ES-1
Distribution Network Assets Summary

Inventory Results	West Sacramento	Deep Water	Davis	Plainfield	Woodland	Total
1. Feeders from Substation	8	2	11	2	12	35
2. Length of HV Overhead Feeders (miles)	91.0	30.4	146	68	108	443.4
3. Length of HV Underground Feeders (mi)	29.3	42.4	105	2	81	259.7
4. Poles	2,655	846	3,571	1,348	2,580	11,000
5. Overhead Distribution Transformers	1,041	309	1,007	362	1,314	4,033
6. Subsurface or Pad Mounted Transformer	301	382	1,088	17	779	2,567
7. Length of LV circuits (miles)	18.2	25.0	83	4	51	181.2
8. Service Drops	4,821	6,747	15,580	1,126	12,408	40,682
9. Pole's Risers	174	49	213	11	226	673
10. Switches	227	76	344	53	312	1,012
11. Voltage Regulators	1	0	3	2	6	12
12. Capacitor Banks Overhead type	36	12	48	8	72	176
13. Capacitor Banks Pad Mounted type	4	0	6	0	3	13

The distribution feeder analysis identified numerous feeders that do not comply with SMUD's criteria for voltage reliability. The total investment required to correct these deficiencies is expected to be approximately $255,000 and has been included in the analysis.

Separation

An analysis was performed to determine the best separation points from the PG&E system in terms of reliability and investment. These points are needed to create clear separation from the PG&E and SMUD systems for system operation, safety, reliability, and accounting purposes. Areas served by the West Sacramento and Deepwater Substations are relatively easily separated from the PG&E system. Separation of Davis poses a more difficult problem due to the UC Davis Substation and considerable rural load to the north and south of Davis. Separation of Davis would require a minimum of 7 metering points and a maximum of 10, depending on the solution for Feeder 1107 south of Davis.

Separation of Woodland requires 7 metering points, but could be reduced to 5 if Plainfield Substation is not acquired. If Davis and Woodland are both included in the annexation, it is recommended that the Plainfield Substation be included in the annexation.

Depending on the area acquired, the separation and metering points will vary. These scenarios are identified in detail in Section 1, Technical Assessment.

Distribution Investments

Projected power flow cases were run for each substation in the Study Area for the years 2006, 2008, and 2013. Two separate service scenarios were considered to reliably meet the projected load. The first scenario assumed no new substations and was estimated to cost approximately $15 million. The second scenario considered the addition of new substations in Davis and Woodland at a total cost of approximately $18 million. Scenario 2 is the preferred alternative due to reliability criteria and was used in the analysis.

Finally, allocations were made for the renewal and replacement of existing facilities.

Valuation

There are three generally accepted approaches to estimating the value of property: the cost approach, the income approach and the market approach. Under the cost approach, the value of the property is based on the premise that an informed buyer would pay no more than the cost of producing a substitute property with the same utility as the subject property. Under the income approach, the value of the property is estimated by capitalizing or determining the present worth of the prospective net income from the property. The market approach assesses value based on recent fair market sales of similar facilities under similar circumstances.

Indicators of value were estimated based on the cost and income approaches to value. The market approach is difficult to apply in valuing utility property due to the lack of utility sales transactions that are comparable to the Study Area and thus was not relied upon in this Study.

Two indicators of value that are commonly considered when valuing electric transmission and distribution facilities under the cost approach are the Original Cost Less Depreciation (OCLD) value and the Reproduction Cost New Less Depreciation (RCNLD) value of the property. OCLD is defined as the original cost of the property when it was first put into service, less accrued depreciation. The OCLD value is an estimate of the net book value of the property, which is generally equivalent to the rate base value of the property for ratemaking purposes. RCNLD is defined as the cost of constructing an exact replica of the property at current prices with the same or closely related materials, less accrued depreciation. The RCNLD and OCLD values tend to set the upper and lower limits, respectively, on the range of fair market value for electric transmission and distribution facilities.

The income approach estimates the value of property by capitalizing or determining the present worth of anticipated economic benefits form the property as a going concern. Both the direct capitalization of income and discounted cash flow methods were used to estimate the value of the distribution systems under the Income Approach.

the Cost Approach provides the best indication of the range of value for the specific facilities that would be acquired by SMUD and any stranded assets identified in the Technical Assessment section of this Study. In theory, the income value for regulated utility property should be equal to its rate base value, which is generally equivalent to the OCLD value of the property. The income indicators of value developed in this study for the distribution systems tended to support the lower end of the range of value between OCLD and RCNLD.

Based on our experience with utility sales and acquisitions, the purchase price for regulated utility property generally is in the range between OCLD and RCNLD, with depreciation calculated using the straight line method of depreciation. These values are summarized by scenario in Table ES-2.

Table ES-2
Estimated Range of Purchase Prices
(Distribution and Transmission Facilities)

Scenario	Low Value (OCLD)	High Value (RCNLD)
West Sacramento Only	$19,217,580	$32,852,736
West Sacramento and Davis	$43,115,143	$74,431,012
W. Sac., Davis and Woodland	$54,673,628	$104,697,714
All Areas	$,56,108,472	$107,973,864

Source: Table 2-1

In our opinion, the fair market value of the electric distribution and transmission facilities that would be acquired in each scenario is equal to or close to the OCLD value of the range of purchase prices shown above. However, the RCNLD value of the facilities is a reasonable and conservative estimate of the purchase price to use in evaluating the economic feasibility of SMUD annexing all of a portion of the electrical facilities serving the Yolo Jurisdictions. In order to keep with the conservative use of estimates in the Study, the high-end RCNLD value was used in the economic analysis.

Economic Analysis

Approach

The approach employed in the Study was to calculate the cost to serve the Yolo Jurisdictions individually and collectively. Because of the existing transmission configuration in Yolo County, an incremental approach was used, essentially working out from the existing SMUD system from the east to the west. Therefore, in the scenarios where there are transmission facilities provided by SMUD, the analysis was done incrementally. First, the Study Team evaluated service to West Sacramento, then West Sacramento and Davis, and finally, West Sacramento, Davis, Woodland and Yolo County. Since Woodland is at the far northwest end of the Study Area, unincorporated Yolo County was included with Woodland. There are small amounts of Yolo County customers included in the West Sacramento and Davis Scenarios, since the Study was based on existing electrical feeders, not geographic boundaries. With the same caveat, in the cases where transmission service from the California Independent System Operator (CAISO) was considered it was possible to evaluate each of the Yolo Jurisdictions independently. In these cases, the Study Team ran analyses for West Sacramento, Davis, Woodland and Yolo County, followed by cases with West Sacramento and Davis, and West Sacramento, Davis, Woodland and Yolo County. These Base Case Scenarios are summarized as follows:

Base Case Scenarios Analyzed

SMUD Builds Transmission

1. West Sacramento
2. West Sacramento and Davis
3. West Sacramento, Davis, Woodland and Yolo (portion) "All Region"

CAISO Transmission Reliance

4. West Sacramento
5. Davis
6. Woodland and Yolo (portion)
7. West Sacramento and Davis
8. West Sacramento, Davis, Woodland and Yolo (portion) "All Region"

Methodology

Since it would neither be in the interest of existing PG&E ratepayers in the potential annexation area or in the interest of existing SMUD ratepayers if the analysis were overly optimistic in terms of underlying assumptions, The Study Team employed reasonable, yet relatively conservative assumptions, as described throughout the Study. The Study quantifies the economic impact on current PG&E customers in the potential annexation areas, including the identification of potential surcharges above standard SMUD rates in order to have no impact on existing SMUD customers.

The methodology employed to determine the economic viability of the potential annexation included a systematic review of facilities and potential costs in order to quantify revenues, operating expenses, initial investments, and ongoing improvements associated with the electric utility facilities in the Study Area. The estimated cost to serve customers in the Study Area was developed through a bottoms-up approach to determine the rate that SMUD would need to charge in order to assure that its existing ratepayers would not subsidize service to the Yolo Jurisdictions. Costs included in this methodology include, but are not limited to, the cost of acquisition, improvements needed to serve the area, cost of separation from PG&E, power supply cost, operating and maintenance cost, administrative and general cost, franchise fees, property taxes, applicable non-bypassable charges, and renewals and replacements.

The total of all costs result in an average revenue requirement for the applicable Study Area. This revenue requirement, expressed on a $/kWh basis, is compared to both the

PG&E average Rate Revenues and the SMUD average Rate Revenues for the area under study. If the Basic Revenue Requirements were found to be higher than the SMUD Rate Revenues, the revenue shortfall is included in the "surcharge" in order to cover the amount above the existing SMUD Rate Revenues. If SMUD Rate Revenues exceed the Basic Revenue Requirement, revenue surplus is applied as a credit when calculating the surcharge. Figures ES-2 and ES-3 illustrate the comparison of the basic revenue requirement to PG&E's rate revenues and the corresponding surcharge and savings that would apply. Depending on the scenario, this surcharge could last anywhere from five years to the entire life of the Study (20 years). For each scenario studied, savings are calculated on an annual basis in dollars and percent and on a Net Present Value (NPV) basis over the life of the Study period. A detailed discussion of the Methodology employed appears in Section 3 of this Study.

Figure ES-2
Basic Breakeven Revenue Requirements

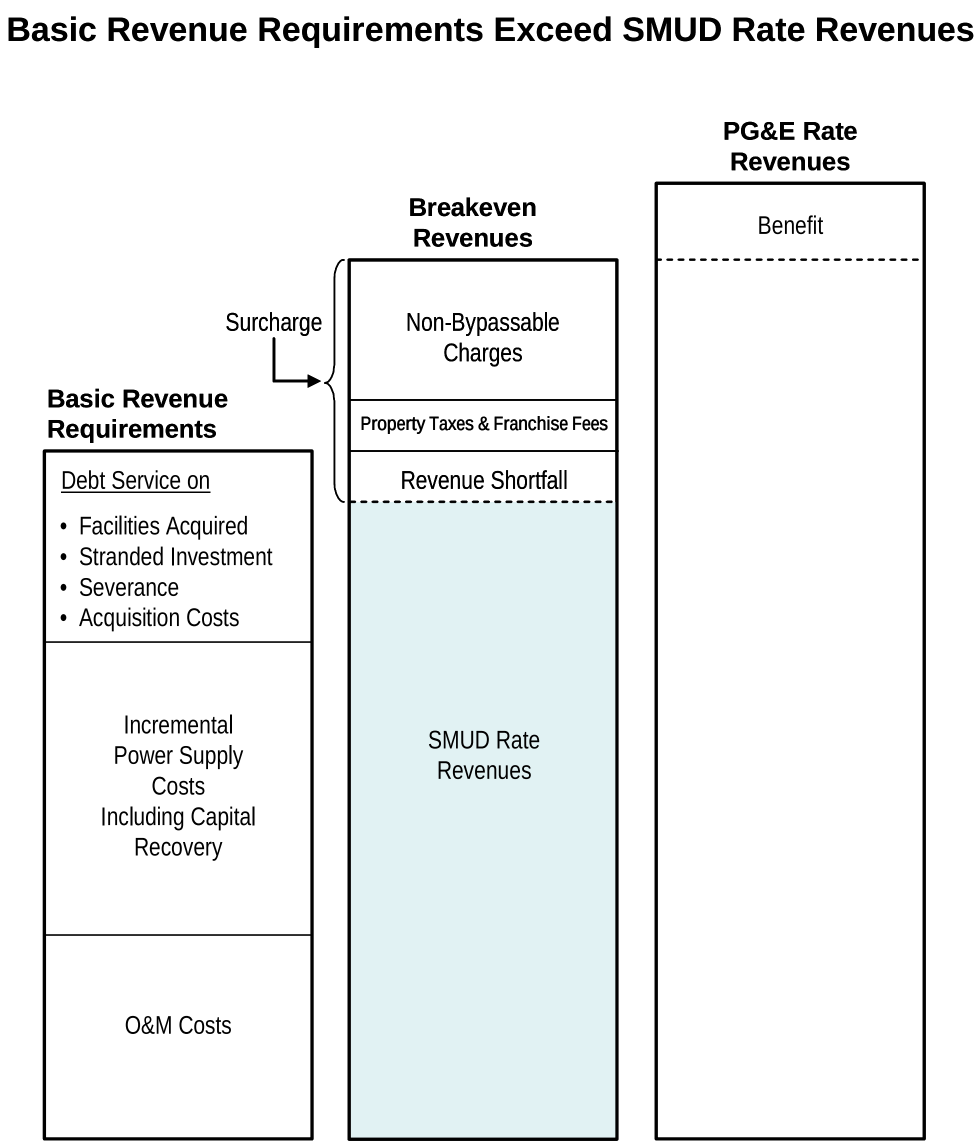
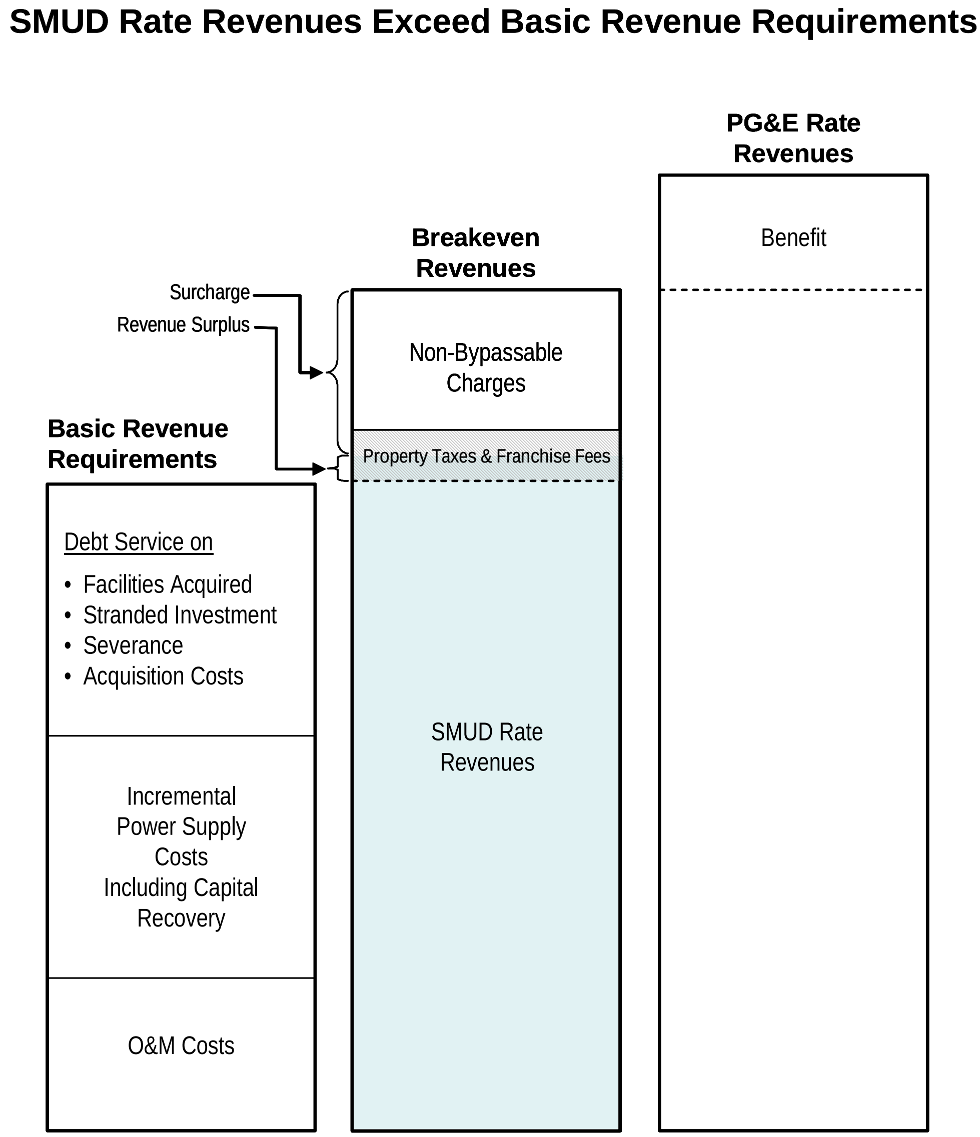


Figure ES-3
Breakeven Revenue Example 2



Rate Comparisons

One of the key measures in the analysis is the comparison of rates between PG&E and SMUD. Figures ES-4 shows a historical system average comparison of this rate relationship. Over the last 15 years, SMUD has maintained system average rates approximately 20% below those of PG&E. SMUD estimates that its rates will be 23% below PG&E, including its proposed 6% rate increase in 2005.

The conservative assumptions contained in this Study show this relationship, using Yolo Jurisdiction usage data, shrinking over time to about an 8% difference, as indicated in Figure ES-5. To the extent that SMUD can continue to effectively maintain a larger margin, the annexation savings would be enhanced and the amount of the surcharge diminished towards the end of the Study period.

Figure ES-4
Historical System Average Rate Comparison
SMUD versus PG&E

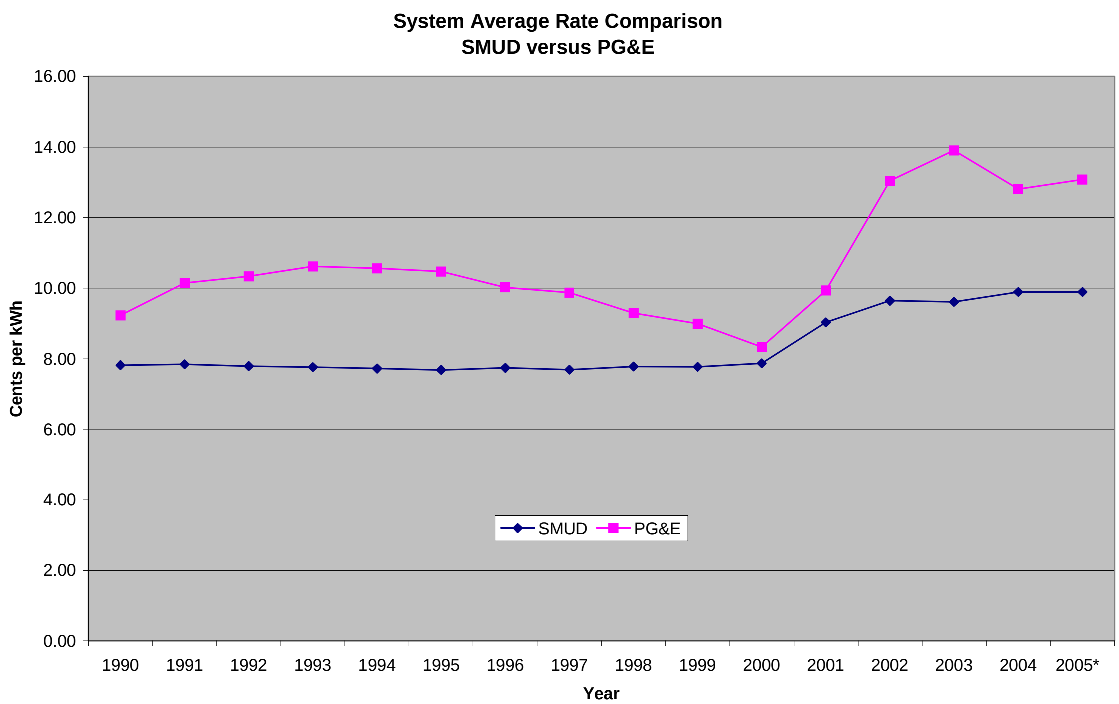
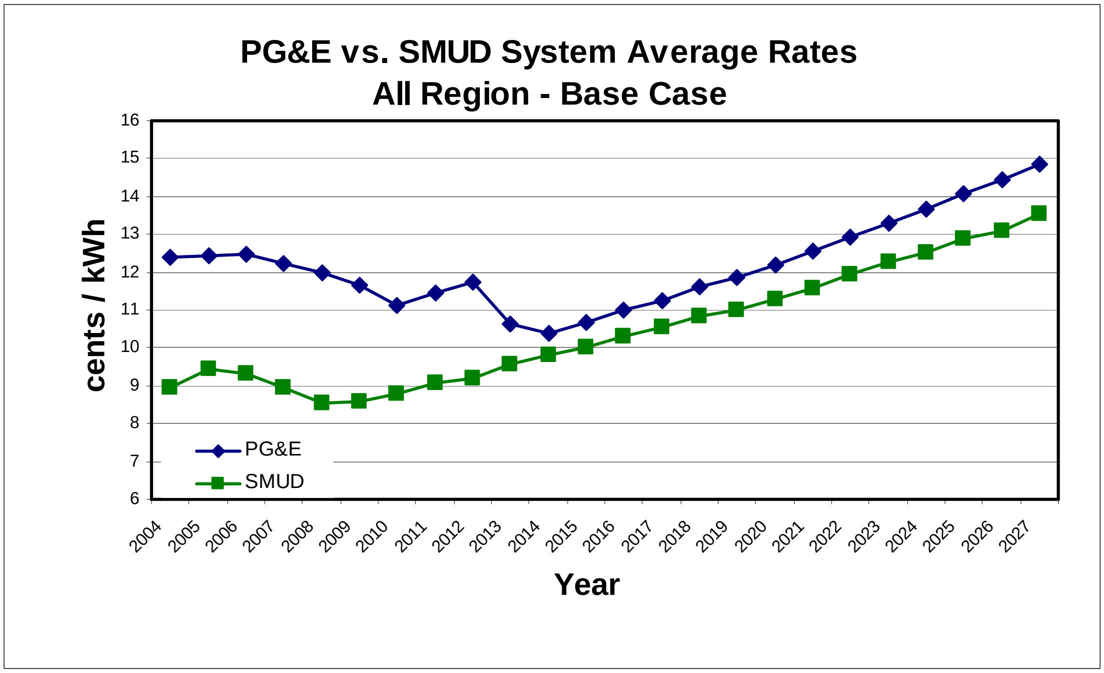


Figure ES-5
Forecasted PG&E vs. SMUD System Average Rates, All Region



General Guidelines for Evaluation of Results

The analysis of the Base Case and the scenarios are based upon guidelines that the Study Team has considered in terms of making findings and recommendations. In general, these are:

- Positive or neutral impact (in terms of rates charged, and reliable service) for existing PG&E customers in the Study Area
- Positive or neutral effect of annexation on existing SMUD ratepayers, again in terms of rates charged. No degradation of reliability of service to existing SMUD customers
- Positive NPV to existing PG&E ratepayers in the Study Area and existing SMUD customers

Alternatives and Scenarios not meeting these criteria would not likely to be approved by either the Yolo Jurisdictions or SMUD.

Results

Base Case – Transmission Build Option

Three Base Case Scenarios were run assuming that SMUD builds the transmission facilities identified in Section 1. These include (1) West Sacramento; (2) West Sacramento and Davis; and (3) West Sacramento, Davis, Woodland, and Yolo County (All Region). Table ES-3 below presents a summary of these results. The Base Case–Transmission Build Option assumes an acquisition cost based on Replacement Cost New Less Depreciation (RCNLD), the most conservative and highest cost acquisition option. The Study Team believes that a much lower acquisition price based on Original Cost Less Depreciation (OCLD) is justified.

Table ES-3
Base Case – Transmission Build Option Results

	Base Case	NPV Savings $000	Average Surcharge ¢/kWh	Surcharge Range ¢/kWh	Savings
1	West Sacramento	$6,712	1.18¢	0.52–2.83¢	0.95%
2	West Sacramento & Davis	$10,641	1.39¢	0.79–2.78¢	0.94%
3	All Region	$87,046	1.01¢	0.35–2.52¢	4.27%

There are two important items to note in the Transmission Build option. Essentially, a similar amount of transmission investment is needed to serve just West Sacramento and Davis as the entire Study Area. Finally, it is important to note that the rate for the Study Area applies the Cost Responsibility Surcharge (CRS) to all customers served in each scenario, except those in Davis. Since the cost to build transmission to Davis is high and the Davis load profile produces less revenue per customer due to the amount and type of residential load, it is actually both beneficial and equitable to bundle their rate (including their CRS credit) with the other jurisdictions. The estimated base case savings for the entire study area are 4.27% below PG&E rates over the life of the study. In this case, a rate surcharge of approximately 1.01¢ would be needed to cover breakeven revenues over the life of the Study. The surcharge is as high as 2.52¢ per kWh and as low as 0.35¢ per kWh.

Base Case – CAISO Option

In order to evaluate each of the cities separately and to be able to allocate the total savings from Davis's avoidance of the CRS to Davis customers, options were run that assume that transmission service is purchased from the CAISO. In these cases, it is not necessary for SMUD to build transmission to physically serve these customers. Instead, transmission service is purchased from the CAISO under existing tariffs. It is important to note that this option may not be acceptable to SMUD. SMUD has recently formed its own Control Area in order to better manage its facilities and resources, and avoid exposure to negative operational and price impacts from CAISO. This includes the cost of scheduling and dispatching resources through the CAISO, as well as exposure to other CAISO fees. Before seriously considering any of these options for implementation, it would be in the interest of the Yolo Jurisdictions to understand the reliability of service implications and to know if the CAISO option is acceptable to SMUD. As discussed later in this report, much of the service presently provided in the Study Area does not meet SMUD criteria for reliability and significant improvements are needed to meet SMUD's existing reliability criteria. This presents yet another reason why SMUD may not find the CAISO option acceptable.

Table ES-4 presents a summary of the results of the Base Case CAISO options.

Table ES-4
Results of Base Case CAISO Options

	Base Case	NPV Savings $000	Average Surcharge ¢/kWh	Surcharge Range ¢/kWh	Savings
4	West Sacramento	$6,453	1.18¢	0.55–2.83¢	0.91%
5	Davis	$20,389	1.28¢	0.85–2.20¢	4.80%
6	Woodland & Yolo	$57,408	0.79¢	0.07–2.43¢	6.33%
7	West Sacramento & Davis	$23,117	1.26¢	0.69–2.62¢	2.04%
8	All Region	$84,181	1.03¢	0.40–2.52¢	4.13%

Since the Davis customers are able to avoid the CRS under this CAISO option, in this case, the savings are largest for the Davis Only Scenario.

Sensitivity Analyses

In addition to the base case scenarios, other options were studied in order to test major assumptions for sensitivity. Cases were run assuming a 20% increase and decrease in power market prices from the base case. In addition, the acquisition cost was tested using the OCNLD methodology. In total, more than 32 scenarios were run. Given the number and complexity of the scenarios that were run, not every one is included in the analysis. Certain of the scenarios are described in greater detail in Section 3 in order to present the results of the analysis under differing conditions. In order to make it easier for those interested in only one City, or combination of Cities, there are tables in this section which provide the results in this fashion. The sensitivity scenario analyses in the order run are as follows:

Table ES-5
Comparison of Sensitivity NPV Costs/Savings

Scenario	Scenario Description	NPV ($000) (Costs) Savings	% (Cost) Savings
9	West Sacramento, Build, High Market	$(15,753)	-2.04%
10	West Sacramento & Davis, Build, High Market	$(27,048)	-2.20%
11	All Region, Build, High Market	$21,434	0.97%
12	West Sacramento, CAISO, High Market	$(16,011)	-2.08%
13	Davis, CAISO, High Market	$5,172	1.13%
14	Woodland & Yolo, CAISO, High Market	$29,477	3.00%
15	West Sacramento & Davis, CAISO, High Market	$(14,572)	-1.19%
16	All Region, CAISO, High Market	$18,569	0.84%
17	West Sacramento, Build, Low Market	$26,265	4.09%
18	West Sacramento & Davis, Build, Low Market	$48,048	4.65%
19	All Region, Build, Low Market	$133,135	7.15%
20	West Sacramento, CAISO, Low Market	$27,548	4.29%
21	Davis, CAISO, Low Market	$35,489	9.06%
22	West Sacramento & Davis, CAISO, Low Market	$60,524	5.86%
23	Woodland & Yolo, CAISO, Low Market	$62,616	7.55%
24	All Region, CAISO, Low Market	$134,957	7.24%
25	All Region, OCLD, Build	$143,634	7.05%
26	All Region, OCLD, CAISO	$127,869	6.27%
27	All Region, Most Savings, Build	$154,659	8.30%
28	All Region, Most Savings, CAISO	$151,452	8.13%
29	All Region, Least Savings, Build	$(13,738)	-0.62%
30	All Region, Least Savings, CAISO	$195	0.01%
31	All Region, PG&E Power Supply Adjustment	$124,205	5.99%
32	All Region, New Customer Additions Adjustment	$105,413	5.17%
33	West Sacramento, PG&E Regular Residential Prices	$25,061	3.45%
34	Davis, PG&E Regular Residential Prices	$50,929	11.25%
35	Woodland & Yolo Reg. Residential Prices	$56,071	6.18%

Results

In this section the results are presented for each of the Yolo Jurisdictions. For each entity a table is presented that contains the various scenarios from highest cost, or least savings as the case may be to highest savings. The (cost) savings are the amounts calculated over the life of the study in 2008 dollars. The scenario analysis is skewed toward higher savings, since the basic underlying assumptions employed in the analysis were very conservative in nature (i.e., use of high-end acquisition cost and addition of substantial capital improvements).

The Descriptions used in the summary table have the following meanings:

Table ES-6
Summary of Descriptions

Base	Base Case
Build	Build Transmission
CAISO	CAISO Transmission Service
&	With Identified City
All Region	Entire Study Area
High Market	Market Price + 20%
Low Market	Market Price – 20%
Least Savings	RCNLD Present Worth Depreciation, High Market
Largest Savings	OCLD, Low Market

West Sacramento

The results for West Sacramento range from an increase (cost) of 2.20% under the Build Transmission Scenario with Davis, with an increase in power market prices of 20% above the base case to a decrease of 9.06%, assuming the CAISO Low Market Scenario with Davis. The All Region Base Case provides a savings of 4.27% over the life of the Study.

Table ES-7
West Sacramento

Case	Description	% (Costs) Savings Relative to PG&E
10	& Davis, Build, High Market	-2.20%
12	CAISO, High Market	-2.08%
9	Build, High Market	-2.04%
15	& Davis, CAISO, High Market	-1.19%
29	All Region, Least Savings, Build	-0.62%
30	All Region, Least Savings, CAISO	0.01%
16	All Region, CAISO, High Market	0.84%
4	Base, CAISO	0.91%
2	& Davis, Base, Build	0.94%
1	Base, Build	0.95%
11	All Region, Build, High Market	0.97%
7	& Davis, Base, CAISO	2.04%
33	Regular Residential Prices, CAISO	3.45%
17	Build, Low Cost	4.09%
8	All Region, Base, CAISO	4.13%
3	All Region, Base, Build	4.27%
20	CAISO, Low Cost	4.29%
18	& Davis, Build, Low Market	4.65%
32	All Region, New Customer Additions @ 20%, Build	5.17%
31	All Region, PG&E Power Supply Adjusted, Build,	5.99%
26	All Region, OCLD, CAISO	6.27%
25	All Region, OCLD, Build	7.05%
19	All Region, Build, Low Market	7.15%
24	All Region, CAISO, Low Market	7.24%
28	All Region, Largest Savings, CAISO	8.13%
27	All Region, Largest Savings, Build	8.30%
21	& Davis, CAISO, Low Market	9.06%

Davis

There is a greater range of results for Davis due to their exemption from the CRS charge. The only negative cases are those in which market prices are 20% above the base case. The CAISO transmission service scenario with service along with West Sacramento is projected to cost 2.20% more than PG&E over the life of the study. The greatest savings scenario (11.15%) for Davis is under the CAISO scenario with PG&E system average residential revenues.

Table ES-8
Davis

Case	Scenario Description	% (Costs) Savings Relative to PG&E
10	& West Sacramento, Build, High Market	-2.20%
15	& West Sacramento, CAISO, High Market	-1.19%
29	All Region, Least Savings, Build	-0.62%
30	All Region, Least Savings, CAISO	0.01%
16	All Region, CAISO, High Market	0.84%
2	& West Sacramento, Base, Build	0.94%
11	All Region, Build, High Market	0.97%
13	CAISO, High Market	1.13%
7	& West Sacramento, Base, CAISO	2.04%
8	All Region, Base, CAISO	4.13%
3	All Region, Base, Build	4.27%
18	& West Sacramento, Build, Low Market	4.65%
5	Base, CAISO	4.80%
32	All Region, New Customer Additions @ 20%, Build	5.17%
22	& West Sacramento, CAISO, Low Market	5.86%
31	All Region, PG&E Power Supply Adjusted, Build,	5.99%
26	All Region, OCLD, CAISO	6.27%
25	All Region, OCLD, Build	7.05%
19	All Region, Build, Low Market	7.15%
24	All Region, CAISO, Low Market	7.24%
28	All Region, Largest Savings, CAISO	8.13%
27	All Region, Largest Savings, Build	8.30%
21	ISO, Low Market	9.06%
34	Regular Residential Prices, CAISO	11.15%

Woodland and Yolo County (Portions)

Due to the geography, being furthest removed from the existing SMUD service area, there are the fewest number of scenarios for Woodland and portions of Yolo County. However, almost all of the cases studied resulted in savings. The one negative savings scenario, -0.62%, was the All Region Least Savings Build Transmission Case. The greatest savings (8.30%) occur in the All Region Largest Savings Build Transmission Case.

Table ES-9
Woodland and Yolo County

Case	Scenario Description	% (Costs) Savings Relative to PG&E
29	All Region, Least Savings, Build	-0.62
30	All Region, Least Savings, CAISO	0.01%
16	All Region, CAISO, High Market	0.84%
11	All Region, Build, High Market	0.97%
14	CAISO, High Market	3.00%
8	All Region, CAISO, Base	4.13%
3	All Region, Build, Base	4.27%
32	All Region, New Customer Additions @ 20%, Build	5.17%
31	All Region, PG&E Power Supply Adjusted, Build,	5.99%
35	Regular Residential Prices, CAISO	6.18%
26	All Region, OCLD, CAISO	6.27%
6	Base, CAISO	6.33%
25	All Region, OCLD, Build	7.05%
19	All Region, Build, Low Market	7.15%
24	All Region, CAISO, Low Market	7.24%
23	CAISO, Low Market	7.55%
28	All Region, Largest Savings, CAISO	8.13%
27	All Region, Largest Savings, Build	8.30%

Other Considerations

In addition to the economic evaluation, there are a number of factors that are difficult or impossible to quantify with respect to annexation, but are important distinctions worth noting. These factors are addressed in greater detail in Section 4 and include:

- **Structural Financial Differences Between PG&E and SMUD** — Structural financial differences include the fact that PG&E profits are paid to stockholders, whereas SMUD either reinvests in their system or lowers their rates to create a return to ratepayers. SMUD is exempt from state and federal income taxes, property taxes, and franchise fees, where PG&E is not, and SMUD's cost of capital is lower than PG&E's.
- **Regulation** — SMUD is generally self-regulated, providing for a more open process of public participation in deliberation and decision-making. SMUD directors are elected and accountable to their constituents. PG&E is regulated by the CPUC. PG&E's regulatory decisions are generally made system-wide leaving little room for addressing local issues. PG&E is not required to make much of its data and records available to the public.
- **Reliability** — The design criteria employed by SMUD provides for greater reliability of electric service. This criteria both reduces the likelihood of outages and results in less time to restore service when an outage occurs.

Structure of Annexation Study Report

The Annexation Feasibility Study is comprised of four major sections. These sections are:

- **Section 1, Technical Assessment**: Section 1 addresses the inventory of PG&E facilities in the Study Area, the condition of these facilities, and identifies the alternatives for potential SMUD service to Yolo County.
- **Section 2, Valuation**: In this section of the Study, indicators of value for the facilities are estimated based on the Original Cost Less Depreciation (OCLD), Reproduction Cost New (RCN) less Depreciation (RCNLD), and the Income approaches to valuation.
- **Section 3, Economic Evaluation**: This section describes the approach, methodologies, and assumptions employed in the development of the analysis. The section also includes the scenario analyses.
- **Section 4, Other Considerations**: Section 4 identifies a number of factors that are difficult or impossible to quantify with respect to the annexation, but need to be considered nonetheless.

Section 1
TECHNICAL ASSESSMENT

Section 1 of the Study contains a discussion of the transmission and distribution facilities in the Study Area, their condition, and investments that would be needed for service from SMUD.

1.1 Transmission

1.1.1 Introduction

This section of the Report provides an estimate of the transmission system investments that would be required for SMUD to provide electricity service to the Cities of Davis, West Sacramento and Woodland, as well as the intervening areas of Yolo County.

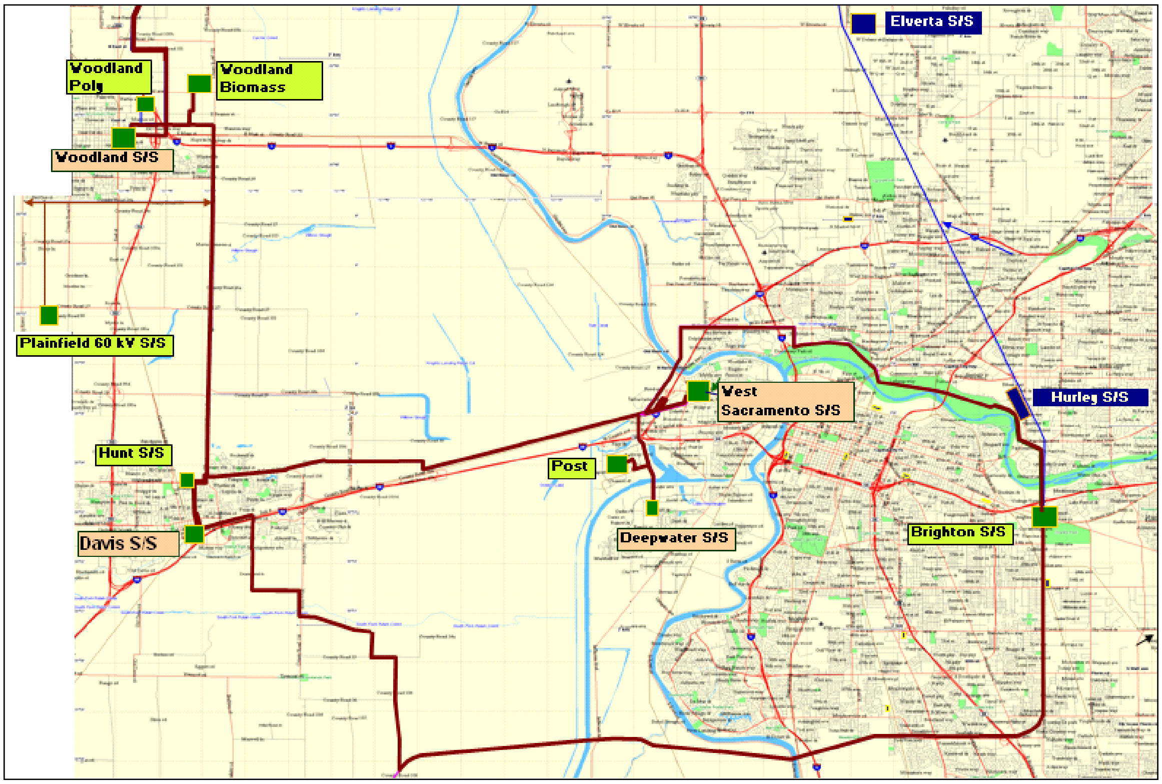
Figure 1 (in Appendix A) contains a one-line diagram of the existing PG&E system for the area under study. PG&E's 115-kV and 60-kV lines are included in the analysis. In addition, a location map is provided on the next page.

The transmission system was evaluated based on SMUD acquiring four specific areas or loads within the Study Area. These four scenarios are:

1. Scenario 1: Acquisition of the areas served by the West Sacramento and Deepwater Substations, as well as the U.S. Postal Service load (Post Substation).
2. Scenario 2: Scenario 1 plus the addition of areas served by the Davis and Hunt Substations.
3. Scenario 3: Scenario 2 plus the addition of areas served by the Woodland and Woodland Poly (Mobilche) and Woodland Bio Mass Substations.
4. Scenario 4: Scenario 3 plus the addition of the area served by the Plainfield Substation (presently served at 60 kV) annexed to the proposed 115-kV SMUD system.

As presented below, there are significant investments associated with all these scenarios as a result of both the acquisition as well as serving the load growth forecasted by PG&E for the area. This report makes the distinction of the cause of the investment whenever appropriate.

Figure 1-1
Location Map for the Study Area



1.1.2 Transmission System Description

The SMUD 230-kV transmission system is interconnected with the PG&E system at two eastern locations (Elverta and Hurley); however, the SMUD and PG&E 115-kV, 69-kV, and 60-kV systems are not interconnected. This fact necessitates building and rerouting several 115-kV lines to achieve effective separation.

The present 115-kV system Study Area is tied to PG&E's Rio Oso and Brighton 230-kV Substations via three lines and two lines respectively. There is also limited back-up capability from the 230/115-kV Vaca-Dixon substation by closing the switches at Zamora Substation, and at Davis by closing into the Vaca-Dixon 60-kV system. The 60-kV system that supports the load at Plainfield is connected to the East Nicolaus Substation (line operated open) and Vaca-Dixon Substation.

Four power flow cases for the years 2004, 2006, 2008, and 2013 were run. The 2004 case was developed for operational studies focusing on the SMUD and Roseville area loads but not on the PG&E loads. The other three cases were developed for extended heat storm weather conditions that have a probability of occurrence of about 10% in each year. All four power flow cases represent the full-loop Western Electricity Coordinating Council (WECC) electric system. The only change made to this system in all four cases was to take the 25-MW Woodland Biomass generator out of service to represent a more demanding situation from the point of view of power imports. With the Woodland Biomass generator in service there would be reduced line loadings and increased voltage support. To account for this loss of 25 MW, the output at Belden – a northern power plant – was increased.

1.1.3 Criteria

The SMUD criteria, "Reliability Criteria for Transmission System Planning," dated February 21, 1995, were utilized in the study of the existing system (Study Area system without transfer to SMUD), and for the four scenarios involving transfer to SMUD. In simple terms the criteria indicate that for all lines in service, the normal line rating shall not be exceeded. For single contingency conditions, the emergency rating shall not be exceeded. The power flow contained these ratings as Rating A (normal) and Rating B (emergency). In addition, the voltage at any bus during a single contingency shall not be below 95.0% of its nominal voltage.

While all of the high voltage lines within WECC were monitored to ensure compliance with the criteria, they did not specifically address any additional constraints that SMUD may have from a Control Area Perspective. In simpler terms, this report focuses on the local area transmission system thermal overload performance under single contingency conditions. It does not address any potential voltage instability issues that may arise under the Northern American Reliability Council (NERC)/WECC criteria that are applicable to control areas within the WECC interconnection.

Since the PG&E criteria were not made available to the Project team, the SMUD criteria were applied to the existing system for the four study years and to each of the scenarios for the four years. Only single contingency outages were applied in the Study Area. Double contingency 230-kV outages between Rio Oso and Brighton Substations and Elverta and Hurley Substations were checked to make sure that the prevailing north to south flow was not causing problems by flowing on the 115-kV system during these outages.

PG&E uses line taps at 115 kV, sometimes called multi-point lines. This practice results in multiple line outages during a fault, as relays shut down the lines in all sections. This multi-line outage remains for whatever period of time is required by the dispatcher to recognize the problem, operate remote-controlled switches, or dispatch a line crew to perform the necessary manual switching to isolate permanent faults to one line section. Several PG&E substations have tapped service, but also have a secondary line that is normally out of service. These lines must also be switched by a line crew or by a controllable switcher when the primary service goes out. SMUD does not utilize this method of service on their 115-kV system. In this study, we evaluated the impact of the simultaneous loss of multipoint lines to ensure that there were no overloads in the remaining system (beyond the emergency rating) and that the load could be supplied. However, PG&E's use of multipoint lines is inherently less reliable than SMUD's practice of point-to-point lines between substations, as it can potentially result in longer periods of time, when several substations are exposed to loss of service upon a secondary contingency. The most important multi-point lines in the Study Area are associated with the supply to the Deepwater Substation. A solution to this problem, should SMUD acquire these facilities, is identified in Appendix A of this report.

The power flow procedure employed in this Study simulated taking each line out of service – one at a time – and solving for the line loadings and bus voltages. This included each leg of a multi-section line configuration. This condition represents what the system would look like after PG&E crews switched the faulted section out of service. In addition, each line segment of a multi-section line was taken out of service simultaneously. This represents the condition immediately after a fault when the relays clear the lines. A special case was studied if a substation normally had one energized line in service with a back up line that was out of service. When the energized line was faulted and taken out service the back-up line was placed in service. This would account for all loads being served after the permanent fault was located and isolated by switching. In the case of Deepwater, the PG&E dispatcher can use a motorized switcher thus reducing the outage time. In other cases the PG&E dispatcher must send a crew to the location to accomplish the switching.

1.1.4 Existing Electric System

Figure 1 (in Appendix A) depicts the Study Area in one-line diagram format for the year 2004. The PG&E Study Area was evaluated to determine its capability to supply load for the four study years, 2004, 2006, 2008, and 2013. Additional support to the West Sacramento/Davis area would be required in about 2006 based on PG&E's forecasted load growth. A single contingency outage of the Woodland to Biomass tap 115-kV line results in loading of 117% and 143% based on the emergency rating for the two segments of the West Sacramento-Davis 115-kV line (West Sacramento to Deepwater Tap and Deepwater Tap to Davis line, respectively). The voltage at the Davis Substation drops to 0.946 per unit. A similar, but not as severe, overload results with the loss of the Biomass tap to Davis 115 kV. In this case, the West Sacramento-Davis 115 kV line overloads above its emergency rating and the voltage at Davis drops below the SMUD criteria. Figure 6 in Appendix A shows the contingency, overload lines, and the voltage problem for the loss of the Woodland to Biomass tap 115-kV line in 2006.

The current distribution system, based on power flow data, appears to have its reactive power corrected to reasonable values. Additional system support, obtained by placing capacitors at either the distribution or transmission level, is not a long-term solution. Reconductoring the lines would solve the line loading problem but because the reactance of a line is only reduced slightly when larger conductors are used (line spacing is a substantial contributor to reactance and this remains about the same with larger conductors) the voltage problem would still require a solution. Reconductoring the current PG&E system is at best a short-term solution.

There is also the need for additional support in the Davis area sometime after 2008. PG&E has proposed a Vaca-Dixon to Davis 115-kV line, but this fix would not be useful to SMUD. To solve this problem, a Hurley to Davis line would be more suitable to meet SMUD's reliability criteria. This is discussed further under the analysis of the different scenarios below.

Sometime just after 2013 there is a requirement for a line into the Woodland/Knights Landing area to reduce line loading during single contingency outage conditions. A line from the Rio Oso Substation to Woodland is one alternative that would solve the line loadings that are above criteria limits.

In summary, it can be stated that the PG&E transmission system in the Study Area has many undersized facilities for the magnitude of the load to be supported. If the area were to remain with PG&E, the company would most likely be required to construct in the long term: (a) a new line to Davis (from Brighton or Vaca-Dixon), and (b) a new Rio Oso–Woodland line. In addition, PG&E needs to reconductor the Davis to West Sacramento line in the short term.

The two most likely points to provide service to the Study Area from SMUD's system are the Hurley and Elverta Substations. Therefore, it is necessary to assess the present loading situation at those points to establish a baseline to assess the impact of the annexation.

SMUD's Elverta 230/115/69-kV Substation has two transformers rated at 130-MVA each (115-kV winding[1]). The Hurley 230-/115-kV Substation has one 230-115-kV transformer rated at 200 MVA.[2] Table 1-1 shows the loading on these transformers. This table shows that without the annexation, no new transformers are required through the Study period at either the Elverta or Hurley Substations.

Table 1-1
Transformer Loadings without the Annexation

	Elverta – 2 Banks (Total Rating 130 × 2 = 260 MVA)			Hurley – 1 Bank (Total Rating 200 MVA)		
Yr	MW	MVAr	%	MW	MVAr	%
2004	81.2	11.4	32%	123.3	20.3	62%
2006	66.0	13.9	26%	110.3	21.3	56%
2008	65.5	13.0	26%	114.2	20.7	58%
2013	55.7	11.1	26%	115.4	17.2	59%

[1] According to the one-line diagrams provided by SMUD, these transformers have one primary winding (230 kV) and two secondary windings (115 kV and 69 kV). The diagrams indicate a total transformer rating of 240 MVA, however, the load flow has a rating of 130 MVA for the 230-/115-kV transformation. Therefore, we estimate that the balance (i.e., 110 MVA) is the 230-/69-rated capacity.
[2] There are also two 230-kV/69 transformers rated at 224 MVA.

1.1.5 Potential Annexation Plans and Costs

The Study considered four potential annexation scenarios: (1) City of West Sacramento only; (2) Cities of West Sacramento and Davis; (3) Cities of West Sacramento, Davis, and Woodland; and (4) Cities of West Sacramento, Davis, Woodland and the rural areas supplied by the Plainfield Substation.

The potential expansion plans consider/account explicitly for the following:

1. For costing purposes, it is assumed that the first year of annexation is 2008.
2. The existing PG&E electric system in the study area requires immediate attention to maintain reliability using single contingency outage criteria. In the long term, there is a significant line loading problem in the Woodland area. Our studies indicate that PG&E would have to build a new 115 kV line between Rio Oso and Woodland prior to 2013 to address this condition.
3. To improve current conditions, PG&E is proposing to reconductor the Davis-Deepwater Tap-West Sacramento line. We have assumed that this happens before the annexation.
4. In addition, we have assumed that PG&E provides another source into Davis, such as a second Brighton to Davis 115 kV line or a line from Vaca-Dixon, as proposed by that company.

A summary of the facilities required for the existing PG&E system and for each scenario is presented in the following section.

One optional investment that would be common to all scenarios is the investment required to eliminate some of the multipoint lines in the system. This investment is optional in the sense that with all the facilities discussed in service, the system complies with the performance criteria, although it is less flexible and reliable. As indicated before, the most important three-point line in the system are the lines that provide service to the Deepwater Substation from the point known as Deepwater Tap (1 and 2). One option to solve this problem would be to build a double circuit line from West Sacramento to Deepwater Tap (approximately two miles), where it would connect to the double circuit line to Deepwater. In addition, it would be necessary to add two 115-kV breaker bays at West Sacramento Substation, as well as two breaker bays at Deepwater Substation. It is estimated that this additional investment would be approximately $2.3 million (assuming that the rights-of-way are available). Table 1-2 below provides additional details on this calculation.

Table 1-2
Investments to Eliminate the Three-Point Supply to Deepwater Substation

Description All lines and equipment are 115 kV, unless otherwise stated	Status	Quantity	Unit	Price	RCN
Additional					
West Sacramento - Deepwater Tap 1 & 2					
Steel poles, double circuit, 715.5 AAC Violet	New	2.00	Mi	$570,000	$1,140,000
West Sacramento Substation					
Line Breaker Bays	New	2.00	Each	$298,480	$596,960
Deepwater Substation					
Line Breaker Bays	New	2.00	Each	$298,480	$596,960
Total Investments					$2,333,920

1.1.6 Summary of Transmission Expansion Plans

Table 1-3
Case: Existing PG&E System
Description: Either Load is Not Annexed or CAISO Option is Implemented[3]

Year 2008	Year 2013
1. Build a Brighton-Davis line or Vaca-Dixon to Davis (increase voltage from 60 kV to 115 kV)	1. Build a new Rio Oso-Woodland line

[3] This option assumes that PG&E continues operating the 115 kV system, and that SMUD purchases transmission services from the CAISO to import some of the additional requirements of the annexed loads.

Table 1-4
Case: Scenario 1
Description: Annexation of the West Sacramento and Deepwater Substations, as well as the U.S. Postal Service Load (Post Substation)

Year 2008	Year 2013
1. Acquire and rearrange the Rio Oso-W.Sac line by connecting into Hurley Substation and changing the connections near I-5 intersection to form a Hurley-Deepwater-W.Sac Line 2. Construct a new line segment from Hurley to near the I-5/80 intersection to form a Hurley-Post- W.Sac Line assumed a 954 kcmil AAC conductor 3. Add two 115 kV line breaker bays to the Hurley Substation 4. Reconnect the Brighton-Deepwater Tap -W.Sac line to form a Brighton-Davis Line. 5. One side of the double circuit 115 kV line segment from a point close to Hurley to Brighton and the single line from Brighton to Rio Oso might become stranded and possibly would have to be acquired 6. One 115 kV line breaker bay at Rio Oso and one at Brighton might arguably become stranded. These bays are associated with the lines above and in our opinion PG&E could keep as reserve for further expansion and not be considered stranded 7. Acquire the 115 kV lines to West Sacramento – Deepwater Tap – Deepwater and the 115 kV tap to Post Substation. 8. SMUD would also have to acquire the West Sacramento, Deepwater and Post Substations. The cost of this is included in the distribution system acquisition cost	1. Reconductor the original Hurley-W.Sac line using 715.5 kcmil AAC conductor. Alternatively build a new line using parts of the former line W.Sac – Davis near I5 in West Sacramento that would become idle 2. PG&E to construct a new Rio Oso-Woodland line

Table 1-5
Case: Scenario 2
Description: Scenario 1 Plus Annexation of the Loads Served from the Davis and Hunt Substations

Year 2008	Year 2013
1. Acquire and connect the Rio Oso-W.Sac line into Hurley 2. Acquire and connect the Brighton-Deepwater Tap 2 – W.Sac line into Hurley 3. Acquire and connect the Brighton-Baker Junction-Davis line into Hurley. Use the segment from Hurley to Brighton of the Brighton-Deepwater Tap- W.Sac line which will become idle 4. Acquire the 115 kV lines Deepwater Tap 1&2 to Deepwater and tap to Post 5. Acquire the 115 kV line W.Sac – Deepwater Tap 1 - Davis 6. Construct a new Hurley-Davis line (22 miles 954 kcmil AAC conductor) 7. Add four 115 kV line breaker bays to the Hurley Substation 8. One side of the double circuit 115 kV line segment from a point close to Hurley to Brighton and the single line from Brighton to Rio Oso might become stranded and possibly would have to be acquired. Also the segment from Baker Junction to Baker Slough might become stranded (if a metering point cannot be arranged) 9. One 115 kV line breaker bay at Rio Oso and two at Brighton might arguably become stranded. These bays are associated with the lines above and in our opinion PG&E could keep as reserve for further expansion and not be considered stranded 10. Add a second 200 MVA transformer and necessary breakers at the Hurley Substation 11. SMUD would also have to acquire West Sacramento and Davis substations, but their cost is included in the distribution system acquisition cost	1. Reconductor the Hurley-Deepwater-W.Sac line and the Hurley-W.Sac lines using 715.5 kcmil AAC conductors. Alternatively construct a new Hurley-W.Sac line 2. PG&E to Construct a new Rio Oso-Woodland line

Table 1-6
Case: Scenario 3
Description: Scenario 2 plus the addition of the Woodland, Woodland Poly (Mobilche), and Woodland Bio Mass Substations

Year 2008	Year 2013
1. Acquire and connect the Rio Oso-W.Sac line into Hurley 2. Acquire and connect the Brighton-Deepwater Tap 2-Sacramento line into Hurley 3. Acquire and connect the Brighton-Baker Junction-Davis line into Hurley. Use the segment from Hurley to Brighton of the Brighton-Deepwater-Sacramento line, which will become idle 4. Add three 115 kV line breaker bays to the Hurley Substation 5. Acquire the 115 kV lines Deepwater Tap 1&2 to Deepwater and tap to Post 6. Acquire the 115 kV line W.Sac – Deepwater Tap 1 - Davis 7. Construct a new double circuit line from Elverta and connect into existing line Woodland-Woodland Junction (16 miles). Use at least 954 kcmil AAC and reconductor the segments of the Woodland-Woodland Junction line that might be used (approximately 2 miles) 8. Add two line breaker 115 kV bays to the Elverta Substation 9. One side of the double circuit 115 kV line segment from close to Hurley to Brighton and the single line from Brighton to Rio Oso might become stranded and would have to be acquired 10. One 115 kV line breaker bay at Rio Oso and two at Brighton might arguably become stranded. These bays are associated with the lines above and in our opinion PG&E could keep as reserve for further expansion and not be considered stranded 11. The line from Woodland to Woodland Junction might become stranded (except 2 mile salvaged in the new line to Elverta) and possibly would have to be acquired. Finally the segment from Baker Junction to Baker Slough might become stranded (unless HV metering point is arranged) 12. Add a second 200 MVA transformer and necessary breakers at the Hurley Substation 13. SMUD would also have to acquire West Sacramento, Woodland and Davis substations, but their cost is included in the distribution system acquisition cost	1. Reconductor the two Hurley-W.Sac lines using 715.5 kcmil AAC conductors. Alternatively construct a new Hurley-W.Sac line

Table 1-7
Case: Scenario 4
Description: Scenario 3 Plus the Addition of the Plainfield Substation (presently served at 60 kV) Annexed to the Proposed 115 kV SMUD System

Year 2008	Year 2013
1. Identical investments as Scenario 3 plus the investments indicated below	1. Identical investments as Scenario 3
2. Open the 115 kV line from Hunt to Woodland Bio Mass line near Plainfield. Extend a double circuit 115 kV to Plainfield	
3. Uprate Plainfield to 115 kV and provide loop service by adding two breakers a circuit switcher and a 115 kV/12 kV transformer	
4. Alternatively, given the load at Plainfield it might be justified to initially (2008) only bring one115 kV line and add switcher and transformer to the substation	
5. SMUD would also have to acquire West Sacramento, Woodland, Plainfield and Davis substations, but their cost is included in the distribution system acquisition cost	

1.1.7 Estimated Capital Costs

Table 1-8 below contains a summary of the investment costs associated with each scenario. In this table, investments are separated into the following categories: (a) facilities to be acquired from PG&E and actually used, (b) new facilities to be built, (c) stranded assets that SMUD would likely have to pay for; and (4) additional potential stranded assets (i.e., bays at Rio Oso and Brighton as well as the line to Baker Slough Pumping Station), which in our opinion should not be considered stranded, but may nevertheless be claimed as such by PG&E.

The unit cost used in the valuation reflect costs which generally were current on or about January 1, 2004 and are in line with those costs used in the valuation of the transmission and distribution inventory. However, this cost assumes that the rights of way can be secured and that there is appropriate space at the Elverta and Hurley substations to accommodate the expansions indicated in this report.

Scenarios 1 and 2 are less amenable to transmission separation than Scenarios 3 and 4. Chart 1-1 below which shows the total investment costs for the separation (Table 1-8) divided by the MVA of transformation acquired. In this ratio the MVA of transformation is considered a good proxy to the acquired market size.

Chart 1-1 shows that Scenarios 1 and 2 are significantly more expensive (per MVA basis) than Scenarios 3 and 4. This fact ratifies the convenience from a transmission perspective (non-CAISO option), of the simultaneous annexation of the three cities. Correspondingly, if only one of the cities were to be annexed, the transmission option may be too costly and the CAISO option preferred.

Finally, in Table 1-8, we note that there is the potential for significant stranded costs; however, these costs represent a different percentage of the total costs depending on the Scenario. Thus, as shown in Chart 1-2, Scenario 1 has the highest ratio of stranded cost to total (42%), while Scenario 4 has the minimum (29%). This again points towards the convenience of Scenarios 3 and 4.

Chart 1-1
Transmission Separation Cost in $ per MVA

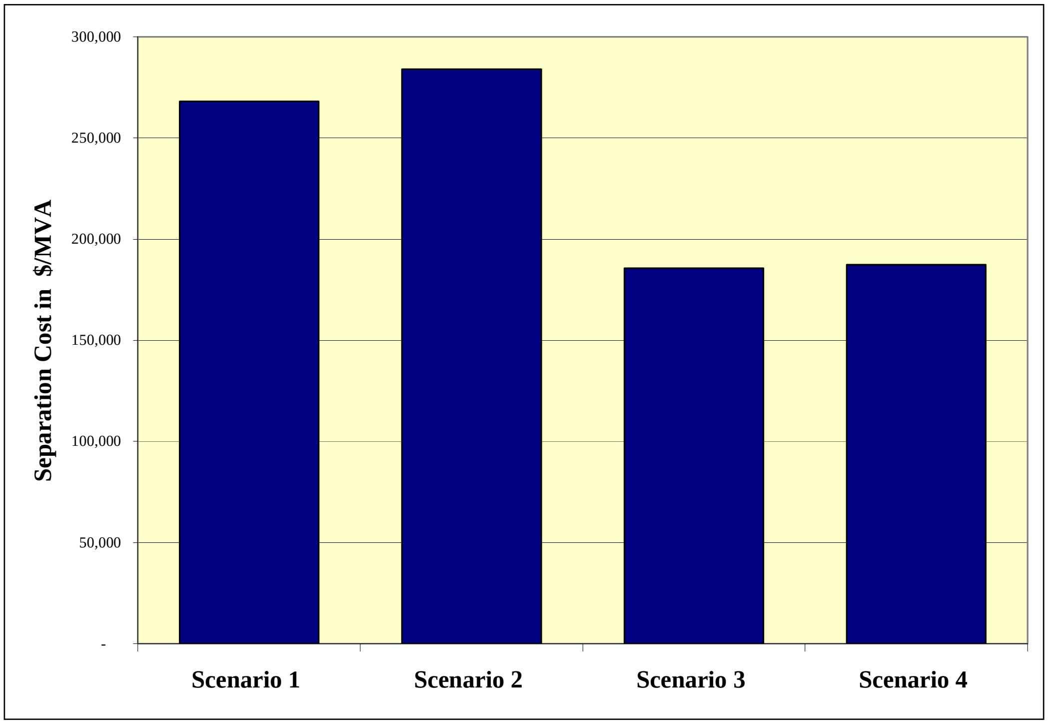
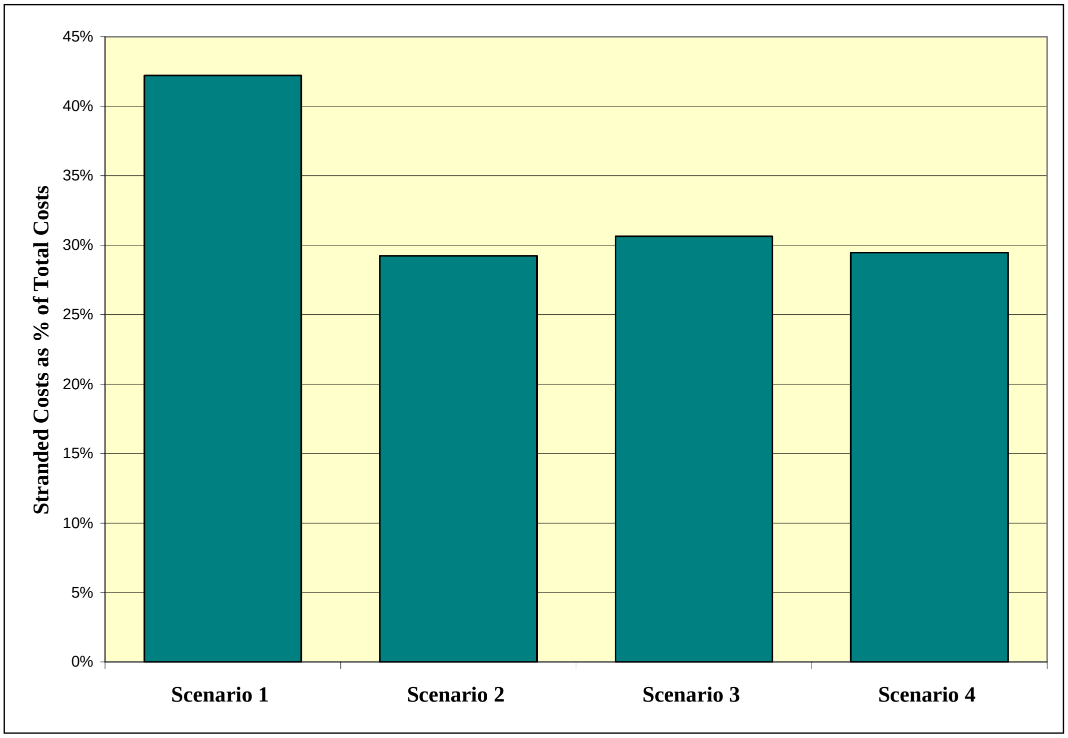


Chart 1-2
Stranded Costs as a Percentage of Total Costs



1.1.8 Conclusions

The analysis concludes that if (a) SMUD can secure the necessary rights of way and permits for new lines and (b) there is the required space for expansion at the Elverta and Hurley substations, then it would be feasible for SMUD to provide electric service to the cities under any of the scenarios evaluated. However the results also show that Scenario 3 (annexation of West Sacramento, Davis and Woodland) and Scenario 4 (Scenario 3 plus the annexation of Plainfield substation), are less stringent in terms of the requirements for new rights of way and in general less costly in proportion to the size of the annexed market.

If SMUD decides to eliminate the most important three-way lines which provide service to Deepwater in addition to the investments indicated in Table 1-8, it would be necessary to invest approximately $2.3 million in additional transmission facilities as indicated in Table 1-7.

SMUD, as a certified WECC control area, must evaluate any potential reliability impacts resulting from the increased customer load and transmission reconfiguration for each feasible scenario.

The option of having the CAISO provide the transmission service is considered in the Economic Analysis section as an alternative to acquiring and building transmission in the Study Area.

Table 1-8
Estimated Investment Costs Associated with Each Scenario
2004 Dollars

	Transmission Capital	Additional Stranded	New Capital	Total
Scenario 1				
2008	$4,877,299	$453,690	$7,806,360	$13,137,349
2013			5,500,000	5,500,000
				$18,637,349
Scenario 2				
2008	$9,0S25,664	$5,835,134	$19,969,400	$34,830,198
2013			6,424,000	6,424,000
				$41,254,198
Scenario 3				
2008	$11,077,290	$5,835,134	$17,914,696	$34,827,120
2013			6,424,000	6,424,000
				$41,251,120
Scenario 4				
2008	$11,077,290	$5,835,134	$20,799,776	$37,712,200
2013			6,424,000	6,424,000
				$44,136,200

1.2 Distribution

1.2.1 Introduction

The Distribution section presents the results on the inventory of the Distribution facilities associated with the cities of West Sacramento, Davis and Woodland as well as the rural regions of Yolo County served by feeders originating within the cities and the Plainfield substation.

This section contains a description of the methodology, describes the 12-kV Distribution Network, and offers a brief description of the substations from the point of view of connectivity with the Distribution Network facilities.

An analysis of the distribution system is also performed in order to identify immediate capital improvement needs. It also identifies options for separation from PG&E's system under several scenarios.

The Distribution section is organized in six subsections, as follows:

- Section 1.2.1, Introduction
- Section 1.2.2, Distribution Inventory Approach. In this section the general methodology used to gather the distribution network information is presented. This subsection also includes a description of the problems found and how they were addressed.
- Section 1.2.3, Inventory Results for the Distribution Networks. This subsection presents summary tables with the results of the inventory for each city and the rural areas. It also provides additional details on how the inventory was produced.
- Section 1.2.4, Distribution Network Analysis. A distribution network analysis for each city is described in this subsection. In this subsection we also present our estimation of network improvements and additions necessary to achieve compliance with SMUD system criteria with respect to voltage drop and loading criteria under the 2004 expected peak load conditions.
- Section 1.2.5, Separation Feasible Configuration. In this subsection, the feasibility of separating the different distribution networks from PG&E's system and the associated costs is examined.
- Section 1.2.6, Emerging Issues. This subsection presents a list of issues identified in the analysis that will be addressed in further detail.

1.2.2 Distribution Inventory Approach

1.2.2.1 Scope

The scope of the Distribution Inventory includes the estimation of the number and determination of the main technical characteristics of the medium and low voltage electrical assets of the cities of West Sacramento, Woodland, Davis, as well as those of the rural areas within Yolo County served from the cities and from the Plainfield Substation.

The final objective of the inventory is to present a view of the acquisition and capital cost associated with the potential annexation by SMUD.

1.2.2.2 Approach

The initial approach was to collect the information for the inventory by following each feeder and recording the data on draft maps. However, early on it was apparent that this approach was not sufficient. The density of the distribution network and the extensive use of underground facilities was larger than originally expected. The approach was adjusted by making frequent stops and walks under overhead feeders or on the sidewalk to detect the presence of underground distribution networks.

For inventory purposes, 1:5,000 scale streets maps were used as a base to prepare the distribution network draft drawings. Also, 1:1,000 scale maps were used to gather detailed information in the field. These maps were used to estimate other parameters using extrapolation from this detailed sample. For example extrapolation was used to estimate the total length of the low voltage network as well as the number of poles.

1.2.2.3 Maps Used for the Inventory

For the data gathering and recording of the inventory, Stone & Webster developed a self-consistent street map that covered all of the territory to be inventoried. The map was created based on the following drawings provided by SMUD and the local Authorities.

The Woodland, West Sacramento, and Davis files contained complete and detailed street information. However, these files did not include data on rural areas, i.e., only information inside of city limits was provided.

A new file for Yolo was created linking the city files with the rural area file. This file contained street names, lot limits, lot names, and other information.

It is important to mention that roads on the Yolo file were verified with an independent mapping source and it matched perfectly.

The area from the Yolo map was divided to get streets maps in 1:5,000 scale, and these maps were used to draw the information gathered directly on site. To generate these maps, the Yolo area was divided with a 700-millimeter × 500-millimeter grid in AutoCAD, which represents a surface of 3.5 km by 2.5 km, equivalent to 2.18 miles × 1.55 miles.

Each drawing was identified by horizontal and vertical letters of the general drawing that will be used as an index map.

Figure 1-2 shows the general index for each of the 1:5,000 scale drawings.

Figure 1-2
General Map or Index

1.2.2.4 Overhead Network Inventory

The inventory teams followed all overhead feeders. The electric network was drawn in one-line diagram form, using the roads as reference. As a result, initial overhead network draft drawings were produced.

Inside the urban areas, it was not necessary to take distance measurements between elements since the streets served as a reference. Circuit routes were drawn taking into account how close or how far they were from street corners and sidewalks. Sometimes the vehicle's odometer was used in order to calculate distances in rural areas. A GPS device was used for the transmission inventory.

The original methodology (when planning and budgeting this project) did not contemplate gathering network information on foot. In many cases, this was necessary in order to obtain adequate information on overhead and underground feeders. This improved the quality of the work.

Our crews were not provided with access to PG&E substations, so all observations were made from the outside, sometimes with the help of bucket trucks.

In many cases, overhead distribution transformers capacity could not be read, making it almost impossible to get their exact capacity. In these cases, the capacity was estimated by comparison with other units of similar size whose capacity was known. Each inventory team used the same estimation criteria to ensure consistency. However, there remains the possibility of discrepancy between estimates and the real capacity.

In some cases, distribution transformer banks contained two or more different unit sizes in which case all the available sizes were recorded. This situation was generally limited to older banks as the newer distribution transformer banks had the same capacity for each individual unit.

In all of the cities, and in Davis in particular, parts of residential overhead circuits were located in backyards. This situation combined with the existence of large trees created some problems observing the network. This may have caused our teams to miss some distribution transformer banks which could have been located behind large houses or trees. It is also possible that hot-stick cut-off fuses, hot-stick switches, or other network distribution equipment may have been missed due to the same access problem. In any case, the inventory teams always tried to minimize this kind of omission.

In Stone & Webster's opinion, the efficiency of the network distribution maintenance is negatively affected by the practice of using backyards for routing main lines and/or branches or laterals.

In many cases, there was not sufficient information (e.g., date nails or markings) on poles to determine their age. At times, it was not possible to gain access to facilities, as they were located in backyards. However, the inventory teams did find poles with information and this allowed us to estimate that the average age is in the order of 20 years. However, there is a large variation as there were poles observed as old as 45 years old and as new as three years old.

Overhead bare conductor sizes were estimated by observation and verification with PG&E standards. From these observations it was concluded that all outgoing feeders from substations use either ACSR 715 or 397 kcmils bare conductors for overhead main lines.

PG&E uses a large number of overhead capacitor banks along feeder routes. Three sizes of capacitor banks were most common; 600, 900, and 1200 kVAr. These banks are made of 100 or 200 kVAr single units combined in packs of six each to get standards capacitor bank sizes. (i.e., 6x100 to get 600 kVAr or 3X200+3x100 to get 900 kVAr etc.)

Voltage regulators or voltage boosters were observed, but their technical information could not be read from the ground. Catalog information was used to estimate whether the units were 5-step or 32-step voltage boosters.

1.2.2.5 Underground Network Inventory

Due to its nature, inventorying underground distribution networks is significantly more difficult than overhead networks. The general approach in this case was to observe the location and external characteristics of pad-mounted equipment as well as to measure underground covers of manholes and hand-holes. Based on this information, load served, and PG&E's standards, the inventory teams were able to produce a feasible underground grid which was used to complement the inventory by providing estimates for unobserved elements such as the length of cables. This aspect is discussed in greater detail in the next section.

Underground distribution transformers were classified in two types: (1) pad-mounted distribution transformers and (2) sub-surface distribution transformers. In both cases, there was no possibility of reading the transformer capacity; therefore, estimation methodologies were developed for each case.

1. For pad-mounted transformers, the capacities were estimated based on size measurements and manufacturer's information.
2. For sub-surface transformers, two sizes were adopted: 50 and 100 kVA for residential areas, and two sizes for commercial areas: 300 and 500 kVA. We selected either size based on our estimation of the load served and PG&E's standards.

Similarly, underground distribution switches were classified in two types: (1) pad-mounted distribution switches and (2) sub-surface distribution switches. In both cases, there was no possibility of reading switch information. However, in the case of pad-mounted switches, it was possible to get some information from tags to determine switches types (the majority observed were PMH 4, PMH 43, and PMH 43w). In the case of underground switches, their adopted configuration was estimated to be one, two or three way, etc., according to PG&E's standards.

It was not possible to look inside the enclosures (manholes or hand-holes), and it was not possible to gather the underground feeder routes directly from observation. Similarly, it was not possible to observe the type of ducts and sizes of underground cables. Consequently, the underground network inventory consisted of a systematic search in all sidewalks and in the areas where there was evidence of underground networks. In several cases, it was necessary to conduct multiple searches in order to find underground transformers and/or underground switches. In most of the areas having underground elements, the information was gathered on foot in order to determine the existence of an underground transformer or any other underground equipment. In almost all cases, the identification number placed by PG&E was noted and drawn as a part of the underground inventory.

It was not possible to verify if the underground or pad-mounted protection and disconnection equipment was in an open or a closed position. This also applied to unions with elbows or equipment used in joint operation.

It was not possible to verify if the subsurface or pad-mounted protection and maneuvering equipment was open or closed. This also applied to unions with elbows and "JOINT" type equipment.

1.2.2.6 Underground Distribution Network Layout Estimation

Based on the information gathered in the field, and PG&E's Design & Construction Standards, a "possible distribution network layout" for underground areas, including cable sizes, standardized switches and protection equipment, was developed. Pad-mounted transformer capacities were estimated based on external dimensions taken during the inventory work, manufacturer's specifications, and the number of customer per underground distribution transformer. Subsurface transformer capacities were estimated based on the total number of customers served.

The most relevant criteria that were adopted to estimate "best distribution network layout" are:

Industrial and Commercial Design

- All feeders had a radial configuration from an operational point of view.
- Underground high voltage cables types are 25 kV, XLP-CONC. PVC. ENCAP-Aluminum PE. Sizes 1/0, 350, 700 and 1,000 kcmils.
- Primary underground cables are installed in ducts.
- Two types of underground network transformers: (1) pad-mounted or (2) correct underground transformers.
- Underground branches or lateral feeders serving a transformer larger than 1,000 kVA are radial without any back-up branches.
- Underground branches or lateral feeders serving five or less transformers and not more than 1,000 kVA are radial without any back-up branches.
- Underground branches or lateral feeders serving more than five transformers and more than 1,000 kVA, are radial with back-up branches. Upon customer's request, two PMH-43 are used on each branch forming the loop. This is the most secure and reliable configuration as well as the most expensive.
- Underground branches or lateral feeders serving more than five transformers and more than 1,000 kVA, are radial with back-up branches. Based on customer's request, one PMH-6 is used in the main branch forming the loop and a junction box in the other branch, with load break elbows. This is the second safest, most reliable and less expensive configuration.
- Two underground branches or lateral feeders derived from the same point, serving more than five transformers and more than 1,000 kVA each, are radial with two back-up branches. Based on customer's request, one PMH-9 is used in the two main branches forming the loop with the other branch. A junction box with load break elbows is used to derive the back-up branches from two different points. This is the second safest and most reliable configuration used to serve a larger number of customers.
- Underground branches or lateral feeders serving more than five transformers and more than 1,000 kVA, are radial with back-up branches. Based on customer's request, one PMH-4 branch is used after derivation from the main feeder and a

junction box is used in the other branch with load break elbows to loop both branches. This is a safe and reliable configuration and also less expensive than the previous configuration.

- The typical service drop consists of 600 V, XLP aluminum cable installed in different sizes of 1/0, 4/0, 350,700 and 1,000 kcmils.
- Secondary cables are installed in a rigid conduit system.
- Joint trench construction is frequently used
- More than one service drop can be run because up to seven sets of cables can be handled in a three-phase, pad-mounted transformer.

Residential Design

- Primary extensions to feed residential areas are designed as two phases (two wires) radial tap, except in the case of big houses, and apartment buildings which are designed as three phase radial taps.
- Rigid conduit throughout the system (primary, secondary and service drops) is used.
- Pad-mounted and underground transformers are used, as observed during inventory works on site.
- Loops are to be used when they are combined with commercial loads of no more than 1,000 kVA.
- 25 kV Aluminum primary cables XLP-CONC-ENCAP-PE with different ranges of 1/0, 350, 700 and 1,000 kcmils are used.
- Radial derivations are used to serve up to 100 consumers.
- 2 cables #1/0 aluminum radial derivations are used.
- Main Connections are:
  - 2 threads Primary Risers.
  - 200 A pre-molded elbows derived from an elbows, pre-molded of 600 A with an OMH4 switch, with an empty position when it is not required to cut the main connection.
- PMH6 or PMH9 switches, when so required, cutting the main connection, with an empty position (more than 1,500 voltage kVA).

1.2.2.7 CAD Drawings

Once the inventory of the Distribution Network was finished and the draft drawings were completed, they were transferred to AutoCAD. The procedure consisted of tracing the routes of each one of the feeders, both aerial and underground, and other elements of protection and sectioning in the distribution networks. Special libraries were used in AutoCAD which facilitated the task and ensured consistency. Once each area of the AutoCAD map was finished, it was thoroughly reviewed to minimize errors and omissions and the distribution network maps for each city were produced. All of the individual drawings were combined in a master Yolo file.

The libraries used for the drawings are part of special software called Distribution Integrated System (DIS), which was used later to analyze the network.

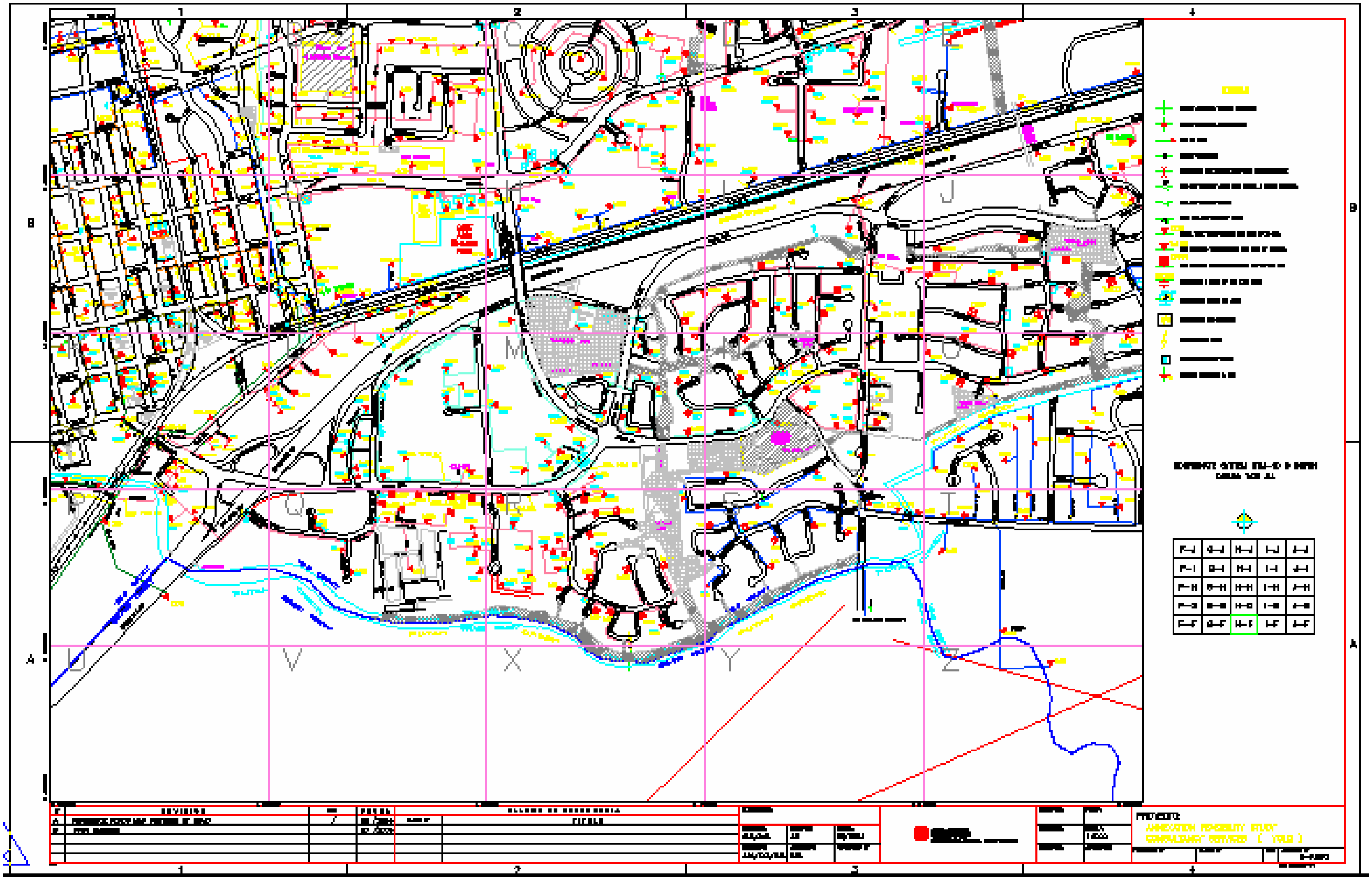
The distribution networks drawn in AutoCAD are limited to the medium voltage distribution network of all the cities and contain the route of all feeders and the location and estimated capacity transformers, capacitor banks, boosters, switches, fuses and other additional equipment.

In the case of underground networks, the information obtained from the field inventory was an estimation of a technically feasible underground network, which was used to complement the field information and produce complete drawings including our best estimate of the run of cables and location of possible switches and other elements of protection.

The actual underground system represented in the AutoCAD drawings might differ, in some cases, perhaps materially, from the actual grid. However, the network shown utilizes all of the underground elements found, and it is in as much detail as it could be given the time and information available for this assignment. It also is in accordance with PG&E's design and construction standards.

Figure 1-3 below presents an example of such maps.

Figure 1-3
Example Map



1.2.3 Inventory Results for the Distribution Networks

1.2.3.1 Introduction

This section contains the summary tables with the results of the inventory for each city and the rural areas. It also provides additional details on how the inventory was produced by extrapolation of sample areas for some of the elements.

1.2.3.2 Summary of Results for Distribution Network Assets

Table 1-9 below shows the consolidated results of the Distribution Network Assets according to the inventory carried out for the distribution networks associated with each substation located in Davis, Woodland, Plainfield and West Sacramento. These results were produced based on the drawings of the medium voltage network created using the methodology discussed in the previous section and the extrapolation discussed in the following sub-section.

Table 1-9 shows from a high-level perspective that the city of Davis (Davis Substation) has the largest distribution system followed by the city of Woodland (Woodland Substation). When considered in aggregate, the city of West Sacramento (West Sacramento and Deepwater Substations) are very close to Woodland, however, individually the system associated with West Sacramento is the third largest, Deepwater the forth, and Plainfield the fifth.

Table 1-9
Distribution Network Assets Summary

Inventory Results	West Sacramento	Deep Water	Davis	Plainfield	Woodland	Total
1. Feeders from Substation	8	2	11	2	12	35
2. Length of HV Overhead Feeders (miles)	91.0	30.4	146	68	108	443.4
3. Length of HV Underground Feeders (mi)	29.3	42.4	105	2	81	259.7
4. Poles	2,655	846	3,571	1,348	2,580	11,000
5. Overhead Distribution Transformers	1,041	309	1,007	362	1,314	4,033
6. Subsurface or Pad Mounted Transformer	301	382	1,088	17	779	2,567
7. Length of LV circuits (miles)	18.2	25.0	83	4	51	181.2
8. Service Drops	4,821	6,747	15,580	1,126	12,408	40,682
9. Pole's Risers	174	49	213	11	226	673
10. Switches	227	76	344	53	312	1,012
11. Voltage Regulators	1	0	3	2	6	12
12. Capacitor Banks Overhead type	36	12	48	8	72	176
13. Capacitor Banks Pad Mounted type	4	0	6	0	3	13

A short description of the items in Table 1-9 follows.

Feeders from Substation

This item represents the number of feeders that were inventoried for each one of the substations.

Length of High-Voltage (HV) Overhead Feeders (miles)

This item represents the total (sum) of the lengths of the overhead sections of the distribution feeders for each substation. It includes both three phase with two phase circuits.

Length of HV Underground Feeders (miles)

This item represents the total (sum) of the lengths of the underground sections of the distribution feeders for each substation. It includes both three phase with two phase circuits.

Poles

The total number of poles which was estimated using feeder length and typical spans for urban and rural areas determined from detailed sampling.

Overhead Distribution Transformers

This item represents the sum of all pole mounted distribution transformers. This number adds transformer banks of different capacities.

Subsurface and Pad Mounted Distribution Transformers

This item represents the sum of all Pad Mounted Distribution Transformer units of each one of the distribution feeders for each substation. Included are three phase and single phase units as well as different capacities.

Length of Low-Voltage (LV) Circuits (miles)

This item represents the sum the lengths of the low voltage sector for each transformer, including both overhead as the underground circuits. Similarly, it adds three phase and the two phase LV circuits. This provides the order of magnitude related with the total of miles in LV circuits for each city or substation.

Service Drops

The total number of service drops was estimated starting from the number of transformers (overhead and underground). The total number of service drops do not represent the total number of customers served, because there are many residential (Condominiums) industrial and commercial loads which have a common main service drop. From this point a proper service drop for each customer is derived to serve a single customer (not part of the inventory).

Switches

This item represents the sum of all switches for each city or substation. It represents the number of switches that were inventoried for each substation, including overhead and underground units. It provides the order of magnitude related with the total number of switches in each city or substation.

Voltage Regulator

This item represents the sum of all Voltage Regulators or Boosters that were inventoried for each substation.

Capacitor Banks

This item represents the sum of all capacitors banks of each one of the distribution feeders for each substation, including overhead and underground banks.

1.2.3.3 Criteria and Methodology for the Production of the Inventory Results

For the computation of the inventory summarized above, the following methodology and criteria were employed.

Elements Included in Each Item

When it was inventoried, the associated infrastructure and equipment for its connection to the system was included, except for equipment specifically classified as a separate item.

Feeder Length

The length (in miles) for each of the medium voltage feeders was segregated according to the different conductors used and discriminated according to the following criteria:

- Number of wires:
  - 2 phase
  - 3 phase
- Density:
  - Rural
  - Urban
- Shared with transmission

This information was gathered directly during the inventory and no extrapolation was necessary.

Number of Poles

For this calculation, an average span was estimated based on the detailed inventory of selected areas. The average span changes whether the feeder considered is rural, an urban main line, or a lateral (branch). The criteria employed is presented below:

- Urban feeders
  - Main line 0.04 miles per pole
  - Lateral 0.025 miles per pole
- Rural feeders
  - Main line 0.04 miles per pole
  - Lateral 0.06 miles per pole
- Shared by transmission. Does not apply for the calculation of poles.

Transformers

The number of transformers and capacity for each type of transformer bank (overhead, pad mounted, subsurface, one phase, etc.) was gathered directly during the inventory. The capacity of transformers needed to be estimated in some cases.

Low Voltage Circuit Length

The estimated length (in miles) of the secondary network was extrapolated based on typical parameters obtained during the detailed inventory. These parameters are presented below:

- 0.05 miles of secondary circuit per each aerial transformer of 1x50 kVA or 1x75kVA, 50% of triplex wires 4/0 AWG AL and 50% of 3 # 4/0 AL on cross-arms.
- For 50% of aerial transformers of 1x74 kVA, 0.05 miles of secondary circuit were computed, 50% of triplex wires 4/0 AWG AL, and 50% of 3 # 4/0 AL on cross-arms.
- On each pad-mounted or single phase subsurface transformer of 1x50 kVA, 0.048 miles of underground circuit of 3# 4/0 AWG AL 600V was assumed.
- For each pad-mounted or single phase subsurface transformer of 1x100 kVA, 0.15 miles of underground circuit of 3# 700 kcmils AL 600V was assumed.

Service Drops

The estimated length of the service drops was extrapolated based on typical parameters obtained during the detailed inventory. These parameters are presented below:

- For each one of 50% of the aerial transformers of 1x25 kVA, five type 2 service lines and l type 12.
- For each aerial transformer of 1x37.5 kVA or 1x50 kVA, 10 type 2 service lines.

- For each one of 50% of the aerial transformers of 1x75 kVA, 10 type 2 service lines and 1 type 16.
- For each pad-mounted or single phase subsurface transformer of 1x50 kVA, 10 type 1 service lines.
- For each pad-mounted or single phase subsurface transformer of 1x75 kVA, 20 type 1 service lines.
- For each pad-mounted or single phase subsurface transformer of 1x100 kVA, 14 type 1 service lines.
- For each 2-transformer Delta bank, 1 single phase and 1 3-phase service lines.
- For each transformer or transformer bank different from the previous ones, one service line was assigned.

Pole Risers

The number of risers of each type for each feeder was recorded directly from field observations.

Switches and Other Equipment

This information includes such elements as overhead and underground switches, voltages regulators, and reclosers. The information was gathered directly from field observations (not extrapolated).

Capacitors

The information on the type of capacitor banks was gathered directly from field observations (not extrapolated).

1.2.4 Distribution Network Analysis

1.2.4.1 Introduction

As a result of the inventory, a detailed representation of the distribution system associated with the cities of Davis, Woodland and West Sacramento was developed. Based on this representation, it was possible to conduct network analysis using a load flow program to determine the investments are needed in the short term in the system.

This section of the report presents such analysis.

Criteria and Assumptions for Feeder Analysis

The following assumptions and operation criteria were employed in this evaluation:

- 12 kV is the nominal voltage.
- Substation transformers have automatic tap changers that can raise the voltage up to 105% nominal during maximum load conditions.

- There is a 0.99 power factor assumed at the substation. This is based on the large number of condensers found in the distribution network and the results from the load flow analysis.
- The maximum allowable voltage drop in primary urban feeders is 5% and 6% in rural areas.
- The maximum allowable main line loading is 66% of the conductor thermal capacity (100% was utilized at the end).
- Conductor loading capacity is based on PG&E standards.

Based on available information, PG&E standards do not establish a maximum allowable voltage drop on primary feeders; the only aspect that PG&E guarantees is that the customer meter will have a maximum voltage drop of 6.5 V on the basis of 120 V nominal.

To use this criterion, it would be necessary to complete an analysis of the primary system, transformer, and secondary, which is beyond the scope of this work. Therefore, we selected the voltage drop criteria indicated above. The use of this criterion gives a margin of another 5% for voltage drops in the transformer and in the secondary system.

The maximum voltage drop allowed in rural areas is 6%, based on the fact that there are no long secondary networks, and that dedicated transformers are generally less loaded than those shared among different customers through a secondary system.

With respect to the maximum feeder loading, it was necessary to make a concession since many PG&E feeders are at more than 66% of their current carrying capability during peak demand. This 66% is normally specified in order allow the totality of the load served by one feeder to be taken over by two adjacent feeders during emergencies. However, this is not the case with PG&E networks in the cities of Davis, Woodland, and West Sacramento. The criterion was relaxed to allow loading up to 100% of capacity. This means that there is limited back-up capability among feeders regardless of the presence of connections. The alternative would have been an inordinately large number of new additions.

Assumed Demand

The evaluation was done assuming peak summer load conditions as provided in the load flows for 2004. The table below presents a comparison between the load for 1999 as supplied by PG&E by substation feeder and the 2004 load according to the load flows. It should be noted that Davis has had a growth that was in line with expectations, West Sacramento's substation load is essentially flat which is to be expected given that most of the load growth might be captured by Deepwater Substation (combined growth about 2%) and Woodland had limited growth according to these results. In conclusion, the load used for the analysis appears to be conservative.

Table 1-10
Assumed Load

Substation	1999 Load MW (1)	2004 Load MW (2)	Growth 1999-2004
Davis	72	82.6	2.9%
Woodland	90	93	0.7%
West Sacramento	52	53	0.4%
Deepwater	12	18	8.0%
Plainfield	6.5	9	5%

(1) Based on feeder demand provided by PG&E and assuming 70% coincidence factor.
(2) From load flow provided by SMUD.

Peak substation load for 2004 was assigned to each of the feeders assuming the same loading distribution provided for 1999. Further, the feeder load was assigned to different transformation banks according to their capacity (uniform utilization factor per feeders). These assumptions might condition the accuracy of the results as discussed below.

Distribution Feeder Load Flow Results

The result of the analysis is reflected in Table 1-11 in which the following data is presented.

- Name and number of feeder.
- Current or demand at substation's exist in amperes (total load current in amps).
- Transformer average utilization factor at peak load (Demand/Nominal capacity).
- Feeder's power factor as seen from the substation. It is the natural power factor of loads and existing condensers in the feeder.
- Total load connected. It is the sum of all the rated capacities of transformation connected in one feeder, in kVA.
- Feeder's maximum voltage drop percentage, usually at its end.
- Feeder's maximum voltage load is the maximum percent of current divided by conductor's rated capacity in amps in each of the feeder's sections (normally at 75°C).
- Total losses. These are total instantaneous losses for feeder's maximum demand in kW.
- Demand (kVA). This is the feeder's total demand in kVA.

Table 1-11
Distribution Network Analysis Results 2004

No.	Feeder Name	AMP	FP	FU	Conected Load (kVA)	% V	%Load	Losses (kW)	Demand (kVA)	Demand (kW)
2	FEEDER 1102 DV S/S DAVIS	332.2	0.99	0.48	16,115.0	0.89	59.72	24.85	7,250.07	7,170.82
3	FEEDER 1103 DV S/S DAVIS	560.4	0.99	0.73	21,525.0	8.31	97.64	425.14	12,230.76	12,097.93
4	FEEDER 1104 DV S/S DAVIS	505.4	0.99	0.59	32,600.0	4.61	85.79	309.06	11,030.12	10,909.95
5	FEEDER 1105 DV S/S DAVIS	536.5	0.99	0.62	29,062.5	4.57	93.46	194.65	11,707.42	11,579.46
6	FEEDER 1106 DV S/S DAVIS	564.5	0.99	0.51	27,755.0	10.42	98.34	528.01	12,318.58	12,183.93
7	FEEDER 1107 DV S/S DAVIS	386.3	0.99	0.59	14,557.5	7.38	67.30	370.90	8,430.64	8,338.78
8	FEEDER 1108 DV S/S DAVIS	430.4	0.99	1.22	8,490.0	2.19	74.97	98.41	9,391.63	9,288.49
9	FEEDER 1109 DV S/S DAVIS	545.4	0.99	0.89	13,900.0	4.28	95.02	246.64	11,902.99	11,773.93
10	FEEDER 1110 DV S/S DAVIS	741.6	0.99	0.66	26,050.0	9.18	101.07	777.66	16,185.05	16,017.10
11	FEEDER 1111 DV S/S DAVIS	496.4	0.99	1.78	7,350.0	4.68	87.40	330.16	10,833.09	10,715.05
12	FEEDER 1112 DV S/S DAVIS	324.9	0.99	0.76	9,290.0	1.45	58.99	53.72	7,091.30	7,013.66
	Subtotal				206,695.0				118,371.65	117,089.10
21	FEEDER 1104 WS S/S WEST SACRAMENTO	517.4	0.99	0.53	25,235.0	8.61	90.14	597.86	11,291.78	11,168.91
22	FEEDER 1105 WS S/S WEST SACRAMENTO	380.3	0.99	0.76	11,532.0	2.46	66.25	102.33	8,299.41	8,209.52
23	FEEDER 1106 WS S/S WEST SACRAMENTO	380.3	0.99	0.87	9,925.0	1.93	72.54	78.59	8,298.93	8,209.42
24	FEEDER 1107 WS S/S WEST SACRAMENTO	444.8	0.99	0.82	24,540.0	3.98	97.36	328.51	9,707.04	9,619.25
25	FEEDER 1108 WS S/S WEST SACRAMENTO	371.3	0.99	0.80	15,372.5	4.67	64.28	181.53	8,103.23	8,014.94
26	FEEDER 1109 WS S/S WEST SACRAMENTO	490.4	0.99	1.09	11,260.0	5.32	81.46	319.46	10,702.30	10,584.74
27	FEEDER 1110 WS S/S WEST SACRAMENTO	380.3	0.99	0.73	11,575.0	3.15	94.14	142.74	8,298.90	8,209.01
28	FEEDER 1111 WS S/S WEST SACRAMENTO	504.2	0.99	0.82	13,500.0	1.21	87.84	66.94	11,003.40	10,885.56
	Subtotal				122,939.5				75,704.99	74,901.35
31	FEEDER 1109 DW S/S DEEP WATER	353.0	0.99	0.54	25,912.0	2.95	61.49	124.61	7,702.65	7,620.07
32	FEEDER 1100 DW S/S DEEP WATER	352.3	0.99	0.29	28,685.0	1.45	61.37	35.86	7,687.56	7,603.97
	Subtotal				54,597.0				15,390.21	15,224.04
41	FEEDER 1101 PF S/S PLAINFIELD	317.2	0.99	0.99	7,090.0	14.56	75.28	427.15	6,923.32	6,848.31
42	FEEDER 1102 PF S/S PLAINFIELD	134.1	0.99	0.43	9,258.5	3.03	29.18	49.90	2,926.60	2,896.39
	Subtotal				16,348.5				9,849.92	9,744.70
61	FEEDER 1101 WD S/S WOODLAND	531.4	0.99	0.79	17,235.0	3.66	92.58	169.87	11,597.40	11,471.55
62	FEEDER 1102 WD S/S WOODLAND	535.4	0.99	0.64	20,405.0	2.93	93.28	161.43	11,684.74	11,557.93
63	FEEDER 1103 WD S/S WOODLAND	517.4	0.99	1.10	10,511.5	5.39	90.14	323.66	11,291.58	11,169.08
64	FEEDER 1104 WD S/S WOODLAND	561.4	0.99	0.88	13,802.5	5.40	98.60	366.33	12,251.00	12,118.61
65	FEEDER 1105 WD S/S WOODLAND	508.4	0.99	0.73	23,090.0	4.90	88.57	238.76	11,095.42	10,973.64
66	FEEDER 1106 WD S/S WOODLAND	584.5	0.99	1.12	11,742.0	7.63	153.80	406.70	12,755.12	12,616.30
67	FEEDER 1107 WD S/S WOODLAND	561.4	0.99	0.95	13,525.0	6.51	103.96	300.31	12,252.30	12,118.01
68	FEEDER 1108 WD S/S WOODLAND	497.4	0.99	0.97	12,854.0	3.95	89.01	224.98	10,855.92	10,737.36
69	FEEDER 1109 WD S/S WOODLAND	531.4	0.99	1.34	8,622.5	5.24	97.07	292.49	11,595.78	11,470.10
70	FEEDER 1110 WD S/S WOODLAND	434.8	0.99	0.88	16,155.0	4.07	85.74	271.20	9,489.71	9,395.55
71	FEDDER 1111 WD S/S WOODLAND	273.2	0.99	1.07	6,224.0	1.39	47.59	43.03	5,962.42	5,897.23
72	FEEDER 1112 WD S/S WOODLAND	521.4	0.99	1.34	8,637.5	3.14	90.83	203.08	11,377.66	11,255.28
	Subtotal				162,804.0				132,209.05	10,974.45

Analysis of Results

The analysis shown in Table 1-11 must be examined carefully, since the loading assigned to the feeders is based on 1999 conditions. The analysis would have been improved if PG&E were willing to provide actual feeder current measurements at each substation.

Another issue is that it is possible to have load center displacement in mixed rural and urban feeders. When load is distributed proportionally to the transformer capacity, it assumes uniform utilization. In reality, it could be that rural transformers have smaller utilization factors than the urban transformers. The result of this is that more load is assigned farther away from substation, so there is greater voltage drop.

In West Sacramento, there are two cases where the voltage criterion is not met. The first case corresponds to the rural section of Feeder 1104, which exceeds the criteria by a large factor. The second case corresponds to Feeder 1109 (only by 0.32%) in a highly loaded area of West Sacramento.

In Plainfield, there is a large voltage drop on Feeder 1101, which could be due to the fact that there is a capacitor bank and voltage booster on this feeder that are disconnected. It is likely that PG&E will reconnect this equipment when the load begins to increase.

Woodland is a special case. Thirteen feeder loads (presented in 1999 results) are distributed proportionally to the 12 feeders found in the inventory. Feeders 1103, 1104, 1106, 1007, and 1109 all exceed the voltage drop criteria and two of them have sections with overloaded conductors.

There are some feeders with Distribution Transformer Utilization Factors greater than 1, meaning that some distribution transformers are overloaded. In order to confirm these results, we would need access to measured currents.

All of the feeders may have their voltage drop reduced to less than 5% in the urban area and 6% in the rural, by making some investment such as:

- Placing capacitor banks
- Installing voltage regulators
- Upgrading conductor size on some feeders sections
- Rerouting load
- Providing new circuits

Table 1-12 below presents possible solutions for each one of the feeders that do not comply with SMUD's voltage criteria. These investments are priced together with the pricing of the distribution inventory

Table 1-12
Possible Solutions for Feeder Not Meeting the Criteria Used

Feeder #	Investment	City
#3, 1103 S/S Davis	2 Capacitor banks, pad mounted type, one 1200 kVAr and another of 600 kVAr.	Davis
#6, 1106 S/S Davis	2 capacitor bank, 600 kVAr each, overhead type. One of them exist but is disconnected. Two Additional capacitor Bank 600 kVAr, pad mounted on residential zone	Davis
#7, 1107 S/S Davis	UC Davis (not corrected)	Davis
#10, 1110 S/S Davis	3 capacitor bank, 600 kVAr each, overhead type	Davis
#11, 1111 S/S Davis	New Section, 640 feet, 1,000 kcmils underground, ducts exists. And one new Pad Mounted Capacitor Bank 600 kVAr. Need to check Voltage regulator capacity.	Davis
#21, 1104 S/S West Sacramento	2 capacitor banks, 1200 and 1800 kVAr, Pad mounted type	Sacramento
#26, 1109 S/S West Sacramento	To keep rural under 5% voltage drop , a 300 kVAr capacitor bank , overhead type is needed	Sacramento
#41, 1101 S/S Plainfield	Voltage Regulator need to be reconnected as an existing Capacitor bank. Additional 1200 kVAr capacitor bank overhead type, is needed at south feeder end.	Plainfield
#63, 1103 S/S Woodland	300 kVAr capacitor Bank Pad mounted type, at South, on Residential Zone.	Woodland
#64, 1104 S/S Woodland	Increase capacitor bank from 300 to 600 kVAr, overhead type, near Biomass Plant	Woodland
#66, 1106 S/S Woodland	Change ½ mile of 3 phases, Overhead conductor to 397.5 Al on Buckeye St. And increase existing capacitor bank from 600 to 1200 kVAr, same location.	Woodland
#67, 1107 S/S Woodland	Change ½ mile of 3 phase, Overhead conductor to 395.5 on Pendencast and West St. Capacitor Bank upgrade form 600 to 1200 kVAr, overhead type	Woodland
#69, 1109 S/S Woodland	1 600 kVAr capacitor bank pad mounted type near Walgreen Center	Woodland
#70, 1110 S/S Woodland	1 Capacitor Bank that was installed during, inventory, must be operating.	Woodland

Table 1-13 shows an estimation of the investment required for the improvements discussed in the previous section. For this estimation, the same unit costs were used as for the inventory valuation plus a 10% contingency. In addition, for feeder reconductoring/replacements, the unit costs were increased by a factor of 1.5 to take into account the shortness of the lines. The total investment required should be in the order of $255,000 to correct most of the voltage problems found.

Table 1-13
Value of the Investments per City (Include 10% Contingency)

Davis

ITEM	DESCRIPTION	Unit	Q.	Unit Cost	Total
1.0	**FEEDERS**				
1.7	12 Kv Underground feeder, 3 # 1000 MCM AL, on conduits. 1.5 short line factor	mi	0.121	$242,835	$ **29,441**
4.0	**CAPACITORS BANKS.**				
4.2	Overhead Capacitors Bank 3 x 200 kVAR .	Unit	5	4,735	**23,673**
4.8	Pad Mounted Capacitors Bank 3 x 200 kVAR.	Unit	1	6,508	**6,508**
4.10	Pad Mounted Capacitors Bank 6 x 200 kVAR.	Unit	1	11,952	**11,952**
	Total Davis				**$ 71,575**

West Sacramento

ITEM	DESCRIPTION	Unit	Q.	Unit Cost	Total
4.0	**CAPACITORS BANKS.**				
4.1	Overhead Capacitors Bank 3 x 100 kVAR .	Unit	1.0	$ 4,735	$ **4,735**
4.10	Pad Mounted Capacitors Bank 6 x 200 kVAR.	Unit	1.0	11,952	**11,952**
4.11	Pad Mounted Capacitors Bank 6 x 300 kVAR.	Unit	1.0	10,866	**10,866**
	Total West Sacramento				**$ 27,553**

Woodland

ITEM	DESCRIPTION	Unit	Q.	Unit Cost	Total
1.0	**FEEDERS**				
1.2	12 kv Overhead feeder, 3 # 397.5 MCM AL, on insulators. 1.5 short line factor	mi	1.0	$ 50,372	$ **50,372**
	Poles 1.5 short line factor		25	2,875	**71,883**
4.0	**CAPACITORS BANKS.**				
4.1	Overhead Capacitors Bank 3 x 100 kVAR .	Unit	2	4,735	**9,469**
4.2	Overhead Capacitors Bank 3 x 200 kVAR .	Unit	1	4,735	**4,735**
4.8	Pad Mounted Capacitors Bank 3 x 200 kVAR.	Unit	1	6,508	**6,508**
4.11	Pad Mounted Capacitors Bank 6 x 300 kVAR.	Unit	1	10,866	**10,866**
	Total Woodland				**$ 153,833**

	Total System				**$ 252,960**

Table 1-14
2004 Network Performance with Suggested Investments

No.	Feeder Name	AMP	Power Factor	V Drop %	Lading %	Losses (kW)	Demand (kVA)	Demand (kW)
2	FEEDER 1102 DV S/S DAVIS	332.2	0.99	0.89	59.72	24.85	7,250.14	7,170.87
3	FEEDER 1103 DV S/S DAVIS	552.7	1.00	4.76	96.29	389.40	12,062.31	12,062.00
4	FEEDER 1104 DV S/S DAVIS	505.4	0.99	4.61	85.79	309.08	11,030.45	10,910.27
5	FEEDER 1105 DV S/S DAVIS	536.5	0.99	4.57	93.46	194.65	11,707.47	11,579.47
6	FEEDER 1106 DV S/S DAVIS	556.7	1.00	5.76	96.98	474.74	12,149.34	12,131.48
7	FEEDER 1107 DV S/S DAVIS	386.3	0.99	7.38	67.30	370.90	8,430.61	8,338.74
8	FEEDER 1108 DV S/S DAVIS	430.4	0.99	2.19	74.97	98.41	9,391.64	9,288.52
9	FEEDER 1109 DV S/S DAVIS	479.0	1.00	3.70	83.44	198.51	10,453.29	10,399.34
10	FEEDER 1110 DV S/S DAVIS	733.6	1.00	5.43	97.57	764.54	16,010.19	16,004.28
11	FEEDER 1111 DV S/S DAVIS	558.4	0.99	4.75	97.28	361.17	12,185.82	12,072.94
12	FEEDER 1112 DV S/S DAVIS	324.9	0.99	1.45	58.99	53.72	7,091.36	7,013.70
	Subtotal						117,762.62	116,971.61
21	FEEDER 1104 WS S/S WEST SACRAMENTO	514.1	0.99	4.37	89.56	555.05	11,219.76	11,126.11
22	FEEDER 1105 WS S/S WEST SACRAMENTO	380.3	0.99	2.46	66.25	102.33	8,299.54	8,209.66
23	FEEDER 1106 WS S/S WEST SACRAMENTO	380.3	0.99	1.93	72.54	78.59	8,298.91	8,209.40
24	FEEDER 1107 WS S/S WEST SACRAMENTO	444.8	0.99	3.98	97.36	328.50	9,706.69	9,618.84
25	FEEDER 1108 WS S/S WEST SACRAMENTO	371.3	0.99	4.67	64.28	181.54	8,103.61	8,015.26
26	FEEDER 1109 WS S/S WEST SACRAMENTO	489.3	0.99	4.39	81.28	334.41	10,678.21	10,599.49
27	FEEDER 1110 WS S/S WEST SACRAMENTO	380.3	0.99	3.15	94.14	142.74	8,298.79	8,208.88
28	FEEDER 1111 WS S/S WEST SACRAMENTO	504.2	0.99	1.21	87.84	66.94	11,003.40	10,885.56
	Subtotal						75,608.91	74,873.20
31	FEEDER 1109 DW S/S DEEPWATER	352.9	0.99	2.95	61.48	124.60	7,701.72	7,619.00
32	FEEDER 1100 DW S/S DEEPWATER	352.3	0.99	1.45	61.37	35.86	7,688.03	7,604.40
	Subtotal						15,389.75	15,223.40
41	FEEDER 1101 PF S/S PLAINFIELD	313.7	0.99	5.31	69.83	371.20	6,846.25	6,792.19
42	FEEDER 1102 PF S/S PLAINFIELD	134.1	0.99	3.03	29.18	49.90	2,926.53	2,896.31
	Subtotal						9,772.78	9,688.50
61	FEEDER 1101 WD S/S WOODLAND	531.4	0.99	3.66	92.58	169.89	11,597.37	11,471.51
62	FEEDER 1102 WD S/S WOODLAND	535.4	0.99	2.93	93.28	161.43	11,684.82	11,558.02
63	FEEDER 1103 WD S/S WOODLAND	513.9	1.00	4.43	89.52	319.58	11,214.05	11,164.96
64	FEEDER 1104 WD S/S WOODLAND	559.4	0.99	4.96	98.14	364.13	12,207.49	12,116.44
65	FEEDER 1105 WD S/S WOODLAND	508.5	0.99	4.90	88.58	238.80	11,096.58	10,974.65
66	FEEDER 1106 WD S/S WOODLAND	572.6	1.00	4.42	99.75	225.78	12,495.26	12,435.43
67	FEEDER 1107 WD S/S WOODLAND	555.5	1.00	4.57	96.77	245.88	12,122.22	12,063.63
68	FEEDER 1108 WD S/S WOODLAND	497.5	0.99	3.95	89.01	224.98	10,855.97	10,737.42
69	FEEDER 1109 WD S/S WOODLAND	527.4	1.00	4.74	95.40	282.85	11,510.19	11,460.46
70	FEEDER 1110 WD S/S WOODLAND	431.0	1.00	3.31	85.51	280.49	9,405.95	9,404.83
71	FEDDER 1111 WD S/S WOODLAND	273.2	0.99	1.39	47.59	43.03	5,962.42	5,897.23
72	FEEDER 1112 WD S/S WOODLAND	521.4	0.99	3.14	90.83	203.08	11,377.66	11,255.28
	Subtotal						131,529.98	130,539.86

1.2.5 Separation Feasible Configuration (Immediate Term)

This section of the report presents a possible configuration to separate the distribution systems of the cities of West Sacramento, Davis and Woodland, as well as that of the intervening regions of Yolo County from PG&E's system. It is assumed that this separation is performed using today's distribution system configuration, as reflected in the inventory. However, the study considered different annexation scenarios as discussed below.

1.2.5.1 Scope

The scope of the separation configuration was to determine necessary investments and impacts on reliability in order to determine the best separation points between annexed systems and the rest of PG&E's network to minimize investments and impacts on reliability.

Given the great distances between substations, there is very little capability for effective support from one substation to another, with the exception of West Sacramento – Deepwater. In fact, the only interconnections found during the inventory between substations (other than West Sacramento – Deepwater) were done with feeders with relatively small conductors (2/0 A1) stretching over great distances (of more than four miles). This fact facilitates the annexation of one city and not the others without major impacts on reliability.

Considerations and investments for each city or substation are described as follows:

1.2.5.2 Separation of West Sacramento and Deepwater

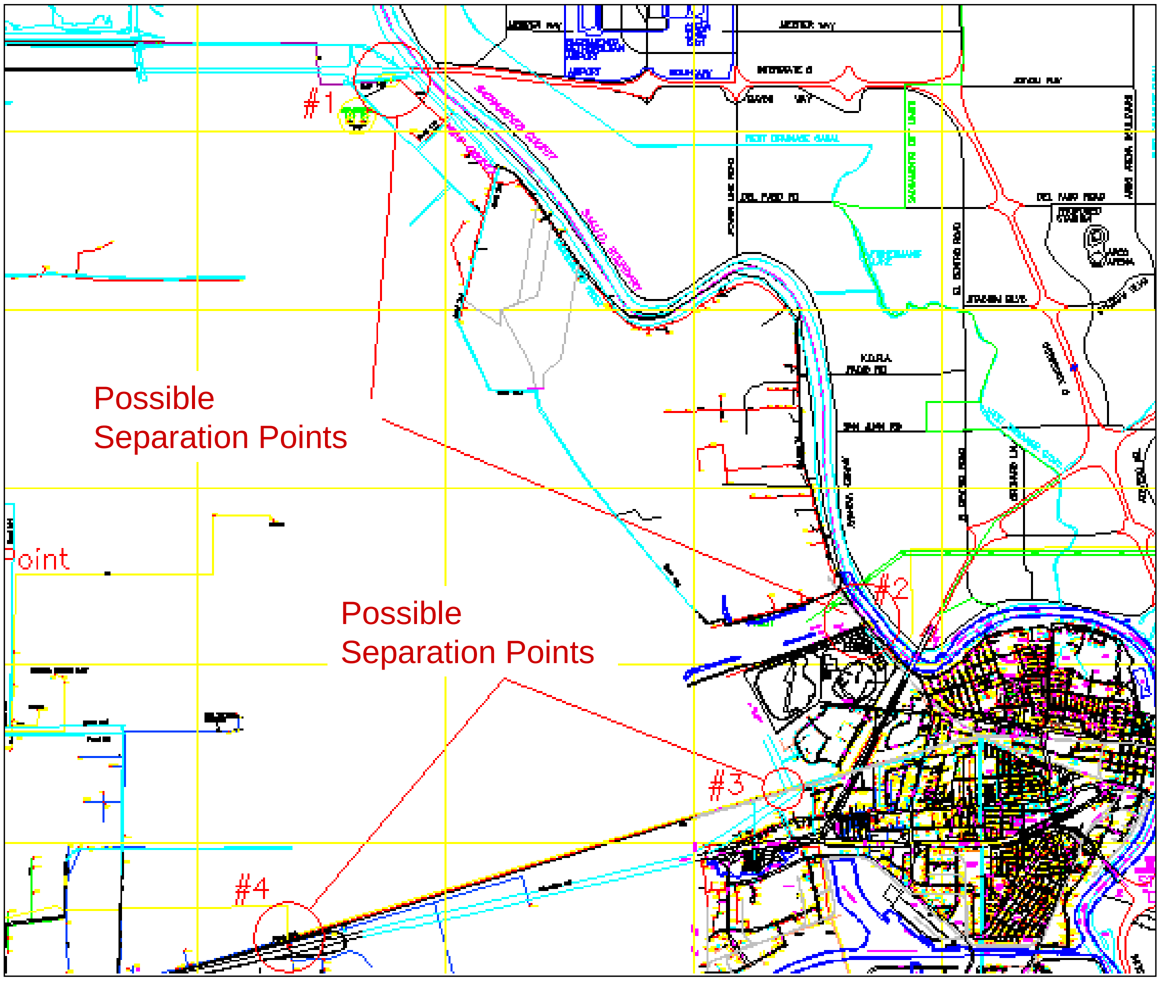
The areas served by the West Sacramento and Deepwater substation are relatively easily separated from the PG&E system. In order to isolate West Sacramento and Deepwater from the other cities, it is necessary to evaluate two feeders with laterals leaving West Sacramento toward the rural zones.

Feeder 1109, which exits on North Harbor Boulevard and Old River Road, goes towards the airport and beyond, before turning west towards Woodland. This feeder serves rural loads along the way and can be interconnected with a Woodland feeder at its very end, providing limited back-up capabilities..

Feeder 1104 has a branch that goes parallel to the railway and to the causeway connecting West Sacramento with Davis. This branch only serves the railway transformers for purposes of railroad signaling. It can be interconnected with Davis feeder 1110. Given the distances involved, the support to Davis is limited, constituting a backup only in the event of total Davis blackout, or for rural loads served from Davis substation.

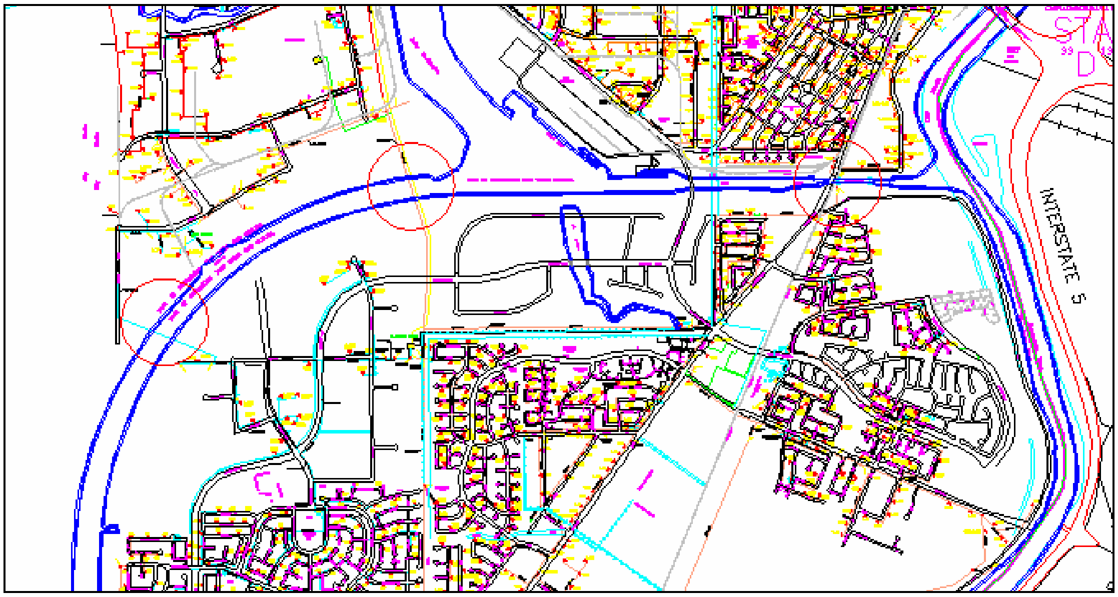
For this separation scenario, our recommendation would be for SMUD to take over the entire rural branch of feeder 1109, as this load is closer (physically and electrically) to West Sacramento and it is served better from this area. Similarly, SMUD would acquire all of feeder 1104. In this case, SMUD would likely want to install metering at points # 1 and # 4 in Figure 1-4.

Figure 1-4
Separation Point on West Sacramento, Feeders 1109 and 1104



Separation of West Sacramento and Deepwater, even though it is not recommended because of the mutual support that they share, could be implemented by the physical separation of the facilities along the deepwater Channel. There are three points of interconnection in which the Deepwater circuits cross the river. The possible separation points are shown in Figure 1-5.

Figure 1-5
Separation Points Between West Sacramento and Deepwater



If such separation were to be carried out, it would be necessary to construct one or two feeders in order to take those loads that are presently served from Deepwater. However, it is not recommended.

1.2.5.3 Separation of Davis

The separation of Davis substation poses a more difficult problem from a transmission and distribution point of view, as this substation interconnects at 60 kV with UC Davis substation, and to a considerable rural zone (at 12 kV) to the north and south of Davis. The main issues are discussed below.

Davis feeder 1107 was not surveyed in its entirety, since it extends beyond the area into Solano County. It does serve a few loads at the UC Davis in the outskirts of the city, continuing toward the UC Davis Substation. This feeder has two branches with two reclosers. One branch serves the rural areas of Solano County and the other serves the Veterinarian School and the Airport, among other UC Davis loads. The first branch continues up to County Road 98. The second branch continues south, parallel to the railroad and shares the 60 kV line pole route.

This feeder should be completely separated from the Davis system, either by metering at Davis substation, or by rerouting it to UC Davis substation; this last option is most desirable, as it would leave an additional capacity at Davis to serve city loads.

Feeder 1110 serves important commercial loads in the city of Davis and the residential zone southwest of the city. It has two points which cross the city limits, one on Drumond Road, which enters Solano County and the other on Mace Blvd., which becomes Yolo County Road 104.

The branch exiting on Drumond Road was not surveyed, but it appears to have an interconnection with the feeder on County Road 104, since it shares the poles of the Davis-Brighton 115 kV transmission line.

The County Road 104 branch serves some rural loads and continues approximately six miles to Road 38. The most important loads are Davis Transmittal and Davis Migrant Center. Furthermore, this feeder has an interconnection with Davis feeder 1107 through Tremond Road. It has two additional laterals entering Solano County.

The possibilities for this feeder are:

- SMUD not to take over rural loads: This would require the installation of two HV metering points at the two point where the feeder crosses the city limits. Points #5 and # 6 in Figure 1-6.
- SMUD to take only the rural loads within Yolo: In this case, HV meters are required in laterals entering Solano County at points # 5, 7, 8, and 9 in Figure 1-7.
- SMUD to takeover all of the feeder, including those branches entering Solano County, and placing HV metering points at the south end, Point # 9.

This last possibility would require negotiation with PG&E since there are loads served in Solano County.

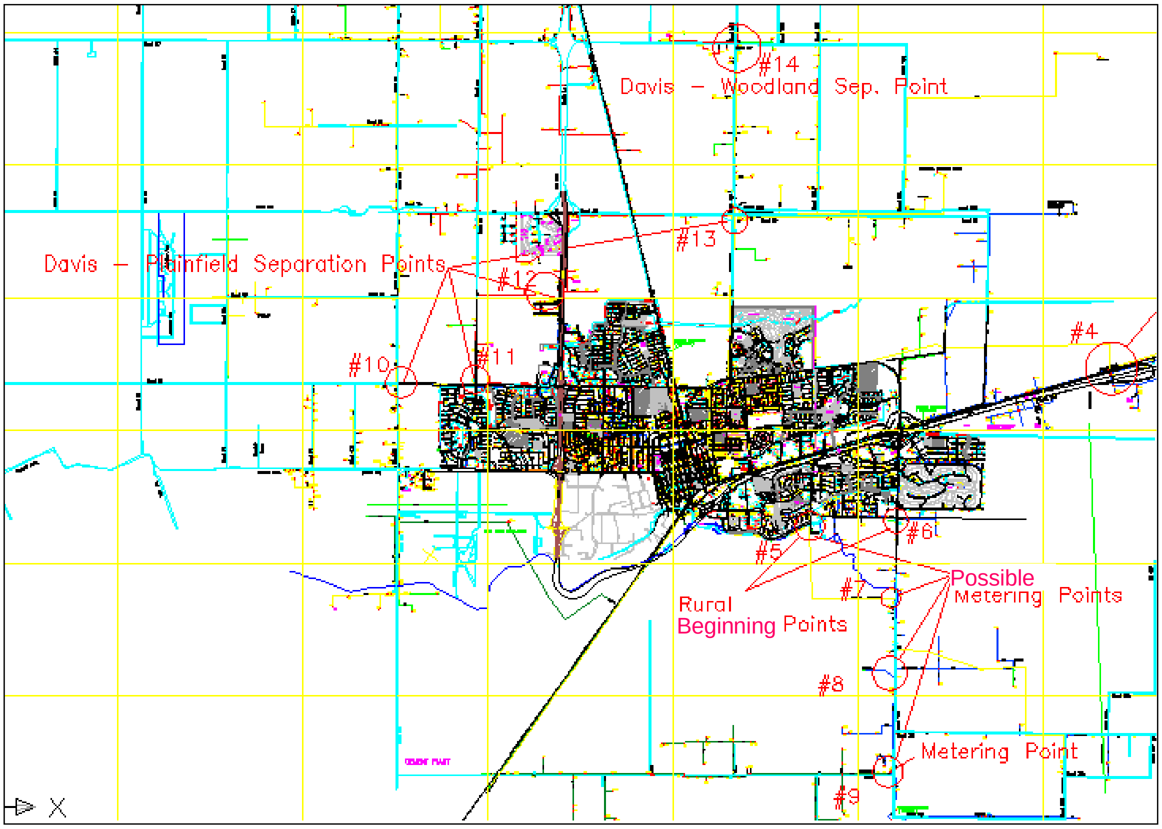
To separate Davis from Plainfield there are several points where there is the possibility of interconnection. These points are identified as 10, 11, 12, and 13. All these points are normally open; however, during emergencies small mutual support is possible.

With Woodland, there is another interconnection point where it would be necessary to install metering in case of separation. This point is identified as #14.

Finally, for separation from West Sacramento, metering at point #4 is needed.

Based on these observations, it can be concluded that separation of Davis would require a minimum of seven metering points and a maximum of 10, depending on the solution for Feeder 1107 south of Davis.

Figure 1-6
Separation of Davis



1.2.5.4 Separation of Plainfield

For this scenario, it is recommended that SMUD annex the Plainfield Substation if the Cities of Davis and Woodland are included in the acquisition. This substation serves all of the rural loads within these cities and offers support to areas in the outskirts of Woodland and Davis. Its area of influence is completely within Yolo County.

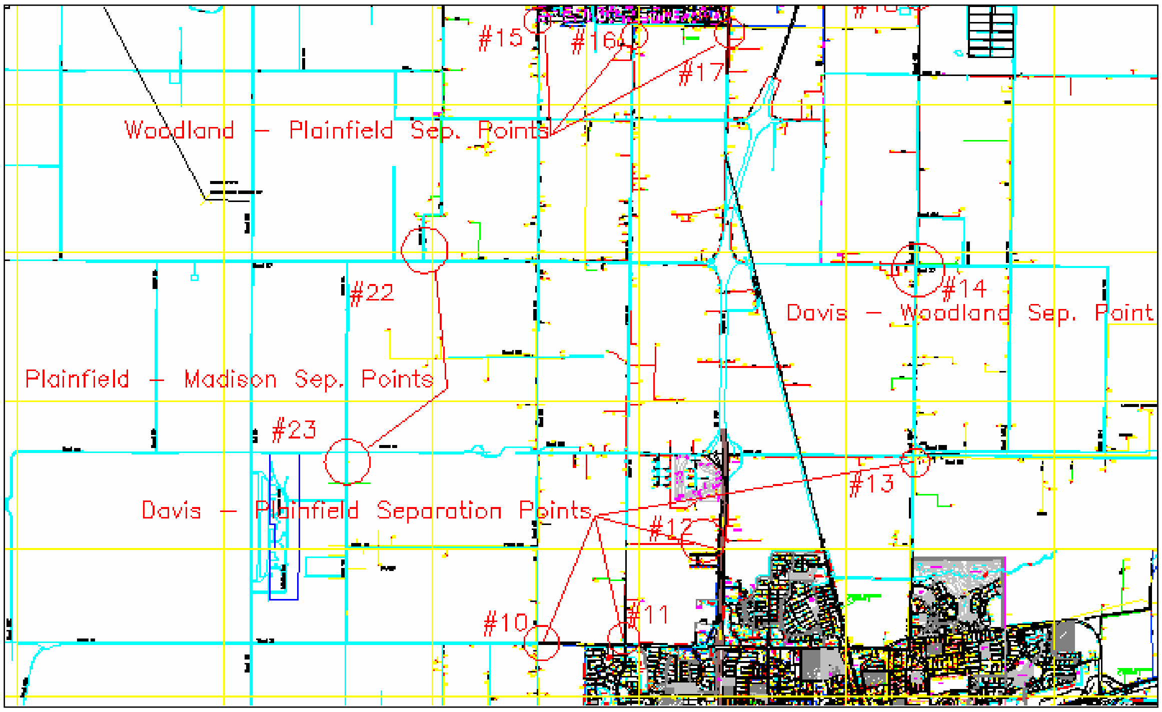
If SMUD were to acquire Plainfield, it will be necessary to convert it to 115 kV (changing the transformer and the hardware at the 60 kV side) and supplying power from a tap in the Woodland - Davis 115 kV transmission line. This is presented in further detail in the Transmission section.

Plainfield's feeders have interconnection points with Davis, as discussed above. There also are three interconnection points with Woodland's feeders and two more interconnection points with other distribution feeders that presumably come from the Madison Substation.

Figure 1-7 shows Plainfield interconnection points.

If it is decided not to acquire the Plainfield Substation, then the three interconnection points with Woodland may be reduced to just one by making a new section interconnecting all the three points. This section would consist of approximately two miles of three-phase overhead feeder with conductor sizes 2/0 AWG. A least three cut-outs, three-phases kits are also recommended.

Figure 1-7
Plainfield Separation

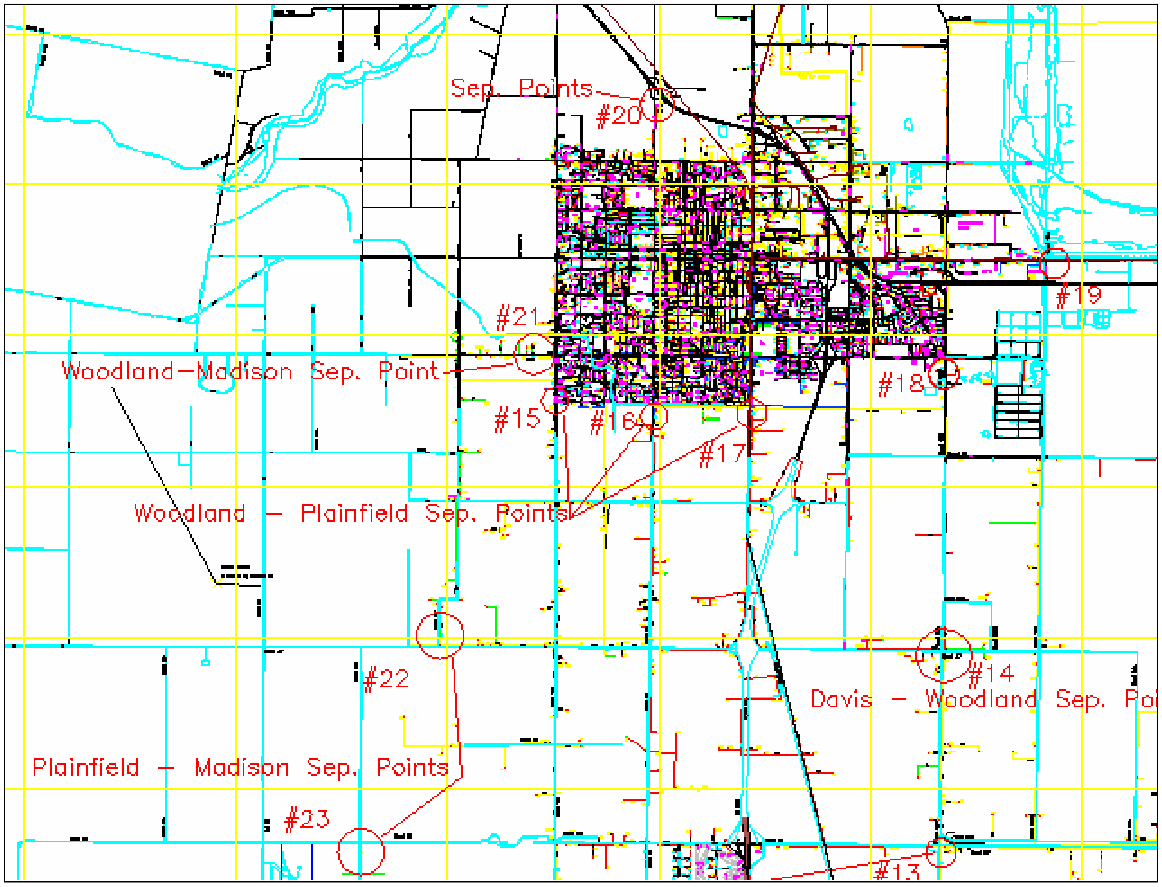


1.2.5.5 Separation of Woodland

This substation has the following interconnection points (see Figure 1-8).

- Three points with Plainfield (identified with numbers #15, #16, and #17)
- One Point with Madison (identified with number #21)
- One more point with an unidentified distribution Network on the North Side (identified with number #20)
- One Point with West Sacramento (identified with number #19)
- One point with Davis (identified with number #14)

Figure 1-8
Woodland Separation



The three points of interconnection with Plainfield can be reduced to just one, but the others cannot be reduced or worked around. However it appears that these points only provide limited backup to rural loads, therefore one option would be to leave them as open points or to install HV meters to be used during those emergencies that back up is required.

Table 1-15 below presents a summary of all the issues discussed above and presents what points SMUD would have to consider, under a wide range of acquisition options.

Table 1-15
Summary Table of Separation Metering Points

	City of West Sacramento				City of Davis					City of Woodland					All Cities
	Only the city and no rural loads	Only the city and associated rural loads	City+ Davis + intervening rural loads	City+ Woodland + intervening rural loads	Only the city and no rural loads	Only the city and associated rural loads	City+ West Sacramento + intervening rural loads	City+ Woodland + intervening rural loads (no	City+ Woodland + intervening rural loads (with	Only the city and no rural loads	Only the city and associated rural loads	City+ West Sacramento + intervening rural loads	City+ Davis + intervening rural loads (no	City+ Davis + intervening rural loads (with	
Interconnection Issue ID This number identifies investments at specific points in the network	2	1	1	4	4	4	1	4	4	15	15	4	4	4	20
	3	4	5	15	5	9	5	5	5	16	16	15	5	5	21
			7	16	6	10	7	7	7	17	17	16	7	7	22
			8	17	10	11	8	8	8	18	18	17	8	8	23
			9	14	11	12	9	9	9	19	1	14	9	9	F 1107
			10	20	12	13	10	10	19	20	20	20	10	19	
			11	21	13	14	11	11	20	21	21	21	11	20	
			12		F 1107	F 1107	12	12	21				12	21	
			13				13	13	22				13	22	
			14				14	15	23				15	23	
			F 1107				F 1107	16	F 1107				16	F 1107	
								17					17		
								19					19		
								20					20		
								21					21		
								F 1107					F 1107		

Notes: The scenarios only consider the annexation of whole cities (i.e. the annexation of West Sacramento without Deepwater is not an option)
When two cities are annexed then the rural loads between the cities are also annexed. However the only exception are the loads supplied from Plainfield.
F1107 Is the metering at Davis 1107 Feeder serving University of Davis
Shaded areas correspond to investments associated with the "paired" city due to issues of exclusivity to that city (e.g Davis in the City of West Sacramento Analysis)

1.3 Future Load Distribution Network Investment

1.3.1 Introduction

This section of the report provides an estimation of the investments that are likely to be necessary in each of the cities' distribution systems, to attend the projected load growth

An estimated load is calculated for each of the substations within the annexation area for the years 2006, 2008 and 2013 as represented in the corresponding power flow cases. This forecast corresponds to peak demand during summer heat conditions that have 10% probability of being exceeded. This demand differs from the 2004 values that correspond to a case developed for operational studies.

Table 1-16 summarizes the peak loads per substation and the Compounded Annual Growth Rate (CAGR) between the years shown.

Table 1-16
Load Forecast

	Peak Demand MW								
	1999	2004	CAGR 99-04 %	2006	CAGR 04-06 %	2008	CAGR 06-08 %	2013	CAGR 08-13 %
Davis	72.03	82.9	2.9%	121.4	21.0%	119.7	-0.7%	127.8	1.3%
West Sacramento	52.99	52.8	-0.1%	70.3	15%	74.3	2.8%	79.8	1.4%
Woodland	90.14	92.5	0.5%	121.2	14%	129.8	3.5%	138.5	1.3%
Deepwater	11.97	13.6	2.6%	27.3	42%	28.4	2.0%	29.8	1.0%
Plainfield	12.22	7.1	-10.3%	14.4	42%	17.8	11.2%	19	1.3%
West Sacramento & Deepwater combined	65.0	66.4	0.4%	97.6	21%	102.7	2.6%	109.6	1.3%

In Table 1-16, the 1999 values were provided by PG&E as part of a previous investigation and are included here as a reference. The 1999 to 2004 growth demonstrates that the 2004 load is conservative and, with the exception of Plainfield, consistent with previous values[4]

This table also shows that there is a significant jump in load from 2004 to 2006 and that there is a much moderate growth thereafter. This jump is probably largely due to the changes in the assumptions for load forecasting discussed above.

Considering that with the 2004 load conditions the target distribution system is already close to capacity, the 2006 jump implies that very important investments in the network will be necessary to achieve compliance with technical performance criteria.

The evaluation of the required investments is presented in two phases. The first and most important phase was the estimation of the required investment to achieve compliance with the load forecasting assumptions above to meet 2006 conditions. Once system compliance was achieved, an evaluation of its performance under the 2008 and 2013 load conditions was performed.

[4] The load at Plainfield for 2004 and 2006 (10.1 MW) appeared too small and inconsistent with 1999 values and 2008 and 2013 projections. Therefore for 2006 it was adjusted to 14.4 MW as shown.

This approach is considered reasonable as the date of the annexation is currently unknown. It is unlikely that PG&E will undertake major investments in the network while the annexation process is ongoing. Therefore, the conservative assumption is to estimate that SMUD will have to make the 2006 estimated investments just after the acquisition, even though this might happen until 2008 or later.

Finally, it is important to mention that the results presented herein should be considered as indicative as they are based on the inventoried system, which is an approximation and on some important assumptions regarding load distribution, as discussed below.

1.3.2 Network Performance Under 2006 Load Conditions

To evaluate the feeders' performance under the projected peak summer conditions for 2006 (10% probability hot spell), the load was increased at each distribution transformer proportionally to the forecast load at the 115 kV substation. This procedure implicitly assumes that the load increases have the same geographical distribution as present loads. That is to say, the new loads will be placed near existing transformers.

Of course, this method does not take into consideration available land lots or the possibility of changes in the use of land. Therefore, it cannot contemplate geographical movements of load centers.

This approach is generally accepted for projections across shorter time periods. It provides a means to quickly estimate the necessary investments in the system. Similarly, this method is appropriate for estimating the necessary investments associated with the change in load forecasting criteria for 2006 onwards, as it does not imply significant displacement of the load centers.

There are more precise methods for load forecasting (e.g. land-use grid approach), but these methods require much more information than currently available.

The overall procedure to select the improvements was iterative. We started by loading the system and running load flows to evaluate its compliance with the operation criteria (5% of voltage drop and 100% of feeder load, except for rural feeders). If criteria violations were present then we added appropriate improvements to correct them. These improvements include:

- Modify configuration of feeders
- Add capacitors
- Add Voltage boosters
- Build New feeders
- Build new substations or enlarge existing ones.

With the reconfigured system, the procedure above was repeated until there were no violations and final configuration was reached. No changes were made to Davis Feeder 1107, as this feeder is not considered part of the annexation, (it provides service to UC Davis loads.)

Based on this analysis, two expansion scenarios were developed: one without new substations and one with new substations.

1.3.3 Expansion Scenario 1 — Without New Substations

This expansion scenario involves expanding existing substations to attend the load growth. Even without new substations, Scenario 1 requires significant improvements to the system.

From a high-level perspective, quite a large number of new feeders would be necessary to achieve compliance with the voltage drop and loading criteria, as shown in Table 1-17 below. These new feeders however, will reinstate some of the lost flexibility in the system's operation, as they will provide for some of the required spare capacity necessary for transferring load between feeders during emergencies or scheduled maintenance.

To complement the investments above on the medium voltage network (12 kV), several capacitor banks were placed on long feeders to lower the current and compensate for voltage drop. In fact, it was found that it was very important for these capacitors to be switched, otherwise there would be over-compensation during lower load conditions.

Table 1-17
New Feeders by Substation under Expansion Scenario 1

Substation	Quantity
Davis	6
West Sacramento	2
Deepwater	4
Woodland	5

For the implementation of Expansion Scenario 1, it is also necessary to reinforce the transformation at all substations in the system. Table 1-18 below shows the installed transformation capacity at each substation, forecasted demand for 2006 and 2008 and the reserve margin (defined as the ratio of transformation capacity to coincident demand). These results indicate that if no new transformation capacity were installed, it would be necessary to curtail significant amounts of load upon a transformer failure, given the limited capacity of transferring load between substations. The only potential exception to this finding is West Sacramento, where there is some reserve (20%) and it is possible to transfer some load to Deepwater during emergencies. However, it is very likely that even in this case there would be some level of load curtailment[5].

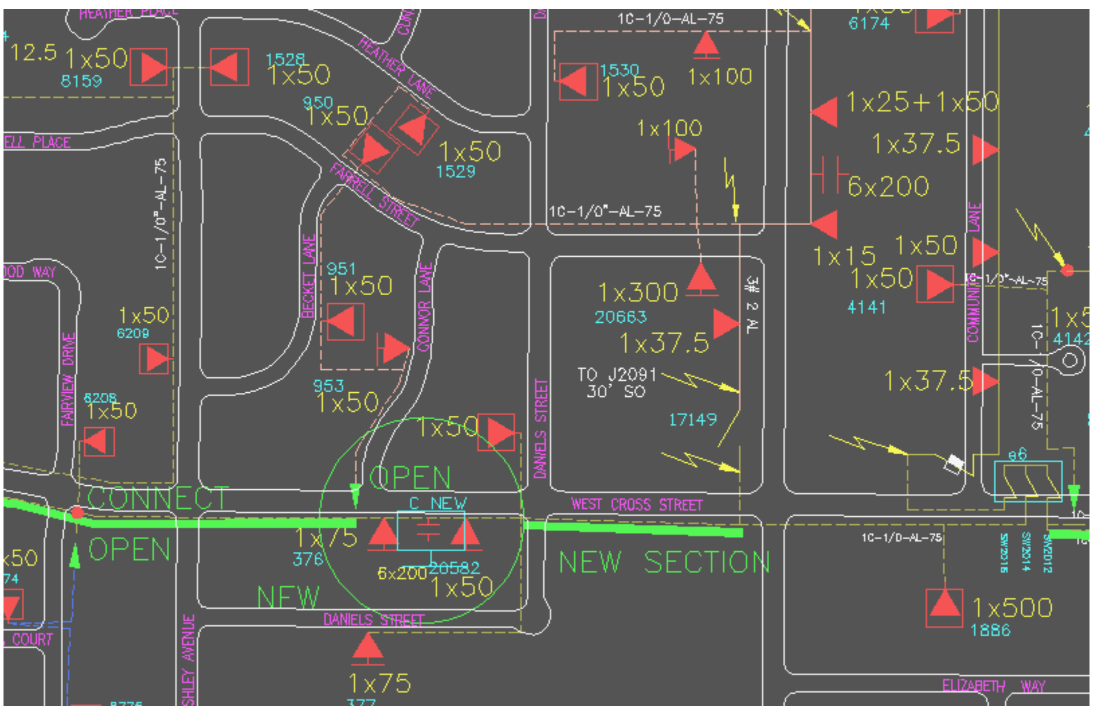
Table 1-18 presents the recommended additional transformation capacity.

[5] The 2008 reserve in West Sacramento is 15 MVA, which means that if a 30 MVA transformer were to fail, the remaining two would be overloaded by 25%. However assuming 10% overload capability then the shortfall is reduced to 9 MVA; part of it could be transferred to Deepwater but the rest would have to be curtailed.

Table 1-18
Transformation Capacity and Loading for Expansion Scenario 1

	Current Capacity MVA	2006 Demand Conditions Non Coincident MW	Coincident MW	Coincident MVA	2,008 Coincident MVA	2008 Reserve	Additional MVA
Davis	120	171,417	121	124	124	-3%	1x45
West Sacramento	90	100,923	70	71	75	20%	1x30
Deepwater	16	41,290	27	29	30	-47%	2x30
Woodland	135	173,563	121	122	131	3%	1x45
Plainfield	12	14,059	14	14	18	-33%	1x30
Total	373	501,252	354	361	378	-1%	210

Figure 1-9
Investments Example



1.3.4 Expansion Scenario 2 — With New Substations

Expansion Scenario 2 adds two new 115 kV/12 kV substations to attend the load growth in Davis and Woodland.

A Davis substation located at the site of the Hunt idling substation (see Figure 1-10) as this site has enough space and is adequately located to take load growth. However, there was no attempt to optimize the location of the new substation. Detailed studies might recommend a different site.

To be consistent with SMUD's practices, it was assumed that the new Davis substation would have a looped design. Therefore, it would be connected to either the Davis – Woodland 115 kV line or the Davis – West Sacramento 115 kV line. Under either case, the chosen line would be open and taken to the substation, therefore two 115 kV line circuit breakers will be required.

Given that the new Davis substation (called Hunt in the diagrams) will carry a coincident demand close to 34 MVA during peak conditions (see Table 1-19), it is estimated that it should have initially at least two 30 MVA transformers. In addition, the results of the evaluation indicate that it would have 6 12 kV feeders connected to it as shown in Table 1-19 and Figure 1-10.

Table 1-19
Transformation Capacity and Loading for Expansion Scenario 2

		2006 Demand Conditions					
	Current Capacity MVA	Non Coincident MW	Coincident MW	Coincident MVA	2,008 Coincident MVA	2008 Reserve	Additional MVA
Davis	120	123,600	87	89	89	35%	
Davis II (Hunt)		46,882	33	34	34		2x30
West Sacramento	90	100,923	70	71	75	20%	1x30
Deepwater	16	41,290	27	29	30	-47%	2x30
Woodland	135	134,957	94	95	102	33%	
Woodland II		38,566	27	27	29		2x30
Plainfield	12	14,059	14	14	18	-33%	1x30
Total	373	500,276	353	360	377	-1%	240

Table 1-20
New Feeders by Substation under Expansion Scenario 2

Substation	Quantity
Davis	1
West Sacramento	2
Deepwater	4
Woodland	1
New Davis (Hunt)	6
New Woodland	5

Figure 1-10
Location of New Substation at Davis

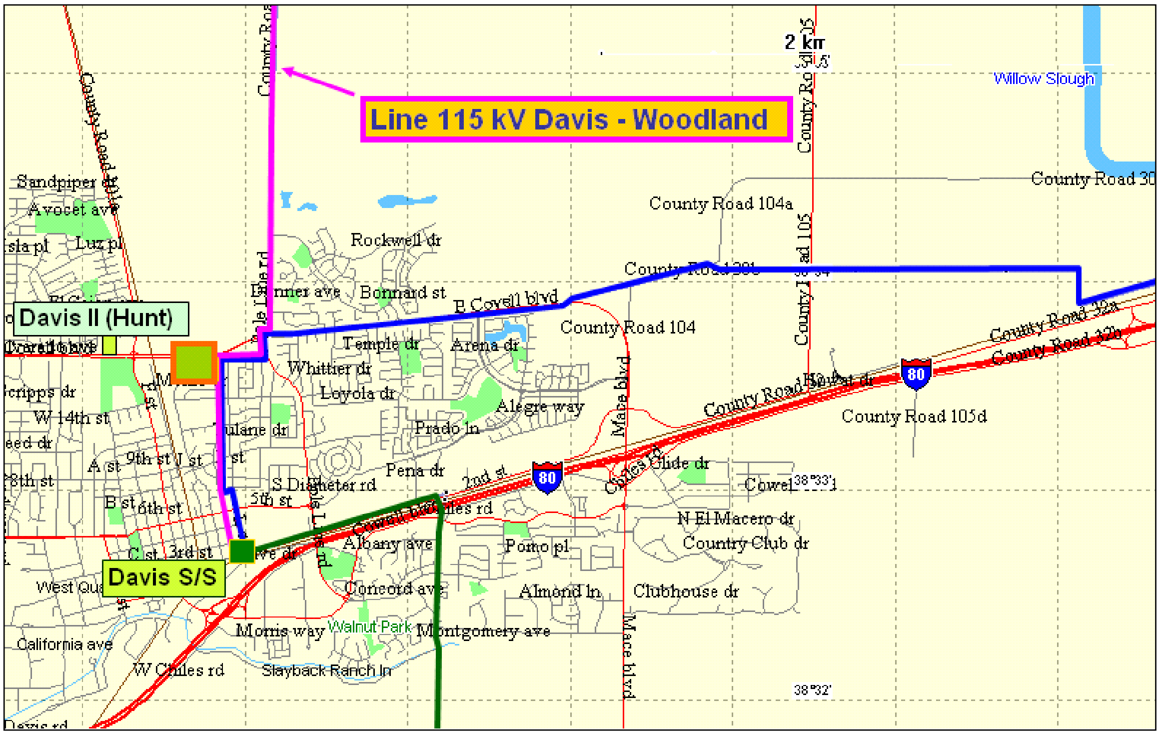
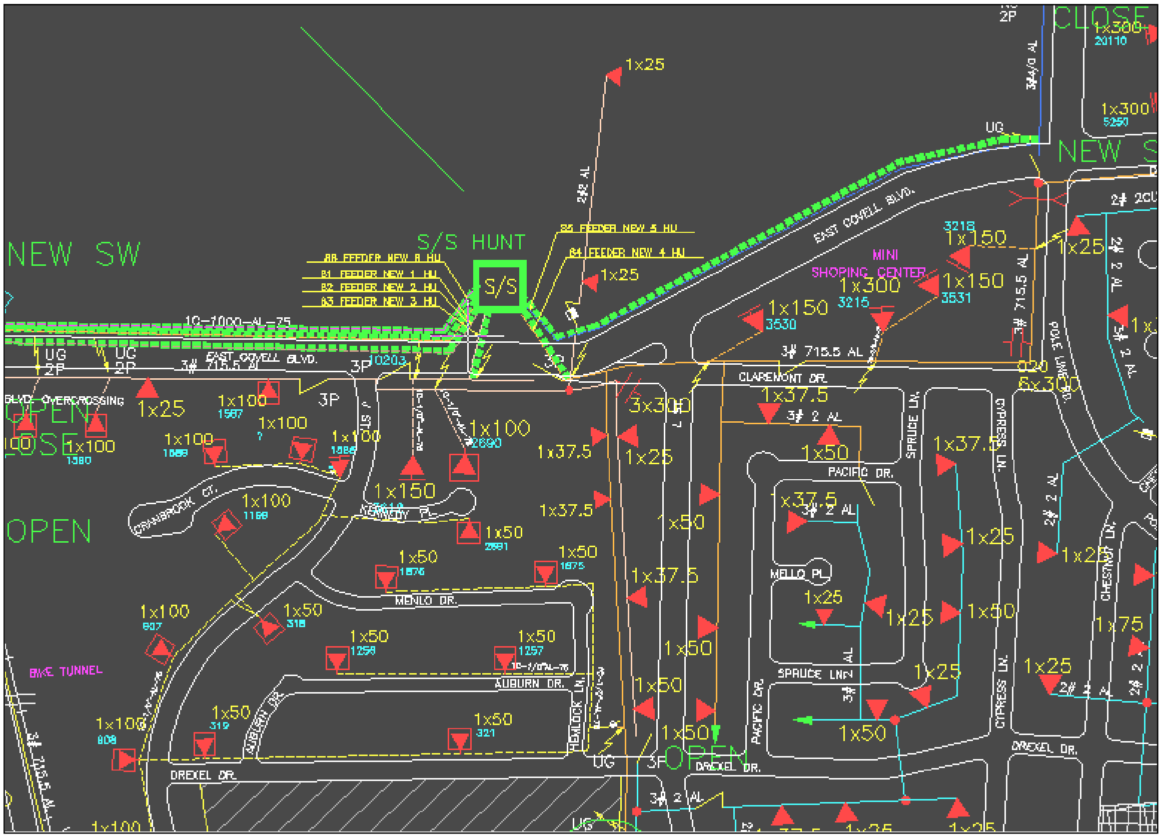


Figure 1-11
Detail of the New Substation at Davis (Hunt)



The second new substation is assumed to be in Woodland at the intersection of East Beamer and County Road 102 (see Figure 1-12). This site has adequate space and can supply load growth. However, optimization studies might find a different, more desirable site.

It is assumed that the new Woodland substation would also have looped design, and that it would be connected to the Davis – Woodland 115 kV line. However, its location would make it easy for it to be connected to the lines to Woodland Junction (or Elverta in the future). Under either case, the chosen line would be open and taken to the substation, therefore two 115 kV line circuit breakers will be required.

Given that the new Woodland substation (called Wood 2 in the diagrams) will carry a load close to 29 MVA during peak conditions (see Table 1-19), it is estimated that it should also have initially least two 30 MVA transformers. The results of our evaluation indicate that it would have Table 1-20 and Figure 1-12.

Figure 1-12
Location of New Substation at Woodland

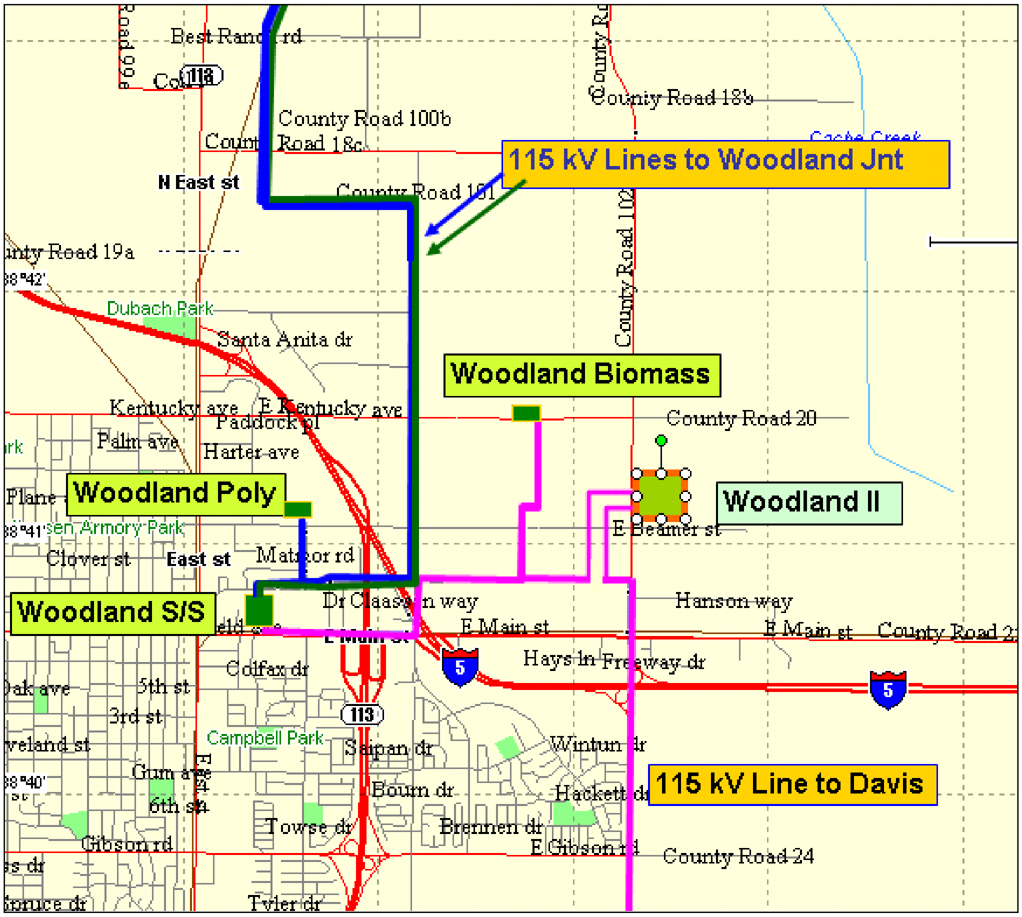
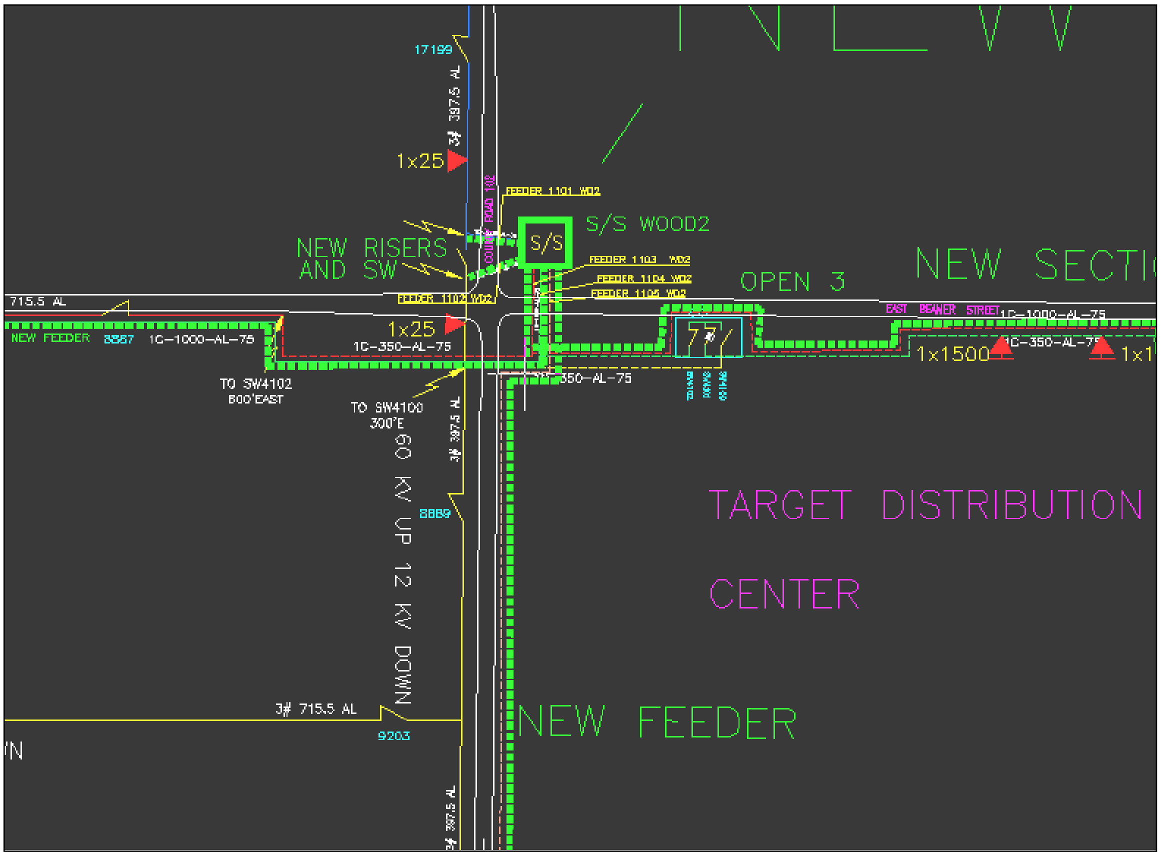


Figure 1-13
Detail of the New Substation at Woodland (WOOD 2)



1.3.5 Additional Considerations

One important consideration with respect of the suggested expansions is that the expansions are based on the inventory and desktop work. Therefore, it would be necessary for SMUD to verify, in the field, certain important aspects, including availability of rights of way and possible interferences with other public services, before the viability of the suggested additions can be assured. Such field verification is beyond the scope of our work.

Finally, Expansion Scenario 1 is not recommended for the following reasons:

- Without a new substation in Davis and Woodland the additions to these substations (new feeders and associated 115/12-kV transformation) will significantly congest them. This means that there will be no more room for any further expansion and possibly force a new substation in the short term.
- The load and number of customers that will become dependent on the Davis and Woodland substation is substantial, increasing the probability of extended blackouts if a major event were to happen at these locations.

- A large number of feeders on the same duct will reduce the cable ampacity and it would be necessary to increase conductor size or utilize two conductors per phase.
- Under Scenario 2, the new substations add flexibility, which could be used in the future for example for a change to 20 kV.

1.3.6 Distribution Analysis for 2008 and 2013 Load conditions

Load flow analysis for the 2008 and 2013 were run given expected load conditions under both grid expansion scenarios (i.e., with and without new substations). The results of this analysis indicate that they allow estimating the ability of each expansion scenario to attend the load growth.

Based on these results, the following conclusions can be reached:

- If new substations are added to the system (Expansion Scenario 2), the system will be able to withstand the forecasted load conditions for year 2008, with marginal additional investments. These marginal investments consist mostly of capacitor banks and Voltage boosters in rural feeders. There is only one feeder in Woodland that may need reconductoring as it may be overloaded by 4%. The main reason for this is that this feeder serves the load at southwest side of the city, which is on the opposite side of the new proposed substation Woodland II. By 2013, there are possibly four feeders that will be required at Woodland, as well as one in West Sacramento. However, there is significant uncertainty, since there may be load displacements not considered here. For such long term, it may be more appropriate to estimate the level of investments based on a multiplier per new customer.
- Under expansion Scenario 1 under 2008 load conditions, the voltage problems are significant and for that year Woodland would require a new substation with at least three feeders and possibly five.

1.3.7 Capital Expenditures

This section presents a summary of the capital expenditures required under the two expansion scenarios discussed above.

1.3.7.1 2006 Investments for Expansion Scenario 1

Table 1-21 shows a summary of the investments for expansion Scenario 1 (no new substations) required at each distribution system to achieve compliance with the voltage and loading criteria under 2006 summer peak conditions (hot spell with 10% probability of being exceeded). As can be observed the investments in the existing substations is substantial. Further detail on these investments is provided below.

Table 1-21
Investments for Expansion Scenario 1

	Medium Voltage Grid				
	Feeders	Others	Total	Substation	Total
Davis	$2,094,414	$ 350,576	$2,444,990	$1,694,880	$ 4,139,870
West Sacramento	539,323	304,959	844,281	1,129,680	1,973,961
Deepwater	414,151	96,588	510,739	3,053,010	3,563,749
Woodland	1,907,403	249,196	2,156,599	1,647,330	3,803,929
Plainfield	139,456	1,764	141,220	1,034,580	1,175,800
Total Scenario 1	$5,094,747	$1,003,082	$6,097,830	$8,559,480	$14,657,310

Davis

Table 1-22 contains additional details on the investments required at Davis under Expansion Scenario 1.

Table 1-22
2006 Investments at Davis under Expansion Scenario 1

ITEM	DESCRIPTION	Unit	Quantity	Price	Total
1.0	**FEEDERS**				
1.5	12 kV change Overhead feeder to 3 # 397.5 MCM AL, on insulators.	mi	0.281	$69,010	$ 19,363
1.7	12 Kv Underground feeder, 3 # 1000 MCM AL, on conduits.	mi	8.492	157,192	1,334,812
1.8	12 Kv Underground feeder, 3 # 350 MCM AL, on conduits.	mi	1.971	129,403	255,100
1.9	12 Kv Underground feeder, 3 # 1/0 AWG AL, on conduits.	mi	0.384	117,388	45,126
1.11	12 Kv Change Underground feeder, to 3 # 350 MCM AL, on conduits.	mi	2.001	209,560	419,356
1.12	12 Kv Change Underground feeder, from 2 ph to 3 ph 1/0 AWG AL, on conduits.	mi	0.480	43,042	20,654
3.0	**SWITCHES**				
3.1	Overhead three-phase Switch	Unit	5	3,615	18,077
3.6	Pad Mounted Switch PMH 43W	Unit	2	6,824	13,647
3.9	Subsurface 600 A 2 Ways.	Unit	1	6,824	6,823
3.10	Subsurface 600 A 3 Ways, 2 Ways switched.	Unit	2	6,824	13,647
3.11	Subsurface 600 A 3 Ways, 3 Ways switched.	Unit	3	6,917	20,751
4.0	**CAPACITORS BANKS.**				-
4.2	Overhead Capacitors Bank 3 x 200 kVAR .	Unit	3	4,458	13,375
4.3	Overhead Capacitors Bank 3 x 300 kVAR.	Unit	1	4,458	4,458
4.4	Overhead Capacitors Bank 6 x 200 kVAR.	Unit	3	8,272	24,815
4.7	Overhead Capacitors Change 3 X 300 KVAR	Unit	1	4,458	4,458
4.9	Pad Mounted Capacitors Bank 3 x 300 kVAR.	Unit	2	6,071	12,141
4.10	Pad Mounted Capacitors Bank 6 x 200 kVAR.	Unit	16	11,174	178,786
4.11	Pad Mounted Capacitors Bank 6 x 300 kVAR.	Unit	3	11,174	33,522
4.13	Pad Mounted Capacitors Bank Change 3 x 300 kVAR.	Unit	1	6,071	6,070
6.0	**OPERATIONS**				
6.1	SWITCH OR PREMOLDED OPERATION	#	50	6,824	
	TOTAL Medium Voltage Grid				**$ 2,444,990**
6.0	**SUBSTATIONS**				
7.1	115/12 kV Transf. 45 MVA	Unit	1	$1,125,000	$1,125,000
7.3	115kV Circuit Swithcher	Unit	1	180,000	180,000
7.4	115kV Disconnect Switch	Unit	3	27,300	81,900
7.5	115kV PT	Unit	1	16,800	16,800
7.6	115kV Lightning Arrester	Unit	1	5,880	5,880
7.7	12 kV Circuit Breaker	Unit	6	27,000	162,000
7.8	12 kV Disconnect Switch	Unit	18	6,850	123,300
	TOTAL Substations				**$ 1,694,880**
	GRAND TOTAL				**$ 4,139,870**

West Sacramento

Table 1-23 contains additional details on the investments required at West Sacramento under Expansion Scenario 1, which are also the same for Expansion Scenario 2.

Table 1-23
2006 Investments at West Sacramento under Expansion Scenario 1

ITEM	DESCRIPTION	Unit	Quantity	Price	Total
1.0	**FEEDERS**				
1.2	12 kv Overhead feeder, 3 # 397.5 MCM AL, on insulators.	mi	1.064	$39,408	$41,940
1.6	12 kV change Overhead feeder to 3 # 4/0 AWG AL, on insulators.	mi	0.036	66,190	2,393
1.7	12 Kv Underground feeder, 3 # 1000 MCM AL, on conduits.	mi	2.447	157,192	384,630
1.8	12 Kv Underground feeder, 3 # 350 MCM AL, on conduits.	mi	0.077	129,403	9,991
1.9	12 Kv Underground feeder, 3 # 1/0 AWG AL, on conduits.	mi	0.067	117,388	7,909
1.11	12 Kv Upsize Underground feeder, to 3 # 350 MCM AL, on conduits.	mi	0.441	209,560	92,459
3.0	**SWITCHES**				
3.1	Overhead three-phase Switch	Unit	2	3,615	7,231
3.5	Pad Mounted Switch PMH4	Unit	1	5,534	5,534
4.0	**CAPACITORS BANKS.**				
4.4	Overhead Capacitors Bank 6 x 200 kVAR.	Unit	9	8,272	74,445
4.6	Overhead Capacitors Upsize 3 X 200 KVAR	Unit	1	4,458	4,458
4.7	Overhead Capacitors Upsize 3 X 300 KVAR	Unit	2	4,458	8,917
4.9	Pad Mounted Capacitors Bank 3 x 300 kVAR.	Unit	2	6,071	12,142
4.10	Pad Mounted Capacitors Bank 6 x 200 kVAR.	Unit	3	11,174	33,523
5.0	**REGULATORS**				
5.1	Four Step Voltage Regulator	Banks	1.000	1,764	1,764
6.0	**OPERATIONS**				
6.1	SWITCH OR PREMOLDED OPERATION	#	23	6,824	156,946
	TOTAL Medium Voltage Grid				**$844,281**
6.0	**SUBSTATIONS**				
7.1	115/12 kV Transf. 30 MVA	Unit	1	$750,000	$750,000
7.2	115kV Circuit Breaker	Unit		238,000	0
7.3	115kV Circuit Swithcher	Unit	1	180,000	180,000
7.4	115kV Disconnect Switch	Unit	3	27,300	81,900
7.5	115kV PT	Unit	1	16,800	16,800
7.6	115kV Lightning Arrester	Unit	1	5,880	5,880
7.7	12 kV Circuit Breaker	Unit	2	27,000	54,000
7.8	12 kV Disconnect Switch	Unit	6	6,850	41,100
	TOTAL Substations				**$1,129,680**
	GRAND TOTAL				**$1,973,961**

Deepwater

Table 1-24 contains additional details on the investments required at Deepwater under Expansion Scenario 1, which are also the same for Expansion Scenario 2.

Table 1-24
2006 Investments at Deepwater under Expansion Scenario 1

ITEM	DESCRIPTION	Unit	Quantity	Price	Total
1.0	**FEEDERS**				
1.7	12 Kv Underground feeder, 3 # 1000 MCM AL, on conduits.	mi	2.635	$157,192	$ 414,151
3.0	**SWITCHES**				
3.1	Overhead three-phase Switch	Unit	1	3,615	3,615
3.11	Subsurface 600 A 3 Ways, 3 Ways switched.	Unit	1	6,917	6,917
4.0	**CAPACITORS BANKS.**				-
4.4	Overhead Capacitors Bank 6 x 200 kVAR.	Unit	5	8,272	41,358
4.10	Pad Mounted Capacitors Bank 6 x 200 kVAR.	Unit	4	11,174	44,697
6.0	**OPERATIONS**				
6.1	SWITCH OR PREMOLDED OPERATION	#	16	6,824	
	TOTAL Medium Voltage Grid				**$ 510,739**
6.0	**SUBSTATIONS**				
7.1	115/12 kV Transf. 30 MVA	Unit	2	$750,000	$ 1,500,000
7.2	115kV Circuit Breaker	Unit	2	238,000	476,000
7.3	115kV Circuit Swithcher	Unit	2	180,000	360,000
7.4	115kV Disconnect Switch	Unit	18	27,300	491,400
7.5	115kV PT	Unit	1	16,800	16,800
7.6	115kV Lightning Arrester	Unit	2	5,880	11,760
7.7	12 kV Circuit Breaker	Unit	4	27,000	108,000
7.8	12 kV Disconnect Switch	Unit	13	6,850	89,050
	TOTAL Substations				**$ 3,053,010**
	GRAND TOTAL				**$ 3,563,749**

Woodland

Table 1-25 contains additional details on the investments required at Woodland under Expansion Scenario 1.

Table 1-25
2006 Investments for Woodland Under Expansion Scenario 1

ITEM	DESCRIPTION	Unit	Quantity	Price	Total
1.0	**FEEDERS**				
1.1	12 kv Overhead feeder, 3 # 715.5 MCM AL, on insulators.	mi	1.406	$44,338	$ 62,346
1.2	12 kv Overhead feeder, 3 # 397.5 MCM AL, on insulators.	mi	0.316	39,408	12,446
1.3	12 kV Overhead feeder, 3 # 4/0 AWG AL, on insulators.	mi	0.000	36,588	-
1.4	12 kV change Overhead feeder to 3 # 715.5 MCM AL, on insulators.	mi	0.268	73,938	19,838
1.5	12 kV change Overhead feeder to 3 # 397.5 MCM AL, on insulators.	mi	2.274	69,010	156,898
1.6	12 kV change Overhead feeder to 3 # 4/0 AWG AL, on insulators.	mi	0.000	66,190	-
1.7	12 Kv Underground feeder, 3 # 1000 MCM AL, on conduits.	mi	7.905	157,192	1,242,664
1.8	12 Kv Underground feeder, 3 # 350 MCM AL, on conduits.	mi	1.773	129,403	229,384
1.9	12 Kv Underground feeder, 3 # 1/0 AWG AL, on conduits.	mi	0.021	117,388	2,462
1.10	12 Kv Change Underground feeder, to 3 # 1000 MCM AL, on conduits.	mi	0.255	237,350	60,619
1.11	12 Kv Change Underground feeder, to 3 # 350 MCM AL, on conduits.	mi	0.000	209,560	-
1.12	12 Kv Change Underground feeder, from 2 ph to 3 ph 1/0 AWG AL, on conduits.	mi	0.000	43,042	-
2.0	**POLES**				
2.1	40 to 45 feets pole, with all hardwares and accessories	Unit	57	2,103	120,740
3.0	**SWITCHES**				
3.1	Overhead three-phase Switch	Unit	9	3,615	32,539
3.5	Pad Mounted Switch PMH4	Unit	5	5,534	27,668
3.9	Subsurface 600 A 2 Ways.	Unit	1	6,824	6,823
4.0	**CAPACITORS BANKS.**				-
4.5	Overhead Capacitors Bank 6 x 200 kVAR.	Unit	3	8,272	24,815
4.7	Overhead Capacitors Change 3 X 200 KVAR	Unit	5	4,458	22,291
4.9	Pad Mounted Capacitors Bank 3 x 200 kVAR .	Unit	2	6,071	12,141
4.11	Pad Mounted Capacitors Bank 6 x 200 kVAR.	Unit	11	11,174	122,915
5.0	**REGULATORS**				
5.1	Four Step Voltage Regulator	Banks	0.000	1,764	-
5.2	Thirty Two Step Voltage Regulator	Banks	0.000	2,137	-
6.0	**OPERATIONS**				
6.1	SWITCH OR PREMOLDED OPERATION	#	47	$6,824	
	TOTAL Medium Voltage Grid				**$ 2,156,599**
6.0	**SUBSTATIONS**				
7.1	115/12 kV Transf. 45 MVA	Unit	1	$1,125,000	$ 1,125,000
7.3	115kV Circuit Swithcher	Unit	1	180,000	180,000
7.4	115kV Disconnect Switch	Unit	3	27,300	81,900
7.5	115kV PT	Unit	1	16,800	16,800
7.6	115kV Lightning Arrester	Unit	1	5,880	5,880
7.7	12 kV Circuit Breaker	Unit	5	27,000	135,000
7.8	12 kV Disconnect Switch	Unit	15	6,850	102,750
	TOTAL Substations				**$ 1,647,330**
	GRAND TOTAL				**$ 3,803,929**

Plainfield

Table 1-26 contains additional details on the investments required at Plainfield under Expansion Scenario 1, which are the same for Expansion Scenario 2. The investments at the substation correspond to those necessary to convert to 115 kV (from 60 kV).

Table 1-26
2006 Investments at Plainfield under Expansion Scenario 1

ITEM	DESCRIPTION	Unit	Quantity	Price	Total
1.0	**FEEDERS**				
1.5	12 kV change Overhead feeder to 3 # 397.5 MCM AL, on insulators.	mi	2.021	$69,010	$ 139,455
5.0	**REGULATORS**				
5.1	Four Step Voltage Regulator	Banks	1.000	1,764	1,763
6.0	**OPERATIONS**				
6.1	SWITCH OR PREMOLDED OPERATION	#	2	6,824	
	TOTAL Medium Voltage Grid				**$ 141,220**
6.0	**SUBSTATIONS**				
7.1	115/12 kV Transf. 30 MVA	Unit	1	$750,000	$ 750,000
7.3	115kV Circuit Swithcher	Unit	1	180,000	180,000
7.4	115kV Disconnect Switch	Unit	3	27,300	81,900
7.5	115kV PT	Unit	1	16,800	16,800
7.6	115kV Lightning Arrester	Unit	1	5,880	5,880
	TOTAL Substations				**$ 1,034,580**
	GRAND TOTAL				**$ 1,175,800**

1.3.7.2 2006 Investments for Expansion Scenario 2

Table 1-27 shows a summary of the investments for expansion Scenario 2, including the new substations. These investments would make each distribution system compliant with the voltage and loading criteria under 2006 summer peak conditions (hot spell with 10% probability of being exceeded). These investments are about $3 million higher than those required under Expansion Scenario 1, but as discussed in previous sections they provide much greater flexibility.

Further detail on these investments at Davis and Woodland are provided below. West Sacramento, Deepwater and Plainfield remain the same.

Table 1-27
Investments for Expansion Scenario 2

	Medium Voltage Grid				
	Feeders	Others	Total	Substation	Total
Davis	$ 792,049	$ 237,240	$1,029,289	$ 47,550	$ 1,076,839
Davis II (Hunts)	847,766	258,059	1,105,824	3,107,970	4,213,794
West Sacramento	539,323	304,959	844,281	1,129,680	1,973,961
Deepwater	414,151	96,588	510,739	3,053,010	3,563,749
Woodland	1,694,746	200,008	1,894,754	47,550	1,942,304
Woodland II	676,571	33,846	710,417	3,107,970	3,818,387
Plainfield	139,456	1,764	141,220	1,034,580	1,175,800
Total Scenario 2	$5,104,061	$1,132,464	$6,236,525	$11,528,310	$17,764,835

Davis

Table 1-28 contains additional details on the investments required at Davis substation under Expansion Scenario 2. These investments do not include the investments at Davis II (Hunt), which are presented below.

Table 1-28
2006 Investments at Existing Davis under Expansion Scenario 2

ITEM	DESCRIPTION	Unit	Quantity	Price	Total
1.0	**FEEDERS**				
1.4	12 kV change Overhead feeder to 3 # 715.5 MCM AL, on insulators.	mi	0.235	$73,938	$ 17,375
1.7	12 Kv Underground feeder, 3 # 1000 MCM AL, on conduits.	mi	3.265	157,192	513,232
1.8	12 Kv Underground feeder, 3 # 350 MCM AL, on conduits.	mi	0.920	129,403	119,050
1.9	12 Kv Underground feeder, 3 # 1/0 AWG AL, on conduits.	mi	0.180	117,388	21,129
1.11	12 Kv Upsize Underground feeder, to 3 # 350 MCM AL, on conduits.	mi	0.526	209,560	110,150
1.12	12 Kv Change Underground feeder, from 2 ph to 3 ph 1/0 AWG AL, on conduits.	mi	0.258	43,042	11,110
3.0	**SWITCHES**				
3.1	Overhead three-phase Switch	Unit	2	3,615	7,230
3.5	Pad Mounted Switch PMH4	Unit	1	5,534	5,533
3.10	Subsurface 600 A 3 Ways, 2 Ways switched.	Unit	3	6,824	20,471
3.11	Subsurface 600 A 3 Ways, 3 Ways switched.	Unit	2	6,917	13,834
4.0	**CAPACITORS BANKS.**				-
4.2	Overhead Capacitors Bank 3 x 200 kVAR .	Unit	1	4,458	4,458
4.4	Overhead Capacitors Bank 6 x 200 kVAR.	Unit	2	8,272	16,543
4.5	Overhead Capacitors Bank 6 x 300 kVAR.	Unit	1	8,272	8,271
4.7	Overhead Capacitors Upsize 3 X 300 KVAR	Unit	1	4,458	4,458
4.10	Pad Mounted Capacitors Bank 6 x 200 kVAR.	Unit	9	11,174	100,567
4.11	Pad Mounted Capacitors Bank 6 x 300 kVAR.	Unit	5	11,174	55,870
6.0	**OPERATIONS**				
6.1	SWITCH OR PREMOLDED OPERATION	#	31	6,824	
	TOTAL Medium Voltage Grid				**$ 1,029,289**
6.0	**SUBSTATIONS**				
7.7	12 kV Circuit Breaker	Unit	1	$27,000	$ 27,000
7.8	12 kV Disconnect Switch	Unit	3	6,850	20,550
	TOTAL Substations				**$ 47,550**
	GRAND TOTAL				**$ 1,076,839**

New Davis (Davis II or Hunt)

Table 1-29 contains additional details on the investments required at the new Davis substation under Expansion Scenario 2.

Table 1-29
2006 Investments at New Davis (Hunt) under Expansion Scenario 2

ITEM	DESCRIPTION	Unit	Quantity	Price	Total
1.0	**FEEDERS**				
1.5	12 kV change Overhead feeder to 3 # 397.5 MCM AL, on insulators.	mi	0.278	$69,010	$19,193
1.7	12 Kv Underground feeder, 3 # 1000 MCM AL, on conduits.	mi	3.730	157,192	586,327
1.8	12 Kv Underground feeder, 3 # 350 MCM AL, on conduits.	mi	0.613	129,403	79,340
1.11	12 Kv Change Underground feeder, to 3 # 350 MCM AL, on conduits.	mi	0.768	209,560	160,968
1.12	12 Kv Change Underground feeder, from 2 ph to 3 ph 1/0 AWG AL, on conduits.	mi	0.045	43,042	1,937
3.0	**SWITCHES**				
3.1	Overhead three-phase Switch	Unit	2	3,615	7,231
3.11	Subsurface 600 A 3 Ways, 3 Ways switched.	Unit	2	6,917	13,834
4.0	**CAPACITORS BANKS.**				
4.2	Overhead Capacitors Bank 3 x 200 kVAR .	Unit	1	4,458	4,458
4.9	Pad Mounted Capacitors Bank 3 x 300 kVAR.	Unit	1	6,071	6,071
4.10	Pad Mounted Capacitors Bank 6 x 200 kVAR.	Unit	4	11,174	44,697
4.11	Pad Mounted Capacitors Bank 6 x 300 kVAR.	Unit	1	11,174	11,174
6.0	**OPERATIONS**				
6.1	SWITCH OR PREMOLDED OPERATION	#	25	6,824	170,593
	TOTAL Medium Voltage Grid				**$1,105,824**
6.0	**SUBSTATIONS**				
7.1	115/12 kV Transf. 30 MVA	Unit	2	$750,000	$1,500,000
7.2	115kV Circuit Breaker	Unit	2	238,000	476,000
7.3	115kV Circuit Swithcher	Unit	2	180,000	360,000
7.4	115kV Disconnect Switch	Unit	12	27,300	327,600
7.5	115kV PT	Unit	2	16,800	33,600
7.6	115kV Lightning Arrester	Unit	4	5,880	23,520
7.7	12 kV Circuit Breaker	Unit	8	27,000	216,000
7.8	12 kV Disconnect Switch	Unit	25	6,850	171,250
	TOTAL Substations				**$3,107,970.00**
	GRAND TOTAL				**$4,213,794.50**

Woodland

Table 1-30 contains additional details on the investments required at the existing Woodland substation under Expansion Scenario 2. They do not include the investments in the new Woodland substation.

Table 1-30
2006 Investments at Woodland under Expansion Scenario 2

ITEM	DESCRIPTION	Unit	Quantity	Price	Total
1.0	**FEEDERS**				
1.1	12 kv Overhead feeder, 3 # 715.5 MCM AL, on insulators.	mi	0.000	$44,338	-
1.2	12 kv Overhead feeder, 3 # 397.5 MCM AL, on insulators.	mi	0.503	39,408	$ 19,827
1.3	12 kV Overhead feeder, 3 # 4/0 AWG AL, on insulators.	mi	0.000	36,588	-
1.4	12 kV change Overhead feeder to 3 # 715.5 MCM AL, on insulators.	mi	0.000	73,938	-
1.5	12 kV change Overhead feeder to 3 # 397.5 MCM AL, on insulators.	mi	1.778	69,010	122,708
1.6	12 kV change Overhead feeder to 3 # 4/0 AWG AL, on insulators.	mi	0.000	66,190	-
1.7	12 Kv Underground feeder, 3 # 1000 MCM AL, on conduits.	mi	9.321	157,192	1,465,228
1.8	12 Kv Underground feeder, 3 # 350 MCM AL, on conduits.	mi	0.000	129,403	-
1.9	12 Kv Underground feeder, 3 # 1/0 AWG AL, on conduits.	mi	0.000	117,388	-
1.10	12 Kv Change Underground feeder, to 3 # 1000 MCM AL, on conduits.	mi	0.255	237,350	60,524
1.11	12 Kv Change Underground feeder, to 3 # 350 MCM AL, on conduits.	mi	0.000	209,560	-
1.12	12 Kv Change Underground feeder, from 2 ph to 3 ph 1/0 AWG AL, on conduits.	mi	0.000	43,042	-
2.0	**POLES**				
2.1	40 to 45 feets pole, with all hardwares and accessories	Unit	13	2,103	26,457
3.0	**SWITCHES**				
3.1	Overhead three-phase Switch	Unit	5	3,615	18,077
3.5	Pad Mounted Switch PMH4	Unit	3	5,534	16,601
3.11	Subsurface 600 A 3 Ways, 3 Ways switched.	Unit	1	6,917	6,917
4.0	**CAPACITORS BANKS.**				-
4.2	Overhead Capacitors Bank 3 x 200 kVAR .	Unit	2	4,458	8,916
4.5	Overhead Capacitors Bank 6 x 200 kVAR.	Unit	6	8,272	49,630
4.7	Overhead Capacitors Change 3 X 200 KVAR	Unit	6	4,458	26,750
4.11	Pad Mounted Capacitors Bank 6 x 200 kVAR.	Unit	6	11,174	67,045
4.13	Pad Mounted Capacitors Bank Change 3 x 200 kVAR.	Unit	1	6,071	6,070
5.0	**REGULATORS**				
5.1	Four Step Voltage Regulator	Banks	0.000	1,764	-
5.2	Thirty Two Step Voltage Regulator	Banks	0.000	2,137	-
6.0	**OPERATIONS**				
6.1	SWITCH OR PREMOLDED OPERATION	#	45	$6,824	
	TOTAL Medium Voltage Grid				**$ 1,894,754**
6.0	**SUBSTATIONS**				
7.7	12 kV Circuit Breaker	Unit	1	$27,000	27,000
7.8	12 kV Disconnect Switch	Unit	3	6,850	20,550
	TOTAL Substations				**$ 47,550**
	GRAND TOTAL				**$ 1,942,304**

New Woodland (Woodland II)

Table 1-31 contains additional details on the investments required at the new Woodland substation under Expansion Scenario 2.

Table 1-31
2006 Investments at Woodland II under Expansion Scenario 2

ITEM	DESCRIPTION	Unit	Quantity	Price	Total
1.0	**FEEDERS**				
1.7	12 Kv Underground feeder, 3 # 1000 MCM AL, on conduits.	mi	2.401	$157,192	$ 377,359
1.8	12 Kv Underground feeder, 3 # 350 MCM AL, on conduits.	mi	0.864	129,403	111,771
1.11	12 Kv Upsize Underground feeder, to 3 # 350 MCM AL, on conduits.	mi	0.083	209,560	17,419
2.0	**POLES**				
2.1	40 to 45 feets pole, with all hardwares and accessories	Unit	81	2,103	170,020
3.0	**SWITCHES**				
3.5	Pad Mounted Switch PMH4	Unit	3	5,534	16,601
4.0	**CAPACITORS BANKS.**				-
4.10	Pad Mounted Capacitors Bank 6 x 200 kVAR.	Unit	1	11,174	11,174
4.12	Pad Mounted Capacitors Bank Upsize 3 x 200 kVAR.	Unit	1	6,071	6,070
6.0	**OPERATIONS**				
6.1	SWITCH OR PREMOLDED OPERATION	#	6	6,824	
	TOTAL Medium Voltage Grid				**$ 710,417**
6.0	**SUBSTATIONS**				
7.1	115/12 kV Transf. 30 MVA	Unit	2	$750,000	$ 1,500,000
7.2	115kV Circuit Breaker	Unit	2	238,000	476,000
7.3	115kV Circuit Swithcher	Unit	2	180,000	360,000
7.4	115kV Disconnect Switch	Unit	12	27,300	327,600
7.5	115kV PT	Unit	2	16,800	33,600
7.6	115kV Lightning Arrester	Unit	4	5,880	23,520
7.7	12 kV Circuit Breaker	Unit	8	27,000	216,000
7.8	12 kV Disconnect Switch	Unit	25	6,850	171,250
	TOTAL Substations				**$ 3,107,970**
	GRAND TOTAL				**$ 3,818,387**

1.3.8 Recommended Procedure to Estimate Long-Term Investments

In the previous section, estimates of the investments necessary to bring the target distribution system in compliance with SMUD's criteria was provided, as well as proposed performance criteria. Any further investments will be driven by natural load growth. Given the uncertainties associated with new load growth, a top-down approach to estimate the associated investments is performed.

This top-down procedure is based on estimating and investment per new customer plus and allowance for replacement of assets. Based on experience, the results of this methodology are appropriate for feasibility calculations.

Table 1-32 shows the RCN for the target distribution system for each of the cities (Woodland includes Plainfield) and the ratio of the total investments per customer.

This ratio is in our experience remarkably constant for different distribution areas, which makes sense as its bulk is represented by the medium voltage and low voltage grids.

Estimates of the long-term investments (post 2006) are calculated by multiplying the growth in the number of customers by $1,200 per customer to estimate the investments in the 12 kV network and $520 per customer for low voltage service drops and meters.

Major investments in substations under expansion Scenario 2 are not anticipated and expansion Scenario 1 is not recommended.

The top-down approach could be refined if demand projections by customer class and service type (overhead/underground) become available.

Table 1-32
RCN per Customer

	West Sac	Davis	Woodland	Total
Substations	$ 9,544,353	$ 8,201,776	$ 9,069,754	$ 26,815,883
Value MV network	25,480,256	32,110,373	29,074,643	86,665,272
Value LV network, drops & meters	9,492,951	16,609,880	10,898,007	37,000,839
Total	$44,517,560	$56,922,029	$49,042,404	$150,481,994
Estimated Customers	16,600	32,100	23,600	72,300
Substations / Customer	575	256	384	371
MV network / Customer	1,535	1,000	1,232	1,199
LV network, drop & meters /Customer	572	517	462	512
Total per Customer	$ 2,682	$ 1,773	$ 2,078	$ 2,081

Finally, to estimate allowance for replacement of assets, the estimated useful life for the different asset classes was used, with the following considerations. The overhead system is a mature system so it is reasonable to expect that SMUD will have to reinvest a value close to the depreciation in asset replacement; hence 1/40th of the RCN was used. The same consideration applies to meters and the low voltage overhead network. In this case, 1/25th of the RCN was used. The underground network is rather new and to use its depreciation would overstate the investments, therefore, 1% of the RCN was used to account for asset replacement or equipment failure.

Table 1-33 shows these calculations for the target distribution systems.

Table 1-33
RCN by Asset Class and Replacement Allowance

	West Sac	Davis	Woodland	Total
Substations	$ 9,544,353	$ 8,201,776	$ 9,069,754	$26,815,883
Value MV network O/H	12,833,625	15,837,322	16,039,079	44,710,026
Value MV network U/G	12,646,631	16,273,051	13,035,564	41,955,246
LV Network O/H (includes S drops)	4,141,424	5,463,208	5,093,891	14,698,523
LV network U/G	3,625,083	8,789,798	3,784,248	16,199,129
Meters	1,726,444	2,356,874	2,019,868	6,103,186
Total	44,517,560	56,922,029	49,042,404	150,481,994
Asset Replacement Allowance per year				
Overhead MV network, factor 1/40	320,841	395,933	400,977	1,117,751
Underground MV network, factor 1%	126,466	162,731	130,356	419,552
Meters, factor 1/25	69,058	94,275	80,795	244,127
LV Network O/H (includes S drops) factor 1/25	12,834	15,837	16,039	44,710
LV network U/G factor 1%	3,208	3,959	4,010	11,178
Total Asset Replacement	$ 532,407	$ 672,735	$ 632,176	$ 1,837,318

It should be noted that the values above a guidelines and SMUD practices and experience might dictate different values.

Section 2
VALUATION

An important consideration in evaluating the feasibility of SMUD annexing all or a portion of the electrical facilities serving the Yolo Jurisdictions is the purchase price that would be paid to PG&E to acquire its transmission and distribution facilities. This section of the Study develops indicators of value for the electrical transmission and distribution facilities serving the Yolo Jurisdictions using generally accepted valuation methodologies. The indicators of value represent the value of facilities that would be acquired by SMUD and stranded assets identified in Section 1, Technical Assessment, of this report for each annexation scenario. These values were employed in the Economic Evaluation contained in Section 3.

2.1 Fair Market Value Analyses

There are three generally accepted approaches to estimating the value of property: the cost approach, the income approach and the market approach. Under the cost approach, the value of the property is based on the premise that an informed buyer would pay no more than the cost of producing a substitute property with the same utility as the subject property. Under the income approach, the value of the property is estimated by capitalizing or determining the present worth of the prospective net income from the property. The market approach assesses value based on recent fair market sales of similar facilities under similar circumstances.

Indicators of value were estimated based on the cost and income approaches to value. The market approach is difficult to apply in valuing utility property due to the lack of utility sales transactions that are comparable to the Study Area and thus was not relied upon in this Study.

2.2 Cost Approach

Two indicators of value that are commonly considered when valuing electric transmission and distribution facilities under the cost approach are the Original Cost Less Depreciation (OCLD) value and the Reproduction Cost New Less Depreciation (RCNLD) value of the property. OCLD is defined as the original cost of the property when it was first put into service, less accrued depreciation. The OCLD value is an estimate of the net book value of the property, which is generally equivalent to the rate base value of the property for ratemaking purposes. RCNLD is defined as the cost of constructing an exact replica of the property at current prices with the same or closely related materials, less accrued depreciation. The RCNLD and OCLD values tend to set the upper and lower limits, respectively, on the range of fair market value for electric transmission and distribution facilities.

Appendix C shows the calculation of the estimated RCNLD and OCLD values for the distribution systems in West Sacramento, Davis, Woodland and Plainfield and the transmission facilities by annexation scenario.

The starting point for the RCNLD and OCLD analyses was the inventory quantities and the estimated Reproduction Cost New (RCN) values developed in Section 1, Technical Assessment.

The general concept of the reproduction cost contemplates a normal construction effort in that the property would be constructed as a whole, in one continuous sequence, by a general contractor acting for the owner and under the supervision of its representatives. The inventory of the property, its condition and approximate age were established from the field inspection described in Section 1.

The RCN value of the facilities was determined by the application of unit prices to the items of inventory. The unit prices applied reflect costs which generally were current on or about January 1, 2004, in the general area in which the property is located. They include the cost of material and labor as well as certain miscellaneous construction costs consisting of such items as superintendence, field office, temporary construction, use of construction equipment, inspection and expediting, and contingencies. General construction costs cover expenditures which the owner would be required to make during the construction period over and above the amounts disbursed through the medium of the general contractor. These costs include the items of engineering, contractor's services, administrative and legal expense, and interest during construction. As the general construction costs cannot be identifiably related to specific items of property, they have been added as a percentage to the total direct cost.

The amount of accumulated depreciation was estimated based on the age of the facilities and depreciation factors (average service lives, survivor curves and net salvage rates) reported by PG&E in its FERC Form 1 Annual Report using the straight line method of depreciation. The accumulated depreciation was then subtracted from the RCN value to determine the RCNLD value.

The OCLD value was estimated by trending the current cost figures to the year of installation using the *Handy-Whitman Index of Public Utility Construction Costs*, a semi-annual publication widely used in the utility industry.

Table 2-1 shows the estimated RCNLD and OCLD values for each annexation scenario.

Table 2-1
Estimated RCNLD and OCLD Value of PG&E Transmission and Distribution Facilities Straight Line Depreciation

Description	RCN	RCNLD	OC	OCLD
Scenario 1 - Acquire West Sacramento Only				
Transmission Plant	$21,735,120	$4,877,299	$3,653,042	$866,929
Distribution System				
West Sacramento (includes Deepwater)	$44,517,560	$27,521,747	$29,849,152	$18,569,709
Total Plant Cost	**$66,252,680**	**$32,399,046**	**$33,502,194**	**$19,436,638**
Scenario 2 - Acquire West Sacramento and Davis				
Transmission Plant	$47,535,210	$9,025,664	$7,495,351	$1,495,712
Distribution System				
West Sacramento (includes Deepwater)	$44,517,560	$27,521,747	$29,849,152	$18,569,709
Davis	$54,809,357	$33,229,139	$37,442,292	$22,830,262
Davis (1107) - Not Acquired	(2,112,673)	(1,180,538)	(1,313,813)	(747,524)
Davis (Net)	$52,696,684	$32,048,601	$36,128,479	$22,082,738
Total Distribution System	$97,214,244	$59,570,347	$65,977,631	$40,652,447
Total Plant Cost	**$144,749,454**	**$68,596,012**	**$73,472,982**	**$42,148,159**
Scenario 3 - Acquire West Sacramento, Davis & Woodland				
Transmission Plant	$54,669,880	$11,077,290	$9,192,158	$2,152,932
Distribution System				
West Sacramento (includes Deepwater)	$44,517,560	$27,521,747	$29,849,152	$18,569,709
Davis	$54,809,357	$33,229,139	$37,442,292	$22,830,262
Davis (1107) - Not Acquired	(2,112,673)	(1,180,538)	(1,313,813)	(747,524)
Davis (Net)	$52,696,684	$32,048,601	$36,128,479	$22,082,738
Woodland	42,287,310	28,214,942	25,296,922	10,734,159
Total Distribution System	$139,501,554	$87,785,290	$91,274,553	$51,386,606
Total Plant Cost	**$194,171,434**	**$98,862,580**	**$100,466,711**	**$53,539,538**
Scenario 4 - Acquire All Areas				
Transmission Plant (same as Scenario 3)	$54,669,880	$11,077,290	$9,192,158	$2,152,932
Distribution System				
West Sacramento (includes Deepwater)	$44,517,560	$27,521,747	$29,849,152	$18,569,709
Davis	$54,809,357	$33,229,139	$37,442,292	$22,830,262
Davis (1107) - Not Acquired	(2,112,673)	(1,180,538)	(1,313,813)	(747,524)
Davis (Net)	$52,696,684	$32,048,601	$36,128,479	$22,082,738
Woodland	42,287,310	28,214,942	25,296,922	10,734,159
Plainfield	6,755,094	3,276,150	3,120,915	1,542,720
Total Distribution System	$146,256,648	$91,061,440	$94,395,468	$52,929,326
Total Plant Cost	**$200,926,528**	**$102,138,730**	**$103,587,626**	**$55,082,258**

2.2.1 Straight Line versus Present Worth Methods of Depreciation

It is our experience based on past sales and acquisitions of property involving PG&E that PG&E typically uses the present worth method of depreciation, as opposed to the straight line method of depreciation, to estimate the value of utility property it sells to municipalities and public power utilities. The calculation of present worth depreciation is equivalent to sinking fund depreciation and includes an interest rate component. The effect of using the present worth method of depreciation is to understate the reserve for accumulated depreciation and thus overstate the value of net plant compared to the straight line method of depreciation.

Table 2-2 shows the difference in the RCNLD values for the annexation scenarios using the straight line method of depreciation versus a 5% present worth depreciation method. As shown, the RCNLD values calculated using present worth depreciation are approximately 25% greater than the RCNLD values calculated using straight line depreciation.

Table 2-2
Comparison of RCNLD Values Using
Straight Line versus Present Worth Methods of Depreciation

Scenario	RCNLD Straight Line Depreciation	RCNLD 5% Present Worth Depreciation	% Difference
West Sacramento Only	$32,399,046	$41,459,038	28%
West Sacramento and Davis	$68,596,012	$86,259,847	26%
W. Sac., Davis and Woodland	$98,862,580	$124,183,368	26%
All Areas	$102,138,730	$127,825,427	25%

R. W. Beck does not endorse the present worth method of depreciation and this information is only presented to indicate the values that PG&E may propose for the facilities. Also, the purchase price in the recent sale of PG&E electric distribution facilities to Turlock Irrigation District (TID) was based on the RCNLD value of the facilities using present worth depreciation.[1]

Calculating a value for the facilities based on the RCNLD value using the present worth method of depreciation, increases the likelihood that PG&E will be successful in getting a higher purchase price through negotiation or court award. In other words, the RCNLD (straight line) value becomes the midpoint in the range between the OCLD (straight line) and RCNLD (present worth) values. This can be seen by

[1] TID and PG&E agreed to use the same method of valuation that was agreed to by Modesto Irrigation District (MID) when MID sought to acquire facilities from PG&E, i.e., RCNLD using present worth depreciation. (Note: the MID sale was never completed.)

comparing the OCLD (straight line), RCNLD (straight line) and RCNLD (present worth) values by scenario presented in Tables 2-1 and 2-2.

An extensive review of the appraisal and depreciation literature and interviews with other accredited senior utility appraisers in the U.S. performed by R. W. Beck conclusively shows that the straight line method of depreciation is the generally accepted method of depreciation to use in valuing utility property.

2.3 Income Approach

The income approach estimates the value of property by capitalizing or determining the present worth of anticipated economic benefits from the property as a going concern. Both the direct capitalization of income and discounted cash flow (DCF) methods were used to estimate the value of the distribution systems under the Income Approach.

2.3.1 Direct Capitalization of Income

Under the direct capitalization of earnings method, the income value of the property is estimated by capitalizing (i.e., dividing) the net income associated with the property for a one-year period by an appropriate capitalization rate. This is shown in Equation (1) below:

(1) Value = (Revenues – Expenses) / Capitalization Rate

In theory, the income value for a regulated utility should equal its rate base value, since this is the value of the utility's investment on which it is allowed to earn its authorized rate of return. Generally speaking, rate base is equal to the original cost of plant in service less accumulated depreciation. Rates are designed to recover the utility's operating expenses plus a return on rate base, as shown in Equation (2) below:

(2) Operating Revenues = Operating Expenses + (Rate of Return)(Rate Base)

Equation (2) can be rewritten as follows:

(3) Rate Base = (Operating Revenues – Operating Expenses) / Rate of Return

By comparing Equations (1) and (3), one can see that the capitalized income value for regulated utility property is generally equivalent to its rate base value.

The direct capitalization of income indicator of value is based on the premise that the income generating ability of the property that exists today will continue into perpetuity.[2] It is expected that the delivery portion of electric retail distribution service will continue to be regulated by the CPUC for the foreseeable future. Therefore, it is reasonable to use the direct capitalization approach to estimate the income value of the electric distribution systems.

[2] In comparison, the discounted cash flow method is used to estimate the present worth of a projected stream of net earnings for the property over a specified period of time.

Table 2-3 shows the development of the capitalized income value for the West Sacramento, Davis and Woodland & Yolo distribution systems. The PG&E average system distribution rate shown in Table 2-3 for each system reflects the customer load characteristics for each system (e.g., residential; small, medium and large commercial; agriculture; and streetlight loads). Operating expenses were estimated as 85% of revenues based on the relationship between operating expenses and operating revenues reported in PG&E's FERC Form 1 Annual Reports for the period 1999-2003.[3] The capitalization rate used in the analysis is equal to PG&E's weighted average cost of capital recently approved by the CPUC.

The estimated income value of the West Sacramento, Davis and Woodland & Yolo distribution systems based on the direct capitalization of income method is shown in Table 2-3. More details regarding the income approach analyses are provided in Appendix D.

Table 2-3
Direct Capitalization of Income Value
as of December 31, 2004

	West Sacramento	Davis	Woodland & Yolo
Load Served (MWh)	384,338	262,914	537,727
PG&E Average Distribution Rate (cents/kWh) [1]	2.5403	3.6594	2.9403
Retail Revenues	9,763,472	9,620,943	15,810,691
Operating Expenses [2]	8,298,951	8,177,802	13,439,088
Net Utility Operating Income	1,464,521	1,443,142	2,371,604
Capitalization Rate [3]	8.77%	8.77%	8.77%
Estimated Income Value	16,699,211	16,455,434	27,042,232

Notes:
1 PG&E average distribution rate calculated to reflect customer load characteristics of each area.
2 Operating expenses estimated as 85% of operating revenues based on data reported in PG&E's 1999-2004 FERC Form 1 Annual Reports. Operating expenses include depreciation and income taxes.
3 PG&E's weighted average cost of capital equals 8.77%, as approved in CPUC Decision 04-12-047, December 16, 2004.

2.3.2 Discounted Cash Flow Method

Under the DCF method, the direct economic benefits derived from continued ownership of the system are expressed in terms of free cash flow, which represents the total cash flow generated by the going concern that is available to the providers of both debt and equity capital.

[3] PG&E's operating expense ratio (the ratio of operating expenses to operating revenues) has fluctuated over the 1999-2004 time period. However, 85% is a reasonable estimate based on the data shown and the experience of other utilities.

The DCF model used to estimate the value of the distribution systems is essentially an after-tax cash flow model of annual revenues and expenses over the 2004-2027 time period. This time period was selected based on the projection period used in the Economic Evaluation described in Section 3. The calculation of free cash flow is illustrated as follows:

Annual Operating Revenues	
Less:	*Annual Operating Expenses*
Equals:	*Pre-tax Net Operating Income*
Less:	*Income Taxes*
Equals:	*Earnings Before Interest, Depreciation & Amortization (EBIDA)*
Less:	*Future Capital Expenditures*
	Net Changes in Working Capital
Equals:	*Free Cash Flow*

Table 2-4 shows the calculation of the income value for the West Sacramento, Davis and Woodland & Yolo distribution systems using the DCF method. Due to limited space, not all years of the projection period are shown in Table 2-4. The complete analyses are provided in Appendix D.

The assumptions used in the direct capitalization of income analysis to estimate projected revenues and expenses were also used in the DCF analysis. The PG&E average system distribution rate shown for each system reflects the customer load characteristics for each system. Operating expenses were estimated as 85% of revenues. In addition, in the DCF analysis it was necessary to estimate future capital expenditures and add back projected depreciation expense (a non-cash item). The assumptions and detailed analyses used to estimate future cash flows are provided in Appendix D.

Table 2-4
Discounted Cash Flow Indicator of Value
as of December 31, 2004

	2004	2005	2006	2007	2008	* * *	2024	2025	2026	2027
West Sacramento										
Load Served (MWh)	384,338	393,870	403,401	412,922	422,460		674,578	693,467	712,884	732,844
PG&E Average Distribution Rate (cents/kWh) [1]	2.5403	2.6542	2.7355	2.7861	2.8304		4.0365	4.1302	4.2194	4.3188
Retail Revenues	$9,763,472	$10,454,201	$11,034,863	$11,504,527	$11,957,485		$27,229,354	$28,641,235	$30,079,232	$31,650,039
Operating Expenses [2]	8,298,951	8,886,071	9,379,634	9,778,848	10,163,862		23,144,951	24,345,050	25,567,348	26,902,533
Depreciation Expense	852,833	868,666	884,932	901,636	918,829		1,722,132	1,795,034	1,872,253	1,953,897
Capital Expenditures	1,407,000	1,437,954	1,469,589	1,503,390	1,537,967		4,273,675	4,497,712	4,729,794	4,970,173
Net Cash Flow	$910,354	$998,842	$1,070,572	$1,123,926	$1,174,484		$1,532,860	$1,593,506	$1,654,343	$1,731,230
Discount Rate [3]	8.77%									
Net Present Value of 2004-2027 Cash Flow	$10,739,515									
Terminal Value	$5,587,432									
Estimated Income Value	$16,326,947									
Davis										
Load Served (MWh)	262,914	267,620	272,437	277,177	281,779		315,090	316,445	317,806	319,172
PG&E Average Distribution Rate (cents/kWh) [1]	3.6594	3.8109	3.9308	4.0124	4.0805		5.8065	5.9409	6.0718	6.2138
Retail Revenues	$9,620,943	$10,198,753	$10,708,967	$11,121,556	$11,497,967		$18,295,813	$18,799,675	$19,296,421	$19,832,697
Operating Expenses [2]	8,177,802	8,668,940	9,102,622	9,453,323	9,773,272		15,551,441	15,979,724	16,401,957	16,857,792
Depreciation Expense	1,032,242	1,058,807	1,085,846	1,114,715	1,143,130		1,139,589	1,132,288	1,125,914	1,120,461
Capital Expenditures	1,962,000	2,005,164	2,096,279	2,109,233	2,095,440		884,046	909,215	935,074	961,642
Net Cash Flow	$513,384	$583,456	$595,911	$673,715	$772,385		$2,999,915	$3,043,024	$3,085,303	$3,133,724
Discount Rate [3]	8.77%									
Net Present Value of 2004-2027 Cash Flow	$16,692,279									
Terminal Value	$6,297,249									
Estimated Income Value	$22,989,528									
Woodland + Yolo										
Load Served (MWh)	537,727	547,925	557,264	566,551	575,706		739,070	747,818	756,670	765,627
PG&E Average Distribution Rate (cents/kWh) [1]	2.9403	3.0676	3.1630	3.2249	3.2773		4.6679	4.7761	4.8802	4.9949
Retail Revenues	$15,810,691	$16,808,295	$17,626,420	$18,270,843	$18,867,804		$34,499,040	$35,716,661	$36,927,292	$38,242,309
Operating Expenses [2]	13,439,088	14,287,050	14,982,457	15,530,216	16,037,634		29,324,184	30,359,161	31,388,198	32,505,963
Depreciation Expense	811,938	829,883	848,220	868,032	887,559		1,373,670	1,390,882	1,409,592	1,429,819
Capital Expenditures	1,440,000	1,471,680	1,541,658	1,551,472	1,537,967		1,976,102	2,045,734	2,117,523	2,191,532
Net Cash Flow	$1,743,542	$1,879,447	$1,950,524	$2,057,186	$2,179,762		$4,572,424	$4,702,648	$4,831,163	$4,974,633
Discount Rate [3]	8.77%									
Net Present Value of 2004-2027 Cash Flow	$26,844,317									
Terminal Value	$12,472,472									
Estimated Income Value	$39,316,789									

Notes:
1 PG&E average distribution rate calculated to reflect customer load characteristics of each area.
2 Operating expenses estimated as 85% of operating revenues based on data reported in PG&E's 1999-2003 FERC Form 1 Annual Report. Operating expenses include depreciation and income
3 PG&E's weighted average cost of capital equals 8.77%, as approved in CPUC Decision 04-12-047, December 16, 2004.

Under the DCF method, the income indicator of value is equal to the sum of the present value of the projected cash flows plus the present value of the projected terminal value.

The series of annual cash flows from 2004 to 2027 was discounted using an 8.77% discount rate, which is equal to PG&E's weighted average cost of capital. For the terminal (or residual) value, the projected cash flow in year 2027 was capitalized into perpetuity at the discount rate less the growth in cash flow over the period 2004 through 2027, and then discounted back to 2004.

2.4 Market Approach

The comparable sales method under the market approach involves review of recent sales of similar facilities between a willing buyer and a willing seller, who are unrelated, as an indication of the general market price for such facilities. Caution must be exercised when using the comparable sales method as an indicator of value for utility property. Normally, the appraiser will, when necessary, make adjustments to the comparables in order to correlate the sales price to the characteristics of the subject property. There are many factors that can influence sales price including, among others, market area, age and other considerations that may be reflected in the sales price. Each party's motivation can affect the negotiation and the terms of the sale. Strategic objectives are the driving motivator for some sales. These objectives are often kept confidential and are not available to an appraiser for evaluation.

The comparable sales method is primarily applicable to property that is readily substitutable and where a number of similar type properties have recently been sold. To be an indication of market value, these sales must also involve a willing buyer and willing seller. The market approach is difficult to apply in valuing utility property due to the lack of comparable utility sales transactions. For this reason, we did not use the Market Approach to estimate the value of the systems in this Study.

2.5 Discussion of Results

Table 2-5 is a summary of the indicators of value developed using the Income and Cost Approach for the West Sacramento, Davis and Woodland & Yolo electric distribution systems. For comparison purposes with the income indicators of value, the OCLD and RCNLD values shown in Table 2-5 represent the value of only the distribution facilities that would be acquired by SMUD under the annexation scenarios. The value of the transmission facilities that would be acquired or stranded are identified in Table 2-1 and would be added to the values shown in Table 2-5 below.

Table 2-5
Comparison of Indicators of Value
(Distribution Systems Only)

	Direct Capitalization	Discounted Cash Flow	OCLD	RCNLD
Individual Systems:				
West Sacramento	$16,699,211	$16,326,947	$18,569,709	$27,521,747
Davis	$16,455,434	$22,989,528	$22,082,738	$32,048,601
Woodland & Yolo	$27,042,232	$39,316,789	$12,276,879	$31,491,092
Scenarios:				
West Sacramento	$16,699,211	$16,326,947	$18,569,709	$27,521,747
West Sacramento and Davis	$33,154,644	$39,316,475	$40,652,447	$59,570,348
West Sac, Davis, Woodland & Yolo	$60,196,876	$78,633,264	$52,929,326	$91,061,440

Note: The OCLD and RCNLD values shown above reflect the value of the electric distribution facilities only. Values were calculated using straight line depreciation.

As stated previously, the income value for regulated utility property should equal its rate base value (or OCLD value), since this is the value of the utility's investment on which it is allowed to earn a rate of return or profit. This is true if rates (and revenues) reflect the cost of service. However, utility rates are charged on a system average (or "postage stamp") basis and do not necessarily reflect the cost to serve a specific area. In addition, we had to rely on PG&E system average data to estimate operating expenses and capital expenditures for the distribution systems because we did not have specific data regarding PG&E's cost to serve the West Sacramento, Davis and Woodland & Yolo systems. When relying on system average rates and assumptions to estimate costs, there can be differences between the income and OCLD indicators of value.

As shown in Table 2-5, the income indicators of value developed for the West Sacramento and Davis systems are equal to or less than the OCLD values for the distribution systems. However, for the Woodland & Yolo system, the income indicators of value are greater than the OCLD value.

One possible explanation for the high income value for the Woodland & Yolo system is that the facilities are considerably older and thus more depreciated (approximately 60% depreciated) than the West Sacramento and Davis systems, which are approximately 40% depreciated. The depreciation reserve ratio or percent depreciated for the West Sacramento and Davis facilities is close to PG&E's system average reserve ratio. Because rates are developed and charged on a system average basis, utilities can earn more on an older system than a newer system; however, operating and maintenance expenses can be higher on an older system.

The Cost Approach analysis is specific to the systems analyzed, whereas the Income Approach analysis is not and relies on system average assumptions. We would place greater reliance on the Cost Approach indicators of value developed in this Study. For the scenarios analyzed in the Economic Evaluation section of this Study, as shown in Table 2-5, the income indicators of value are generally within or below the range of the OCLD and RCNLD values. We believe that the RCNLD values are a conservative estimate of the assumed purchase price to use in the Economic Evaluation.

2.6 Summary

For the reasons stated above, we believe that the Cost Approach provides the best indication of the range of value for the specific facilities that would be acquired by SMUD and any stranded assets identified in the Technical Assessment section of this Study. In theory, the income value for regulated utility property should be equal to its rate base value, which is generally equivalent to the OCLD value of the property. The income indicators of value developed in this study for the distribution systems tended to support the lower end of the range of value between OCLD and RCNLD.

Based on our experience with utility sales and acquisitions, the purchase price for regulated utility property generally is in the range between OCLD and RCNLD, with depreciation calculated using the straight line method of depreciation. These values are summarized by scenario in Table 2-6.

Table 2-6
Estimated Range of Purchase Prices
(Distribution and Transmission Facilities)

Scenario	Low Value (OCLD)	High Value (RCNLD)
West Sacramento Only	$19,436,638	$32,399,046
West Sacramento and Davis	$42,148,159	$68,596,012
W. Sac., Davis and Woodland	$53,359,538	$98,862,580
All Areas	$55,082,258	$102,138,730

Source: Table 2-1

In our opinion, the fair market value of the electric distribution and transmission facilities that would be acquired in each scenario is equal to or close to the OCLD value of the range of purchase prices shown above. However, the RCNLD value of the facilities is a reasonable and conservative estimate of the purchase price to use in evaluating the economic feasibility of SMUD annexing all of a portion of the electrical facilities serving the Yolo Jurisdictions.

Section 3
ECONOMIC EVALUATION

An economic analysis has been developed to evaluate the feasibility of SMUD annexing all or a portion of the existing PG&E electric distribution system in the Cities of West Sacramento, Davis, Woodland, and certain unincorporated portions of Yolo County (Yolo Jurisdictions), as defined by the Technical Assessment and Valuation information presented in Sections 1 and 2 of this Study.

The economic analysis includes projections of net income, net present value, and cash flow based on reasonable assumptions about severance costs, system valuation, bond financing, energy sales, bundled electric rates, non-bypassable charges, and other costs. The analysis includes a comparison of projected PG&E and SMUD retail rates.

The major subjects of this section include a detailed discussion of the key assumptions, base case results, the scenario analysis, and the overall results of the economic analysis.

3.1 Purpose

The purpose of the economic evaluation is to estimate the cost/benefit to existing PG&E ratepayers in the Study Area, as well as the cost/benefit to existing SMUD ratepayers of potential annexation into the SMUD system. This required an understanding of the underlying cost structure of PG&E and SMUD; quantification of costs, such as non-bypassable charges; and quantification of costs that may no longer be applicable, such as certain taxes. Changes in these costs and charges were then projected throughout the Study period. Full recovery of these costs were assumed to constitute Breakeven Revenue Requirements. It was also necessary to assess SMUD's long-term competitiveness with PG&E. It was also necessary to consider the impact of different service options on the reliability of service, as identified in Section 1 of this Study.

Since it is would neither be in the interest of existing PG&E ratepayers in the potential annexation area, or in the interest of existing SMUD ratepayers if the analysis were optimistic in terms of underlying assumptions, R. W. Beck employed reasonable yet reasonably conservative assumptions, as described in this section of the Study. The economic impact on current PG&E customers in the potential annexation areas are quantified in the Study, including the identification of potential surcharges above standard SMUD rates in order to keep existing SMUD ratepayers whole. A basic premise in the development of revenue requirements in the Study Area was to guarantee that existing SMUD ratepayers would be held harmless and, at a minimum, indifferent (from an economic standpoint) to the potential addition of the Study Area.

3.2 Approach

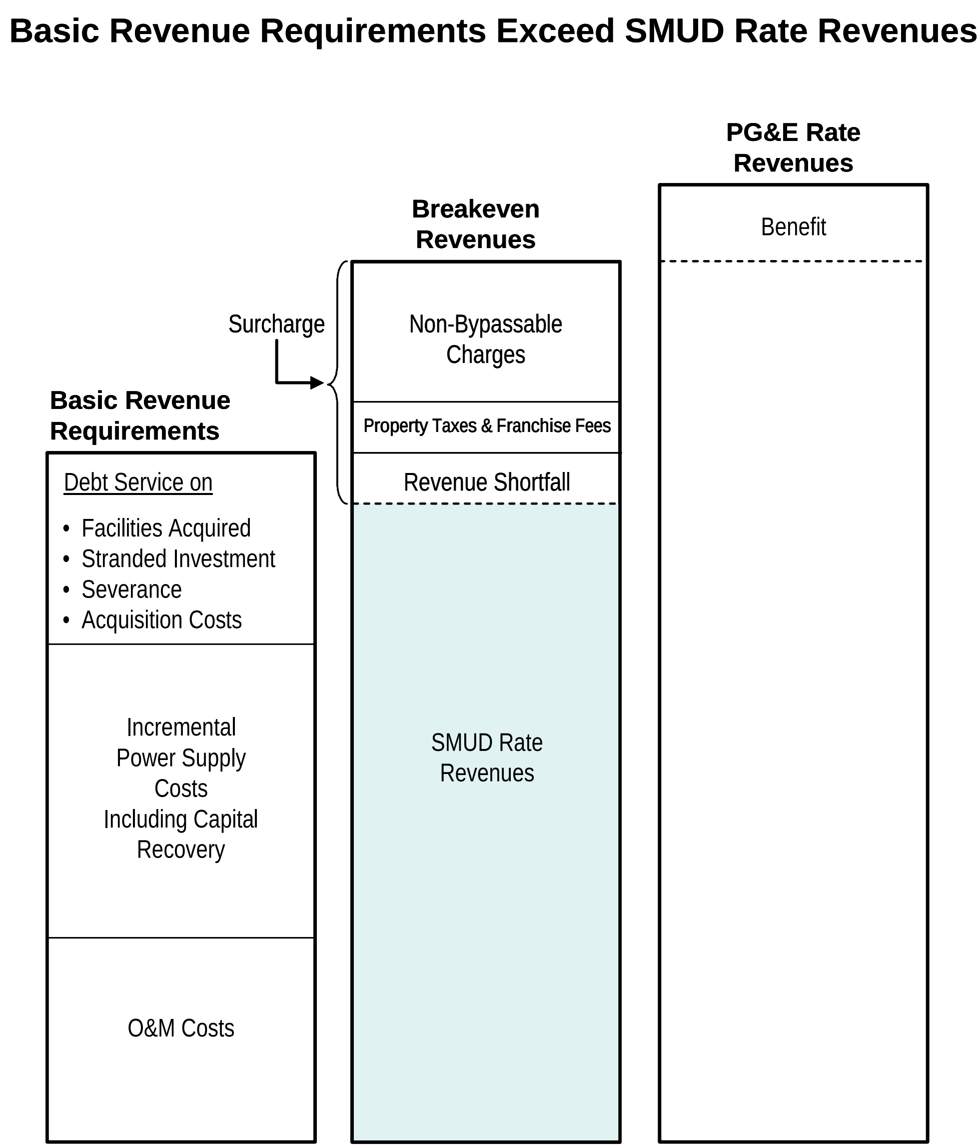
The costs and benefits of annexing the Cities and the unincorporated area of Yolo County into the SMUD service area are evaluated in the economic analysis. The assessment includes:

- Evaluation of existing and new load for the Yolo Jurisdictions.
- Acquisition cost, separation, and PG&E stranded investment.
- Other costs, such as non-bypassable charges, taxes and fees, and start-up costs.
- Identification of costs to integrate existing facilities into the SMUD system.
- Evaluation of rates and associated revenues needed to pay for the annexation.
- Evaluation of the economic impacts on the Yolo Jurisdictions.
- Assessment of the impact on existing SMUD customers.

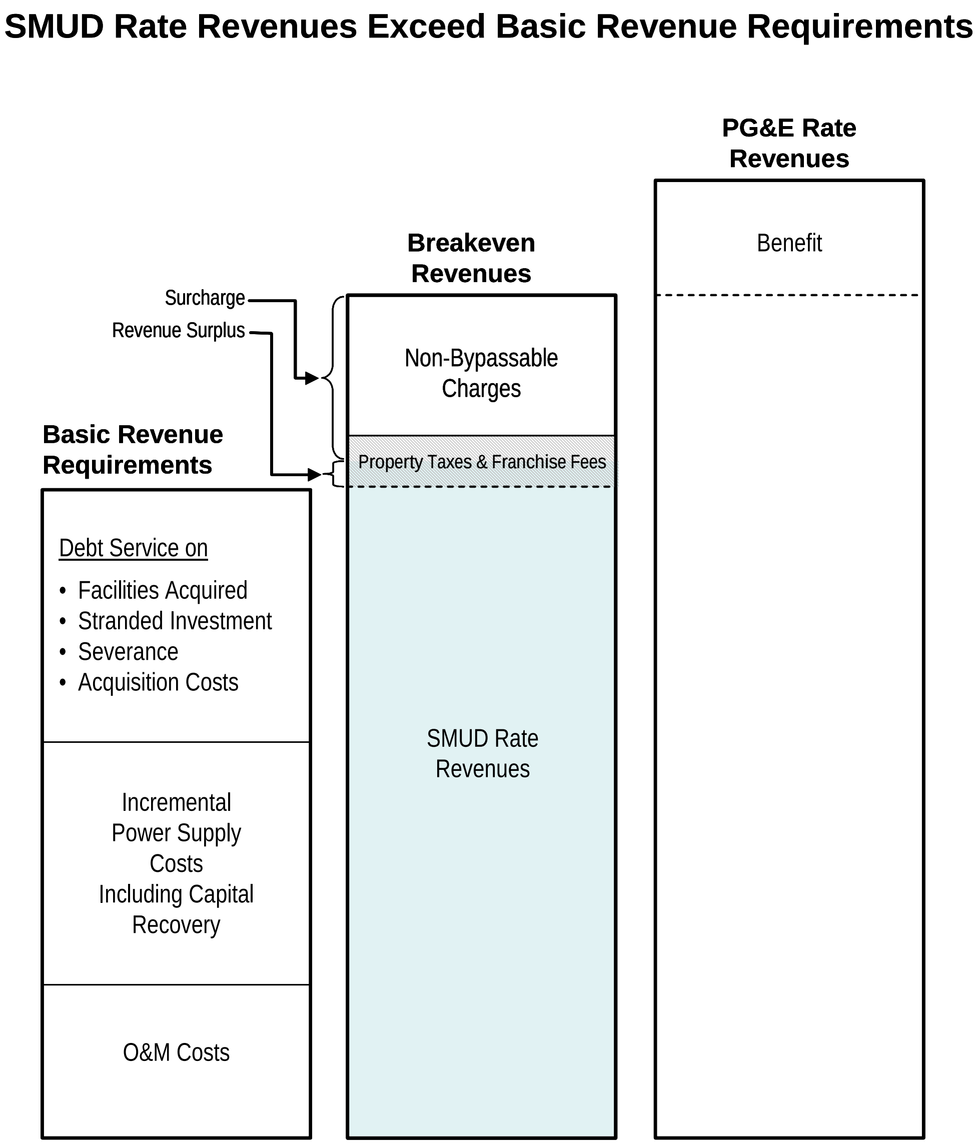
3.3 Methodology

The methodology employed in the analysis is to build up costs to be recovered within the Study areas, recognizing the incremental costs of power supply, debt service on all system acquisition costs and upgrades and system operation and maintenance. These are the costs that would normally have to be recovered and they make up the Basic Revenue Requirements shown in the left bars of Graphs 3-1 and 3-2. To the extent the Basic Revenue Requirements are different than revenues from SMUD's general rates, a revenue shortfall or revenue surplus is calculated. Additionally, in recognition of potentially foregone franchise fees and property taxes, an amount is added to assure a fair economic evaluation, whether such jurisdiction revenues are actually foregone or collected through a utility user's tax. Finally, non-bypassable charges are added to recover payments that SMUD will need to pay PG&E for Municipal Departing Load (MDL). The sum of these revenue requirements make up "Breakeven Revenues," as seen in the center bar of Graphs 3-1 and 3-2. Breakeven Revenues should result in no harm or benefit to SMUD's existing customers. It is recognized in the comparison of Breakeven revenues and revenues from SMUD rates, that SMUD rates produce retained earnings that are used to pay for a portion of new plant investment. Although not exactly comparable, the Breakeven revenues include the cost of acquiring the distribution system, capital additions, and renewals and replacements. The cost of power supply also includes the debt service related to amortization of the full capital cost.

Graph 3-1
Breakeven Revenue Example 1



Graph 3-2
Breakeven Revenue Example 2



Once Breakeven Revenues are determined, they are compared with projected PG&E revenues for each jurisdiction to evaluate benefits (or costs) of SMUD acquisition from the perspective of the average ratepayer in each jurisdiction. The remaining value, either positive or negative in each year, is discounted at 6% per year in order to identify the NPV of the analysis. It should be noted throughout this discussion that the term “revenues” is used instead of “rates.” Although they are closely related, and readers can think “rates,” the term “revenues” more accurately reflects the fact that the same rates produce different revenues, depending on the load characteristics of a customer class.

3.4 NPV Discussion

A number of scenarios and sensitivity analyses were run to aid in evaluation of results.

The methodology employed to determine the economic viability of the potential annexation included a systematic review of facilities and potential costs in order to quantify the total revenues, operating expenses, initial investments, and ongoing improvements associated with the utility facilities in the Study Area. In summary, the methodology included the following steps:

1. Development of a general boundary map of the proposed service area and facilities to be acquired. Although Study Areas are defined by City names or Yolo County, there are often overlaps. As an example, the Davis Study Area also includes unincorporated portions of Yolo County. (See Figure ES-1, Map of Study Area.)
2. A determination of the transmission, subtransmission, distribution, substation and related facilities in the potential acquisition area(s). This was accomplished through a detailed inventory of existing PG&E facilities (see Section 1).
3. A general condition assessment of the existing PG&E facilities to determine both the age and condition of the existing system (see Section 1).
4. An estimate of existing system value using industry standard methodologies (see Section 2).
5. A projection of power supply costs using an impartial third party source. In this case the forecast of Henwood Energy Services Inc. (HESI) was used.
6. A forecast of load, usage, and load growth patterns by city for the Study Area. This was accomplished using limited data provided by PG&E that related to total City loads, and through projections obtained from the Sacramento Area Council of Governments (SACOG) as discussed later in this section.
7. A forecast of revenue by city/county unincorporated area for the forecast period.
8. A projection of operating and maintenance expenditures, renewal and replacement costs, and other costs affecting the operations and maintenance of utility facilities in the Study Area.
9. Quantification of emerging regulatory requirements including planning reserve margins, ancillary service fees, public purpose program commitments, and renewable resource requirements.
10. Identification and quantification of applicable non-bypassable charges including California Department of Water Resources Bond and Energy charges, Regulatory Assets, Competition Transition Charges, Nuclear Decommissioning, and Fixed Transition Account (FTA).
11. An estimate of the future retail rates for both PG&E and SMUD.
12. Identification and quantification of direct access load within the Study Area not subject to power supply and related charges.

13. Identification and quantification of severance or separation costs for each scenario.
14. Estimation of costs associated with the acquisition, including legal, consulting litigation, and other expenses.
15. Estimation of the amounts to be financed, including facilities, separation, stranded PG&E costs, working capital, acquisition costs, and the cost of financing.
16. Estimation of current franchise fee payments and property taxes that could be foregone or recovered through other mechanisms.

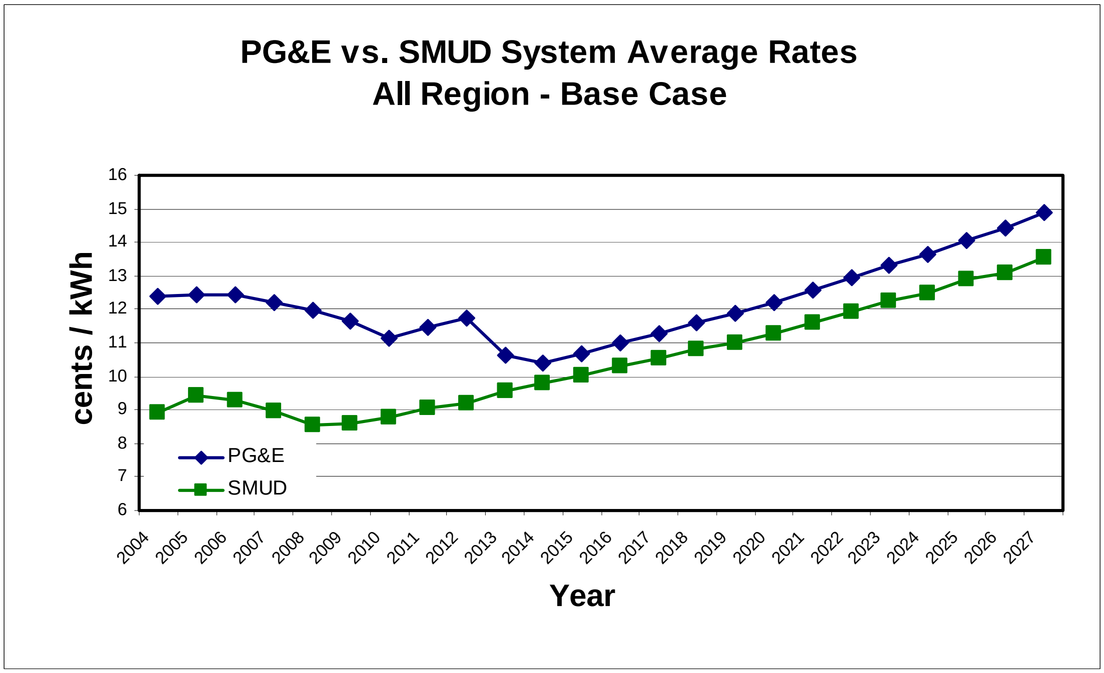
A more detailed discussion of the sources of information employed and assumptions needed in order to complete the analysis is contained in Section 3.5.

The next step in the process was a comparative analysis between PG&E and SMUD rates. Based on projected costs and rates, an incremental rate analysis was conducted in order to determine the future rates and associated revenues for the cities and the selected unincorporated County areas. This analysis is performed by jurisdiction and includes:

1. Calculation of PG&E and SMUD System Average Rates

SMUD and PG&E's system average rates for each year are calculated based on the projections of load and power supply resource costs. The starting point for PG&E's rates was their General Rate Case (GRC) Phase 2, which has now been approved. SMUD rates include the currently proposed 6% rate increase and in 2006 show a decline to track projected natural gas prices. See Graph 3-3 for the results. The analysis shows that due to the burden of non-bypassable charges on PG&E's rates, SMUD's rates are likely to remain about 24.7% below those of PG&E's through 2012. Then, the difference shrinks to an average of approximately 7.6% from 2013 through the end of the study period (2027). The historical rate differential between SMUD and PG&E (see Section 4.1) is expected to decline as PG&E is provided the opportunity to optimize its power supply portfolio once the CDWR power costs burden is eliminated, the FTA is paid off, and the PG&E Regulatory Asset is amortized.

Graph 3-3
PG&E vs. SMUD System Average Rates



2. Identification of Breakeven Revenues and Associated Rates

Each jurisdiction's breakeven revenue for each year is calculated based on all the expenses that SMUD would have to undergo to annex the Yolo regions into its service territory. These expenses include, but are not limited to, generation expenditures, O&M expenditures, capital expenditures, and amortization of all acquisition costs. Breakeven revenues have also been increased to account for the amount of franchise fees and property taxes that SMUD is not responsible for paying the jurisdictions and to provide funds to pay non-bypassable charges to PG&E. The total revenue requirement in each jurisdiction then becomes a proxy for rates. If the breakeven revenue requirement is 5% lower than PG&E's revenue requirement in a certain year for a jurisdiction, then that represents a 5% average rate decrease.

3. Identification of Applicable Non-Bypassable Charges

These charges cover the regulatory costs that are to be collected by SMUD and passed on to PG&E for departing load. Such non-bypassable charges include Regulatory Assets, Competition Transition Charge, nuclear decommissioning, FTA, and California Department of Water Resources (CDWR) related charges, including power supply and bonds. Based on the recent decision released by the CPUC, Davis customers are exempt from CDWR related power supply and bond charges, while they are still responsible to pay the rest of the non-bypassable charges, including Regulatory Assets, Competition Transition Charge, and nuclear decommissioning. As the potential exemption for new load was not as clear in the decision, R. W. Beck conservatively assumed that the new customers in other jurisdictions, connected after annexation, would pay 80% of non-bypassable charges related to CDWR costs.

4. Identification of Rate Savings

Rate savings, as seen on average by customers, are equivalent to the differences between PG&E revenues and the breakeven revenues. They are calculated in both dollars and percentages in each scenario.

5. Calculation of NPV of Projected Revenue Differentials (Benefits/Costs)

The NPV of Revenue Differentials throughout the study period is calculated for the annexed regions at a 6% discount rate. This represents the cumulative savings or costs, taking the value of money into account.

6. Calculation of Average Revenue for Bundled Customers

The customers within the annexed regions are assumed to pay rates sufficient to produce revenues that cover the capital acquisition cost, SMUD's operation costs, and other charges not covered in SMUD's base rate, as well as the non-bypassable charges for PG&E.

7. Calculation of Average Revenue for Direct Access Customers

Direct Access Customers are also subject to non-bypassable charges, with the exemption of Davis customers from certain CDWR costs, as mentioned in paragraph 3. However, they are exempt from SMUD's power supply related costs including ancillary services and planning reserves as they are responsible for these items themselves. The average revenue for these customers is calculated by crediting the Direct Access customers the power supply related charges, ancillary service charges, and planning reserves from the average SMUD revenue for bundled customers. This is a conservative assumption in that Direct Access customers, depending on the date they started Direct Access, are exempt from varying categories of exit fees.

The revenue analysis is based on available information from numerous sources including, but not limited to, the Cities of West Sacramento, Davis, and Woodland; the County of Yolo, the Sacramento Area Council of Governments, the California Public Utilities Commission, the California Energy Commission, PG&E, the CDWR, and SMUD.

3.5 Underlying Assumptions

Each of the scenarios contained in the Study includes assumptions regarding future events that are reasonably conservative. The following describes the key assumptions employed in the underlying analysis. Some of these assumptions have been modified in the Scenario Analysis (Section 3.6) in order to test the impact of changes from underlying assumptions. Such changes are identified with each scenario.

3.5.1 Energy Sales and Customer Base

In response to Data Requests, PG&E has provided energy sales by aggregated revenue classes for the years 2002 and 2003. They also provided a list of which rate schedules were included in those broad classes. They did not provide data by rate schedule. In addition, they provided hourly typical weekday and weekend load shapes for each of the regions subject to annexation based on 2001 information. The following are some of the key characteristics of the energy sales information provided by PG&E:

- Sales information was provided by revenue class but not applicable rate schedules for each month of 2002 and 2003. This information was not sufficient for R. W. Beck to disaggregate the load by rate schedules. PG&E initially did not provide large commercial load information due to customer confidentiality concerns. At the end of November, PG&E provided some of this information. R. W. Beck has incorporated this revised information into its analysis. The lack of sales and revenue data for each class required R. W. Beck to make assumptions, which to the extent they are inaccurate, would affect the results. Because such assumptions were generally conservative, the greater the lack of PG&E data, the more conservative were the results.
- PG&E provided one typical hourly weekday and one weekend load shape by load class (residential, small commercial, medium and large commercial, and other) for each month in 2001 for each region. This was the year of the energy crisis and such data may be skewed as a result of customers' responses to the crisis. Additionally, the medium and large commercial customers were merged into one category making it difficult to tie to other information provided by PG&E. This information was useful in load-shaping the market prices based on on-peak and off-peak distribution of load for the subject regions, but was insufficient for determining average revenues in each jurisdiction.
- PG&E provided comparative rate tables that included the retail rate comparisons of PG&E versus SMUD rates for each of the subject regions. Although it did not have the load by rate schedules, it did include sales by revenue class for each jurisdiction. This information appeared to have the most accurate data by customer class, including the Direct Access data for West Sacramento, Davis, and Woodland. However, the average revenue for the residential class, as compared between the three cities, was not consistent with the average usage per customer and was not used. This required an estimate of average revenues per kWh for residential customers in each City, using assumptions as to the percentage of residential sales in each tier of PG&E's residential rate schedule. The unincorporated Yolo load was not included in the comparative rate tables provided by PG&E. The unincorporated Yolo load was estimated by using the other typical weekday and weekend load shape information and based on other load information provided by PG&E.

  The outcome of the economic evaluation is relatively sensitive to the estimates of average residential revenues per kWh in each jurisdiction. Had PG&E provided residential sales information by rate tier, R. W. Beck could have been less conservative and it is likely that greater economic benefits (particularly for Davis) would have resulted. Sensitivity analyses using PG&E system average residential revenues indicated that NPVs for the cities would increase by 288% for Davis, 150% for West Sacramento, and would be reduced by 2% for Woodland/Yolo.

- The load for each region, except the unincorporated portion of Yolo, is contained in the Direct Access and non-Direct Access categories.
- PG&E provided the load growth projections at the city level for West Sacramento, Davis, and Woodland only through 2009.
- None of the data provided by PG&E included the identification of the number of customers for any of the regions under consideration; however, customer estimates were determined using city/county information and field evaluation.

In light of the limitations in the data provided by PG&E, it was necessary to estimate the load projections for future years based on the following assumptions:

- PG&E's projection through 2009 for each region was used in the analysis. From 2010 through 2027, the Sacramento Area Council of Government's (SACOG) housing projections dated March 15, 2001, were used for each city to project the load growth in these areas. The difference between the PG&E and SACOG's projections resulted in noticeable changes in 2010. To smooth the transition from one projection to another, a three-year moving average was employed with the current year reading of SACOG's housing projections from 2010 through 2015. The projections from 2016 through 2027 are solely based on SACOG's projections. The load projection for Yolo is based solely on SACOG's housing projections of Unincorporated Yolo County.
- Due to lack of data from PG&E, all the customer classes are assumed to grow at the same rate as the City growth projections throughout the study period. Hence, transitions among the customer classes are not taken into consideration in this study. It is assumed that customer profiles in each city will remain the same throughout the study period.
- PG&E provided Direct Access load data for each of the cities. The Direct Access energy requirements were not included in the power supply requirements.

In order to determine Direct Access revenue, it was assumed that existing Direct Access customers would receive a cost-based credit from SMUD when participating in a Direct Access program. In other words, SMUD would provide a credit for energy costs, transmission charges (if applicable), and certain non-bypassable charges (if applicable) based on the cost SMUD incurs in providing the services to Direct Access customers. The load projections for each jurisdiction, including the Direct Access customers, are presented below in Table 3-1.

Table 3-1
MWh
Load Projections through 2027

	West Sacramento	Davis	Woodland	Yolo Unincorporated	Total
2004	403,677	289,379	369,562	197,494	1,260,113
2005	413,688	294,742	376,380	201,602	1,286,412
2006	423,699	300,216	383,341	204,707	1,311,962
2007	433,699	305,611	390,202	207,859	1,337,371
2008	443,717	310,869	396,884	211,060	1,362,531
2009	453,745	316,035	403,447	214,311	1,387,538
2010	466,525	320,509	410,439	217,611	1,415,085
2011	480,034	324,632	417,466	220,897	1,443,029
2012	494,951	328,411	424,700	224,233	1,472,294
2013	510,810	331,969	432,063	227,619	1,502,461
2014	527,704	335,351	439,590	231,056	1,533,701
2015	545,508	338,617	447,267	234,545	1,565,936
2016	561,928	341,056	456,857	237,711	1,597,552
2017	578,842	343,534	466,656	240,920	1,629,952
2018	596,265	346,051	476,669	244,172	1,663,157
2019	614,213	348,609	486,899	247,469	1,697,190
2020	632,700	351,209	497,354	250,810	1,732,073
2021	651,302	353,760	505,070	254,221	1,764,352
2022	670,450	356,353	512,915	257,678	1,797,397
2023	689,223	358,927	519,524	260,976	1,828,651
2024	708,521	361,542	526,231	264,317	1,860,611
2025	728,360	364,197	533,037	267,700	1,893,294
2026	748,754	366,895	539,945	271,127	1,926,720
2027	769,719	369,636	546,954	274,597	1,960,906

3.5.2 SMUD's Retail Rates

If SMUD were to annex the distribution system in the subject regions, it would need to determine the ultimate retail rates to be charged to new retail customers. The rate design would likely include its general rates plus a surcharge that reflects SMUD's cost of acquisition, ongoing differences in operations and maintenance costs, customer characteristics, legal and political concerns, and competition. As SMUD's electric system would continue to be completely surrounded by PG&E, implied "rate-to-rate" competition and comparisons would occur between PG&E and SMUD. For the purposes of this analysis, it is assumed that SMUD will charge the same retail rates it is charging to its current customers in its service territory, with the addition of a surcharge made up of non-bypassable charges and revenue deficiencies or surpluses, as shown in Graphs 3-1 and 3-2.

SMUD has provided its preliminary projection of retail rates by customer class for 2005. These rates are assumed to include the 6% increase as announced by SMUD. Even though SMUD has stated that the proposed rate increase would provide for the next three years, in order to be consistent with the methodology used for PG&E, SMUD's revenue requirements are set to track power supply costs. Starting from 2006, SMUD's projected retail revenue requirements are based on a combination of the Consumer Price Index and the trend in natural gas prices. It is estimated that 35% of SMUD's retail revenue requirements represent the costs other than power supply, and will directly be influenced by the Consumer Price Index, while the remaining 65% represent the power supply related costs. Out of the power supply related portion, 20% is assumed to be fixed power supply costs, which are escalated at the Consumer Price Index. The remaining 80% is assumed to follow the trend in natural gas price projections. Additionally, SMUD rates were increased to pay for the higher cost of those renewable resources required to increase the percentage of renewables from 10% to 20% of the total energy sold. An estimate of SMUD's retail revenue projections by customer class through 2027 are presented in Table 3-2. The reduction in prices from 2006 to 2008 is reflective of a partial return to historic natural gas prices.

3.5.2.1 Public Purpose Programs

Public purpose program charges are assumed to be at 3.17% of the retail revenues based on SMUD's 2004 proposed budget.

Table 3-2
SMUD Retail Revenue Requirement Projections (¢ per kWh)

		Commercial				
Yr	Residential	Small	Medium	Large	Agricultural	Other
2004	9.90¢	10.04¢	8.88¢	7.46¢	9.08¢	8.58¢
2005	10.49	10.66	9.31	7.90	9.62	9.44
2006	10.33	10.51	9.18	7.79	9.48	9.30
2007	9.94	10.11	8.83	7.49	9.12	8.95
2008	9.49	9.65	8.43	7.16	8.71	8.55
2009	9.54	9.70	8.48	7.20	8.76	8.59
2010	9.75	9.92	8.66	7.36	8.95	8.78
2011	10.07	10.23	8.94	7.60	9.24	9.07
2012	10.22	10.39	9.08	7.72	9.38	9.21
2013	10.62	10.80	9.44	8.02	9.75	9.57
2014	10.89	11.07	9.68	8.22	10.00	9.81
2015	11.14	11.32	9.90	8.41	10.23	10.04
2016	11.45	11.64	10.17	8.65	10.51	10.32
2017	11.70	11.90	10.40	8.84	10.74	10.54
2018	12.04	12.24	10.70	9.09	11.05	10.85
2019	12.25	12.45	10.88	9.25	11.24	11.03
2020	12.55	12.76	11.15	9.48	11.52	11.31
2021	12.89	13.10	11.45	9.73	11.83	11.61
2022	13.26	13.48	11.78	10.01	12.17	11.95
2023	13.63	13.86	12.11	10.29	12.51	12.28
2024	13.91	14.14	12.36	10.50	12.77	12.53
2025	14.35	14.59	12.75	10.83	13.17	12.93
2026	14.57	14.81	12.94	11.00	13.37	13.12
2027	15.09¢	15.34¢	13.41¢	11.39¢	13.85¢	13.59¢

3.5.3 PG&E's Retail Rates

SMUD's projected revenue requirements for those customers included in the potential annexation will be compared against estimated revenues produced from PG&E's retail rates. Unfortunately, a great deal of uncertainty surrounds the future of PG&E retail rates. PG&E was unwilling to provide long-term projections of their retail rates. In addition, PG&E provided estimates of its short-term rates based on different sales estimates and varying assumptions of regulatory cases, including PG&E's bankruptcy case, the 2003 GRC Phase 2 settlement, and the long-term procurement case. The outcome of these proceedings will affect PG&E's retail rates for many years to come.

For the purposes of this Study, PG&E's energy usage by rate class was used in conjunction with PG&E's 2003 GRC Phase 2, which was approved by the CPUC on December 16, 2004, to arrive at the current average rate for each class. It is important to note that if PG&E had provided the load and demand information for each applicable rate schedule for the given regions at the required detail, a more precise retail rate projection could have been developed for each rate class. Due to this lack of data for the given regions, PG&E's system average rates presented for each rate class in PG&E's 2003 GRC Phase 2, were used, with the exception of the residential class. The retail rate components for each rate class are also taken from PG&E's 2003 GRC Phase 2 filing. For each jurisdiction, PG&E's system average revenues for the residential class were adjusted to reflect different average use per residential customer in that jurisdiction. This was necessary to account for PG&E's steeply inverted residential rates. The lower the use per average customer, the lower the average revenue per kWh. For other classes, the GRC Phase 2 average revenues were applied to sales profiles, or the percentage of the class contribution to total load, in each jurisdiction. PG&E's retail rates are projected through 2027 based on the following:

- The CPUC adopted Decision D. 03-07-028 on November 19, 2004, on the MDL CRS. The decision creates a CRS exception applicable to the transferred load within PG&E's service territory with respect to estimates set forth in PG&E's August 2000 Bypass report. This report was relied upon by CDWR in its power procurement process. In this Bypass report, Redding, Roseville, Lodi, and Davis were recognized to have loads likely to be served from municipal entities. Therefore, Davis's load is held exempt from the CRS related to CDWR power supply and bonds for the purposes of this analysis.

- The CPUC adopted a decision (D. 04-01-050) in January 2004 establishing Resource Adequacy Requirements for Load Serving Entities (LSEs). According to this decision, each LSE is required to acquire sufficient reserves for its customers' load located within their service territory. Initially, each LSE is required to have 15-17% planning reserve margin for all months of the year no later than January 1, 2008. However, based on the recent rulings in July and October 2004 (R.04-04-003), the full implementation of 15-17% planning reserve margin is planned to be effective January 1, 2006. In addition, each LSE must forward contract 90% of its summer (May through September) peaking needs (Loads plus reserves) a year in advance. Although, the CPUC has not issued a final decision, this ruling will likely be implemented. An adjustment for planning reserve margin is reflected in both the Breakeven revenue requirement and PG&E's retail rates at the same marginal cost of 0.1¢ per kWh.

- The Regulatory Asset component is a non-bypassable charge that was established in SB 772 on April 29, 2004. This component provides for new debt to pay off remaining PG&E bankruptcy claims and expenses. It is assumed that these costs will be collected at a constant rate of 0.5970¢ per kWh through 2013 applicable to each rate schedule.

- On September 12, 2002, SB 1078 was signed requiring California IOUs to generate 20% of their electricity from renewable energy resources no later than 2017. PG&E is required to increase the contribution of renewable resources in its portfolio by at least 1% over the previous year's renewable resource base (as long as the additional costs can be paid from Public Benefits proceeds) to eventually equal 20% of its retail sales from renewable resources by 2017. SMUD has indicated that it will reach the 20% ratio by 2011. It has been assumed that SMUD's base rates cover the cost of the first 10% mix of renewable resources. However, a 10% premium over market prices has been assumed for obtaining the second 10% of the mix. For PG&E, no rate impact is assumed because the legislation allows PG&E to fund the extra costs from public benefits charges. The full cost of achieving the 20% mix in the annexed areas is included in the power supply cost and resulting breakeven revenues. To the extent that public benefit charges are not sufficient to fund PG&E renewable portfolio objectives, it is likely that the CPUC will allow rates to be increased for this purpose. In order to maintain conservatism, no such rate increase has been assumed.

- Due to changes in non-bypassable charges over time, PG&E's retail rates can be expected to decline as non-bypassable costs are paid off. Specifically, PG&E rates have been reduced in 2009 to reflect removal of the FTA from rates, and in 2013 to reflect removal of "Tail" CTC. Additional reductions to PG&E rates to remove the effect of CDWR contract costs on the average cost of PG&E's energy resources have also been made. As the above-market price CDWR contracts expire, it is assumed that they are replaced by long-term contracts that reflect market prices. It is assumed that QF contracts will continue and escalate with gas price increases. To the extent that this causes QF contracts to continue to be above market, this assumption is conservative.

In addition to the above mentioned regulatory issues, PG&E's retail rates were also adjusted for the changes in their power supply, transmission, distribution, and reliability services costs over time.

The power supply component of PG&E's tariff is calculated based on the following assumptions:

- Average rates are adjusted annually based, in part, on changes in market power supply costs. A portion of PG&E's energy resources comes from purchases of energy at market prices. As market energy prices change, the average cost of PG&E's resource portfolio also changes. Changes to PG&E's average cost of energy resources have been captured within the PG&E rate projections used in this Study. Based on PG&E's 2003 FERC Form 1 filing, the following table identifies PG&E's generation by resource type and the contribution of these resources to PG&E's total power supply cost for 2003. PG&E's 2003 CDWR quantities and power costs are obtained from the Alternate Draft Decision on Application 00-11-038 dated August 20, 2003. PG&E's short-term market allocation is determined by taking the difference in the total power supply requirement for 2003 and the power supply from various resources, including hydro, nuclear, QFs, and CDWR. This breakdown was used to determine the changes in PG&E's power supply portfolio throughout the Study period.

Table 3-3
PG&E Generation Component Distribution

Resources	Generation MWh	Generation %	Cost Dollars	Cost %
Hydro	11,055,305	12.71%	$ 93,359,740	2.18%
Nuclear	17,285,039	19.87%	322,144,047	7.51%
QF	30,134,920	34.65%	1,924,031,638	44.85%
CDWR	20,296,174	23.34%	1,521,198,219	35.46%
Short Term	7,705,611	8.86%	394,736,034	9.20%
Other	496,131	0.57%	34,915,599	0.81%
Total	86,973,180	100.00%	$4,290,385,277	100.00%

With respect to the available data from PG&E's Long-Term Procurement filing, it is observed that the share of these resources in generation, excluding the CDWR contracts, remain fairly constant through 2014. PG&E's projections of hydro, nuclear, and QFs through 2014, contained in their long-term procurement plan filing with the CPUC, were used for simplicity's sake, and to remain conservative, the ratios were kept at constant 2014 levels thereafter. Although PG&E has announced plans for substantial new investment in its nuclear plant, that investment has not been authorized and has not been included in the evaluation. Since nuclear costs are far below market prices, it is likely that this investment will be allowed. A sensitivity case was run to determine the effect on PG&E rates and revenue requirements if less conservative estimates of PG&E's power supply costs were used. See Section 3.8. CDWR contracts provided in the long-term procurement plan only reflected the Total Must-Take CDWR Contracts allocated by the CPUC. Total Dispatchable CDWR Contracts allocated by the CPUC and the renewables are determined based on "Activities and Expenditures Report Year Ended December 31, 2003" by the CDWR. CDWR contracts are assumed to expire by 2012, as presented in the long-term procurement plan. Although new CDWR contracts, such as the Kings River Conservation District and the City and County of San Francisco, extend through 2016 they are estimated to have no major impact on PG&E's resource portfolio. In the absence of data from PG&E, it is assumed that CDWR contracts would be replaced by market purchases as the contracts expire. Based on the percentages by MWh from the Table 3-3, annexed regions' energy requirements (including losses) are distributed among the various power supply resources resulting in the allocation shown in Table 3-4.

Table 3-4
Power Supply by Resource Adjustment for the Annexed Region

2003	MWh
Hydro	162,675
Nuclear	254,343
QF	443,424
CDWR	298,650
ST	120,686
Total	1,279,777

The annexed regions' power supply requirement by resource type is projected based on PG&E's system level power supply requirement projection. New load is assumed to be allocated to the power supply market as the load in the annexed region grows with time.

PG&E's 2004 renewable resource portfolio is estimated to be at 12% of its total power supply requirement. It is assumed that PG&E will increase its renewable resources by 1% annually until it reaches 20% of its power supply requirement, as required by SB 1078. It is assumed that any additional costs will be funded from public benefits charges. Hence, no rate adjustment is made to pay for the renewable resources. As noted earlier, a sensitivity case was run for a less conservative assumption. See Section 3.8.

PG&E's power supply prices are projected based on the following assumptions throughout the Study period:

- Hydroelectric and nuclear resources are escalated at the inflation forecast based on the Blue Chip Economic Indicators, March 2004, report. See Section 3.8 for a less conservative assumption that includes nuclear investments of $1 billion and hydroelectric investments of $100 million.
- Market-based resources are priced at HESI's market price projections. 2004 market price is calculated by deescalating the 2005 market price at the inflation rate.
- CDWR prices are assumed to follow half of the trend in natural gas price projections.

PG&E's power supply cost projection is calculated in dollars per MWh for each year throughout the projection period. The power supply costs per rate class are provided in PG&E's GRC Phase 2. These rates are projected throughout the study period following the trend in PG&E's power supply costs projection for the annexed regions.

Other cost assumptions relevant to PG&E's retail rates:

- Transmission, distribution and reliability services components of PG&E's retail prices are based on PG&E's Proposed GRC Phase 2 rates. They are escalated from 2005 until 2013 based on the CEC's report titled "California Investor Owned Utilities Retail Electricity Prices Outlook" dated July 2003. These costs are escalated at the forecasted inflation rate thereafter.
- The Public Purpose Program component is assumed to remain at the existing percentage ranging from 2.26% to 3.33% as its contribution to the revenue of each rate class from PG&E's proposed 2003 GRC Phase 2 filing. It should be noted that this may not be sufficient to fund PG&E's renewable portfolio objectives.
- The Nuclear Decommissioning component is assumed to remain constant based on PG&E's proposed 2003 GRC Phase 2 filing, based on in its contribution to the revenue of each rate class.

With respect to the above-mentioned adjustments, PG&E's retail rate projections by customer class through 2027 are presented in Table 3-5.

Table 3-5
PG&E Retail Rate Projections (¢ per kWh)*

		Commercial				
Yr	Residential	Small	Medium	Large	Agriculture	Other
2004	14.08¢	15.02¢	11.91¢	9.70¢	11.70¢	14.40¢
2005	14.16	15.11	11.91	9.66	11.73	14.48
2006	14.25	15.19	11.89	9.62	11.78	14.59
2007	14.05	14.98	11.59	9.32	11.55	14.48
2008	13.84	14.75	11.30	9.01	11.32	14.39
2009	13.16	14.05	11.32	9.08	11.41	14.60
2010	12.67	13.50	10.70	8.49	10.89	14.27
2011	13.02	13.88	11.04	8.77	11.21	14.69
2012	13.33	14.21	11.31	8.99	11.46	15.06
2013	12.18	13.00	10.16	8.09	10.14	14.91
2014	11.96	12.80	9.90	7.78	9.86	14.74
2015	12.28	13.15	10.18	8.00	10.13	15.12
2016	12.64	13.54	10.51	8.27	10.44	15.54
2017	12.95	13.87	10.77	8.48	10.71	15.92
2018	13.33	14.28	11.11	8.76	11.03	16.36
2019	13.63	14.60	11.38	8.98	11.29	16.72
2020	14.01	15.01	11.72	9.26	11.61	17.17
2021	14.40	15.43	12.07	9.55	11.95	17.63
2022	14.81	15.87	12.43	9.84	12.29	18.10
2023	15.23	16.32	12.81	10.15	12.65	18.59
2024	15.64	16.75	13.17	10.44	13.00	19.07
2025	16.09	17.24	13.58	10.78	13.39	19.59
2026	16.50	17.68	13.94	11.07	13.74	20.08
2027	16.99¢	18.21¢	14.39¢	11.44¢	14.16¢	20.64¢

*Includes 0.1¢ per kWh starting in 2006 for Resource Adequacy Requirements.

3.5.4 Power Supply Costs

The power supply cost scenario contained in this Study conservatively assumes that SMUD obtains its supply for the newly annexed regions entirely from the market until 2013. Starting in 2014, it is assumed that SMUD will gradually integrate the annexed loads into its power supply portfolio by 2017, and that 80% of the power supply prices then escalate to track the natural gas prices while 20% escalate at the rate of inflation. These costs would likely be lower if SMUD could more quickly meld these additional supply requirements into its current resource planning activities. This integration should not be adverse to existing SMUD customers and may even be of benefit. The annexation will increase the diversity of loads served by SMUD, reducing system power supply costs. Additionally, the annexed areas will have contributed their full share of a 20% renewable resource mix. In all likelihood, if the system is acquired by SMUD, it will gradually be absorbed into SMUD's resource base. Loads that are under consideration for annexation by customer class for year 2004 are shown below in Table 3-6 and were provided by PG&E.

Table 3-6
Consumption by Customer Class for 2004
(MWh)

		Commercial/Industrial					
	Residential	Small	Medium	Large	Agricultural	Other	Total
West Sacramento							
Bundled	92,163	45,691	141,243	98,470	4,646	2,126	384,338
Direct Access	24	1,069	15,193	3,052			19,339
West Sacramento Total							403,677
Davis							
Bundled	163,469	34,013	61,495	—	1,495	2,443	262,914
Direct Access	802	2,544	23,119	—			26,466
Davis Total							289,379
Woodland							
Bundled	130,036	41,887	100,421	65,707	136	2,045	340,233
Direct Access	625	306	16,475	11,924			29,329
Woodland Total							369,562
Yolo Unincorporated							
Bundled	66,325	20,320	53,769	21,121	35,733	228	197,494
Direct Access							-
Yolo Unincorporated Total							197,494
Total Consumption							1,260,113

The cost of energy associated with serving the potentially annexed load is based on a confidential study prepared by HESI. This includes on-peak and off-peak market clearing price projections at California Oregon Border from 2005 through 2018 This projection was adjusted to reflect load characteristics in the jurisdictions. The average market price per annum for the subject annexed areas is calculated based on the typical weekday and weekend load shape data provided by PG&E for each service area. Market price projections are carried forward using five-year moving averages thereafter through 2027.

In the long term, PG&E rates will have to reflect changes, whether up or down, in electricity prices for that part of their resource mix that is tied to market and gas prices. Therefore, to the extent that market prices and gas prices are above or below actual future prices, PG&E rates would be expected to track such changes by approximately 90%. This reflects the fact that PG&E's nuclear and hydroelectric resources are not linked to natural gas or electricity market prices.

3.5.5 Expenses

3.5.5.1 O&M and A&G Costs

Cost projections for the potentially annexed areas include an assumption that the costs of distribution and transmission O&M will be the same as those experienced in the current SMUD service area. SMUD's distribution related O&M and A&G costs are estimated at $12.30 per MWh based on SMUD's 2003 annual report. This cost is escalated at the rate of inflation throughout the study period. Capital-related costs are based on debt service related to the estimated cost of acquisition, litigation costs, issuance costs, debt service reserves, and working capital.

The transmission O&M and associated A&G costs are addressed using two separate methods in the analysis: one assumes that SMUD would acquire the transmission system as part of the annexation. The second assumes that SMUD would not acquire the system, but instead pay CAISO charges for transmission service. Both of these options were studied given that the costs of transmission vary by jurisdiction and the cost of building transmission could increase dramatically if only one area (such as Davis) was annexed.

In the first method, SMUD's transmission O&M and related A&G expenses were estimated at $2.0 per MWh and escalated at the rate of inflation thereafter. It was also assumed that new transmission would be built to connect to the SMUD system. In the second method, a CAISO charge of $3.7698 per MWh would apply for transmission service. This cost is escalated at the <u>Blue Chip Economic Indicator's</u> inflation rate thereafter. Table 3-7 shows the breakdown of current CAISO fees.

Table 3-7
CAISO Fee Breakdown

	$/MWh
Control Area Services	$0.5690
Congestion Management	0.3200
A/S & R-T Energy Operations	1.2960
TAC	1.5848
Total CAISO Fees	$3.7698

3.5.5.2 Franchise Fees and Property Taxes

Since SMUD is technically not subject to all of the fees and taxes that PG&E is, there is the potential for a loss of revenues for the Yolo Jurisdictions. R. W. Beck has accounted for these taxes and fees in the acquisition surcharge. Therefore, the Yolo Jurisdictions will see no less revenue as a result of annexation, and the remaining

SMUD ratepayers will not be affected by these charges. PG&E has provided the franchise fee payments for 2003 for each City, which came very close to 1.5% of the total retail revenue for West Sacramento and Davis, and to 1.2% of retail revenues for Woodland. Property taxes are based on an assumption that they amount to 3.16% of PG&E's distribution revenue requirement. This issue is discussed in more detail in Section 4.

3.5.5.3 Ancillary Services

Ancillary Services charges are estimated to be 10% of the market price applicable to the entire energy requirement, after losses, in the cases where SMUD provides direct transmission service. Ancillary service fees are included in the CAISO cost in the scenarios in which service is provided through CAISO facilities.

3.5.5.4 Resource Adequacy Requirement

Resource Adequacy Requirements for LSEs were adopted by the CPUC in Decision D. 04-01-050 in January 2004. This decision requires each LSE to have a 15-17% planning reserve margin. Although the implementation date has not been finalized, R. W. Beck has assumed that it will be effective January 1, 2006. The adjustment for planning reserve margin is also included in the breakeven revenue requirement as a line item, at the same marginal cost of 0.1¢ per kWh over its total energy requirement, including losses. To the extent that the timing or amount varies, it applies to both PG&E and annexed areas, although SMUD'S Board of Directors will ultimately determine SMUD's resource balance (loads vs. resources) and the resource mix and is not required to adopt the CPUC standards.

3.5.6 Non-Bypassable Charges

In dealing with the financial aftershocks of the 2000-2001 energy crisis, the California Legislature and CPUC made it very clear that, as the electric market structure continued to change, customers would not be able to avoid certain costs allocated to them as a part of initial electric restructuring or the energy crisis. Beginning in 2002, the CPUC began to define the costs that customers who bypass one or more IOU service would pay after they bypass. These costs have been defined by the CPUC as CRS and apply mainly to certain Direct Access customers or customers who are served under an AB 117 Community Aggregation Plan, and customers who bypass the IOU's electric delivery services either through cogeneration or purchase of certain electric facilities. The CRS that eventually is paid by each of these groups of bypass customers could be very different. In addition, the CRS that applies to each customer class (residential, commercial, and industrial) is also likely to be different. A CRS is expected to apply to the customers transferred to SMUD, as well as to new customers connected after annexation, in the regions subject to annexation. While decisions regarding the composition of these charges (who they would apply to, the amount of the charges, and how long the charges would apply) are still evolving, the following describes the type and size of the CRS that was assumed to apply for the purposes of this Study.

3.5.6.1 CDWR Energy Contract Costs, Bond Repayments, and Other Costs

The CDWR took over purchasing obligations for the California's IOUs in January 2001. The CDWR purchased billions of dollars' worth of energy during the summer and fall of 2001 that was eventually amortized and is assumed to be paid for through a bond issue over the next 20 years. In addition, the CDWR signed many long-term contracts that have turned out to be in excess of the market price of power over the long term. The cost of the contracts above-market prices is absorbed by all of the IOUs' customers, including those customers that choose to bypass IOU service. The CPUC issued Decision D.02-11-022 in 2002 that determined how much cost responsibility certain Direct Access customers would have for newly signed CDWR energy contracts, bond costs, and other CDWR administrative and management costs. The surcharge for these customers was initially capped at $0.027 per kWh.

The CPUC recently adopted Decision D.03-07-028 on November 19, 2004, that determined the CRS that would apply to MDL, which is "… departing load served by a 'publicly owned utility' as that term is defined in Public Utilities Code Section 9604(d), including municipalities or irrigation districts." The CRS that applies to MDL load for CDWR costs is assumed to equal $0.027 per kWh for all customers until 2013. While there is evidence that some Commissioners and other parties believe the charge should be higher in the short term and lower over time, the current majority of Commissioners have twice ruled that the $0.027 per kWh charge is appropriate. This decision also creates a CRS exception applicable to the transferred load within PG&E's service territory with respect to estimates set forth in PG&E's August 2000 Bypass report. This report was relied upon by CDWR in its power procurement process. In this Bypass report, Redding, Roseville, Lodi, and Davis were recognized as load likely to be served from municipal entities. Therefore, R. W. Beck has assumed that the $0.027 per kWh would apply to all of the energy sales in the potential annexation areas, with the exception of Davis's load, as it is held exempt from the CRS related to CDWR power supply and CDWR bonds for the purposes of this analysis.

3.5.6.2 Nuclear Decommissioning Costs (NDC)

NDC charges are defined by the Public Utilities Code to be non-bypassable. The charges included in this Study for SMUD were based on PG&E's proposed 2003 GRC Phase 2. They were assumed to remain constant through 2018 in their contribution to the revenue of each rate class.

3.5.6.3 Post-Transition Period Competition Transition Charge (Tail CTC)

Tail CTC is also defined as a non-bypassable charge under Public Utilities Code regulations. Tail CTC is composed principally of above-market costs associated with an IOU's Qualifying Facility and other long-term contracts, as well as other restructuring costs (including employee restructuring costs). Tail CTC is assumed to be based on PG&E's proposed 2003 GRC Phase 2 that shows the rate component for CTC charges by customer class. After 2012, the tail CTC is assumed to be paid off. However, QF contracts are assumed to continue and to escalate at natural gas prices.

3.5.6.4 Regulatory Assets Charge

The Regulatory Assets Charge is also defined as a non-bypassable charge under Public Utilities Code regulations. This charge is established pursuant to SB 772 passed on April 29, 2004. It is designed to securitize new debt to pay off the remaining PG&E bankruptcy claims and expenses, with the costs collected in rates. It is assumed to be collected at a constant rate of 0.5970¢ per kWh through 2013 at the same rate on each rate schedule.

3.5.6.5 Fixed Transition Amount

The FTA was imposed to pay for the Rate Reduction Bonds used during industry restructuring to provide a 10% discount to residential and small commercial customers. The FTA is a non-bypassable charge and generally applies to customers with peak demands of less than 20 kW. The FTA charges included in this Study were based on PG&E's proposed 2003 GRC Phase 2 that shows the rate component for FTA charges by customer class. The FTA is scheduled to terminate when the Rate Reduction Bonds are paid off in 2008.

3.5.6.6 Total CRS

Table 3-8 shows the initial amount of CRS included for this Study. All CRS is assumed to expire in 2012.

Table 3-8
Assumed CRS in 2004

	NDC (¢/kWh)	FTA[1] (¢/kWh)	CRS Costs[2] (¢/kWh)
Residential	0.0475¢	0.07820¢	0.027¢
Small Commercial	0.0504¢	0.8130¢	0.027¢
Medium Commercial	0.0382¢	0.0447¢	0.027¢
Large Commercial	0.0268¢	N/A	0.027¢
Agricultural	0.0415¢	N/A	0.027¢
Streetlights	0.0490¢	N/A	0.027¢

[1] The FTA applies to small commercial customers who have elected to take service from Medium Commercial Rate Schedules A-10 or E-19V.
[2] CDWR costs are capped at 2.7¢ per kWh and assumed to include CDWR power charges, bond costs, regulatory assets and the post transition period CTC charges

3.5.7 Facility Financing Costs

The capital acquisition cost related to PG&E assets is 100% debt financed at a taxable interest rate of 6.25%, over 30 years. The assumed debt for the transmission and distribution annexation investment costs by each scenario is presented in Table 3-9. Distribution Capital represents the acquisition cost of Distribution facilities based on the Replacement Cost Scenario. This is an extremely conservative assumption, since R. W. Beck is of the opinion that the much lower OCLD approach to valuation is appropriate. The transmission components are broken into those acquired from PG&E, an estimate of PG&E's stranded facilities, and new facilities that would need to be constructed by SMUD to more reliably serve the load in 2008 and 2013.

This table provides a summary of assumed acquisition costs based on Sections 1 and 2. For reference purposes:

- Scenario 1 is for the West Sacramento region
- Scenario 2 is for the West Sacramento and Davis regions
- Scenario 3 is for the West Sacramento, Davis, Woodland regions
- Scenario 4 is for the entire Study Area, including the area served by the Plainfield Substation

Table 3-9
SMUD Transmission and Distribution
Annexation Investment Costs – RCNLD

	Distribution Capital	Transmission Capital	Additional Stranded	New Capital	Total
Scenario 1					
2008	$27,521,747	$4,877,299	$453,690	$7,806,360	$40,659,096
2013				5,500,000	5,500,000
					$46,159,096
Scenario 2					
2008	$59,570,348	$9,025,664	5,835,134	$19,969,400	$94,400,546
2013				6,424,000	6,424,000
					$100,824,546
Scenario 3					
2008	$87,785,290	$11,077,290	$5,835,134	$17,914,696	$122,612,410
2013				6,424,000	6,424,000
					$129,036,410
Scenario 4					
2008	$91,061,440	$11,077,290	$5,835,134	$20,799,776	$128,773,640
2013				6,424,000	6,424,000
					$135,197,640

Table 3-10 presents the additional distribution capital investment that needs to be made per each additional customer, depending on the jurisdiction, in 2004 dollars. The number of new customers for each year is determined and the additional capital investment that needs to be made is calculated based on these costs and added to the capital investments in the previous table for each scenario. In the Base Cases, it is assumed that these investments are net of contributions in aid of construction provided by developers.

Table 3-10
Distribution Capital Investment per
Additional New Customer in 2004 Dollars

	West Sacramento	Davis	Woodland
Medium voltage network/customer	$1,348	$1,699	$1,538
Low voltage network and service drops/customer	502	455	407
Total per customer	$1,850	$2,154	$1,945

In addition to the capital investment costs, allocations for debt service reserve, litigation expenses, and cost of issuance are included in debt service. Litigation expenses at approximately 20% of the debt service requirement were included. A debt service reserve equal to one year principal and interest and issuance cost of 1.5% of the issue size were also added.

Debt related to estimated litigation costs, issuance costs, working capital and debt service reserves is assumed to be exempt from income taxes and issued at an interest rate of 5%.

Working capital is assumed to be financed for purposes of the analyses, even though SMUD believes that its current working capital is sufficient. Working capital requirements are based on 45 days of 2008 revenues requirements exclusive of debt service and non-bypassable charges.

3.5.8 Renewals and Replacements

Based on the evaluation of the annexed regions' distribution and transmission systems, the following table presents the Renewal and Replacement cost estimates per annum by city in 2004 dollars. These costs are escalated at the forecasted inflation rate by Blue Chip Economic Indicators, March 2004, report throughout the study period.

Table 3-11
Asset Replacement Allowance per Year in 2004 Dollars

	West Sacramento	Davis	Woodland & Yolo	Entire Study Area
Overhead medium voltage network	$320,841	$395,933	$400,977	$1,117,751
Underground medium voltage network	126,466	162,731	130,356	419,552
Meters	69,058	94,275	80,795	244,127
Low voltage network overhead (includes service drops)	12,834	15,837	16,039	44,710
Low voltage network underground	3,208	3,959	4,010	11,178
Total Replacement	$532,407	$672,735	$632,176	$1,837,318

3.5.9 Severance

Severance costs are those costs of reconfiguring the PG&E system to allow them to continue to serve their remaining customers with no reduction in reliability or increase in operating costs. The definition of areas to be annexed has been designed to minimize severance costs. With respect to transmission, when proposed new transmission is constructed to meet SMUD reliability standards, some existing PG&E lines will be stranded. The cost of those stranded lines has been included in the cost of acquisition. Load flow studies were performed that demonstrate that PG&E's transmission system will not be adversely affected by separation from the transmission and substation assets acquired by SMUD.

No joint use of substations has been proposed, such that there should be no severance costs related to substations.

The distribution system acquisitions have been defined to include all load served by identified substations. This will eliminate nearly all distribution system severance costs.

The Study does include business severance costs to compensate PG&E for transfer of customer records, provision of system maps and facility drawings, right-of-way and property transfers, and miscellaneous accounting activities. An assumed severance cost of 1% of the acquisition cost should also cover any minor physical system severance, such as line switching and line switch removal.

3.5.10 Calculation of Surcharge

The surcharge is the additional charge applied to the jurisdictions that is needed to fund the annexation while keeping the existing SMUD ratepayers whole. The surcharge is assumed to be the difference between the breakeven revenues and SMUD's system average revenues, and includes non-bypassable charges and consideration of franchise fees and property taxes.

3.6 Scenario Analysis

Given the fact that there are six different jurisdictions directly involved in the Study Area (the Cities of West Sacramento, Davis and Woodland; the County of Yolo, PG&E, and SMUD) and provided the complexities of serving a variety of customers at generation, transmission and distribution levels, the number of possible scenarios is considerable. Based upon the analyses conducted in this study, the major drivers in terms of cost and benefit are:

- Average rates and revenues
- Customer loads and load characteristics
- Market Price of Electricity
- Acquisition Cost
- Exit or Non-Bypassable Fees and Costs

- Transmission Service versus CAISO Costs

Eight Base Case Scenarios have been prepared to reflect the three feasible area acquisition options, which assume SMUD construction of transmission, and the five feasible area acquisition options, which assume reliance on the CAISO for transmission. The Base Case options all assume a very conservative acquisition price based on RCNLD, medium cost estimates for power supply, and non-bypassable charges that include a levelized CRS at 2.7¢ per kWh. In each area definition, the City containing the majority of load is listed even though some of the load may include unincorporated areas of Yolo County. The areas include:

SMUD Builds Transmission

1. West Sacramento
2. West Sacramento and Davis
3. West Sacramento, Davis, Woodland, and Yolo (portion)

ISO Transmission Reliance

4. West Sacramento
5. Davis
6. Woodland and Yolo (portion)
7. West Sacramento and Davis
8. West Sacramento, Davis, Woodland, Yolo (portion)

3.6.2 Sensitivity Analyses

Sensitivity analyses have been run to determine the influence of different key assumptions. These include:

- Different acquisition costs
  - OCLD, which represents a fair acquisition price.
  - RCNLD at 5% Present Worth Depreciation, which presents the highest acquisition price.
- Different power supply costs
  - High
  - Low

Because of the large number of potential combinations, sensitivity analyses were run only on Base Scenarios 3 and 8, allowing only one variable to change at a time. Additionally, a lowest and highest cost case was run for Base Case Scenarios 3 and 8. These cases are defined as:

A. Lowest Savings Case — OCLD, low-cost power

B. Largest Savings Case — RCNLD at Present Worth Depreciation, high-cost power

Additionally, three specific sensitivity analyses were run to test sensitivity to:

- Residential average revenue adjustments
- PG&E power supply costs
- Contributions in aid of construction

Results of these specific sensitivity analyses are discussed in Section 3.8.

3.7 Summary of Base Cases

The best understanding of the study results can be obtained from the graphs presented in Graphs 3-2 through 3-14. These graphs show the year-by-year comparison of the projected breakeven revenues with projected SMUD and PG&E revenues. At times, the breakeven revenues are higher than PG&E's revenues and at other times, they are lower. Long-term trends are important and can be discerned from the graphs. Additionally, the NPV of costs above or below PG&E are shown in Table 3-12. Since these NPVs represent only the period form 2008 to 2127, it is important to consider the trend in the later years of the Study when evaluating results. It is also notable that a change in the timing of an annexation could alter the results. This is primarily due to the decline and eventual elimination of non-bypassable charges.

Table 3-12
Comparison of Base Case NPV Costs/Savings

Scenario	Scenario Description	NPV ($000) (Costs) Savings
1	West Sacramento Build	$6,712
2	West Sacramento & Davis Build	$10,641
3	All Region Build	$87,046
4	West Sacramento CAISO	$6,453
5	Davis CAISO	$20,389
6	Woodland & Yolo CAISO	$57,408
7	West Sacramento & Davis CAISO	$23,117
8	All Region CAISO	$84,181

A more complete description of each base case follows, along with the graph that presents a visual representation of the results.

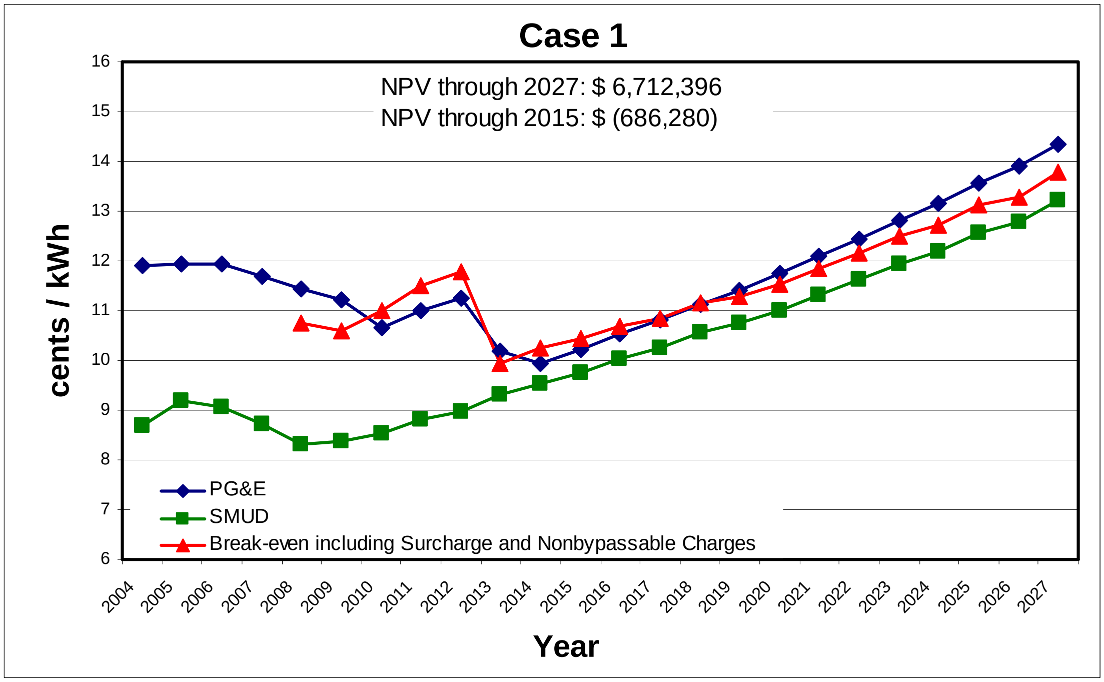
3.7.1 Base Cases: Build Option

As mentioned above, three base cases were created with respect to the transmission and distribution annexation scenarios presented in the Technical Analysis section. Under these scenarios, SMUD is assumed to annex the West Sacramento area only, West Sacramento and Davis areas, and West Sacramento, Davis, Woodland and Yolo Unincorporated areas.

3.7.1.1 Base Case 1: West Sacramento Only

In this case, SMUD and PG&E system average retail rates are by customer class based on West Sacramento area customers only. The following graph presents PG&E's and SMUD's system average revenue versus the breakeven revenue for West Sacramento. The breakeven revenue includes the surcharge that needs to be added to cover the costs of annexation and the non-bypassable charges that would be paid to PG&E.

Graph 3-4
West Sacramento Build Transmission Option

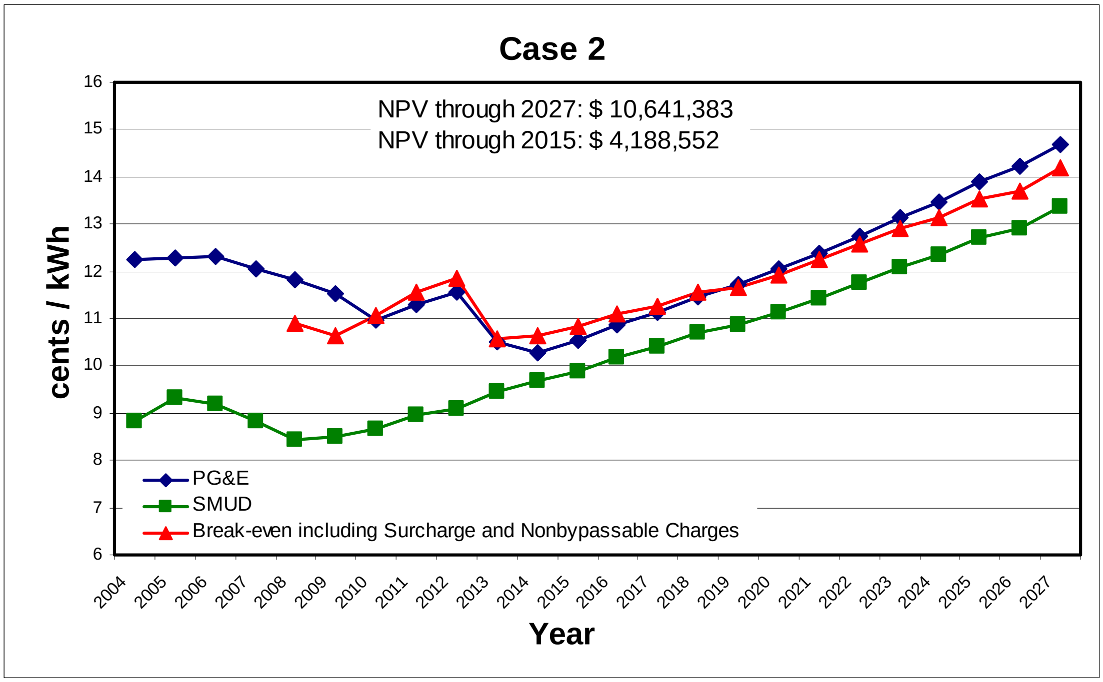


In the above graph, the breakeven revenue in the early years is high, since it includes the CRS, which is capped at 2.7¢ per kWh through 2012.

3.7.1.2 Base Case 2: West Sacramento and Davis

The SMUD and PG&E system average retail rates are weighted by customer class energy sales for both West Sacramento and Davis area customers only. The following graph presents PG&E's and SMUD's system average revenues versus the breakeven revenue for the subject customers within the annexed region only. The breakeven revenue includes the surcharge that needs to be added to cover the costs of annexation and in this case, the non-bypassable charges that would be paid to PG&E. As mentioned in the early sections of this study under regulatory issues, Davis is exempt from the CRS resulting from CDWR power cost responsibility (based on CPUC's Decision D. 03-07-028 on November 19, 2004, on the MDL). Davis's load was recognized as a potential MDL in PG&E's August 2000 Bypass report which was relied upon by CDWR in its power procurement process. These savings are shared across all customers.

Graph 3-5
West Sacramento and Davis Build Transmission Option

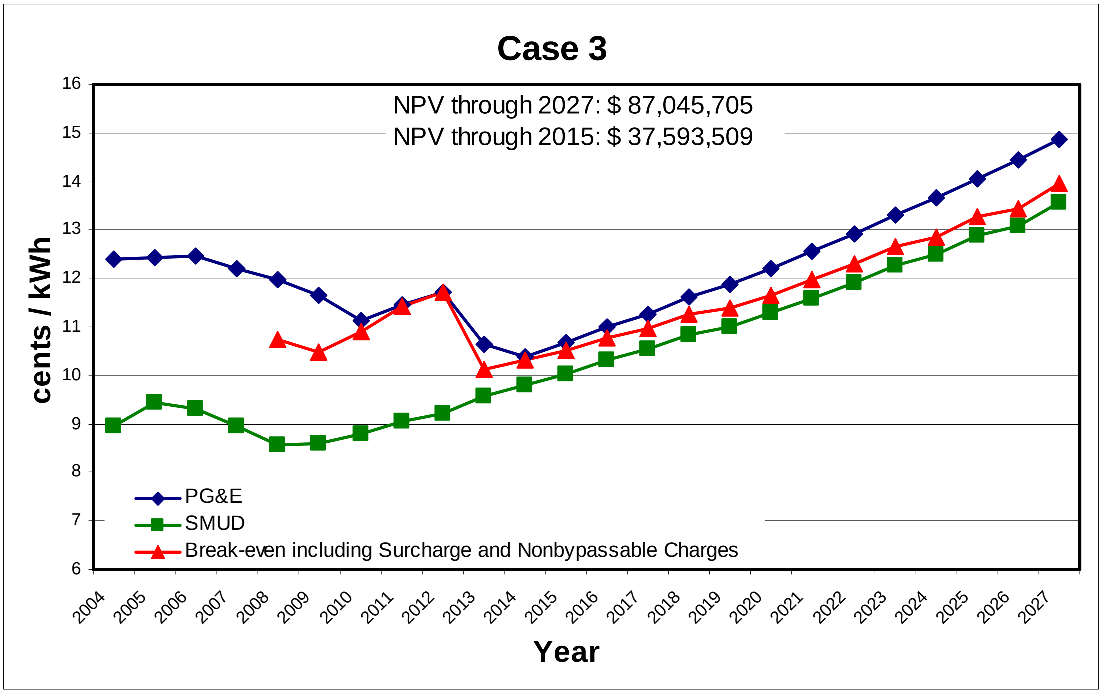


The breakeven revenue in this case includes the CRS for West Sacramento but excludes it for Davis. However, breakeven revenues are similar due to adjustments in Davis for low average residential use. One reason this occurs is due to the fact that the debt requirement more than doubled from $45.2 million for the West Sacramento only case to $105 million for the West Sacramento and Davis case.

3.7.1.3 Base Case 3: Three Cities and Yolo

The SMUD and PG&E system average retail rates are weighted by customer class energy sales for West Sacramento's, Davis's, Woodland's, and Yolo Unincorporated's customers. The following graph presents PG&E's and SMUD's system average revenues versus the breakeven revenue for the subject customers within the entire annexed region. The breakeven revenue includes the surcharge that would be added to cover the costs of annexation and, in this case, the non-bypassable charges that need to be paid to PG&E.

Graph 3-6
Three Cities and Yolo Build Transmission Option



The breakeven revenue includes the CRS for West Sacramento and Woodland, but not Davis. Among all the "Build Transmission" cases, this scenario results in the largest savings. This is due largely to the fact that the incremental debt requirement is shared by a higher number of customers. The incremental debt is $38.7 million, resulting in a total of $143.7 million of debt requirement. The NPV Savings in this scenario is approximately $87,046,000, or 4.27% over the life of the study.

3.7.2 Base Cases: CAISO Options

Five additional base cases under the CAISO service option were studied. Under these scenarios, it was possible to evaluate each city separately, as their Distribution Capital Investment requirements were handled discretely and were additive in contrast to the transmission scenarios presented in the Technical Analysis section. Therefore, the following cases were considered: West Sacramento area only; Davis area only; Woodland and Yolo Unincorporated areas only; West Sacramento and Davis areas; and West Sacramento, Davis, Woodland, and Yolo Unincorporated areas.

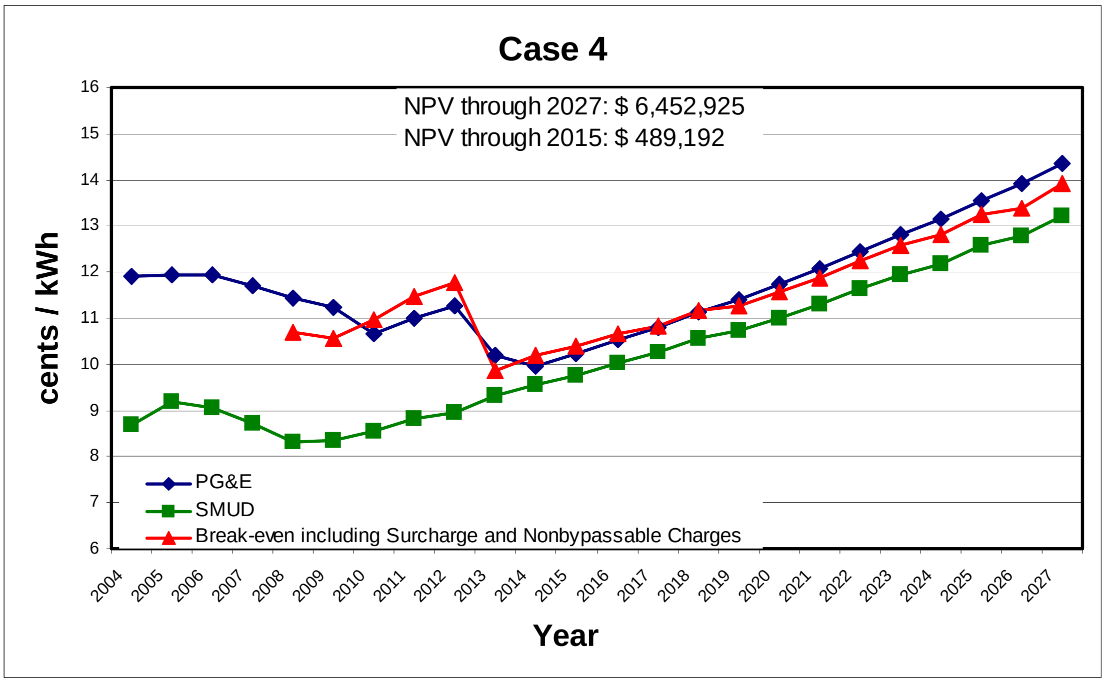
This option may not be acceptable to SMUD as it would tend to not take advantage of benefits that have been attained by forming its own control area. In most cases, the build transmission options are superior to the CAISO service option. None the less, savings are substantial under some of the CAISO options, and these scenarios could have relevance if one or more of the Yolo jurisdictions chose not to pursue annexation. For example, this option might remain attractive to Davis if West Sacramento chose not to annex because of Davis' exemption from CRS.

The detailed versions of these Financial Pro Formas appear in Appendix B.

3.7.2.1 Base Case 4: West Sacramento Area Only

Similar to the "Build" option, SMUD and PG&E system average retail revenues are weighted by customer class energy sales for West Sacramento area customers only. The following graph presents PG&E's and SMUD's system average revenues versus the breakeven rate for West Sacramento. The breakeven revenue requirement includes the surcharge that needs to be added to cover the costs of annexation of the distribution system and the non-bypassable charges that would be paid to PG&E.

Graph 3-7
West Sacramento CAISO Option



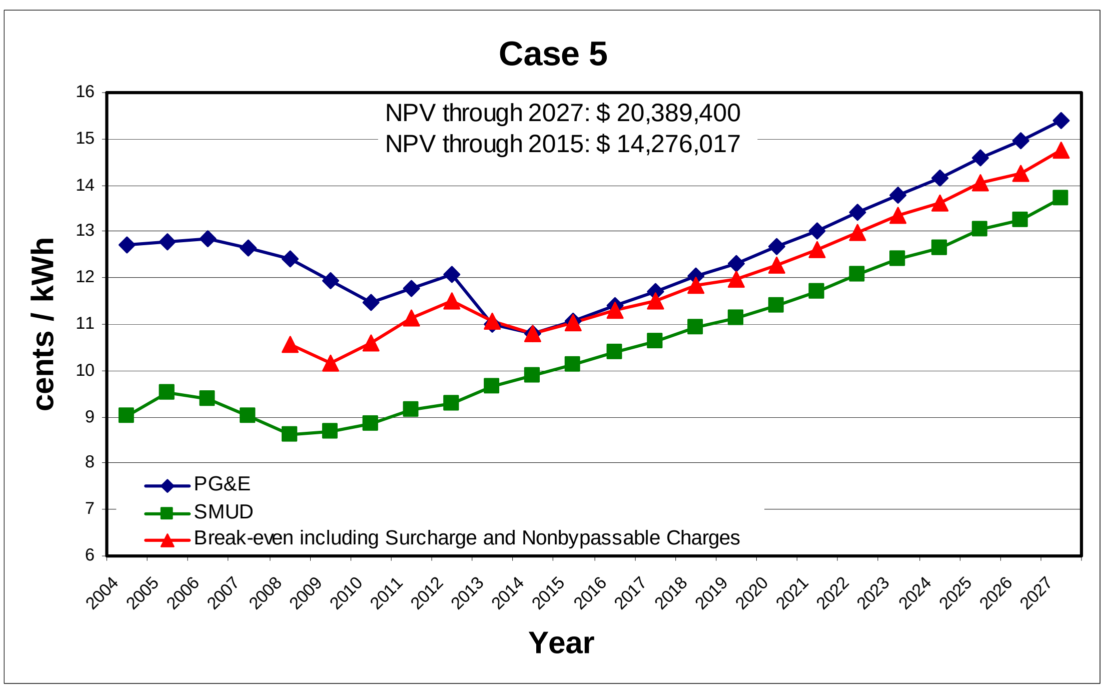
The above graph presents very similar results to the West Sacramento Build option with somewhat lower savings in the long run. The NPV savings for the West Sacramento area customers from the Build Option to the CAISO option are about $0.26 million. The CAISO option results in fewer savings due to the fact that the incremental burden of CAISO wheeling charges are not offset by the savings from the transmission system's capital investment in the Build option. In addition to the economic benefits, the benefits of other factors such as reliability or becoming an independent service territory would likely make SMUD's decision on annexing the whole transmission and distribution system appear to be the better option than relying on CAISO.

3.7.2.2 Base Case 5: Davis Area Only

In this case, it was possible to isolate the analysis for the City of Davis under the CAISO option as the distribution system investment costs were discrete and additive from city to city.

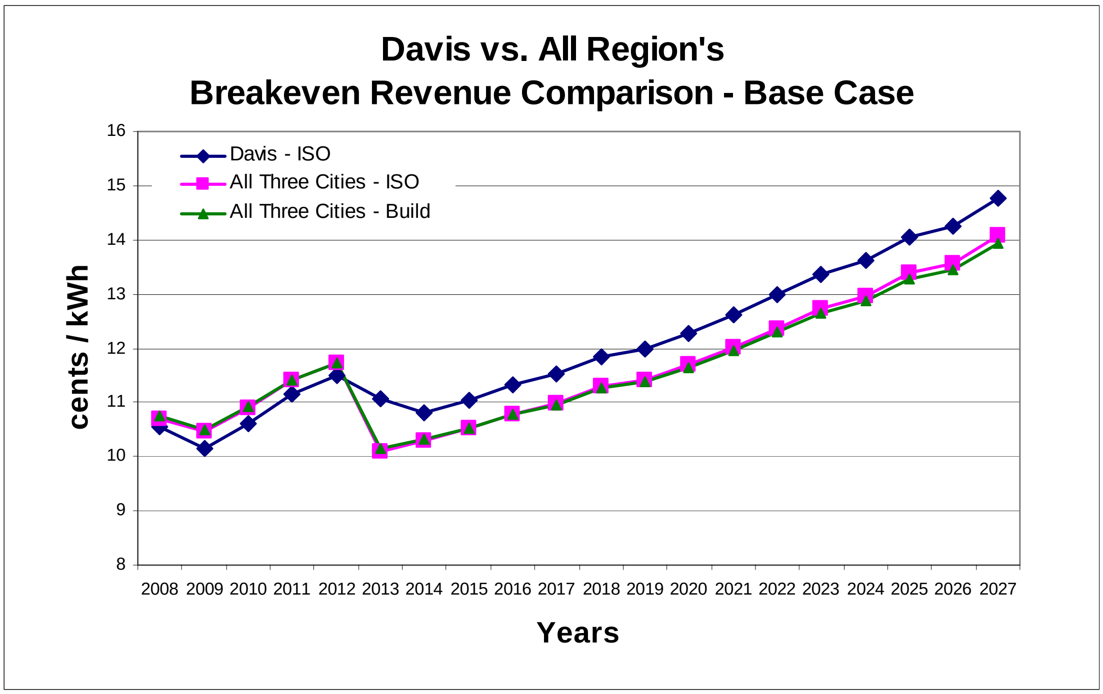
The SMUD and PG&E system average retail revenue requirements are weighted by customer class energy sales for Davis area customers only. Given the fact that there are more residential (with relatively low average usage) than commercial customers in Davis's customer profile, the cost of serving this City alone (on a per kWh basis) is higher compared to the other cities. As can be observed in the following graph, both PG&E's and SMUD's customer profiled revenues rise above the levels that were observed in most of the other cases. PG&E's revenues rise to nearly 15.5¢ per kWh in 2027, and SMUD's rise to nearly 14¢ per kWh in 2027. It should be noted that these high revenues are based on estimates of usage by rate block by R. W. Beck that may be conservative. If higher residential revenues per customer under PG&E and SMUD rates were to occur, savings could increase dramatically. The following graph presents PG&E's and SMUD's revenues versus the breakeven revenue for the subject customers within Davis. The breakeven revenue includes the surcharge that needs to be added to cover the costs of annexation and the operation expenses in this case. As mentioned in the earlier sections of this study, Davis is exempt from the CRS based on CPUC's decision (D. 03-07-028) on November 19, 2004, on the MDL. Davis's load was recognized as a potential MDL in PG&E's August 2000 Bypass report which was relied upon by CDWR in its power procurement process.

Graph 3-8
Davis CAISO Option



Due to the exemption of the Davis's customers from the non-bypassable charges, the above graph presents the slightly better savings in the initial years compared to the other cases. However, due to the factors mentioned above regarding the cost of serving Davis alone, the amount of breakeven revenue needed is estimated to be higher. This is illustrated in Graph 3-9, which compares breakeven revenues for three cases. In the All Regions cases, it was assumed that the Davis CRS exemption would be used to offset breakeven revenue requirements for the region. This would allow a single set of rates for all jurisdictions.

Graph 3-9
Davis vs. All Region's Breakeven Revenue Comparison

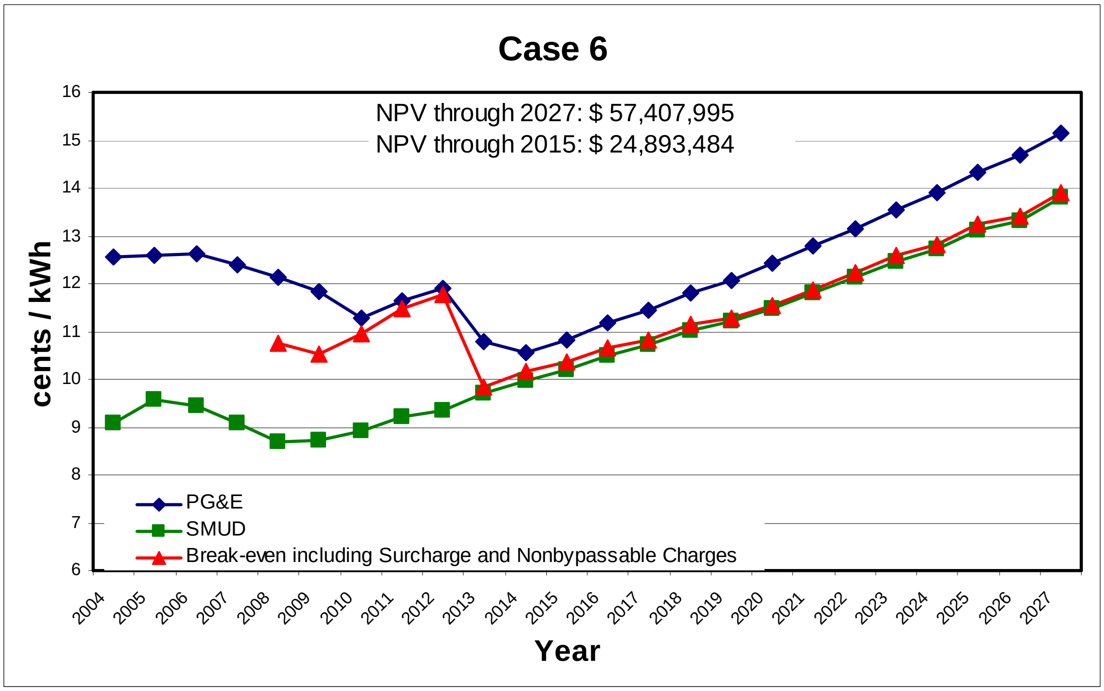


3.7.2.3 Base Case 6: Woodland Area and Yolo Unincorporated Only

Similar to the Davis only case, it was possible to isolate the analysis for City of Woodland and Yolo Unincorporated under the CAISO options as the distribution system investment costs were discrete and additive from city to city.

The SMUD and PG&E system average retail revenues are weighted by customer class energy sales for Woodland and Yolo Unincorporated customers. In contrast to the Davis case, although the customer profile in Woodland and Yolo is more evenly distributed among the different rate classes, it has slightly more agricultural load compare to other regions. In SMUD's retail rates, agricultural customers' rates are proportionately higher than PG&E's. This results in more distinct lower customer profiled revenues in PG&E's case than in SMUD's case in which the load profiled system average SMUD rate is higher than that of Davis's. The following graph presents PG&E's and SMUD's revenues versus the breakeven revenue of the Woodland and Yolo Unincorporated customers only. The breakeven revenue includes the surcharge that needs to be added to cover the costs of annexation of the distribution system, operation expenses and the non-bypassable charges that would be paid to PG&E.

Graph 3-10
Woodland and Yolo CAISO Option

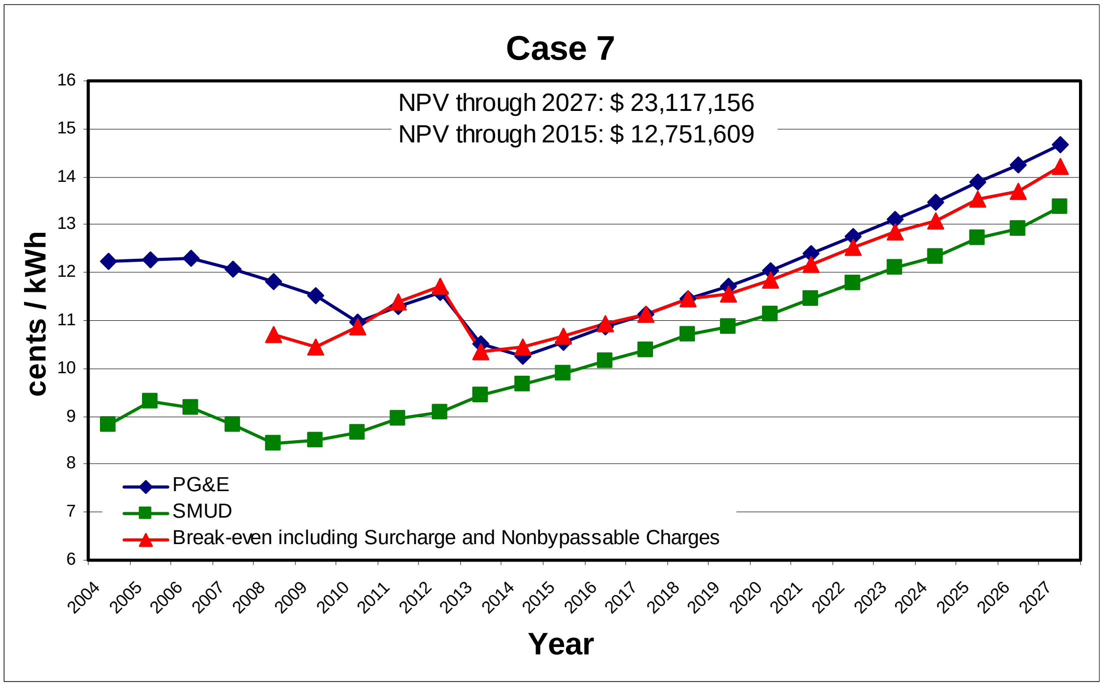


Similar to the other cases where the CRS is applicable, the initial years generally track PG&E's retail revenue with slight savings

3.7.2.4 Base Case 7: West Sacramento and Davis

Similar to the "Build" option, SMUD and PG&E system average retail rates are weighted by customer class energy sales for West Sacramento and Davis customers only. The following graph presents PG&E's and SMUD's revenues versus the breakeven revenue of the subject customers within the annexed region only. The breakeven revenue includes the surcharge that would be added to cover the costs of annexation, the operation expenses and the non-bypassable charges that would be paid to PG&E.

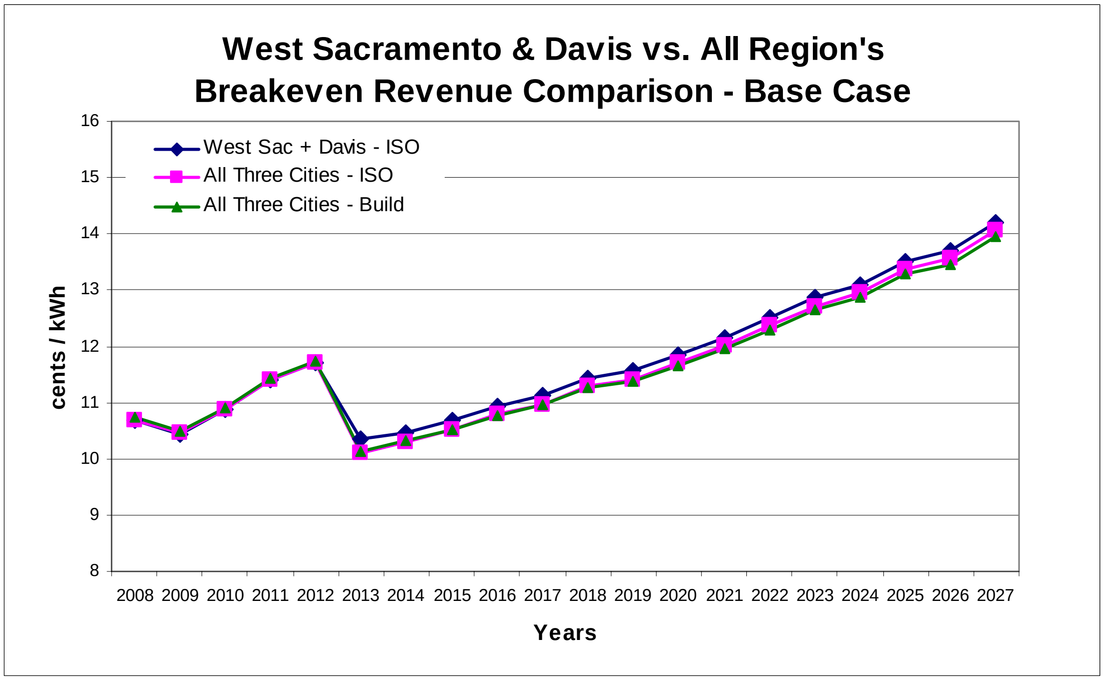
Graph 3-11
West Sacramento and Davis CAISO Option



The above graph presents very similar results to the West Sacramento and Davis Build option with fewer savings for the customers. Similar to the West Sacramento only cases, the build option in this case also looks better due to the CAISO option transmission system capital investment requirements.

The following graph maps the breakeven revenues for the All Regions CAISO option (refer to Section 3.7.2.5) versus All Regions Build option (refer to Section 3.7.1.3) versus the West Sacramento and Davis CAISO option.

Graph 3-12
West Sacramento and Davis vs. All Region's Breakeven Revenue Comparison

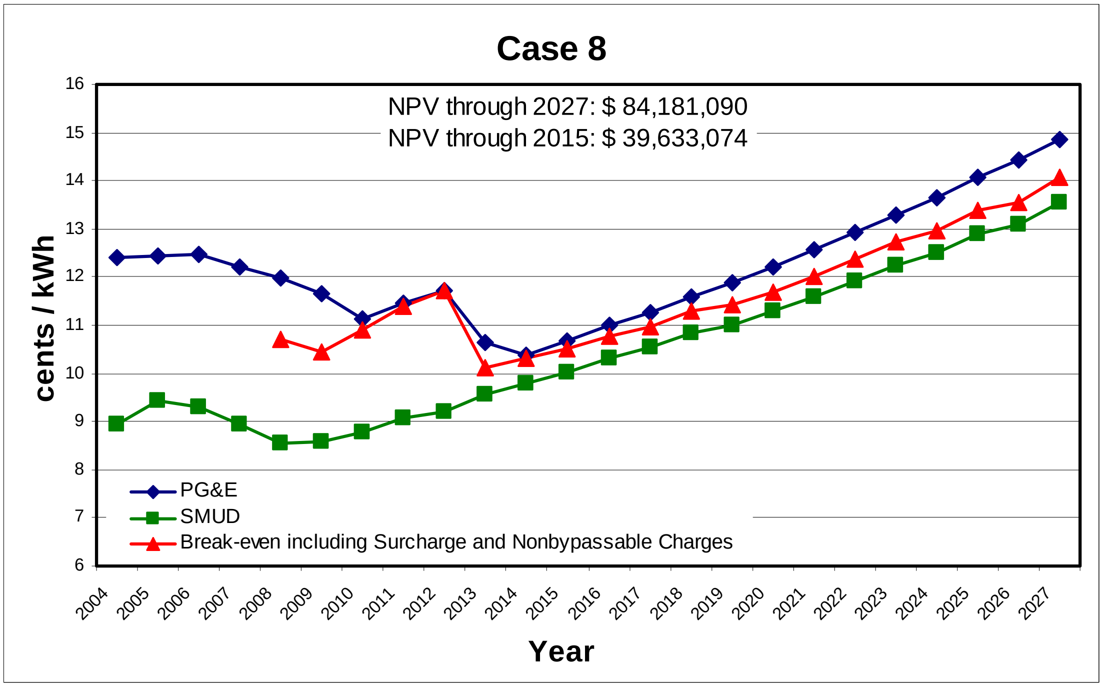


The difference among all three cases is not extreme. The initial years benefit all regions the same while the later years, especially from year 2013. Although the breakeven rates seem close, the Three Cities and Yolo cases are slightly more beneficial in the long run. Hence, the final decision on whether to annex just West Sacramento and Davis versus all the regions will eventually rely on SMUD's and the jurisdictions' collective decisions on reliability and risks.

3.7.2.5 Base Case 8: Three Cities and Yolo – CAISO Option

Similar to the Build option, SMUD and PG&E system average retail rates are weighted by customer class energy sales for West Sacramento, Davis, Woodland, and Yolo Unincorporated customers. The following graph presents PG&E's and SMUD's revenues versus the breakeven revenue of the subject customers within the entire region. The breakeven revenue includes the surcharge that needs to be added to cover the costs of annexation, operating expenses and in this case, the non-bypassable charges that would be paid to PG&E.

Graph 3-13
Three Cities and Yolo CAISO Option



Similar to all Build versus CAISO cases, the above graph presents very similar results to the Build option, with fewer savings for the customers. The reduction in savings for the annexed regions' customers from the Build Option to the CAISO option are about $3 million. In addition to the economic benefits, other factors, such as reliability or becoming an independent service territory, favors the Build option over the CAISO option in the long run. Hence, the final decision on whether to annex the whole transmission and distribution system or just the distribution system will eventually rely on SMUD's and the jurisdictions' decisions on control, reliability, and cost issues.

3.7.3 Scenario Analysis

In total, more than 32 scenarios were run. In this section the results of many of these scenarios are presented. Given the number and complexity of the scenarios that were run, not every one is included in this discussion. Certain of the scenarios are described in order to present the results of the analysis under differing conditions. This exercise also demonstrates the sensitivity to certain variables and major assumptions. In order to make it easier for those interested in only one City, or combination of Cities, there are tables in this section which provide the results in this fashion.

Table 3-13
Comparison of Sensitivity NPV Costs/Savings

Scenario	Scenario Description	NPV ($000) (Costs) Savings	% (Cost) Savings
9	West Sacramento, Build, High Market	$(15,753)	-2.04%
10	West Sacramento & Davis, Build, High Market	$(27,048)	-2.20%
11	All Region, Build, High Market	$21,434	0.97%
12	West Sacramento, CAISO, High Market	$(16,011)	-2.08%
13	Davis, CAISO, High Market	$5,172	1.13%
14	Woodland & Yolo, CAISO, High Market	$29,477	3.00%
15	West Sacramento & Davis, CAISO, High Market	$(14,572)	-1.19%
16	All Region, CAISO, High Market	$18,569	0.84%
17	West Sacramento, Build, Low Market	$26,265	4.09%
18	West Sacramento & Davis, Build, Low Market	$48,048	4.65%
19	All Region, Build, Low Market	$133,135	7.15%
20	West Sacramento, CAISO, Low Market	$27,548	4.29%
21	Davis, CAISO, Low Market	$35,489	9.06%
22	West Sacramento & Davis, CAISO, Low Market	$60,524	5.86%
23	Woodland & Yolo, CAISO, Low Market	$62,616	7.55%
24	All Region, CAISO, Low Market	$134,957	7.24%
25	All Region, OCLD, Build	$143,634	7.05%
26	All Region, OCLD, CAISO	$127,869	6.27%
27	All Region, Most Savings, Build	$154,659	8.30%
28	All Region, Most Savings, CAISO	$151,452	8.13%
29	All Region, Least Savings, Build	$(13,738)	-0.62%
30	All Region, Least Savings, CAISO	$195	0.01%
31	All Region, PG&E Power Supply Adjustment	$124,205	5.99%
32	All Region, New Customer Additions Adjustment	$105,413	5.17%
33	West Sacramento, PG&E Regular Residential Prices	$25,061	3.45%
34	Davis, PG&E Regular Residential Prices	$50,929	11.25%
35	Woodland & Yolo Reg. Residential Prices	$56,071	6.18%

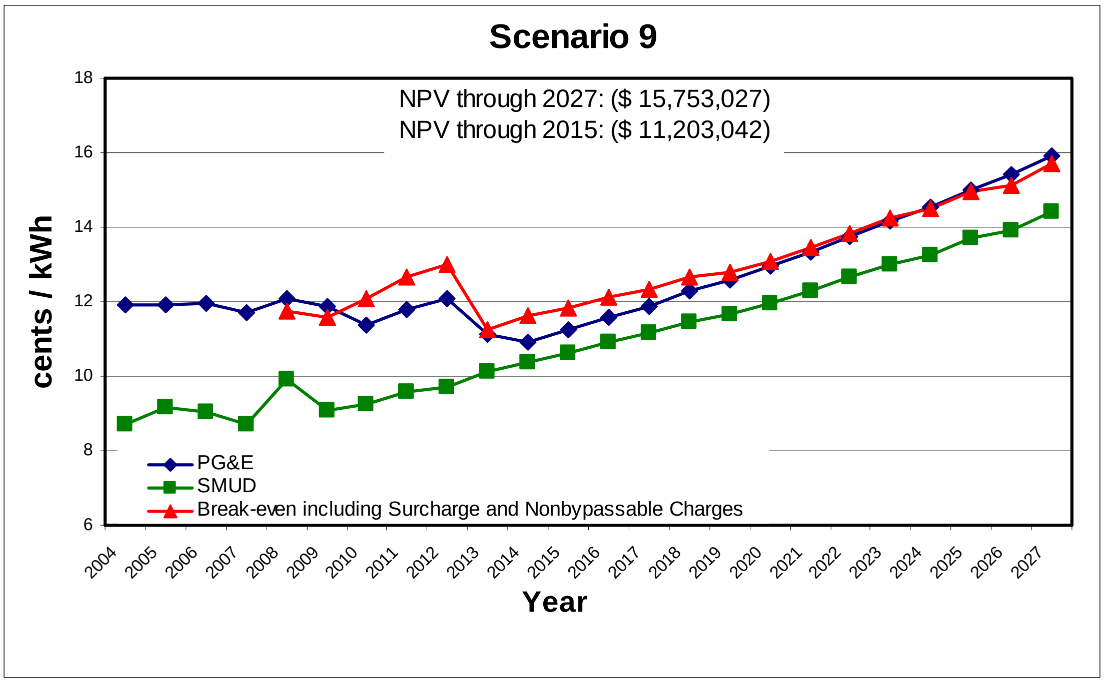
3.7.4 Market Price 20% High and 20% Low Cases (Scenarios 9 Through 24)

For the build transmission options, in the high market price cases, the only scenario that continues to show savings is the All region scenario (Scenario 11). There are no savings in the base case high market condition for West Sacramento or West Sacramento and Davis scenarios. The NPV cost in these cases is $15,753,000

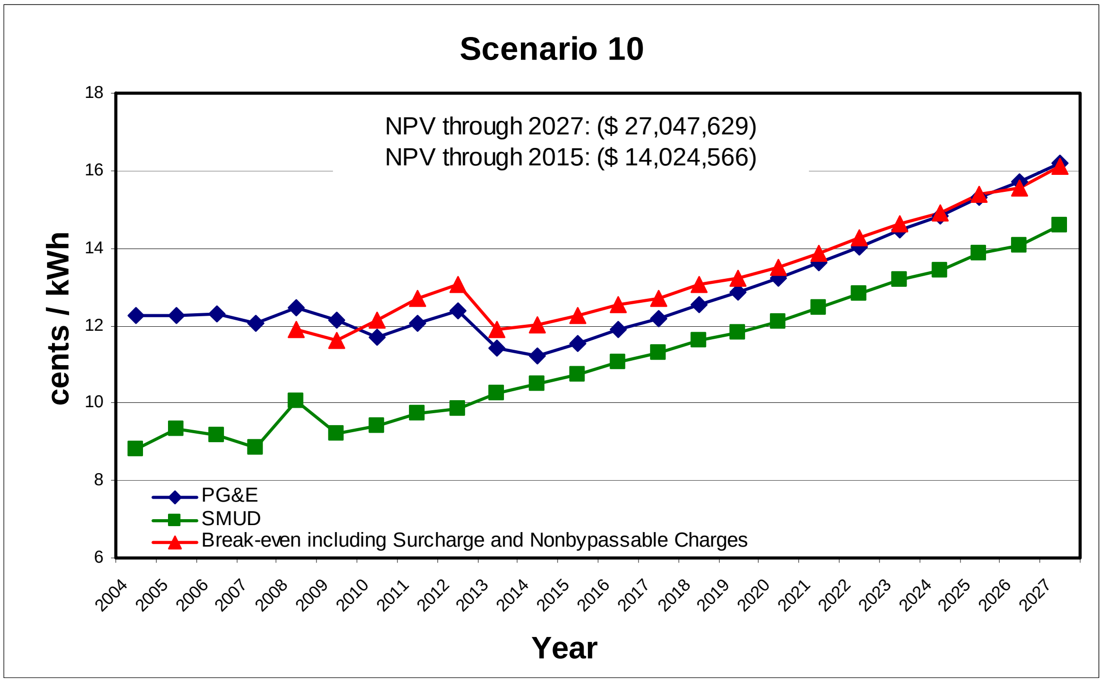
(-2.04%) and $27,048,000 (-2.20%) over the life of the analysis. For the high cost base case all region scenario there continue to be savings of $21,434,000 (0.97%).

Graphs 3-14, 3-15, and 3-16 show the results of the 20% higher market price scenarios for the three Base Case Build options.

Graph 3-14
West Sacramento Build Transmission Option – Market Price 20% High, Scenario 9

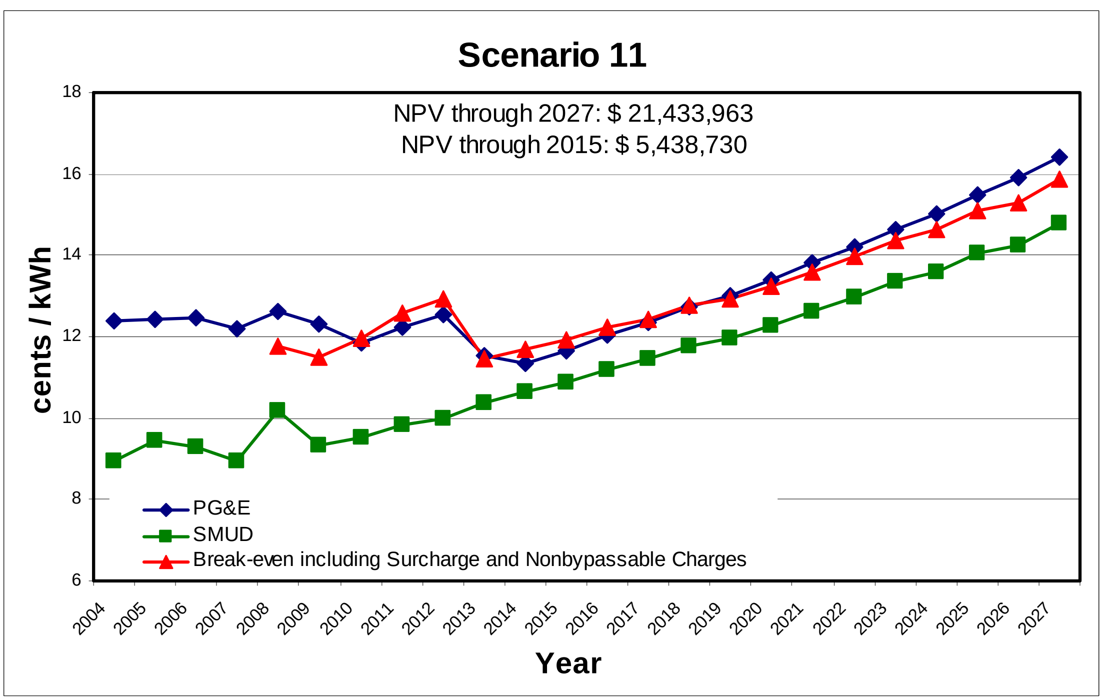


Graph 3-15
Scenario 10



3.7.4.1 Three Cities and Yolo Unincorporated – CAISO Option

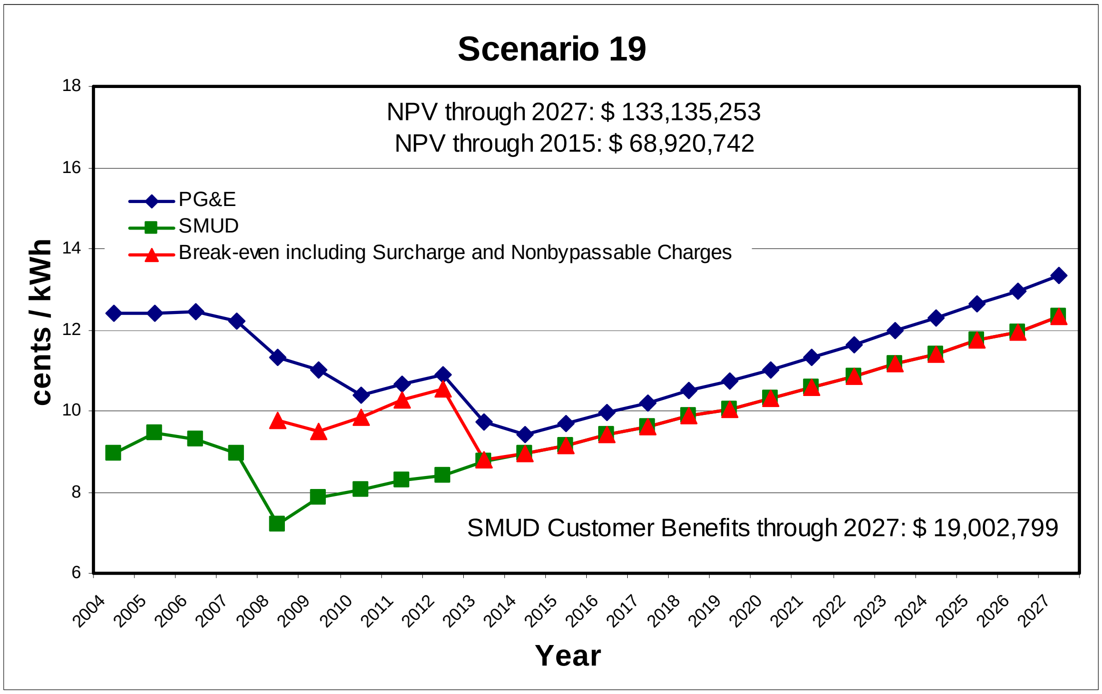
Graph 3-16
Three Cities and Yolo Build Transmission Option – Market Price 20% High, Scenario 11



3.7.4.2 All Region – Build Transmission Option – 20% Low Market Price

The build transmission low market cases all result in savings, but again, the greatest savings occur in the all region case (Scenario 19). In this case, the savings are $133,135,000, or 7.15% over the life of the analysis.

Graph 3-17
Three Cities and Yolo Build Transmission Option
Market Price 20% Low, Scenario 19



SMUD customer benefits are shown at the bottom of Graph 3-16 and some of the following graphs to indicate the NPV of the benefits to existing SMUD customers. Such benefits begin to accrue when the surcharge is no longer required and annexed customer transfer to SMUD rates.

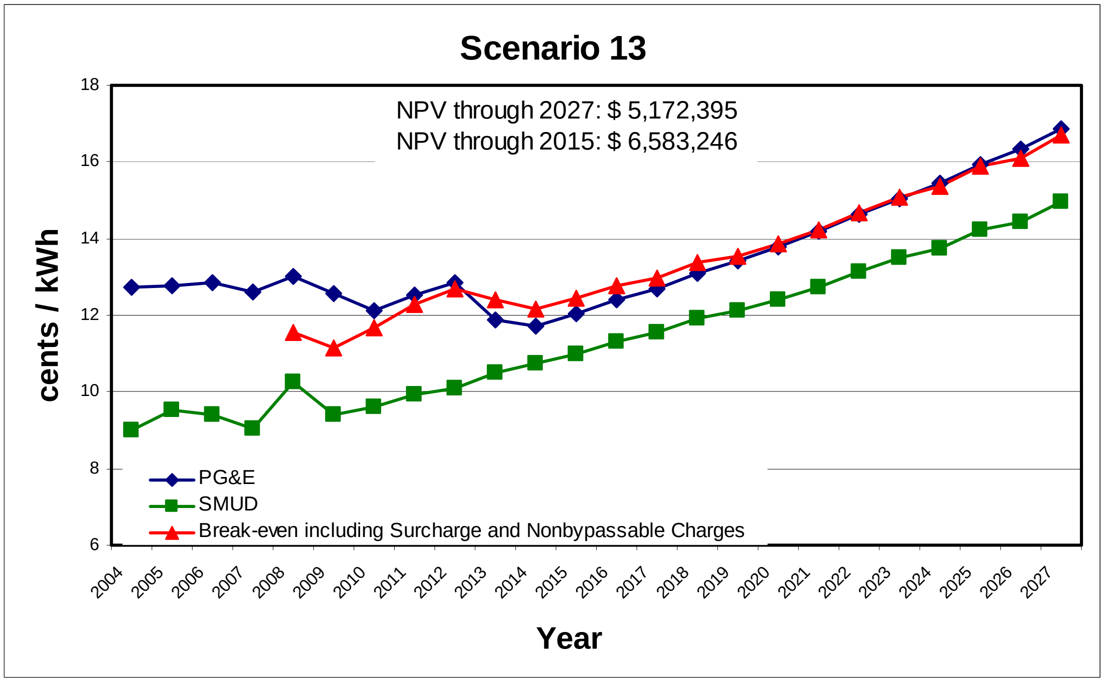
3.7.4.3 CAISO Options – High and Low Market Prices

Savings are similar between the transmission build options and the CAISO options. Given the deficiencies described in Section 1 in the existing transmission and distribution system in Yolo County, it is clearly more desirable to build a more reliable system to SMUD's standards. However, given the unique aspect of the Davis exemption from CRS fees it is worth evaluating the CAISO options for Davis and Woodland/Yolo in the event that West Sacramento opts not to pursue the annexation.

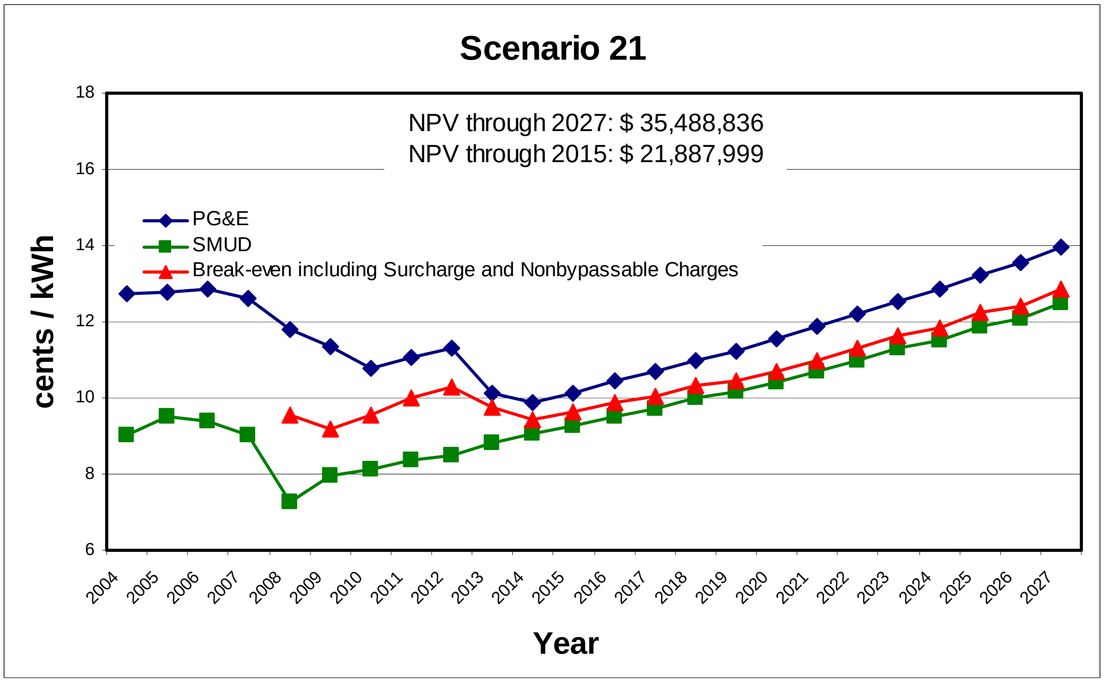
3.7.4.4 Davis only – CAISO Option

Under the high market price CAISO scenario (Scenario 13), the savings for Davis alone continue to be positive. In this case, they are approximately $5,172,000, or 1.13%. In the low market price scenario (Scenario 21), they jump to approximately $35,489,000, or 9.06% over the life of the analysis.

Graph 3-18
Davis CAISO Option – Market Price 20% High, Scenario 13



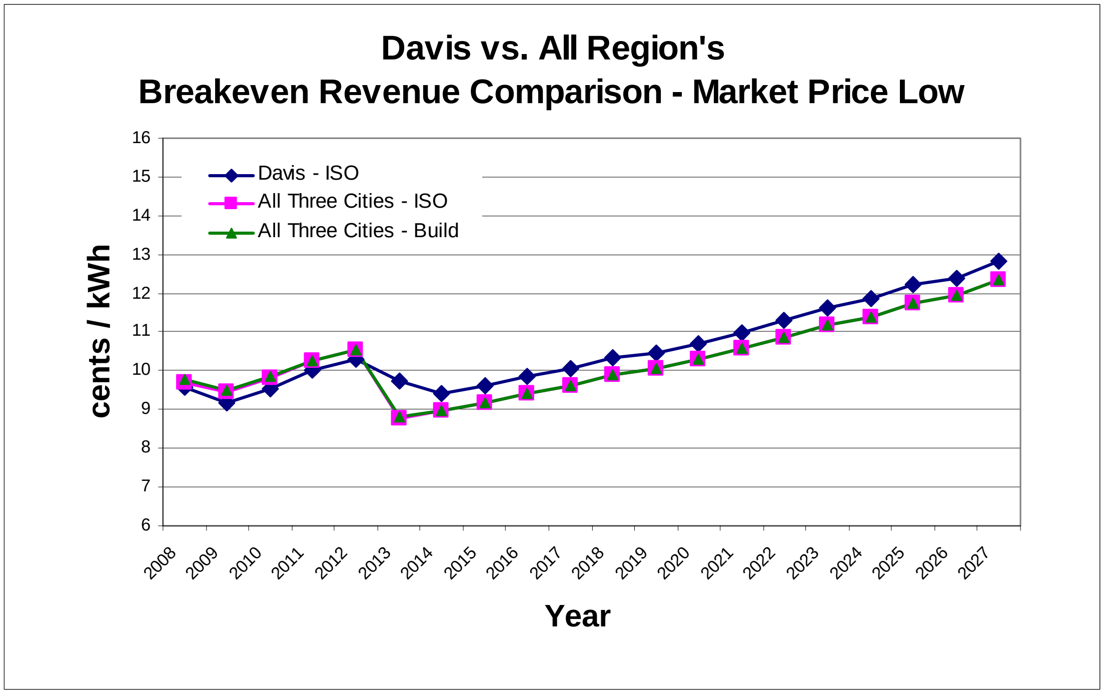
Graph 3-19
Davis CAISO Option – Market Price 20% Low, Scenario 21



Davis versus All Region's Breakeven Rate Presentation Under High Market Price Cases

In the following graph, the Davis CAISO scenario is compared to the All Region breakeven case.

Graph 3-20
Davis vs. All Region's Breakeven Revenue Comparison

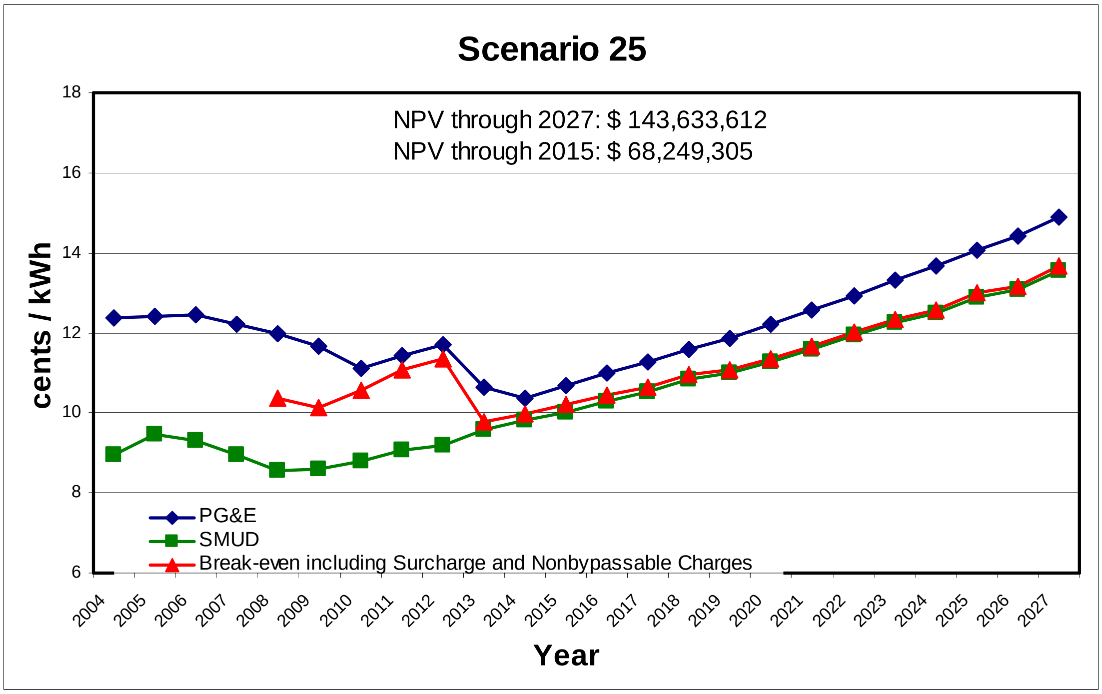


3.7.5 Original Cost Less Depreciation Approach

The following graph presents the results if Original Cost is used for the acquisition price (Scenario 25). In this case, the NPV savings amount to $143,634,000, or 7.05% over the life of the analysis. The OCNLD approach is more indicative of the regulated investment that PG&E has in the system, but the purchase price settled upon (either through litigation or negotiation) is often somewhere between OCNLD and RCNLD.

3.7.5.1 All Region – Build Option – OCLD, Scenario 25

Graph 3-21
Three Cities and Yolo Build Transmission Option – OCLD Option

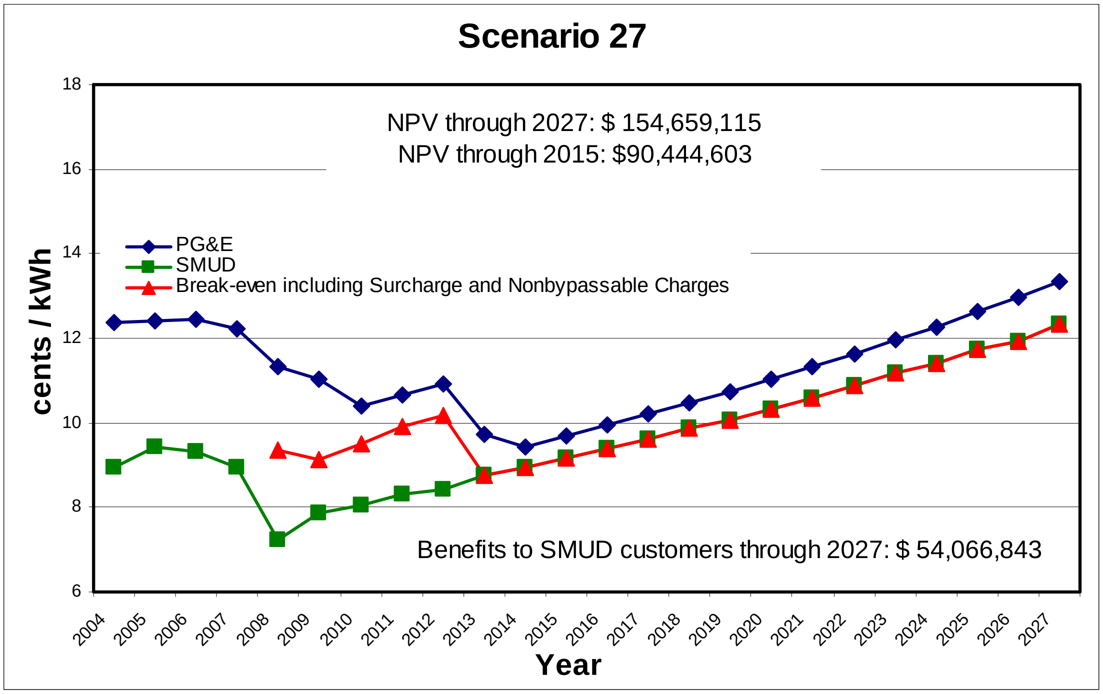


3.7.6 Scenario Exhibiting the Largest Savings – Scenario 27

The scenario that presents the largest savings overall is the one which used OCLD for valuation and the low market price projection. In this case, the approximate savings were $154,659,000, or 8.30% over the life of the study period.

3.7.6.1 All Region Unincorporated – Build –OCLD Option

Graph 3-22
System Average Revenues – Three Cities and Yolo Build Transmission Option –
Largest Savings, Market Price 20% Low and OCLD

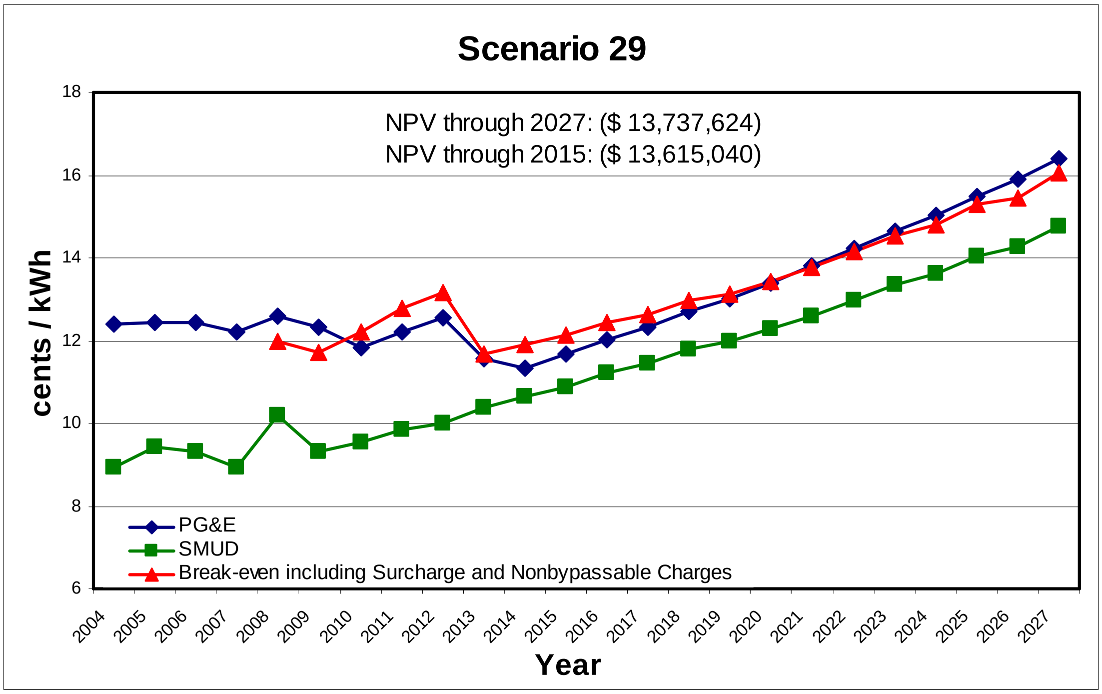


3.7.7 Scenario Exhibiting the Least Savings, Scenario 29

The scenario that presented the least savings (most cost) was the transmission build option assuming RCNLD with present worth depreciation, and with market prices 20% higher than the base case. In this scenario, the NPV costs are approximately -$13,738,000, or -0.62%.

3.7.7.1 All Region – Build-RCNLD Present Worth – High Market Price Option

Graph 3-23
System Average Revenues – Three Cities and Yolo Build Transmission Option – Worst Case, Market Price 20% High – RCNLD PW



3.8 Specific Sensitivity Analyses

In each case where key assumptions had to be defined, R. W. Beck made a conscious choice to err on the side of conservatism. Unfortunately, this conservatism compounds in the final analysis. As a result, even Scenario 29, described as the Scenario Exhibiting the Largest Savings, may be conservative. In order to provide decision-makers with an understanding of the sensitivity of results to some of these conservative assumptions, the following sensitivity analyses were performed:

3.8.1 Sensitivity to Residential Revenue Adjustment

PG&E's system average residential revenue, approved in GRC Phase 2, is 14.08¢ per kWh. Because of the inverted tier residential rate structure, low-use customers pay much less than the average. In Davis, the average use per customer is 508 kWh per month. The PG&E system average is estimated at 629 kWh per month. Although PG&E did not provide information on usage by tier, estimates were developed to use in estimating residential average revenues in Davis. That resulted in an adjustment from 14.08¢ per kWh to 12.53¢ per kWh. This in turn resulted in a 6% reduction in average revenues per kWh for all class sales and revenue in Davis and dramatically reduced the NPV savings for all Davis cases.

In order to determine the sensitivity of this one conservative adjustment, we ran the Davis-CAISO Case (Base Case 5), using the PG&E system average residential revenue of 14.08¢ per kWh. NPV savings through 2027 increased from $20.4 million to $50.9 million, a 150% increase.

Similar runs were done for the West Sacramento and Woodland/Unincorporated Yolo cases where the differences in average use were less pronounced.

In the West Sacramento Base Case 4, NPV savings through 2027 increased from $6.5 million to $25.1 million, a 288% increase.

In Woodland/Yolo Unincorporated, because average use per residential customer is higher than the PG&E system average, NPV savings declined slightly from $57.4 million to $56.1 million, a 2.3% decrease.

3.8.2 Sensitivity to PG&E Power Supply Costs

A number of conservative assumptions were made when estimating PG&E's power supply costs, which in turn drive PG&E's rates and revenues. Examples include no assumed investment in nuclear and hydroelectric generation and that PG&E pays for new renewable resources entirely from public benefit funds. A sensitivity case was run on Base Case 3, the Build Option for all jurisdictions. The sensitivity case included:

- Investments of $1 billion in Diablo Canyon and $100 million on hydroelectric relicensing over the period 2008 to 2012, using an assumed 15% carrying charge.
- PG&E uses rate revenues to meet their renewable portfolio requirements in excess of their current 12% mix.

The sensitivity result is an increase in Base Case 3 NPV from $87 million to $124.2 million, a 42.7% increase.

3.8.3 Sensitivity to Contributions in Aid of Construction

It has been assumed that the capital costs of new customer additions would be born by the annexed areas. It is likely that a large part of these costs will be offset by developers providing Contributions In Aid of Construction (CIAC) under SMUD's Rules 15 and 16. A sensitivity analyses was run on Base Case 3 assuming that 80% of the capital costs for distribution were provided as CIAC.

The sensitivity result is an increase in the Base Case 3 NPV from $87 million to $105.4 million, a 21.1% increase.

3.9 Scenario Summary

Sections 3.5 and 3.6 addressed the Economic Analysis of various cases using different key variables and assumptions. In this section, the results are presented for each of the Yolo Jurisdictions. For each entity, a table is presented that contains the various scenarios from highest cost, or least savings as the case may be to highest savings. The (cost) savings are the amounts calculated over the life of the study in 2008 dollars.

The Descriptions used in the summary table have the following meanings:

Table 3-14
Summary of Descriptions

Base	Base Case
Build	Build Transmission
CAISO	CAISO Transmission Service
&	With Identified City
All Region	Entire Study Area
High Market	Market Price + 20%
Low Market	Market Price – 20%

3.9.1 West Sacramento

The results for West Sacramento range from an increase (Cost) of 2.20 % under Case 10, the Build scenario with Davis, and an increase in power market prices of 20% above the base case, to a decrease of 9.06% in Case 21, which assumes market prices 20% below the base case scenario and the CAISO option with Davis. The All Region Base Case provides a savings of 4.27% over the life of the study.

Table 3-15
West Sacramento

Case	Description	% (Costs) Savings Relative to PG&E
10	& Davis, Build, High Market	-2.20%
12	CAISO, High Market	-2.08%
9	Build, High Market	-2.04%
15	& Davis, CAISO, High Market	-1.19%
29	All Region, Least Savings, Build	-0.62%
30	All Region, Least Savings, CAISO	0.01%
16	All Region, CAISO, High Market	0.84%
4	Base, CAISO	0.91%
2	& Davis, Base, Build	0.94%
1	Base, Build	0.95%
11	All Region, Build, High Market	0.97%
7	& Davis, Base, CAISO	2.04%
33	Regular Residential Prices, CAISO	3.45%
17	Build, Low Cost	4.09%
8	All Region, Base, CAISO	4.13%
3	All Region, Base, Build	4.27%
20	CAISO, Low Cost	4.29%
18	& Davis, Build, Low Market	4.65%
32	All Region, New Customer Additions @ 20%, Build	5.17%
31	All Region, PG&E Power Supply Adjusted, Build,	5.99%
26	All Region, OCLD, CAISO	6.27%
25	All Region, OCLD, Build	7.05%
19	All Region, Build, Low Market	7.15%
24	All Region, CAISO, Low Market	7.24%
28	All Region, Largest Savings, CAISO	8.13%
27	All Region, Largest Savings, Build	8.30%
21	& Davis, CAISO, Low Market	9.06%

3.9.2 Davis

There is a somewhat greater range of results for Davis due to their exemption from the CRS charge. The only negative cases are those in which market prices are 20% above the base case. The Build transmission with West Sacramento and high market price scenario (Case 10) is projected to cost 2.20% more than PG&E over the life of the study. The greatest savings scenario is Case 34 (11.15%) for Davis is under the CAISO scenario with regular PG&E residential prices.

Table 3-16
Davis

Case	Scenario Description	% (Costs) Savings Relative to PG&E
10	& West Sacramento, Build, High Market	-2.20%
15	& West Sacramento, CAISO, High Market	-1.19%
29	All Region, Least Savings, Build	-0.62%
30	All Region, Least Savings, CAISO	0.01%
16	All Region, CAISO, High Market	0.84%
2	& West Sacramento, Base, Build	0.94%
11	All Region, Build, High Market	0.97%
13	CAISO, High Market	1.13%
7	& West Sacramento, Base, CAISO	2.04%
8	All Region, Base, CAISO	4.13%
3	All Region, Base, Build	4.27%
18	& West Sacramento, Build, Low Market	4.65%
5	Base, CAISO	4.80%
32	All Region, New Customer Additions @ 20%, Build	5.17%
22	& West Sacramento, CAISO, Low Market	5.86%
31	All Region, PG&E Power Supply Adjusted, Build,	5.99%
26	All Region, OCLD, CAISO	6.27%
25	All Region, OCLD, Build	7.05%
19	All Region, Build, Low Market	7.15%
24	All Region, CAISO, Low Market	7.24%
28	All Region, Largest Savings, CAISO	8.13%
27	All Region, Largest Savings, Build	8.30%
21	ISO, Low Market	9.06%
34	Regular Residential Prices, CAISO	11.15%

3.9.3 Woodland and Yolo County (Portions)

Due to the geography, being furthest removed from the existing SMUD service area, there are the fewest number of scenarios for Woodland and portions of Yolo County. However, all but one of the cases studied resulted in savings. The lowest of these (0.62%) is Case 29, the All Region scenario with Build transmission and with market prices 20% above the base case. The greatest savings (8.30%) occur in Case 27, the Build case with market prices 20% below the base case.

Table 3-17
Woodland and Yolo County

Case	Scenario Description	% (Costs) Savings Relative to PG&E
29	All Region, Least Savings, Build	-0.62
30	All Region, Least Savings, CAISO	0.01%
16	All Region, CAISO, High Market	0.84%
11	All Region, Build, High Market	0.97%
14	CAISO, High Market	3.00%
8	All Region, CAISO, Base	4.13%
3	All Region, Build, Base	4.27%
32	All Region, New Customer Additions @ 20%, Build	5.17%
31	All Region, PG&E Power Supply Adjusted, Build,	5.99%
35	Regular Residential Prices, CAISO	6.18%
26	All Region, OCLD, CAISO	6.27%
6	Base, CAISO	6.33%
25	All Region, OCLD, Build	7.05%
19	All Region, Build, Low Market	7.15%
24	All Region, CAISO, Low Market	7.24%
23	CAISO, Low Market	7.55%
28	All Region, Largest Savings, CAISO	8.13%
27	All Region, Largest Savings, Build	8.30%

3.10 SMUD Customer Benefits

Throughout the analysis, the term "Breakeven Revenues" has been used to establish revenue requirements that would assure existing SMUD customers that they would suffer no economic loss due to potential annexations. However, there are several instances in which SMUD customers would benefit.

- Annexations would bring greater load diversity, which should provide an opportunity to optimize power supply costs.

- In several scenarios, Breakeven Revenues were constrained from falling below SMUD system average revenues. It was generally noted in the discussion that after some cross-over point, a surcharge was no longer needed. In such cases, the NPV of the unconstrained Breakeven Revenues and SMUD revenues produce a benefit that will eventually be shared with SMUD customers. Example NPVs of such SMUD customer benefits are shown below:

Table 3-18
Example NPVs of SMUD Customer Benefits

Scenario	NPV SMUD Customer Benefits $000
19	$19,003
23	$22,487
24	$14,317
27	$54,067
28	$41,509

Section 4
OTHER CONSIDERATIONS

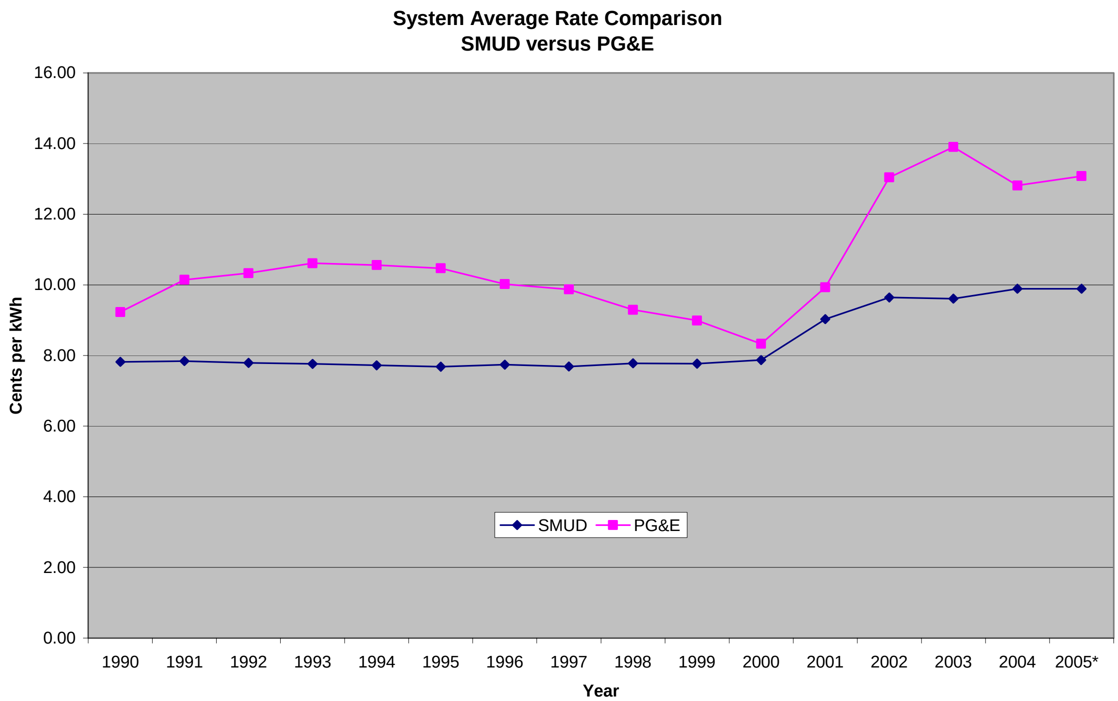
In addition to the economic evaluation, there are a number of factors that are difficult or impossible to quantify with respect to annexation. These are discussed briefly in this section.

4.1 Structural Financial Differences Between PG&E and SMUD

- PG&E is an IOU that has a cost structure that includes:
  - Profits are paid to stockholders.
  - State and federal income taxes are paid.
  - Property taxes and franchise fees are paid.
  - The interest on PG&E debt is taxable.
- SMUD is a publicly-owned utility.
  - Any retained earnings are invested in the utility, as there are no stockholders.
  - SMUD is exempt from state and federal income taxes.
  - SMUD does not believe it can legally pay certain property taxes and franchise fees.
  - The interest on SMUD debt is generally tax-exempt, although debt used to purchase PG&E assets is taxable.

These differences create an economic advantage for a publicly-owned utility that, in the long term, should always produce lower rates. The following graph shows the historical relationship between PG&E and SMUD rates.

Graph 4-1
Historical Relationship Between PG&E and SMUD Rates



4.2 Regulation

- PG&E is regulated by the CPUC with respect to retail service and tariffs.
    - Its Board of Directors' meetings are closed to the public.
    - Rate hearings are held at the CPUC with limited opportunity for individual public involvement.
    - Regulatory considerations are generally system-wide, leaving little room for addressing local issues.
    - PG&E is not required to make data and records available to the public.
- SMUD is generally self-regulated.
    - All Board of Director and Board Committee meetings are publicly noticed and open to the public.
    - Rates are adopted only after public notice and hearings where any individual customer can participate.
    - SMUD is subject to the Public Records Act and must make nearly all data and records available to the public and the news media.

- Decisions regarding new projects, budgets, contract awards, utility easements and rights-of-way, environmental actions, and most decisions that will affect ratepayers are made in public, only after the opportunity for public comment.

4.3 Community Focus

- PG&E maintains community and customer involvement through a number of avenues:
  - The CPUC directs the development and approves programs for energy efficiency and demand-side management on a utility-wide basis.
  - The Legislature has mandated certain expenditures and rate discounts for low-income and usage for medical equipment, funded by public benefit funds.
  - PG&E provides financial assistance or facilities to local communities, depending on their own criteria.
  - PG&E is directed by the CPUC or Legislature with respect to required investments for renewable and green energy, conservation, and demand-side management.
- SMUD is less directed by law or regulation, but often exceeds industry standards for community and environmental contributions.
  - SMUD has been a leader in energy conservation and demand-side management programs and expenditures.
  - SMUD spends more, as a percentage of revenues, on public benefit programs than any IOU in California and does so without regulatory or legislative control on how that money is spent in the community. This allows expenditures to match community needs.
  - SMUD was a leader in undergrounding of electric power lines and the aesthetic design of facilities and substation.

4.4 Reliability

- PG&E's reliability of service has declined in recent years.
  - Distribution system outages exceed SMUD's.
  - Rotating blackouts due to power supply during the first part of this decade were extensive on the PG&E system.
  - PG&E's design of transmission and subtransmission facilities in the areas being evaluated for annexation is less reliable than the design criteria used by SMUD.

- SMUD maintains high reliability standards.
  - 2003 distribution outages on the SMUD system, as measured and reported as SAIDI (System Average Interruption Duration Index), were 71.7 minutes per customer. This can be compared with PG&E's system average SAIDI reported to the CPUC of 193 minutes per customer.
  - SMUD participated in rotating blackouts during the energy crises at the request of CAISO to assist in protecting the state transmission grid, not because of a deficiency of SMUD power supply resource availability.
  - The economic evaluation of annexation assumes SMUD expenditures to upgrade PG&E facilities to meet SMUD standards.

4.5 Economic Development

- Because PG&E is subject to income taxes on assets constructed by developers and then deeded to PG&E, developers must not only install or pay for facilities, they must pay the equivalent of PG&E's income taxes on those facilities (typically 30% to 35%).
- Developers' costs would decline by the amount of the tax equivalent in any annexed areas.

4.6 Franchise Fees and Property Taxes

SMUD believes that under state law, it is prohibited from paying in-lieu fees or taxes to agencies or jurisdictions where they own electric system improvements. It is understood that they will not pay such fees or taxes in any annexed areas. As a result, rates charged for electric service will not include any costs for franchise fees or property taxes.

The jurisdictions considering annexation currently receive franchise and property tax revenues from PG&E. In order to fairly evaluate the SMUD vs. PG&E option, the economic analysis needs to consider this potential loss of revenues. To simplify the analysis, it is assumed that each jurisdiction will add a tax, similar to a utility user's tax to the electric bills to offset the loss of revenue from PG&E. That tax would match the lost revenue and has been included in the breakeven rates calculated in each pro forma. As an alternative, the additional benefits could pass through to customers in the form of lower bills.

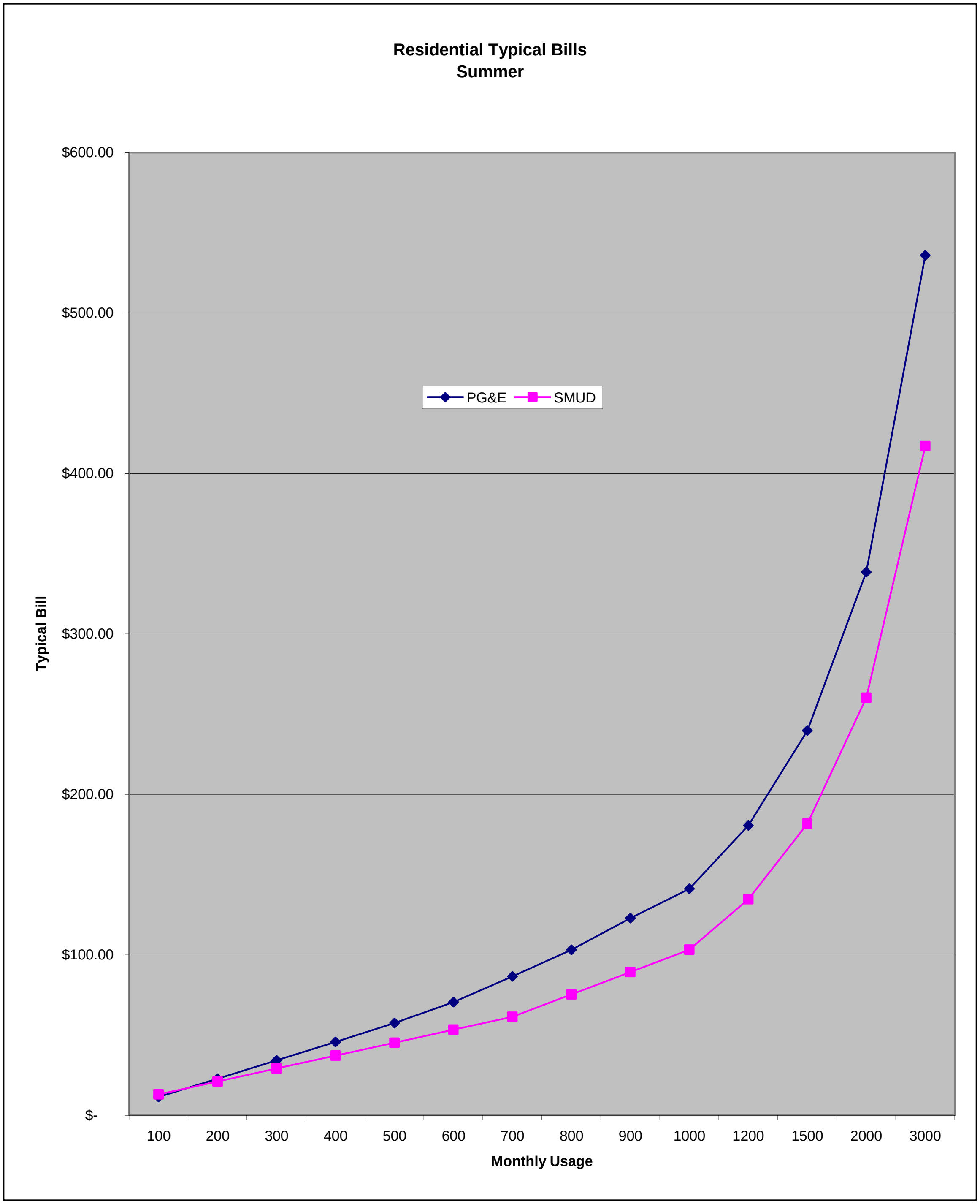
4.7 Tiered Rate Structures (Residential)

Both PG&E and SMUD employ tiered rate structures for residential customers, with per kilowatt-hour charges increasing in each successive tier. In order to determine the impact of annexation for residential customers falling into different tiers, it was necessary to develop typical bill comparisons throughout the billing ranges. Graph 4-1 and Graph 4-2 show the comparison of PG&E and SMUD typical summer and winter bills for residential customers with no SMUD surcharges. Graph 4-3 and Graph 4-4 show typical summer and winter bills with an assumed surcharge of 3.0¢ per kWh, applied across the board.

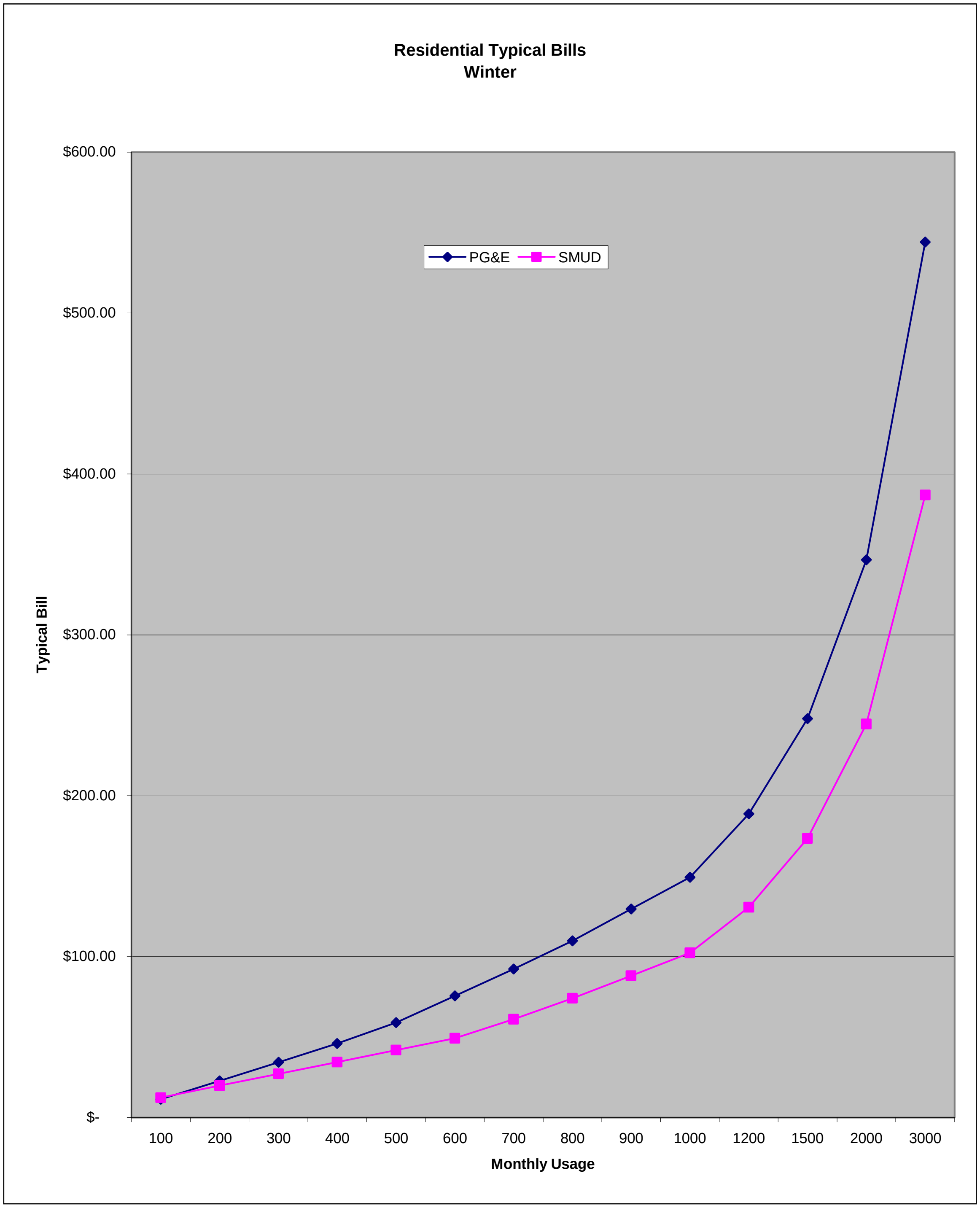
Graph 4-3 illustrates the potential for customers using 600 kWh per month or less to pay more Graph 4-4 illustrates that the cross-over point drops to between 400 and 500 kWh per month where the SMUD rate with surcharge becomes lower than the PG&E rate.

This issue will be mitigated with any PG&E rate increases in excess of SMUD rate increases. It could also be mitigated or eliminated with a tiered surcharge.

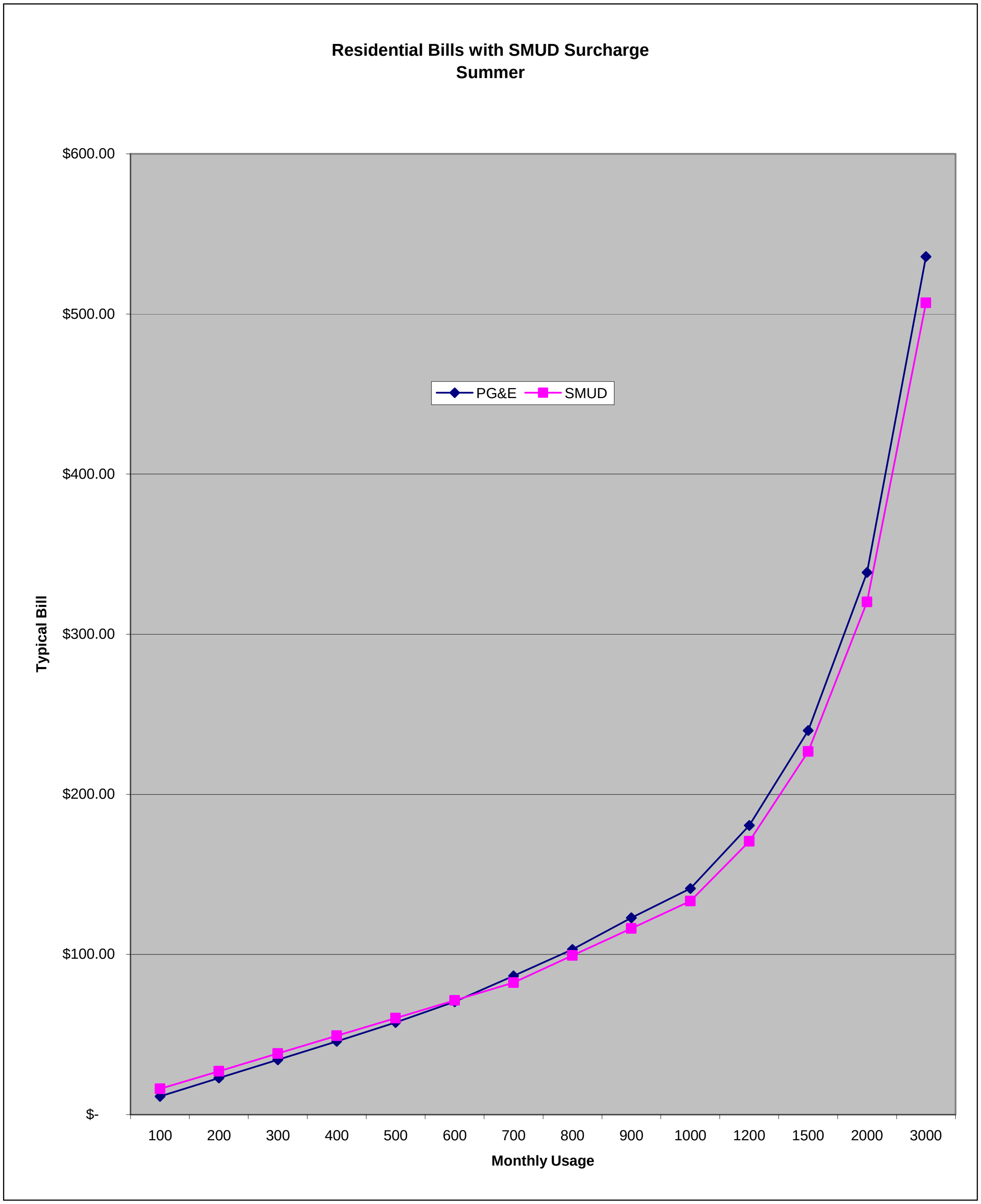
Graph 4-1
Typical Residential Summer Bill with No SMUD Surcharges



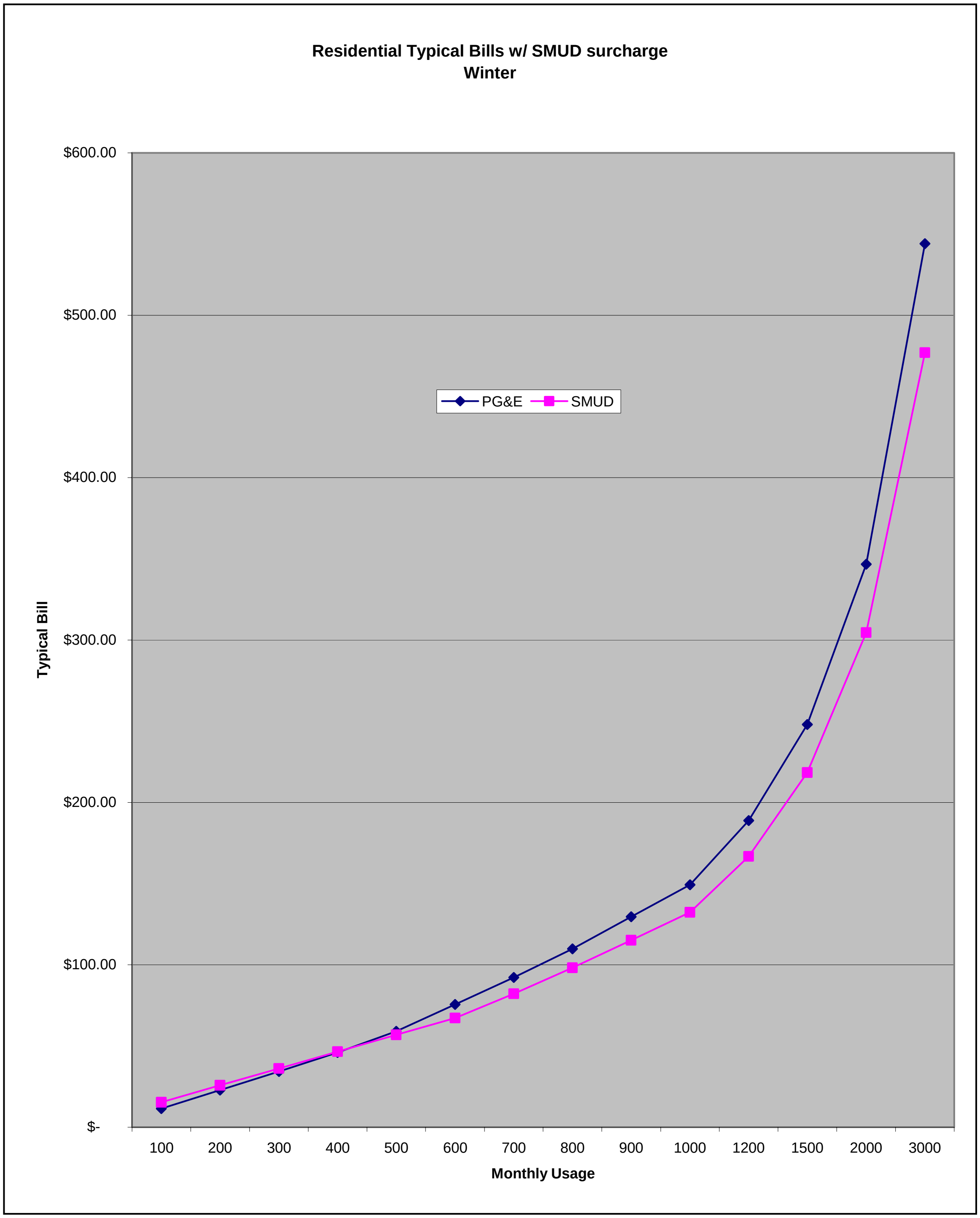
Graph 4-2
Typical Residential Winter Bill with No SMUD Surcharges



Graph 4-3
Typical Summer Bill with an Assumed Surcharge of 3.0¢ per kWh



Graph 4-4
Typical Winter Bill with an Assumed Surcharge of 3.0¢ per kWh



4.8 Issues Under SMUD Annexation

1. Breakeven means in terms of impact on existing SMUD ratepayers that there is no economic gain or loss. However, values of synergy from economy of scale, load diversity, and other factors may accrue that have not been quantified in the economic evaluation.
2. Different customers and customer classes will benefit differently. Although the Study predicts economic benefits (lower rates) on average, some customers could pay more, particularly customers with below average usage.
3. When evaluating economic benefits, the level of uncertainty as to cost and rate comparison increase with time. Key issues include:
   - PG&E's re-entry into generation ownership.
   - The success of both PG&E and SMUD is optimizing and managing risks of power supply portfolios.
   - Differing responses to environmental concerns, social pressures, and mandates.
   - The speed with which SMUD integrates the annexed loads into its power supply portfolio versus keeping the annexed loads in the position of paying the incremental cost of power supply.
4. Key differences in power supply cost forecasts. The primary difference in projected prices beyond 2015 is a result of different assumptions as to cost drivers between PG&E and SMUD.
   - With respect to PG&E, it is assumed that their portfolio of owned and QF resources will not expand and that the prices of purchased power will reflect long-term averages of market prices. Because market price projections include an assumption of increasing spark spreads (the value of capacity increases), PG&E's power supply costs increase at a higher rate than SMUD's.
   - With respect to SMUD, it is assumed that they will work towards being fully resourced and that their costs for the thermal portion of their portfolio will track natural gas prices. Because of SMUD's lower cost of capital, it has a greater incentive to be fully resourced.
   - With respect to both utilities, it has been assumed that they will meet the state's Resource Portfolio Standards. Both are assumed to pay the same price for renewable energy. In fact, SMUD has an aggressive program to build its own renewable generation. Due to its lower cost of capital, this should provide an additional cost advantage that has not been factored into the comparative analyses.

- To the extent that PG&E builds its own optimized resource portfolio, it could experience cost trends that are more aligned with natural gas prices, avoiding the projected increase in spark spread. Although it has higher costs of capital, it also has greater diversity of loads and the benefits of size, which could offset the capital cost disadvantage. If that were to happen, PG&E and SMUD power supply costs would be similar after 2015, eliminating most of the cost differential after that date.

4.9 Other Power Supply Uncertainties

- PG&E cost projections are based on the Diablo Canyon Nuclear Plant producing at the incremental cost of fuel and O&M. Previous regulatory actions have resulted in the capital cost being paid off. Cost projections used in the Study do not include capital costs associated with license extensions, steam generator replacements, or containment and control system upgrades. This important resource could become more expensive (see Section 3.8).
- Projected costs of PG&E and SMUD hydroelectric production include assumptions that relicensing will result in a 5% loss of average water year energy. However, only near-term relicensing has been included in the estimated energy reductions. Long-term relicensing or more severe operating restrictions could adversely affect both utilities.
- Nuclear decommissioning costs are uncertain and could affect long-term power supply costs for either or both utilities.

4.10 The Changing Industry Structure

It is expected that retail competition will be allowed to expand in the next few years, at least for large commercial and industrial customers. No assumptions have been made in the Study as to how retail competition will affect the competitive position of either PG&E or SMUD. PG&E now provides Direct Access service to approximately 10% of the load in its service area. SMUD does not currently serve any Direct Access customers. It is assumed that SMUD would honor existing Direct Access contracts in any annexed area and offer such customers the choice of becoming full-service customers.

4.11 Metering and Billing Systems

It has been assumed that all full-service customers will transfer to SMUD rates, presenting no problems for the SMUD billing system. However, Direct Access customers will pose non-standard metering and billing requirements. Since SMUD prepared for and once offered Direct Access service, it is assumed that they will be able to handle these customers without system modifications.

4.12 Transmission Reliability

Since in a few scenarios the most cost-effective annexation approach is to rely on CAISO transmission rather than building new transmission, SMUD will need to address any differences in reliability between core and annexed customers if CAISO is selected. To the extent that SMUD intends to build new transmission and turn it over to the CAISO, there may be issues relating to which upgrades and associated capital expenditures the CAISO will allow.

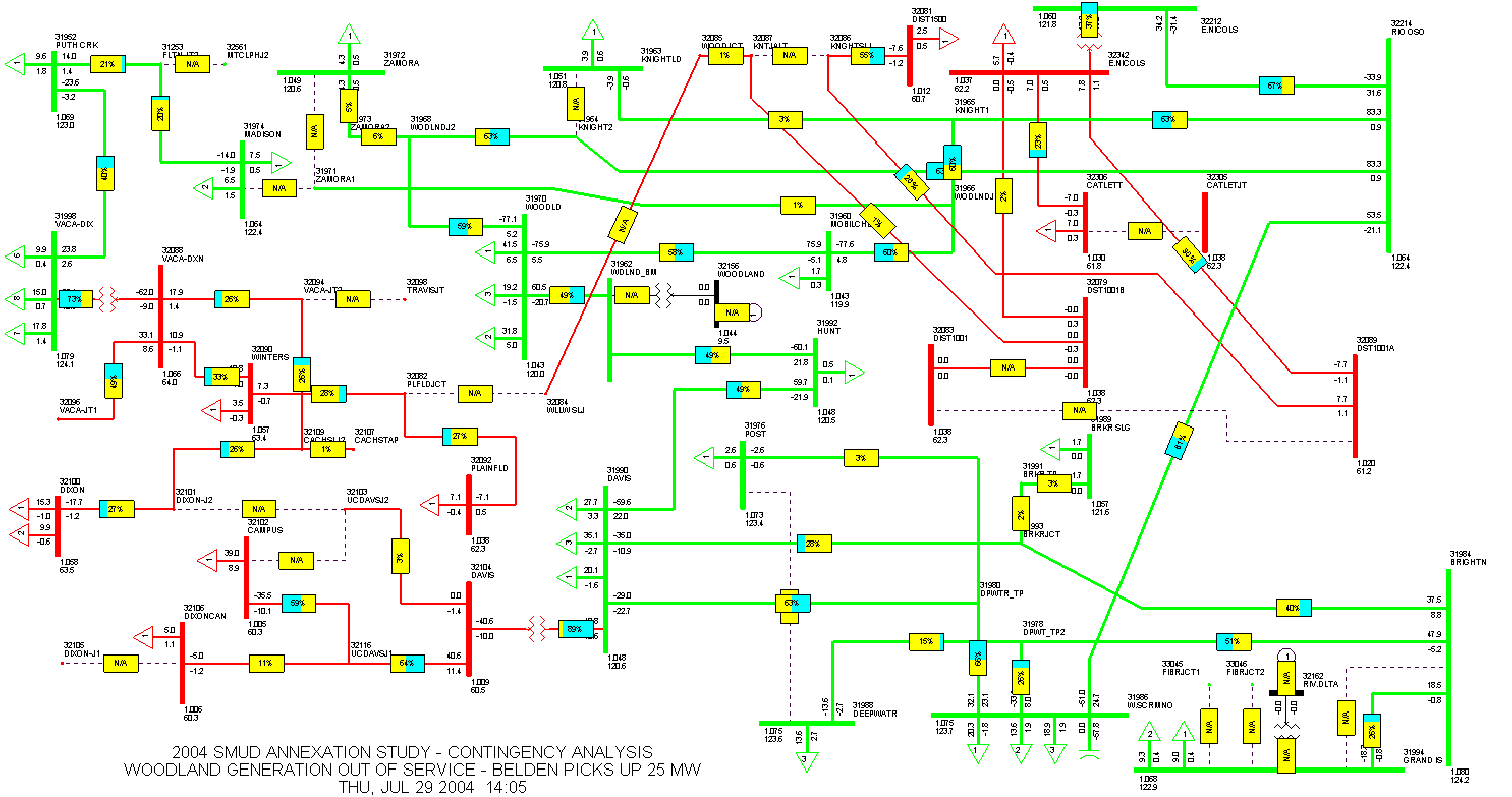
No costs have been included in the Study for the potential that SMUD serves core customers in its own control area and annexed customers in the CAISO control area.

Appendix A

SYSTEM DIAGRAMS, FIGURES 1 TO 6

FIGURE 1

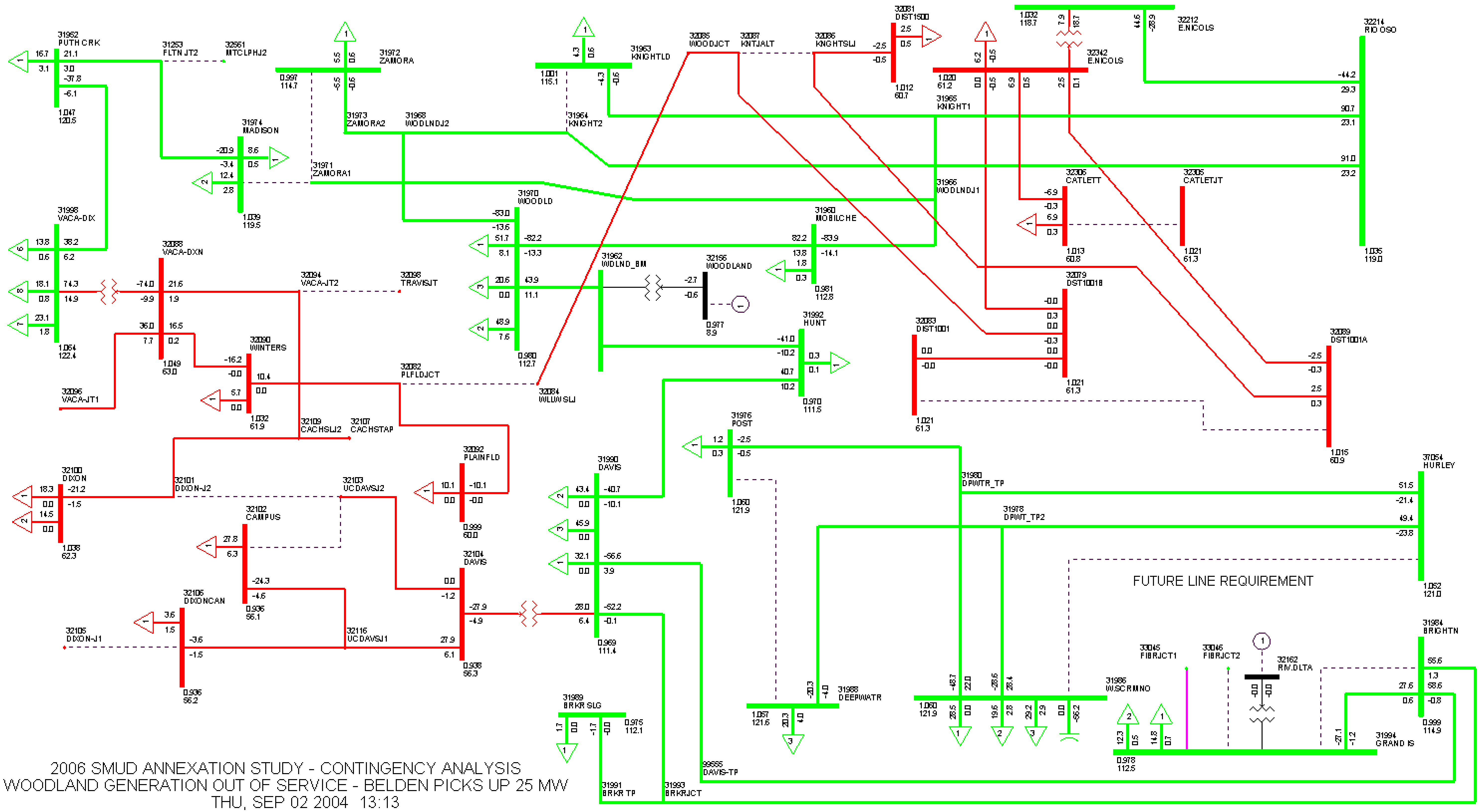
ELECTRIC SYSTEM AS PRESENTLY CONFIGURED



2004 SMUD ANNEXATION STUDY - CONTINGENCY ANALYSIS
WOODLAND GENERATION OUT OF SERVICE - BELDEN PICKS UP 25 MW
THU, JUL 29 2004 14:05

FIGURE 2

INITIAL ANNEXATION CONFIGURATION FOR WEST SACRAMENTO-POST-DAVIS



2006 SMUD ANNEXATION STUDY - CONTINGENCY ANALYSIS
WOODLAND GENERATION OUT OF SERVICE - BELDEN PICKS UP 25 MW
THU, SEP 02 2004 13:13

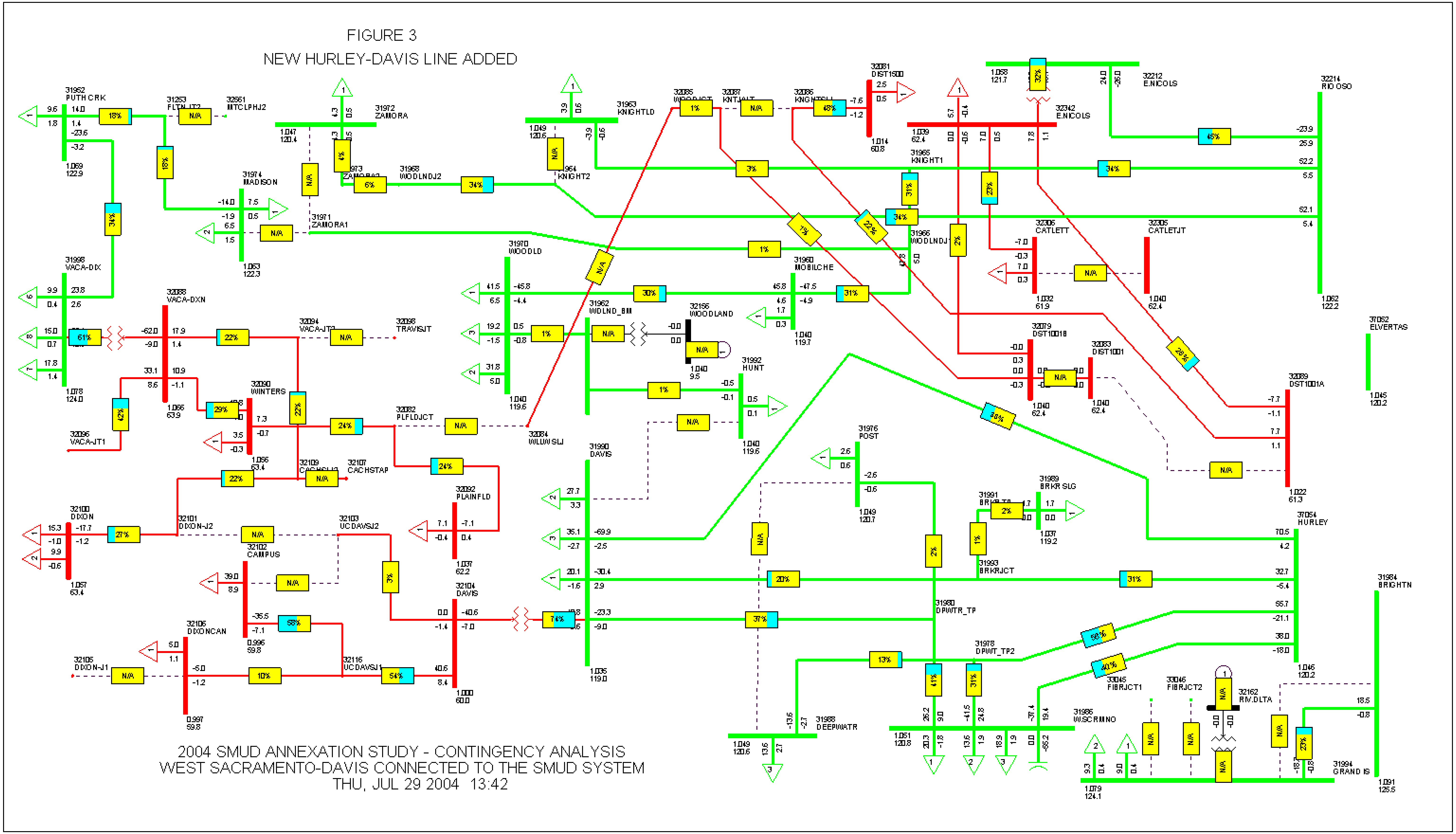
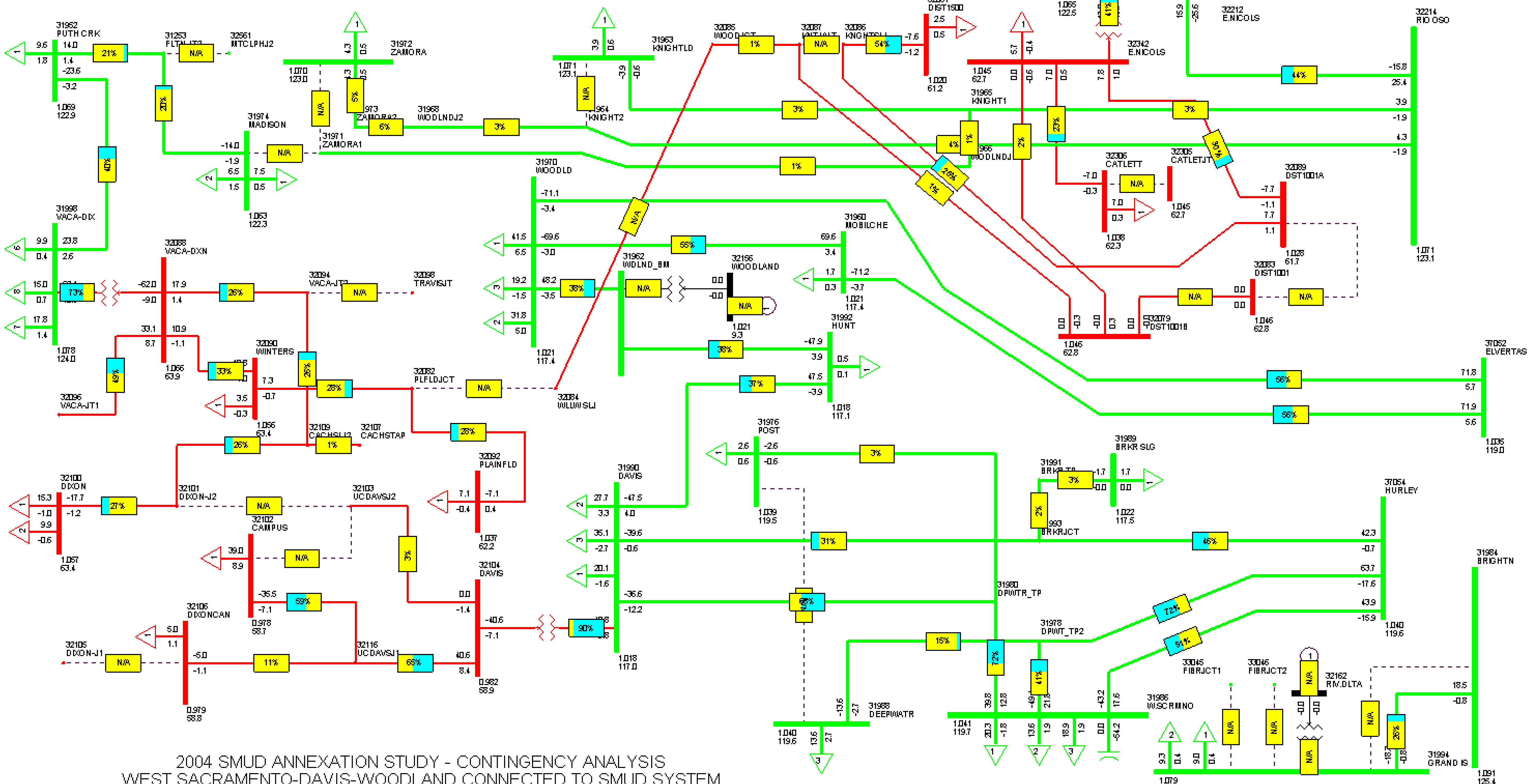


FIGURE 3
NEW HURLEY-DAVIS LINE ADDED
31952 PUTH CRK
31253 FLTN JT2
32561 MTCLPHJ2
31972 ZAMORA
31963 KNIGHTLD
32085 WOODJCT
32087 KNTJ-JT
32086 KNGHTSLJ
32081 DIST1500
32212 E.NICOLS
32214 RIO OSO
32342 E.NICOLS
31974 MADISON
31968 WOODLNDJ2
31971 ZAMORA1
31965 KNIGHT1
31966 WOODLNDJ1
32306 CATLETT
32305 CATLETJT
31998 VACA-DIX
32088 VACA-DXN
31970 WOODLD
31960 MOBILCHE
32094 VACA-JT2
32098 TRAVISJT
31962 WDLND_BM
32156 WOODLAND
32079 DST10018
32083 DIST1001
37052 ELVERTAS
32090 WINTERS
31992 HUNT
32089 DST1001A
32096 VACA-JT1
32082 PLFLDJCT
32084 WLLWSLJ
31990 DAVIS
31976 POST
32109 CACHSLJ2
32107 CACHSTAP
32092 PLAINFLD
31989 BRKR SLG
31991 BRKR TP
37054 HURLEY
32100 DIXON
32101 DIXON-J2
32103 UCDAVSJ2
32102 CAMPUS
31993 BRKRJCT
32104 DAVIS
31980 DPWTR_TP
31984 BRIGHTN
32106 DIXONCAN
31978 DPWT_TP2
32116 UCDAVSJ1
32105 DIXON-J1
33045 FIBRJCT1
33046 FIBRJCT2
32162 RV.DLTA
31986 WSCRMNO
31988 DEEPWATR
31994 GRAND IS
2004 SMUD ANNEXATION STUDY - CONTINGENCY ANALYSIS
WEST SACRAMENTO-DAVIS CONNECTED TO THE SMUD SYSTEM
THU, JUL 29 2004 13:42

FIGURE 4

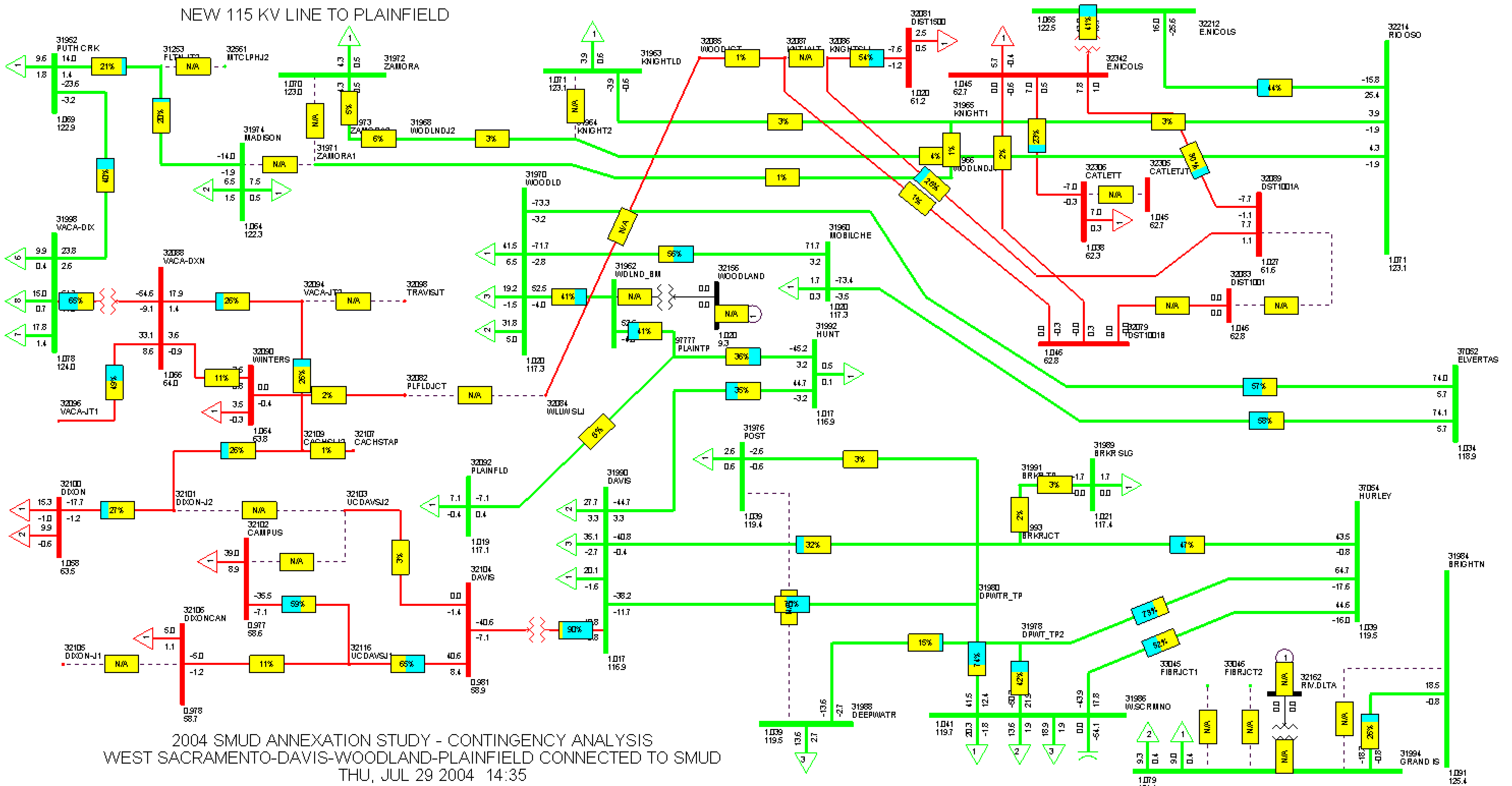
TWO NEW LINES ELVERTA-WOODLAND



2004 SMUD ANNEXATION STUDY - CONTINGENCY ANALYSIS
WEST SACRAMENTO-DAVIS-WOODLAND CONNECTED TO SMUD SYSTEM
THU, JUL 29 2004 14:29

FIGURE 5

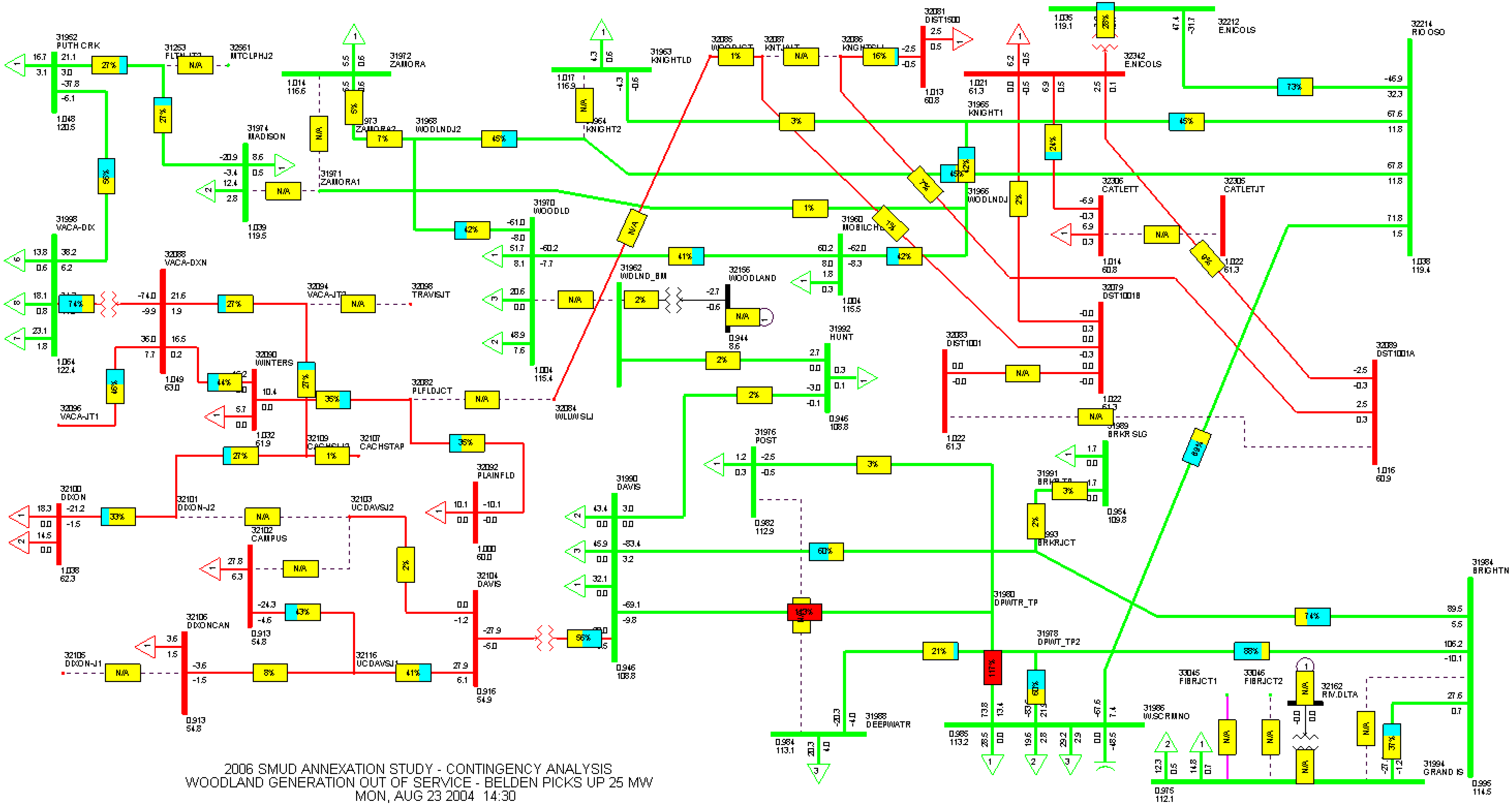
NEW 115 KV LINE TO PLAINFIELD



2004 SMUD ANNEXATION STUDY - CONTINGENCY ANALYSIS
WEST SACRAMENTO-DAVIS-WOODLAND-PLAINFIELD CONNECTED TO SMUD
THU, JUL 29 2004 14:35

FIGURE 6

OUTAGE OF WOODLAND TO BIOMASS LINE-RATING B



2006 SMUD ANNEXATION STUDY - CONTINGENCY ANALYSIS
WOODLAND GENERATION OUT OF SERVICE - BELDEN PICKS UP 25 MW
MON, AUG 23 2004 14:30

Appendix B

FINANCIAL PRO FORMAS

CASE 1 - WEST SACRAMENTO - BUILD OPTION

Municipalization Evaluation Model: Replacement Cost New Less Depreciation - Straight Line Approach / Tranmisssion Build Option

		2004	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
	CUSTOMERS/LOAD																					
	Customers	18,917	20,794	21,264	21,862	22,496	23,195	23,938	24,729	25,564	26,333	27,126	27,942	28,783	29,650	30,522	31,419	32,299	33,203	34,133	35,088	36,071
2,3	Load (MWh)																					
	Bundled only																					
	Residential	92,163	101,304	103,594	106,511	109,596	113,001	116,622	120,479	124,544	128,293	132,154	136,132	140,230	144,450	148,697	153,069	157,355	161,761	166,290	170,946	175,733
	Commercial																					
	Small	45,691	50,223	51,358	52,805	54,334	56,022	57,817	59,729	61,744	63,603	65,517	67,489	69,521	71,613	73,719	75,886	78,011	80,195	82,441	84,749	87,122
	Medium	141,243	155,253	158,762	163,233	167,960	173,179	178,728	184,639	190,869	196,614	202,532	208,628	214,908	221,377	227,885	234,585	241,153	247,906	254,847	261,983	269,318
	Large	98,470	108,237	110,683	113,800	117,096	120,734	124,603	128,724	133,067	137,072	141,198	145,448	149,826	154,336	158,873	163,544	168,123	172,831	177,670	182,645	187,759
	Agricultural	4,646	5,107	5,222	5,369	5,525	5,696	5,879	6,073	6,278	6,467	6,662	6,862	7,069	7,282	7,496	7,716	7,932	8,154	8,383	8,617	8,858
	Other	2,126	2,337	2,390	2,457	2,528	2,607	2,690	2,779	2,873	2,960	3,049	3,140	3,235	3,332	3,430	3,531	3,630	3,732	3,836	3,944	4,054
	Direct Access	19,339	21,257	21,737	22,349	22,997	23,711	24,471	25,280	26,133	26,920	27,730	28,565	29,425	30,310	31,201	32,119	33,018	33,942	34,893	35,870	36,874
	Total Load at Meter	403,677	443,717	453,745	466,525	480,034	494,951	510,810	527,704	545,508	561,928	578,842	596,265	614,213	632,700	651,302	670,450	689,223	708,521	728,360	748,754	769,719
	Load Served (MWh)	384,338	422,460	432,008	444,176	457,037	471,239	486,339	502,424	519,375	535,008	551,112	567,700	584,788	602,390	620,101	638,331	656,205	674,578	693,467	712,884	732,844
4	Losses @8.0% (MWh)	30,747	33,797	34,561	35,534	36,563	37,699	38,907	40,194	41,550	42,801	44,089	45,416	46,783	48,191	49,608	51,067	52,496	53,966	55,477	57,031	58,628
	Energy Requirement	415,085	456,257	466,568	479,710	493,600	508,939	525,247	542,618	560,925	577,809	595,201	613,116	631,571	650,581	669,709	689,398	708,701	728,545	748,944	769,914	791,472
5	Conventional Energy	373,577	392,381	391,918	393,362	394,880	407,151	420,197	434,094	448,740	462,247	476,161	490,493	505,257	520,465	535,767	551,518	566,961	582,836	599,155	615,932	633,178
6	Renewable Energy	41,509	63,876	74,651	86,348	98,720	101,788	105,049	108,524	112,185	115,562	119,040	122,623	126,314	130,116	133,942	137,880	141,740	145,709	149,789	153,983	158,294
	PRICES ($/MWh)																					
7,8	Market Electricity	$ 44.15	$ 37.28	$ 38.22	$ 41.14	$ 44.68	$ 46.74	$ 51.68	$ 53.66	$ 54.86	$ 56.37	$ 57.22	$ 59.16	$ 59.88	$ 61.48	$ 63.34	$ 65.48	$ 67.58	$ 68.77	$ 71.46	$ 72.10	$ 75.42
9	Renewable Prices	48.56	41.00	42.04	45.26	49.15	51.42	56.85	59.02	60.34	62.01	62.94	65.08	65.87	67.63	69.67	72.03	74.33	75.65	78.60	79.31	82.96
10	DWR Bond Repayment	27.00	27.00	27.00	27.00	27.00	27.00	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	O&M and A&G	14.30	15.63	16.01	16.39	16.77	17.15	17.55	17.95	18.36	18.79	19.22	19.66	20.11	20.58	21.05	21.53	22.03	22.53	23.05	23.58	24.13
12	Ancillary Services	4.77	4.03	4.13	4.44	4.83	5.05	5.58	5.80	5.92	6.09	6.18	6.39	6.47	6.64	6.84	7.07	7.30	7.43	7.72	7.79	8.15
13,14	**REVENUES ($000)**																					
	Residential	$ 8,352	$ 8,804	$ 9,051	$ 9,512	$ 10,104	$ 10,576	$ 11,346	$ 12,015	$ 12,706	$ 13,454	$ 14,163	$ 15,011	$ 15,728	$ 16,606	$ 17,555	$ 18,593	$ 19,646	$ 20,602	$ 21,852	$ 22,807	$ 24,281
	Commercial / Industrial																					
	Small	4,587	4,847	4,982	5,236	5,561	5,821	6,244	6,612	6,992	7,404	7,794	8,261	8,655	9,139	9,661	10,232	10,812	11,338	12,025	12,551	13,362
	Medium	12,542	13,089	13,457	14,143	15,023	15,726	16,870	17,864	18,892	20,004	21,059	22,320	23,385	24,691	26,101	27,645	29,212	30,633	32,491	33,911	36,103
	Large	7,346	7,749	7,968	8,376	8,899	9,316	9,994	10,583	11,192	11,851	12,476	13,223	13,854	14,628	15,463	16,378	17,306	18,148	19,249	20,090	21,389
	Agricultural	422	445	457	481	511	534	573	607	642	680	716	758	795	839	887	939	993	1,041	1,104	1,152	1,227
	Other	182	200	205	216	229	240	257	273	288	305	321	341	357	377	398	422	446	468	496	518	551
	Direct Access	967	1,162	1,217	1,281	1,348	1,422	1,501	1,587	1,678	1,768	1,863	1,964	2,069	2,181	2,296	2,418	2,543	2,674	2,813	2,958	3,111
	Total Revenues	$ 34,399	$ 36,295	$ 37,337	$ 39,244	$ 41,676	$ 43,635	$ 46,785	$ 49,540	$ 52,389	$ 55,465	$ 58,392	$ 61,878	$ 64,843	$ 68,459	$ 72,362	$ 76,628	$ 80,958	$ 84,903	$ 90,030	$ 93,986	$ 100,025
	COST OF SERVICE ($000)																					
15	Conventional Power Supply (@market prices)	16,493	14,626	14,977	16,184	17,645	19,032	21,718	23,292	24,616	26,057	27,246	29,019	30,256	31,997	33,935	36,116	38,313	40,082	42,813	44,406	47,756
16	Renewable Power Supply(@renewable prices)	2,016	2,619	3,138	3,908	4,852	5,234	5,972	6,405	6,769	7,166	7,493	7,980	8,320	8,799	9,332	9,932	10,536	11,023	11,774	12,212	13,133
17	O&M and A&G	6,234	7,491	7,844	8,258	8,693	9,169	9,681	10,231	10,819	11,401	12,014	12,661	13,342	14,059	14,806	15,591	16,397	17,243	18,134	19,070	20,055
	Ancillary Services	1,833	1,701	1,783	1,974	2,206	2,379	2,715	2,912	3,077	3,257	3,406	3,627	3,782	4,000	4,242	4,514	4,789	5,010	5,352	5,551	5,969
18	Planning Reserve	-	393	412	456	510	550	628	673	711	753	787	839	874	925	981	1,044	1,107	1,158	1,237	1,283	1,380
19	Public Purpose Programs	1,090	1,151	1,184	1,244	1,321	1,383	1,483	1,570	1,661	1,758	1,851	1,962	2,056	2,170	2,294	2,429	2,566	2,691	2,854	2,979	3,171
	Total Expenses	$ 27,666	$ 27,980	$ 29,338	$ 32,024	$ 35,227	$ 37,747	$ 42,196	$ 45,084	$ 47,653	$ 50,392	$ 52,797	$ 56,088	$ 58,630	$ 61,950	$ 65,590	$ 69,626	$ 73,708	$ 77,208	$ 82,164	$ 85,502	$ 91,464
	Net Revenues ($000)	$ 6,733	$ 8,315	$ 7,999	$ 7,220	$ 6,449	$ 5,888	$ 4,589	$ 4,457	$ 4,736	$ 5,074	$ 5,595	$ 5,791	$ 6,214	$ 6,509	$ 6,772	$ 7,001	$ 7,249	$ 7,695	$ 7,866	$ 8,484	$ 8,560
	DEBT SERVICE ($000)																					
20	Federally Taxable		$ 3,370	$ 3,370	$ 3,370	$ 3,370	$ 3,370	$ 3,370	$ 3,370	$ 3,370	$ 3,370	$ 3,370	$ 3,370	$ 3,370	$ 3,370	$ 3,370	$ 3,370	$ 3,370	$ 3,370	$ 3,370	$ 3,370	$ 3,370
21	Federally Non - Taxable		$ 939	$ 991	$ 1,117	$ 1,248	$ 1,393	$ 1,933	$ 2,076	$ 2,252	$ 2,420	$ 2,598	$ 2,783	$ 2,977	$ 3,179	$ 3,388	$ 3,605	$ 3,824	$ 4,054	$ 4,293	$ 4,544	$ 4,805
	Total Debt Service	$ -	$ 4,309	$ 4,362	$ 4,487	$ 4,619	$ 4,764	$ 5,304	$ 5,446	$ 5,622	$ 5,791	$ 5,968	$ 6,153	$ 6,347	$ 6,550	$ 6,758	$ 6,976	$ 7,195	$ 7,424	$ 7,664	$ 7,914	$ 8,176
	Net Income ($000)	$6,733	$4,006	$3,637	$2,733	$1,830	$1,125	($715)	($989)	($886)	($717)	($372)	($362)	($133)	($41)	$14	$26	$55	$271	$203	$570	$385
	Bundled Customer Rates																					
	PG&E																					
	PG&E System Average	**$ 0.1192**	**$ 0.1143**	**$ 0.1123**	**$ 0.1067**	**$ 0.1099**	**$ 0.1126**	**$ 0.1020**	**$ 0.0995**	**$ 0.1022**	**$ 0.1054**	**$ 0.1081**	**$ 0.1114**	**$ 0.1141**	**$ 0.1174**	**$ 0.1208**	**$ 0.1244**	**$ 0.1281**	**$ 0.1316**	**$ 0.1356**	**$ 0.1392**	**$ 0.1435**
	SMUD																					
	Average SMUD Rates ($/kWh)	$ 0.0870	$ 0.0832	$ 0.0836	$ 0.0855	$ 0.0882	$ 0.0896	$ 0.0931	$ 0.0954	$ 0.0976	$ 0.1004	$ 0.1026	$ 0.1055	$ 0.1073	$ 0.1100	$ 0.1130	$ 0.1163	$ 0.1195	$ 0.1219	$ 0.1258	$ 0.1277	$ 0.1322
	Amount SMUD lower than PG&E	$0.0322	$0.0311	$0.0287	$0.0212	$0.0217	$0.0230	$0.0089	$0.0040	$0.0046	$0.0051	$0.0055	$0.0059	$0.0067	$0.0073	$0.0078	$0.0081	$0.0086	$0.0097	$0.0098	$0.0115	$0.0113
	Percentage SMUD lower than PG&E	27.02%	27.24%	25.54%	19.88%	19.74%	20.45%	8.71%	4.04%	4.48%	4.80%	5.09%	5.26%	5.88%	6.25%	6.47%	6.53%	6.69%	7.37%	7.25%	8.25%	7.87%
22	Franchise Fees	$0.0013	$0.0012	$0.0013	$0.0013	$0.0013	$0.0013	$0.0014	$0.0014	$0.0015	$0.0015	$0.0015	$0.0016	$0.0016	$0.0017	$0.0017	$0.0017	$0.0018	$0.0018	$0.0019	$0.0019	$0.0020
23	Property Taxes	$0.0008	$0.0009	$0.0009	$0.0010	$0.0010	$0.0010	$0.0010	$0.0010	$0.0011	$0.0011	$0.0011	$0.0011	$0.0012	$0.0012	$0.0012	$0.0012	$0.0013	$0.0013	$0.0013	$0.0014	$0.0014
	Average West Sacramento Rates including surcharge ($/kWh)	$ 0.0733	$ 0.0777	$ 0.0792	$ 0.0835	$ 0.0885	$ 0.0915	$ 0.0990	$ 0.1020	$ 0.1040	$ 0.1065	$ 0.1081	$ 0.1112	$ 0.1127	$ 0.1153	$ 0.1183	$ 0.1217	$ 0.1250	$ 0.1272	$ 0.1314	$ 0.1329	$ 0.1379
	DWR Energy/Bond Costs/Reg Assets/CTC	0.0270	0.0265	0.0264	0.0263	0.0261	0.0260	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
24	Nuclear Decomissioning	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	-	-	-	-	-	-	-	-	-
25	FTA	0.0030	0.0030	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Average West Sacramento Rates including Surcharge and Non-bypa	**$ 0.1037**	**$ 0.1076**	**$ 0.1060**	**$ 0.1101**	**$ 0.1150**	**$ 0.1179**	**$ 0.0994**	**$ 0.1024**	**$ 0.1044**	**$ 0.1069**	**$ 0.1085**	**$ 0.1116**	**$ 0.1127**	**$ 0.1153**	**$ 0.1183**	**$ 0.1217**	**$ 0.1250**	**$ 0.1272**	**$ 0.1314**	**$ 0.1329**	**$ 0.1379**
	Amount West Sacramento lower than PG&E ($ / kwh)		0.0067	0.0063	(0.0034)	(0.0051)	(0.0053)	0.0026	(0.0029)	(0.0022)	(0.0014)	(0.0004)	(0.0002)	0.0014	0.0020	0.0025	0.0027	0.0030	0.0044	0.0042	0.0063	0.0056
	Revenue West Sacramento lower than PG&E ($ in millions)		$2,844	$2,702	($1,531)	($2,315)	($2,500)	$1,256	($1,452)	($1,128)	($771)	($246)	($94)	$804	$1,228	$1,543	$1,709	$1,990	$2,940	$2,933	$4,472	$4,137
	Percentage West Sacramento lower than PG&E		5.89%	5.57%	-3.23%	-4.61%	-4.71%	2.53%	-2.91%	-2.12%	-1.37%	-0.41%	-0.15%	1.21%	1.74%	2.06%	2.15%	2.37%	3.31%	3.12%	4.51%	3.93%
	NPV through 2027 @ 6.0%		$6,712																			
	NPV through 2015 @ 6.0%		($686)																			
	Assumed Debt ($000)		$ 45,176																			
	Real Surcharge		$ 0.0244	$ 0.0224	$ 0.0246	$ 0.0268	$ 0.0283	$ 0.0063	$ 0.0069	$ 0.0068	$ 0.0065	$ 0.0059	$ 0.0060	$ 0.0053	$ 0.0053	$ 0.0053	$ 0.0054	$ 0.0055	$ 0.0053	$ 0.0056	$ 0.0052	$ 0.0057
	Smoothed Surcharge		$ 0.0118	$ 0.0118	$ 0.0118	$ 0.0118	$ 0.0118	$ 0.0118	$ 0.0118	$ 0.0118	$ 0.0118	$ 0.0118	$ 0.0118	$ 0.0118	$ 0.0118	$ 0.0118	$ 0.0118	$ 0.0118	$ 0.0118	$ 0.0118	$ 0.0118	$ 0.0118
	Min		$ 0.0052																			
	Max		$ 0.0283																			

Assumptions:

1 Inflation rate is based on March, 2004 Blue Chip Consensus long-term rate indicator.

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21 Federally non-taxable debt service requirement includes all the capital investment costs for new customers each year, renewals and replacement costs, additional tranmission investment required in 2013, debt service reserve equal to the principal and interest payment for one year, the cost of issuance (1.5% of total debt), revenue requirement for 45 days, and the litigation cost of 20% of the total capital investment.

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25 FTA charges are allocated based on PG&E's proposed GRC - Phase 2 and terminate in 2008.These costs are applicable only to certain rates but at the same rate for all classes.

CASE 2 - WEST SACRAMENTO & DAVIS - BUILD OPTION

Municipalization Evaluation Model: Replacement Cost New Less Depreciation - Straight Line Approach / Tranmisssion Build Option

		2004	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
	CUSTOMERS/LOAD																					
	Customers	55,431	59,927	61,023	62,127	63,210	64,298	65,391	66,498	67,624	68,583	69,566	70,573	71,606	72,665	73,722	74,805	75,871	76,963	78,081	79,225	80,398
2,3	Load (MWh)																					
	Bundled only																					
	Residential	255,631	276,502	281,595	286,773	291,870	297,018	302,204	307,475	312,845	317,441	322,154	326,986	331,943	337,026	342,101	347,305	352,426	357,671	363,042	368,544	374,181
	Commercial																					
	Small	79,704	86,676	88,394	90,311	92,259	94,310	96,431	98,637	100,924	102,959	105,050	107,200	109,410	111,682	113,960	116,301	118,599	120,958	123,379	125,863	128,413
	Medium	202,738	221,160	225,723	231,045	236,529	242,403	248,542	254,985	261,705	267,769	274,007	280,425	287,028	293,821	300,641	307,654	314,536	321,604	328,862	336,316	343,971
	Large	98,470	108,237	110,683	113,800	117,096	120,734	124,603	128,724	133,067	137,072	141,198	145,448	149,826	154,336	158,873	163,544	168,123	172,831	177,670	182,645	187,759
	Agricultural	6,141	6,709	6,850	7,018	7,192	7,379	7,576	7,783	8,000	8,197	8,399	8,608	8,822	9,043	9,264	9,492	9,716	9,946	10,182	10,424	10,673
	Other	4,569	4,955	5,050	5,151	5,252	5,357	5,463	5,574	5,687	5,786	5,888	5,992	6,100	6,210	6,320	6,434	6,545	6,659	6,776	6,896	7,019
	Direct Access	45,804	50,348	51,485	52,936	54,468	56,161	57,961	59,877	61,898	63,761	65,680	67,657	69,693	71,791	73,902	76,075	78,205	80,394	82,645	84,959	87,338
	Total Load at Meter	693,056	754,586	769,780	787,035	804,666	823,362	842,780	863,056	884,125	902,984	922,376	942,317	962,822	983,910	1,005,062	1,026,804	1,048,150	1,070,063	1,092,557	1,115,649	1,139,355
	Load Served (MWh)	647,252	704,239	718,295	734,099	750,198	767,201	784,819	803,178	822,227	839,223	856,696	874,660	893,129	912,118	931,160	950,729	969,946	989,668	1,009,912	1,030,689	1,052,017
4	Losses @8.0% (MWh)	51,780	56,339	57,464	58,728	60,016	61,376	62,786	64,254	65,778	67,138	68,536	69,973	71,450	72,969	74,493	76,058	77,596	79,173	80,793	82,455	84,161
	Energy Requirement	699,032	760,578	775,758	792,827	810,214	828,577	847,605	867,432	888,005	906,361	925,232	944,632	964,579	985,088	1,005,653	1,026,787	1,047,541	1,068,842	1,090,704	1,113,144	1,136,178
5	Conventional Energy	629,129	654,097	651,637	650,118	648,171	662,862	678,084	693,946	710,404	725,089	740,185	755,706	771,663	788,070	804,523	821,430	838,033	855,074	872,564	890,516	908,942
6	Renewable Energy	69,903	106,481	124,121	142,709	162,043	165,715	169,521	173,486	177,601	181,272	185,046	188,926	192,916	197,018	201,131	205,357	209,508	213,768	218,141	222,629	227,236
	PRICES ($/MWh)																					
7,8	Market Electricity	$ 44.15	$ 37.28	$ 38.22	$ 41.14	$ 44.68	$ 46.74	$ 51.68	$ 53.66	$ 54.86	$ 56.37	$ 57.22	$ 59.16	$ 59.88	$ 61.48	$ 63.34	$ 65.48	$ 67.58	$ 68.77	$ 71.46	$ 72.10	$ 75.42
9	Renewable Prices	48.56	41.00	42.04	45.26	49.15	51.42	56.85	59.02	60.34	62.01	62.94	65.08	65.87	67.63	69.67	72.03	74.33	75.65	78.60	79.31	82.96
10	DWR Bond Repayment	27.00	27.00	27.00	27.00	27.00	27.00	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	O&M and A&G	14.30	15.63	16.01	16.39	16.77	17.15	17.55	17.95	18.36	18.79	19.22	19.66	20.11	20.58	21.05	21.53	22.03	22.53	23.05	23.58	24.13
12	Ancillary Services	4.77	4.03	4.13	4.44	4.83	5.05	5.58	5.80	5.92	6.09	6.18	6.39	6.47	6.64	6.84	7.07	7.30	7.43	7.72	7.79	8.15
13,14	**REVENUES ($000)**																					
	Residential	$ 22,820	$ 23,675	$ 24,241	$ 25,237	$ 26,519	$ 27,400	$ 28,981	$ 30,230	$ 31,469	$ 32,828	$ 34,053	$ 35,568	$ 36,731	$ 38,230	$ 39,857	$ 41,638	$ 43,436	$ 44,974	$ 47,106	$ 48,557	$ 51,065
	Commercial / Industrial																					
	Small	8,002	8,365	8,576	8,955	9,442	9,799	10,414	10,919	11,429	11,985	12,497	13,122	13,622	14,252	14,934	15,681	16,437	17,101	17,997	18,640	19,695
	Medium	18,003	18,645	19,132	20,018	21,157	22,012	23,459	24,670	25,903	27,243	28,490	30,001	31,233	32,771	34,435	36,256	38,101	39,739	41,927	43,532	46,111
	Large	7,346	7,749	7,968	8,376	8,899	9,316	9,994	10,583	11,192	11,851	12,476	13,223	13,854	14,628	15,463	16,378	17,306	18,148	19,249	20,090	21,389
	Agricultural	558	584	600	628	665	692	739	778	818	862	902	951	992	1,042	1,096	1,156	1,216	1,270	1,341	1,394	1,478
	Other	392	424	434	452	476	493	523	547	571	597	621	650	673	702	734	769	804	834	876	905	954
	Direct Access	2,290	2,752	2,881	3,034	3,193	3,368	3,556	3,758	3,974	4,188	4,414	4,651	4,901	5,165	5,439	5,728	6,023	6,334	6,662	7,006	7,367
	Total Revenues	$ 59,411	$ 62,194	$ 63,832	$ 66,700	$ 70,351	$ 73,079	$ 77,666	$ 81,485	$ 85,356	$ 89,554	$ 93,453	$ 98,167	$ 102,005	$ 106,789	$ 111,958	$ 117,606	$ 123,323	$ 128,400	$ 135,158	$ 140,124	$ 148,060
	COST OF SERVICE ($000)																					
15	Power Supply (@market prices)	27,775	24,382	24,903	26,748	28,963	30,984	35,046	37,235	38,969	40,873	42,353	44,710	46,209	48,449	50,958	53,790	56,631	58,804	62,350	64,202	68,554
16	Renewable Power Supply(@renewable prices)	3,395	4,366	5,218	6,459	7,965	8,521	9,638	10,240	10,717	11,240	11,647	12,295	12,707	13,323	14,014	14,792	15,573	16,171	17,146	17,656	18,852
17	O&M and A&G	10,704	12,739	13,307	13,932	14,571	15,253	15,972	16,732	17,535	18,321	19,145	20,009	20,914	21,864	22,847	23,879	24,936	26,042	27,201	28,415	29,686
	Ancillary Services	3,086	2,835	2,965	3,262	3,620	3,873	4,381	4,654	4,871	5,109	5,294	5,589	5,776	6,056	6,370	6,724	7,079	7,350	7,794	8,025	8,569
18	Planning Reserve	-	656	685	754	837	896	1,013	1,076	1,126	1,181	1,224	1,292	1,336	1,400	1,473	1,555	1,637	1,700	1,802	1,856	1,981
19	Public Purpose Programs	1,883	1,972	2,023	2,114	2,230	2,317	2,462	2,583	2,706	2,839	2,962	3,112	3,234	3,385	3,549	3,728	3,909	4,070	4,285	4,442	4,693
	Total Expenses	$ 46,843	$ 46,949	$ 49,101	$ 53,269	$ 58,187	$ 61,843	$ 68,512	$ 72,521	$ 75,924	$ 79,563	$ 82,626	$ 87,006	$ 90,175	$ 94,478	$ 99,211	$ 104,468	$ 109,765	$ 114,138	$ 120,578	$ 124,596	$ 132,337
	Net Revenues ($000)	$ 12,568	$ 15,246	$ 14,731	$ 13,431	$ 12,164	$ 11,236	$ 9,154	$ 8,964	$ 9,432	$ 9,991	$ 10,827	$ 11,161	$ 11,830	$ 12,311	$ 12,747	$ 13,138	$ 13,559	$ 14,263	$ 14,581	$ 15,528	$ 15,722
	DEBT SERVICE ($000)																					
20	Federally Taxable		$ 7,825	$ 7,825	$ 7,825	$ 7,825	$ 7,825	$ 7,825	$ 7,825	$ 7,825	$ 7,825	$ 7,825	$ 7,825	$ 7,825	$ 7,825	$ 7,825	$ 7,825	$ 7,825	$ 7,825	$ 7,825	$ 7,825	$ 7,825
21	Federally Non - Taxable		$ 1,969	$ 2,117	$ 2,374	$ 2,632	$ 2,896	$ 3,615	$ 3,865	$ 4,151	$ 4,412	$ 4,685	$ 4,969	$ 5,263	$ 5,569	$ 5,881	$ 6,205	$ 6,533	$ 6,875	$ 7,229	$ 7,596	$ 7,978
	Total Debt Service	$ -	$ 9,794	$ 9,942	$ 10,199	$ 10,457	$ 10,721	$ 11,440	$ 11,690	$ 11,976	$ 12,237	$ 12,510	$ 12,794	$ 13,088	$ 13,394	$ 13,706	$ 14,030	$ 14,358	$ 14,699	$ 15,054	$ 15,421	$ 15,803
	Net Income ($000)	$12,568	$5,452	$4,789	$3,232	$1,707	$516	($2,287)	($2,726)	($2,544)	($2,246)	($1,683)	($1,633)	($1,258)	($1,083)	($958)	($892)	($800)	($437)	($473)	$107	($81)
	Bundled Customer Rates																					
	PG&E																					
	PG&E System Average	**$ 0.1224**	**$ 0.1182**	**$ 0.1152**	**$ 0.1098**	**$ 0.1130**	**$ 0.1157**	**$ 0.1051**	**$ 0.1026**	**$ 0.1054**	**$ 0.1086**	**$ 0.1112**	**$ 0.1146**	**$ 0.1172**	**$ 0.1205**	**$ 0.1240**	**$ 0.1275**	**$ 0.1312**	**$ 0.1348**	**$ 0.1388**	**$ 0.1424**	**$ 0.1467**
	SMUD																					
	Average SMUD Rates ($/kWh)	$ 0.0883	$ 0.0844	$ 0.0849	$ 0.0867	$ 0.0895	$ 0.0909	$ 0.0944	$ 0.0968	$ 0.0990	$ 0.1017	$ 0.1039	$ 0.1069	$ 0.1087	$ 0.1114	$ 0.1144	$ 0.1177	$ 0.1209	$ 0.1233	$ 0.1272	$ 0.1292	$ 0.1337
	Amount SMUD lower than PG&E	$0.0342	$0.0338	$0.0303	$0.0231	$0.0235	$0.0249	$0.0106	$0.0058	$0.0064	$0.0069	$0.0073	$0.0077	$0.0085	$0.0091	$0.0096	$0.0099	$0.0103	$0.0114	$0.0115	$0.0132	$0.0130
	Percentage SMUD lower than PG&E	27.93%	28.62%	26.33%	21.01%	20.81%	21.49%	10.11%	5.69%	6.07%	6.32%	6.57%	6.68%	7.25%	7.56%	7.73%	7.74%	7.85%	8.49%	8.32%	9.28%	8.86%
22	Franchise Fees	$0.0013	$0.0013	$0.0013	$0.0013	$0.0013	$0.0014	$0.0014	$0.0015	$0.0015	$0.0015	$0.0016	$0.0016	$0.0016	$0.0017	$0.0017	$0.0018	$0.0018	$0.0019	$0.0019	$0.0019	$0.0020
23	Property Taxes	$0.0010	$0.0011	$0.0011	$0.0011	$0.0011	$0.0012	$0.0012	$0.0012	$0.0012	$0.0013	$0.0013	$0.0013	$0.0013	$0.0014	$0.0014	$0.0014	$0.0014	$0.0015	$0.0015	$0.0015	$0.0016
	Average West Sacramento & Davis Rates including surcharge ($	$ 0.0735	$ 0.0816	$ 0.0832	$ 0.0875	$ 0.0925	$ 0.0956	$ 0.1029	$ 0.1059	$ 0.1080	$ 0.1105	$ 0.1121	$ 0.1152	$ 0.1167	$ 0.1194	$ 0.1224	$ 0.1258	$ 0.1291	$ 0.1313	$ 0.1355	$ 0.1370	$ 0.1420
	DWR Energy/Bond Costs/Reg Assets/CTC	0.0230	0.0228	0.0228	0.0227	0.0227	0.0226	0.0023	-	-	-	-	-	-	-	-	-	-	-	-	-	-
24	Nuclear Decomissioning	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	-	-	-	-	-	-	-	-	-
25	FTA	0.0042	0.0042	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Average West Sacramento & Davis Rates including Surcharge a	**$ 0.1012**	**$ 0.1090**	**$ 0.1064**	**$ 0.1106**	**$ 0.1156**	**$ 0.1187**	**$ 0.1056**	**$ 0.1063**	**$ 0.1084**	**$ 0.1109**	**$ 0.1125**	**$ 0.1156**	**$ 0.1167**	**$ 0.1194**	**$ 0.1224**	**$ 0.1258**	**$ 0.1291**	**$ 0.1313**	**$ 0.1355**	**$ 0.1370**	**$ 0.1420**
	Amount West Sacramento & Davis lower than PG&E ($ / kwh)		0.0092	0.0088	(0.0008)	(0.0026)	(0.0029)	(0.0006)	(0.0037)	(0.0030)	(0.0023)	(0.0013)	(0.0010)	0.0005	0.0012	0.0016	0.0018	0.0021	0.0034	0.0033	0.0054	0.0047
	Revenue West Sacramento & Davis lower than PG&E ($ in millions)		$6,487	$6,322	($597)	($1,937)	($2,243)	($440)	($2,981)	($2,476)	($1,930)	($1,120)	($913)	$446	$1,053	$1,485	$1,688	$2,060	$3,413	$3,345	$5,524	$4,967
	Percentage West Sacramento & Davis lower than PG&E		7.79%	7.64%	-0.74%	-2.28%	-2.53%	-0.53%	-3.62%	-2.86%	-2.12%	-1.18%	-0.91%	0.43%	0.96%	1.29%	1.39%	1.62%	2.56%	2.39%	3.76%	3.22%
	NPV through 2027 @ 6.0%		$10,641																			
	NPV through 2015 @ 6.0%		$4,189																			
	Assumed Debt ($000)		$ 104,887																			
	Real Surcharge		$ 0.0246	$ 0.0215	$ 0.0239	$ 0.0261	$ 0.0278	$ 0.0112	$ 0.0096	$ 0.0094	$ 0.0092	$ 0.0086	$ 0.0087	$ 0.0080	$ 0.0080	$ 0.0080	$ 0.0081	$ 0.0082	$ 0.0080	$ 0.0082	$ 0.0079	$ 0.0083
	Smoothed Surcharge		$ 0.0139	$ 0.0139	$ 0.0139	$ 0.0139	$ 0.0139	$ 0.0139	$ 0.0139	$ 0.0139	$ 0.0139	$ 0.0139	$ 0.0139	$ 0.0139	$ 0.0139	$ 0.0139	$ 0.0139	$ 0.0139	$ 0.0139	$ 0.0139	$ 0.0139	$ 0.0139
	Min		$ 0.0079																			
	Max		$ 0.0278																			

Assumptions:

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23 Property tax is calculated at 3.16% based on PG&E 's distribution revenue requirement from its GRC model.

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25 FTA charges are allocated based on PG&E's proposed GRC - Phase 2 and terminate in 2008.These costs are applicable only to certain rates but at the same rate for all classes.

CASE 3 - ALL REGION - BUILD OPTION

Municipalization Evaluation Model: Replacement Cost New Less Depreciation - Straight Line Approach / Tranmisssion Build Option

		2004	2008	2009	2010	2011	2012	2013	2014	2015
	CUSTOMERS/LOAD									
	Customers	82,257	88,678	90,234	91,816	93,375	94,948	96,531	98,135	99,764
2,3	Load (MWh)									
	Bundled only									
	Residential	451,992	486,749	495,163	503,767	512,279	520,896	529,594	538,427	547,408
	Commercial									
	Small	141,910	153,284	156,055	159,058	162,089	165,240	168,473	171,809	175,241
	Medium	356,927	386,249	393,419	401,429	409,592	418,190	427,083	436,321	445,875
	Large	185,298	201,230	205,151	209,792	214,606	219,789	225,220	230,925	236,874
	Agricultural	42,010	45,042	45,774	46,541	47,312	48,106	48,918	49,749	50,600
	Other	6,842	7,390	7,524	7,665	7,806	7,952	8,100	8,252	8,408
	Direct Access	75,134	82,586	84,453	86,831	89,346	92,122	95,074	98,218	101,532
	Total Load at Meter	1,260,113	1,362,531	1,387,538	1,415,085	1,443,029	1,472,294	1,502,461	1,533,701	1,565,936
	Load Served (MWh)	1,184,979	1,279,945	1,303,085	1,328,253	1,353,684	1,380,172	1,407,387	1,435,483	1,464,404
4	Losses @8.0% (MWh)	94,798	102,396	104,247	106,260	108,295	110,414	112,591	114,839	117,152
	Energy Requirement	1,279,777	1,382,340	1,407,332	1,434,514	1,461,978	1,490,586	1,519,978	1,550,321	1,581,556
5	Conventional Energy	1,151,800	1,188,813	1,182,159	1,176,301	1,169,583	1,192,469	1,215,982	1,240,257	1,265,245
6	Renewable Energy	127,978	193,528	225,173	258,212	292,396	298,117	303,996	310,064	316,311
	PRICES ($/MWh)									
7,8	Market Electricity	$ 44.15	$ 37.28	$ 38.22	$ 41.14	$ 44.68	$ 46.74	$ 51.68	$ 53.66	$ 54.86
9	Renewable Prices	48.56	41.00	42.04	45.26	49.15	51.42	56.85	59.02	60.34
10	DWR Bond Repayment	27.00	27.00	27.00	27.00	27.00	27.00	-	-	-
11	O&M and A&G	14.30	15.63	16.01	16.39	16.77	17.15	17.55	17.95	18.36
12	Ancillary Services	4.77	4.03	4.13	4.44	4.83	5.05	5.58	5.80	5.92
13,14	**REVENUES ($000)**									
	Residential	$ 41,750	$ 43,110	$ 44,087	$ 45,846	$ 48,127	$ 49,681	$ 52,503	$ 54,718	$ 56,912
	Commercial / Industrial									
	Small	14,248	14,793	15,140	15,771	16,589	17,168	18,194	19,019	19,845
	Medium	31,695	32,564	33,346	34,780	36,636	37,974	40,311	42,215	44,131
	Large	13,823	14,406	14,768	15,441	16,310	16,959	18,064	18,986	19,923
	Agricultural	3,815	3,924	4,009	4,166	4,372	4,513	4,770	4,973	5,174
	Other	587	632	647	673	708	732	775	809	844
	Direct Access	3,757	4,514	4,726	4,976	5,238	5,525	5,833	6,165	6,519
	Total Revenues	$ 109,674	$ 113,942	$ 116,722	$ 121,654	$ 127,981	$ 132,552	$ 140,450	$ 146,885	$ 153,348
	COST OF SERVICE ($000)									
15	Power Supply (@market prices)	50,851	44,314	45,177	48,397	52,262	55,740	62,848	66,549	69,405
16	Renewable Power Supply(@renewable prices)	6,215	7,935	9,466	11,686	14,372	15,328	17,283	18,301	19,086
17	O&M and A&G	19,461	23,002	23,986	25,049	26,131	27,275	28,474	29,734	31,057
	Ancillary Services	5,650	5,153	5,378	5,902	6,533	6,967	7,856	8,319	8,676
18	Planning Reserve	-	1,191	1,244	1,365	1,511	1,611	1,816	1,923	2,006
19	Public Purpose Programs	3,477	3,612	3,700	3,856	4,057	4,202	4,452	4,656	4,861
	Total Expenses	$ 85,654	$ 85,207	$ 88,950	$ 96,255	$ 104,866	$ 111,123	$ 122,729	$ 129,483	$ 135,092
	Net Revenues ($000)	$ 24,020	$ 28,736	$ 27,772	$ 25,399	$ 23,115	$ 21,429	$ 17,721	$ 17,402	$ 18,256
	DEBT SERVICE ($000)									
20	Federally Taxable		$ 10,720	$ 10,720	$ 10,720	$ 10,720	$ 10,720	$ 10,720	$ 10,720	$ 10,720
21	Federally Non - Taxable		$ 2,960	$ 3,168	$ 3,542	$ 3,921	$ 4,309	$ 5,157	$ 5,539	$ 5,961
	Total Debt Service	$ -	$ 13,680	$ 13,888	$ 14,263	$ 14,642	$ 15,030	$ 15,878	$ 16,260	$ 16,682
	Net Income ($000)	$24,020	$15,055	$13,884	$11,136	$8,473	$6,399	$1,844	$1,142	$1,574
	Bundled Customer Rates									
	PG&E									
	PG&E System Average	**$ 0.1239**	**$ 0.1196**	**$ 0.1166**	**$ 0.1112**	**$ 0.1145**	**$ 0.1172**	**$ 0.1063**	**$ 0.1039**	**$ 0.1067**
	SMUD									
	Average SMUD Rates ($/kWh)	$ 0.0894	$ 0.0855	$ 0.0859	$ 0.0878	$ 0.0907	$ 0.0920	$ 0.0957	$ 0.0980	$ 0.1003
	Amount SMUD lower than PG&E	$0.0345	$0.0341	$0.0307	$0.0233	$0.0238	$0.0252	$0.0107	$0.0058	$0.0064
	Percentage SMUD lower than PG&E	27.85%	28.54%	26.30%	20.98%	20.79%	21.47%	10.04%	5.62%	6.01%
22	Franchise Fees	$0.0013	$0.0013	$0.0013	$0.0013	$0.0014	$0.0014	$0.0014	$0.0015	$0.0015
23	Property Taxes	$0.0010	$0.0011	$0.0011	$0.0011	$0.0011	$0.0012	$0.0012	$0.0012	$0.0012
	Average All Cities Rates including surcharge ($/kWh)	$ 0.0735	$ 0.0784	$ 0.0801	$ 0.0844	$ 0.0895	$ 0.0926	$ 0.0997	$ 0.1027	$ 0.1049
	DWR Energy/Bond Costs/Reg Assets/CTC	0.0248	0.0245	0.0245	0.0244	0.0243	0.0243	0.0013	-	-
24	Nuclear Decomissioning	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004
25	FTA	0.0041	0.0041	-	-	-	-	-	-	-
	Average All Cities Rates including Surcharge and Non-bypassat	**$ 0.1029**	**$ 0.1074**	**$ 0.1049**	**$ 0.1092**	**$ 0.1142**	**$ 0.1173**	**$ 0.1014**	**$ 0.1031**	**$ 0.1053**
	Amount All Cities lower than PG&E ($ / kwh)		0.0122	0.0117	0.0020	0.0003	(0.0001)	0.0050	0.0007	0.0014
	Revenue All Cities lower than PG&E ($ in millions)		$15,611	$15,208	$2,648	$349	($86)	$6,986	$1,022	$2,058
	Percentage All Cities lower than PG&E		10.19%	10.01%	1.79%	0.23%	-0.05%	4.67%	0.69%	1.32%
	NPV through 2027 @ 6.0%		$87,046							
	NPV through 2015 @ 6.0%		$37,594							
	Assumed Debt ($000)		$ 143,700							
	Real Surcharge		$ 0.0219	$ 0.0190	$ 0.0213	$ 0.0235	$ 0.0252	$ 0.0057	$ 0.0051	$ 0.0050
	Smoothed Surcharge		$ 0.0101	$ 0.0101	$ 0.0101	$ 0.0101	$ 0.0101	$ 0.0101	$ 0.0101	$ 0.0101
	Min		$ 0.0035							
	Max		$ 0.0252							

		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
	CUSTOMERS/LOAD												
	Customers	101,385	103,044	104,741	106,477	108,255	109,813	111,405	112,885	114,395	115,936	117,508	119,113
2,3	Load (MWh)												
	Bundled only												
	Residential	556,276	565,342	574,611	584,086	593,774	602,426	611,258	619,491	627,885	636,444	645,170	654,069
	Commercial												
	Small	178,635	182,112	185,673	189,321	193,059	196,471	199,962	203,246	206,601	210,031	213,535	217,118
	Medium	455,279	464,921	474,806	484,941	495,333	504,960	514,819	524,148	533,691	543,453	553,442	563,661
	Large	242,839	248,963	255,251	261,705	268,332	274,463	280,750	286,695	292,784	299,021	305,410	311,955
	Agricultural	51,373	52,159	52,960	53,774	54,603	55,444	56,300	57,123	57,959	58,810	59,674	60,553
	Other	8,561	8,718	8,879	9,043	9,212	9,365	9,521	9,668	9,818	9,971	10,127	10,287
	Direct Access	104,588	107,736	110,979	114,319	117,760	121,223	124,787	128,281	131,872	135,565	139,361	143,263
	Total Load at Meter	1,597,552	1,629,952	1,663,157	1,697,190	1,732,073	1,764,352	1,797,397	1,828,651	1,860,611	1,893,294	1,926,720	1,960,906
	Load Served (MWh)	1,492,964	1,522,216	1,552,178	1,582,871	1,614,312	1,643,130	1,672,610	1,700,370	1,728,738	1,757,729	1,787,359	1,817,643
4	Losses @8.0% (MWh)	119,437	121,777	124,174	126,630	129,145	131,450	133,809	136,030	138,299	140,618	142,989	145,411
	Energy Requirement	1,612,401	1,643,993	1,676,353	1,709,500	1,743,457	1,774,580	1,806,419	1,836,400	1,867,037	1,898,348	1,930,348	1,963,055
5	Conventional Energy	1,289,921	1,315,194	1,341,082	1,367,600	1,394,766	1,419,664	1,445,135	1,469,120	1,493,630	1,518,678	1,544,278	1,570,444
6	Renewable Energy	322,480	328,799	335,271	341,900	348,691	354,916	361,284	367,280	373,407	379,670	386,070	392,611
	PRICES ($/MWh)												
7,8	Market Electricity	$ 56.37	$ 57.22	$ 59.16	$ 59.88	$ 61.48	$ 63.34	$ 65.48	$ 67.58	$ 68.77	$ 71.46	$ 72.10	$ 75.42
9	Renewable Prices	62.01	62.94	65.08	65.87	67.63	69.67	72.03	74.33	75.65	78.60	79.31	82.96
10	DWR Bond Repayment	-	-	-	-	-	-	-	-	-	-	-	-
11	O&M and A&G	18.79	19.22	19.66	20.11	20.58	21.05	21.53	22.03	22.53	23.05	23.58	24.13
12	Ancillary Services	6.09	6.18	6.39	6.47	6.64	6.84	7.07	7.30	7.43	7.72	7.79	8.15
13,14	**REVENUES ($000)**												
	Residential	$ 59,455	$ 61,757	$ 64,590	$ 66,784	$ 69,592	$ 72,513	$ 75,705	$ 78,867	$ 81,544	$ 85,284	$ 87,776	$ 92,162
	Commercial / Industrial												
	Small	20,794	21,665	22,727	23,571	24,636	25,747	26,962	28,168	29,209	30,637	31,624	33,301
	Medium	46,321	48,341	50,797	52,769	55,246	57,837	60,670	63,492	65,946	69,286	71,637	75,561
	Large	20,995	21,998	23,206	24,199	25,432	26,714	28,116	29,512	30,744	32,396	33,594	35,537
	Agricultural	5,400	5,603	5,853	6,045	6,292	6,561	6,854	7,149	7,399	7,746	7,980	8,386
	Other	883	919	963	998	1,042	1,088	1,138	1,187	1,230	1,289	1,329	1,398
	Direct Access	6,870	7,240	7,629	8,039	8,472	8,922	9,395	9,880	10,390	10,927	11,491	12,085
	Total Revenues	$ 160,718	$ 167,522	$ 175,766	$ 182,405	$ 190,711	$ 199,380	$ 208,840	$ 218,255	$ 226,461	$ 237,565	$ 245,430	$ 258,430
	COST OF SERVICE ($000)												
15	Power Supply (@market prices)	72,712	75,255	79,342	81,894	85,747	89,921	94,633	99,277	102,718	108,518	111,336	118,446
16	Renewable Power Supply(@renewable prices)	19,996	20,695	21,819	22,521	23,581	24,728	26,024	27,301	28,247	29,843	30,617	32,573
17	O&M and A&G	32,413	33,831	35,314	36,866	38,489	40,108	41,799	43,504	45,282	47,137	49,073	51,092
	Ancillary Services	9,089	9,407	9,918	10,237	10,718	11,240	11,829	12,410	12,840	13,565	13,917	14,806
18	Planning Reserve	2,102	2,175	2,293	2,367	2,478	2,599	2,735	2,869	2,969	3,136	3,218	3,423
19	Public Purpose Programs	5,095	5,310	5,572	5,782	6,046	6,320	6,620	6,919	7,179	7,531	7,780	8,192
	Total Expenses	$ 141,406	$ 146,673	$ 154,259	$ 159,667	$ 167,059	$ 174,917	$ 183,640	$ 192,280	$ 199,235	$ 209,730	$ 215,941	$ 228,533
	Net Revenues ($000)	$ 19,312	$ 20,849	$ 21,507	$ 22,737	$ 23,652	$ 24,463	$ 25,199	$ 25,975	$ 27,227	$ 27,835	$ 29,489	$ 29,898
	DEBT SERVICE ($000)												
20	Federally Taxable	$ 10,720	$ 10,720	$ 10,720	$ 10,720	$ 10,720	$ 10,720	$ 10,720	$ 10,720	$ 10,720	$ 10,720	$ 10,720	$ 10,720
21	Federally Non - Taxable	$ 6,390	$ 6,836	$ 7,299	$ 7,779	$ 8,277	$ 8,742	$ 9,228	$ 9,700	$ 10,192	$ 10,700	$ 11,227	$ 11,773
	Total Debt Service	$ 17,111	$ 17,556	$ 18,019	$ 18,499	$ 18,998	$ 19,463	$ 19,948	$ 20,421	$ 20,912	$ 21,421	$ 21,948	$ 22,494
	Net Income ($000)	$2,201	$3,292	$3,488	$4,238	$4,654	$5,000	$5,251	$5,554	$6,314	$6,414	$7,541	$7,404
	Bundled Customer Rates												
	PG&E												
	PG&E System Average	**$ 0.1099**	**$ 0.1126**	**$ 0.1160**	**$ 0.1187**	**$ 0.1221**	**$ 0.1256**	**$ 0.1292**	**$ 0.1330**	**$ 0.1366**	**$ 0.1406**	**$ 0.1443**	**$ 0.1487**
	SMUD												
	Average SMUD Rates ($/kWh)	$ 0.1030	$ 0.1053	$ 0.1083	$ 0.1102	$ 0.1129	$ 0.1159	$ 0.1192	$ 0.1225	$ 0.1250	$ 0.1289	$ 0.1309	$ 0.1355
	Amount SMUD lower than PG&E	$0.0069	$0.0073	$0.0077	$0.0086	$0.0092	$0.0097	$0.0100	$0.0104	$0.0116	$0.0117	$0.0134	$0.0132
	Percentage SMUD lower than PG&E	6.26%	6.52%	6.64%	7.21%	7.54%	7.71%	7.73%	7.85%	8.49%	8.33%	9.29%	8.87%
22	Franchise Fees	$0.0015	$0.0016	$0.0016	$0.0017	$0.0017	$0.0017	$0.0018	$0.0018	$0.0019	$0.0019	$0.0020	$0.0020
23	Property Taxes	$0.0012	$0.0013	$0.0013	$0.0013	$0.0014	$0.0014	$0.0014	$0.0015	$0.0015	$0.0015	$0.0015	$0.0016
	Average All Cities Rates including surcharge ($/kWh)	$ 0.1074	$ 0.1091	$ 0.1122	$ 0.1138	$ 0.1165	$ 0.1196	$ 0.1230	$ 0.1264	$ 0.1287	$ 0.1328	$ 0.1344	$ 0.1395
	DWR Energy/Bond Costs/Reg Assets/CTC	-	-	-	-	-	-	-	-	-	-	-	-
24	Nuclear Decomissioning	0.0004	0.0004	0.0004	-	-	-	-	-	-	-	-	-
25	FTA	-	-	-	-	-	-	-	-	-	-	-	-
	Average All Cities Rates including Surcharge and Non-bypassat	**$ 0.1078**	**$ 0.1095**	**$ 0.1127**	**$ 0.1138**	**$ 0.1165**	**$ 0.1196**	**$ 0.1230**	**$ 0.1264**	**$ 0.1287**	**$ 0.1328**	**$ 0.1344**	**$ 0.1395**
	Amount All Cities lower than PG&E ($ / kwh)	0.0021	0.0031	0.0034	0.0049	0.0056	0.0060	0.0062	0.0066	0.0079	0.0078	0.0099	0.0093
	Revenue All Cities lower than PG&E ($ in millions)	$3,159	$4,725	$5,232	$7,771	$8,989	$9,894	$10,397	$11,195	$13,704	$13,732	$17,661	$16,846
	Percentage All Cities lower than PG&E	1.92%	2.76%	2.91%	4.14%	4.56%	4.79%	4.81%	4.95%	5.80%	5.55%	6.85%	6.23%
	Real Surcharge	$ 0.0048	$ 0.0042	$ 0.0043	$ 0.0037	$ 0.0036	$ 0.0037	$ 0.0038	$ 0.0039	$ 0.0037	$ 0.0039	$ 0.0035	$ 0.0039
	Smoothed Surcharge	$ 0.0101	$ 0.0101	$ 0.0101	$ 0.0101	$ 0.0101	$ 0.0101	$ 0.0101	$ 0.0101	$ 0.0101	$ 0.0101	$ 0.0101	$ 0.0101

Assumptions:

1 Inflation rate is based on March, 2004 Blue Chip Consensus long-term rate indicator.

2 Load growth projections through 2009 for West Sacramento, Davis and Woodland are based on PGE's forecast from "1SMUD-Q3-yolo.xls" file, from 2010 through 2016, they are based on a three year moving average with the current yaer reading of Sacramento Area Council of Government's (SACOG) housing projections for each city dated 3/15/2001, and from 2017 on they are only based on SACOG projections. The load projection for Yolo is based only on SACOG's housing projections of Unincorporated Yolo County.Yolo County load is based on typical hour load data provided by PG&E and updated with the latest information on the large commercial customers.

3 Load by region for 2003 is based on PGE's "Rate comparison using PG&E Proposed Phase 2 Rates" file.

4 Losses are assumed to be 8%.

5 SMUD currently supplies 90% of its energy requirement through conventional resources and plans to decrease this amount gradually to 80% by 2011.

6 SMUD currently supplies 10% of its energy requirement through renewable resources and plans to increase this amount gradually to 20% by 2011.

7 On-peak and off-peak market price projections from 2005 through 2018 are provided by SMUD. The average market price per annum is calculated based on the typical weekday and weekend load shape data provided by PG&E for each city. Market price projections are carried forward with five year moving averages thereafter.

8 Market prices shown on this proforma are manipulated to reflect SMUD's costs based on their retail price projections. SMUD is assumed to gradually integrate this new load into its current resource planning starting in year 2014. The integration is assumed to be completed by 2017. Hence, the market price projections are melded with the the gas price index starting from 2014. Starting in year 2017, the projections are only based on the trend in the Gas price index as SMUD's retail rate projections.

9 Based on its current experience, SMUD estimates the renewable resource costs to be 10% higher than the market price projections.

10 DWR costs are capped at 2.7 cents per kWh and assumed to include DWR power charges, bond costs, regulatory assets and the post transition period CTC charges.

11 O&M and A&G for tranmission and distribution costs are based on SMUD's operations at 14.3 $ / MWh and inflated at the inflation rate thereafter.

12 Ancillary Services charges are provided by SMUD and assumed to be 10% of the market price projections.

13 System average retail rate projections for year 2004 and 2005 are provided by SMUD.

14 SMUD estimates the Direct Access revenues to be 5 cents/kWh for the initial year and it escalates at the rate of inflation thereafter.

15 SMUD's power supply cost for the annexed region is calculated at market price rates.

16 SMUD's power supply cost of renewable resources for the annexed region is calculated at renewable price projection.

17 O&M and A&G for tranmission and distribution costs are based on SMUD's operations at 14.3 $ / MWh and inflated at the inflation rate thereafter.

18 SMUD estimates a cost of .001 cents/kWh for meeting the planning reserve requirement and follow the trend in conventional power supply cost of SMUD.

19 Public Purpose Programs are calculated to be at 3.17% of the retail revenues based on SMUD's 2004 proposed budget.

20 Federally taxable debt service requirement includes all the capital investment costs for Transmission and Distibution Annexation in 2008 and real estate acquisitions, debt service reserve equal to the principal and interest payment for one year, the cost of issuance (1.5% of total debt), and the severance cost of 1% of the total capital investment.

21 Federally non-taxable debt service requirement includes all the capital investment costs for new customers each year, renewals and replacement costs, additional tranmission investment required in 2013, debt service reserve equal to the principal and interest payment for one year, the cost of issuance (1.5% of total debt), revenue requirement for 45 days, and the litigation cost of 20% of the total capital investment.

22 Franchise fees are calculated at 1.5% of the retail revenues

23 Property tax is calculated at 3.16% based on PG&E 's distribution revenue requirement from its GRC model.

24 Nuclear Decommissioning cost is allocated based on PG&E's proposed GRC- Phase 2. It is allocated to each rate class at the same rate of 0.024 cents /kWh) based on the latest rate schedules filed by PG&E. Nuclear Decommissioning cost is assumed to continue at the same rate through 2018.

25 FTA charges are allocated based on PG&E's proposed GRC - Phase 2 and terminate in 2008.These costs are applicable only to certain rates but at the same rate for all classes.

CASE 4 - WEST SACRAMENTO - CAISO OPTION

Municipalization Evaluation Model:Replacement Cost New Less Depreciation - Straight Line Approach / CAISO Option

		2004	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
	CUSTOMERS/LOAD																					
	Customers	18,917	20,794	21,264	21,862	22,496	23,195	23,938	24,729	25,564	26,333	27,126	27,942	28,783	29,650	30,522	31,419	32,299	33,203	34,133	35,088	36,071
2,3	Load (MWh)																					
	Bundled only																					
	Residential	92,163	101,304	103,594	106,511	109,596	113,001	116,622	120,479	124,544	128,293	132,154	136,132	140,230	144,450	148,697	153,069	157,355	161,761	166,290	170,946	175,733
	Commercial																					
	Small	45,691	50,223	51,358	52,805	54,334	56,022	57,817	59,729	61,744	63,603	65,517	67,489	69,521	71,613	73,719	75,886	78,011	80,195	82,441	84,749	87,122
	Medium	141,243	155,253	158,762	163,233	167,960	173,179	178,728	184,639	190,869	196,614	202,532	208,628	214,908	221,377	227,885	234,585	241,153	247,906	254,847	261,983	269,318
	Large	98,470	108,237	110,683	113,800	117,096	120,734	124,603	128,724	133,067	137,072	141,198	145,448	149,826	154,336	158,873	163,544	168,123	172,831	177,670	182,645	187,759
	Agricultural	4,646	5,107	5,222	5,369	5,525	5,696	5,879	6,073	6,278	6,467	6,662	6,862	7,069	7,282	7,496	7,716	7,932	8,154	8,383	8,617	8,858
	Other	2,126	2,337	2,390	2,457	2,528	2,607	2,690	2,779	2,873	2,960	3,049	3,140	3,235	3,332	3,430	3,531	3,630	3,732	3,836	3,944	4,054
	Direct Access	19,339	21,257	21,737	22,349	22,997	23,711	24,471	25,280	26,133	26,920	27,730	28,565	29,425	30,310	31,201	32,119	33,018	33,942	34,893	35,870	36,874
	Total Load at Meter	403,677	443,717	453,745	466,525	480,034	494,951	510,810	527,704	545,508	561,928	578,842	596,265	614,213	632,700	651,302	670,450	689,223	708,521	728,360	748,754	769,719
	Load Served (MWh)	384,338	422,460	432,008	444,176	457,037	471,239	486,339	502,424	519,375	535,008	551,112	567,700	584,788	602,390	620,101	638,331	656,205	674,578	693,467	712,884	732,844
4	Losses @8.0% (MWh)	30,747	33,797	34,561	35,534	36,563	37,699	38,907	40,194	41,550	42,801	44,089	45,416	46,783	48,191	49,608	51,067	52,496	53,966	55,477	57,031	58,628
	Energy Requirement	415,085	456,257	466,568	479,710	493,600	508,939	525,247	542,618	560,925	577,809	595,201	613,116	631,571	650,581	669,709	689,398	708,701	728,545	748,944	769,914	791,472
5	Conventional Energy	373,577	392,381	391,918	393,362	394,880	407,151	420,197	434,094	448,740	462,247	476,161	490,493	505,257	520,465	535,767	551,518	566,961	582,836	599,155	615,932	633,178
6	Renewable Energy	41,509	63,876	74,651	86,348	98,720	101,788	105,049	108,524	112,185	115,562	119,040	122,623	126,314	130,116	133,942	137,880	141,740	145,709	149,789	153,983	158,294
	PRICES ($/MWh)																					
7,8	Market Electricity	$ 44.15	$ 37.28	$ 38.22	$ 41.14	$ 44.68	$ 46.74	$ 51.68	$ 53.66	$ 54.86	$ 56.37	$ 57.22	$ 59.16	$ 59.88	$ 61.48	$ 63.34	$ 65.48	$ 67.58	$ 68.77	$ 71.46	$ 72.10	$ 75.42
9	Renewable Prices	48.56	41.00	42.04	45.26	49.15	51.42	56.85	59.02	60.34	62.01	62.94	65.08	65.87	67.63	69.67	72.03	74.33	75.65	78.60	79.31	82.96
10	DWR Bond Repayment	27.00	27.00	27.00	27.00	27.00	27.00	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Distribution O&M and A&G	12.30	13.44	13.77	14.10	14.42	14.75	15.09	15.44	15.80	16.16	16.53	16.91	17.30	17.70	18.10	18.52	18.95	19.38	19.83	20.28	20.75
12	ISO / TAC	4.28	4.67	4.79	4.90	5.01	5.13	5.25	5.37	5.49	5.62	5.75	5.88	6.01	6.15	6.29	6.44	6.59	6.74	6.89	7.05	7.21
13	Ancillary Services	4.77	4.03	4.13	4.44	4.83	5.05	5.58	5.80	5.92	6.09	6.18	6.39	6.47	6.64	6.84	7.07	7.30	7.43	7.72	7.79	8.15
14,15	**REVENUES ($000)**																					
	Residential	$ 8,352	$ 8,804	$ 9,051	$ 9,512	$ 10,104	$ 10,576	$ 11,346	$ 12,015	$ 12,706	$ 13,454	$ 14,163	$ 15,011	$ 15,728	$ 16,606	$ 17,555	$ 18,593	$ 19,646	$ 20,602	$ 21,852	$ 22,807	$ 24,281
	Commercial / Industrial																					
	Small	4,587	4,847	4,982	5,236	5,561	5,821	6,244	6,612	6,992	7,404	7,794	8,261	8,655	9,139	9,661	10,232	10,812	11,338	12,025	12,551	13,362
	Medium	12,542	13,089	13,457	14,143	15,023	15,726	16,870	17,864	18,892	20,004	21,059	22,320	23,385	24,691	26,101	27,645	29,212	30,633	32,491	33,911	36,103
	Large	7,346	7,749	7,968	8,376	8,899	9,316	9,994	10,583	11,192	11,851	12,476	13,223	13,854	14,628	15,463	16,378	17,306	18,148	19,249	20,090	21,389
	Agricultural	422	445	457	481	511	534	573	607	642	680	716	758	795	839	887	939	993	1,041	1,104	1,152	1,227
	Other	182	200	205	216	229	240	257	273	288	305	321	341	357	377	398	422	446	468	496	518	551
	Direct Access	967	1,162	1,217	1,281	1,348	1,422	1,501	1,587	1,678	1,768	1,863	1,964	2,069	2,181	2,296	2,418	2,543	2,674	2,813	2,958	3,111
	Total Revenues	$ 34,399	$ 36,295	$ 37,337	$ 39,244	$ 41,676	$ 43,635	$ 46,785	$ 49,540	$ 52,389	$ 55,465	$ 58,392	$ 61,878	$ 64,843	$ 68,459	$ 72,362	$ 76,628	$ 80,958	$ 84,903	$ 90,030	$ 93,986	$ 100,025
	COST OF SERVICE ($000)																					
16	Power Supply (@market prices)	16,493	14,626	14,977	16,184	17,645	19,032	21,718	23,292	24,616	26,057	27,246	29,019	30,256	31,997	33,935	36,116	38,313	40,082	42,813	44,406	47,756
17	Renewable Power Supply(@renewable prices)	2,016	2,619	3,138	3,908	4,852	5,234	5,972	6,405	6,769	7,166	7,493	7,980	8,320	8,799	9,332	9,932	10,536	11,023	11,774	12,212	13,133
18	Distribution O&M and A&G	5,362	6,443	6,747	7,103	7,477	7,887	8,327	8,800	9,306	9,807	10,334	10,890	11,476	12,093	12,735	13,411	14,103	14,832	15,598	16,403	17,250
	ISO / TAC	1,644	1,975	2,068	2,177	2,292	2,417	2,552	2,697	2,852	3,006	3,167	3,338	3,517	3,706	3,903	4,110	4,323	4,546	4,781	5,027	5,287
	Ancillary Services	1,833	1,701	1,783	1,974	2,206	2,379	2,715	2,912	3,077	3,257	3,406	3,627	3,782	4,000	4,242	4,514	4,789	5,010	5,352	5,551	5,969
19	Planning Reserve	-	393	412	456	510	550	628	673	711	753	787	839	874	925	981	1,044	1,107	1,158	1,237	1,283	1,380
20	Public Purpose Programs	1,090	1,151	1,184	1,244	1,321	1,383	1,483	1,570	1,661	1,758	1,851	1,962	2,056	2,170	2,294	2,429	2,566	2,691	2,854	2,979	3,171
	Total Expenses	$ 28,438	$ 28,908	$ 30,309	$ 33,046	$ 36,303	$ 38,881	$ 43,394	$ 46,350	$ 48,992	$ 51,803	$ 54,284	$ 57,655	$ 60,281	$ 63,690	$ 67,422	$ 71,556	$ 75,738	$ 79,342	$ 84,408	$ 87,862	$ 93,946
	Net Revenues ($000)	$ 5,961	$ 7,388	$ 7,028	$ 6,198	$ 5,373	$ 4,754	$ 3,391	$ 3,190	$ 3,397	$ 3,663	$ 4,108	$ 4,224	$ 4,562	$ 4,769	$ 4,940	$ 5,072	$ 5,220	$ 5,561	$ 5,622	$ 6,124	$ 6,078
	DEBT SERVICE ($000)																					
21	Federally Taxable		$ 2,254	$ 2,254	$ 2,254	$ 2,254	$ 2,254	$ 2,254	$ 2,254	$ 2,254	$ 2,254	$ 2,254	$ 2,254	$ 2,254	$ 2,254	$ 2,254	$ 2,254	$ 2,254	$ 2,254	$ 2,254	$ 2,254	$ 2,254
22	Federally Non - Taxable		$ 939	$ 991	$ 1,117	$ 1,248	$ 1,393	$ 1,548	$ 1,714	$ 1,890	$ 2,058	$ 2,236	$ 2,421	$ 2,615	$ 2,818	$ 3,026	$ 3,244	$ 3,463	$ 3,692	$ 3,931	$ 4,182	$ 4,443
	Total Debt Service	$ -	$ 3,193	$ 3,245	$ 3,370	$ 3,502	$ 3,647	$ 3,802	$ 3,967	$ 4,144	$ 4,312	$ 4,490	$ 4,675	$ 4,869	$ 5,071	$ 5,280	$ 5,497	$ 5,716	$ 5,946	$ 6,185	$ 6,436	$ 6,697
	Net Income ($000)	$5,961	$4,195	$3,783	$2,827	$1,871	$1,106	($411)	($777)	($746)	($650)	($381)	($451)	($306)	($303)	($340)	($426)	($496)	($384)	($563)	($312)	($619)
	Bundled Customer Rates																					
	PG&E																					
	PG&E System Average	**$ 0.1192**	**$ 0.1143**	**$ 0.1123**	**$ 0.1067**	**$ 0.1099**	**$ 0.1126**	**$ 0.1020**	**$ 0.0995**	**$ 0.1022**	**$ 0.1054**	**$ 0.1081**	**$ 0.1114**	**$ 0.1141**	**$ 0.1174**	**$ 0.1208**	**$ 0.1244**	**$ 0.1281**	**$ 0.1316**	**$ 0.1356**	**$ 0.1392**	**$ 0.1435**
	SMUD																					
	Average SMUD Rates ($/kWh)	$ 0.0870	$ 0.0832	$ 0.0836	$ 0.0855	$ 0.0882	$ 0.0896	$ 0.0931	$ 0.0954	$ 0.0976	$ 0.1004	$ 0.1026	$ 0.1055	$ 0.1073	$ 0.1100	$ 0.1130	$ 0.1163	$ 0.1195	$ 0.1219	$ 0.1258	$ 0.1277	$ 0.1322
	Amount SMUD lower than PG&E	$0.0322	$0.0311	$0.0287	$0.0212	$0.0217	$0.0230	$0.0089	$0.0040	$0.0046	$0.0051	$0.0055	$0.0059	$0.0067	$0.0073	$0.0078	$0.0081	$0.0086	$0.0097	$0.0098	$0.0115	$0.0113
	Percentage SMUD lower than PG&E	27.02%	27.24%	25.54%	19.88%	19.74%	20.45%	8.71%	4.04%	4.48%	4.80%	5.09%	5.26%	5.88%	6.25%	6.47%	6.53%	6.69%	7.37%	7.25%	8.25%	7.87%
23	Franchise Fees	$0.0013	$0.0012	$0.0013	$0.0013	$0.0013	$0.0013	$0.0014	$0.0014	$0.0015	$0.0015	$0.0015	$0.0016	$0.0016	$0.0017	$0.0017	$0.0017	$0.0018	$0.0018	$0.0019	$0.0019	$0.0020
24	Property Taxes	$0.0008	$0.0009	$0.0009	$0.0010	$0.0010	$0.0010	$0.0010	$0.0010	$0.0011	$0.0011	$0.0011	$0.0011	$0.0012	$0.0012	$0.0012	$0.0012	$0.0013	$0.0013	$0.0013	$0.0014	$0.0014
	Average West Sacramento Rates including surcharge ($/kWh)	$ 0.0752	$ 0.0771	$ 0.0788	$ 0.0831	$ 0.0883	$ 0.0914	$ 0.0983	$ 0.1014	$ 0.1036	$ 0.1062	$ 0.1080	$ 0.1112	$ 0.1128	$ 0.1156	$ 0.1188	$ 0.1223	$ 0.1257	$ 0.1281	$ 0.1323	$ 0.1340	$ 0.1391
	DWR Energy/Bond Costs/Reg Assets/CTC	0.0270	0.0265	0.0264	0.0263	0.0261	0.0260	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
25	Nuclear Decomissioning	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	-	-	-	-	-	-	-	-	-
26	FTA	0.0030	0.0030	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Average West Sacramento Rates including Surcharge and Non-by	**$ 0.1056**	**$ 0.1070**	**$ 0.1056**	**$ 0.1098**	**$ 0.1148**	**$ 0.1178**	**$ 0.0987**	**$ 0.1018**	**$ 0.1040**	**$ 0.1066**	**$ 0.1084**	**$ 0.1116**	**$ 0.1128**	**$ 0.1156**	**$ 0.1188**	**$ 0.1223**	**$ 0.1257**	**$ 0.1281**	**$ 0.1323**	**$ 0.1340**	**$ 0.1391**
	Amount West Sacramento lower than PG&E ($ / kwh)		0.0073	0.0067	(0.0031)	(0.0049)	(0.0052)	0.0033	(0.0023)	(0.0018)	(0.0012)	(0.0003)	(0.0002)	0.0012	0.0017	0.0021	0.0021	0.0023	0.0035	0.0033	0.0052	0.0044
	Revenue West Sacramento lower than PG&E ($ in millions)		$3,078	$2,895	($1,387)	($2,223)	($2,464)	$1,617	($1,179)	($924)	($636)	($183)	($108)	$711	$1,050	$1,276	$1,350	$1,536	$2,386	$2,275	$3,703	$3,252
	Percentage West Sacramento lower than PG&E		6.37%	5.97%	-2.93%	-4.42%	-4.64%	3.26%	-2.36%	-1.74%	-1.13%	-0.31%	-0.17%	1.07%	1.49%	1.70%	1.70%	1.83%	2.69%	2.42%	3.73%	3.09%
	NPV through 2027 @ 6.0%		$6,453																			
	NPV through 2015 @ 6.0%		$489																			
	Assumed Debt ($000)		$ 30,211																			
	Real Surcharge		$ 0.0239	$ 0.0220	$ 0.0243	$ 0.0266	$ 0.0283	$ 0.0056	$ 0.0064	$ 0.0064	$ 0.0062	$ 0.0058	$ 0.0061	$ 0.0055	$ 0.0056	$ 0.0058	$ 0.0060	$ 0.0062	$ 0.0062	$ 0.0066	$ 0.0063	$ 0.0069
	Smoothed Surcharge		$ 0.0118	$ 0.0118	$ 0.0118	$ 0.0118	$ 0.0118	$ 0.0118	$ 0.0118	$ 0.0118	$ 0.0118	$ 0.0118	$ 0.0118	$ 0.0118	$ 0.0118	$ 0.0118	$ 0.0118	$ 0.0118	$ 0.0118	$ 0.0118	$ 0.0118	$ 0.0118
	Min		$ 0.0055																			
	Max		$ 0.0283																			

Assumptions:

1 Inflation rate is based on March, 2004 Blue Chip Consensus long-term rate indicator.

2 Load growth projections through 2009 for West Sacramento, Davis and Woodland are based on PGE's forecast from "1SMUD-Q3-yolo.xls" file, from 2010 through 2016, they are based on a three year moving average with the current yaer reading of Sacramento Area Council of Government's (SACOG) housing projections for each city dated 3/15/2001, and from 2017 on they are only based on SACOG projections. The load projection for Yolo is based only on SACOG's housing projections of Unincorporated Yolo County.Yolo County load is based on typical hour load data provided by PG&E and updated with the latest information on the large commercial customers.

3 Load by region for 2003 is based on PGE's "Rate comparison using PG&E Proposed Phase 2 Rates" file.

4 Losses are assumed to be 8%.

5 SMUD currently supplies 90% of its energy requirement through conventional resources and plans to decrease this amount gradually to 80% by 2011.

6 SMUD currently supplies 10% of its energy requirement through renewable resources and plans to increase this amount gradually to 20% by 2011.

7 On-peak and off-peak market price projections from 2005 through 2018 are provided by SMUD. The average market price per annum is calculated based on the typical weekday and weekend load shape data provided by PG&E for each city. Market price projections are carried forward with five year moving averages thereafter.

8 Market prices shown on this proforma are manipulated to reflect SMUD's costs based on their retail price projections. SMUD is assumed to gradually integrate this new load into its current resource planning starting in year 2014. The integration is assumed to be completed by 2017. Hence, the market price projections are melded with the the gas price index starting from 2014. Starting in year 2017, the projections are only based on the trend in the Gas price index as SMUD's retail rate projections.

9 Based on its current experience, SMUD estimates the renewable resource costs to be 10% higher than the market price projections.

10 DWR costs are capped at 2.7 cents per kWh and assumed to include DWR power charges, bond costs, regulatory assets and the post transition period CTC charges.

11 O&M and A&G for distribution costs are based on SMUD's operations at 12.3 $ / MWh and inflated at the inflation rate thereafter.

12 ISO / TAC is based on ISO charges which is estimated at $3.7698 per MWh for year 2004 and escalated at the inflation rate thereafter.

13 Ancillary Services charges are provided by SMUD and assumed to be 10% of the market price projections.

14 System average retail rate projections for year 2004 and 2005 are provided by SMUD.

15 SMUD estimates the Direct Access revenues to be 5 cents/kWh for the initial year and it escalates at the rate of inflation thereafter.

16 SMUD's power supply cost for the annexed region is calculated at market price rates.

17 SMUD's power supply cost of renewable resources for the annexed region is calculated at renewable price projection.

18 O&M and A&G for distribution costs are based on SMUD's operations at 12.3 $ / MWh and inflated at the inflation rate thereafter.

19 SMUD estimates a cost of .001 cents/kWh for meeting the planning reserve requirement and follow the trend in conventional power supply cost of SMUD.

20 Public Purpose Programs are calculated to be at 3.17% of the retail revenues based on SMUD's 2004 proposed budget.

21 Federally taxable debt service requirement includes all the capital investment costs for Distibution Annexation in 2008, debt service reserve equal to the principal and interest payment for one year, the cost of issuance (1.5% of total debt), and the severance cost of 1% of the total capital investment.

22 Federally non-taxable debt service requirement includes all the capital investment costs for new customers each year, renewals and replacement costs, debt service reserve equal to the principal and interest payment for one year, the cost of issuance (1.5% of total debt), revenue requirement for 45 days, and the litigation cost of 20% of the total capital investment.

23 Franchise fees are calculated at 1.5% of the retail revenues

24 Property tax is calculated at 3.16% based on PG&E 's distribution revenue requirement from its GRC model.

25 Nuclear Decommissioning cost is allocated based on PG&E's proposed GRC- Phase 2. It is allocated to each rate class at the same rate of 0.024 cents /kWh) based on the latest rate schedules filed by PG&E. Nuclear Decommissioning cost is assumed to continue at the same rate through 2018.

26 FTA charges are allocated based on PG&E's proposed GRC - Phase 2 and terminate in 2008.These costs are applicable only to certain rates but at the same rate for all classes.

CASE 5 - DAVIS - CAISO OPTION

Municipalization Evaluation Model:Replacement Cost New Less Depreciation - Straight Line Approach / CAISO Option

		2004	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
	CUSTOMERS/LOAD																					
	Customers	36,514	39,134	39,760	40,265	40,714	41,103	41,453	41,769	42,060	42,250	42,440	42,631	42,822	43,015	43,200	43,386	43,572	43,760	43,948	44,137	44,327
2,3	Load (MWh)																					
	Bundled only																					
	Residential	163,469	175,198	178,001	180,262	182,275	184,017	185,582	186,996	188,301	189,148	189,999	190,854	191,713	192,576	193,404	194,236	195,071	195,910	196,752	197,598	198,448
	Commercial																					
	Small	34,013	36,453	37,036	37,507	37,926	38,288	38,614	38,908	39,179	39,356	39,533	39,711	39,889	40,069	40,241	40,414	40,588	40,763	40,938	41,114	41,291
	Medium	61,495	65,907	66,962	67,812	68,569	69,224	69,813	70,345	70,836	71,155	71,475	71,797	72,120	72,444	72,756	73,069	73,383	73,698	74,015	74,334	74,653
	Large	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Agricultural	1,495	1,602	1,628	1,649	1,667	1,683	1,697	1,710	1,722	1,730	1,738	1,745	1,753	1,761	1,769	1,776	1,784	1,792	1,799	1,807	1,815
	Other	2,443	2,618	2,660	2,694	2,724	2,750	2,773	2,794	2,814	2,826	2,839	2,852	2,865	2,878	2,890	2,902	2,915	2,927	2,940	2,953	2,965
	Direct Access	26,466	29,091	29,748	30,586	31,472	32,450	33,490	34,597	35,764	36,841	37,950	39,092	40,269	41,481	42,700	43,956	45,187	46,452	47,752	49,090	50,464
	Total Load at Meter	289,379	310,869	316,035	320,509	324,632	328,411	331,969	335,351	338,617	341,056	343,534	346,051	348,609	351,209	353,760	356,353	358,927	361,542	364,197	366,895	369,636
	Load Served (MWh)	262,914	281,779	286,287	289,923	293,160	295,962	298,480	300,754	302,852	304,215	305,584	306,959	308,341	309,728	311,060	312,398	313,741	315,090	316,445	317,806	319,172
4	Losses @8.0% (MWh)	21,033	22,542	22,903	23,194	23,453	23,677	23,878	24,060	24,228	24,337	24,447	24,557	24,667	24,778	24,885	24,992	25,099	25,207	25,316	25,424	25,534
	Energy Requirement	283,947	304,321	309,190	313,117	316,613	319,639	322,358	324,815	327,081	328,552	330,031	331,516	333,008	334,506	335,945	337,389	338,840	340,297	341,760	343,230	344,706
5	Market purchases	255,552	261,716	259,720	256,756	253,291	255,711	257,886	259,852	261,664	262,842	264,025	265,213	266,406	267,605	268,756	269,911	271,072	272,238	273,408	274,584	275,765
6	Renewable Market purchases	28,395	42,605	49,470	56,361	63,323	63,928	64,472	64,963	65,416	65,710	66,006	66,303	66,602	66,901	67,189	67,478	67,768	68,059	68,352	68,646	68,941
	PRICES ($/MWh)																					
7,8	Market Electricity	$ 44.15	$ 37.28	$ 38.22	$ 41.14	$ 44.68	$ 46.74	$ 51.68	$ 53.66	$ 54.86	$ 56.37	$ 57.22	$ 59.16	$ 59.88	$ 61.48	$ 63.34	$ 65.48	$ 67.58	$ 68.77	$ 71.46	$ 72.10	$ 75.42
9	Renewable Prices	48.56	41.00	42.04	45.26	49.15	51.42	56.85	59.02	60.34	62.01	62.94	65.08	65.87	67.63	69.67	72.03	74.33	75.65	78.60	79.31	82.96
10	DWR Bond Repayment	17.27	17.27	17.27	17.27	17.27	17.27	5.97	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Distribution O&M & A&G	12.30	13.44	13.77	14.10	14.42	14.75	15.09	15.44	15.80	16.16	16.53	16.91	17.30	17.70	18.10	18.52	18.95	19.38	19.83	20.28	20.75
12	ISO / TAC	4.48	4.91	5.03	5.16	5.29	5.42	5.56	5.70	5.85	6.00	6.15	6.31	6.47	6.64	6.82	6.99	7.17	7.36	7.55	7.75	7.95
13	Ancillary Services	4.77	4.03	4.13	4.44	4.83	5.05	5.58	5.80	5.92	6.09	6.18	6.39	6.47	6.64	6.84	7.07	7.30	7.43	7.72	7.79	8.15
14,15	**REVENUES ($000)**																					
	Residential	$ 14,468	$ 14,871	$ 15,190	$ 15,724	$ 16,414	$ 16,823	$ 17,635	$ 18,215	$ 18,764	$ 19,375	$ 19,890	$ 20,557	$ 21,003	$ 21,624	$ 22,302	$ 23,045	$ 23,790	$ 24,372	$ 25,254	$ 25,750	$ 26,783
	Commercial / Industrial																					
	Small	3,415	3,518	3,593	3,719	3,882	3,978	4,170	4,307	4,437	4,581	4,703	4,861	4,966	5,113	5,274	5,449	5,625	5,763	5,972	6,089	6,333
	Medium	5,461	5,556	5,676	5,875	6,133	6,286	6,589	6,806	7,011	7,239	7,432	7,681	7,848	8,080	8,333	8,611	8,889	9,107	9,436	9,622	10,008
	Large	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Agricultural	136	140	143	148	154	158	165	171	176	182	187	193	197	203	209	216	223	229	237	242	251
	Other	210	224	229	237	247	253	265	274	282	292	299	309	316	325	336	347	358	367	380	387	403
	Direct Access	1,323	1,590	1,665	1,753	1,845	1,946	2,055	2,172	2,296	2,420	2,550	2,687	2,832	2,984	3,143	3,309	3,480	3,660	3,849	4,048	4,257
	Total Revenues	$ 25,012	$ 25,899	$ 26,495	$ 27,456	$ 28,675	$ 29,444	$ 30,880	$ 31,945	$ 32,967	$ 34,089	$ 35,060	$ 36,289	$ 37,162	$ 38,330	$ 39,597	$ 40,978	$ 42,366	$ 43,497	$ 45,128	$ 46,138	$ 48,035
	COST OF SERVICE ($000)																					
16	Power Supply (@market prices)	11,282	9,756	9,925	10,564	11,318	11,953	13,329	13,943	14,354	14,816	15,107	15,691	15,953	16,452	17,023	17,675	18,318	18,722	19,537	19,796	20,799
17	Renewable Power Supply(@renewable prices)	1,379	1,747	2,080	2,551	3,113	3,287	3,665	3,834	3,947	4,074	4,155	4,315	4,387	4,524	4,681	4,861	5,037	5,149	5,373	5,444	5,720
18	Distribution O&M & A&G	3,844	4,514	4,699	4,880	5,056	5,233	5,411	5,592	5,777	5,952	6,133	6,320	6,513	6,713	6,917	7,128	7,345	7,568	7,799	8,038	8,284
	ISO / TAC	1,178	1,383	1,440	1,496	1,550	1,604	1,659	1,714	1,770	1,824	1,880	1,937	1,996	2,057	2,120	2,185	2,251	2,320	2,390	2,463	2,539
	Ancillary Services	1,254	1,134	1,182	1,288	1,415	1,494	1,666	1,743	1,794	1,852	1,888	1,961	1,994	2,056	2,128	2,209	2,290	2,340	2,442	2,475	2,600
19	Planning Reserve	-	262	273	298	327	345	385	403	415	428	437	454	461	476	492	511	529	541	565	572	601
20	Public Purpose Programs	793	821	840	870	909	933	979	1,013	1,045	1,081	1,111	1,150	1,178	1,215	1,255	1,299	1,343	1,379	1,431	1,463	1,523
	Total Expenses	$ 19,730	$ 19,618	$ 20,439	$ 21,947	$ 23,688	$ 24,850	$ 27,094	$ 28,242	$ 29,102	$ 30,028	$ 30,711	$ 31,828	$ 32,483	$ 33,493	$ 34,616	$ 35,867	$ 37,113	$ 38,019	$ 39,536	$ 40,251	$ 42,065
	Net Revenues ($000)	$ 5,282	$ 6,281	$ 6,056	$ 5,509	$ 4,988	$ 4,595	$ 3,786	$ 3,703	$ 3,865	$ 4,061	$ 4,349	$ 4,460	$ 4,679	$ 4,837	$ 4,980	$ 5,111	$ 5,252	$ 5,478	$ 5,592	$ 5,887	$ 5,970
	DEBT SERVICE ($000)																					
21	Federally Taxable		$ 2,625	$ 2,625	$ 2,625	$ 2,625	$ 2,625	$ 2,625	$ 2,625	$ 2,625	$ 2,625	$ 2,625	$ 2,625	$ 2,625	$ 2,625	$ 2,625	$ 2,625	$ 2,625	$ 2,625	$ 2,625	$ 2,625	$ 2,625
22	Federally Non - Taxable		$ 692	$ 809	$ 940	$ 1,067	$ 1,185	$ 1,300	$ 1,412	$ 1,522	$ 1,614	$ 1,710	$ 1,808	$ 1,909	$ 2,012	$ 2,116	$ 2,222	$ 2,331	$ 2,443	$ 2,557	$ 2,675	$ 2,795
	Total Debt Service	$ -	$ 3,317	$ 3,433	$ 3,565	$ 3,691	$ 3,810	$ 3,925	$ 4,036	$ 4,146	$ 4,238	$ 4,334	$ 4,432	$ 4,533	$ 4,636	$ 4,740	$ 4,847	$ 4,956	$ 5,067	$ 5,182	$ 5,299	$ 5,420
	Net Income ($000)	$5,282	$2,964	$2,622	$1,944	$1,296	$785	($139)	($334)	($282)	($178)	$15	$28	$146	$200	$240	$264	$297	$411	$410	$588	$550
	Bundled Customer Rates																					
	PG&E																					
	PG&E System Average	**$ 0.1272**	**$ 0.1241**	**$ 0.1196**	**$ 0.1146**	**$ 0.1179**	**$ 0.1207**	**$ 0.1100**	**$ 0.1079**	**$ 0.1108**	**$ 0.1141**	**$ 0.1170**	**$ 0.1204**	**$ 0.1232**	**$ 0.1267**	**$ 0.1303**	**$ 0.1340**	**$ 0.1379**	**$ 0.1416**	**$ 0.1458**	**$ 0.1495**	**$ 0.1541**
	SMUD																					
	Average SMUD Rates ($/kWh)	$ 0.0901	$ 0.0863	$ 0.0867	$ 0.0887	$ 0.0915	$ 0.0929	$ 0.0966	$ 0.0990	$ 0.1013	$ 0.1041	$ 0.1064	$ 0.1095	$ 0.1113	$ 0.1141	$ 0.1172	$ 0.1206	$ 0.1239	$ 0.1264	$ 0.1304	$ 0.1324	$ 0.1372
	Amount SMUD lower than PG&E	$0.0371	$0.0379	$0.0328	$0.0259	$0.0264	$0.0278	$0.0135	$0.0089	$0.0095	$0.0100	$0.0106	$0.0110	$0.0119	$0.0126	$0.0131	$0.0134	$0.0139	$0.0152	$0.0153	$0.0171	$0.0169
	Percentage SMUD lower than PG&E	29.16%	30.51%	27.46%	22.62%	22.36%	23.04%	12.23%	8.23%	8.59%	8.79%	9.04%	9.11%	9.64%	9.92%	10.05%	10.03%	10.11%	10.71%	10.50%	11.43%	10.97%
23	Franchise Fees	$0.0014	$0.0013	$0.0013	$0.0013	$0.0014	$0.0014	$0.0014	$0.0015	$0.0015	$0.0016	$0.0016	$0.0016	$0.0017	$0.0017	$0.0018	$0.0018	$0.0019	$0.0019	$0.0020	$0.0020	$0.0021
24	Property Taxes	$0.0012	$0.0013	$0.0013	$0.0014	$0.0014	$0.0014	$0.0014	$0.0015	$0.0015	$0.0015	$0.0016	$0.0016	$0.0016	$0.0017	$0.0017	$0.0017	$0.0018	$0.0018	$0.0019	$0.0019	$0.0019
	Average Davis Rates including surcharge ($/kWh)	$ 0.0757	$ 0.0819	$ 0.0838	$ 0.0884	$ 0.0938	$ 0.0971	$ 0.1042	$ 0.1075	$ 0.1099	$ 0.1127	$ 0.1147	$ 0.1181	$ 0.1199	$ 0.1228	$ 0.1262	$ 0.1299	$ 0.1335	$ 0.1361	$ 0.1405	$ 0.1424	$ 0.1477
	DWR Energy/Bond Costs/Reg Assets/CTC	0.0173	0.0173	0.0173	0.0173	0.0173	0.0173	0.0060	-	-	-	-	-	-	-	-	-	-	-	-	-	-
25	Nuclear Decomissioning	0.0005	0.0005	0.0005	0.0005	0.0005	0.0005	0.0005	0.0005	0.0005	0.0005	0.0005	0.0005	-	-	-	-	-	-	-	-	-
26	FTA	0.0060	0.0060	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Average Davis Rates including Surcharge and Non-bypassable ch	**$ 0.0994**	**$ 0.1056**	**$ 0.1015**	**$ 0.1061**	**$ 0.1115**	**$ 0.1149**	**$ 0.1106**	**$ 0.1080**	**$ 0.1104**	**$ 0.1132**	**$ 0.1151**	**$ 0.1185**	**$ 0.1199**	**$ 0.1228**	**$ 0.1262**	**$ 0.1299**	**$ 0.1335**	**$ 0.1361**	**$ 0.1405**	**$ 0.1424**	**$ 0.1477**
	Amount Davis lower than PG&E ($ / kWh)		0.0185	0.0180	0.0084	0.0064	0.0058	(0.0006)	(0.0001)	0.0004	0.0010	0.0018	0.0019	0.0033	0.0038	0.0041	0.0042	0.0043	0.0055	0.0052	0.0071	0.0063
	Revenue Davis lower than PG&E ($ in millions)		$5,225	$5,157	$2,449	$1,872	$1,730	($180)	($38)	$121	$290	$555	$589	$1,028	$1,189	$1,284	$1,297	$1,364	$1,742	$1,655	$2,270	$2,020
	Percentage Davis lower than PG&E		14.94%	15.07%	7.37%	5.42%	4.84%	-0.55%	-0.12%	0.36%	0.84%	1.55%	1.59%	2.71%	3.03%	3.17%	3.10%	3.15%	3.91%	3.59%	4.78%	4.11%
	NPV through 2027 @ 6.0%		$20,389																			
	NPV through 2015 @ 6.0%		$14,276																			
	Assumed Debt ($000)		$ 35,180																			
	Real Surcharge		$ 0.0193	$ 0.0148	$ 0.0175	$ 0.0200	$ 0.0220	$ 0.0141	$ 0.0090	$ 0.0091	$ 0.0091	$ 0.0088	$ 0.0090	$ 0.0085	$ 0.0087	$ 0.0090	$ 0.0093	$ 0.0096	$ 0.0096	$ 0.0101	$ 0.0100	$ 0.0106
	Smoothed Surcharge		$ 0.0128	$ 0.0128	$ 0.0128	$ 0.0128	$ 0.0128	$ 0.0128	$ 0.0128	$ 0.0128	$ 0.0128	$ 0.0128	$ 0.0128	$ 0.0128	$ 0.0128	$ 0.0128	$ 0.0128	$ 0.0128	$ 0.0128	$ 0.0128	$ 0.0128	$ 0.0128
	Min		$ 0.0085																			
	Max		$ 0.0220																			

Assumptions:

1 Inflation rate is based on March, 2004 Blue Chip Consensus long-term rate indicator.

2 Load growth projections through 2009 for West Sacramento, Davis and Woodland are based on PGE's forecast from "1SMUD-Q3-yolo.xls" file, from 2010 through 2016, they are based on a three year moving average with the current yaer reading of Sacramento Area Council of Government's (SACOG) housing projections for each city dated 3/15/2001, and from 2017 on they are only based on SACOG projections. The load projection for Yolo is based only on SACOG's housing projections of Unincorporated Yolo County.Yolo County load is based on typical hour load data provided by PG&E and updated with the latest information on the large commercial customers.

3 Load by region for 2003 is based on PGE's "Rate comparison using PG&E Proposed Phase 2 Rates" file.

4 Losses are assumed to be 8%.

5 SMUD currently supplies 90% of its energy requirement through conventional resources and plans to decrease this amount gradually to 80% by 2011.

6 SMUD currently supplies 10% of its energy requirement through renewable resources and plans to increase this amount gradually to 20% by 2011.

7 On-peak and off-peak market price projections from 2005 through 2018 are provided by SMUD. The average market price per annum is calculated based on the typical weekday and weekend load shape data provided by PG&E for each city. Market price projections are carried forward with five year moving averages thereafter.

8 Market prices shown on this proforma are manipulated to reflect SMUD's costs based on their retail price projections. SMUD is assumed to gradually integrate this new load into its current resource planning starting in year 2014. The integration is assumed to be completed by 2017. Hence, the market price projections are melded with the the gas price index starting from 2014. Starting in year 2017, the projections are only based on the trend in the Gas price index as SMUD's retail rate projections.

9 Based on its current experience, SMUD estimates the renewable resource costs to be 10% higher than the market price projections.

10 Although DWR costs are capped at 2.7 cents per kWh and assumed to include DWR power charges, bond costs, regulatory assets and the post transition period CTC charges Davis is assumed to be exempt from these charges with regards to Bill XXX.

11 O&M and A&G for distribution costs are based on SMUD's operations at 12.3 $ / MWh and inflated at the inflation rate thereafter.

12 ISO / TAC is based on ISO charges which is estimated at $3.7698 per MWh for year 2004 and escalated at the inflation rate thereafter.

13 Ancillary Services charges are provided by SMUD and assumed to be 10% of the market price projections.

14 System average retail rate projections for year 2004 and 2005 are provided by SMUD.

15 SMUD estimates the Direct Access revenues to be 5 cents/kWh for the initial year and it escalates at the rate of inflation thereafter.

16 SMUD's power supply cost for the annexed region is calculated at market price rates.

17 SMUD's power supply cost of renewable resources for the annexed region is calculated at renewable price projection.

18 O&M and A&G for distribution costs are based on SMUD's operations at 12.3 $ / MWh and inflated at the inflation rate thereafter.

19 SMUD estimates a cost of .001 cents/kWh for meeting the planning reserve requirement and follow the trend in conventional power supply cost of SMUD.

20 Public Purpose Programs are calculated to be at 3.17% of the retail revenues based on SMUD's 2004 proposed budget.

21 Federally taxable debt service requirement includes all the capital investment costs for Distibution Annexation in 2008, debt service reserve equal to the principal and interest payment for one year, the cost of issuance (1.5% of total debt), and the severance cost of 1% of the total capital investment.

22 Federally non-taxable debt service requirement includes all the capital investment costs for new customers each year, renewals and replacement costs, debt service reserve equal to the principal and interest payment for one year, the cost of issuance (1.5% of total debt), revenue requirement for 45 days, and the litigation cost of 20% of the total capital investment.

23 Franchise fees are calculated at 1.5% of the retail revenues

24 Property tax is calculated at 3.16% based on PG&E 's distribution revenue requirement from its GRC model.

25 Nuclear Decommissioning cost is allocated based on PG&E's proposed GRC- Phase 2. It is allocated to each rate class at the same rate of 0.024 cents /kWh) based on the latest rate schedules filed by PG&E. Nuclear Decommissioning cost is assumed to continue at the same rate through 2018.

26 FTA charges are allocated based on PG&E's proposed GRC - Phase 2 and terminate in 2008.These costs are applicable only to certain rates but at the same rate for all classes.

CASE 6 - WOODLAND & YOLO UNINCORPORATED - CAISO OPTION

Municipalization Evaluation Model:Replacement Cost New Less Depreciation - Straight Line Approach / CAISO Option

		2004	2008	2009	2010	2011	2012	2013	2014	2015
	CUSTOMERS/LOAD									
	Customers	26,826	28,751	29,211	29,689	30,166	30,651	31,140	31,637	32,140
2,3	Load (MWh)									
	Bundled only									
	Residential	196,360	210,247	213,568	216,994	220,408	223,879	227,390	230,951	234,563
	Commercial									
	Small	62,207	66,608	67,661	68,747	69,829	70,930	72,043	73,172	74,317
	Medium	154,190	165,089	167,696	170,384	173,063	175,786	178,541	181,336	184,170
	Large	86,828	92,993	94,468	95,992	97,511	99,055	100,617	102,201	103,807
	Agricultural	35,869	38,334	38,924	39,524	40,121	40,726	41,342	41,966	42,600
	Other	2,273	2,435	2,474	2,514	2,554	2,595	2,636	2,678	2,721
	Direct Access	29,329	32,239	32,967	33,896	34,877	35,961	37,113	38,341	39,634
	Total Load at Meter	567,056	607,944	617,758	628,050	638,363	648,932	659,681	670,645	681,811
	Load Served (MWh)	537,727	575,706	584,790	594,154	603,486	612,971	622,568	632,304	642,177
4	Losses @8.0% (MWh)	43,018	46,056	46,783	47,532	48,279	49,038	49,805	50,584	51,374
	Energy Requirement	580,745	621,762	631,574	641,687	651,765	662,009	672,373	682,889	693,551
5	Market purchases	522,671	534,716	530,522	526,183	521,412	529,607	537,899	546,311	554,841
6	Renewable Market purchases	58,075	87,047	101,052	115,504	130,353	132,402	134,475	136,578	138,710
	PRICES ($/MWh)									
7,8	Market Electricity	$ 44.15	$ 37.28	$ 38.22	$ 41.14	$ 44.68	$ 46.74	$ 51.68	$ 53.66	$ 54.86
9	Renewable Prices	48.56	41.00	42.04	45.26	49.15	51.42	56.85	59.02	60.34
10	DWR Bond Repayment	27.00	27.00	27.00	27.00	27.00	27.00	-	-	-
11	Distribution O&M & A&G	12.30	13.44	13.77	14.10	14.42	14.75	15.09	15.44	15.80
12	ISO / TAC	4.29	4.70	4.81	4.93	5.05	5.17	5.29	5.42	5.55
13	Ancillary Services	4.77	4.03	4.13	4.44	4.83	5.05	5.58	5.80	5.92
14,15	**REVENUES ($000)**									
	Residential	$ 18,930	$ 19,435	$ 19,846	$ 20,609	$ 21,608	$ 22,281	$ 23,522	$ 24,489	$ 25,443
	Commercial / Industrial									
	Small	6,246	6,428	6,564	6,816	7,147	7,370	7,780	8,100	8,416
	Medium	13,692	13,918	14,214	14,762	15,480	15,962	16,852	17,545	18,229
	Large	6,477	6,657	6,800	7,065	7,411	7,643	8,070	8,403	8,731
	Agricultural	3,257	3,339	3,409	3,538	3,707	3,821	4,031	4,195	4,356
	Other	195	208	213	221	232	239	252	263	273
	Direct Access	1,466	1,762	1,845	1,943	2,045	2,157	2,277	2,407	2,545
	Total Revenues	$ 50,263	$ 51,748	$ 52,890	$ 54,954	$ 57,630	$ 59,473	$ 62,785	$ 65,400	$ 67,992
	COST OF SERVICE ($000)									
16	Power Supply (@market prices)	23,075	19,932	20,274	21,649	23,299	24,756	27,801	29,314	30,436
17	Renewable Power Supply(@renewable prices)	2,820	3,569	4,248	5,227	6,407	6,808	7,645	8,061	8,370
18	Distribution O&M & A&G	7,533	8,828	9,185	9,563	9,943	10,340	10,753	11,183	11,631
	ISO / TAC	2,309	2,706	2,815	2,931	3,047	3,169	3,296	3,428	3,565
	Ancillary Services	2,564	2,318	2,414	2,640	2,912	3,094	3,475	3,664	3,804
19	Planning Reserve	-	536	558	610	673	716	804	847	880
20	Public Purpose Programs	1,593	1,640	1,677	1,742	1,827	1,885	1,990	2,073	2,155
	Total Expenses	$ 39,894	$ 39,528	$ 41,171	$ 44,362	$ 48,110	$ 50,768	$ 55,764	$ 58,571	$ 60,841
	Net Revenues ($000)	$ 10,369	$ 12,220	$ 11,719	$ 10,592	$ 9,520	$ 8,705	$ 7,020	$ 6,829	$ 7,151
	DEBT SERVICE ($000)									
21	Federally Taxable		$ 2,579	$ 2,579	$ 2,579	$ 2,579	$ 2,579	$ 2,579	$ 2,579	$ 2,579
22	Federally Non - Taxable		$ 1,329	$ 1,367	$ 1,486	$ 1,606	$ 1,731	$ 1,859	$ 1,991	$ 2,128
	Total Debt Service	$ -	$ 3,908	$ 3,946	$ 4,064	$ 4,185	$ 4,310	$ 4,438	$ 4,570	$ 4,706
	Net Income ($000)	$10,369	$8,312	$7,773	$6,528	$5,335	$4,395	$2,583	$2,259	$2,445
	Bundled Customer Rates									
	PG&E									
	PG&E System Average	**$ 0.1256**	**$ 0.1214**	**$ 0.1184**	**$ 0.1129**	**$ 0.1162**	**$ 0.1190**	**$ 0.1079**	**$ 0.1054**	**$ 0.1083**
	SMUD									
	Average SMUD Rates ($/kWh)	$ 0.0907	$ 0.0868	$ 0.0873	$ 0.0892	$ 0.0921	$ 0.0935	$ 0.0972	$ 0.0996	$ 0.1019
	Amount SMUD lower than PG&E	$0.0349	$0.0345	$0.0311	$0.0236	$0.0241	$0.0255	$0.0107	$0.0058	$0.0064
	Percentage SMUD lower than PG&E	27.77%	28.45%	26.26%	20.95%	20.76%	21.45%	9.95%	5.52%	5.93%
23	Franchise Fees	$0.0014	$0.0013	$0.0013	$0.0013	$0.0014	$0.0014	$0.0015	$0.0015	$0.0015
24	Property Taxes	$0.0009	$0.0011	$0.0011	$0.0011	$0.0011	$0.0011	$0.0012	$0.0012	$0.0012
	Average Woodland &Yolo Rates including surcharge ($/kWh)	$ 0.0755	$ 0.0766	$ 0.0783	$ 0.0827	$ 0.0879	$ 0.0911	$ 0.0979	$ 0.1011	$ 0.1033
	DWR Energy/Bond Costs/Reg Assets/CTC	0.0270	0.0266	0.0266	0.0265	0.0264	0.0263	-	-	-
25	Nuclear Decomissioning	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004
26	FTA	0.0039	0.0039	-	-	-	-	-	-	-
	Average Woodland &Yolo Rates including Surcharge and Non-by	**$ 0.1068**	**$ 0.1076**	**$ 0.1053**	**$ 0.1096**	**$ 0.1147**	**$ 0.1178**	**$ 0.0983**	**$ 0.1015**	**$ 0.1037**
	Amount Woodland &Yolo lower than PG&E ($ / kwh)		0.0137	0.0131	0.0033	0.0015	0.0012	0.0096	0.0039	0.0046
	Revenue Woodland &Yolo lower than PG&E ($ in millions)		$7,900	$7,635	$1,942	$932	$751	$5,966	$2,486	$2,958
	Percentage Woodland &Yolo lower than PG&E		11.31%	11.03%	2.90%	1.33%	1.03%	8.88%	3.73%	4.25%
	NPV through 2027 @ 6.0%		$57,408							
	NPV through 2015 @ 6.0%		$24,893							
	Assumed Debt ($000)		$ 34,568							
	Real Surcharge		$ 0.0208	$ 0.0180	$ 0.0204	$ 0.0226	$ 0.0243	$ 0.0012	$ 0.0019	$ 0.0018
	Smoothed Surcharge		$ 0.0079	$ 0.0079	$ 0.0079	$ 0.0079	$ 0.0079	$ 0.0079	$ 0.0079	$ 0.0079
	Min		$ 0.0007							
	Max		$ 0.0243							

		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
	CUSTOMERS/LOAD												
	Customers	32,802	33,478	34,168	34,872	35,590	36,092	36,601	37,014	37,432	37,855	38,283	38,716
2,3	Load (MWh)												
	Bundled only												
	Residential	238,836	243,189	247,624	252,143	256,747	260,325	263,953	267,065	270,215	273,401	276,626	279,888
	Commercial												
	Small	75,676	77,061	78,473	79,911	81,377	82,511	83,661	84,646	85,643	86,652	87,672	88,705
	Medium	187,511	190,914	194,381	197,913	201,512	204,319	207,165	209,611	212,087	214,591	217,125	219,690
	Large	105,767	107,765	109,802	111,879	113,996	115,590	117,206	118,572	119,953	121,351	122,766	124,196
	Agricultural	43,176	43,760	44,352	44,952	45,560	46,180	46,808	47,407	48,013	48,628	49,250	49,880
	Other	2,775	2,830	2,886	2,944	3,002	3,045	3,087	3,123	3,159	3,195	3,231	3,268
	Direct Access	40,827	42,056	43,322	44,626	45,969	47,321	48,712	50,076	51,478	52,920	54,401	55,925
	Total Load at Meter	694,568	707,576	720,841	734,368	748,163	759,290	770,593	780,501	790,548	800,737	811,071	821,551
	Load Served (MWh)	653,740	665,520	677,519	689,742	702,194	711,969	721,881	730,425	739,070	747,818	756,670	765,627
4	Losses @8.0% (MWh)	52,299	53,242	54,202	55,179	56,176	56,958	57,750	58,434	59,126	59,825	60,534	61,250
	Energy Requirement	706,040	718,761	731,720	744,921	758,369	768,927	779,631	788,859	798,196	807,643	817,203	826,877
5	Market purchases	564,832	575,009	585,376	595,937	606,695	615,141	623,705	631,087	638,556	646,115	653,763	661,502
6	Renewable Market purchases	141,208	143,752	146,344	148,984	151,674	153,785	155,926	157,772	159,639	161,529	163,441	165,375
	PRICES ($/MWh)												
7,8	Market Electricity	$ 56.37	$ 57.22	$ 59.16	$ 59.88	$ 61.48	$ 63.34	$ 65.48	$ 67.58	$ 68.77	$ 71.46	$ 72.10	$ 75.42
9	Renewable Prices	62.01	62.94	65.08	65.87	67.63	69.67	72.03	74.33	75.65	78.60	79.31	82.96
10	DWR Bond Repayment	-	-	-	-	-	-	-	-	-	-	-	-
11	Distribution O&M & A&G	16.16	16.53	16.91	17.30	17.70	18.10	18.52	18.95	19.38	19.83	20.28	20.75
12	ISO / TAC	5.68	5.82	5.96	6.10	6.24	6.39	6.54	6.70	6.86	7.03	7.20	7.37
13	Ancillary Services	6.09	6.18	6.39	6.47	6.64	6.84	7.07	7.30	7.43	7.72	7.79	8.15
14,15	**REVENUES ($000)**												
	Residential	$ 26,627	$ 27,704	$ 29,022	$ 30,053	$ 31,362	$ 32,656	$ 34,067	$ 35,431	$ 36,569	$ 38,177	$ 39,219	$ 41,097
	Commercial / Industrial												
	Small	8,809	9,168	9,606	9,949	10,384	10,813	11,280	11,731	12,108	12,640	12,984	13,605
	Medium	19,078	19,851	20,796	21,536	22,475	23,402	24,414	25,391	26,207	27,359	28,104	29,450
	Large	9,144	9,522	9,982	10,345	10,804	11,251	11,738	12,205	12,596	13,147	13,504	14,148
	Agricultural	4,538	4,701	4,902	5,053	5,250	5,464	5,699	5,933	6,129	6,405	6,586	6,908
	Other	286	298	313	325	340	354	369	384	396	413	424	444
	Direct Access	2,682	2,826	2,978	3,138	3,307	3,483	3,667	3,857	4,056	4,266	4,486	4,717
	Total Revenues	$ 71,164	$ 74,069	$ 77,599	$ 80,400	$ 83,922	$ 87,422	$ 91,234	$ 94,931	$ 98,061	$ 102,406	$ 105,306	$ 110,370
	COST OF SERVICE ($000)												
16	Power Supply (@market prices)	31,839	32,902	34,633	35,686	37,298	38,963	40,843	42,646	43,914	46,169	47,134	49,892
17	Renewable Power Supply(@renewable prices)	8,756	9,048	9,524	9,814	10,257	10,715	11,232	11,728	12,076	12,696	12,962	13,720
18	Distribution O&M & A&G	12,121	12,632	13,165	13,721	14,300	14,846	15,414	15,971	16,549	17,148	17,769	18,412
	ISO / TAC	3,715	3,872	4,035	4,205	4,383	4,550	4,724	4,895	5,072	5,256	5,446	5,643
	Ancillary Services	3,980	4,113	4,329	4,461	4,662	4,870	5,105	5,331	5,489	5,771	5,892	6,236
19	Planning Reserve	920	951	1,001	1,031	1,078	1,126	1,180	1,233	1,269	1,334	1,362	1,442
20	Public Purpose Programs	2,256	2,348	2,460	2,549	2,660	2,771	2,892	3,009	3,109	3,246	3,338	3,499
	Total Expenses	$ 63,587	$ 65,865	$ 69,147	$ 71,466	$ 74,639	$ 77,842	$ 81,390	$ 84,813	$ 87,478	$ 91,620	$ 93,902	$ 98,845
	Net Revenues ($000)	$ 7,577	$ 8,204	$ 8,452	$ 8,933	$ 9,283	$ 9,580	$ 9,843	$ 10,119	$ 10,583	$ 10,786	$ 11,404	$ 11,526
	DEBT SERVICE ($000)												
21	Federally Taxable	$ 2,579	$ 2,579	$ 2,579	$ 2,579	$ 2,579	$ 2,579	$ 2,579	$ 2,579	$ 2,579	$ 2,579	$ 2,579	$ 2,579
22	Federally Non - Taxable	$ 2,295	$ 2,468	$ 2,647	$ 2,833	$ 3,025	$ 3,179	$ 3,340	$ 3,484	$ 3,634	$ 3,789	$ 3,948	$ 4,112
	Total Debt Service	$ 4,874	$ 5,047	$ 5,226	$ 5,411	$ 5,604	$ 5,757	$ 5,918	$ 6,063	$ 6,213	$ 6,368	$ 6,527	$ 6,691
	Net Income ($000)	$2,702	$3,157	$3,226	$3,522	$3,679	$3,822	$3,925	$4,056	$4,369	$4,419	$4,877	$4,835
	Bundled Customer Rates												
	PG&E												
	PG&E System Average	**$ 0.1117**	**$ 0.1144**	**$ 0.1179**	**$ 0.1207**	**$ 0.1241**	**$ 0.1277**	**$ 0.1314**	**$ 0.1353**	**$ 0.1390**	**$ 0.1432**	**$ 0.1469**	**$ 0.1515**
	SMUD												
	Average SMUD Rates ($/kWh)	$ 0.1048	$ 0.1070	$ 0.1101	$ 0.1120	$ 0.1148	$ 0.1179	$ 0.1213	$ 0.1247	$ 0.1272	$ 0.1312	$ 0.1332	$ 0.1380
	Amount SMUD lower than PG&E	$0.0069	$0.0074	$0.0078	$0.0087	$0.0093	$0.0098	$0.0101	$0.0106	$0.0118	$0.0119	$0.0137	$0.0135
	Percentage SMUD lower than PG&E	6.19%	6.47%	6.60%	7.18%	7.51%	7.69%	7.72%	7.84%	8.49%	8.33%	9.31%	8.89%
23	Franchise Fees	$0.0016	$0.0016	$0.0017	$0.0017	$0.0017	$0.0018	$0.0018	$0.0019	$0.0019	$0.0020	$0.0020	$0.0021
24	Property Taxes	$0.0012	$0.0013	$0.0013	$0.0013	$0.0014	$0.0014	$0.0014	$0.0015	$0.0015	$0.0015	$0.0016	$0.0016
	Average Woodland &Yolo Rates including surcharge ($/kWh)	$ 0.1060	$ 0.1078	$ 0.1111	$ 0.1127	$ 0.1156	$ 0.1187	$ 0.1223	$ 0.1257	$ 0.1281	$ 0.1324	$ 0.1340	$ 0.1392
	DWR Energy/Bond Costs/Reg Assets/CTC	-	-	-	-	-	-	-	-	-	-	-	-
25	Nuclear Decomissioning	0.0004	0.0004	0.0004	-	-	-	-	-	-	-	-	-
26	FTA	-	-	-	-	-	-	-	-	-	-	-	-
	Average Woodland &Yolo Rates including Surcharge and Non-by	**$ 0.1064**	**$ 0.1082**	**$ 0.1115**	**$ 0.1127**	**$ 0.1156**	**$ 0.1187**	**$ 0.1223**	**$ 0.1257**	**$ 0.1281**	**$ 0.1324**	**$ 0.1340**	**$ 0.1392**
	Amount Woodland &Yolo lower than PG&E ($ / kwh)	0.0053	0.0062	0.0064	0.0079	0.0086	0.0090	0.0092	0.0096	0.0109	0.0108	0.0129	0.0123
	Revenue Woodland &Yolo lower than PG&E ($ in millions)	$3,447	$4,136	$4,364	$5,470	$6,004	$6,406	$6,631	$6,983	$8,064	$8,082	$9,751	$9,410
	Percentage Woodland &Yolo lower than PG&E	4.72%	5.43%	5.46%	6.57%	6.89%	7.04%	6.99%	7.07%	7.85%	7.55%	8.77%	8.12%
	Real Surcharge	$ 0.0016	$ 0.0012	$ 0.0013	$ 0.0007	$ 0.0008	$ 0.0008	$ 0.0010	$ 0.0011	$ 0.0009	$ 0.0011	$ 0.0008	$ 0.0012
	Smoothed Surcharge	$ 0.0079	$ 0.0079	$ 0.0079	$ 0.0079	$ 0.0079	$ 0.0079	$ 0.0079	$ 0.0079	$ 0.0079	$ 0.0079	$ 0.0079	$ 0.0079

Assumptions:

1 Inflation rate is based on March, 2004 Blue Chip Consensus long-term rate indicator.

2 Load growth projections through 2009 for West Sacramento, Davis and Woodland are based on PGE's forecast from "1SMUD-Q3-yolo.xls" file, from 2010 through 2016, they are based on a three year moving average with the current yaer reading of Sacramento Area Council of Government's (SACOG) housing projections for each city dated 3/15/2001, and from 2017 on they are only based on SACOG projections. The load projection for Yolo is based only on SACOG's housing projections of Unincorporated Yolo County.Yolo County load is based on typical hour load data provided by PG&E and updated with the latest information on the large commercial customers.

3 Load by region for 2003 is based on PGE's "Rate comparison using PG&E Proposed Phase 2 Rates" file.

4 Losses are assumed to be 8%.

5 SMUD currently supplies 90% of its energy requirement through conventional resources and plans to decrease this amount gradually to 80% by 2011.

6 SMUD currently supplies 10% of its energy requirement through renewable resources and plans to increase this amount gradually to 20% by 2011.

7 On-peak and off-peak market price projections from 2005 through 2018 are provided by SMUD. The average market price per annum is calculated based on the typical weekday and weekend load shape data provided by PG&E for each city. Market price projections are carried forward with five year moving averages thereafter.

8 Market prices shown on this proforma are manipulated to reflect SMUD's costs based on their retail price projections. SMUD is assumed to gradually integrate this new load into its current resource planning starting in year 2014. The integration is assumed to be completed by 2017. Hence, the market price projections are melded with the the gas price index starting from 2014. Starting in year 2017, the projections are only based on the trend in the Gas price index as SMUD's retail rate projections.

9 Based on its current experience, SMUD estimates the renewable resource costs to be 10% higher than the market price projections.

10 DWR costs are capped at 2.7 cents per kWh and assumed to include DWR power charges, bond costs, regulatory assets and the post transition period CTC charges.

11 O&M and A&G for distribution costs are based on SMUD's operations at 12.3 $ / MWh and inflated at the inflation rate thereafter.

12 ISO / TAC is based on ISO charges which is estimated at $3.7698 per MWh for year 2004 and escalated at the inflation rate thereafter.

13 Ancillary Services charges are provided by SMUD and assumed to be 10% of the market price projections.

14 System average retail rate projections for year 2004 and 2005 are provided by SMUD.

15 SMUD estimates the Direct Access revenues to be 5 cents/kWh for the initial year and it escalates at the rate of inflation thereafter.

16 SMUD's power supply cost for the annexed region is calculated at market price rates.

17 SMUD's power supply cost of renewable resources for the annexed region is calculated at renewable price projection.

18 O&M and A&G for distribution costs are based on SMUD's operations at 12.3 $ / MWh and inflated at the inflation rate thereafter.

19 SMUD estimates a cost of .001 cents/kWh for meeting the planning reserve requirement and follow the trend in conventional power supply cost of SMUD.

20 Public Purpose Programs are calculated to be at 3.17% of the retail revenues based on SMUD's 2004 proposed budget.

21 Federally taxable debt service requirement includes all the capital investment costs for Distibution Annexation in 2008, debt service reserve equal to the principal and interest payment for one year, the cost of issuance (1.5% of total debt), and the severance cost of 1% of the total capital investment.

22 Federally non-taxable debt service requirement includes all the capital investment costs for new customers each year, renewals and replacement costs, debt service reserve equal to the principal and interest payment for one year, the cost of issuance (1.5% of total debt), revenue requirement for 45 days, and the litigation cost of 20% of the total capital investment.

23 Franchise fees are calculated at 1.5% of the retail revenues

24 Property tax is calculated at 3.16% based on PG&E 's distribution revenue requirement from its GRC model.

25 Nuclear Decommissioning cost is allocated based on PG&E's proposed GRC- Phase 2. It is allocated to each rate class at the same rate of 0.024 cents /kWh) based on the latest rate schedules filed by PG&E. Nuclear Decommissioning cost is assumed to continue at the same rate through 2018.

26 FTA charges are allocated based on PG&E's proposed GRC - Phase 2 and terminate in 2008.These costs are applicable only to certain rates but at the same rate for all classes.

CASE 7 - WEST SACRAMENTO & DAVIS - CAISO OPTION

Municipalization Evaluation Model:Replacement Cost New Less Depreciation - Straight Line Approach / CAISO Option

Ref	Item	2004	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
	CUSTOMERS/LOAD																					
	Customers	55,431	59,927	61,023	62,127	63,210	64,298	65,391	66,498	67,624	68,583	69,566	70,573	71,606	72,665	73,722	74,805	75,871	76,963	78,081	79,225	80,398
2,3	Load (MWh)																					
	Bundled only																					
	Residential	255,631	276,502	281,595	286,773	291,870	297,018	302,204	307,475	312,845	317,441	322,154	326,986	331,943	337,026	342,101	347,305	352,426	357,671	363,042	368,544	374,181
	Commercial																					
	Small	79,704	86,676	88,394	90,311	92,259	94,310	96,431	98,637	100,924	102,959	105,050	107,200	109,410	111,682	113,960	116,301	118,599	120,958	123,379	125,863	128,413
	Medium	202,738	221,160	225,723	231,045	236,529	242,403	248,542	254,985	261,705	267,769	274,007	280,425	287,028	293,821	300,641	307,654	314,536	321,604	328,862	336,316	343,971
	Large	98,470	108,237	110,683	113,800	117,096	120,734	124,603	128,724	133,067	137,072	141,198	145,448	149,826	154,336	158,873	163,544	168,123	172,831	177,670	182,645	187,759
	Agricultural	6,141	6,709	6,850	7,018	7,192	7,379	7,576	7,783	8,000	8,197	8,399	8,608	8,822	9,043	9,264	9,492	9,716	9,946	10,182	10,424	10,673
	Other	4,569	4,955	5,050	5,151	5,252	5,357	5,463	5,574	5,687	5,786	5,888	5,992	6,100	6,210	6,320	6,434	6,545	6,659	6,776	6,896	7,019
	Direct Access	45,804	50,348	51,485	52,936	54,468	56,161	57,961	59,877	61,898	63,761	65,680	67,657	69,693	71,791	73,902	76,075	78,205	80,394	82,645	84,959	87,338
	Total Load at Meter	693,056	754,586	769,780	787,035	804,666	823,362	842,780	863,056	884,125	902,984	922,376	942,317	962,822	983,910	1,005,062	1,026,804	1,048,150	1,070,063	1,092,557	1,115,649	1,139,355
	Load Served (MWh)	647,252	704,239	718,295	734,099	750,198	767,201	784,819	803,178	822,227	839,223	856,696	874,660	893,129	912,118	931,160	950,729	969,946	989,668	1,009,912	1,030,689	1,052,017
4	Losses @8.0% (MWh)	51,780	56,339	57,464	58,728	60,016	61,376	62,786	64,254	65,778	67,138	68,536	69,973	71,450	72,969	74,493	76,058	77,596	79,173	80,793	82,455	84,161
	Energy Requirement	699,032	760,578	775,758	792,827	810,214	828,577	847,605	867,432	888,005	906,361	925,232	944,632	964,579	985,088	1,005,653	1,026,787	1,047,541	1,068,842	1,090,704	1,113,144	1,136,178
5	Conventional Energy	629,129	654,097	651,637	650,118	648,171	662,852	678,084	693,946	710,404	725,089	740,185	755,706	771,663	788,070	804,523	821,430	838,033	855,074	872,564	890,516	908,942
6	Renewable Energy	69,903	106,481	124,121	142,709	162,043	165,715	169,521	173,486	177,601	181,272	185,046	188,926	192,916	197,018	201,131	205,357	209,508	213,768	218,141	222,629	227,236
	PRICES ($/MWh)																					
7,8	Market Electricity	$ 44.15	$ 37.28	$ 38.22	$ 41.14	$ 44.68	$ 46.74	$ 51.68	$ 53.66	$ 54.86	$ 56.37	$ 57.22	$ 59.16	$ 59.88	$ 61.48	$ 63.34	$ 65.48	$ 67.58	$ 68.77	$ 71.46	$ 72.10	$ 75.42
9	Renewable Prices	48.56	41.00	42.04	45.26	49.15	51.42	56.85	59.02	60.34	62.01	62.94	65.08	65.87	67.63	69.67	72.03	74.33	75.65	78.60	79.31	82.96
10	DWR Bond Repayment	27.00	27.00	27.00	27.00	27.00	27.00	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Distribution O&M & A&G	12.30	13.44	13.77	14.10	14.42	14.75	15.09	15.44	15.80	16.16	16.53	16.91	17.30	17.70	18.10	18.52	18.95	19.38	19.83	20.28	20.75
12	ISO / TAC	4.36	4.77	4.88	5.00	5.12	5.24	5.36	5.49	5.62	5.76	5.89	6.03	6.17	6.32	6.47	6.62	6.78	6.94	7.10	7.27	7.44
13	Ancillary Services	4.77	4.03	4.13	4.44	4.83	5.05	5.58	5.80	5.92	6.09	6.18	6.39	6.47	6.64	6.84	7.07	7.30	7.43	7.72	7.79	8.15
14,15	**REVENUES ($000)**																					
	Residential	$ 22,820	$ 23,675	$ 24,241	$ 25,237	$ 26,519	$ 27,400	$ 28,981	$ 30,230	$ 31,469	$ 32,828	$ 34,053	$ 35,568	$ 36,731	$ 38,230	$ 39,857	$ 41,638	$ 43,436	$ 44,974	$ 47,106	$ 48,557	$ 51,065
	Commercial / Industrial																					
	Small	8,002	8,365	8,576	8,955	9,442	9,799	10,414	10,919	11,429	11,985	12,497	13,122	13,622	14,252	14,934	15,681	16,437	17,101	17,997	18,640	19,695
	Medium	18,003	18,645	19,132	20,018	21,157	22,012	23,459	24,670	25,903	27,243	28,490	30,001	31,233	32,771	34,435	36,256	38,101	39,739	41,927	43,532	46,111
	Large	7,346	7,749	7,968	8,376	8,899	9,316	9,994	10,583	11,192	11,851	12,476	13,223	13,854	14,628	15,463	16,378	17,306	18,148	19,249	20,090	21,389
	Agricultural	558	584	600	628	665	692	739	778	818	862	902	951	992	1,042	1,096	1,156	1,216	1,270	1,341	1,394	1,478
	Other	392	424	434	452	476	493	523	547	571	597	621	650	673	702	734	769	804	834	876	905	954
	Direct Access	2,290	2,752	2,881	3,034	3,193	3,368	3,556	3,758	3,974	4,188	4,414	4,651	4,901	5,165	5,439	5,728	6,023	6,334	6,662	7,006	7,367
	Total Revenues	$ 59,411	$ 62,194	$ 63,832	$ 66,700	$ 70,351	$ 73,079	$ 77,666	$ 81,485	$ 85,356	$ 89,554	$ 93,453	$ 98,167	$ 102,005	$ 106,789	$ 111,958	$ 117,606	$ 123,323	$ 128,400	$ 135,158	$ 140,124	$ 148,060
	COST OF SERVICE ($000)																					
16	Power Supply (@market prices)	27,775	24,382	24,903	26,748	28,963	30,984	35,046	37,235	38,969	40,873	42,353	44,710	46,209	48,449	50,958	53,790	56,631	58,804	62,350	64,202	68,554
17	Renewable Power Supply(@renewable prices)	3,395	4,366	5,218	6,459	7,965	8,521	9,638	10,240	10,717	11,240	11,647	12,295	12,707	13,323	14,014	14,792	15,573	16,171	17,146	17,656	18,852
18	Distribution O&M & A&G	9,207	10,957	11,446	11,983	12,534	13,120	13,738	14,392	15,083	15,759	16,467	17,210	17,989	18,806	19,652	20,539	21,448	22,400	23,397	24,441	25,534
	ISO / TAC	2,822	3,358	3,508	3,673	3,841	4,021	4,211	4,411	4,623	4,830	5,047	5,275	5,513	5,764	6,023	6,295	6,574	6,865	7,171	7,491	7,826
	Ancillary Services	3,086	2,835	2,965	3,262	3,620	3,873	4,381	4,654	4,871	5,109	5,294	5,589	5,776	6,056	6,370	6,724	7,079	7,350	7,794	8,025	8,569
19	Planning Reserve	-	656	685	754	837	896	1,013	1,076	1,126	1,181	1,224	1,292	1,336	1,400	1,473	1,555	1,637	1,700	1,802	1,856	1,981
20	Public Purpose Programs	1,883	1,972	2,023	2,114	2,230	2,317	2,462	2,583	2,706	2,839	2,962	3,112	3,234	3,385	3,549	3,728	3,909	4,070	4,285	4,442	4,693
	Total Expenses	$ 48,168	$ 48,525	$ 50,748	$ 54,993	$ 59,991	$ 63,731	$ 70,489	$ 74,592	$ 78,094	$ 81,830	$ 84,995	$ 89,483	$ 92,764	$ 97,184	$ 102,039	$ 107,423	$ 112,851	$ 117,361	$ 123,944	$ 128,113	$ 136,012
	Net Revenues ($000)	$ 11,243	$ 13,669	$ 13,084	$ 11,707	$ 10,361	$ 9,348	$ 7,177	$ 6,893	$ 7,262	$ 7,723	$ 8,458	$ 8,684	$ 9,241	$ 9,605	$ 9,920	$ 10,183	$ 10,472	$ 11,040	$ 11,214	$ 12,011	$ 12,048
	DEBT SERVICE ($000)																					
21	Federally Taxable		$ 4,878	$ 4,878	$ 4,878	$ 4,878	$ 4,878	$ 4,878	$ 4,878	$ 4,878	$ 4,878	$ 4,878	$ 4,878	$ 4,878	$ 4,878	$ 4,878	$ 4,878	$ 4,878	$ 4,878	$ 4,878	$ 4,878	$ 4,878
22	Federally Non - Taxable		$ 1,969	$ 2,117	$ 2,374	$ 2,632	$ 2,896	$ 3,165	$ 3,443	$ 3,728	$ 3,989	$ 4,262	$ 4,546	$ 4,841	$ 5,146	$ 5,458	$ 5,783	$ 6,111	$ 6,452	$ 6,806	$ 7,174	$ 7,555
	Total Debt Service	$ -	$ 6,847	$ 6,996	$ 7,252	$ 7,510	$ 7,774	$ 8,044	$ 8,321	$ 8,607	$ 8,868	$ 9,141	$ 9,424	$ 9,719	$ 10,025	$ 10,337	$ 10,661	$ 10,989	$ 11,330	$ 11,684	$ 12,052	$ 12,434
	Net Income ($000)	$11,243	$6,822	$6,088	$4,454	$2,850	$1,574	($867)	($1,428)	($1,345)	($1,144)	($683)	($740)	($478)	($420)	($417)	($478)	($517)	($290)	($470)	($41)	($385)
	Bundled Customer Rates																					
	PG&E																					
	PG&E System Average	**$ 0.1224**	**$ 0.1182**	**$ 0.1152**	**$ 0.1098**	**$ 0.1130**	**$ 0.1157**	**$ 0.1051**	**$ 0.1026**	**$ 0.1054**	**$ 0.1086**	**$ 0.1112**	**$ 0.1146**	**$ 0.1172**	**$ 0.1205**	**$ 0.1240**	**$ 0.1275**	**$ 0.1312**	**$ 0.1348**	**$ 0.1388**	**$ 0.1424**	**$ 0.1467**
	SMUD																					
	Average SMUD Rates ($/kWh)	$ 0.0883	$ 0.0844	$ 0.0849	$ 0.0867	$ 0.0895	$ 0.0909	$ 0.0944	$ 0.0968	$ 0.0990	$ 0.1017	$ 0.1039	$ 0.1069	$ 0.1087	$ 0.1114	$ 0.1144	$ 0.1177	$ 0.1209	$ 0.1233	$ 0.1272	$ 0.1292	$ 0.1337
	Amount SMUD lower than PG&E	$0.0342	$0.0338	$0.0303	$0.0231	$0.0235	$0.0249	$0.0106	$0.0058	$0.0064	$0.0069	$0.0073	$0.0077	$0.0085	$0.0091	$0.0096	$0.0099	$0.0103	$0.0114	$0.0115	$0.0132	$0.0130
	Percentage SMUD lower than PG&E	27.93%	28.62%	26.33%	21.01%	20.81%	21.49%	10.11%	5.69%	6.07%	6.32%	6.57%	6.68%	7.25%	7.56%	7.73%	7.74%	7.85%	8.49%	8.32%	9.28%	8.86%
23	Franchise fees	$0.0013	$0.0013	$0.0013	$0.0013	$0.0013	$0.0014	$0.0014	$0.0015	$0.0015	$0.0015	$0.0016	$0.0016	$0.0016	$0.0017	$0.0017	$0.0018	$0.0018	$0.0019	$0.0019	$0.0019	$0.0020
24	Property Taxes	$0.0010	$0.0011	$0.0011	$0.0011	$0.0011	$0.0012	$0.0012	$0.0012	$0.0012	$0.0013	$0.0013	$0.0013	$0.0013	$0.0014	$0.0014	$0.0014	$0.0014	$0.0015	$0.0015	$0.0015	$0.0016
	Average West Sacramento & Davis Rates including surcharge ($/k	$ 0.0754	$ 0.0795	$ 0.0812	$ 0.0856	$ 0.0908	$ 0.0941	$ 0.1009	$ 0.1041	$ 0.1063	$ 0.1090	$ 0.1108	$ 0.1140	$ 0.1156	$ 0.1184	$ 0.1216	$ 0.1251	$ 0.1286	$ 0.1309	$ 0.1352	$ 0.1369	$ 0.1420
	DWR Energy/Bond Costs/Reg Assets/CTC	0.0230	0.0228	0.0228	0.0227	0.0227	0.0226	0.0023	-	-	-	-	-	-	-	-	-	-	-	-	-	-
25	Nuclear Decomissioning	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	-	-	-	-	-	-	-	-	-
26	FTA	0.0042	0.0042	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Average West Sacramento & Davis Rates including Surcharge an	**$ 0.1031**	**$ 0.1069**	**$ 0.1044**	**$ 0.1088**	**$ 0.1139**	**$ 0.1171**	**$ 0.1036**	**$ 0.1045**	**$ 0.1067**	**$ 0.1094**	**$ 0.1112**	**$ 0.1144**	**$ 0.1156**	**$ 0.1184**	**$ 0.1216**	**$ 0.1251**	**$ 0.1286**	**$ 0.1309**	**$ 0.1352**	**$ 0.1369**	**$ 0.1420**
	Amount West Sacramento & Davis lower than PG&E ($ / kwh)		0.0113	0.0108	0.0010	(0.0009)	(0.0014)	0.0014	(0.0019)	(0.0014)	(0.0008)	0.0001	0.0002	0.0016	0.0021	0.0024	0.0024	0.0027	0.0038	0.0036	0.0055	0.0047
	Revenue West Sacramento & Davis lower than PG&E ($ in millions)		$7,962	$7,732	$741	($671)	($1,056)	$1,116	($1,539)	($1,125)	($668)	$48	$158	$1,415	$1,914	$2,235	$2,321	$2,574	$3,801	$3,602	$5,645	$4,943
	Percentage West Sacramento & Davis lower than PG&E		9.56%	9.34%	0.92%	-0.79%	-1.19%	1.35%	-1.87%	-1.30%	-0.73%	0.05%	0.16%	1.35%	1.74%	1.94%	1.91%	2.02%	2.85%	2.57%	3.85%	3.20%
	NPV through 2027 @ 6.0%		$23,117																			
	NPV through 2015 @ 6.0%		$12,752																			
	Assumed Debt ($000)		$ 65,391																			
	Real Surcharge		$ 0.0225	$ 0.0196	$ 0.0221	$ 0.0244	$ 0.0262	$ 0.0092	$ 0.0078	$ 0.0078	$ 0.0077	$ 0.0073	$ 0.0075	$ 0.0069	$ 0.0070	$ 0.0072	$ 0.0074	$ 0.0077	$ 0.0076	$ 0.0080	$ 0.0077	$ 0.0083
	Smoothed Surcharge		$ 0.0126	$ 0.0126	$ 0.0126	$ 0.0126	$ 0.0126	$ 0.0126	$ 0.0126	$ 0.0126	$ 0.0126	$ 0.0126	$ 0.0126	$ 0.0126	$ 0.0126	$ 0.0126	$ 0.0126	$ 0.0126	$ 0.0126	$ 0.0126	$ 0.0126	$ 0.0126
	Min		$ 0.0069																			
	Max		$ 0.0262																			

Assumptions:

1 Inflation rate is based on March, 2004 Blue Chip Consensus long-term rate indicator.

2 Load growth projections through 2009 for West Sacramento, Davis and Woodland are based on PGE's forecast from "1SMUD-Q3-yolo.xls" file, from 2010 through 2016, they are based on a three year moving average with the current yaer reading of Sacramento Area Council of Government's (SACOG) housing projections for each city dated 3/15/2001, and from 2017 on they are only based on SACOG projections. The load projection for Yolo is based only on SACOG's housing projections of Unincorporated Yolo County.Yolo County load is based on typical hour load data provided by PG&E and updated with the latest information on the large commercial customers.

3 Load by region for 2003 is based on PGE's "Rate comparison using PG&E Proposed Phase 2 Rates" file.

4 Losses are assumed to be 8%.

5 SMUD currently supplies 90% of its energy requirement through conventional resources and plans to decrease this amount gradually to 80% by 2011.

6 SMUD currently supplies 10% of its energy requirement through renewable resources and plans to increase this amount gradually to 20% by 2011.

7 On-peak and off-peak market price projections from 2005 through 2018 are provided by SMUD. The average market price per annum is calculated based on the typical weekday and weekend load shape data provided by PG&E for each city. Market price projections are carried forward with five year moving averages thereafter.

8 Market prices shown on this proforma are manipulated to reflect SMUD's costs based on their retail price projections. SMUD is assumed to gradually integrate this new load into its current resource planning starting in year 2014. The integration is assumed to be completed by 2017. Hence, the market price projections are melded with the the gas price index starting from 2014. Starting in year 2017, the projections are only based on the trend in the Gas price index as SMUD's retail rate projections.

9 Based on its current experience, SMUD estimates the renewable resource costs to be 10% higher than the market price projections.

10 DWR costs are capped at 2.7 cents per kWh and assumed to include DWR power charges, bond costs, regulatory assets and the post transition period CTC charges.

11 O&M and A&G for distribution costs are based on SMUD's operations at 12.3 $ / MWh and inflated at the inflation rate thereafter.

12 ISO / TAC is based on ISO charges which is estimated at $3.7698 per MWh for year 2004 and escalated at the inflation rate thereafter.

13 Ancillary Services charges are provided by SMUD and assumed to be 10% of the market price projections.

14 System average retail rate projections for year 2004 and 2005 are provided by SMUD.

15 SMUD estimates the Direct Access revenues to be 5 cents/kWh for the initial year and it escalates at the rate of inflation thereafter.

16 SMUD's power supply cost for the annexed region is calculated at market price rates.

17 SMUD's power supply cost of renewable resources for the annexed region is calculated at renewable price projection.

18 O&M and A&G for distribution costs are based on SMUD's operations at 12.3 $ / MWh and inflated at the inflation rate thereafter.

19 SMUD estimates a cost of .001 cents/kWh for meeting the planning reserve requirement and follow the trend in conventional power supply cost of SMUD.

20 Public Purpose Programs are calculated to be at 3.17% of the retail revenues based on SMUD's 2004 proposed budget.

21 Federally taxable debt service requirement includes all the capital investment costs for Distibution Annexation in 2008, debt service reserve equal to the principal and interest payment for one year, the cost of issuance (1.5% of total debt), and the severance cost of 1% of the total capital investment.

22 Federally non-taxable debt service requirement includes all the capital investment costs for new customers each year, renewals and replacement costs, debt service reserve equal to the principal and interest payment for one year, the cost of issuance (1.5% of total debt), revenue requirement for 45 days, and the litigation cost of 20% of the total capital investment.

23 Franchise fees are calculated at 1.5% of the retail revenues

24 Property tax is calculated at 3.16% based on PG&E 's distribution revenue requirement from its GRC model.

25 Nuclear Decommissioning cost is allocated based on PG&E's proposed GRC- Phase 2. It is allocated to each rate class at the same rate of 0.024 cents /kWh) based on the latest rate schedules filed by PG&E. Nuclear Decommissioning cost is assumed to continue at the same rate through 2018.

26 FTA charges are allocated based on PG&E's proposed GRC - Phase 2 and terminate in 2008.These costs are applicable only to certain rates but at the same rate for all classes.

CASE 8 - ALL REGION - CAISO OPTION

Municipalization Evaluation Model:Replacement Cost New Less Depreciation - Straight Line Approach / CAISO Option

#		2004	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
	CUSTOMERS/LOAD																					
	Customers	82,257	88,678	90,234	91,816	93,375	94,948	96,531	98,135	99,764	101,385	103,044	104,741	106,477	108,255	109,813	111,405	112,885	114,395	115,936	117,508	119,113
2,3	Load (MWh)																					
	Bundled only																					
	Residential	451,992	486,749	495,163	503,767	512,279	520,896	529,594	538,427	547,408	556,276	565,342	574,611	584,086	593,774	602,426	611,258	619,491	627,885	636,444	645,170	654,069
	Commercial																					
	Small	141,910	153,284	156,055	159,058	162,089	165,240	168,473	171,809	175,241	178,635	182,112	185,673	189,321	193,059	196,471	199,962	203,246	206,601	210,031	213,535	217,118
	Medium	356,927	386,249	393,419	401,429	409,592	418,190	427,083	436,321	445,875	455,279	464,921	474,806	484,941	495,333	504,960	514,819	524,148	533,691	543,453	553,442	563,661
	Large	185,298	201,230	205,151	209,792	214,606	219,789	225,220	230,925	236,874	242,839	248,963	255,251	261,705	268,332	274,463	280,750	286,695	292,784	299,021	305,410	311,955
	Agricultural	42,010	45,042	45,774	46,541	47,312	48,106	48,918	49,749	50,600	51,373	52,159	52,960	53,774	54,603	55,444	56,300	57,123	57,959	58,810	59,674	60,553
	Other	6,842	7,390	7,524	7,665	7,806	7,952	8,100	8,252	8,408	8,561	8,718	8,879	9,043	9,212	9,365	9,521	9,668	9,818	9,971	10,127	10,287
	Direct Access	75,134	82,586	84,453	86,831	89,346	92,122	95,074	98,218	101,532	104,588	107,736	110,979	114,319	117,760	121,223	124,787	128,281	131,872	135,565	139,361	143,263
	Total Load at Meter	1,260,113	1,362,531	1,387,538	1,415,085	1,443,029	1,472,294	1,502,461	1,533,701	1,565,936	1,597,552	1,629,952	1,663,157	1,697,190	1,732,073	1,764,352	1,797,397	1,828,651	1,860,611	1,893,294	1,926,720	1,960,906
	Load Served (MWh)	1,184,979	1,279,945	1,303,085	1,328,253	1,353,684	1,380,172	1,407,387	1,435,483	1,464,404	1,492,964	1,522,216	1,552,178	1,582,871	1,614,312	1,643,130	1,672,610	1,700,370	1,728,738	1,757,729	1,787,359	1,817,643
4	Losses @8.0% (MWh)	94,798	102,396	104,247	106,260	108,295	110,414	112,591	114,839	117,152	119,437	121,777	124,174	126,630	129,145	131,450	133,809	136,030	138,299	140,618	142,989	145,411
	Energy Requirement	1,279,777	1,382,340	1,407,332	1,434,514	1,461,978	1,490,586	1,519,978	1,550,321	1,581,556	1,612,401	1,643,993	1,676,353	1,709,500	1,743,457	1,774,580	1,806,419	1,836,400	1,867,037	1,898,348	1,930,348	1,963,055
5	Conventional Energy	1,151,800	1,188,813	1,182,159	1,176,301	1,169,583	1,192,469	1,215,982	1,240,257	1,265,245	1,289,921	1,315,194	1,341,082	1,367,600	1,394,766	1,419,664	1,445,135	1,469,120	1,493,630	1,518,678	1,544,278	1,570,444
6	Renewable Energy	127,978	193,528	225,173	258,212	292,396	298,117	303,996	310,064	316,311	322,480	328,799	335,271	341,900	348,691	354,916	361,284	367,280	373,407	379,670	386,070	392,611
	PRICES ($/MWh)																					
7,8	Market Electricity	$ 44.15	$ 37.28	$ 38.22	$ 41.14	$ 44.68	$ 46.74	$ 51.68	$ 53.66	$ 54.86	$ 56.37	$ 57.22	$ 59.16	$ 59.88	$ 61.48	$ 63.34	$ 65.48	$ 67.58	$ 68.77	$ 71.46	$ 72.10	$ 75.42
9	Renewable Prices	48.56	41.00	42.04	45.26	49.15	51.42	56.85	59.02	60.34	62.01	62.94	65.08	65.87	67.63	69.67	72.03	74.33	75.65	78.60	79.31	82.96
10	DWR Bond Repayment	27.00	27.00	27.00	27.00	27.00	27.00	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Distribution O&M and A&G	12.30	13.44	13.77	14.10	14.42	14.75	15.09	15.44	15.80	16.16	16.53	16.91	17.30	17.70	18.10	18.52	18.95	19.38	19.83	20.28	20.75
12	ISO / TAC	4.33	4.74	4.85	4.97	5.09	5.21	5.33	5.46	5.59	5.72	5.86	6.00	6.14	6.29	6.43	6.59	6.74	6.91	7.07	7.24	7.41
13	Ancillary Services	4.77	4.03	4.13	4.44	4.83	5.05	5.58	5.80	5.92	6.09	6.18	6.39	6.47	6.64	6.84	7.07	7.30	7.43	7.72	7.79	8.15
14,15	**REVENUES ($000)**																					
	Residential	$ 41,750	$ 43,110	$ 44,087	$ 45,846	$ 48,127	$ 49,681	$ 52,503	$ 54,718	$ 56,912	$ 59,455	$ 61,757	$ 64,590	$ 66,784	$ 69,592	$ 72,513	$ 75,705	$ 78,867	$ 81,544	$ 85,284	$ 87,776	$ 92,162
	Commercial / Industrial																					
	Small	14,248	14,793	15,140	15,771	16,589	17,168	18,194	19,019	19,845	20,794	21,665	22,727	23,571	24,636	25,747	26,962	28,168	29,209	30,637	31,624	33,301
	Medium	31,695	32,564	33,346	34,780	36,636	37,974	40,311	42,215	44,131	46,321	48,341	50,797	52,769	55,246	57,837	60,670	63,492	65,946	69,286	71,637	75,561
	Large	13,823	14,406	14,768	15,441	16,310	16,959	18,064	18,986	19,923	20,995	21,998	23,206	24,199	25,432	26,714	28,116	29,512	30,744	32,396	33,594	35,537
	Agricultural	3,815	3,924	4,009	4,166	4,372	4,513	4,770	4,973	5,174	5,400	5,603	5,853	6,045	6,292	6,561	6,854	7,149	7,399	7,746	7,980	8,386
	Other	587	632	647	673	708	732	775	809	844	883	919	963	998	1,042	1,088	1,138	1,187	1,230	1,289	1,329	1,398
	Direct Access	3,757	4,514	4,726	4,976	5,238	5,525	5,833	6,165	6,519	6,870	7,240	7,629	8,039	8,472	8,922	9,395	9,880	10,390	10,927	11,491	12,085
	Total Revenues	$ 109,674	$ 113,942	$ 116,722	$ 121,654	$ 127,981	$ 132,552	$ 140,450	$ 146,885	$ 153,348	$ 160,718	$ 167,522	$ 175,766	$ 182,405	$ 190,711	$ 199,380	$ 208,840	$ 218,255	$ 226,461	$ 237,565	$ 245,430	$ 258,430
	COST OF SERVICE ($000)																					
16	Power Supply (@market prices)	50,851	44,314	45,177	48,397	52,262	55,740	62,848	66,549	69,405	72,712	75,255	79,342	81,894	85,747	89,921	94,633	99,277	102,718	108,518	111,336	118,446
17	Renewable Power Supply(@renewable prices)	6,215	7,935	9,466	11,686	14,372	15,328	17,283	18,301	19,086	19,996	20,695	21,819	22,521	23,581	24,728	26,024	27,301	28,247	29,843	30,617	32,573
18	Distribution O&M and A&G	16,739	19,785	20,631	21,546	22,477	23,460	24,491	25,576	26,714	27,880	29,100	30,375	31,710	33,106	34,498	35,953	37,419	38,949	40,545	42,210	43,947
	ISO / TAC	5,130	6,064	6,323	6,604	6,889	7,190	7,506	7,839	8,187	8,545	8,919	9,310	9,719	10,147	10,573	11,019	11,469	11,937	12,426	12,937	13,469
	Ancillary Services	5,650	5,153	5,378	5,902	6,533	6,967	7,856	8,319	8,676	9,089	9,407	9,918	10,237	10,718	11,240	11,829	12,410	12,840	13,565	13,917	14,806
19	Planning Reserve	-	1,191	1,244	1,365	1,511	1,611	1,816	1,923	2,006	2,102	2,175	2,293	2,367	2,478	2,599	2,735	2,869	2,969	3,136	3,218	3,423
20	Public Purpose Programs	3,477	3,612	3,700	3,856	4,057	4,202	4,452	4,656	4,861	5,095	5,310	5,572	5,782	6,046	6,320	6,620	6,919	7,179	7,531	7,780	8,192
	Total Expenses	$ 88,062	$ 88,053	$ 91,919	$ 99,355	$ 108,101	$ 114,499	$ 126,253	$ 133,163	$ 138,936	$ 145,418	$ 150,860	$ 158,629	$ 164,230	$ 171,823	$ 179,881	$ 188,814	$ 197,664	$ 204,839	$ 215,564	$ 222,015	$ 234,856
	Net Revenues ($000)	$ 21,612	$ 25,889	$ 24,803	$ 22,299	$ 19,881	$ 18,053	$ 14,198	$ 13,722	$ 14,413	$ 15,300	$ 16,662	$ 17,137	$ 18,175	$ 18,888	$ 19,499	$ 20,026	$ 20,591	$ 21,622	$ 22,001	$ 23,415	$ 23,574
	DEBT SERVICE ($000)																					
21	Federally Taxable		$ 7,457	$ 7,457	$ 7,457	$ 7,457	$ 7,457	$ 7,457	$ 7,457	$ 7,457	$ 7,457	$ 7,457	$ 7,457	$ 7,457	$ 7,457	$ 7,457	$ 7,457	$ 7,457	$ 7,457	$ 7,457	$ 7,457	$ 7,457
22	Federally Non - Taxable		$ 2,960	$ 3,168	$ 3,542	$ 3,921	$ 4,309	$ 4,707	$ 5,117	$ 5,539	$ 5,968	$ 6,413	$ 6,876	$ 7,356	$ 7,854	$ 8,320	$ 8,805	$ 9,278	$ 9,769	$ 10,278	$ 10,805	$ 11,350
	Total Debt Service	$ -	$ 10,417	$ 10,625	$ 11,000	$ 11,378	$ 11,767	$ 12,164	$ 12,574	$ 12,996	$ 13,425	$ 13,871	$ 14,333	$ 14,813	$ 15,312	$ 15,777	$ 16,262	$ 16,735	$ 17,226	$ 17,735	$ 18,262	$ 18,808
	Net Income ($000)	$21,612	$15,472	$14,178	$11,299	$8,502	$6,286	$2,033	$1,148	$1,416	$1,875	$2,791	$2,803	$3,361	$3,577	$3,722	$3,764	$3,856	$4,396	$4,266	$5,153	$4,767
	Bundled Customer Rates																					
	PG&E																					
	PG&E System Average	**$ 0.1239**	**$ 0.1196**	**$ 0.1166**	**$ 0.1112**	**$ 0.1145**	**$ 0.1172**	**$ 0.1063**	**$ 0.1039**	**$ 0.1067**	**$ 0.1099**	**$ 0.1126**	**$ 0.1160**	**$ 0.1187**	**$ 0.1221**	**$ 0.1256**	**$ 0.1292**	**$ 0.1330**	**$ 0.1366**	**$ 0.1406**	**$ 0.1443**	**$ 0.1487**
	SMUD																					
	Average SMUD Rates ($/kWh)	$ 0.0894	$ 0.0855	$ 0.0859	$ 0.0878	$ 0.0907	$ 0.0920	$ 0.0957	$ 0.0980	$ 0.1003	$ 0.1030	$ 0.1053	$ 0.1083	$ 0.1102	$ 0.1129	$ 0.1159	$ 0.1192	$ 0.1225	$ 0.1250	$ 0.1289	$ 0.1309	$ 0.1355
	Amount SMUD lower than PG&E	$0.0345	$0.0341	$0.0307	$0.0233	$0.0238	$0.0252	$0.0107	$0.0058	$0.0064	$0.0069	$0.0073	$0.0077	$0.0086	$0.0092	$0.0097	$0.0100	$0.0104	$0.0116	$0.0117	$0.0134	$0.0132
	Percentage SMUD lower than PG&E	27.85%	28.54%	26.30%	20.98%	20.79%	21.47%	10.04%	5.62%	6.01%	6.26%	6.52%	6.64%	7.21%	7.54%	7.71%	7.73%	7.85%	8.49%	8.33%	9.29%	8.87%
23	Franchise Fees	$0.0013	$0.0013	$0.0013	$0.0013	$0.0014	$0.0014	$0.0014	$0.0015	$0.0015	$0.0015	$0.0016	$0.0016	$0.0017	$0.0017	$0.0017	$0.0018	$0.0018	$0.0019	$0.0019	$0.0020	$0.0020
24	Property Taxes	$0.0010	$0.0011	$0.0011	$0.0011	$0.0011	$0.0012	$0.0012	$0.0012	$0.0012	$0.0012	$0.0013	$0.0013	$0.0013	$0.0014	$0.0014	$0.0014	$0.0015	$0.0015	$0.0015	$0.0015	$0.0016
	Average All Cities Rates including surcharge ($/kWh)	$ 0.0754	$ 0.0779	$ 0.0797	$ 0.0841	$ 0.0893	$ 0.0925	$ 0.0994	$ 0.1026	$ 0.1048	$ 0.1074	$ 0.1093	$ 0.1125	$ 0.1142	$ 0.1170	$ 0.1201	$ 0.1237	$ 0.1272	$ 0.1295	$ 0.1338	$ 0.1355	$ 0.1407
	DWR Energy/Bond Costs/Reg Assets/CTC	0.0248	0.0245	0.0245	0.0244	0.0243	0.0243	0.0013	-	-	-	-	-	-	-	-	-	-	-	-	-	-
25	Nuclear Decomissioning	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	-	-	-	-	-	-	-	-	-
26	FTA	0.0041	0.0041	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Average All Cities Rates including Surcharge and Non-bypassable	**$ 0.1048**	**$ 0.1070**	**$ 0.1046**	**$ 0.1089**	**$ 0.1140**	**$ 0.1172**	**$ 0.1011**	**$ 0.1030**	**$ 0.1052**	**$ 0.1079**	**$ 0.1097**	**$ 0.1129**	**$ 0.1142**	**$ 0.1170**	**$ 0.1201**	**$ 0.1237**	**$ 0.1272**	**$ 0.1295**	**$ 0.1338**	**$ 0.1355**	**$ 0.1407**
	Amount All Cities lower than PG&E ($ / kwh)		0.0127	0.0120	0.0023	0.0004	0.0000	0.0053	0.0009	0.0015	0.0021	0.0030	0.0031	0.0045	0.0051	0.0055	0.0055	0.0058	0.0070	0.0068	0.0088	0.0081
	Revenue All Cities lower than PG&E ($ in millions)		$16,200	$15,684	$3,001	$578	$13	$7,399	$1,264	$2,149	$3,096	$4,501	$4,839	$7,202	$8,235	$8,957	$9,269	$9,874	$12,183	$12,002	$15,713	$14,671
	Percentage All Cities lower than PG&E		10.58%	10.32%	2.03%	0.37%	0.01%	4.94%	0.85%	1.38%	1.89%	2.63%	2.69%	3.83%	4.18%	4.34%	4.29%	4.37%	5.16%	4.85%	6.09%	5.43%
	NPV through 2027 @ 6.0%		$84,181																			
	NPV through 2015 @ 6.0%		$39,633																			
	Assumed Debt ($000)		$ 99,960																			
	Real Surcharge		$ 0.0215	$ 0.0186	$ 0.0211	$ 0.0234	$ 0.0252	$ 0.0054	$ 0.0050	$ 0.0049	$ 0.0048	$ 0.0044	$ 0.0046	$ 0.0040	$ 0.0041	$ 0.0042	$ 0.0044	$ 0.0046	$ 0.0045	$ 0.0049	$ 0.0046	$ 0.0051
	Smoothed Surcharge		$ 0.0103	$ 0.0103	$ 0.0103	$ 0.0103	$ 0.0103	$ 0.0103	$ 0.0103	$ 0.0103	$ 0.0103	$ 0.0103	$ 0.0103	$ 0.0103	$ 0.0103	$ 0.0103	$ 0.0103	$ 0.0103	$ 0.0103	$ 0.0103	$ 0.0103	$ 0.0103
	Min		$ 0.0040																			
	Max		$ 0.0252																			

Assumptions:

1 Inflation rate is based on March, 2004 Blue Chip Consensus long-term rate indicator.
Load growth projections through 2009 for West Sacramento, Davis and Woodland are based on PGE's forecast from "1SMUD-Q3-yolo.xls" file, from 2010 through 2016, they are based on a three year moving average with the current yaer reading of Sacramento Area Council of Government's (SACOG) housing projections for each city dated 3/15/2001, and from 2017 on they are only based on SACOG projections.
2 The load projection for Yolo is based only on SACOG's housing projections of Unincorporated Yolo County.Yolo County load is based on typical hour load data provided by PG&E and updated with the latest information on the large commercial customers.
3 Load by region for 2003 is based on PGE's "Rate comparison using PG&E Proposed Phase 2 Rates" file.
4 Losses are assumed to be 8%.
5 SMUD currently supplies 90% of its energy requirement through conventional resources and plans to decrease this amount gradually to 80% by 2011.
6 SMUD currently supplies 10% of its energy requirement through renewable resources and plans to increase this amount gradually to 20% by 2011.
7 On-peak and off-peak market price projections from 2005 through 2018 are provided by SMUD. The average market price per annum is calculated based on the typical weekday and weekend load shape data provided by PG&E for each city. Market price projections are carried forward with five year moving averages thereafter.
Market prices shown on this proforma are manipulated to reflect SMUD's costs based on their retail price projections. SMUD is assumed to gradually integrate this new load into its current resource planning starting in year 2014. The integration is assumed to be completed by 2017. Hence, the market price projections are melded with the the gas price index starting from 2014. Starting in year 2017, the projections are
8 only based on the trend in the Gas price index as SMUD's retail rate projections.
9 Based on its current experience, SMUD estimates the renewable resource costs to be 10% higher than the market price projections.
10 DWR costs are capped at 2.7 cents per kWh and assumed to include DWR power charges, bond costs, regulatory assets and the post transition period CTC charges.
11 O&M and A&G for distribution costs are based on SMUD's operations at 12.3 $ / MWh and inflated at the inflation rate thereafter.
12 ISO / TAC is based on ISO charges which is estimated at $3.7698 per MWh for year 2004 and escalated at the inflation rate thereafter.
13 Ancillary Services charges are provided by SMUD and assumed to be 10% of the market price projections.
14 System average retail rate projections for year 2004 and 2005 are provided by SMUD.
15 SMUD estimates the Direct Access revenues to be 5 cents/kWh for the initial year and it escalates at the rate of inflation thereafter.
16 SMUD's power supply cost for the annexed region is calculated at market price rates.
17 SMUD's power supply cost of renewable resources for the annexed region is calculated at renewable price projection.
18 O&M and A&G for distribution costs are based on SMUD's operations at 12.3 $ / MWh and inflated at the inflation rate thereafter.
19 SMUD estimates a cost of .001 cents/kWh for meeting the planning reserve requirement and follow the trend in conventional power supply cost of SMUD.
20 Public Purpose Programs are calculated to be at 3.17% of the retail revenues based on SMUD's 2004 proposed budget.
21 Federally taxable debt service requirement includes all the capital investment costs for Distibution Annexation in 2008, debt service reserve equal to the principal and interest payment for one year, the cost of issuance (1.5% of total debt), and the severance cost of 1% of the total capital investment.
22 Federally non-taxable debt service requirement includes all the capital investment costs for new customers each year, renewals and replacement costs, debt service reserve equal to the principal and interest payment for one year, the cost of issuance (1.5% of total debt), revenue requirement for 45 days, and the litigation cost of 20% of the total capital investment.
23 Franchise fees are calculated at 1.5% of the retail revenues
24 Property tax is calculated at 3.16% based on PG&E 's distribution revenue requirement from its GRC model.
25 Nuclear Decommissioning cost is allocated based on PG&E's proposed GRC- Phase 2. It is allocated to each rate class at the same rate of 0.024 cents /kWh) based on the latest rate schedules filed by PG&E. Nuclear Decommissioning cost is assumed to continue at the same rate through 2018.
26 FTA charges are allocated based on PG&E's proposed GRC - Phase 2 and terminate in 2008.These costs are applicable only to certain rates but at the same rate for all classes.

Appendix C

COST APPROACH (RCNLD AND OCLD) VALUATION ANALYSES

R·W·BECK

SMUD Transmission & Distribution Annexation
Estimated RCNLD and OCLD Value of PG&E Facilities
Straight Line Depreciation

Description	RCN	RCNLD	OC	OCLD
Scenario 1 - Acquire West Sacramento Only				
Transmission Plant	$21,735,120	$4,877,299	$3,653,042	$866,929
Distribution System				
West Sacramento (includes Deepwater)	$44,517,560	$27,521,747	$29,849,152	$18,569,709
Total Plant Cost	**$66,252,680**	**$32,399,046**	**$33,502,194**	**$19,436,638**
Scenario 2 - Acquire West Sacramento and Davis				
Transmission Plant	$47,535,210	$9,025,664	$7,495,351	$1,495,712
Distribution System				
West Sacramento (includes Deepwater)	$44,517,560	$27,521,747	$29,849,152	$18,569,709
Davis	$54,809,357	$33,229,139	$37,442,292	$22,830,262
Davis (1107) - Not Acquired	(2,112,673)	(1,180,538)	(1,313,813)	(747,524)
Davis (Net)	$52,696,684	$32,048,601	$36,128,479	$22,082,738
Total Distribution System	$97,214,244	$59,570,347	$65,977,631	$40,652,447
Total Plant Cost	**$144,749,454**	**$68,596,012**	**$73,472,982**	**$42,148,159**
Scenario 3 - Acquire West Sacramento, Davis & Woodland				
Transmission Plant	$54,669,880	$11,077,290	$9,192,158	$2,152,932
Distribution System				
West Sacramento (includes Deepwater)	$44,517,560	$27,521,747	$29,849,152	$18,569,709
Davis	$54,809,357	$33,229,139	$37,442,292	$22,830,262
Davis (1107) - Not Acquired	(2,112,673)	(1,180,538)	(1,313,813)	(747,524)
Davis (Net)	$52,696,684	$32,048,601	$36,128,479	$22,082,738
Woodland	42,287,310	28,214,942	25,296,922	10,734,159
Total Distribution System	$139,501,554	$87,785,290	$91,274,553	$51,386,606
Total Plant Cost	**$194,171,434**	**$98,862,580**	**$100,466,711**	**$53,539,538**
Scenario 4 - Acquire All Areas				
Transmission Plant (same as Scenario 3)	$54,669,880	$11,077,290	$9,192,158	$2,152,932
Distribution System				
West Sacramento (includes Deepwater)	$44,517,560	$27,521,747	$29,849,152	$18,569,709
Davis	$54,809,357	$33,229,139	$37,442,292	$22,830,262
Davis (1107) - Not Acquired	(2,112,673)	(1,180,538)	(1,313,813)	(747,524)
Davis (Net)	$52,696,684	$32,048,601	$36,128,479	$22,082,738
Woodland	42,287,310	28,214,942	25,296,922	10,734,159
Plainfield	6,755,094	3,276,150	3,120,915	1,542,720
Total Distribution System	$146,256,648	$91,061,440	$94,395,468	$52,929,326
Total Plant Cost	**$200,926,528**	**$102,138,730**	**$103,587,626**	**$55,082,258**

SMUD Annexation Study
Distribution System Summary
Straight Line Depreciation

Description	Unit	Quantity	RCN	RCNLD	OC	OCLD
WEST SACRAMENTO (includes Deepwater)						
SUBSTATIONS	MVA	117.20	9,544,353	7,730,518	6,546,065	5,307,616
FEEDERS						
12 kv Overhead feeder,	mi	121.44	$2,926,710	$1,300,132	$1,675,034	$744,099
12 Kv Underground feeder	mi	71.65	8,337,076	5,170,255	6,574,767	4,077,355
	mi	193.09	11,263,786	6,470,387	8,249,801	4,821,454
POLES	Unit	3,500	7,362,973	4,650,343	4,371,765	2,761,141
TRANSFORMERS						
OVERHEAD	Unit	8,175	1,715,057	1,122,889	1,406,732	921,022
PAD MOUNTED	Unit	43	3,480,669	2,295,636	1,646,581	1,089,276
	Unit	8,218	5,195,726	3,418,525	3,053,313	2,010,298
LOW VOLTAGE CIRCUITS	mi	43.19	3,994,792	2,412,338	3,070,399	1,866,889
SERVICE DROPS & METERS	Unit	11,568	5,498,159	2,103,204	3,609,023	1,380,832
RISERS, SWITCHES, CAPACITORS ETC.	Unit	579	1,657,771	736,432	948,786	421,479
			$44,517,560	**$27,521,747**	**$29,849,152**	**$18,569,709**
DAVIS						
SUBSTATIONS	MVA	130.50	8,201,776	6,579,465	5,523,268	4,430,765
FEEDERS						
12 kv Overhead feeder,	mi	146.00	$3,999,554	$1,776,722	$2,289,053	$1,016,865
12 Kv Underground feeder	mi	104.68	10,825,113	6,713,215	8,536,877	5,294,161
	mi	250.68	14,824,667	8,489,937	10,825,930	6,311,026
POLES	Unit	3,571	7,512,499	4,744,782	4,460,546	2,817,214
TRANSFORMERS						
OVERHEAD	Unit	913	1,481,097	969,710	1,214,832	795,378
PAD MOUNTED	Unit	1,087	4,454,773	3,201,297	2,417,526	1,773,403
	Unit	2,000	5,935,870	4,171,007	3,632,358	2,568,781
LOW VOLTAGE CIRCUITS	mi	82.68	9,169,347	5,619,618	7,149,018	4,395,263
SERVICE DROPS & METERS	Unit	15,580	7,317,647	2,803,593	4,793,769	1,837,483
RISERS, SWITCHES, CAPACITORS ETC.	Unit	612	1,847,551	820,737	1,057,403	469,730
			$54,809,357	**$33,229,139**	**$37,442,292**	**$22,830,262**
DAVIS (1107)						
FEEDERS						
12 kv Overhead feeder,	mi	27.10	$779,571	$346,309	$446,171	$198,203
12 Kv Underground feeder	mi	0.35	55,017	34,119	43,388	26,907
	mi	27.45	834,588	380,428	489,559	225,110
POLES	Unit	440	925,074	584,263	549,263	346,906
TRANSFORMERS						
OVERHEAD	Unit	94	164,494	107,698	134,923	88,339
PAD MOUNTED	Unit	2	14,372	9,410	6,717	4,398
	Unit	96	178,866	117,108	141,640	92,737
LOW VOLTAGE CIRCUITS	mi	0.55	14,153	6,287	8,100	3,598
SERVICE DROPS & METERS	Unit	212	108,734	41,195	73,993	27,915
RISERS, SWITCHES, CAPACITORS ETC.	Unit	14	51,258	51,258	51,258	51,258
			$2,112,673	**$1,180,538**	**$1,313,813**	**$747,524**
PLAINFIELD						
SUBSTATIONS	MVA	12.00	585,975	417,449	246,796	175,818
FEEDERS						
12 kv Overhead feeder,	mi	67.81	$1,671,667	$527,152	$686,892	$216,608
12 Kv Underground feeder	mi	1.70	132,697	82,292	104,647	64,897
	mi	69.51	1,804,364	609,444	791,539	281,505
POLES	Unit	1,348	2,835,487	1,598,308	1,246,855	702,827
TRANSFORMERS						
OVERHEAD	Unit	301	528,858	306,457	332,761	192,824
PAD MOUNTED	Unit	17	51,333	40,590	31,732	25,649
	Unit	318	580,192	347,047	364,493	218,473
LOW VOLTAGE CIRCUITS	mi	3.58	198,384	103,028	131,664	73,434
SERVICE DROPS & METERS	Unit	1,126	559,508	140,586	261,009	65,889
RISERS, SWITCHES, CAPACITORS ETC.	Unit	73	191,184	60,289	78,559	24,774
			$6,755,094	**$3,276,150**	**$3,120,915**	**$1,542,720**
WOODLAND						
SUBSTATIONS	MVA	145.50	8,483,779	6,434,797	3,378,374	2,231,859
FEEDERS						
12 kv Overhead feeder,	mi	107.69	$2,738,320	$1,216,444	$1,097,152	$226,141
12 Kv Underground feeder	mi	81.30	8,755,188	5,429,547	6,214,073	3,591,413
	mi	188.99	11,493,508	6,645,991	7,311,225	3,817,554
POLES	Unit	2,580	5,427,758	3,428,091	2,255,894	1,068,591
TRANSFORMERS						
OVERHEAD	Unit	1,145	1,836,376	1,202,319	1,054,076	534,009
PAD MOUNTED	Unit	779	3,095,734	2,230,851	1,340,374	894,381
	Unit	1,924	4,932,110	3,433,170	2,394,450	1,428,390
LOW VOLTAGE CIRCUITS	mi	51.47	4,249,753	2,530,244	2,831,246	1,547,127
SERVICE DROPS & METERS	Unit	12,408	5,890,362	4,938,575	6,400,538	491,184
RISERS, SWITCHES, CAPACITORS ETC.	Unit	613	1,810,039	804,074	725,195	149,454
			$42,287,310	**$28,214,942**	**$25,296,922**	**$10,734,159**
TOTAL DISTRIBUTION		40,893	**$150,481,994**	**$93,422,516**	**$97,023,094**	**$54,424,374**

SMUD Annexation Study
Estimated RCNLD and OCLD Values
Straight Line Depreciation

West Sacramento (includes Deepwater)

															HANDY-WHITMAN						
Description	Unit	Quantity	Price	RCN	Year	FERC Acct	Survivor Curve	ASL	Age % of ASL	Unadjusted Deprec.	Net Salvage %	Adjusted Deprec.	RCN Depreciation	RCNLD	Line No.	Year Installed	7/31/04	Factor	Original Cost	Orig Cost Depreciation	OCLD
SUBSTATIONS																					
West Sacramento	MVA	90.00	70,171	6,315,387	1989	362	L0	43	35	19.78%	0%	19.78%	1,249,184	5,066,203	43	299	444	0.6734	4,252,930	841,229	3,411,701
Deepwater	MVA	16.00	84,441	1,351,051	1994	362	L0	43	23	14.30%	0%	14.30%	193,200	1,157,851	43	338	444	0.7613	1,028,503	147,076	881,427
Post Office	MVA	11.20	167,671	1,877,915	1989	362	L0	43	35	19.78%	0%	19.78%	371,452	1,506,463	43	299	444	0.6734	1,264,632	250,144	1,014,488
		117.20		**9,544,353**									**1,813,835**	**7,730,518**					**6,546,065**	**1,238,449**	**5,307,616**
FEEDERS																					
12 kv Overhead Feeder																					
3 # 397.5 MCM AL	mi	28.00	39,408	1,103,234	1984	365	R1	37	54	37.30%	-49%	55.58%	613,144	490,090	45	273	477	0.5723	631,410	350,919	280,491
3 # 4/0 AWG AL	mi	15.36	36,588	561,838	1984	365	R1	37	54	37.30%	-49%	55.58%	312,253	249,585	45	273	477	0.5723	321,555	178,711	142,844
3 # 2/0 AWG AL	mi	0.15	25,236	3,880	1984	365	R1	37	54	37.30%	-49%	55.58%	2,156	1,724	45	273	477	0.5723	2,221	1,234	987
3 # 1/0 AWG AL	mi	14.79	21,462	317,499	1984	365	R1	37	54	37.30%	-49%	55.58%	176,457	141,043	45	273	477	0.5723	181,713	100,991	80,722
3 # 2 AWG AL	mi	0.41	21,565	8,896	1984	365	R1	37	54	37.30%	-49%	55.58%	4,944	3,952	45	273	477	0.5723	5,091	2,830	2,261
2 # 2 AWG AL	mi	0.19	14,377	2,669	1984	365	R1	37	54	37.30%	-49%	55.58%	1,483	1,186	45	273	477	0.5723	1,527	849	678
3 # 4 AWG AL	mi	21.77	21,565	469,408	1984	365	R1	37	54	37.30%	-49%	55.58%	260,883	208,525	45	273	477	0.5723	268,655	149,310	119,345
2 # 4 AWG AL	mi	7.03	14,377	101,068	1984	365	R1	37	54	37.30%	-49%	55.58%	56,171	44,898	45	273	477	0.5723	57,844	32,148	25,696
3 # 6 AWG CU	mi	15.69	12,917	202,718	1984	365	R1	37	54	37.30%	-49%	55.58%	112,664	90,053	45	273	477	0.5723	116,021	64,481	51,540
2 # 6 AWG CU	mi	18.06	8,611	155,500	1984	365	R1	37	54	37.30%	-49%	55.58%	86,422	69,078	45	273	477	0.5723	88,997	49,462	39,535
		121.44		**2,926,710**									**1,626,578**	**1,300,132**					**1,675,034**	**930,935**	**744,099**
12 Kv Underground feeder																					
3 # 1000 MCM AL	mi	23.99	157,192	3,770,747	1994	367	S3	31	32	31.92%	-19%	37.98%	1,432,311	2,338,437	47	291	369	0.7886	2,973,679	1,129,546	1,844,133
3 # 350 MCM AL	mi	0.80	129,403	103,765	1994	367	S3	31	32	31.92%	-19%	37.98%	39,415	64,350	47	291	369	0.7886	81,831	31,083	50,748
3 # 4/0 MCM AL	mi	0.24	129,403	31,623	1994	367	S3	31	32	31.92%	-19%	37.98%	12,012	19,611	47	291	369	0.7886	24,938	9,473	15,465
3 # 1/0 MCM AL	mi	20.01	117,388	2,348,632	1994	367	S3	31	32	31.92%	-19%	37.98%	892,123	1,456,509	47	291	369	0.7886	1,852,173	703,544	1,148,629
2 # 1/0 MCM AL	mi	26.61	78,258	2,082,309	1994	367	S3	31	32	31.92%	-19%	37.98%	790,961	1,291,348	47	291	369	0.7886	1,642,146	623,766	1,018,380
		71.65		**8,337,076**									**3,166,822**	**5,170,255**					**6,574,767**	**2,497,412**	**4,077,355**
POLES																			-		
40 to 45 foot poles, with all hardware and accessories	Unit	3,500	2,103	7,362,973	1984	364	L0	37	54	27.29%	-35%	36.84%	2,712,630	4,650,343	44	266	448	0.5938	4,371,765	1,610,624	2,761,141
		3,500		**7,362,973**									**2,712,630**	**4,650,343**					**4,371,765**	**1,610,624**	**2,761,141**
OVERHEAD SINGLE-PHASE TRANSFORMERS																					
5 kVA	Unit	2	822	1,644	1984	368.1	R0.5	32	63	37.53%	8%	34.53%	568	1,077	48	219	267	0.8202	1,349	466	883
1x10 kVA	Unit	141	822	115,917	1984	368.1	R0.5	32	63	37.53%	8%	34.53%	40,023	75,893	48	219	267	0.8202	95,078	32,828	62,250
1x15 kVA	Unit	174	832	144,842	1984	368.1	R0.5	32	63	37.53%	8%	34.53%	50,010	94,831	48	219	267	0.8202	118,803	41,020	77,783
1x25 kVA	Unit	268	1,061	284,431	1984	368.1	R0.5	32	63	37.53%	8%	34.53%	98,207	186,224	48	219	267	0.8202	233,297	80,552	152,745
1x37.5 kVA	Unit	117	1,248	146,037	1984	368.1	R0.5	32	63	37.53%	8%	34.53%	50,423	95,614	48	219	267	0.8202	119,783	41,358	78,425
1x50 kVA	Unit	161	1,670	268,871	1984	368.1	R0.5	32	63	37.53%	8%	34.53%	92,835	176,037	48	219	267	0.8202	220,535	76,145	144,390
1x75 kVA	Unit	51	1,763	89,936	1984	368.1	R0.5	32	63	37.53%	8%	34.53%	31,053	58,883	48	219	267	0.8202	73,767	25,470	48,297
1x100 kVA	Unit	7	1,857	12,998	1984	368.1	R0.5	32	63	37.53%	8%	34.53%	4,488	8,510	48	219	267	0.8202	10,661	3,681	6,980
OVERHEAD 3-PHASE TRANSFORMERS																					
1x45 kVA	Unit	4	1,670	6,680	1984	368.1	R0.5	32	63	37.53%	8%	34.53%	2,306	4,374	48	219	267	0.8202	5,479	1,892	3,587
1x112.5 kVA	Unit	1	3,360	3,360	1984	368.1	R0.5	32	63	37.53%	8%	34.53%	1,160	2,200	48	219	267	0.8202	2,756	951	1,805
1x150 kVA	Unit	8	3,547	28,373	1984	368.1	R0.5	32	63	37.53%	8%	34.53%	9,796	18,576	48	219	267	0.8202	23,272	8,035	15,237
1x225 kVA	Unit	3	3,733	11,200	1984	368.1	R0.5	32	63	37.53%	8%	34.53%	3,867	7,333	48	219	267	0.8202	9,187	3,172	6,015
OVERHEAD 3-PHASE TRANSFORMER BANKS																					
3x10 kVA	Unit	9	2,466	22,197	1984	368.1	R0.5	32	63	37.53%	8%	34.53%	7,664	14,533	48	219	267	0.8202	18,206	6,286	11,920
3x15 kVA	Unit	17	2,497	42,454	1984	368.1	R0.5	32	63	37.53%	8%	34.53%	14,658	27,795	48	219	267	0.8202	34,822	12,023	22,799
3x25 kVA	Unit	35	3,184	111,437	1984	368.1	R0.5	32	63	37.53%	8%	34.53%	38,477	72,961	48	219	267	0.8202	91,404	31,560	59,844
3x37.5 kVA	Unit	2	3,745	7,489	1984	368.1	R0.5	32	63	37.53%	8%	34.53%	2,586	4,903	48	219	267	0.8202	6,143	2,121	4,022
3x50 kVA	Unit	5	5,010	25,050	1984	368.1	R0.5	32	63	37.53%	8%	34.53%	8,649	16,401	48	219	267	0.8202	20,547	7,094	13,453
3x75 kVA	Unit	4	5,290	21,161	1984	368.1	R0.5	32	63	37.53%	8%	34.53%	7,306	13,855	48	219	267	0.8202	17,357	5,993	11,364
3x167 kVA	Unit	1	10,640	10,640	1984	368.1	R0.5	32	63	37.53%	8%	34.53%	3,674	6,966	48	219	267	0.8202	8,727	3,013	5,714
2x10+1x25 kVA	Unit	3	2,706	8,117	1984	368.1	R0.5	32	63	37.53%	8%	34.53%	2,802	5,314	48	219	267	0.8202	6,657	2,299	4,358
2x10+1x75 kVA	Unit	1	3,408	3,408	1984	368.1	R0.5	32	63	37.53%	8%	34.53%	1,177	2,231	48	219	267	0.8202	2,795	965	1,830
2x15+1x37.5 kVA	Unit	1	2,913	2,913	1984	368.1	R0.5	32	63	37.53%	8%	34.53%	1,006	1,907	48	219	267	0.8202	2,389	825	1,564
2x15+1x50 kVA	Unit	1	3,335	3,335	1984	368.1	R0.5	32	63	37.53%	8%	34.53%	1,151	2,183	48	219	267	0.8202	2,735	944	1,791
2x25+1x50 kVA	Unit	2	3,793	7,585	1984	368.1	R0.5	32	63	37.53%	8%	34.53%	2,619	4,966	48	219	267	0.8202	6,222	2,148	4,074
2x25+1x75 kVA	Unit	1	3,886	3,886	1984	368.1	R0.5	32	63	37.53%	8%	34.53%	1,342	2,544	48	219	267	0.8202	3,187	1,101	2,086
2x25+1x100 kVA	Unit	1	3,979	3,979	1984	368.1	R0.5	32	63	37.53%	8%	34.53%	1,374	2,605	48	219	267	0.8202	3,264	1,127	2,137
2x37.5+1x50 kVA	Unit	1	4,166	4,166	1984	368.1	R0.5	32	63	37.53%	8%	34.53%	1,439	2,728	48	219	267	0.8202	3,417	1,180	2,237
2x50+1x25 kVA	Unit	1	4,401	4,401	1984	368.1	R0.5	32	63	37.53%	8%	34.53%	1,520	2,882	48	219	267	0.8202	3,610	1,246	2,364

SMUD Annexation Study
Estimated RCNLD and OCLD Values
Straight Line Depreciation

West Sacramento (includes Deepwater)

Description	Unit	Quantity	Price	RCN	Year	FERC Acct	Survivor Curve	ASL	Age % of ASL	Unadjusted Deprec.	Net Salvage %	Adjusted Deprec.	RCN Depreciation	RCNLD	HANDY-WHITMAN Line No.	HANDY-WHITMAN Year Installed	HANDY-WHITMAN 7/31/04	HANDY-WHITMAN Factor	Original Cost	Orig Cost Depreciation	OCLD
OVERHEAD 2-TRANSFORMER BANKS																					
1x10 + 1x15 kVA	Unit	11	1,655	18,200	1984	368.1	R0.5	32	63	37.53%	8%	34.53%	6,284	11,916	48	219	267	0.8202	14,928	5,154	9,774
1x10 + 1x25 kVA	Unit	19	1,883	35,785	1984	368.1	R0.5	32	63	37.53%	8%	34.53%	12,356	23,429	48	219	267	0.8202	29,352	10,134	19,218
1x10 + 1x37.5 kVA	Unit	5	2,070	10,351	1984	368.1	R0.5	32	63	37.53%	8%	34.53%	3,574	6,777	48	219	267	0.8202	8,490	2,932	5,558
1x10 + 1x50 kVA	Unit	3	2,492	7,476	1984	368.1	R0.5	32	63	37.53%	8%	34.53%	2,581	4,895	48	219	267	0.8202	6,132	2,117	4,015
1x10 + 1x75 kVA	Unit	1	2,586	2,586	1984	368.1	R0.5	32	63	37.53%	8%	34.53%	893	1,693	48	219	267	0.8202	2,121	732	1,389
1x10 + 1x100 kVA	Unit	1	2,679	2,679	1984	368.1	R0.5	32	63	37.53%	8%	34.53%	925	1,754	48	219	267	0.8202	2,197	759	1,438
1x15 + 1x25 kVA	Unit	10	1,894	18,937	1984	368.1	R0.5	32	63	37.53%	8%	34.53%	6,539	12,399	48	219	267	0.8202	15,533	5,363	10,170
1x15 + 1x37.5 kVA	Unit	3	2,081	6,242	1984	368.1	R0.5	32	63	37.53%	8%	34.53%	2,155	4,087	48	219	267	0.8202	5,120	1,768	3,352
1x15 + 1x50 kVA	Unit	9	2,502	22,522	1984	368.1	R0.5	32	63	37.53%	8%	34.53%	7,776	14,746	48	219	267	0.8202	18,473	6,378	12,095
1x15 + 1x75 kVA	Unit	3	2,596	7,788	1984	368.1	R0.5	32	63	37.53%	8%	34.53%	2,689	5,099	48	219	267	0.8202	6,388	2,205	4,183
1x15 + 1x100 kVA	Unit	2	2,689	5,379	1984	368.1	R0.5	32	63	37.53%	8%	34.53%	1,857	3,522	48	219	267	0.8202	4,412	1,523	2,889
1x25 + 1x37.5 kVA	Unit	4	2,309	9,238	1984	368.1	R0.5	32	63	37.53%	8%	34.53%	3,190	6,048	48	219	267	0.8202	7,577	2,616	4,961
1x25 + 1x50 kVA	Unit	11	2,731	30,044	1984	368.1	R0.5	32	63	37.53%	8%	34.53%	10,374	19,671	48	219	267	0.8202	24,643	8,509	16,134
1x25 + 1x75 kVA	Unit	2	2,825	5,650	1984	368.1	R0.5	32	63	37.53%	8%	34.53%	1,951	3,699	48	219	267	0.8202	4,634	1,600	3,034
1x37.5 + 1x50 kVA	Unit	4	2,918	11,673	1984	368.1	R0.5	32	63	37.53%	8%	34.53%	4,030	7,642	48	219	267	0.8202	9,574	3,306	6,268
1x50 + 1x75 kVA	Unit	2	3,433	6,867	1984	368.1	R0.5	32	63	37.53%	8%	34.53%	2,371	4,496	48	219	267	0.8202	5,632	1,945	3,687
2x10 kVA	Unit	25	1,644	41,105	1984	368.1	R0.5	32	63	37.53%	8%	34.53%	14,193	26,913	48	219	267	0.8202	33,716	11,641	22,075
2x15 kVA	Unit	20	1,665	33,297	1984	368.1	R0.5	32	63	37.53%	8%	34.53%	11,497	21,800	48	219	267	0.8202	27,311	9,430	17,881
2x25 kVA	Unit	12	2,123	25,471	1984	368.1	R0.5	32	63	37.53%	8%	34.53%	8,795	16,677	48	219	267	0.8202	20,892	7,214	13,678
2x50 kVA	Unit	3	3,340	10,020	1984	368.1	R0.5	32	63	37.53%	8%	34.53%	3,460	6,560	48	219	267	0.8202	8,219	2,838	5,381
2x75 kVA	Unit	1	3,527	3,527	1984	368.1	R0.5	32	63	37.53%	8%	34.53%	1,218	2,309	48	219	267	0.8202	2,893	999	1,894
2x100 kVA	Unit	1	3,714	3,714	1984	368.1	R0.5	32	63	37.53%	8%	34.53%	1,282	2,431	48	219	267	0.8202	3,046	1,052	1,994
		8,175		**1,715,057**									**592,168**	**1,122,889**					**1,406,732**	**485,710**	**921,022**
PAD MOUNTED SINGLE-PHASE TRANSFORMERS																					
1x50 kVA	Unit	93	1,850	172,072	1984	368.2	R0.5	32	63	37.53%	8%	34.53%	59,412	112,660	49	215	460	0.4674	80,425	27,769	52,656
1x75 kVA	Unit	271	2,454	664,973	1984	368.2	R0.5	32	63	37.53%	8%	34.53%	229,599	435,374	49	215	460	0.4674	310,802	107,313	203,489
1x100 kVA	Unit	3	2,870	8,611	1984	368.2	R0.5	32	63	37.53%	8%	34.53%	2,973	5,638	49	215	460	0.4674	4,025	1,390	2,635
PAD MOUNTED 3-PHASE TRANSFORMERS																					
1x75 kVA	Unit	87	3,780	328,848	1984	368.2	R0.5	32	63	37.53%	8%	34.53%	113,543	215,305	49	215	460	0.4674	153,701	53,069	100,632
1x150 kVA	Unit	66	7,186	474,276	1984	368.2	R0.5	32	63	37.53%	8%	34.53%	163,756	310,520	49	215	460	0.4674	221,672	76,538	145,134
1x225 kVA	Unit	2	8,058	16,116	1984	368.2	R0.5	32	63	37.53%	8%	34.53%	5,564	10,551	49	215	460	0.4674	7,532	2,601	4,931
1x300 kVA	Unit	76	8,930	678,673	1984	368.2	R0.5	32	63	37.53%	8%	34.53%	234,330	444,344	49	215	460	0.4674	317,206	109,524	207,682
1x500 kVA	Unit	5	10,844	54,218	1984	368.2	R0.5	32	63	37.53%	8%	34.53%	18,720	35,498	49	215	460	0.4674	25,341	8,750	16,591
1x750 kVA	Unit	6	15,126	90,758	1984	368.2	R0.5	32	63	37.53%	8%	34.53%	31,337	59,421	49	215	460	0.4674	42,420	14,646	27,774
1x1000 kVA	Unit	29	16,294	472,540	1984	368.2	R0.5	32	63	37.53%	8%	34.53%	163,157	309,383	49	215	460	0.4674	220,861	76,258	144,603
1x1500 kVA	Unit	17	24,818	421,910	1984	368.2	R0.5	32	63	37.53%	8%	34.53%	145,675	276,235	49	215	460	0.4674	197,197	68,087	129,110
SUBSURFACE SINGLE-PHASE TRANSFORMERS																					
1x75 kVA	Unit	3	2,541	7,622	1994	368.2	R0.5	32	31	18.88%	8%	17.37%	1,324	6,298	49	308	460	0.6696	5,103	886	4,217
1x100 kVA	Unit	20	2,957	59,147	1994	368.2	R0.5	32	31	18.88%	8%	17.37%	10,274	48,873	49	308	460	0.6696	39,603	6,879	32,724
SUBSURFACE 3-PHASE TRANSFORMERS																					
1x150 kVA	Unit	3	7,290	21,871	1994	368.2	R0.5	32	31	18.88%	8%	17.37%	3,799	18,072	49	308	460	0.6696	14,644	2,544	12,100
1x300 kVA	Unit	1	9,034	9,034	1994	368.2	R0.5	32	31	18.88%	8%	17.37%	1,569	7,465	49	308	460	0.6696	6,049	1,051	4,998
		682		**3,480,669**									**1,185,033**	**2,295,636**					**1,646,581**	**557,305**	**1,089,276**
OVERHEAD LOW VOLTAGE CIRCUITS																					
3 # 1/0 AWG AL Bare	mi	7.59	18,058	137,013	1984	365	R1	37	54	37.30%	-49%	55.58%	76,148	60,865	45	273	477	0.5723	78,416	43,581	34,835
3 # 4/0 AWG AL Bare	mi	7.59	30,668	232,696	1984	365	R1	37	54	37.30%	-49%	55.58%	129,326	103,371	45	273	477	0.5723	133,178	74,017	59,161
UNDERGROUND LOW VOLTAGE CIRCUITS																					
3 # 4/0 AWG AL 600V	mi	4.46	129,403	577,653	1994	367	S3	31	32	31.92%	-19%	37.98%	219,420	358,233	47	291	369	0.7886	455,547	173,039	282,508
3 # 350 AWG AL	mi	20.55	129,403	2,659,222	1994	367	S3	31	32	31.92%	-19%	37.98%	1,010,100	1,649,122	47	291	369	0.7886	2,097,110	796,583	1,300,527
3 # 700 AWG AL	mi	3.00	129,403	388,208	1994	367	S3	31	32	31.92%	-19%	37.98%	147,460	240,748	47	291	369	0.7886	306,148	116,290	189,858
		43.19		**3,994,792**									**1,582,454**	**2,412,338**					**3,070,399**	**1,203,510**	**1,866,889**

SMUD Annexation Study
Estimated RCNLD and OCLD Values
Straight Line Depreciation

West Sacramento (includes Deepwater)

															HANDY-WHITMAN						
Description	Unit	Quantity	Price	RCN	Year	FERC Acct	Survivor Curve	ASL	Age % of ASL	Unadjusted Deprec.	Net Salvage %	Adjusted Deprec.	RCN Depreciation	RCNLD	Line No.	Year Installed	7/31/04	Factor	Original Cost	Orig Cost Depreciation	OCLD
SERVICE DROPS																					
Overhead Low Voltage Single-Phase Service Drop, 50 Feet																					
1C Triplex # 6 AWG AL.	Unit	372	294	109,552	1984	369.1	R4	43	47	46.04%	-45%	66.76%	73,135	36,417	50	255	393	0.6489	71,083	47,454	23,629
1C Triplex # 2 AWG AL.	Unit	161	311	50,010	1984	369.1	R4	43	47	46.04%	-45%	66.76%	33,385	16,624	50	255	393	0.6489	32,449	21,662	10,787
1C Triplex # 1/0 AWG de AL.	Unit	3,717	327	1,216,905	1984	369.1	R4	43	47	46.04%	-45%	66.76%	812,382	404,524	50	255	393	0.6489	789,595	527,118	262,477
1C Triplex # 4/0 AWG de AL.	Unit	8	327	2,619	1984	369.1	R4	43	47	46.04%	-45%	66.76%	1,748	871	50	255	393	0.6489	1,699	1,135	564
1 C Quadruplex # 1/0 AWG AL.	Unit	163	534	87,045	1984	369.1	R4	43	47	46.04%	-45%	66.76%	58,110	28,936	50	255	393	0.6489	56,480	37,705	18,775
1 C Quadruplex # 4/0 AWG de AL.	Unit	53	534	28,303	1984	369.1	R4	43	47	46.04%	-45%	66.76%	18,895	9,409	50	255	393	0.6489	18,365	12,260	6,105
2 # 1/0 AWG. (phases) y 1 # 2 AWG (neutral) AL 600 V.	Unit	6,732	309	2,078,009	1984	369.1	R4	43	47	46.04%	-45%	66.76%	1,387,237	690,772	50	255	393	0.6489	1,348,327	900,116	448,211
2 # 350 MCM. (phases) y 1 # 4/0 AWG (neutral) AL 600 V.	Unit	30	364	10,746	1984	369.1	R4	43	47	46.04%	-45%	66.76%	7,174	3,572	50	255	393	0.6489	6,973	4,655	2,318
2 # 1000 MCM. (phases) y 1 # 350 MCM (neutral) AL 600 V.	Unit	7	373	2,612	1984	369.1	R4	43	47	46.04%	-45%	66.76%	1,744	868	50	255	393	0.6489	1,695	1,132	563
Overhead Low Voltage three-phase Service Drop, 50 Feet																					
3 # 4/0 AWG (phases) y 1 # 1/0 AWG (neutral) AL 600 V.	Unit	87	449	39,086	1984	369.2	R4	43	47	46.04%	-45%	66.76%	26,093	12,993	51	218	275	0.7927	30,985	20,685	10,300
3 # 350 MCM (phases) y 1 # 4/0 AWG (neutral) AL 600 V.	Unit	9	489	4,398	1984	369.2	R4	43	47	46.04%	-45%	66.76%	2,936	1,462	51	218	275	0.7927	3,486	2,328	1,158
3 # 1000 MCM (phases) y 1 # 350 MCM (neutral) AL 600 V.	Unit	85	498	42,294	1984	369.2	R4	43	47	46.04%	-45%	66.76%	28,235	14,059	51	218	275	0.7927	33,528	22,382	11,146
2 circuits 3 # 1000 MCM (phases) y 1 # 350 MCM (neutral) AL 600 V.	Unit	92	621	57,171	1984	369.2	R4	43	47	46.04%	-45%	66.76%	38,166	19,005	51	218	275	0.7927	45,321	30,255	15,066
3 circuits 3 # 1000 MCM (phases) y 1 # 350 MCM (neutral) AL 600 V.	Unit	35	745	26,084	1984	369.2	R4	43	47	46.04%	-45%	66.76%	17,413	8,671	51	218	275	0.7927	20,678	13,804	6,874
5 circuits 3 # 1000 MCM (phases) y 1 # 350 MCM (neutral) AL600 V.	Unit	17	993	16,880	1984	369.2	R4	43	47	46.04%	-45%	66.76%	11,269	5,611	51	218	275	0.7927	13,381	8,933	4,448
		11,568		**3,771,715**									**2,517,922**	**1,253,794**					**2,474,045**	**1,651,624**	**822,421**
METERS																					
Residential	Unit	10,411	131	1,362,191	1984	370	R2	32	63	50.80%	0%	50.80%	691,993	670,198	52	213	324	0.6574	895,515	454,921	440,594
Commercial	Unit	1,041	290	301,984	1984	370	R2	32	63	50.80%	0%	50.80%	153,408	148,576	52	213	324	0.6574	198,527	100,851	97,676
Industrial	Unit	116	538	62,268	1984	370	R2	32	63	50.80%	0%	50.80%	31,632	30,636	52	213	324	0.6574	40,936	20,795	20,141
		11,568		**1,726,444**									**877,033**	**849,410**					**1,134,978**	**576,567**	**558,411**
RISERS																					
Three-phase Riser 12 kV 3 # 1000 MCM AL.	Unit	56	496	27,787	1984	365	R1	37	54	37.30%	-49%	55.58%	15,443	12,344	45	273	477	0.5723	15,903	8,838	7,065
Three-phase Riser 12 kV 3 # 4/0 AWG AL.	Unit	2	408	817	1984	365	R1	37	54	37.30%	-49%	55.58%	454	363	45	273	477	0.5723	468	260	208
Three-phase Riser 12 kV 3 # 1/0 AWG AL.	Unit	154	371	57,063	1984	365	R1	37	54	37.30%	-49%	55.58%	31,714	25,349	45	273	477	0.5723	32,659	18,151	14,508
Three-phase Riser 12 kV 2 # 1/0 AWG AL.	Unit	11	371	4,076	1984	365	R1	37	54	37.30%	-49%	55.58%	2,265	1,811	45	273	477	0.5723	2,333	1,296	1,037
SWITCHES																					
Overhead three-phase Switch	Unit	109	3,615	394,088	1984	365	R1	37	54	37.30%	-49%	55.58%	219,022	175,066	45	273	477	0.5723	225,547	125,352	100,195
Three single-phase Cutouts.	Set	48	1,594	75,732	1984	365	R1	37	54	37.30%	-49%	55.58%	42,090	33,642	45	273	477	0.5723	43,343	24,089	19,254
Two single-phase Cutouts	Set	48	1,063	50,488	1984	365	R1	37	54	37.30%	-49%	55.58%	28,060	22,428	45	273	477	0.5723	28,896	16,059	12,837
Pad Mounted Switch PMH4	Unit	8	5,534	44,270	1984	365	R1	37	54	37.30%	-49%	55.58%	24,604	19,666	45	273	477	0.5723	25,337	14,081	11,256
Pad Mounted Switch PMH 43W	Unit	20	6,824	136,475	1984	365	R1	37	54	37.30%	-49%	55.58%	75,849	60,626	45	273	477	0.5723	78,108	43,410	34,698
Pad Mounted Switch PMH6	Unit	1	8,207	8,207	1984	365	R1	37	54	37.30%	-49%	55.58%	4,561	3,646	45	273	477	0.5723	4,697	2,611	2,086
Pad Mounted Switch PMH9	Unit	18	9,796	176,328	1984	365	R1	37	54	37.30%	-49%	55.58%	97,998	78,330	45	273	477	0.5723	100,917	56,087	44,830
Subsurface 600 A 2 Ways.	Unit	13	6,824	88,709	1984	365	R1	37	54	37.30%	-49%	55.58%	49,302	39,407	45	273	477	0.5723	50,770	28,217	22,553
Subsurface 600 A 3 Ways, 2 Ways switched.	Unit	10	6,824	68,237	1984	365	R1	37	54	37.30%	-49%	55.58%	37,924	30,313	45	273	477	0.5723	39,054	21,705	17,349
Subsurface 600 A 3 Ways, 3 Ways switched.	Unit	7	6,917	48,420	1984	365	R1	37	54	37.30%	-49%	55.58%	26,911	21,510	45	273	477	0.5723	27,712	15,402	12,310
Subsurface 200 A Fused Switch.	Unit	16	6,917	110,675	1984	365	R1	37	54	37.30%	-49%	55.58%	61,510	49,165	45	273	477	0.5723	63,342	35,204	28,138
Recloser	Unit	6	9,404	56,422	1984	365	R1	37	54	37.30%	-49%	55.58%	31,358	25,065	45	273	477	0.5723	32,292	17,947	14,345
CAPACITORS BANKS.																					
Overhead Capacitors Bank 3 x 200 kVAR .	Unit	5	4,458	22,292	1984	365	R1	37	54	37.30%	-49%	55.58%	12,389	9,903	45	273	477	0.5723	12,758	7,091	5,667
Overhead Capacitors Bank 3 x 300 kVAR.	Unit	26	4,458	115,917	1984	365	R1	37	54	37.30%	-49%	55.58%	64,423	51,494	45	273	477	0.5723	66,342	36,871	29,471
Overhead Capacitors Bank 6 x 200 kVAR.	Unit	2	8,272	16,543	1984	365	R1	37	54	37.30%	-49%	55.58%	9,194	7,349	45	273	477	0.5723	9,468	5,262	4,206
Overhead Capacitors Bank 6 x 300 kVAR.	Unit	15	8,272	124,075	1984	365	R1	37	54	37.30%	-49%	55.58%	68,957	55,118	45	273	477	0.5723	71,012	39,466	31,546
Pad Mounted Capacitors Bank 3 x 300 kVAR.	Unit	3	6,071	18,213	1984	365	R1	37	54	37.30%	-49%	55.58%	10,122	8,091	45	273	477	0.5723	10,424	5,793	4,631
Pad Mounted Capacitors Bank 6 x 300 kVAR.	Unit	1	11,174	11,174	1984	365	R1	37	54	37.30%	-49%	55.58%	6,210	4,964	45	273	477	0.5723	6,395	3,554	2,841
REGULATORS																					
4 Step Voltage Regulator	Unit	1	1,764	1,764	1984	365	R1	37	54	37.30%	-49%	55.58%	980	783	45	273	477	0.5723	1,009	561	448
		579		**1,657,771**									**921,339**	**736,432**					**948,786**	**527,307**	**421,479**
				44,517,560									**16,995,813**	**27,521,747**					**29,849,152**	**11,279,443**	**18,569,709**

SMUD Annexation Study
Estimated RCNLD and OCLD Values
Straight Line Depreciation

Davis

Description	Unit	Quantity	Price	RCN	Year	FERC Acct	Survivor Curve	ASL	Age % of ASL	Unadjusted Deprec.	Net Salvage %	Adjusted Deprec.	RCN Depreciation	RCNLD	HANDY-WHITMAN Line No.	HANDY-WHITMAN Year Installed	HANDY-WHITMAN 7/31/04	HANDY-WHITMAN Factor	Original Cost	Orig Cost Depreciation	OCLD
SUBSTATIONS																					
Davis	MVA	120.00	60,277	7,233,206	1989	362	L0	43	35	19.78%	0%	19.78%	1,430,728	5,802,478	43	299	444	0.6734	4,871,010	963,486	3,907,524
Hunt	MVA	10.50	92,245	968,570	1989	362	L0	43	35	19.78%	0%	19.78%	191,583	776,987	43	299	444	0.6734	652,258	129,017	523,241
		130.50		**8,201,776**									**1,622,311**	**6,579,465**					**5,523,268**	**1,092,503**	**4,430,765**
FEEDERS																					
12 kv Overhead Feeder																					
3 # 715.5 MCM AL	mi	25.28	44,338	1,120,643	1984	365	R1	37	54	37.30%	-49%	55.58%	622,820	497,823	45	273	477	0.5723	641,374	356,457	284,917
3 # 397.5 MCM AL	mi	9.98	39,408	393,220	1984	365	R1	37	54	37.30%	-49%	55.58%	218,540	174,680	45	273	477	0.5723	225,051	125,076	99,975
3 # 4/0 AWG AL	mi	10.57	36,588	386,625	1984	365	R1	37	54	37.30%	-49%	55.58%	214,875	171,750	45	273	477	0.5723	221,276	122,979	98,297
3 # 2/0 AWG AL	mi	12.18	25,236	307,405	1984	365	R1	37	54	37.30%	-49%	55.58%	170,846	136,558	45	273	477	0.5723	175,936	97,780	78,156
3 # 1/0 AWG AL	mi	0.57	21,462	12,180	1984	365	R1	37	54	37.30%	-49%	55.58%	6,769	5,411	45	273	477	0.5723	6,971	3,874	3,097
3 # 2 AWG AL	mi	47.23	21,565	1,018,507	1984	365	R1	37	54	37.30%	-49%	55.58%	566,055	452,451	45	273	477	0.5723	582,919	323,969	258,950
2 # 2 AWG AL	mi	9.05	14,377	130,163	1984	365	R1	37	54	37.30%	-49%	55.58%	72,341	57,822	45	273	477	0.5723	74,496	41,403	33,093
3 # 4 AWG AL	mi	25.59	21,565	551,770	1984	365	R1	37	54	37.30%	-49%	55.58%	306,657	245,113	45	273	477	0.5723	315,793	175,508	140,285
2 # 4 AWG AL	mi	5.41	14,377	77,706	1984	365	R1	37	54	37.30%	-49%	55.58%	43,187	34,519	45	273	477	0.5723	44,473	24,717	19,756
2 # 6 AWG CU	mi	0.16	8,611	1,335	1984	365	R1	37	54	37.30%	-49%	55.58%	742	593	45	273	477	0.5723	764	425	339
		146.00		**3,999,554**									**2,222,832**	**1,776,722**					**2,289,053**	**1,272,188**	**1,016,865**
12 Kv Underground feeder																					
3 # 1250 MCM AL	mi	0.05	157,192	7,368	1994	367	S3	31	32	31.92%	-19%	37.98%	2,799	4,570	47	291	369	0.7886	5,811	2,207	3,604
3 # 1000 MCM AL	mi	7.07	157,192	1,112,037	1994	367	S3	31	32	31.92%	-19%	37.98%	422,405	689,632	47	291	369	0.7886	876,972	333,116	543,856
3 # 350 MCM AL	mi	9.89	129,403	1,280,115	1994	367	S3	31	32	31.92%	-19%	37.98%	486,249	793,866	47	291	369	0.7886	1,009,521	383,465	626,056
3 # 1/0 MCM AL	mi	39.99	117,388	4,693,890	1994	367	S3	31	32	31.92%	-19%	37.98%	1,782,965	2,910,925	47	291	369	0.7886	3,701,685	1,406,078	2,295,607
2 # 1/0 MCM AL	mi	47.68	78,258	3,731,703	1994	367	S3	31	32	31.92%	-19%	37.98%	1,417,480	2,314,223	47	291	369	0.7886	2,942,888	1,117,850	1,825,038
		105		**10,825,113**									**4,111,897**	**6,713,215**					**8,536,877**	**3,242,716**	**5,294,161**
POLES																					
40 to 45 foot poles, with all hardware and accessories	Unit	3,571	2,103	7,512,499	1984	364	L0	37	54	27.29%	-35%	36.84%	2,767,717	4,744,782	44	266	448	0.5938	4,460,546	1,643,332	2,817,214
		3,571		**7,512,499**									**2,767,717**	**4,744,782**					**4,460,546**	**1,643,332**	**2,817,214**
OVERHEAD SINGLE-PHASE TRANSFORMERS																					
5 kVA	Unit	35	822	28,774	1984	368.1	R0.5	32	63	37.53%	8%	34.53%	9,935	18,839	48	219	267	0.8202	23,601	8,149	15,452
1x10 kVA	Unit	39	822	32,062	1984	368.1	R0.5	32	63	37.53%	8%	34.53%	11,070	20,992	48	219	267	0.8202	26,298	9,080	17,218
1x15 kVA	Unit	64	832	53,275	1984	368.1	R0.5	32	63	37.53%	8%	34.53%	18,395	34,881	48	219	267	0.8202	43,698	15,088	28,610
1x25 kVA	Unit	219	1,061	232,427	1984	368.1	R0.5	32	63	37.53%	8%	34.53%	80,251	152,175	48	219	267	0.8202	190,642	65,824	124,818
1x37.5 kVA	Unit	48	1,248	59,913	1984	368.1	R0.5	32	63	37.53%	8%	34.53%	20,686	39,226	48	219	267	0.8202	49,142	16,967	32,175
1x50 kVA	Unit	202	1,670	337,342	1984	368.1	R0.5	32	63	37.53%	8%	34.53%	116,476	220,866	48	219	267	0.8202	276,696	95,536	181,160
1x75 kVA	Unit	90	1,763	158,710	1984	368.1	R0.5	32	63	37.53%	8%	34.53%	54,799	103,911	48	219	267	0.8202	130,178	44,947	85,231
1x100 kVA	Unit	17	1,857	31,567	1984	368.1	R0.5	32	63	37.53%	8%	34.53%	10,899	20,668	48	219	267	0.8202	25,892	8,940	16,952
1x167 kVA	Unit	1	1,857	1,857	1984	368.1	R0.5	32	63	37.53%	8%	34.53%	641	1,216	48	219	267	0.8202	1,523	526	997
OVERHEAD 3-PHASE TRANSFORMERS																					
1x45 kVA	Unit	8	1,670	13,360	1984	368.1	R0.5	32	63	37.53%	8%	34.53%	4,613	8,747	48	219	267	0.8202	10,958	3,784	7,174
1x112.5 kVA	Unit	34	3,360	114,231	1984	368.1	R0.5	32	63	37.53%	8%	34.53%	39,441	74,790	48	219	267	0.8202	93,695	32,351	61,344
1x150 kVA	Unit	7	3,547	24,826	1984	368.1	R0.5	32	63	37.53%	8%	34.53%	8,572	16,254	48	219	267	0.8202	20,363	7,031	13,332
1x225 kVA	Unit	3	3,733	11,200	1984	368.1	R0.5	32	63	37.53%	8%	34.53%	3,867	7,333	48	219	267	0.8202	9,187	3,172	6,015
OVERHEAD 3-PHASE TRANSFORMER BANKS																					
3x10 kVA	Unit	8	2,466	19,730	1984	368.1	R0.5	32	63	37.53%	8%	34.53%	6,812	12,918	48	219	267	0.8202	16,183	5,588	10,595
3x15 kVA	Unit	6	2,497	14,984	1984	368.1	R0.5	32	63	37.53%	8%	34.53%	5,173	9,810	48	219	267	0.8202	12,290	4,243	8,047
3x25 kVA	Unit	30	3,184	95,518	1984	368.1	R0.5	32	63	37.53%	8%	34.53%	32,980	62,538	48	219	267	0.8202	78,346	27,051	51,295
3x37.5 kVA	Unit	4	3,745	14,978	1984	368.1	R0.5	32	63	37.53%	8%	34.53%	5,172	9,807	48	219	267	0.8202	12,285	4,242	8,043
3x50 kVA	Unit	9	5,010	45,090	1984	368.1	R0.5	32	63	37.53%	8%	34.53%	15,569	29,522	48	219	267	0.8202	36,984	12,770	24,214
2x10+1x5 kVA	Unit	1	2,466	2,466	1984	368.1	R0.5	32	63	37.53%	8%	34.53%	852	1,615	48	219	267	0.8202	2,023	698	1,325
2x10+1x75 kVA	Unit	1	3,408	3,408	1984	368.1	R0.5	32	63	37.53%	8%	34.53%	1,177	2,231	48	219	267	0.8202	2,795	965	1,830
2x25+1x50 kVA	Unit	1	3,793	3,793	1984	368.1	R0.5	32	63	37.53%	8%	34.53%	1,310	2,483	48	219	267	0.8202	3,111	1,074	2,037
2x25+1x75 kVA	Unit	1	3,886	3,886	1984	368.1	R0.5	32	63	37.53%	8%	34.53%	1,342	2,544	48	219	267	0.8202	3,187	1,101	2,086
2x50+1x37.5 kVA	Unit	1	4,588	4,588	1984	368.1	R0.5	32	63	37.53%	8%	34.53%	1,584	3,004	48	219	267	0.8202	3,763	1,299	2,464
OVERHEAD 2-TRANSFORMER BANKS																					
1x5 + 1x25 kVA	Unit	1	1,510	1,510	1984	368.1	R0.5	32	63	37.53%	8%	34.53%	521	988	48	219	267	0.8202	1,238	428	810
1x5 + 1x37.5 kVA	Unit	2	1,790	3,580	1984	368.1	R0.5	32	63	37.53%	8%	34.53%	1,236	2,344	48	219	267	0.8202	2,936	1,014	1,922
1x10 + 1x15 kVA	Unit	1	1,655	1,655	1984	368.1	R0.5	32	63	37.53%	8%	34.53%	571	1,083	48	219	267	0.8202	1,357	469	888
1x10 + 1x25 kVA	Unit	7	1,883	13,184	1984	368.1	R0.5	32	63	37.53%	8%	34.53%	4,552	8,632	48	219	267	0.8202	10,814	3,734	7,080
1x10 + 1x50 kVA	Unit	2	2,492	4,984	1984	368.1	R0.5	32	63	37.53%	8%	34.53%	1,721	3,263	48	219	267	0.8202	4,088	1,412	2,676
1x10 + 1x75 kVA	Unit	2	2,586	5,171	1984	368.1	R0.5	32	63	37.53%	8%	34.53%	1,785	3,386	48	219	267	0.8202	4,241	1,464	2,777
1x15 + 1x25 kVA	Unit	3	1,894	5,681	1984	368.1	R0.5	32	63	37.53%	8%	34.53%	1,962	3,720	48	219	267	0.8202	4,660	1,609	3,051
1x15 + 1x50 kVA	Unit	1	2,502	2,502	1984	368.1	R0.5	32	63	37.53%	8%	34.53%	864	1,638	48	219	267	0.8202	2,053	709	1,344
1x25 + 1x37.5 kVA	Unit	2	2,309	4,619	1984	368.1	R0.5	32	63	37.53%	8%	34.53%	1,595	3,024	48	219	267	0.8202	3,789	1,308	2,481
1x25 + 1x50 kVA	Unit	8	2,731	21,851	1984	368.1	R0.5	32	63	37.53%	8%	34.53%	7,544	14,306	48	219	267	0.8202	17,922	6,188	11,734
1x25 + 1x75 kVA	Unit	2	2,825	5,650	1984	368.1	R0.5	32	63	37.53%	8%	34.53%	1,951	3,699	48	219	267	0.8202	4,634	1,600	3,034
1x37.5 + 1x50 kVA	Unit	1	2,918	2,918	1984	368.1	R0.5	32	63	37.53%	8%	34.53%	1,008	1,911	48	219	267	0.8202	2,394	826	1,568
2x5 kVA	Unit	3	1,644	4,933	1984	368.1	R0.5	32	63	37.53%	8%	34.53%	1,703	3,230	48	219	267	0.8202	4,046	1,397	2,649
2x10 kVA	Unit	15	1,644	24,663	1984	368.1	R0.5	32	63	37.53%	8%	34.53%	8,516	16,148	48	219	267	0.8202	20,229	6,985	13,244
2x15 kVA	Unit	10	1,665	16,648	1984	368.1	R0.5	32	63	37.53%	8%	34.53%	5,748	10,900	48	219	267	0.8202	13,655	4,715	8,940
2x25 kVA	Unit	22	2,123	46,698	1984	368.1	R0.5	32	63	37.53%	8%	34.53%	16,124	30,574	48	219	267	0.8202	38,303	13,225	25,078
2x50 kVA	Unit	1	3,340	3,340	1984	368.1	R0.5	32	63	37.53%	8%	34.53%	1,153	2,187	48	219	267	0.8202	2,740	946	1,794
2x75 kVA	Unit	1	3,527	3,527	1984	368.1	R0.5	32	63	37.53%	8%	34.53%	1,218	2,309	48	219	267	0.8202	2,893	999	1,894
		913		**1,481,097**									**511,387**	**969,710**					**1,214,832**	**419,454**	**795,378**

SMUD Annexation Study
Estimated RCNLD and OCLD Values
Straight Line Depreciation

Davis

Description	Unit	Quantity	Price	RCN	Year	FERC Acct	Survivor Curve	ASL	Age % of ASL	Unadjusted Deprec.	Net Salvage %	Adjusted Deprec.	RCN Depreciation	RCNLD	HANDY-WHITMAN Line No.	Year Installed	7/31/04	Factor	Original Cost	Orig Cost Depreciation	OCLD
PAD MOUNTED SINGLE-PHASE TRANSFORMERS																					
1x15 kVA	Unit	1	1,432	1,432	1984	368.2	R0.5	32	63	37.53%	8%	34.53%	495	938	49	215	460	0.4674	669	231	438
1x37.5 kVA	Unit	4	1,850	7,401	1984	368.2	R0.5	32	63	37.53%	8%	34.53%	2,555	4,846	49	215	460	0.4674	3,459	1,194	2,265
1x50 kVA	Unit	91	1,850	168,371	1984	368.2	R0.5	32	63	37.53%	8%	34.53%	58,135	110,237	49	215	460	0.4674	78,695	27,172	51,523
1x75 kVA	Unit	80	2,454	196,302	1984	368.2	R0.5	32	63	37.53%	8%	34.53%	67,778	128,524	49	215	460	0.4674	91,750	31,679	60,071
1x100 kVA	Unit	170	2,870	487,975	1984	368.2	R0.5	32	63	37.53%	8%	34.53%	168,486	319,489	49	215	460	0.4674	228,075	78,749	149,326
1x167 kVA	Unit	2	2,964	5,928	1984	368.2	R0.5	32	63	37.53%	8%	34.53%	2,047	3,881	49	215	460	0.4674	2,771	957	1,814
PAD MOUNTED 3-PHASE TRANSFORMERS																					
1x45 kVA	Unit	6	2,124	12,741	1984	368.2	R0.5	32	63	37.53%	8%	34.53%	4,399	8,342	49	215	460	0.4674	5,955	2,056	3,899
1x67.5 kVA	Unit	-	3,780	-	1984	368.2	R0.5	32	63	37.53%	8%	34.53%	-	-	49	215	460	0.4674	-	-	-
1x75 kVA	Unit	8	3,780	30,239	1984	368.2	R0.5	32	63	37.53%	8%	34.53%	10,441	19,798	49	215	460	0.4674	14,133	4,880	9,253
1x150 kVA	Unit	111	7,186	797,646	1984	368.2	R0.5	32	63	37.53%	8%	34.53%	275,408	522,238	49	215	460	0.4674	372,813	128,723	244,090
1x300 kVA	Unit	48	8,930	428,636	1984	368.2	R0.5	32	63	37.53%	8%	34.53%	147,998	280,638	49	215	460	0.4674	200,341	69,173	131,168
1x500 kVA	Unit	26	10,844	281,934	1984	368.2	R0.5	32	63	37.53%	8%	34.53%	97,345	184,589	49	215	460	0.4674	131,773	45,498	86,275
1x750 kVA	Unit	11	15,126	166,390	1984	368.2	R0.5	32	63	37.53%	8%	34.53%	57,450	108,939	49	215	460	0.4674	77,769	26,852	50,917
1x1000 kVA	Unit	5	16,294	81,472	1984	368.2	R0.5	32	63	37.53%	8%	34.53%	28,130	53,342	49	215	460	0.4674	38,080	13,148	24,932
1x1500 kVA	Unit	4	24,818	99,273	1984	368.2	R0.5	32	63	37.53%	8%	34.53%	34,277	64,996	49	215	460	0.4674	46,399	16,021	30,378
1x2000 kVA	Unit	1	30,039	30,039	1984	368.2	R0.5	32	63	37.53%	8%	34.53%	10,372	19,668	49	215	460	0.4674	14,040	4,848	9,192
SUBSURFACE SINGLE-PHASE TRANSFORMERS																					
1x50 kVA	Unit	146	2,124	310,103	1994	368.2	R0.5	32	31	18.88%	8%	17.37%	53,864	256,239	49	308	460	0.6696	207,634	36,065	171,569
1x100 kVA	Unit	337	2,957	996,622	1994	368.2	R0.5	32	31	18.88%	8%	17.37%	173,109	823,512	49	308	460	0.6696	667,303	115,908	551,395
SUBSURFACE 3-PHASE TRANSFORMERS																					
1x150 kVA	Unit	8	7,290	58,322	1994	368.2	R0.5	32	31	18.88%	8%	17.37%	10,130	48,192	49	308	460	0.6696	39,050	6,783	32,267
1x300 kVA	Unit	9	9,034	81,308	1994	368.2	R0.5	32	31	18.88%	8%	17.37%	14,123	67,185	49	308	460	0.6696	54,441	9,456	44,985
1x500 kVA	Unit	18	10,965	197,374	1994	368.2	R0.5	32	31	18.88%	8%	17.37%	34,283	163,091	49	308	460	0.6696	132,155	22,955	109,200
1x1000 kVA	Unit	1	15,265	15,265	1994	368.2	R0.5	32	31	18.88%	8%	17.37%	2,652	12,614	49	308	460	0.6696	10,221	1,775	8,446
		1,087		**4,454,773**									**1,253,476**	**3,201,297**					**2,417,526**	**644,123**	**1,773,403**
OVERHEAD LOW VOLTAGE CIRCUITS																					
1C Triplex # 4/0 AWG AL Bare	mi	7.38	20,796	153,370	1984	365	R1	37	54	37.30%	-49%	55.58%	85,238	68,131	45	273	477	0.5723	87,778	48,784	38,994
3 # 4/0 AWG AL Bare	mi	7.38	30,668	226,179	1984	365	R1	37	54	37.30%	-49%	55.58%	125,704	100,476	45	273	477	0.5723	129,449	71,944	57,505
UNDERGROUND LOW VOLTAGE CIRCUITS																					
3 # 4/0 AWG AL 600V	mi	11.38	129,403	1,472,083	1994	367	S3	31	32	31.92%	-19%	37.98%	559,168	912,915	47	291	369	0.7886	1,160,911	440,970	719,941
3 # 350 AWG AL	mi	6.00	129,403	776,415	1994	367	S3	31	32	31.92%	-19%	37.98%	294,920	481,496	47	291	369	0.7886	612,295	232,579	379,716
3 # 700 AWG AL	mi	50.55	129,403	6,541,299	1994	367	S3	31	32	31.92%	-19%	37.98%	2,484,699	4,056,600	47	291	369	0.7886	5,158,585	1,959,478	3,199,107
		82.68		**9,169,347**									**3,549,729**	**5,619,618**					**7,149,018**	**2,753,755**	**4,395,263**
SERVICE DROPS																					
Overhead Low Voltage single-phase Service Drop, 50 Feet																					
1C Triplex # 6 AWG AL.	Unit	155	294	45,647	1984	369.1	R4	43	47	46.04%	-45%	66.76%	30,473	15,174	50	255	393	0.6489	29,618	19,772	9,846
1C Triplex # 2 AWG AL.	Unit	121	311	37,430	1984	369.1	R4	43	47	46.04%	-45%	66.76%	24,987	12,442	50	255	393	0.6489	24,286	16,213	8,073
1C Triplex # 1/0 AWG de AL.	Unit	3,698	327	1,210,685	1984	369.1	R4	43	47	46.04%	-45%	66.76%	808,229	402,456	50	255	393	0.6489	785,559	524,423	261,136
1C Triplex # 4/0 AWG de AL.	Unit	6	327	1,964	1984	369.1	R4	43	47	46.04%	-45%	66.76%	1,311	653	50	255	393	0.6489	1,275	851	424
1 C Quadruplex # 1/0 AWG AL.	Unit	92	534	49,130	1984	369.1	R4	43	47	46.04%	-45%	66.76%	32,798	16,332	50	255	393	0.6489	31,878	21,281	10,597
1 C Quadruplex # 4/0 AWG de AL.	Unit	43	534	22,963	1984	369.1	R4	43	47	46.04%	-45%	66.76%	15,330	7,633	50	255	393	0.6489	14,900	9,947	4,953
2 # 1/0 AWG. (phases) y 1 # 2 AWG (neutral) AL 600 V.	Unit	11,088	309	3,422,603	1984	369.1	R4	43	47	46.04%	-45%	66.76%	2,284,862	1,137,742	50	255	393	0.6489	2,220,773	1,482,544	738,229
2 # 350 MCM. (phases) y 1 # 4/0 AWG (neutral) AL 600 V.	Unit	45	364	16,393	1984	369.1	R4	43	47	46.04%	-45%	66.76%	10,943	5,449	50	255	393	0.6489	10,637	7,101	3,536
2 # 1000 MCM. (phases) y 1 # 350 MCM (neutral) AL 600 V.	Unit	17	373	6,344	1984	369.1	R4	43	47	46.04%	-45%	66.76%	4,235	2,109	50	255	393	0.6489	4,116	2,748	1,368
Overhead Low Voltage three-phase Service Drop, 50 Feet																					
3 # 1/0 AWG (phases) y 1 # 2 AWG (neutral) AL 600 V.	Unit	6	411	2,469	1984	369.2	R4	43	47	46.04%	-45%	66.76%	1,648	821	51	218	275	0.7927	1,957	1,306	651
3 # 4/0 AWG (phases) y 1 # 1/0 AWG (neutral) AL 600 V.	Unit	8	449	3,594	1984	369.2	R4	43	47	46.04%	-45%	66.76%	2,399	1,195	51	218	275	0.7927	2,849	1,902	947
3 # 350 MCM (phases) y 1 # 4/0 AWG (neutral) AL 600 V.	Unit	40	489	19,547	1984	369.2	R4	43	47	46.04%	-45%	66.76%	13,049	6,498	51	218	275	0.7927	15,496	10,345	5,151
3 # 1000 MCM (phases) y 1 # 350 MCM (neutral) AL 600 V.	Unit	135	498	67,173	1984	369.2	R4	43	47	46.04%	-45%	66.76%	44,843	22,330	51	218	275	0.7927	53,250	35,549	17,701
2 circuits 3 # 1000 MCM (phases) y 1 # 350 MCM (neutral) AL 600 V.	Unit	72	621	44,742	1984	369.2	R4	43	47	46.04%	-45%	66.76%	29,869	14,873	51	218	275	0.7927	35,468	23,678	11,790
3 circuits 3 # 1000 MCM (phases) y 1 # 350 MCM (neutral) AL 600 V.	Unit	49	745	36,518	1984	369.2	R4	43	47	46.04%	-45%	66.76%	24,378	12,139	51	218	275	0.7927	28,949	19,325	9,624
5 circuits 3 # 1000 MCM (phases) y 1 # 350 MCM (neutral) AL600 V.	Unit	4	993	3,972	1984	369.2	R4	43	47	46.04%	-45%	66.76%	2,651	1,320	51	218	275	0.7927	3,149	2,102	1,047
7 circuits 3 # 1000 MCM (phases) y 1 # 350 MCM (neutral) AL600 V.	Unit	1	1,241	1,241	1984	369.2	R4	43	47	46.04%	-45%	66.76%	828	412	51	218	275	0.7927	983	657	326
		15,580		**4,992,414**									**3,332,836**	**1,659,578**					**3,265,143**	**2,179,744**	**1,085,399**
METERS																					
Residential	Unit	14,022	131	1,834,646	1984	370	R2	32	63	50.80%	0%	50.80%	932,000	902,646	52	213	324	0.6574	1,206,110	612,704	593,406
Commercial	Unit	1,402	290	406,722	1984	370	R2	32	63	50.80%	0%	50.80%	206,615	200,107	52	213	324	0.6574	267,382	135,830	131,552
Industrial	Unit	156	538	83,865	1984	370	R2	32	63	50.80%	0%	50.80%	42,603	41,262	52	213	324	0.6574	55,134	28,008	27,126
		15,580		**2,325,233**									**1,181,218**	**1,144,015**					**1,528,626**	**776,542**	**752,084**
RISERS																					
Three-phase Riser 12 kV 3 # 1000 MCM AL.	Unit	27	496	13,397	1984	365	R1	37	54	37.30%	-49%	55.58%	7,446	5,951	45	273	477	0.5723	7,668	4,261	3,407
Three-phase Riser 12 kV 3 # 350 MCM AL.	Unit	12	408	4,902	1984	365	R1	37	54	37.30%	-49%	55.58%	2,724	2,177	45	273	477	0.5723	2,805	1,559	1,246
Three-phase Riser 12 kV 3 # 4/0 AWG AL.	Unit	1	408	408	1984	365	R1	37	54	37.30%	-49%	55.58%	227	181	45	273	477	0.5723	234	130	104
Three-phase Riser 12 kV 3 # 1/0 AWG AL.	Unit	105	371	38,907	1984	365	R1	37	54	37.30%	-49%	55.58%	21,623	17,284	45	273	477	0.5723	22,267	12,376	9,891
Three-phase Riser 12 kV 2 # 1/0 AWG AL.	Unit	68	371	25,197	1984	365	R1	37	54	37.30%	-49%	55.58%	14,004	11,193	45	273	477	0.5723	14,421	8,015	6,406

SMUD Annexation Study
Estimated RCNLD and OCLD Values
Straight Line Depreciation

Davis

Description	Unit	Quantity	Price	RCN	Year	FERC Acct	Survivor Curve	ASL	Age % of ASL	Unadjusted Deprec.	Net Salvage %	Adjusted Deprec.	RCN Depreciation	RCNLD	HANDY-WHITMAN Line No.	Year Installed	7/31/04	Factor	Original Cost	Orig Cost Depreciation	OCLD
SWITCHES																					
Overhead three-phase Switch	Unit	118	3,615	426,627	1984	365	R1	37	54	37.30%	-49%	55.58%	237,106	189,521	45	273	477	0.5723	244,170	135,702	108,468
Three single-phase Cutouts.	Set	67	1,594	106,822	1984	365	R1	37	54	37.30%	-49%	55.58%	59,368	47,454	45	273	477	0.5723	61,137	33,978	27,159
Two single-phase Cutouts	Set	41	1,063	43,579	1984	365	R1	37	54	37.30%	-49%	55.58%	24,220	19,359	45	273	477	0.5723	24,941	13,862	11,079
Pad Mounted Switch PMH4	Unit	7	5,534	38,736	1984	365	R1	37	54	37.30%	-49%	55.58%	21,528	17,208	45	273	477	0.5723	22,170	12,321	9,849
Pad Mounted Switch PMH 43W	Unit	29	6,824	197,888	1984	365	R1	37	54	37.30%	-49%	55.58%	109,980	87,908	45	273	477	0.5723	113,257	62,945	50,312
Pad Mounted Switch PMH6	Unit	1	8,207	8,207	1984	365	R1	37	54	37.30%	-49%	55.58%	4,561	3,646	45	273	477	0.5723	4,697	2,611	2,086
Pad Mounted Switch PMH9	Unit	1	9,796	9,796	1984	365	R1	37	54	37.30%	-49%	55.58%	5,444	4,352	45	273	477	0.5723	5,607	3,116	2,491
Subsurface 600 A 2 Ways.	Unit	27	6,824	184,241	1984	365	R1	37	54	37.30%	-49%	55.58%	102,396	81,845	45	273	477	0.5723	105,446	58,604	46,842
Subsurface 600 A 3 Ways, 2 Ways switched.	Unit	22	6,824	150,122	1984	365	R1	37	54	37.30%	-49%	55.58%	83,433	66,689	45	273	477	0.5723	85,919	47,751	38,168
Subsurface 600 A 3 Ways, 3 Ways switched.	Unit	17	6,917	117,592	1984	365	R1	37	54	37.30%	-49%	55.58%	65,354	52,238	45	273	477	0.5723	67,301	37,404	29,897
Subsurface 200 A Fused Switch.	Unit	4	6,917	27,669	1984	365	R1	37	54	37.30%	-49%	55.58%	15,377	12,291	45	273	477	0.5723	15,836	8,801	7,035
Recloser	Unit	8	9,404	75,230	1984	365	R1	37	54	37.30%	-49%	55.58%	41,811	33,419	45	273	477	0.5723	43,056	23,929	19,127
CAPACITOR BANKS																					
Overhead Capacitors Bank 3 x 100 kVAR .	Unit	2	4,458	8,917	1984	365	R1	37	54	37.30%	-49%	55.58%	4,956	3,961	45	273	477	0.5723	5,103	2,836	2,267
Overhead Capacitors Bank 3 x 200 kVAR .	Unit	2	4,458	8,917	1984	365	R1	37	54	37.30%	-49%	55.58%	4,956	3,961	45	273	477	0.5723	5,103	2,836	2,267
Overhead Capacitors Bank 3 x 300 kVAR.	Unit	20	4,458	89,167	1984	365	R1	37	54	37.30%	-49%	55.58%	49,556	39,611	45	273	477	0.5723	51,033	28,362	22,671
Overhead Capacitors Bank 3 x 300 kVAR., 3 x 200 kVAR	Unit	1	8,272	8,272	1984	365	R1	37	54	37.30%	-49%	55.58%	4,597	3,675	45	273	477	0.5723	4,734	2,631	2,103
Overhead Capacitors Bank 6 x 200 kVAR.	Unit	1	8,272	8,272	1984	365	R1	37	54	37.30%	-49%	55.58%	4,597	3,675	45	273	477	0.5723	4,734	2,631	2,103
Overhead Capacitors Bank 6 x 300 kVAR.	Unit	22	8,272	181,977	1984	365	R1	37	54	37.30%	-49%	55.58%	101,137	80,840	45	273	477	0.5723	104,150	57,884	46,266
Pad Mounted Capacitors Bank 6 x 300 kVAR.	Unit	6	11,174	67,045	1984	365	R1	37	54	37.30%	-49%	55.58%	37,262	29,783	45	273	477	0.5723	38,372	21,326	17,046
REGULATORS																					
4 Step Voltage Regulator	Unit	2	1,764	3,527	1984	365	R1	37	54	37.30%	-49%	55.58%	1,960	1,567	45	273	477	0.5723	2,019	1,122	897
32 Step Voltage Regulator	Unit	1	2,137	2,137	1984	365	R1	37	54	37.30%	-49%	55.58%	1,188	950	45	273	477	0.5723	1,223	680	543
		612		**1,847,551**									**1,026,813**	**820,737**					**1,057,403**	**587,673**	**469,730**
				54,809,357									**21,580,218**	**33,229,139**					**37,442,292**	**14,612,030**	**22,830,262**

SMUD Annexation Study
Estimated RCNLD and OCLD Values
Straight Line Depreciation

Davis (1107)

Description	Unit	Quantity	Price	RCN	Year	FERC Acct	Survivor Curve	ASL	Age % of ASL	Unadjusted Deprec.	Net Salvage %	Adjusted Deprec.	RCN Depreciation	RCNLD	HANDY-WHITMAN Line No.	Year Installed	7/31/04	Factor	Original Cost	Orig Cost Depreciation	OCLD
FEEDERS																					
12 kv Overhead Feeder																					
3 # 715.5 MCM AL	mi	4.29	44,338	190,127	1984	365	R1	37	54	37.30%	-49%	55.58%	105,667	84,460	45	273	477	0.5723	108,815	60,476	48,339
3 # 397.5 MCM AL	mi	4.54	39,408	178,716	1984	365	R1	37	54	37.30%	-49%	55.58%	99,325	79,391	45	273	477	0.5723	102,284	56,846	45,438
3 # 2/0 AWG AL	mi	4.95	25,236	124,981	1984	365	R1	37	54	37.30%	-49%	55.58%	69,461	55,520	45	273	477	0.5723	71,530	39,754	31,776
3 # 2 AWG AL	mi	3.43	21,565	73,995	1984	365	R1	37	54	37.30%	-49%	55.58%	41,124	32,871	45	273	477	0.5723	42,350	23,537	18,813
2 # 2 AWG AL	mi	0.16	14,377	2,237	1984	365	R1	37	54	37.30%	-49%	55.58%	1,243	994	45	273	477	0.5723	1,281	712	569
3 # 4 AWG AL	mi	9.67	21,565	208,508	1984	365	R1	37	54	37.30%	-49%	55.58%	115,882	92,625	45	273	477	0.5723	119,335	66,323	53,012
2 # 4 AWG AL	mi	0.07	14,377	1,006	1984	365	R1	37	54	37.30%	-49%	55.58%	559	447	45	273	477	0.5723	576	320	256
		27.10		**779,571**									**433,262**	**346,309**					**446,171**	**247,968**	**198,203**
12 Kv Underground Feeder																					
3 # 1000 MCM AL	mi	0.35	157,192	55,017	1994	367	S3	31	32	31.92%	-19%	37.98%	20,898	34,119	47	291	369	0.7886	43,388	16,481	26,907
		0.35		**55,017**									**20,898**	**34,119**					**43,388**	**16,481**	**26,907**
POLES																					
40 to 45 foot poles, with all hardware and accessories	Unit	440	2,103	925,074	1984	364	L0	37	54	27.29%	-35%	36.84%	340,811	584,263	44	266	448	0.5938	549,263	202,357	346,906
		439.78		**925,074**									**340,811**	**584,263**					**549,263**	**202,357**	**346,906**
OVERHEAD SINGLE-PHASE TRANSFORMERS																					
1x10 kVA	Unit	20	822	16,442	1984	368.1	R0.5	32	63	37.53%	8%	34.53%	5,677	10,765	48	219	267	0.8202	13,486	4,656	8,830
1x15 kVA	Unit	6	832	4,995	1984	368.1	R0.5	32	63	37.53%	8%	34.53%	1,724	3,270	48	219	267	0.8202	4,097	1,414	2,683
1x25 kVA	Unit	7	1,061	7,429	1984	368.1	R0.5	32	63	37.53%	8%	34.53%	2,565	4,864	48	219	267	0.8202	6,094	2,104	3,990
1x37.5 kVA	Unit	1	1,248	1,248	1984	368.1	R0.5	32	63	37.53%	8%	34.53%	431	817	48	219	267	0.8202	1,024	353	671
1x75 kVA	Unit	20	1,763	35,269	1984	368.1	R0.5	32	63	37.53%	8%	34.53%	12,177	23,091	48	219	267	0.8202	28,928	9,988	18,940
OVERHEAD 3-PHASE TRANSFORMERS																					
1x45 kVA	Unit	1	1,670	1,670	1984	368.1	R0.5	32	63	37.53%	8%	34.53%	577	1,093	48	219	267	0.8202	1,370	473	897
1x112.5 kVA	Unit	5	3,360	16,799	1984	368.1	R0.5	32	63	37.53%	8%	34.53%	5,800	10,998	48	219	267	0.8202	13,779	4,757	9,022
OVERHEAD 3-PHASE TRANSFORMER BANKS																					
3x10 kVA	Unit	6	2,466	14,798	1984	368.1	R0.5	32	63	37.53%	8%	34.53%	5,109	9,689	48	219	267	0.8202	12,138	4,191	7,947
3x15 kVA	Unit	2	2,497	4,995	1984	368.1	R0.5	32	63	37.53%	8%	34.53%	1,724	3,270	48	219	267	0.8202	4,097	1,414	2,683
3x25 kVA	Unit	6	3,184	19,104	1984	368.1	R0.5	32	63	37.53%	8%	34.53%	6,596	12,508	48	219	267	0.8202	15,669	5,410	10,259
3x37.5 kVA	Unit	1	3,745	3,745	1984	368.1	R0.5	32	63	37.53%	8%	34.53%	1,293	2,452	48	219	267	0.8202	3,071	1,060	2,011
3x50 kVA	Unit	1	5,010	5,010	1984	368.1	R0.5	32	63	37.53%	8%	34.53%	1,730	3,280	48	219	267	0.8202	4,109	1,419	2,690
OVERHEAD 2-TRANSFORMER BANKS																					
1x5 + 1x25 kVA	Unit	1	1,510	1,510	1984	368.1	R0.5	32	63	37.53%	8%	34.53%	521	988	48	219	267	0.8202	1,238	428	810
1x10 + 1x25 kVA	Unit	1	1,883	1,883	1984	368.1	R0.5	32	63	37.53%	8%	34.53%	650	1,233	48	219	267	0.8202	1,545	533	1,012
1x15 + 1x50 kVA	Unit	1	2,502	2,502	1984	368.1	R0.5	32	63	37.53%	8%	34.53%	864	1,638	48	219	267	0.8202	2,053	709	1,344
2x5 kVA	Unit	1	1,644	1,644	1984	368.1	R0.5	32	63	37.53%	8%	34.53%	568	1,077	48	219	267	0.8202	1,349	466	883
2x10 kVA	Unit	7	1,644	11,509	1984	368.1	R0.5	32	63	37.53%	8%	34.53%	3,974	7,536	48	219	267	0.8202	9,440	3,260	6,180
2x15 kVA	Unit	2	1,665	3,330	1984	368.1	R0.5	32	63	37.53%	8%	34.53%	1,150	2,180	48	219	267	0.8202	2,731	943	1,788
2x25 kVA	Unit	5	2,123	10,613	1984	368.1	R0.5	32	63	37.53%	8%	34.53%	3,664	6,949	48	219	267	0.8202	8,705	3,006	5,699
		94		**164,494**									**56,796**	**107,698**					**134,923**	**46,584**	**88,339**
PAD MOUNTED 3-PHASE TRANSFORMERS																					
1x150 kVA	Unit	2	7,186	14,372	1984	368.2	R0.5	32	63	37.53%	8%	34.53%	4,962	9,410	49	215	460	0.4674	6,717	2,319	4,398
		2		**14,372**									**4,962**	**9,410**					**6,717**	**2,319**	**4,398**
OVERHEAD LOW VOLTAGE CIRCUITS																					
1C Triplex # 4/0 AWG AL Bare	mi	0.28	20,796	5,719	1984	365	R1	37	54	37.30%	-49%	55.58%	3,178	2,540	45	273	477	0.5723	3,273	1,819	1,454
3 # 4/0 AWG AL Bare	mi	0.28	30,668	8,434	1984	365	R1	37	54	37.30%	-49%	55.58%	4,687	3,747	45	273	477	0.5723	4,827	2,683	2,144
		0.55		**14,153**									**7,866**	**6,287**					**8,100**	**4,502**	**3,598**
SERVICE DROPS																					
Overhead Low Voltage single-phase Service Drop, 50 Feet																					
1C Triplex # 6 AWG AL.	Unit	28	294	8,246	1984	369.1	R4	43	47	46.04%	-45%	66.76%	5,505	2,741	50	255	393	0.6489	5,350	3,572	1,778
1C Triplex # 2 AWG AL.	Unit	4	311	1,087	1984	369.1	R4	43	47	46.04%	-45%	66.76%	726	361	50	255	393	0.6489	705	471	234
1C Triplex # 1/0 AWG de AL.	Unit	129	327	42,069	1984	369.1	R4	43	47	46.04%	-45%	66.76%	28,085	13,985	50	255	393	0.6489	27,297	18,223	9,074
2 # 350 MCM. (phases) y 1 # 4/0 AWG (neutral) AL 600 V.	Unit	10	364	3,643	1984	369.1	R4	43	47	46.04%	-45%	66.76%	2,432	1,211	50	255	393	0.6489	2,364	1,578	786
Overhead Low Voltage three-phase Service Drop, 50 Feet																					
1 C Quadruplex # 1/0 AWG AL.	Unit	27	534	14,419	1984	369.2	R4	43	47	46.04%	-45%	66.76%	9,626	4,793	51	218	275	0.7927	11,430	7,630	3,800
1 C Quadruplex # 4/0 AWG de AL.	Unit	6	534	3,204	1984	369.2	R4	43	47	46.04%	-45%	66.76%	2,139	1,065	51	218	275	0.7927	2,540	1,696	844
3 # 350 MCM (phases) y 1 # 4/0 AWG (neutral) AL 600 V.	Unit	6	489	2,932	1984	369.2	R4	43	47	46.04%	-45%	66.76%	1,957	975	51	218	275	0.7927	2,324	1,552	772
3 # 1000 MCM (phases) y 1 # 350 MCM (neutral) AL 600 V.	Unit	3	498	1,493	1984	369.2	R4	43	47	46.04%	-45%	66.76%	997	496	51	218	275	0.7927	1,183	790	393
		212		**77,093**									**51,466**	**25,627**					**53,193**	**35,512**	**17,681**

SMUD Annexation Study
Estimated RCNLD and OCLD Values
Straight Line Depreciation

Davis (1107)

															HANDY-WHITMAN						
Description	Unit	Quantity	Price	RCN	Year	FERC Acct	Survivor Curve	ASL	Age % of ASL	Unadjusted Deprec.	Net Salvage %	Adjusted Deprec.	RCN Depreciation	RCNLD	Line No.	Year Installed	7/31/04	Factor	Original Cost	Orig Cost Depreciation	OCLD
METERS																					
Residential	Unit	191	131	24,965	1984	370	R2	32	63	50.80%	0%	50.80%	12,682	12,283	52	213	324	0.6574	16,412	8,337	8,075
Commercial	Unit	19	290	5,535	1984	370	R2	32	63	50.80%	0%	50.80%	2,812	2,723	52	213	324	0.6574	3,638	1,848	1,790
Industrial	Unit	2	538	1,141	1984	370	R2	32	63	50.80%	0%	50.80%	580	561	52	213	324	0.6574	750	381	369
		212		**31,641**									**16,074**	**15,567**					**20,800**	**10,566**	**10,234**
RISERS																					
Three-phase Riser 12 kV 3 # 1000 MCM AL.	Unit	1	496	496	1984	365	R1	37	54	37.30%	-49%	55.58%	276	220	45	273	477	0.5723	284	158	126
Three-phase Riser 12 kV 3 # 1/0 AWG AL.	Unit	2	371	741	1984	365	R1	37	54	37.30%	-49%	55.58%	412	329	45	273	477	0.5723	424	236	188
Three-phase Riser 12 kV 2 # 1/0 AWG AL.	Unit	2	371	741	1984	365	R1	37	54	37.30%	-49%	55.58%	412	329	45	273	477	0.5723	424	236	188
SWITCHES																					
Overhead three-phase Switch	Unit	2	3,615	7,231	1984	365	R1	37	54	37.30%	-49%	55.58%	4,019	3,212	45	273	477	0.5723	4,138	2,300	1,838
Three single-phase Cutouts.	Set	1	1,594	1,594	1984	365	R1	37	54	37.30%	-49%	55.58%	886	708	45	273	477	0.5723	912	507	405
Recloser	Unit	2	9,404	18,807	1984	365	R1	37	54	37.30%	-49%	55.58%	10,453	8,355	45	273	477	0.5723	10,764	5,982	4,782
CAPACITORS BANKS																					
Overhead Capacitors Bank 3 x 100 kVAR .	Unit	1	4,458	4,458	1984	365	R1	37	54	37.30%	-49%	55.58%	2,478	1,981	45	273	477	0.5723	2,552	1,418	1,134
Overhead Capacitors Bank 3 x 200 kVAR .	Unit	1	4,458	4,458	1984	365	R1	37	54	37.30%	-49%	55.58%	2,478	1,981	45	273	477	0.5723	2,552	1,418	1,134
Overhead Capacitors Bank 3 x 300 kVAR.	Unit	1	4,458	4,458	1984	365	R1	37	54	37.30%	-49%	55.58%	2,478	1,981	45	273	477	0.5723	2,552	1,418	1,134
Overhead Capacitors Bank 6 x 200 kVAR.	Unit	1	8,272	8,272	1984	365	R1	37	54	37.30%	-49%	55.58%	4,597	3,675	45	273	477	0.5723	4,734	2,631	2,103
		14		**51,258**									**51,258**	**51,258**					**51,258**	**51,258**	**51,258**
				2,112,673									**983,392**	**1,180,538**					**1,313,813**	**617,547**	**747,524**

SMUD Annexation Study
Estimated RCNLD and OCLD Values
Straight Line Depreciation

Plainfield

															HANDY-WHITMAN						
Description	Unit	Quantity	Price	RCN	Year	FERC Acct	Survivor Curve	ASL	Age % of ASL	Unadjusted Deprec.	Net Salvage %	Adjusted Deprec.	RCN Depreciation	RCNLD	Line No.	Year Installed	7/31/04	Factor	Original Cost	Orig Cost Depreciation	OCLD
SUBSTATIONS																					
Plainfield	MVA	12.00	48,831	585,975	1979	362	L0	43	58	28.76%	0%	28.76%	168,526	417,449	43	187	444	0.4212	246,796	70,978	175,818
		12.00		**585,975**									**168,526**	**417,449**					**246,796**	**70,978**	**175,818**
FEEDERS																					
12 kv Overhead Feeder																					
3 # 715.5 MCM AL	mi	2.26	44,338	100,176	1979	365	R1	37	68	45.95%	-49%	68.47%	68,586	31,590	45	196	477	0.4109	41,163	28,182	12,981
3 # 397.5 MCM AL	mi	5.60	39,408	220,859	1979	365	R1	37	68	45.95%	-49%	68.47%	151,212	69,647	45	196	477	0.4109	90,751	62,133	28,618
3 # 4/0 AWG AL	mi	3.07	36,588	112,189	1979	365	R1	37	68	45.95%	-49%	68.47%	76,811	35,378	45	196	477	0.4109	46,099	31,562	14,537
3 # 2/0 AWG AL	mi	14.27	25,236	360,101	1979	365	R1	37	68	45.95%	-49%	68.47%	246,545	113,556	45	196	477	0.4109	147,966	101,306	46,660
3 # 2 AWG AL	mi	12.57	21,565	271,033	1979	365	R1	37	68	45.95%	-49%	68.47%	185,564	85,469	45	196	477	0.4109	111,368	76,249	35,119
2 # 2 AWG AL	mi	2.45	14,377	35,268	1979	365	R1	37	68	45.95%	-49%	68.47%	24,146	11,122	45	196	477	0.4109	14,492	9,922	4,570
3 # 4 AWG AL	mi	24.40	21,565	526,189	1979	365	R1	37	68	45.95%	-49%	68.47%	360,258	165,931	45	196	477	0.4109	216,212	148,030	68,182
2 # 4 AWG AL	mi	3.19	14,377	45,853	1979	365	R1	37	68	45.95%	-49%	68.47%	31,393	14,459	45	196	477	0.4109	18,841	12,900	5,941
		67.81		**1,671,667**									**1,144,515**	**527,152**					**686,892**	**470,284**	**216,608**
12 Kv Underground Feeder																					
2 # 1/0 MCM AL	mi	1.70	78,258	132,697	1994	367	S3	31	32	31.92%	-19%	37.98%	50,405	82,292	47	291	369	0.7886	104,647	39,750	64,897
		1.70		**132,697**									**50,405**	**82,292**					**104,647**	**39,750**	**64,897**
POLES																					
40 to 45 foot poles, with all hardware and accessories	Unit	1,348	2,103	2,835,487	1979	364	L0	37	68	32.32%	-35%	43.63%	1,237,180	1,598,308	44	197	448	0.4397	1,246,855	544,028	702,827
		1,348		**2,835,487**									**1,237,180**	**1,598,308**					**1,246,855**	**544,028**	**702,827**
OVERHEAD SINGLE-PHASE TRANSFORMERS																					
1x10 kVA	Unit	38	822	31,240	1979	368.1	R0.5	32	78	45.71%	8%	42.05%	13,137	18,103	48	168	267	0.6292	19,657	8,266	11,391
1x15 kVA	Unit	16	832	13,319	1979	368.1	R0.5	32	78	45.71%	8%	42.05%	5,601	7,718	48	168	267	0.6292	8,380	3,524	4,856
1x25 kVA	Unit	62	1,061	65,801	1979	368.1	R0.5	32	78	45.71%	8%	42.05%	27,671	38,130	48	168	267	0.6292	41,403	17,411	23,992
1x37.5 kVA	Unit	11	1,248	13,730	1979	368.1	R0.5	32	78	45.71%	8%	42.05%	5,774	7,956	48	168	267	0.6292	8,639	3,633	5,006
1x50 kVA	Unit	28	1,670	46,760	1979	368.1	R0.5	32	78	45.71%	8%	42.05%	19,664	27,096	48	168	267	0.6292	29,422	12,373	17,049
1x75 kVA	Unit	24	1,763	42,323	1979	368.1	R0.5	32	78	45.71%	8%	42.05%	17,798	24,525	48	168	267	0.6292	26,630	11,199	15,431
1x100 kVA	Unit	12	1,857	22,283	1979	368.1	R0.5	32	78	45.71%	8%	42.05%	9,371	12,912	48	168	267	0.6292	14,020	5,896	8,124
OVERHEAD 3-PHASE TRANSFORMERS																					
1x45 kVA	Unit	8	1,670	13,360	1979	368.1	R0.5	32	78	45.71%	8%	42.05%	5,618	7,742	48	168	267	0.6292	8,406	3,535	4,871
1x112.5 kVA	Unit	1	3,360	3,360	1979	368.1	R0.5	32	78	45.71%	8%	42.05%	1,413	1,947	48	168	267	0.6292	2,114	889	1,225
1x150 kVA	Unit	11	3,547	39,013	1979	368.1	R0.5	32	78	45.71%	8%	42.05%	16,406	22,607	48	168	267	0.6292	24,547	10,323	14,224
OVERHEAD 3-PHASE TRANSFORMER BANKS																					
3x10 kVA	Unit	12	2,466	29,596	1979	368.1	R0.5	32	78	45.71%	8%	42.05%	12,446	17,150	48	168	267	0.6292	18,622	7,831	10,791
3x25 kVA	Unit	12	3,184	38,207	1979	368.1	R0.5	32	78	45.71%	8%	42.05%	16,067	22,140	48	168	267	0.6292	24,040	10,110	13,930
3x37.5 kVA	Unit	2	3,745	7,489	1979	368.1	R0.5	32	78	45.71%	8%	42.05%	3,149	4,340	48	168	267	0.6292	4,712	1,982	2,730
3x50 kVA	Unit	4	5,010	20,040	1979	368.1	R0.5	32	78	45.71%	8%	42.05%	8,428	11,613	48	168	267	0.6292	12,610	5,303	7,307
3x75 kVA	Unit	2	5,290	10,581	1979	368.1	R0.5	32	78	45.71%	8%	42.05%	4,450	6,131	48	168	267	0.6292	6,657	2,800	3,857
2x10+1x25 kVA	Unit	1	2,706	2,706	1979	368.1	R0.5	32	78	45.71%	8%	42.05%	1,138	1,568	48	168	267	0.6292	1,702	716	986
2x10+1x50 kVA	Unit	1	3,314	3,314	1979	368.1	R0.5	32	78	45.71%	8%	42.05%	1,394	1,920	48	168	267	0.6292	2,085	877	1,208
2x37.5+1x50 kVA	Unit	1	4,166	4,166	1979	368.1	R0.5	32	78	45.71%	8%	42.05%	1,752	2,414	48	168	267	0.6292	2,622	1,102	1,520
OVERHEAD 2-TRANSFORMER BANKS																					
1x10 + 1x25 kVA	Unit	7	1,883	13,184	1979	368.1	R0.5	32	78	45.71%	8%	42.05%	5,544	7,640	48	168	267	0.6292	8,295	3,489	4,806
1x10 + 1x37.5 kVA	Unit	3	2,070	6,211	1979	368.1	R0.5	32	78	45.71%	8%	42.05%	2,612	3,599	48	168	267	0.6292	3,908	1,643	2,265
1x10 + 1x50 kVA	Unit	1	2,492	2,492	1979	368.1	R0.5	32	78	45.71%	8%	42.05%	1,048	1,444	48	168	267	0.6292	1,568	659	909
1x10 + 1x75 kVA	Unit	1	2,586	2,586	1979	368.1	R0.5	32	78	45.71%	8%	42.05%	1,087	1,498	48	168	267	0.6292	1,627	684	943
1x15 + 1x25 kVA	Unit	2	1,894	3,787	1979	368.1	R0.5	32	78	45.71%	8%	42.05%	1,593	2,195	48	168	267	0.6292	2,383	1,002	1,381
1x15 + 1x37.5 kVA	Unit	1	2,081	2,081	1979	368.1	R0.5	32	78	45.71%	8%	42.05%	875	1,206	48	168	267	0.6292	1,309	551	758
1x25 + 1x37.5 kVA	Unit	2	2,309	4,619	1979	368.1	R0.5	32	78	45.71%	8%	42.05%	1,942	2,677	48	168	267	0.6292	2,906	1,222	1,684
1x25 + 1x50 kVA	Unit	2	2,731	5,463	1979	368.1	R0.5	32	78	45.71%	8%	42.05%	2,297	3,165	48	168	267	0.6292	3,437	1,445	1,992
2x10 kVA	Unit	6	1,644	9,865	1979	368.1	R0.5	32	78	45.71%	8%	42.05%	4,149	5,717	48	168	267	0.6292	6,207	2,610	3,597
2x15 kVA	Unit	2	1,665	3,330	1979	368.1	R0.5	32	78	45.71%	8%	42.05%	1,400	1,929	48	168	267	0.6292	2,095	881	1,214
2x25 kVA	Unit	21	2,123	44,575	1979	368.1	R0.5	32	78	45.71%	8%	42.05%	18,745	25,830	48	168	267	0.6292	28,047	11,795	16,252
2x50 kVA	Unit	7	3,340	23,380	1979	368.1	R0.5	32	78	45.71%	8%	42.05%	9,832	13,548	48	168	267	0.6292	14,711	6,186	8,525
		301		**528,858**									**222,402**	**306,457**					**332,761**	**139,937**	**192,824**

SMUD Annexation Study
Estimated RCNLD and OCLD Values
Straight Line Depreciation

Plainfield

Description	Unit	Quantity	Price	RCN	Year	FERC Acct	Survivor Curve	ASL	Age % of ASL	Unadjusted Deprec.	Net Salvage %	Adjusted Deprec.	RCN Depreciation	RCNLD	HANDY-WHITMAN Line No.	HANDY-WHITMAN Year Installed	HANDY-WHITMAN 7/31/04	HANDY-WHITMAN Factor	Original Cost	Orig Cost Depreciation	OCLD
PAD MOUNTED SINGLE-PHASE TRANSFORMERS													-	-					-		
1x50 kVA	Unit	4	1,850	7,401	1979	368.2	R0.5	32	78	45.71%	8%	42.05%	3,112	4,289	49	144	460	0.3130	2,317	974	1,343
SUBSURFACE SINGLE-PHASE TRANSFORMERS													-	-							
1x50 kVA	Unit	8	2,124	16,992	1994	368.2	R0.5	32	31	18.88%	8%	17.37%	2,951	14,041	49	308	460	0.6696	11,377	1,976	9,401
1x100 kVA	Unit	3	2,957	8,872	1994	368.2	R0.5	32	31	18.88%	8%	17.37%	1,541	7,331	49	308	460	0.6696	5,940	1,032	4,908
SUBSURFACE 3-PHASE TRANSFORMERS																			-		
1x300 kVA	Unit	2	9,034	18,068	1994	368.2	R0.5	32	31	18.88%	8%	17.37%	3,138	14,930	49	308	460	0.6696	12,098	2,101	9,997
		17		**51,333**									**10,743**	**40,590**					**31,732**	**6,083**	**25,649**
OVERHEAD LOW VOLTAGE CIRCUITS																					
1C Triplex # 4/0 AWG AL Bare	mi	1.28	20,796	26,515	1979	365	R1	37	68	45.95%	-49%	68.47%	18,153	8,361	45	196	477	0.4109	10,895	7,459	3,436
3 # 4/0 AWG AL Bare	mi	1.28	30,668	39,102	1979	365	R1	37	68	45.95%	-49%	68.47%	26,772	12,331	45	196	477	0.4109	16,067	11,000	5,067
UNDERGROUND LOW VOLTAGE CIRCUITS																					
3 # 4/0 AWG AL 600V	mi	0.576	129,403	74,536	1994	367	S3	31	32	31.92%	-19%	37.98%	28,312	46,224	47	291	369	0.7886	58,780	22,328	36,452
3 # 700 AWG AL	mi	0.450	129,403	58,231	1994	367	S3	31	32	31.92%	-19%	37.98%	22,119	36,112	47	291	369	0.7886	45,922	17,443	28,479
		3.576		**198,384**									**95,356**	**103,028**					**131,664**	**58,230**	**73,434**
SERVICE DROPS																					
Overhead Low Voltage single-phase Service Drop, 50 Feet																					
1C Triplex # 6 AWG AL.	Unit	67	294	19,731	1979	369.1	R4	43	58	55.91%	-45%	81.07%	15,996	3,735	50	181	393	0.4606	9,087	7,367	1,720
1C Triplex # 2 AWG AL.	Unit	38	311	11,804	1979	369.1	R4	43	58	55.91%	-45%	81.07%	9,569	2,234	50	181	393	0.4606	5,436	4,407	1,029
1C Triplex # 1/0 AWG de AL.	Unit	667	327	218,369	1979	369.1	R4	43	58	55.91%	-45%	81.07%	177,030	41,338	50	181	393	0.4606	100,572	81,533	19,039
1C Triplex # 4/0 AWG de AL.	Unit	1	327	327	1979	369.1	R4	43	58	55.91%	-45%	81.07%	265	62	50	181	393	0.4606	151	122	29
1 C Quadruplex # 1/0 AWG AL.	Unit	70	534	37,381	1979	369.1	R4	43	58	55.91%	-45%	81.07%	30,305	7,077	50	181	393	0.4606	17,216	13,957	3,259
1 C Quadruplex # 4/0 AWG de AL.	Unit	18	534	9,612	1979	369.1	R4	43	58	55.91%	-45%	81.07%	7,793	1,820	50	181	393	0.4606	4,427	3,589	838
2 # 1/0 AWG. (phases) y 1 # 2 AWG (neutral) AL 600 V.	Unit	122	309	37,659	1979	369.1	R4	43	58	55.91%	-45%	81.07%	30,530	7,129	50	181	393	0.4606	17,344	14,061	3,283
2 # 350 MCM. (phases) y 1 # 4/0 AWG (neutral) AL 600 V.	Unit	13	364	4,736	1979	369.1	R4	43	58	55.91%	-45%	81.07%	3,839	896	50	181	393	0.4606	2,181	1,768	413
2 # 1000 MCM. (phases) y 1 # 350 MCM (neutral) AL 600 V.	Unit	105	373	39,184	1979	369.1	R4	43	58	55.91%	-45%	81.07%	31,767	7,418	50	181	393	0.4606	18,047	14,630	3,417
Overhead Low Voltage three-phase Service Drop, 50 Feet																					
3 # 1/0 AWG (phases) y 1 # 2 AWG (neutral) AL 600 V.	Unit	3	411	1,234	1979	369.2	R4	43	58	55.91%	-45%	81.07%	1,001	234	51	145	275	0.5273	651	528	123
3 # 350 MCM (phases) y 1 # 4/0 AWG (neutral) AL 600 V.	Unit	3	489	1,466	1979	369.2	R4	43	58	55.91%	-45%	81.07%	1,189	278	51	145	275	0.5273	773	627	146
3 # 1000 MCM (phases) y 1 # 350 MCM (neutral) AL 600 V.	Unit	15	498	7,464	1979	369.2	R4	43	58	55.91%	-45%	81.07%	6,051	1,413	51	145	275	0.5273	3,935	3,190	745
2 circuits 3 # 1000 MCM (phases) y 1 # 350 MCM (neutral) AL 600 V	Unit	4	621	2,486	1979	369.2	R4	43	58	55.91%	-45%	81.07%	2,015	471	51	145	275	0.5273	1,311	1,063	248
		1,126		**391,453**									**317,349**	**74,104**					**181,131**	**146,842**	**34,289**
METERS																					
Residential	Unit	1,013	131	132,598	1979	370	R2	32	78	60.44%	0%	60.44%	80,142	52,456	52	154	324	0.4753	63,025	38,092	24,933
Commercial	Unit	101	290	29,396	1979	370	R2	32	78	60.44%	0%	60.44%	17,767	11,629	52	154	324	0.4753	13,972	8,445	5,527
Industrial	Unit	11	538	6,061	1979	370	R2	32	78	60.44%	0%	60.44%	3,663	2,398	52	154	324	0.4753	2,881	1,741	1,140
		1,126		**168,055**									**101,572**	**66,483**					**79,878**	**48,278**	**31,600**
RISERS													-	-							
Three-phase Riser 12 kV 2 # 1/0 AWG AL.	Unit	11	371	4,076	1979	365	R1	37	68	45.95%	-49%	68.47%	2,791	1,285	45	196	477	0.4109	1,675	1,147	528
SWITCHES																					
Overhead three-phase Switch	Unit	25	3,615	90,387	1979	365	R1	37	68	45.95%	-49%	68.47%	61,884	28,503	45	196	477	0.4109	37,140	25,428	11,712
Three single-phase Cutouts.	Set	17	1,594	27,104	1979	365	R1	37	68	45.95%	-49%	68.47%	18,557	8,547	45	196	477	0.4109	11,137	7,625	3,512
Two single-phase Cutouts	Set	9	1,063	9,566	1979	365	R1	37	68	45.95%	-49%	68.47%	6,550	3,017	45	196	477	0.4109	3,931	2,691	1,240
Recloser	Unit	2	9,404	18,807	1979	365	R1	37	68	45.95%	-49%	68.47%	12,877	5,931	45	196	477	0.4109	7,728	5,291	2,437
CAPACITORS BANKS.																					
Overhead Capacitors Bank 3 x 200 kVAR .	Unit	7	4,458	31,208	1979	365	R1	37	68	45.95%	-49%	68.47%	21,367	9,841	45	196	477	0.4109	12,824	8,780	4,044
Overhead Capacitors Bank 6 x 100 kVAR.	Unit	1	8,272	8,272	1979	365	R1	37	68	45.95%	-49%	68.47%	5,663	2,608	45	196	477	0.4109	3,399	2,327	1,072
REGULATORS																					
4 Step Voltage Regulator	Unit	1	1,764	1,764	1979	365	R1	37	68	45.95%	-49%	68.47%	1,208	556	45	196	477	0.4109	725	496	229
		73		**191,184**									**130,895**	**60,289**					**78,559**	**53,785**	**24,774**
				6,755,094									**3,478,944**	**3,276,150**					**3,120,915**	**1,578,195**	**1,542,720**

SMUD Annexation Study
Estimated RCNLD and OCLD Values
Straight Line Depreciation

Woodland

															HANDY-WHITMAN						
Description	Unit	Quantity	Price	RCN	Year	FERC Acct	Survivor Curve	ASL	Age % of ASL	Unadjusted Deprec.	Net Salvage %	Adjusted Deprec.	RCN Depreciation	RCNLD	Line No.	Year Installed	7/31/04	Factor	Original Cost	Orig Cost Depreciation	OCLD
SUBSTATIONS																					
Woodland	MVA	135.00	56,646	7,647,224	1984	362	L0	43	47	24.63%	0%	24.63%	1,883,511	5,763,713	43	244	444	0.5495	2,941,794	1,035,083	1,906,711
Tyco Plastics	MVA	10.50	79,672	836,555	1989	362	L0	43	35	19.78%	0%	19.78%	165,471	671,084	43	299	444	0.6734	436,580	111,432	325,148
		145.50		**8,483,779.00**									**2,048,982**	**6,434,797**					**3,378,374**	**1,146,515**	**2,231,859**
FEEDERS																					
12 kv Overhead Feeder																					
3 # 715.5 MCM AL	mi	15.95	44,338	707,219	1984	365	R1	37	54	37.30%	-49%	55.58%	393,051	314,168	45	273	477	0.5723	283,359	224,954	58,405
3 # 397.5 MCM AL	mi	7.50	39,408	295,685	1984	365	R1	37	54	37.30%	-49%	55.58%	164,333	131,352	45	273	477	0.5723	118,472	94,052	24,420
3 # 4/0 AWG AL	mi	3.96	36,588	144,821	1984	365	R1	37	54	37.30%	-49%	55.58%	80,487	64,334	45	273	477	0.5723	58,034	46,065	11,969
3 # 2/0 AWG AL	mi	0.54	25,236	13,612	1984	365	R1	37	54	37.30%	-49%	55.58%	7,565	6,047	45	273	477	0.5723	5,437	4,330	1,107
3 # 1/0 AWG AL	mi	0.62	21,462	13,373	1984	365	R1	37	54	37.30%	-49%	55.58%	7,432	5,941	45	273	477	0.5723	5,380	4,254	1,126
3 # 2 AWG AL	mi	44.42	21,565	957,936	1984	365	R1	37	54	37.30%	-49%	55.58%	532,392	425,544	45	273	477	0.5723	383,803	304,702	79,101
2 # 2 AWG AL	mi	12.28	14,377	176,546	1984	365	R1	37	54	37.30%	-49%	55.58%	98,119	78,427	45	273	477	0.5723	70,740	56,156	14,584
3 # 4 AWG AL	mi	14.87	21,565	320,754	1984	365	R1	37	54	37.30%	-49%	55.58%	178,265	142,489	45	273	477	0.5723	128,487	102,026	26,461
2 # 4 AWG AL	mi	7.54	14,377	108,374	1984	365	R1	37	54	37.30%	-49%	55.58%	60,231	48,143	45	273	477	0.5723	43,440	34,472	8,968
		107.69		**2,738,320**									**1,521,876**	**1,216,444**					**1,097,152**	**871,011**	**226,141**
12 Kv Underground Feeder																					
3 # 1000 MCM AL	mi	14.88	157,192	2,339,021	1994	367	S3	31	32	31.92%	-19%	37.98%	888,472	1,450,548	47	291	369	0.7886	1,660,120	700,665	959,455
3 # 350 MCM AL	mi	3.44	129,403	444,862	1994	367	S3	31	32	31.92%	-19%	37.98%	168,980	275,882	47	291	369	0.7886	315,763	133,261	182,502
3 # 4/0 MCM AL	mi	1.33	129,403	171,620	1994	367	S3	31	32	31.92%	-19%	37.98%	65,190	106,431	47	291	369	0.7886	121,841	51,410	70,431
3 # 1/0 MCM AL	mi	24.91	117,388	2,923,792	1994	367	S3	31	32	31.92%	-19%	37.98%	1,110,597	1,813,195	47	291	369	0.7886	2,075,169	875,836	1,199,333
2 # 1/0 MCM AL	mi	36.75	78,258	2,875,893	1994	367	S3	31	32	31.92%	-19%	37.98%	1,092,402	1,783,491	47	291	369	0.7886	2,041,180	861,488	1,179,692
		81.30		**8,755,188**									**3,325,641**	**5,429,547**					**6,214,073**	**2,622,660**	**3,591,413**
POLES																					
40 to 45 foot poles, with all hardware and accessories	Unit	2,580	2,103	5,427,758	1984	364	L0	37	54	27.29%	-35%	36.84%	1,999,668	3,428,091	44	266	448	0.5938	2,255,894	1,187,303	1,068,591
		2,580		**5,427,758**									**1,999,668**	**3,428,091**					**2,255,894**	**1,187,303**	**1,068,591**
TRANSFORMERS																					
Overhead Line Transformers																					
1x10 kVA	Unit	66	822	54,259	1984	368.1	R0.5	32	63	37.53%	8%	34.53%	18,734	35,525	48	219	267	0.8202	31,169	15,366	15,803
1x15 kVA	Unit	56	832	46,616	1984	368.1	R0.5	32	63	37.53%	8%	34.53%	16,095	30,520	48	219	267	0.8202	26,739	13,202	13,537
1x25 kVA	Unit	311	1,061	330,067	1984	368.1	R0.5	32	63	37.53%	8%	34.53%	113,964	216,103	48	219	267	0.8202	189,472	93,476	95,996
1x37.5 kVA	Unit	117	1,248	146,037	1984	368.1	R0.5	32	63	37.53%	8%	34.53%	50,423	95,614	48	219	267	0.8202	83,827	41,358	42,469
1x50 kVA	Unit	338	1,670	564,463	1984	368.1	R0.5	32	63	37.53%	8%	34.53%	194,895	369,567	48	219	267	0.8202	324,071	159,858	164,213
1x75 kVA	Unit	20	1,763	35,269	1984	368.1	R0.5	32	63	37.53%	8%	34.53%	12,177	23,091	48	219	267	0.8202	20,260	9,988	10,272
1x100 kVA	Unit	17	1,857	31,567	1984	368.1	R0.5	32	63	37.53%	8%	34.53%	10,899	20,668	48	219	267	0.8202	18,127	8,940	9,187
1x45 kVA	Unit	3	1,670	5,010	1984	368.1	R0.5	32	63	37.53%	8%	34.53%	1,730	3,280	48	219	267	0.8202	2,871	1,419	1,452
1x112.5 kVA	Unit	12	3,360	40,317	1984	368.1	R0.5	32	63	37.53%	8%	34.53%	13,920	26,396	48	219	267	0.8202	23,130	11,418	11,712
1x150 kVA	Unit	5	3,547	17,733	1984	368.1	R0.5	32	63	37.53%	8%	34.53%	6,123	11,610	48	219	267	0.8202	10,171	5,022	5,149
1x225 kVA	Unit	1	3,733	3,733	1984	368.1	R0.5	32	63	37.53%	8%	34.53%	1,289	2,444	48	219	267	0.8202	2,133	1,057	1,076
3x10 kVA	Unit	5	2,466	12,332	1984	368.1	R0.5	32	63	37.53%	8%	34.53%	4,258	8,074	48	219	267	0.8202	7,054	3,492	3,562
3x15 kVA	Unit	4	2,497	9,989	1984	368.1	R0.5	32	63	37.53%	8%	34.53%	3,449	6,540	48	219	267	0.8202	5,742	2,829	2,913
3x25 kVA	Unit	15	3,184	47,759	1984	368.1	R0.5	32	63	37.53%	8%	34.53%	16,490	31,269	48	219	267	0.8202	27,396	13,526	13,870
3x37.5 kVA	Unit	3	3,745	11,234	1984	368.1	R0.5	32	63	37.53%	8%	34.53%	3,879	7,355	48	219	267	0.8202	6,480	3,181	3,299
3x50 kVA	Unit	9	5,010	45,090	1984	368.1	R0.5	32	63	37.53%	8%	34.53%	15,569	29,522	48	219	267	0.8202	25,919	12,770	13,149
3x100 kVA	Unit	3	10,079	30,238	1984	368.1	R0.5	32	63	37.53%	8%	34.53%	10,440	19,797	48	219	267	0.8202	17,389	8,563	8,826
3x250 kVA	Unit	1	11,200	11,200	1984	368.1	R0.5	32	63	37.53%	8%	34.53%	3,867	7,333	48	219	267	0.8202	6,398	3,172	3,226
3x500 kVA	Unit	1	11,200	11,200	1984	368.1	R0.5	32	63	37.53%	8%	34.53%	3,867	7,333	48	219	267	0.8202	6,398	3,172	3,226
2x10+1x37.5 kVA	Unit	1	2,892	2,892	1984	368.1	R0.5	32	63	37.53%	8%	34.53%	999	1,894	48	219	267	0.8202	1,640	819	821
2x15+1x25 kVA	Unit	2	2,726	5,452	1984	368.1	R0.5	32	63	37.53%	8%	34.53%	1,883	3,570	48	219	267	0.8202	3,117	1,544	1,573
2x15+1x50 kVA	Unit	1	3,335	3,335	1984	368.1	R0.5	32	63	37.53%	8%	34.53%	1,151	2,183	48	219	267	0.8202	1,887	944	943
2x25+1x15 kVA	Unit	1	2,955	2,955	1984	368.1	R0.5	32	63	37.53%	8%	34.53%	1,020	1,935	48	219	267	0.8202	1,722	837	885
2x25+1x37.5 kVA	Unit	3	3,371	10,112	1984	368.1	R0.5	32	63	37.53%	8%	34.53%	3,492	6,621	48	219	267	0.8202	5,824	2,864	2,960
2x25+1x50 kVA	Unit	1	3,793	3,793	1984	368.1	R0.5	32	63	37.53%	8%	34.53%	1,310	2,483	48	219	267	0.8202	2,215	1,074	1,141
2x50+1x75 kVA	Unit	2	5,103	10,207	1984	368.1	R0.5	32	63	37.53%	8%	34.53%	3,524	6,683	48	219	267	0.8202	5,824	2,891	2,933
1x10 + 1x15 kVA	Unit	7	1,655	11,582	1984	368.1	R0.5	32	63	37.53%	8%	34.53%	3,999	7,583	48	219	267	0.8202	6,644	3,280	3,364
1x10 + 1x25 kVA	Unit	18	1,883	33,901	1984	368.1	R0.5	32	63	37.53%	8%	34.53%	11,705	22,196	48	219	267	0.8202	19,439	9,601	9,838
1x10 + 1x37.5 kVA	Unit	7	2,070	14,492	1984	368.1	R0.5	32	63	37.53%	8%	34.53%	5,004	9,488	48	219	267	0.8202	8,284	4,104	4,180
1x10 + 1x50 kVA	Unit	16	2,492	39,874	1984	368.1	R0.5	32	63	37.53%	8%	34.53%	13,767	26,106	48	219	267	0.8202	22,884	11,292	11,592
1x15 + 1x25 kVA	Unit	5	1,894	9,469	1984	368.1	R0.5	32	63	37.53%	8%	34.53%	3,269	6,199	48	219	267	0.8202	5,413	2,682	2,731
1x15 + 1x37.5 kVA	Unit	2	2,081	4,161	1984	368.1	R0.5	32	63	37.53%	8%	34.53%	1,437	2,724	48	219	267	0.8202	2,379	1,178	1,201
1x15 + 1x50 kVA	Unit	2	2,502	5,005	1984	368.1	R0.5	32	63	37.53%	8%	34.53%	1,728	3,277	48	219	267	0.8202	2,871	1,417	1,454
1x25 + 1x37.5 kVA	Unit	11	2,309	25,404	1984	368.1	R0.5	32	63	37.53%	8%	34.53%	8,772	16,633	48	219	267	0.8202	14,600	7,195	7,405
1x25 + 1x50 kVA	Unit	12	2,731	32,776	1984	368.1	R0.5	32	63	37.53%	8%	34.53%	11,317	21,459	48	219	267	0.8202	18,783	9,282	9,501
1x25 + 1x100 kVA	Unit	1	2,918	2,918	1984	368.1	R0.5	32	63	37.53%	8%	34.53%	1,008	1,911	48	219	267	0.8202	1,640	826	814

SMUD Annexation Study
Estimated RCNLD and OCLD Values
Straight Line Depreciation

Woodland

Description	Unit	Quantity	Price	RCN	Year	FERC Acct	Survivor Curve	ASL	Age % of ASL	Unadjusted Deprec.	Net Salvage %	Adjusted Deprec.	RCN Depreciation	RCNLD	HANDY-WHITMAN Line No.	Year Installed	7/31/04	Factor	Original Cost	Orig Cost Depreciation	OCLD
1x37.5 + 1x50 kVA	Unit	8	2,918	23,345	1984	368.1	R0.5	32	63	37.53%	8%	34.53%	8,061	15,285	48	219	267	0.8202	13,370	6,612	6,758
1x50 + 1x75 kVA	Unit	1	3,433	3,433	1984	368.1	R0.5	32	63	37.53%	8%	34.53%	1,185	2,248	48	219	267	0.8202	1,969	972	997
1x50 + 1x100 kVA	Unit	1	3,527	3,527	1984	368.1	R0.5	32	63	37.53%	8%	34.53%	1,218	2,309	48	219	267	0.8202	2,051	999	1,052
2x10 kVA	Unit	7	1,644	11,509	1984	368.1	R0.5	32	63	37.53%	8%	34.53%	3,974	7,536	48	219	267	0.8202	6,644	3,260	3,384
2x15 kVA	Unit	4	1,665	6,659	1984	368.1	R0.5	32	63	37.53%	8%	34.53%	2,299	4,360	48	219	267	0.8202	3,855	1,886	1,969
2x25 kVA	Unit	26	2,123	55,188	1984	368.1	R0.5	32	63	37.53%	8%	34.53%	19,055	36,133	48	219	267	0.8202	31,661	15,629	16,032
2x37.5 kVA	Unit	4	2,496	9,985	1984	368.1	R0.5	32	63	37.53%	8%	34.53%	3,448	6,538	48	219	267	0.8202	5,742	2,828	2,914
2x50 kVA	Unit	14	3,340	46,760	1984	368.1	R0.5	32	63	37.53%	8%	34.53%	16,145	30,615	48	219	267	0.8202	26,821	13,243	13,578
2x75 kVA	Unit	1	3,527	3,527	1984	368.1	R0.5	32	63	37.53%	8%	34.53%	1,218	2,309	48	219	267	0.8202	2,051	999	1,052
		1,145		**1,836,376**									**634,056**	**1,202,319**					**1,054,076**	**520,067**	**534,009**
Pad Mounted Single-Phase Transformers																					
1x25 kVA	Unit	1	1,432	1,432	1984	368.2	R0.5	32	63	37.53%	8%	34.53%	495	938	49	215	460	0.4674	467	231	236
1x50 kVA	Unit	174	1,850	321,941	1984	368.2	R0.5	32	63	37.53%	8%	34.53%	111,158	210,782	49	215	460	0.4674	105,350	51,954	53,396
1x75 kVA	Unit	19	2,454	46,622	1984	368.2	R0.5	32	63	37.53%	8%	34.53%	16,097	30,524	49	215	460	0.4674	15,237	7,524	7,713
1x100 kVA	Unit	9	2,870	25,834	1984	368.2	R0.5	32	63	37.53%	8%	34.53%	8,920	16,914	49	215	460	0.4674	8,460	4,169	4,291
1x167 kVA	Unit	4	2,964	11,856	1984	368.2	R0.5	32	63	37.53%	8%	34.53%	4,093	7,762	49	215	460	0.4674	3,879	1,913	1,966
Pad Mounted 3-Phase Transformers																					
1x45 kVA	Unit	8	2,124	16,988	1984	368.2	R0.5	32	63	37.53%	8%	34.53%	5,866	11,123	49	215	460	0.4674	5,562	2,742	2,820
1x75 kVA	Unit	5	3,780	18,899	1984	368.2	R0.5	32	63	37.53%	8%	34.53%	6,525	12,374	49	215	460	0.4674	6,170	3,050	3,120
1x112.5 kVA	Unit	23	4,309	99,113	1984	368.2	R0.5	32	63	37.53%	8%	34.53%	34,221	64,892	49	215	460	0.4674	32,437	15,995	16,442
1x150 kVA	Unit	54	7,186	388,044	1984	368.2	R0.5	32	63	37.53%	8%	34.53%	133,982	254,062	49	215	460	0.4674	126,943	62,622	64,321
1x225 kVA	Unit	4	8,058	32,232	1984	368.2	R0.5	32	63	37.53%	8%	34.53%	11,129	21,103	49	215	460	0.4674	10,563	5,202	5,361
1x300 kVA	Unit	35	8,930	312,547	1984	368.2	R0.5	32	63	37.53%	8%	34.53%	107,915	204,632	49	215	460	0.4674	102,265	50,438	51,827
1x500 kVA	Unit	13	10,844	140,967	1984	368.2	R0.5	32	63	37.53%	8%	34.53%	48,672	92,294	49	215	460	0.4674	46,132	22,749	23,383
1x750 kVA	Unit	11	15,126	166,390	1984	368.2	R0.5	32	63	37.53%	8%	34.53%	57,450	108,939	49	215	460	0.4674	54,451	26,852	27,599
1x1500 kVA	Unit	7	24,818	173,728	1984	368.2	R0.5	32	63	37.53%	8%	34.53%	59,984	113,744	49	215	460	0.4674	56,835	28,036	28,799
1x2000 kVA	Unit	2	30,039	60,079	1984	368.2	R0.5	32	63	37.53%	8%	34.53%	20,744	39,335	49	215	460	0.4674	19,677	9,695	9,982
1x2500 kVA	Unit	1	30,039	30,039	1984	368.2	R0.5	32	63	37.53%	8%	34.53%	10,372	19,668	49	215	460	0.4674	9,815	4,848	4,967
1x3000 kVA	Unit	1	30,039	30,039	1984	368.2	R0.5	32	63	37.53%	8%	34.53%	10,372	19,668	49	215	460	0.4674	9,815	4,848	4,967
1x5000 kVA	Unit	1	30,039	30,039	1984	368.2	R0.5	32	63	37.53%	8%	34.53%	10,372	19,668	49	215	460	0.4674	9,815	4,848	4,967
Subsurface Single-Phase Transformers																					
1x50 kVA	Unit	342	2,124	726,406	1994	368.2	R0.5	32	31	18.88%	8%	17.37%	126,174	600,232	49	308	460	0.6696	437,762	84,482	353,280
1x75 kVA	Unit	17	2,541	43,191	1994	368.2	R0.5	32	31	18.88%	8%	17.37%	7,502	35,689	49	308	460	0.6696	26,046	5,023	21,023
1x100 kVA	Unit	5	2,957	14,787	1994	368.2	R0.5	32	31	18.88%	8%	17.37%	2,568	12,218	49	308	460	0.6696	8,905	1,720	7,185
Subsurface 3-Phase Transformers																					
1x112.5 kVA	Unit	9	4,303	38,725	1994	368.2	R0.5	32	31	18.88%	8%	17.37%	6,726	31,998	49	308	460	0.6696	23,368	4,504	18,864
1x150 kVA	Unit	15	7,290	109,354	1994	368.2	R0.5	32	31	18.88%	8%	17.37%	18,994	90,360	49	308	460	0.6696	65,885	12,718	53,167
1x225 kVA	Unit	1	8,162	8,162	1994	368.2	R0.5	32	31	18.88%	8%	17.37%	1,418	6,744	49	308	460	0.6696	4,888	949	3,939
1x300 kVA	Unit	11	9,034	99,376	1994	368.2	R0.5	32	31	18.88%	8%	17.37%	17,261	82,115	49	308	460	0.6696	59,859	11,558	48,301
1x500 kVA	Unit	3	10,965	32,896	1994	368.2	R0.5	32	31	18.88%	8%	17.37%	5,714	27,182	49	308	460	0.6696	19,819	3,826	15,993
1x1500 kVA	Unit	1	25,096	25,096	1994	368.2	R0.5	32	31	18.88%	8%	17.37%	4,359	20,737	49	308	460	0.6696	15,132	2,919	12,213
1x2500 kVA	Unit	2	30,318	60,635	1994	368.2	R0.5	32	31	18.88%	8%	17.37%	10,532	50,103	49	308	460	0.6696	36,558	7,052	29,506
1x3000 kVA	Unit	1	30,318	30,318	1994	368.2	R0.5	32	31	18.88%	8%	17.37%	5,266	25,051	49	308	460	0.6696	18,279	3,526	14,753
		779		**3,095,734**									**864,884**	**2,230,851**					**1,340,374**	**445,993**	**894,381**
OVERHEAD LOW VOLTAGE CIRCUITS																					
1C Triplex # 4/0 AWG AL Bare	mi	11.63	20,796	241,752	1984	365	R1	37	54	37.30%	-49%	55.58%	134,359	107,394	45	273	477	0.5723	96,838	76,897	19,941
3 # 4/0 AWG AL Bare	mi	11.63	30,668	356,520	1984	365	R1	37	54	37.30%	-49%	55.58%	198,143	158,377	45	273	477	0.5723	142,853	113,403	29,450
UNDERGROUND LOW VOLTAGE CIRCUITS																					
3 # 4/0 AWG AL 600V	mi	24.77	129,403	3,205,042	1994	367	S3	31	32	31.92%	-19%	37.98%	1,217,429	1,987,613	47	291	369	0.7886	2,274,768	960,086	1,314,682
3 # 350 AWG AL	mi	2.70	129,403	349,387	1994	367	S3	31	32	31.92%	-19%	37.98%	132,714	216,673	47	291	369	0.7886	247,941	104,661	143,280
3 # 700 AWG AL	mi	0.75	129,403	97,052	1994	367	S3	31	32	31.92%	-19%	37.98%	36,865	60,187	47	291	369	0.7886	68,846	29,072	39,774
		51.47		**4,249,753**									**1,719,510**	**2,530,244**					**2,831,246**	**1,284,119**	**1,547,127**
SERVICE DROPS																					
Overhead Low Voltage single-phase Service Drop, 50 Feet																					
1C Triplex # 6 AWG AL.	Unit	176	294	51,831	1984	369.1	R4	43	47	46.04%	-45%	66.76%	34,601	17,230	50	255	393	0.6489	23,553	22,451	1,102
1C Triplex # 2 AWG AL.	Unit	194	311	60,105	1984	369.1	R4	43	47	46.04%	-45%	66.76%	40,125	19,980	50	255	393	0.6489	27,317	26,035	1,282
1C Triplex # 1/0 AWG de AL.	Unit	5,453	327	1,785,253	1984	369.1	R4	43	47	46.04%	-45%	66.76%	1,191,799	593,454	50	255	393	0.6489	810,874	773,305	37,569
1C Triplex # 4/0 AWG de AL.	Unit	-	327	-	1984	369.1	R4	43	47	46.04%	-45%	66.76%	-	-	50	255	393	0.6489	0	0	0
1 C Quadruplex # 1/0 AWG AL.	Unit	127	534	67,821	1984	369.1	R4	43	47	46.04%	-45%	66.76%	45,276	22,545	50	255	393	0.6489	30,821	29,377	1,444
1 C Quadruplex # 4/0 AWG de AL.	Unit	34	534	18,157	1984	369.1	R4	43	47	46.04%	-45%	66.76%	12,121	6,036	50	255	393	0.6489	8,240	7,865	375
2 # 1/0 AWG. (phases) y 1 # 2 AWG (neutral) AL 600 V.	Unit	6,142	309	1,895,890	1984	369.1	R4	43	47	46.04%	-45%	66.76%	1,265,658	630,232	50	255	393	0.6489	861,095	821,229	39,866
2 # 350 MCM. (phases) y 1 # 4/0 AWG (neutral) AL 600 V.	Unit	12	364	4,371	1984	369.1	R4	43	47	46.04%	-45%	66.76%	2,918	1,453	50	255	393	0.6489	2,011	1,894	117
2 # 1000 MCM. (phases) y 1 # 350 MCM (neutral) AL 600 V.	Unit	17	373	6,344	1984	369.1	R4	43	47	46.04%	-45%	66.76%	4,235	2,109	50	255	393	0.6489	2,855	2,748	107

SMUD Annexation Study
Estimated RCNLD and OCLD Values
Straight Line Depreciation

Woodland

Description	Unit	Quantity	Price	RCN	Year	FERC Acct	Survivor Curve	ASL	Age % of ASL	Unadjusted Deprec.	Net Salvage %	Adjusted Deprec.	RCN Depreciation	RCNLD	HANDY-WHITMAN Line No.	HANDY-WHITMAN Year Installed	HANDY-WHITMAN 7/31/04	HANDY-WHITMAN Factor	Original Cost	Orig Cost Depreciation	OCLD
Overhead Low Voltage three-phase Service Drop, 50 Feet																					
3 # 1/0 AWG (phases) y 1 # 2 AWG (neutral) AL 600 V.	Unit	8	411	3,292	1984	369.2	R4	43	47	46.04%	-45%	66.76%	2,197	1,094	51	218	275	0.7927	1,823	1,742	81
3 # 4/0 AWG (phases) y 1 # 1/0 AWG (neutral) AL 600 V.	Unit	5	449	2,246	1984	369.2	R4	43	47	46.04%	-45%	66.76%	1,500	747	51	218	275	0.7927	1,268	1,189	79
3 # 350 MCM (phases) y 1 # 4/0 AWG (neutral) AL 600 V.	Unit	23	489	11,240	1984	369.2	R4	43	47	46.04%	-45%	66.76%	7,503	3,736	51	218	275	0.7927	6,263	5,948	315
3 # 1000 MCM (phases) y 1 # 350 MCM (neutral) AL 600 V.	Unit	117	498	58,217	1984	369.2	R4	43	47	46.04%	-45%	66.76%	38,864	19,352	51	218	275	0.7927	32,343	30,809	1,534
2 circuits 3 # 1000 MCM (phases) y 1 # 350 MCM (neutral) AL 600 V.	Unit	66	621	41,014	1984	369.2	R4	43	47	46.04%	-45%	66.76%	27,380	13,634	51	218	275	0.7927	22,751	21,705	1,046
3 circuits 3 # 1000 MCM (phases) y 1 # 350 MCM (neutral) AL 600 V.	Unit	18	745	13,415	1984	369.2	R4	43	47	46.04%	-45%	66.76%	8,955	4,459	51	218	275	0.7927	7,452	7,099	353
5 circuits 3 # 1000 MCM (phases) y 1 # 350 MCM (neutral) AL600 V.	Unit	8	993	7,944	1984	369.2	R4	43	47	46.04%	-45%	66.76%	5,303	2,641	51	218	275	0.7927	4,439	4,204	235
7 circuits 3 # 1000 MCM (phases) y 1 # 350 MCM (neutral) AL600 V.	Unit	2	1,241	2,481	1984	369.2	R4	43	47	46.04%	-45%	66.76%	1,656	825	51	218	275	0.7927	1,348	1,313	35
9 circuits 3 # 1000 MCM (phases) y 1 # 350 MCM (neutral) AL600 V.	Unit	6	1,488	8,930	1984	369.2	R4	43	47	46.04%	-45%	66.76%	5,961	2,968	51	218	275	0.7927	4,994	4,726	268
		12,408		**4,038,549**									**2,696,054**	**1,342,494**					**1,849,447**	**1,763,639**	**85,808**
METERS																					
Residential	Unit	11,167	131	1,461,110	1984	370	R2	32	63	50.80%	0%	50.80%	742,244	718,866	52	213	324	0.6574	672,396	487,957	184,439
Commercial	Unit	1,117	290	323,913	1984	370	R2	32	63	50.80%	0%	50.80%	164,548	159,365	52	213	324	0.6574	149,034	108,175	40,859
Industrial	Unit	124	538	66,790	1984	370	R2	32	63	50.80%	0%	50.80%	33,929	32,861	52	213	324	0.6574	30,767	22,305	8,462
		12,408		**1,851,813**									**6,332,830**	**3,596,081**					**4,551,091**	**4,145,715**	**405,376**
RISERS																					
Three-phase Riser 12 kV 3 # 1000 MCM AL.	Unit	34	496	16,870	1984	365	R1	37	54	37.30%	-49%	55.58%	9,376	7,494	45	273	477	0.5723	6,753	5,366	1,387
Three-phase Riser 12 kV 3 # 350 MCM AL.	Unit	4	408	1,634	1984	365	R1	37	54	37.30%	-49%	55.58%	908	726	45	273	477	0.5723	630	520	110
Three-phase Riser 12 kV 3 # 1/0 AWG AL.	Unit	121	371	44,836	1984	365	R1	37	54	37.30%	-49%	55.58%	24,918	19,917	45	273	477	0.5723	17,971	14,261	3,710
Three-phase Riser 12 kV 2 # 1/0 AWG AL.	Unit	67	371	24,826	1984	365	R1	37	54	37.30%	-49%	55.58%	13,798	11,029	45	273	477	0.5723	9,958	7,897	2,061
SWITCHES																					
Overhead three-phase Switch	Unit	129	3,615	466,397	1984	365	R1	37	54	37.30%	-49%	55.58%	259,210	207,188	45	273	477	0.5723	186,865	148,353	38,512
Three single-phase Cutouts.	Set	59	1,594	94,067	1984	365	R1	37	54	37.30%	-49%	55.58%	52,280	41,787	45	273	477	0.5723	37,659	29,921	7,738
Two single-phase Cutouts	Set	34	1,063	36,139	1984	365	R1	37	54	37.30%	-49%	55.58%	20,085	16,054	45	273	477	0.5723	14,480	11,495	2,985
Pad Mounted Switch PMH4	Unit	7	5,534	38,736	1984	365	R1	37	54	37.30%	-49%	55.58%	21,528	17,208	45	273	477	0.5723	15,510	12,321	3,189
Pad Mounted Switch PMH 43W	Unit	9	6,824	61,414	1984	365	R1	37	54	37.30%	-49%	55.58%	34,132	27,282	45	273	477	0.5723	24,610	19,535	5,075
Pad Mounted Switch PMH9	Unit	3	9,796	29,388	1984	365	R1	37	54	37.30%	-49%	55.58%	16,333	13,055	45	273	477	0.5723	11,790	9,348	2,442
Subsurface 600 A 2 Ways.	Unit	11	6,824	75,061	1984	365	R1	37	54	37.30%	-49%	55.58%	41,717	33,344	45	273	477	0.5723	30,047	23,876	6,171
Subsurface 600 A 3 Ways, 2 Ways switched.	Unit	4	6,824	27,295	1984	365	R1	37	54	37.30%	-49%	55.58%	15,170	12,125	45	273	477	0.5723	10,931	8,682	2,249
Subsurface 600 A 3 Ways, 3 Ways switched.	Unit	4	6,917	27,669	1984	365	R1	37	54	37.30%	-49%	55.58%	15,377	12,291	45	273	477	0.5723	11,103	8,801	2,302
Subsurface 200 A Fused Switch.	Unit	34	6,917	235,184	1984	365	R1	37	54	37.30%	-49%	55.58%	130,708	104,476	45	273	477	0.5723	94,205	74,808	19,397
Recloser	Unit	15	9,404	141,056	1984	365	R1	37	54	37.30%	-49%	55.58%	78,395	62,661	45	273	477	0.5723	56,489	44,867	11,622
CAPACITORS BANKS																					
Overhead Capacitors Bank 3 x 100 kVAR .	Unit	4	4,458	17,833	1984	365	R1	37	54	37.30%	-49%	55.58%	9,911	7,922	45	273	477	0.5723	7,154	5,672	1,482
Overhead Capacitors Bank 3 x 200 kVAR .	Unit	33	4,458	147,125	1984	365	R1	37	54	37.30%	-49%	55.58%	81,768	65,357	45	273	477	0.5723	58,950	46,798	12,152
Overhead Capacitors Bank 3 x 300 kVAR.	Unit	1	4,458	4,458	1984	365	R1	37	54	37.30%	-49%	55.58%	2,478	1,981	45	273	477	0.5723	1,774	1,418	356
Overhead Capacitors Bank 6 x 100 kVAR.	Unit	15	8,272	124,075	1984	365	R1	37	54	37.30%	-49%	55.58%	68,957	55,118	45	273	477	0.5723	49,735	39,466	10,269
Overhead Capacitors Bank 6 x 200 kVAR.	Unit	13	8,272	107,532	1984	365	R1	37	54	37.30%	-49%	55.58%	59,763	47,769	45	273	477	0.5723	43,096	34,204	8,892
Overhead Capacitors Bank 6 x 300 kVAR.	Unit	4	8,272	33,087	1984	365	R1	37	54	37.30%	-49%	55.58%	18,389	14,698	45	273	477	0.5723	13,278	10,524	2,754
Overhead Capacitors Bank 3 x 200 and 3 x 100 kVAR.	Unit	2	8,272	16,543	1984	365	R1	37	54	37.30%	-49%	55.58%	9,194	7,349	45	273	477	0.5723	6,639	5,262	1,377
Pad Mounted Capacitors Bank 6 x 300 kVAR.	Unit	3	11,174	33,523	1984	365	R1	37	54	37.30%	-49%	55.58%	18,631	14,892	45	273	477	0.5723	13,450	10,663	2,787
REGULATORS																					
4 Step Voltage Regulator	Unit	3	1,764	5,291	1984	365	R1	37	54	37.30%	-49%	55.58%	2,941	2,350	45	273	477	0.5723	2,118	1,683	435
		613		**1,810,039**									**1,005,966**	**804,074**					**725,195**	**575,741**	**149,454**
TOTAL				**42,287,310**									**22,149,466**	**28,214,942**					**25,296,922**	**14,562,763**	**10,734,159**

SMUD Annexation Study
Estimated RCNLD and OCLD Values
Straight Line Depreciation

Transmission Plant

Item	Description	Unit	Quantity	Price	RCN	FERC Acct	% Structures/ Conductors	Allocated RCN	Est. Install Year	Survivor Curve	ASL	Age % of ASL	Unadjusted Deprec.	Net Salvage %	Adjusted Deprec.	RCN Depreciation	RCNLD	HANDY-WHITMAN Line No.	HANDY-WHITMAN Year Installed	HANDY-WHITMAN 7/31/04	HANDY-WHITMAN Factor	Original Cost	Orig Cost Depreciation	OCLD
1	**W Sacramento - Close Deepwater tap**																							
	Steel poles, Double with line 2, 715.5 AAC Violet	Mi	1	570,000	592,800	354	1	444,600	1,975	S2	65	45	0	0	1	265,035	179,565	35	145	422	0	152,765	91,067	61,698
						356	25%	148,200	1975	L4	48	60	58.19%	-31%	76.23%	112,971	35,229	37	146	445	0.3281	48,623	37,065	11,558
	Close Deepwater tap - Close to Brightor																							
	Lattice, Double with line 2, 397.5 AAC Canna	Mi	12.82	584,000	8,086,880	354	75%	6,065,160	1965	S2	65	60	53.75%	-40%	75.25%	4,564,033	1,501,127	35	63	422	0.1493	905,462	681,360	224,102
						356	25%	2,021,720	1965	L4	48	81	73.71%	-31%	90.00%	1,819,548	202,172	37	67	445	0.1506	304,394	273,954	30,440
1	**Close to Brighton - Rio Oso**																							
	Lattice, Single, 397.5 AAC Canna	Mi	29.60	500,000	14,800,000	354	80%	11,840,000	1965	S2	65	60	53.75%	-40%	75.25%	8,909,600	2,930,400	35	63	422	0.1493	1,767,583	1,330,106	437,477
						356	20%	2,960,000	1965	L4	48	81	73.71%	-31%	90.00%	2,664,000	296,000	37	67	445	0.1506	445,663	401,097	44,566
2	**W Sacramento - Close Deepwater tap**																							
	Steel poles, Double with line 1, 715.5 AAC Violet	Mi	1.04		included w/ Line 1																			
2	**Close Deepwater tap - Close to Brighton**																							
	Lattice, Double with line 1, 397.5 AAC Canna	Mi	12.82		included w/ Line 1																			
3	**Davis - Deepwater Tap 1**																							
	Wood, Single, 2/0 Cu 7 strand	Mi	10.89	397,000	4,323,330	355	80%	3,458,664	1968	R3	37	97	78.37%	-50%	90.00%	3,112,798	345,866	36	65	470	0.1383	478,326	430,493	47,833
						356	20%	864,666	1968	L4	48	75	69.87%	-31%	90.00%	778,199	86,467	37	73	445	0.1640	141,844	127,660	14,184
3	**Deepwater Tap 1 - West Sacramento**																							
	Wood, Single, 2/0 Cu 7 strand	Mi	1.76	397,000	698,720	355	80%	558,976	1968	R3	37	97	78.37%	-50%	90.00%	503,078	55,898	36	65	470	0.1383	77,305	69,575	7,730
						356	20%	139,744	1968	L4	48	75	69.87%	-31%	90.00%	125,770	13,974	37	73	445	0.1640	22,924	20,632	2,292
4a	**Deepwater Tap 1 - P.O. Tap**																							
	Steel Poles, Double with line 4b, 397.5 AAC Canna	Mi	1.37		included w/ Line 4b																			
4a	**P.O Tap - Deepwater (SW 315 -N.O.)**																							
	Steel Poles, Double with line 4b, 397.5 AAC Canna	Mi	1.02		included w/ Line 4b																			
4b	**Deepwater Tap 2 - Deepwater (SW 325 -N.C.)**																							
	Steel Poles, Double with line 4a, 397.5 AAC Canna	Mi	2.39	554,000	1,324,060	354	75%	993,045	1975	S2	65	45	42.58%	-40%	59.61%	591,974	401,071	35	145	422	0.3436	341,212	203,403	137,809
						356	25%	331,015	1975	L4	48	60	58.19%	-31%	76.23%	252,329	78,686	37	146	445	0.3281	108,603	82,787	25,816
5	**P.O Tap - Post Office**																							
	Wood, Single,397.5 AAC Canna	Mi	0.66	397,000	262,020	355	80%	209,616	1975	R3	37	78	67.27%	-50%	90.00%	188,654	20,962	36	144	470	0.3064	64,223	57,800	6,423
						356	20%	52,404	1975	L4	48	60	58.19%	-31%	76.23%	39,947	12,457	37	146	445	0.3281	17,193	13,106	4,087
6	**Davis - Hunt Tap**																							
	Wood, Single, 715.5 AAC Violet	Mi	1.09	405,000	441,450	355	80%	353,160	1965	R3	37	105	82.06%	-50%	90.00%	317,844	35,316	36	58	470	0.1234	43,581	39,223	4,358
						356	20%	88,290	1965	L4	48	81	73.71%	-31%	90.00%	79,461	8,829	37	67	445	0.1506	13,293	11,964	1,329
6	**Hunt Tap - Wood Bio Mass Tap**																							
	Wood, Single, 715.5 AAC Violet	Mi	9.04	405,000	3,661,200	355	80%	2,928,960	1965	R3	37	105	82.06%	-50%	90.00%	2,636,064	292,896	36	58	470	0.1234	361,446	325,302	36,144
						356	20%	732,240	1965	L4	48	81	73.71%	-31%	90.00%	659,016	73,224	37	67	445	0.1506	110,247	99,223	11,024
6	**Wood Bio Mass Tap - Woodland**																							
	Wood, Single, 715.5 AAC Violet	Mi	1.52	405,000	615,600	355	80%	492,480	1995	R3	37	24	23.15%	-50%	34.73%	171,014	321,466	36	392	470	0.8340	410,749	142,633	268,116
						356	20%	123,120	1995	L4	48	19	19.00%	-31%	24.89%	30,645	92,475	37	368	445	0.8270	101,816	25,342	76,474
6a	**Hunt Tap - Hunt (Idling sub)**																							
	Wood, Single, 715.5 AAC Violet	Mi	0.06	405,000	24,300	355	80%	19,440	1995	R3	37	24	23.15%	-50%	34.73%	6,751	12,689	36	392	470	0.8340	16,214	5,630	10,584
						356	20%	4,860	1995	L4	48	19	19.00%	-31%	24.89%	1,210	3,650	37	368	445	0.8270	4,019	1,000	3,019
6b	**Wood Bio Mass Tap - Wood Bio Mass**																							
	Wood, Single, 715.5 AAC Violet	Mi	0.84	500,000	420,000	355	80%	336,000	1989	R3	37	41	38.55%	-50%	57.83%	194,292	141,708	36	301	470	0.6404	215,183	124,430	90,753
						356	20%	84,000	1989	L4	48	31	30.99%	-31%	40.60%	34,101	49,899	37	320	445	0.7191	60,404	24,522	35,882
7	**Davis - Barker Jct**																							
	Wood, Single, 715.5 AAC Violet	Mi	9.85	405,000	3,989,250	355	80%	3,191,400	1970	R3	37	92	75.76%	-50%	90.00%	2,872,260	319,140	36	76	470	0.1617	516,056	464,451	51,605
						356	20%	797,850	1970	L4	48	71	66.98%	-31%	87.74%	700,064	97,786	37	89	445	0.2000	159,570	140,013	19,557
7	**Barker Jct - Brighton**																							
	Lattice, Single, 397.5 AAC Canna	Mi	18.46	500,000	9,230,000	354	80%	7,384,000	1965	S2	65	60	53.75%	-40%	75.25%	5,556,460	1,827,540	35	63	422	0.1493	1,102,351	829,519	272,832
						356	20%	1,846,000	1965	L4	48	81	73.71%	-31%	90.00%	1,661,400	184,600	37	67	445	0.1506	277,937	250,143	27,794
8a	**Woodland - Wood. Poly Tap**																							
	Lattice, Double with line 8b, 715.5 AAC Violet	Mi	0.31		included w/ Line 8b																			
8a	**Woodland Poly Tap - Woodland J1 (saw 175)**																							
	Lattice, Double with line 8b, 715.5 AAC Violet	Mi	10.35		included w/ Line 8b																			
8b	**Woodland - Woodland J2 (saw 185)**																							
	Lattice, Double with line 8a, 715.5 AAC Violet	Mi	10.66	600,000	6,396,000	354	75%	4,797,000	1968	S2	65	55	50.26%	-40%	70.36%	3,375,361	1,421,639	35	74	422	0.1754	841,180	591,888	249,292
						356	25%	1,599,000	1968	L4	48	75	69.87%	-31%	90.00%	1,439,100	159,900	37	73	445	0.1640	262,308	236,077	26,231
8c	**Wood. Poly Tap - Woodland Poly (Tyco)**																					-		
	Wood, Single, 4/0 Al Alliance	Mi	0.31	397,000	123,070	355	80%	98,456	1989	R3	37	41	38.55%	-50%	57.83%	56,932	41,524	36	301	470	0.6404	63,054	36,461	26,593
						356	20%	24,614	1989	L4	48	31	30.99%	-31%	40.60%	9,993	14,621	37	320	445	0.7191	17,700	7,186	10,514
9	**Barker Jct - Barker Slough**																					-		
	Lattice, Single, 4/0 Al Alliance	Mi	15.62	500,000	7,810,000	354	80%	6,248,000	1965	S2	65	60	53.75%	-40%	75.25%	4,701,620	1,546,380	35	63	422	0.1493	932,758	701,901	230,857
						356	20%	1,562,000	1965	L4	48	81	73.71%	-31%	90.00%	1,405,800	156,200	37	67	445	0.1506	235,178	211,660	23,518
					62,798,680			**62,798,680**								**49,837,323**	**12,961,357**					**10,621,164**	**8,088,673**	**2,532,491**
	Less plant that will not be acquired by SMUD																							
	Items 6b and 9				8,230,000			8,230,000								6,335,813	1,894,187					1,443,523	1,062,513	381,010
	Total Plant Value				**54,568,680**			**54,568,680**								**43,501,510**	**11,067,170**					**9,177,641**	**7,026,160**	**2,151,481**

SMUD Annexation Study
Estimated RCNLD and OCLD Values
Straight Line Depreciation

Transmission Plant - Scenario 1

Item	Description	Status	Unit	Quantity	Price	RCN	FERC Acct	% Structures/ Conductors	Allocated RCN	Est. Install Year	Survivor Curve	ASL	Age % of ASL	Unadjusted Deprec.	Net Salvage %	Adjusted Deprec.	RCN Depreciation	RCNLD	HANDY-WHITMAN Line No.	HANDY-WHITMAN Year Installed	HANDY-WHITMAN 7/31/04	HANDY-WHITMAN Factor	Original Cost	Orig Cost Depreciation	OCLD
1	**W Sacramento - Close Deepwater tap**																								
	Steel poles, Double with line 2, 715.5 AAC Violet	Existing	Mi	1	570,000	592,800	354	75%	444,600	1975	S2	65	45	42.58%	-40%	59.61%	265,035	179,565	35	145	422	0.3436	152,765	91,067	61,698
							356	25%	148,200	1975	L4	48	60	58.19%	-31%	76.23%	112,971	35,229	37	146	445	0.3281	48,623	37,065	11,558
	Deepwater Tap 2 - Hurley																								
	Lattice, Double with line 2, 397.5 AAC Canna	Existing	Mi	11.00	584,000	3,512,000	354	75%	2,634,000	1965	S2	65	60	53.75%	-40%	75.25%	1,982,085	651,915	35	63	422	0.1493	393,227	295,904	97,323
	(Shared use 50%, use 50% of cost)						356	25%	878,000	1965	L4	48	81	73.71%	-31%	90.00%	790,200	87,800	37	67	445	0.1506	132,193	118,974	13,219
	Close to Hurley - Close to Brightor																								
	Lattice, Double with line 2, 397.5 AAC Canna	Stranded	Mi	1.82	584,000	531,440	354	75%	398,580	1965	S2	65	60	53.75%	-40%	75.25%	299,931	98,649	35	63	422	0.1493	59,504	44,776	14,728
	(1 circuit stranded, use 50% of cost)						356	25%	132,860	1965	L4	48	81	73.71%	-31%	90.00%	119,574	13,286	37	67	445	0.1506	20,004	18,003	2,001
1	**Close to Brighton - Rio Oso**																								
	Lattice, Single, 397.5 AAC Canna	Stranded	Mi	29.60	500,000	14,800,000	354	80%	11,840,000	1965	S2	65	60	53.75%	-40%	75.25%	8,909,600	2,930,400	35	63	422	0.1493	1,767,583	1,330,106	437,477
							356	20%	2,960,000	1965	L4	48	81	73.71%	-31%	90.00%	2,664,000	296,000	37	67	445	0.1506	445,663	401,097	44,566
2	**W Sacramento - Close Deepwater tap**																								
	Steel poles, Double with line 1, 715.5 AAC Violet		Mi	1.04		included w/ Line 1																			
2	**Close Deepwater tap - Close to Brighton**																								
	Lattice, Double with line 1, 397.5 AAC Canna		Mi	12.82		included w/ Line 1																			
3	**Deepwater Tap1 - West Sacramento**																								
	Wood, assumed reconductored to 715 AAC	Stranded	Mi	1.76	405,000	712,800	355	80%	570,240	1968	R3	37	97	78.37%	-50%	90.00%	513,216	57,024	36	65	470	0.1383	78,863	70,977	7,886
							356	20%	142,560	1968	L4	48	75	69.87%	-31%	90.00%	128,304	14,256	37	73	445	0.1640	23,386	21,048	2,338
4a	**Deepwater Tap 1 - P.O. Tap**																								
	Steel Poles, Double with line 4b, 397.5 AAC Canna		Mi	1.37		included w/ Line 4b																			
4a	**P.O Tap - Deepwater (SW 315 -N.O.)**																								
	Steel Poles, Double with line 4b, 397.5 AAC Canna		Mi	1.02		included w/ Line 4b																			
4b	**Deepwater Tap 2 - Deepwater (SW 325 -N.C.)**																								
	Steel Poles, Double with line 4a, 397.5 AAC Canna	Existing	Mi	2.39	554,000	1,324,060	354	75%	993,045	1975	S2	65	45	42.58%	-40%	59.61%	591,974	401,071	35	145	422	0.3436	341,212	203,403	137,809
							356	25%	331,015	1975	L4	48	60	58.19%	-31%	76.23%	252,329	78,686	37	146	445	0.3281	108,603	82,787	25,816
5	**P.O Tap - Post Office**																								
	Wood, Single,397.5 AAC Canna	Existing	Mi	0.66	397,000	262,020	355	80%	209,616	1975	R3	37	78	67.27%	-50%	90.00%	188,654	20,962	36	144	470	0.3064	64,223	57,800	6,423
							356	20%	52,404	1975	L4	48	60	58.19%	-31%	76.23%	39,947	12,457	37	146	445	0.3281	17,193	13,106	4,087
						21,735,120			**21,735,120**								**16,857,821**	**4,877,299**					**3,653,042**	**2,786,113**	**866,929**

SMUD Annexation Study
Estimated RCNLD and OCLD Values
Straight Line Depreciation

Transmission Plant - Scenario 2

Item	Description	Status	Unit	Quantity	Price	RCN	FERC Acct	% Structures/ Conductors	Allocated RCN	Est. Install Year	Survivor Curve	ASL	Age % of ASL	Unadjusted Deprec.	Net Salvage %	Adjusted Deprec.	RCN Depreciation	RCNLD	HANDY-WHITMAN Line No.	HANDY-WHITMAN Year Installed	HANDY-WHITMAN 7/31/04	HANDY-WHITMAN Factor	Original Cost	Orig Cost Depreciation	OCLD
1	**W Sacramento - Close Deepwater tap**																								
	Steel poles, Double with line 2, 715.5 AAC Violet	Existing	Mi	1	570,000	592,800	354	75%	444,600	1975	S2	65	45	42.58%	-40%	59.61%	265,035	179,565	35	145	422	0.3436	152,765	91,067	61,698
							356	25%	148,200	1975	L4	48	60	58.19%	-31%	76.23%	112,971	35,229	37	146	445	0.3281	48,623	37,065	11,558
	Deepwater Tap 2 - Hurley																								
	Lattice, Double with line 2, 397.5 AAC Canna	Existing	Mi	11.00	584,000	7,024,000	354	75%	5,268,000	1965	S2	65	60	53.75%	-40%	75.25%	3,964,170	1,303,830	35	63	422	0.1493	786,455	591,807	194,648
							356	25%	1,756,000	1965	L4	48	81	73.71%	-31%	90.00%	1,580,400	175,600	37	67	445	0.1506	264,387	237,948	26,439
	Close to Hurley - Close to Brightor																								
	Lattice, Double with line 2, 397.5 AAC Canna	Existing/	Mi	1.82	584,000	1,062,880	354	75%	797,160	1965	S2	65	60	53.75%	-40%	75.25%	599,863	197,297	35	63	422	0.1493	119,007	89,553	29,454
	(1 circuit used, 1 circuit stranded)	Stranded					356	25%	265,720	1965	L4	48	81	73.71%	-31%	90.00%	239,148	26,572	37	67	445	0.1506	40,007	36,007	4,000
1	**Close to Brighton - Rio Oso**																								
	Lattice, Single, 397.5 AAC Canna	Stranded	Mi	29.60	500,000	14,800,000	354	80%	11,840,000	1965	S2	65	60	53.75%	-40%	75.25%	8,909,600	2,930,400	35	63	422	0.1493	1,767,583	1,330,106	437,477
							356	20%	2,960,000	1965	L4	48	81	73.71%	-31%	90.00%	2,664,000	296,000	37	67	445	0.1506	445,663	401,097	44,566
2	**W Sacramento - Close Deepwater tap**																								
	Steel poles, Double with line 1, 715.5 AAC Violet		Mi	1.04		included w/ Line 1																			
2	**Close Deepwater tap - Close to Brighton**																								
	Lattice, Double with line 1, 397.5 AAC Canna		Mi	12.82		included w/ Line 1																			
3	**Davis - Deepwater Tap 1**																								
	Wood, assumed reconductored to 715 AAC	Existing	Mi	10.89	405,000	4,410,450	355	80%	3,528,360	1968	R3	37	97	78.37%	-50%	90.00%	3,175,524	352,836	36	65	470	0.1383	487,965	439,168	48,797
							356	20%	882,090	1968	L4	48	75	69.87%	-31%	90.00%	793,881	88,209	37	73	445	0.1640	144,702	130,232	14,470
3	**Deepwater Tap 1 - West Sacramento**																								
	Wood, assumed reconductored to 715 AAC	Existing	Mi	1.76	405,000	712,800	355	80%	570,240	1968	R3	37	97	78.37%	-50%	90.00%	513,216	57,024	36	65	470	0.1383	78,863	70,977	7,886
							356	20%	142,560	1968	L4	48	75	69.87%	-31%	90.00%	128,304	14,256	37	73	445	0.1640	23,386	21,048	2,338
4a	**Deepwater Tap 1 - P.O. Tap**																								
	Steel Poles, Double with line 4b, 397.5 AAC Canna		Mi	1.37		included w/ Line 4b																			
4a	**P.O Tap - Deepwater (SW 315 -N.O.)**																								
	Steel Poles, Double with line 4b, 397.5 AAC Canna		Mi	1.02		included w/ Line 4b																			
4b	**Deepwater Tap 2 - Deepwater (SW 325 -N.C.)**																								
	Steel Poles, Double with line 4a, 397.5 AAC Canna	Existing	Mi	2.39	554,000	1,324,060	354	75%	993,045	1975	S2	65	45	42.58%	-40%	59.61%	591,974	401,071	35	145	422	0.3436	341,212	203,403	137,809
							356	25%	331,015	1975	L4	48	60	58.19%	-31%	76.23%	252,329	78,686	37	146	445	0.3281	108,603	82,787	25,816
5	**P.O Tap - Post Office**																								
	Wood, Single,397.5 AAC Canna	Existing	Mi	0.66	397,000	262,020	355	80%	209,616	1975	R3	37	78	67.27%	-50%	90.00%	188,654	20,962	36	144	470	0.3064	64,223	57,800	6,423
							356	20%	52,404	1975	L4	48	60	58.19%	-31%	76.23%	39,947	12,457	37	146	445	0.3281	17,193	13,106	4,087
6	**Davis - Hunt Tap**																								
	Wood, Single, 715.5 AAC Violet	Existing	Mi	1.09	405,000	441,450	355	80%	353,160	1965	R3	37	105	82.06%	-50%	90.00%	317,844	35,316	36	58	470	0.1234	43,581	39,223	4,358
							356	20%	88,290	1965	L4	48	81	73.71%	-31%	90.00%	79,461	8,829	37	67	445	0.1506	13,293	11,964	1,329
6	**Hunt Tap - Wood Bio Mass Tap**																								
	Wood, Single, 715.5 AAC Violet	Stranded	Mi	9.04	405,000	3,661,200	355	80%	2,928,960	1965	R3	37	105	82.06%	-50%	90.00%	2,636,064	292,896	36	58	470	0.1234	361,446	325,302	36,144
							356	20%	732,240	1965	L4	48	81	73.71%	-31%	90.00%	659,016	73,224	37	67	445	0.1506	110,247	99,223	11,024
6a	**Hunt Tap - Hunt (Idling sub)**																								
	Wood, Single, 715.5 AAC Violet	Existing	Mi	0.06	405,000	24,300	355	80%	19,440	1995	R3	37	24	23.15%	-50%	34.73%	6,751	12,689	36	392	470	0.8340	16,214	5,630	10,584
							356	20%	4,860	1995	L4	48	19	19.00%	-31%	24.89%	1,210	3,650	37	368	445	0.8270	4,019	1,000	3,019
7	**Davis - Barker Jct**																								
	Wood, Single, 715.5 AAC Violet	Existing	Mi	9.85	405,000	3,989,250	355	80%	3,191,400	1970	R3	37	92	75.76%	-50%	90.00%	2,872,260	319,140	36	76	470	0.1617	516,056	464,451	51,605
							356	20%	797,850	1970	L4	48	71	66.98%	-31%	87.74%	700,064	97,786	37	89	445	0.2000	159,570	140,013	19,557
7	**Barker Jct - Brighton**																								
	Lattice, Single, 397.5 AAC Canna	Existing	Mi	18.46	500,000	9,230,000	354	80%	7,384,000	1965	S2	65	60	53.75%	-40%	75.25%	5,556,460	1,827,540	35	63	422	0.1493	1,102,351	829,519	272,832
							356	20%	1,846,000	1965	L4	48	81	73.71%	-31%	90.00%	1,661,400	184,600	37	67	445	0.1506	277,937	250,143	27,794
						47,535,210			**47,535,210**								**38,509,546**	**9,025,664**					**7,495,351**	**5,999,639**	**1,495,712**

SMUD Annexation Study

Estimated RCNLD and OCLD Values
Straight Line Depreciation

Transmission Plant - Scenarios 3 & 4

Item	Description	Status	Unit	Quantity	Price	RCN	FERC Acct	% Structures/ Conductors	Allocated RCN	Est. Install Year	Survivor Curve	ASL	Age % of ASL	Unadjusted Deprec.	Net Salvage %	Adjusted Deprec.	RCN Depreciation	RCNLD	HANDY-WHITMAN Line No.	HANDY-WHITMAN Year Installed	HANDY-WHITMAN 7/31/04	HANDY-WHITMAN Factor	Original Cost	Orig Cost Depreciation	OCLD
1	**W Sacramento - Close Deepwater tap**																								
	Steel poles, Double with line 2, 715.5 AAC Violet	Existing	Mi	1.04	$570,000	$592,800	354	75%	444,600	1975	S2	65	45	42.58%	-40%	59.61%	265,035	179,565	35	145	422	0.3436	152,765	91,067	61,698
							356	25%	148,200	1975	L4	48	60	58.19%	-31%	76.23%	112,971	35,229	37	146	445	0.3281	48,623	37,065	11,558
	Deepwater Tap 2 - Hurley																								
	Lattice, Double with line 2, 397.5 AAC Canna	Existing	Mi	11.00	584,000	7,024,000	354	75%	5,268,000	1965	S2	65	60	53.75%	-40%	75.25%	3,964,170	1,303,830	35	63	422	0.1493	786,455	591,807	194,648
							356	25%	1,756,000	1965	L4	48	81	73.71%	-31%	90.00%	1,580,400	175,600	37	67	445	0.1506	264,387	237,948	26,439
	Close to Hurley - Close to Brightor																								
	Lattice, Double with line 2, 397.5 AAC Canna	Existing/	Mi	1.82	584,000	1,062,880	354	75%	797,160	1965	S2	65	60	53.75%	-40%	75.25%	599,863	197,297	35	63	422	0.1493	119,007	89,553	29,454
	(1 circuit used, 1 circuit stranded)	Stranded					356	25%	265,720	1965	L4	48	81	73.71%	-31%	90.00%	239,148	26,572	37	67	445	0.1506	40,007	36,007	4,000
1	**Close to Brighton - Rio Oso**																								
	Lattice, Single, 397.5 AAC Canna	Stranded	Mi	29.60	500,000	14,800,000	354	80%	11,840,000	1965	S2	65	60	53.75%	-40%	75.25%	8,909,600	2,930,400	35	63	422	0.1493	1,767,583	1,330,106	437,477
							356	20%	2,960,000	1965	L4	48	81	73.71%	-31%	90.00%	2,664,000	296,000	37	67	445	0.1506	445,663	401,097	44,566
2	**W Sacramento - Close Deepwater tap**																								
	Steel poles, Double with line 1, 715.5 AAC Violet		Mi	1.04		included w/ Line 1																			
2	**Close Deepwater tap - Close to Brighton**																								
	Lattice, Double with line 1, 397.5 AAC Canna		Mi	12.82		included w/ Line 1																			
3	**Davis - Deepwater Tap1**																								
	Wood, assumed reconductored to 715 AAC	Existing	Mi	10.89	405,000	4,410,450	355	80%	3,528,360	1968	R3	37	97	78.37%	-50%	90.00%	3,175,524	352,836	36	65	470	0.1383	487,965	439,168	48,797
							356	20%	882,090	1968	L4	48	75	69.87%	-31%	90.00%	793,881	88,209	37	73	445	0.1640	144,702	130,232	14,470
3	**Deepwater Tap1 - West Sacramento**																								
	Wood, assumed reconductored to 715 AAC	Existing	Mi	1.76	405,000	712,800	355	80%	570,240	1968	R3	37	97	78.37%	-50%	90.00%	513,216	57,024	36	65	470	0.1383	78,863	70,977	7,886
							356	20%	142,560	1968	L4	48	75	69.87%	-31%	90.00%	128,304	14,256	37	73	445	0.1640	23,386	21,048	2,338
4a	**Deepwater Tap 1 - P.O. Tap**																								
	Steel Poles, Double with line 4b, 397.5 AAC Canna		Mi	1.37		included w/ Line 4b																			
4a	**P.O Tap - Deepwater (SW 315 -N.O.)**																								
	Steel Poles, Double with line 4b, 397.5 AAC Canna		Mi	1.02		included w/ Line 4b																			
4b	**Deepwater Tap 2 - Deepwater (SW 325 -N.C.)**																								
	Steel Poles, Double with line 4a, 397.5 AAC Canna	Existing	Mi	2.39	554,000	1,324,060	354	75%	993,045	1975	S2	65	45	42.58%	-40%	59.61%	591,974	401,071	35	145	422	0.3436	341,212	203,403	137,809
							356	25%	331,015	1975	L4	48	60	58.19%	-31%	76.23%	252,329	78,686	37	146	445	0.3281	108,603	82,787	25,816
5	**P.O Tap - Post Office**																								
	Wood, Single,397.5 AAC Canna	Existing	Mi	0.66	397,000	262,020	355	80%	209,616	1975	R3	37	78	67.27%	-50%	90.00%	188,654	20,962	36	144	470	0.3064	64,223	57,800	6,423
							356	20%	52,404	1975	L4	48	60	58.19%	-31%	76.23%	39,947	12,457	37	146	445	0.3281	17,193	13,106	4,087
6	**Davis - Hunt Tap**																								
	Wood, Single, 715.5 AAC Violet	Existing	Mi	1.09	405,000	441,450	355	80%	353,160	1965	R3	37	105	82.06%	-50%	90.00%	317,844	35,316	36	58	470	0.1234	43,581	39,223	4,358
							356	20%	88,290	1965	L4	48	81	73.71%	-31%	90.00%	79,461	8,829	37	67	445	0.1506	13,293	11,964	1,329
6	**Hunt Tap - Wood Bio Mass Tap**																								
	Wood, Single, 715.5 AAC Violet	Existing	Mi	9.04	405,000	3,661,200	355	80%	2,928,960	1965	R3	37	105	82.06%	-50%	90.00%	2,636,064	292,896	36	58	470	0.1234	361,446	325,302	36,144
							356	20%	732,240	1965	L4	48	81	73.71%	-31%	90.00%	659,016	73,224	37	67	445	0.1506	110,247	99,223	11,024
6	**Wood Bio Mass Tap - Woodland**																								
	Wood, Single, 715.5 AAC Violet	Existing	Mi	1.52	405,000	615,600	355	80%	492,480	1995	R3	37	24	23.15%	-50%	34.73%	171,014	321,466	36	392	470	0.8340	410,749	142,633	268,116
							356	20%	123,120	1995	L4	48	19	19.00%	-31%	24.89%	30,645	92,475	37	368	445	0.8270	101,816	25,342	76,474
6a	**Hunt Tap - Hunt (Idling sub)**																								
	Wood, Single, 715.5 AAC Violet	Existing	Mi	0.06	405,000	24,300	355	80%	19,440	1995	R3	37	24	23.15%	-50%	34.73%	6,751	12,689	36	392	470	0.8340	16,214	5,630	10,584
							356	20%	4,860	1995	L4	48	19	19.00%	-31%	24.89%	1,210	3,650	37	368	445	0.8270	4,019	1,000	3,019
7	**Davis - Barker Jct**																								
	Wood, Single, 715.5 AAC Violet	Existing	Mi	9.85	405,000	3,989,250	355	80%	3,191,400	1970	R3	37	92	75.76%	-50%	90.00%	2,872,260	319,140	36	76	470	0.1617	516,056	464,451	51,605
							356	20%	797,850	1970	L4	48	71	66.98%	-31%	87.74%	700,064	97,786	37	89	445	0.2000	159,570	140,013	19,557
7	**Barker Jct - Brighton**																								
	Lattice, Single, 397.5 AAC Canna	Existing	Mi	18.46	500,000	9,230,000	354	80%	7,384,000	1965	S2	65	60	53.75%	-40%	75.25%	5,556,460	1,827,540	35	63	422	0.1493	1,102,351	829,519	272,832
							356	20%	1,846,000	1965	L4	48	81	73.71%	-31%	90.00%	1,661,400	184,600	37	67	445	0.1506	277,937	250,143	27,794
8a	**Woodland - Wood. Poly Tap**																								
	Lattice, Double with line 8b, 715.5 AAC Violet		Mi	0.31		included w/ Line 8b																			
8a	**Woodland Poly Tap - Woodland J1 (saw 175)**																								
	Lattice, Double with line 8b, 715.5 AAC Violet		Mi	10.35		included w/ Line 8b																			
8b	**Woodland - Woodland J2 (saw 185)**																								
	Lattice, Double with line 8a, 715.5 AAC Violet	Stranded	Mi	10.66	600,000	6,396,000	354	75%	4,797,000	1968	S2	65	55	50.26%	-40%	70.36%	3,375,361	1,421,639	35	74	422	0.1754	841,180	591,888	249,292
							356	25%	1,599,000	1968	L4	48	75	69.87%	-31%	90.00%	1,439,100	159,900	37	73	445	0.1640	262,308	236,077	26,231
8c	**Wood. Poly Tap - Woodland Poly (Tyco)**																						-		
	Wood, Single, 4/0 Al Alliance	Existing	Mi	0.31	397,000	123,070	355	80%	98,456	1989	R3	37	41	38.55%	-50%	57.83%	56,932	41,524	36	301	470	0.6404	63,054	36,461	26,593
							356	20%	24,614	1989	L4	48	31	30.99%	-31%	40.60%	9,993	14,621	37	320	445	0.7191	17,700	7,186	10,514
						54,669,880			**54,669,880**								**43,592,590**	**11,077,290**					**9,192,158**	**7,039,226**	**2,152,932**

Pacific Gas & Electric Company
2003 Depreciation Rates

0.00% Interest Rate (4.72%, 5.00% or 6.00% present worth; 0% =straight line)
90% Depreciation Cap

FERC Acct.	Description	Survivor Curve	ASL	Net Salvage %	Handy Whitman Region 6
352	Structures & Improvements	S6	48	-10%	33
353	Station Equipment	L3	42	0%	34
354	Towers & Fixtures	S2	65	-40%	35
355	Poles & Fixtures	R3	37	-50%	36
356	Overhead Conductors & Devices	L4	48	-31%	37
357	Underground Conduit	R3	60	0%	38
358	Underground Conductors & Devices	R3	45	0%	39
359	Roads & Trails	S0	27	0%	33
361	Structures & Improvements	L4	54	-9%	42
362	Station Equipment	L0	43	0%	43
364	Poles, Towers & Fixtures	L0	37	-35%	44
365	OH Conductors & Devices	R1	37	-49%	45
366	Underground Conduit	R3	63	10%	46
367	UG Conductor & Devices	S3	31	-19%	47
368.1	Transformers - Line	R0.5	32	8%	48
368.2	Transformers - Padmount	R0.5	32	8%	49
369.1	Services	R4	43	-45%	50
369.2	Services	R4	43	-45%	51
370	Meters	R2	32	0%	52
371	Installation on Cust. Premises	S1	36	0%	53
372	Leased Property on Cust. Premises	S1	16	75%	53
373	Street Lighting & Signal Systems	S1	24	-13%	53

SMUD Transmission & Distribution Annexation
Estimated RCNLD and OCLD Value of PG&E Facilities
5% Present Worth Depreciation

Description	RCN	RCNLD	OC	OCLD
Scenario 1 - Acquire West Sacramento Only				
Transmission Plant	$21,735,120	$10,662,986	$3,653,042	$1,830,864
Distribution System				
West Sacramento (includes Deepwater)	$44,517,560	$30,796,052	$29,849,152	$20,834,059
Total Plant Cost	**$66,252,680**	**$41,459,038**	**$33,502,194**	**$22,664,923**
Scenario 2 - Acquire West Sacramento and Davis				
Transmission Plant	$47,535,210	$18,571,358	$7,495,351	$3,025,803
Distribution System				
West Sacramento (includes Deepwater)	$44,517,560	$30,796,052	$29,849,152	$20,834,059
Davis	$54,809,357	$38,151,062	$37,442,292	$26,317,386
Davis (1107) - Not Acquired	(2,112,673)	(1,258,624)	(1,313,813)	(795,786)
Davis (Net)	$52,696,684	$36,892,438	$36,128,479	$25,521,600
Total Distribution System	$97,214,244	$67,688,490	$65,977,631	$46,355,659
Total Plant Cost	**$144,749,454**	**$86,259,847**	**$73,472,982**	**$49,381,462**
Scenario 3 - Acquire West Sacramento, Davis & Woodland				
Transmission Plant	$54,669,880	$22,410,261	$9,192,158	$4,059,032
Distribution System				
West Sacramento (includes Deepwater)	$44,517,560	$30,796,052	$29,849,152	$20,834,059
Davis	$54,809,357	$38,151,062	$37,442,292	$26,317,386
Davis (1107) - Not Acquired	(2,112,673)	(1,258,624)	(1,313,813)	(795,786)
Davis (Net)	$52,696,684	$36,892,438	$36,128,479	$25,521,600
Woodland	42,287,310	34,084,618	25,296,922	14,743,860
Total Distribution System	$139,501,554	$101,773,108	$91,274,553	$61,099,519
Total Plant Cost	**$194,171,434**	**$124,183,368**	**$100,466,711**	**$65,158,551**
Scenario 4 - Acquire All Areas				
Transmission Plant (same as Scenario 3)	$54,669,880	$22,410,261	$9,192,158	$4,059,032
Distribution System				
West Sacramento (includes Deepwater)	$44,517,560	$30,796,052	$29,849,152	$20,834,059
Davis	$54,809,357	$38,151,062	$37,442,292	$26,317,386
Davis (1107) - Not Acquired	(2,112,673)	(1,258,624)	(1,313,813)	(795,786)
Davis (Net)	$52,696,684	$36,892,438	$36,128,479	$25,521,600
Woodland	42,287,310	34,084,618	25,296,922	14,743,860
Plainfield	6,755,094	3,642,059	3,120,915	1,716,507
Total Distribution System	$146,256,648	$105,415,167	$94,395,468	$62,816,026
Total Plant Cost	**$200,926,528**	**$127,825,427**	**$103,587,626**	**$66,875,058**

Appendix D

INCOME APPROACH VALUATION ANALYSES

R·W·BECK

SMUD Annexation Study

Estimated Income Value
Direct Capitalization of Income Method

	West Sacramento	Davis	Woodland & Yolo
Load Served (MWh)	384,338	262,914	537,727
PG&E Average Distribution Rate (cents/kWh) [1]	2.5403	3.6594	2.9403
Retail Revenues	$9,763,472	$9,620,943	$15,810,691
Operating Expenses [2]	$8,298,951	$8,177,802	$13,439,088
Net Utility Operating Income	$1,464,521	$1,443,142	$2,371,604
Capitalization Rate [3]	8.77%	8.77%	8.77%
Estimated Income Value	$16,699,211	$16,455,434	$27,042,232

Notes:
1 PG&E average distribution rate calculated to reflect customer load characteristics of each area.
2 Operating expenses estimated as 85% of operating revenues based on data reported in PG&E's 1999-2004 FERC Form 1 Annual Reports. Operating expenses include depreciation and income taxes.
3 PG&E's weighted average cost of capital equals 8.77%, as approved in CPUC Decision 04-12-047, December 16, 2004.

SMUD Annexation Study

Estimated Income Value - DCF Method

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
West Sacramento												
Load Served (MWh)	384,338	393,870	403,401	412,922	422,460	432,008	444,176	457,037	471,239	486,339	502,424	519,375
PG&E Average Distribution Rate (cents/kWh) [1]	2.5403	2.6542	2.7355	2.7861	2.8304	2.8853	2.9455	3.0090	3.0758	3.1506	3.2258	3.3010
Retail Revenues	$9,763,472	$10,454,201	$11,034,863	$11,504,527	$11,957,485	$12,464,723	$13,083,333	$13,752,284	$14,494,213	$15,322,797	$16,207,381	$17,144,341
Operating Expenses [2]	8,298,951	8,886,071	9,379,634	9,778,848	10,163,862	10,595,015	11,120,833	11,689,441	12,320,081	13,024,377	13,776,274	14,572,690
Depreciation Expense	852,833	868,666	884,932	901,636	918,829	936,519	954,854	986,420	1,021,856	1,064,528	1,112,261	1,165,701
Capital Expenditures	1,407,000	1,437,954	1,469,589	1,503,390	1,537,967	1,578,237	2,059,686	2,226,658	2,515,375	2,735,205	2,982,648	3,213,057
Net Cash Flow	$910,354	$998,842	$1,070,572	$1,123,926	$1,174,484	$1,227,991	$857,667	$822,604	$680,613	$627,742	$560,721	$524,295
Discount Rate [3]	8.77%											
Discount Factor	1.0000	0.9194	0.8452	0.7771	0.7144	0.6568	0.6039	0.5552	0.5104	0.4693	0.4314	0.3966
Discounted Annual Cash Flows	$910,354	$918,307	$904,894	$873,394	$839,094	$806,584	$517,922	$456,696	$347,398	$294,577	$241,911	$207,958
Net Present Value of 2004-2027 Cash Flow	$10,739,515											
Terminal Value	$5,587,432											
Estimated Income Value	$16,326,947											
Davis												
Load Served (MWh)	262,914	267,620	272,437	277,177	281,779	286,287	289,923	293,160	295,962	298,480	300,754	302,852
PG&E Average Distribution Rate (cents/kWh) 1	3.6594	3.8109	3.9308	4.0124	4.0805	4.1580	4.2420	4.3293	4.4251	4.5290	4.6359	4.7434
Retail Revenues	$9,620,943	$10,198,753	$10,708,967	$11,121,556	$11,497,967	$11,903,918	$12,298,467	$12,691,775	$13,096,530	$13,518,019	$13,942,550	$14,365,529
Operating Expenses [2]	8,177,802	8,668,940	9,102,622	9,453,323	9,773,272	10,118,330	10,453,697	10,788,008	11,132,051	11,490,316	11,851,167	12,210,700
Depreciation Expense	1,032,242	1,058,807	1,085,846	1,114,715	1,143,130	1,170,339	1,196,960	1,212,374	1,222,962	1,228,015	1,229,742	1,228,608
Capital Expenditures	1,962,000	2,005,164	2,096,279	2,109,233	2,095,440	2,102,077	1,736,463	1,582,932	1,399,829	1,288,455	1,190,046	1,121,103
Net Cash Flow	$513,384	$583,456	$595,911	$673,715	$772,385	$853,849	$1,305,267	$1,533,208	$1,787,612	$1,967,263	$2,131,078	$2,262,334
Discount Rate [3]	8.77%											
Discount Factor	1.0000	0.9194	0.8452	0.7771	0.7144	0.6568	0.6039	0.5552	0.5104	0.4693	0.4314	0.3966
Discounted Annual Cash Flows	$513,384	$536,412	$503,690	$523,539	$551,820	$560,836	$788,215	$851,211	$912,431	$923,167	$919,408	$897,339
Net Present Value of 2004-2027 Cash Flow	$16,692,279											
Terminal Value	$6,297,249											
Estimated Income Value	$22,989,528											
Woodland + Yolo												
Load Served (MWh)	537,727	547,925	557,264	566,551	575,706	584,790	594,154	603,486	612,971	622,568	632,304	642,177
PG&E Average Distribution Rate (cents/kWh) [1]	2.9403	3.0676	3.1630	3.2249	3.2773	3.3404	3.4090	3.4808	3.5577	3.6431	3.7296	3.8162
Retail Revenues	$15,810,691	$16,808,295	$17,626,420	$18,270,843	$18,867,804	$19,534,230	$20,254,607	$21,006,087	$21,807,869	$22,680,497	$23,582,193	$24,507,066
Operating Expenses [2]	13,439,088	14,287,050	14,982,457	15,530,216	16,037,634	16,604,096	17,216,416	17,855,174	18,536,688	19,278,423	20,044,864	20,831,006
Depreciation Expense	811,938	829,883	848,220	868,032	887,559	906,142	924,386	944,935	965,877	988,146	1,011,452	1,036,030
Capital Expenditures	1,440,000	1,471,680	1,541,658	1,551,472	1,537,967	1,544,657	1,643,623	1,677,908	1,745,289	1,803,837	1,871,687	1,937,851
Net Cash Flow	$1,743,542	$1,879,447	$1,950,524	$2,057,186	$2,179,762	$2,291,620	$2,318,954	$2,417,940	$2,491,769	$2,586,384	$2,677,094	$2,774,239
Discount Rate [3]	8.77%											
Discount Factor	1.0000	0.9194	0.8452	0.7771	0.7144	0.6568	0.6039	0.5552	0.5104	0.4693	0.4314	0.3966
Discounted Annual Cash Flows	$1,743,542	$1,727,909	$1,648,668	$1,598,624	$1,557,301	$1,505,209	$1,400,352	$1,342,399	$1,271,847	$1,213,699	$1,154,974	$1,100,382
Net Present Value of 2004-2027 Cash Flow	$26,844,317											
Terminal Value	$12,472,472											
Estimated Income Value	$39,316,789											

Notes:

1 PG&E average distribution rate calculated to reflect customer load characteristics of each area.

2 Operating expenses estimated as 85% of operating revenues based on data reported in PG&E's 1999-2003 FERC Form 1 Annual Report. Operating expenses include depreciation and income taxes.

3 PG&E's weighted average cost of capital equals 8.77%, as approved in CPUC Decision 04-12-047, December 16, 2004.

SMUD Annexation Study

Estimated Income Value - DCF Method

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
West Sacramento												
Load Served (MWh)	535,008	551,112	567,700	584,788	602,390	620,101	638,331	656,205	674,578	693,467	712,884	732,844
PG&E Average Distribution Rate (cents/kWh) [1]	3.3788	3.4537	3.5329	3.6095	3.6909	3.7748	3.8613	3.9494	4.0365	4.1302	4.2194	4.3188
Retail Revenues	$18,076,679	$19,033,924	$20,056,452	$21,108,212	$22,233,379	$23,407,278	$24,647,868	$25,916,255	$27,229,354	$28,641,235	$30,079,232	$31,650,039
Operating Expenses [2]	15,365,177	16,178,835	17,047,984	17,941,981	18,898,372	19,896,187	20,950,688	22,028,816	23,144,951	24,345,050	25,567,348	26,902,533
Depreciation Expense	1,224,197	1,275,813	1,330,712	1,388,853	1,450,558	1,515,916	1,582,620	1,653,175	1,722,132	1,795,034	1,872,253	1,953,897
Capital Expenditures	3,030,780	3,197,252	3,365,654	3,548,550	3,738,079	3,850,549	4,052,045	4,066,681	4,273,675	4,497,712	4,729,794	4,970,173
Net Cash Flow	$904,919	$933,650	$973,525	$1,006,535	$1,047,486	$1,176,459	$1,227,755	$1,473,932	$1,532,860	$1,593,506	$1,654,343	$1,731,230
Discount Rate [3]												
Discount Factor	0.3647	0.3353	0.3082	0.2834	0.2605	0.2395	0.2202	0.2025	0.1861	0.1711	0.1573	0.1446
Discounted Annual Cash Flows	$329,989	$313,015	$300,068	$285,228	$272,899	$281,787	$270,363	$298,404	$285,312	$272,686	$260,270	$250,406
Net Present Value of 2004-2027 Cash Flow												
Terminal Value												
Estimated Income Value												
Davis												
Load Served (MWh)	304,215	305,584	306,959	308,341	309,728	311,060	312,398	313,741	315,090	316,445	317,806	319,172
PG&E Average Distribution Rate (cents/kWh) 1	4.8544	4.9633	5.0772	5.1894	5.3070	5.4281	5.5526	5.6797	5.8065	5.9409	6.0718	6.2138
Retail Revenues	$14,767,814	$15,167,061	$15,584,995	$16,000,895	$16,437,283	$16,884,555	$17,346,303	$17,819,407	$18,295,813	$18,799,675	$19,296,421	$19,832,697
Operating Expenses [2]	12,552,642	12,892,002	13,247,246	13,600,761	13,971,691	14,351,872	14,744,357	15,146,496	15,551,441	15,979,724	16,401,957	16,857,792
Depreciation Expense	1,225,536	1,211,803	1,199,067	1,187,317	1,176,540	1,166,727	1,156,732	1,147,689	1,139,589	1,132,288	1,125,914	1,120,461
Capital Expenditures	744,886	766,050	787,794	810,133	833,082	816,917	840,223	864,170	884,046	909,215	935,074	961,642
Net Cash Flow	$2,695,822	$2,720,812	$2,749,023	$2,777,318	$2,809,050	$2,882,493	$2,918,454	$2,956,431	$2,999,915	$3,043,024	$3,085,303	$3,133,724
Discount Rate [3]												
Discount Factor	0.3647	0.3353	0.3082	0.2834	0.2605	0.2395	0.2202	0.2025	0.1861	0.1711	0.1573	0.1446
Discounted Annual Cash Flows	$983,064	$912,179	$847,326	$787,025	$731,835	$690,420	$642,671	$598,541	$558,376	$520,731	$485,397	$453,263
Net Present Value of 2004-2027 Cash Flow												
Terminal Value												
Estimated Income Value												
Woodland + Yolo												
Load Served (MWh)	653,740	665,520	677,519	689,742	702,194	711,969	721,881	730,425	739,070	747,818	756,670	765,627
PG&E Average Distribution Rate (cents/kWh) [1]	3.9057	3.9927	4.0841	4.1732	4.2673	4.3645	4.4645	4.5666	4.6679	4.7761	4.8802	4.9949
Retail Revenues	$25,533,457	$26,571,988	$27,670,490	$28,784,418	$29,964,807	$31,073,576	$32,228,702	$33,355,428	$34,499,040	$35,716,661	$36,927,292	$38,242,309
Operating Expenses [2]	21,703,439	22,586,190	23,519,917	24,466,756	25,470,086	26,412,540	27,394,396	28,352,114	29,324,184	30,359,161	31,388,198	32,505,963
Depreciation Expense	1,061,796	1,106,004	1,152,276	1,200,667	1,251,233	1,304,033	1,330,110	1,357,802	1,373,670	1,390,882	1,409,592	1,429,819
Capital Expenditures	2,609,072	2,725,526	2,845,957	2,970,487	3,099,239	2,216,715	2,299,321	1,913,189	1,976,102	2,045,734	2,117,523	2,191,532
Net Cash Flow	$2,282,743	$2,366,276	$2,456,892	$2,547,843	$2,646,716	$3,748,355	$3,865,094	$4,447,927	$4,572,424	$4,702,648	$4,831,163	$4,974,633
Discount Rate [3]												
Discount Factor	0.3647	0.3353	0.3082	0.2834	0.2605	0.2395	0.2202	0.2025	0.1861	0.1711	0.1573	0.1446
Discounted Annual Cash Flows	$832,430	$793,317	$757,283	$721,998	$689,543	$897,812	$851,130	$900,501	$851,067	$804,731	$760,065	$719,534
Net Present Value of 2004-2027 Cash Flow												
Terminal Value												
Estimated Income Value												

Notes:

1 PG&E average distribution rate calculated to reflect customer lc

2 Operating expenses estimated as 85% of operating revenues b

3 PG&E's weighted average cost of capital equals 8.77%, as app

SMUD Annexation Study
Estimated Income Value - DCF Method

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
CUSTOMERS												
West Sacramento	18,917	19,386	19,856	20,324	20,794	21,264	21,862	22,496	23,195	23,938	24,729	25,564
Growth		2.48%	2.42%	2.36%	2.31%	2.26%	2.82%	2.90%	3.11%	3.20%	3.31%	3.37%
Change in Customers	469	469	469	469	469	470	599	633	699	743	792	834
Capital Expenditures	1,407,000	1,437,954	1,469,589	1,503,390	1,537,967	1,578,237	2,059,686	2,226,658	2,515,375	2,735,205	2,982,648	3,213,057
Davis	36,514	37,167	37,836	38,495	39,134	39,760	40,265	40,714	41,103	41,453	41,769	42,060
Growth		1.79%	1.80%	1.74%	1.66%	1.60%	1.27%	1.12%	0.96%	0.85%	0.76%	0.70%
Change in Customers	654	654	669	658	639	626	505	450	389	350	316	291
Capital Expenditures	1,962,000	2,005,164	2,096,279	2,109,233	2,095,440	2,102,077	1,736,463	1,582,932	1,399,829	1,288,455	1,190,046	1,121,103
Woodland+Yolo	26,826	27,306	27,798	28,281	28,751	29,211	29,689	30,166	30,651	31,140	31,637	32,140
Growth		1.79%	1.80%	1.74%	1.66%	1.60%	1.64%	1.61%	1.61%	1.60%	1.60%	1.59%
Change in Customers	480	480	492	484	469	460	478	477	485	490	497	503
Capital Expenditures	1,440,000	1,471,680	1,541,658	1,551,472	1,537,967	1,544,657	1,643,623	1,677,908	1,745,289	1,803,837	1,871,687	1,937,851
PLANT BALANCES												
West Sacramento												
BOY Plant	29,849,152	30,403,319	30,972,607	31,557,264	32,159,018	32,778,156	33,419,874	34,524,707	35,764,945	37,258,464	38,929,142	40,799,528
Additions	1,407,000	1,437,954	1,469,589	1,503,390	1,537,967	1,578,237	2,059,686	2,226,658	2,515,375	2,735,205	2,982,648	3,213,057
Retirements	(852,833)	(868,666)	(884,932)	(901,636)	(918,829)	(936,519)	(954,854)	(986,420)	(1,021,856)	(1,064,528)	(1,112,261)	(1,165,701)
EOY Plant	30,403,319	30,972,607	31,557,264	32,159,018	32,778,156	33,419,874	34,524,707	35,764,945	37,258,464	38,929,142	40,799,528	42,846,884
Depreciation Expense	852,833	868,666	884,932	901,636	918,829	936,519	954,854	986,420	1,021,856	1,064,528	1,112,261	1,165,701
Davis												
BOY Plant	36,128,479	37,058,237	38,004,594	39,015,028	40,009,546	40,961,856	41,893,594	42,433,097	42,803,656	42,980,523	43,040,963	43,001,268
Additions	1,962,000	2,005,164	2,096,279	2,109,233	2,095,440	2,102,077	1,736,463	1,582,932	1,399,829	1,288,455	1,190,046	1,121,103
Retirements	(1,032,242)	(1,058,807)	(1,085,846)	(1,114,715)	(1,143,130)	(1,170,339)	(1,196,960)	(1,212,374)	(1,222,962)	(1,228,015)	(1,229,742)	(1,228,608)
EOY Plant	37,058,237	38,004,594	39,015,028	40,009,546	40,961,856	41,893,594	42,433,097	42,803,656	42,980,523	43,040,963	43,001,268	42,893,763
Depreciation Expense	1,032,242	1,058,807	1,085,846	1,114,715	1,143,130	1,170,339	1,196,960	1,212,374	1,222,962	1,228,015	1,229,742	1,228,608
Woodland + Yolo												
BOY Plant	28,417,837	29,045,899	29,687,696	30,381,134	31,064,574	31,714,983	32,353,497	33,072,734	33,805,708	34,585,119	35,400,809	36,261,044
Additions	1,440,000	1,471,680	1,541,658	1,551,472	1,537,967	1,544,657	1,643,623	1,677,908	1,745,289	1,803,837	1,871,687	1,937,851
Retirements	(811,938)	(829,883)	(848,220)	(868,032)	(887,559)	(906,142)	(924,386)	(944,935)	(965,877)	(988,146)	(1,011,452)	(1,036,030)
EOY Plant	29,045,899	29,687,696	30,381,134	31,064,574	31,714,983	32,353,497	33,072,734	33,805,708	34,585,119	35,400,809	36,261,044	37,162,865
Depreciation Expense	811,938	829,883	848,220	868,032	887,559	906,142	924,386	944,935	965,877	988,146	1,011,452	1,036,030

From RCNLD/OCLD Analysis (distribution only)	**RCN**	**OC**
West Sacramento	44,517,560	29,849,152
Davis	52,696,684	36,128,479
Woodland + Yolo	49,042,404	28,417,837

Capital Expenditures per Additional Customer		
	3,000	West Sac
	3,000	Davis
	3,000	Woodland + Yolo

SMUD Annexation Study
Estimated Income Value - DCF Method

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
CUSTOMERS												
West Sacramento	26,333	27,126	27,942	28,783	29,650	30,522	31,419	32,299	33,203	34,133	35,088	36,071
Growth	3.01%	3.01%	3.01%	3.01%	3.01%	2.94%	2.94%	2.80%	2.80%	2.80%	2.80%	2.80%
Change in Customers	769	793	816	841	866	872	897	880	904	930	956	982
Capital Expenditures	3,030,780	3,197,252	3,365,654	3,548,550	3,738,079	3,850,549	4,052,045	4,066,681	4,273,675	4,497,712	4,729,794	4,970,173
Davis	42,250	42,440	42,631	42,822	43,015	43,200	43,386	43,572	43,760	43,948	44,137	44,327
Growth	0.45%	0.45%	0.45%	0.45%	0.45%	0.43%	0.43%	0.43%	0.43%	0.43%	0.43%	0.43%
Change in Customers	189	190	191	192	193	185	186	187	187	188	189	190
Capital Expenditures	744,886	766,050	787,794	810,133	833,082	816,917	840,223	864,170	884,046	909,215	935,074	961,642
Woodland+Yolo	32,802	33,478	34,168	34,872	35,590	36,092	36,601	37,014	37,432	37,855	38,283	38,716
Growth	2.06%	2.06%	2.06%	2.06%	2.06%	1.41%	1.41%	1.13%	1.13%	1.13%	1.13%	1.13%
Change in Customers	662	676	690	704	718	502	509	414	418	423	428	433
Capital Expenditures	2,609,072	2,725,526	2,845,957	2,970,487	3,099,239	2,216,715	2,299,321	1,913,189	1,976,102	2,045,734	2,117,523	2,191,532
PLANT BALANCES												
West Sacramento												
BOY Plant	42,846,884	44,653,467	46,574,906	48,609,848	50,769,545	53,057,066	55,391,699	57,861,124	60,274,630	62,826,173	65,528,852	68,386,394
Additions	3,030,780	3,197,252	3,365,654	3,548,550	3,738,079	3,850,549	4,052,045	4,066,681	4,273,675	4,497,712	4,729,794	4,970,173
Retirements	(1,224,197)	(1,275,813)	(1,330,712)	(1,388,853)	(1,450,558)	(1,515,916)	(1,582,620)	(1,653,175)	(1,722,132)	(1,795,034)	(1,872,253)	(1,953,897)
EOY Plant	44,653,467	46,574,906	48,609,848	50,769,545	53,057,066	55,391,699	57,861,124	60,274,630	62,826,173	65,528,852	68,386,394	71,402,669
Depreciation Expense	1,224,197	1,275,813	1,330,712	1,388,853	1,450,558	1,515,916	1,582,620	1,653,175	1,722,132	1,795,034	1,872,253	1,953,897
Davis												
BOY Plant	42,893,763	42,413,113	41,967,360	41,556,086	41,178,902	40,835,444	40,485,634	40,169,125	39,885,606	39,630,063	39,406,990	39,216,151
Additions	744,886	766,050	787,794	810,133	833,082	816,917	840,223	864,170	884,046	909,215	935,074	961,642
Retirements	(1,225,536)	(1,211,803)	(1,199,067)	(1,187,317)	(1,176,540)	(1,166,727)	(1,156,732)	(1,147,689)	(1,139,589)	(1,132,288)	(1,125,914)	(1,120,461)
EOY Plant	42,413,113	41,967,360	41,556,086	41,178,902	40,835,444	40,485,634	40,169,125	39,885,606	39,630,063	39,406,990	39,216,151	39,057,332
Depreciation Expense	1,225,536	1,211,803	1,199,067	1,187,317	1,176,540	1,166,727	1,156,732	1,147,689	1,139,589	1,132,288	1,125,914	1,120,461
Woodland + Yolo												
BOY Plant	37,162,865	38,710,141	40,329,663	42,023,344	43,793,164	45,641,169	46,553,851	47,523,062	48,078,449	48,680,881	49,335,733	50,043,663
Additions	2,609,072	2,725,526	2,845,957	2,970,487	3,099,239	2,216,715	2,299,321	1,913,189	1,976,102	2,045,734	2,117,523	2,191,532
Retirements	(1,061,796)	(1,106,004)	(1,152,276)	(1,200,667)	(1,251,233)	(1,304,033)	(1,330,110)	(1,357,802)	(1,373,670)	(1,390,882)	(1,409,592)	(1,429,819)
EOY Plant	38,710,141	40,329,663	42,023,344	43,793,164	45,641,169	46,553,851	47,523,062	48,078,449	48,680,881	49,335,733	50,043,663	50,805,377
Depreciation Expense	1,061,796	1,106,004	1,152,276	1,200,667	1,251,233	1,304,033	1,330,110	1,357,802	1,373,670	1,390,882	1,409,592	1,429,819

From RCNLD/OCLD Analysis (distribution only)
West Sacramento
Davis
Woodland + Yolo

Capital Expenditures per Additional Customer

Calculation of Average Distribution Rate

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
PG&E (cents/kWh)														
Residential	4.0017	4.1426	4.2835	4.3868	4.4714	4.5559	4.6405	4.7250	4.8283	4.9317	5.0451	5.1611	5.2798	5.4013
Commercial														
Small	4.2852	4.4359	4.5932	4.6980	4.7897	4.8815	4.9666	5.0649	5.1698	5.2746	5.3959	5.5200	5.6470	5.7769
Medium	1.8530	1.9245	1.9889	2.0319	2.0748	2.1106	2.1535	2.1964	2.2393	2.2823	2.3348	2.3885	2.4434	2.4996
Large	0.8452	0.8771	0.9090	0.9249	0.9409	0.9648	0.9808	0.9967	1.0206	1.0445	1.0686	1.0931	1.1183	1.1440
Agriculture	2.7678	2.8634	2.9641	3.0345	3.0899	3.1503	3.2106	3.2710	3.3365	3.4069	3.4853	3.5654	3.6474	3.7313
Other	7.2919	7.4523	7.6163	7.7914	7.9707	8.1619	8.3578	8.5501	8.7467	8.9479	9.1537	9.3642	9.5796	9.7999
West Sac Load (MWh)														
Residential	92,163	94,448	96,734	99,017	101,304	103,594	106,511	109,596	113,001	116,622	120,479	124,544	128,293	132,154
Commercial														
Small	45,691	46,824	47,957	49,089	50,223	51,358	52,805	54,334	56,022	57,817	59,729	61,744	63,603	65,517
Medium	141,243	144,746	148,249	151,747	155,253	158,762	163,233	167,960	173,179	178,728	184,639	190,869	196,614	202,532
Large	98,470	100,912	103,354	105,793	108,237	110,683	113,800	117,096	120,734	124,603	128,724	133,067	137,072	141,198
Agricultural	4,646	4,761	4,876	4,991	5,107	5,222	5,369	5,525	5,696	5,879	6,073	6,278	6,467	6,662
Other	2,126	2,179	2,232	2,284	2,337	2,390	2,457	2,528	2,607	2,690	2,779	2,873	2,960	3,049
Total Load	384,338	393,870	403,401	412,922	422,460	432,008	444,176	457,037	471,239	486,339	502,424	519,375	535,008	551,112
Planning Reserves	0.1	0.1257	0.1205	0.1122	0.1038	0.1065	0.1146	0.1245	0.1302	0.1440	0.1500	0.1544	0.1598	0.1608
PG&E System Average - West Sac.	2.5403	2.6542	2.7355	2.7861	2.8304	2.8853	2.9455	3.0090	3.0758	3.1506	3.2258	3.3010	3.3788	3.4537
Davis Load (MWh)														
Residential	163,469	166,395	169,390	172,337	175,198	178,001	180,262	182,275	184,017	185,582	186,996	188,301	189,148	189,999
Commercial														
Small	34,013	34,622	35,245	35,858	36,453	37,036	37,507	37,926	38,288	38,614	38,908	39,179	39,356	39,533
Medium	61,495	62,595	63,722	64,831	65,907	66,962	67,812	68,569	69,224	69,813	70,345	70,836	71,155	71,475
Large	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Agricultural	1,495	1,522	1,549	1,576	1,602	1,628	1,649	1,667	1,683	1,697	1,710	1,722	1,730	1,738
Other	2,443	2,486	2,531	2,575	2,618	2,660	2,694	2,724	2,750	2,773	2,794	2,814	2,826	2,839
Total Load	262,914	267,620	272,437	277,177	281,779	286,287	289,923	293,160	295,962	298,480	300,754	302,852	304,215	305,584
Planning Reserves	0.1	0.1257	0.1205	0.1122	0.1038	0.1065	0.1146	0.1245	0.1302	0.1440	0.1500	0.1544	0.1598	0.1608
PG&E System Average - Davis	3.6594	3.8109	3.9308	4.0124	4.0805	4.1580	4.2420	4.3293	4.4251	4.5290	4.6359	4.7434	4.8544	4.9633
Woodland+ Yolo Load (MWh)														
Residential	196,360	200,068	203,493	206,896	210,247	213,568	216,994	220,408	223,879	227,390	230,951	234,563	238,836	243,189
Woodland	130,036	132,363	134,746	137,090	139,366	141,596	143,913	146,224	148,574	150,948	153,356	155,795	159,005	162,280
Yolo	66,325	67,704	68,747	69,806	70,881	71,972	73,081	74,184	75,304	76,442	77,596	78,767	79,831	80,909
Commercial														
Small	62,207	63,379	64,466	65,546	66,608	67,661	68,747	69,829	70,930	72,043	73,172	74,317	75,676	77,061
Medium	154,190	157,106	159,791	162,460	165,089	167,696	170,384	173,063	175,786	178,541	181,336	184,170	187,511	190,914
Large	86,828	88,443	89,979	91,501	92,993	94,468	95,992	97,511	99,055	100,617	102,201	103,807	105,767	107,765
Agricultural	35,869	36,615	37,179	37,752	38,334	38,924	39,524	40,121	40,726	41,342	41,966	42,600	43,176	43,760
Other	2,273	2,314	2,355	2,396	2,435	2,474	2,514	2,554	2,595	2,636	2,678	2,721	2,775	2,830
Total Load	537,727	547,925	557,264	566,551	575,706	584,790	594,154	603,486	612,971	622,568	632,304	642,177	653,740	665,520
Planning Reserves	0.1	0.1257	0.1205	0.1122	0.1038	0.1065	0.1146	0.1245	0.1302	0.1440	0.1500	0.1544	0.1598	0.1608
PG&E System Average - Woodland &Yolo	2.9403	3.0676	3.1630	3.2249	3.2773	3.3404	3.4090	3.4808	3.5577	3.6431	3.7296	3.8162	3.9057	3.9927

Calculation of Average Distribution Rate

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
PG&E (cents/kWh)										
Residential	5.5255	5.6526	5.7826	5.9156	6.0517	6.1909	6.3332	6.4789	6.6279	6.7804
Commercial										
Small	5.9097	6.0457	6.1847	6.3269	6.4725	6.6213	6.7736	6.9294	7.0888	7.2518
Medium	2.5571	2.6159	2.6761	2.7376	2.8006	2.8650	2.9309	2.9983	3.0672	3.1378
Large	1.1703	1.1972	1.2248	1.2529	1.2818	1.3112	1.3414	1.3722	1.4038	1.4361
Agriculture	3.8171	3.9049	3.9948	4.0866	4.1806	4.2768	4.3751	4.4758	4.5787	4.6840
Other	10.0253	10.2559	10.4918	10.7331	10.9800	11.2325	11.4909	11.7552	12.0255	12.3021
West Sac Load (MWh)										
Residential	136,132	140,230	144,450	148,697	153,069	157,355	161,761	166,290	170,946	175,733
Commercial										
Small	67,489	69,521	71,613	73,719	75,886	78,011	80,195	82,441	84,749	87,122
Medium	208,628	214,908	221,377	227,885	234,585	241,153	247,906	254,847	261,983	269,318
Large	145,448	149,826	154,336	158,873	163,544	168,123	172,831	177,670	182,645	187,759
Agricultural	6,862	7,069	7,282	7,496	7,716	7,932	8,154	8,383	8,617	8,858
Other	3,140	3,235	3,332	3,430	3,531	3,630	3,732	3,836	3,944	4,054
Total Load	567,700	584,788	602,390	620,101	638,331	656,205	674,578	693,467	712,884	732,844
Planning Reserves	0.1642	0.1634	0.1654	0.1682	0.1718	0.1751	0.1753	0.1802	0.1786	0.1850
PG&E System Average - West Sac.	3.5329	3.6095	3.6909	3.7748	3.8613	3.9494	4.0365	4.1302	4.2194	4.3188
Davis Load (MWh)										
Residential	190,854	191,713	192,576	193,404	194,236	195,071	195,910	196,752	197,598	198,448
Commercial										
Small	39,711	39,889	40,069	40,241	40,414	40,588	40,763	40,938	41,114	41,291
Medium	71,797	72,120	72,444	72,756	73,069	73,383	73,698	74,015	74,334	74,653
Large	-	-	-	-	-	-	-	-	-	-
Agricultural	1,745	1,753	1,761	1,769	1,776	1,784	1,792	1,799	1,807	1,815
Other	2,852	2,865	2,878	2,890	2,902	2,915	2,927	2,940	2,953	2,965
Total Load	306,959	308,341	309,728	311,060	312,398	313,741	315,090	316,445	317,806	319,172
Planning Reserves	0.1642	0.1634	0.1654	0.1682	0.1718	0.1751	0.1753	0.1802	0.1786	0.1850
PG&E System Average - Davis	5.0772	5.1894	5.3070	5.4281	5.5526	5.6797	5.8065	5.9409	6.0718	6.2138
Woodland+ Yolo Load (MWh)										
Residential	247,624	252,143	256,747	260,325	263,953	267,065	270,215	273,401	276,626	279,888
Woodland	165,623	169,035	172,517	174,950	177,417	179,421	181,449	183,499	185,573	187,670
Yolo	82,001	83,108	84,230	85,375	86,536	87,644	88,766	89,902	91,053	92,218
Commercial										
Small	78,473	79,911	81,377	82,511	83,661	84,646	85,643	86,652	87,672	88,705
Medium	194,381	197,913	201,512	204,319	207,165	209,611	212,087	214,591	217,125	219,690
Large	109,802	111,879	113,996	115,590	117,206	118,572	119,953	121,351	122,766	124,196
Agricultural	44,352	44,952	45,560	46,180	46,808	47,407	48,013	48,628	49,250	49,880
Other	2,886	2,944	3,002	3,045	3,087	3,123	3,159	3,195	3,231	3,268
Total Load	677,519	689,742	702,194	711,969	721,881	730,425	739,070	747,818	756,670	765,627
Planning Reserves	0.1642	0.1634	0.1654	0.1682	0.1718	0.1751	0.1753	0.1802	0.1786	0.1850
PG&E System Average - Woodland &Yolo	4.0841	4.1732	4.2673	4.3645	4.4645	4.5666	4.6679	4.7761	4.8802	4.9949