APPENDIX A

SUMMARY OF PARTIES' PROPOSED DIRECT ACCESS COST RESPONSIBILITY SURCHARGE ELEMENTS

Party		Amortization of Historic DWR Unercollection			Prospective DWR Costs	CTC Component				Cap
		Historic Undercollection Only		Full Bond Charge		QF/PPAs	URG	Employee Transition Costs	Total CTC Component	
		Cents/kWh		Cents/kWh	Cents/kWh	Cents/kWh	Cents/kWh	Cents/kWh	Cents/kWh	Cents/kWh
		10-Year	20-Year							
Edison		N/A	.56 - .68	Applicable	3.161	N/A	N/A	0.01	0.01	3
CLECA Henwood Base Case (Total Utility Resource Basis By Individual Utility)		N/A	0.36	N/A	3.161	N/A	N/A	N/A	N/A	2.25
CIU	Pay As You Go	N/A	0.313	N/A	2.615	N/A	N/A	Applicable	0	2.5
ORA		N/A	0.533	Applicable	4.252	1.1699	0.3091	N/A	1.479	4
CMTA		N/A	0.285	N/A	0.93	1.3019	-0.4027	N/A	0.8992	2

Summary Of PG&E's 2003 Proposed Charge Components											
Party		Amortization of Historic DWR Unercollection				Prospective DWR Costs	CTC Component				Cap
		Historic Undercollection Only			Full Bond Charge		QF/PPAs	URG	Employee Transition Costs	Total CTC Component	
		Cents/kWh			Cents/kWh	Cents/kWh	Cents/kWh	Cents/kWh	Cents/kWh	Cents/kWh	Cents/kWh
		2003	10-Year	20-Year							
PG&E		0.473	N/A	N/A	Applicable	3.277	0.5178	0	0.0012	0.519	4
CLECA Henwood Base Case (Total Utility Resource Basis By Individual Utility)		N/A	N/A	0.36	N/A	0.812	N/A	N/A	N/A	N/A	2
CIU	Pay As You Go	N/A	N/A	0.313	N/A	2.615	N/A	N/A	Applicable	0	2.5
ORA		N/A	N/A	0.577	Applicable	4.252	0.9604	N/A	0.0006	0.961	4
CMTA		N/A	N/A	0.285	N/A	0.93	0.5576	-0.514	N/A	0.436	2

Party		Amortization of Historic DWR Unercollection			Prospective DWR Costs	CTC Component				Cap
		Historic Undercollection Only		Full Bond Charge		QF/PPAs	URG	Employee Transition Costs	Total CTC Component	
		Cents/kWh		Cents/kWh	Cents/kWh	Cents/kWh	Cents/kWh	Cents/kWh	Cents/kWh	Cents/kWh
		10-Year	20-Year							
SDG&E		N/A	0.64	Applicable	1.26	N/A	N/A	N/A	0.68	2.7
CLECA Henwood Base Case (Total Utility Resource Basis By Individual Utility)		N/A	0.36	N/A	5.709	N/A	N/A	N/A	N/A	2.75
CIU	Pay As You Go	N/A	0.313	N/A	2.615	N/A	N/A	Applicable	0	2.5
ORA		N/A	0.533	Applicable	4.252	N/A	N/A	N/A	N/A	4
CMTA		N/A	0.285	N/A	0.93	0.4736	-0.0499	N/A	0.4236	2

(END OF APPENDIX A)

APPENDIX B

SUMMARY OF MODELING SCENARIOS PERFORMED BY NAVIGANT CONSULTING, INC.

Table 1 - Summary Descriptions of Scenarios and Results

Scenario	Description	Scenario Based On	DA Growth Rate (per year)	DA Load Shape (Table 4)	Incremental DA % (1)	Sales as % of Spot Price	Gas Price (2) (Table 3)	New Gener-ation Entry (Table 2)	Ongoing Operating and Portfolio Costs ($Million)	2003 Average Cost of Spot Purchases ($/MWh)	Revenue Shortfall ($Million)	20-Year Levelized CRS ($/MWh)
Base Case	Based on DWR ProSym Run 19H.	N/A	2%	System Average	2 / 13.1	50%	Base (2)	Base	3,972	40.41	1,043.80	19.98
1	Updated base case assumptions, many changes in URG, hydro, contracts, and load forecast. DWR ProSym Run 28.	N/A	0%	DA Specific	2 / 13.62	50%	Medium	Less than Base	4,959	36.53	1,092.90	26.26
2	High gas prices, low new generation additions and sales at market clearing price.	Base Case	0%	DA Specific	2 / 13.62	100%	High	Low	3,216	49.39	1,092.70	18.64
2A	Scenario 2 with off-system sales @ 50% of spot prices.	Base Case	0%	DA Specific	2 / 13.62	50%	High	Low	4,077	49.39	1,092.70	22.37
3	High gas prices and sales at market clearing price.	Base Case	0%	DA Specific	2 / 13.62	100%	High	Base	3,763	46.38	1,092.70	21.01
4	Low gas prices.	Base Case	0%	DA Specific	2 / 13.62	50%	Low	Base	5,053	35.15	1,092.70	26.59
4 (a)	Scenario 3 with low gas prices.	Base Case	0%	DA Specific	2 / 13.62	100%	Low	Base	4,371	35.15	1,092.70	23.64
5	Service area specific CRS.	Scenario 1	0%	DA Specific	PG&E 1.2/14.8	50%	Medium	Less than Base	PG&E 1,908	40.33	506	19.62
					SCE 1/11				SCE 2,438	35.68	379	30.53
					SDG&E 9.9/20.1				SDG&E 632	33.32	89	32.43
6	Bond charge component of fee removed.	Scenario 1	0%	DA Specific	2 / 13.62	50%	Medium	Less than Base	4,959	36.53	NA	21.52
7	Additional 3.71% of load exempt from CRS.	Scenario 1	0%	DA Specific	5.71 / 13.62	50%	Medium	Less than Base	3,757	36.53	744	28.63
8	Renegotiated DWR contracts.	Scenario 1	0%	DA Specific	2 / 13.62	50%	Medium	Less than Base	4,851	35.26	1,092.90	25.79
9	Scenario 8 with no DA customers exempt.	Scenario 8	0%	DA Specific	2 / 13.62 (4)	100%	Medium	Less than Base	4,302	35.26	1,092.90	18.44

(1) The first number is the DA % on July 1, the second is the DA % after September 2001.

(2) Base is slightly higher than medium through 2006, and lower thereafter.

(3) Table numbers refer to tables in the May 17 Cost Responsibility Paper.

(4) Costs are allocated to all DA customers.

(END OF APPENDIX B)

PACIFIC GAS & ELECTRIC COMPANY
TABLE 3-1

ILLUSTRATIVE ANNUAL CALCULATION OF DWR NBC FOR PG&E

	2003	2004	2005	2006	2007
July, 2001 DA Load (Pre-Migration to DA)					
COSTS ($000)					
Contract Purchases	1,773,852	1,907,979	1,648,625	1,536,284	1,556,485
Spot Purchases	361,573	463,663	407,740	465,599	558,792
Off-System Sales	(23,582)	(36,597)	(26,685)	(17,924)	(12,623)
Net Purchases	2,111,843	2,335,045	2,029,681	1,983,959	2,102,654
Non-Energy Fixed Costs	12,236	12,969	12,298	11,942	12,382
TOTAL COSTS	2,124,079	2,348,014	2,041,978	1,995,901	2,115,036
ENERGY (MWh 000s)					
Net Contract Energy Delivered	19,208	21,960	20,230	19,986	20,531
Spot Energy Delivered	10,188	12,847	11,173	12,335	13,951
Total Delivered Energy	29,395	34,807	31,403	32,322	34,482
DWR UNIT COST DELIVERED ENERGY ($/MWh)	$ 72.26	$ 67.46	$ 65.03	$ 61.75	$ 61.34
September 20, 2001 DA Load (Post-Migration to DA)					
COSTS ($000)	2003	2004	2005	2006	2007
Contract Purchases	1,649,128	1,720,430	1,535,865	1,423,753	1,440,686
Spot Purchases	136,646	256,809	160,255	202,327	270,537
Off-System Sales	(89,286)	(93,546)	(83,719)	(68,666)	(56,228)
Net Purchases	1,696,488	1,883,693	1,612,400	1,557,414	1,654,995
Non-Energy Fixed Costs	11,185	12,234	11,161	10,689	11,233
TOTAL COSTS	1,707,673	1,895,927	1,623,561	1,568,104	1,666,228
ENERGY (MWh 000s)					
Net Contract Energy Delivered	15,257	17,469	16,763	16,701	17,494
Spot Energy Delivered	3,593	6,793	4,094	5,076	6,442
Total Delivered Energy	18,851	24,262	20,858	21,778	23,936
DWR UNIT COST DELIVERED ENERGY ($/MWh)	$ 90.59	$ 78.14	$ 77.84	$ 72.01	$ 69.61
Cost Increase due to Departing Load					
Increase in Unit Cost to Bundled Customers ($/MWh)	$ 18.33	$ 10.68	$ 12.81	$ 10.25	$ 8.27
Annual DA Responsibility: Unit Cost * Bundled Load ($000)	345,543	259,228	267,285	223,321	198,066
ANNUAL DWR NBC	**$ 32.77**	**$ 24.58**	**$ 25.35**	**$ 21.18**	**$ 18.78**

NOTES:
Cost data from Navigant Scenario 8, dated May 17, 2002
Off-system sales revenue recovers 100% of MCP, and is calculated by doubling the sales revenue at 50% of MCP from Navigant's data
Non-energy fixed costs allocated to PG&E based on PG&E's share of DWR total delivered energy pre-migration to DA

(END OF APPENDIX C)

APPENDIX D

SDG&E PROPOSAL

Table 1

Direct Access Exit Fee Model

Summary of DA Cost Responsibility 2001-2010 (@September 30, 2002 Dollars)

1)	Ongoing DWR Contract Costs ($000)	2,379,021
2)	Up-Front Financing Costs ($000)	35,685
3)	Allowance for Uncollectibles ($000)[b]	9,516
4)	Operating Reserve ($000)	242,422
5)	Balance to be Financed ($000)	$ 2,666,644
6)	Annual Revenue Required before Op Reserve ($000)	$ 265,489
7)	Annual Revenue Required after Op Reserve Credit ($000)	$ 249,328

		2002	2003	2004	2005	2006
8)	DA Revenue Requirement ($000)	$ 249,328	$ 249,328	$ 249,328	$ 249,328	$ 249,328
9)	DA Annual Load - Fiscal Year (MWh 000s)[c]	22,685	20,261	20,261	20,261	20,261
10)	DA Rate ($/MWh)	$ 10.99	$ 12.31	$ 12.31	$ 12.31	$ 12.31
11)	Non-Levelized Exit Fee ($/kWh)	$ 0.02175	$ 0.02634	$ 0.02331	$ 0.02038	$ 0.01525
12)	**Levelized Exit Fee ($/kWh)**	$ 0.01220	$ 0.01220	$ 0.01220	$ 0.01220	$ 0.01220

Ongoing DWR Contract Cost Impacts

July 1, 2001 Cutoff

	COSTS ($000)	Oct-Dec 01	2002	2003	2004	2005
13)	Contract Purchases	$ 574,512	$ 3,434,342	$ 4,127,689	$ 4,362,414	$ 3,977,928
14)	Off-System Sales	(14,714)	(9,538)	(27,438)	(41,838)	(32,194)
15)	Net Purchases	$ 559,798	$ 3,424,804	$ 4,100,251	$ 4,320,576	$ 3,945,734
16)	Net Contract Energy Delivered (MWh 000)	5,286	35,979	44,904	50,446	49,056
17)	DWR UNIT COST DELIVERED ENERGY ($/MWh)	$ 105.90	$ 95.19	$ 91.31	$ 85.65	$ 80.43

September 20, 2001 Cutoff

	COSTS ($000)	Oct-Dec 01	2002	2003	2004	2005
18)	Contract Purchases	$ 574,512	$ 3,377,477	$ 4,096,389	$ 4,362,414	$ 3,977,928
19)	Off-System Sales	(12,063)	(71,706)	(115,626)	(126,110)	(119,678)
20)	Net Purchases	$ 562,449	$ 3,305,771	$ 3,980,763	$ 4,236,304	$ 3,858,250
21)	Net Contract Energy Delivered (MWh 000)	4,907	30,016	37,750	43,948	42,836
22)	DWR UNIT COST DELIVERED ENERGY ($/MWh)	$ 114.63	$ 110.14	$ 105.45	$ 96.39	$ 90.07

Cost Increase due to Departed Load

23)	Increase in Unit Contract Cost to Bundled Customers ($/MWh)	$ 8.73	$ 14.95	$ 14.14	$ 10.75	$ 9.64
24)	Annual DA Responsibility: Unit Cost * Delivered Contract Energy ($000)	$ 42,847	$ 448,653	$ 533,737	$ 472,233	$ 412,828
25)	Annual DA Responsibility @ September 30, 2002 ($000)	$ 44,839	$ 448,653	$ 505,960	$ 424,360	$ 351,670
26)	Total DA Responsibility @ September 30, 2002 ($000)	$ 2,379,021				

Assumptions

27)	Cost of Capital[m]	6.20%	6.20%	5.49%	5.49%	5.49%
28)	Loan Initiation Fee	1.50%				
29)	Operations Reserve Percentage	10%				
30)	Term of financing (years)[n]	15				

(END OF APPENDIX D)

Table 1

Year by Year Forward Exit Fee
On a Total Utility Resource Versus DWR Only Basis

All rates in $/MWh	/1 4Qtr 2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	/2 Levelized Exit Fee No Delay	/2 Levelized Exit Fee 2 year Delay
Henwood Base Case													
All IOUs Total Portfolio Basis	27.31	21.69	22.39	24.07	20.43	16.17	12.13	11.41	11.52	11.06	7.02	**13.52**	**14.25**
All IOUs DWR Only Basis	30.34	30.55	27.88	28.68	21.81	17.42	13.96	12.80	12.77	12.34	8.05	**16.03**	**16.90**
Henwood Base Case w/10% Inc MCP													
All IOUs Total Portfolio Basis	27.31	18.25	18.98	20.93	17.46	12.75	8.37	7.63	7.91	7.47	3.60	**10.79**	**11.37**
All IOUs DWR Only Basis	30.34	28.99	25.76	26.29	19.70	14.93	11.21	10.09	10.28	9.96	6.24	**14.24**	**15.02**

Notes:
/1 Using Data from Navigant
/2 Exit fees levelized over 15 years

Table 2

Year by Year Forward Exit Fee
On a Total Utility Resource Basis by Individual Utility

All rates in $/MWh	/1 4Qtr 2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	/2 Levelized Exit Fee No Delay	/2 Levelized Exit Fee 2 year Delay
Henwood Base Case													
PG&E	14.01	5.99	8.12	13.23	12.94	9.84	7.32	7.00	7.26	7.58	4.18	**7.12**	**7.51**
SCE	8.12	35.05	31.61	30.62	25.74	21.40	16.29	15.44	15.04	13.75	9.27	**18.17**	**19.17**
SDG&E	26.64	49.40	57.09	54.70	38.16	27.45	20.10	18.35	19.63	19.35	12.48	**23.15**	**24.42**
Henwood Base Case w/10% Inc MCP													
PG&E	14.01	3.34	5.32	10.78	10.48	7.02	4.15	3.79	4.12	4.42	1.02	**4.85**	**5.11**
SCE	8.12	30.68	27.69	27.10	22.54	17.65	12.11	11.21	11.08	9.77	5.53	**15.10**	**15.93**
SDG&E	26.64	46.51	52.57	49.73	34.27	22.89	15.28	13.61	15.05	14.80	8.72	**20.29**	**21.40**

Notes:

/1 Using Data from Navigant

/2 Exit fee levelized over 15 years for PG&E and SCE and over 20 years for SDG&E

(END OF APPENDIX E)

Appendix F
Preliminary Data Inputs and Computations to Determine Direct Access Cost Responsibility Surcharge

1. *Forecast URG cost and kWh:* Forecast each year for the following calendar year each utility's revenue requirement and projected kWh output for its URG resources including bilateral and QF contracts. Each utility should provide the Commission with an hour-by-hour projection of the cost and availability of each of their (URG) resources for the entire year.

2. *Forecast bundled and DA loads:* Forecast each year for the following calendar year hourly loads from each utility's bundled and post July 1, 2001 DA customers. The "DA-in" loads are defined as the total of the bundled and post July 1, 2001 DA customer loads. The "DA-out" loads are defined as only the total bundled customer loads.

3. *Use production cost model to project resource mix:* Using PROSYM or an equivalent production cost model, forecast the electric resource mix for PG&E, SCE, and SDG&E simultaneously for each hour of the following calendar year. This simulation should incorporate URG resources, DWR's long-term contracts, sales of DWR power off system for any hour at projected spot prices for that hour, and purchases of electricity under short-term (spot) arrangements.

4. *Determine annual net DWR costs for two distinct DA scenarios:* Using the production cost model developed for (3), develop two scenarios for each year, namely, DA-in scenario and the DA-out scenario. Each scenario should identify the total annual cost (for all three utilities combined) of DWR long-term contract power less revenue generated by off system sales of DWR power ("net DWR costs").[1]

5. *Determine the annual cost of spot purchases for the two scenarios:* Using the production cost model developed for (3), determine the total annual amount and cost of spot purchases for each utility under each scenario.

6. *Develop total portfolio cost by utility for DA-in scenario:* For each utility, determine its share of annual net DWR costs identified in (4) for the DA-in scenario by using Commission established allocation factors. To this amount, add the utility specific total annual cost of spot purchases also identified in (5) for the DA-in scenario and the utility-specific URG costs identified in (1). This is the utility specific DA-in total portfolio cost.

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[1] This includes other elements of the Commission-authorized DWR revenue requirement that are not recovered through Bond Charges.

7. *Develop total portfolio cost by utility for DA-out scenario:* For each utility, determine its share of annual net DWR costs identified in (4) for the DA-out scenario by using Commission established allocation factors. To this amount, add the utility specific total annual cost of spot purchases also identified in (5) for the DA-out scenario and the utility-specific URG costs identified in (1). This is the utility specific DA-out total portfolio cost.

8. *Determine the Direct Access Cost Responsibility Surcharge by utility:* For each utility, take the DA-in total portfolio cost and divide it by the total annual DA-in load. This is the DA-in average total portfolio cost. Then take the utility's DA-out total portfolio cost and divided it by the total annual DA-out load. This is the DA-out average total portfolio cost. Subtract the utility's DA-in average total portfolio cost from its DA-out average total portfolio cost and multiply this difference times its DA-out load. This is the total DA Cost Responsibility amount for the utility for that year. Divide the utility's DA CRS amount by the annual DA loads to produces the DA CRS on a cents/kWh basis.

9. *Determine the separate DA Cost Responsibility Surcharge for the two separate component: (1) DWR Power Charge (to be remitted to DWR) and (2) URG-related charge (to be retained by the utility).*
   Separately identify the kWh volumes in the total portfolio calculation attributable to DWR contract sources versus URG-related sources. Determine the separate DWR remittance rate for the DWR-portion of the DA CRS. Determine the separate URG portion based upon application of the Commission-designated market proxy to compute the above-market portion of URG applicable to the DA CRS.

(END OF APPENDIX F)